2014 ANNUAL REPORT

QUESTERRE ENERGY CORPORATION

2014

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.

IN CONJUNCTION WITH A SUPERMAJOR, IT IS AT THE LEADING EDGE OF COMMERCIALIZING A PROVEN PROCESS TO UNLOCK THE MASSIVE RESOURCE POTENTIAL OF OIL SHALE.

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

2014 was an eventful year for Questerre.

Our strategy was to lay the groundwork to monetize our Montney discovery through production and cash flow. In the current price environment, we are focusing on high-grading our assets. We have maintained a strong balance sheet to do this, preserving our options to monetize through partnerships/sales or, should prices improve, production/cash flow.

Success at Kakwa included the results from the 16-07 Well at Kakwa South. It validated our geological ideas for the acreage. Disappointing were the cost overruns on this well and our Kakwa North well where the completion has been delayed by mechanical issues. We were also successful on our joint venture acreage where we moved up the learning curve, drilling longer laterals and improving completion designs.

During the year, we saw Red Leaf and Total S.A. move towards commercializing the EcoShale process to produce oil from shale. The front end engineering and design was completed. Final permits were also issued and construction commenced last summer. Due to low oil prices, this will slow down in 2015. We continued work on appraising our own oil shale acreage at Pasquia Hills. We completed the first phase of the resource assessment which indicates an oil in place resource in excess of two billion barrels.[1]

Highlights

- Corporate proved plus probable reserves increased from 9.04 MMBoe to 13.88 MMBoe with an NPV-10% of $231.6 million
- Best estimate of economic contingent resources for the Company's Montney joint venture acreage is an additional 14.3 MMBoe with an NPV-10% of $149.6 million
- Delineation of operated Montney acreage underway with success at Kakwa South although Kakwa North completion delayed with mechanical failure
- Red Leaf and Total joint venture secured final permit and began construction of commercial scale capsule
- Cash flow from operations of $15.4 million with average daily production of 1,076 boe/d

Kakwa-Resthaven, Alberta

The strong condensate rates from our 2014 joint venture drilling program continue to exceed our expectations. Averaging between 150 to over 200 bbls/MMcf, they are in-line with rates reported by industry drilling immediately offsetting our wells. With Montney development in the immediate area moving to 8 to 10 wells per pad, we are increasingly confident that our acreage lies in one of the better sweet spots of this over-pressured fairway.

Though the condensate rates have been higher than originally expected and stable over the life of the wells to date, they are challenging from an operating perspective. These high liquids volumes are loading up in the wellbore, resulting in uptime for some of the older wells of less than 45%. Anecdotally we have learnt that one of the larger operators in the area has implemented gas lift to address this issue with reported uptimes of over 65%. Once optimized in a stable operating environment, we estimate average uptime should be approximately 85%. The operator continues to evaluate gas lift and other production facilities to materially enhance this uptime and our economics.

We continue to see improvements on the drilling learning curve. We drilled our first multi-well pad this year with each of the three wells having a lateral of about 2000m. Coupled with efficiencies in the drilling programs, drill times have reduced from 64 days for our first well with a lateral of about 1300m to 34 days for our most recent well with a lateral of 2400m. This works out to a 65% reduction in drilling costs per metre of horizontal leg.

The operator recently began focusing on completions. The most recent approach has been to individually place frac treatments with tighter spacing to increase the stimulated rock volume ("SRV") in the reservoir. We recently completed our first well using this approach with 84 individually placed treatments in the 2479m horizontal section and are seeing a step change in the initial rates.

On our operated acreage at Kakwa South, we previously evaluated a similar completion design of individually placing fracs. Furthermore, the design was to maximize SRV while minimize growth into the upper Doig formation that produces sour gas. We completed the 16-07 Well with 25 individually placed stages in the 970m lateral and were pleased with the results of 3.5 MMcf/d and 50 bbls/MMcf of condensate with less than 0.003% sour gas.

While the results from 16-07 were very positive given the short lateral length, the all-in costs were $19 million or about 60% higher than originally budgeted. The majority of this overrun relates to a drilling rig that was later found to be underpowered for the operation and substantially increased drill times. We utilized this same rig for our operated well at Kakwa North. This operation also went over budget by $6 million or 100% due to challenges running the casing to total depth and mechanical issues with the completion. Subsequently, we delayed the drilling of up to three additional wells on this operated acreage.

Notwithstanding the cost overruns and delays, our seven sections at Kakwa North are just as prospective as our four net sections on the joint venture. It is also proximate to two wells drilled by an industry operator with strong condensate and gas rates. Proving up this block will be a priority as we high-grade this acreage.

Our plan for 2015 is to tightly focus our capital spending. The economics of this play remain positive for 1P type wells with a one mile lateral at flat pricing of US$50/bbl. However, the time to achieve payout of capital increases from between one and two years under a US$80/bbl price forecast to about five years under the US$50/bbl price forecast. This proves challenging for companies with balance sheets of our size. As a result, we are limiting our capital investment for the first half of this year to tie-ins and completions of existing wells pending a strengthening in oil prices.

Oil Shale Mining

Just over three years ago, we made our investment in Red Leaf.

The EcoShale process has the potential to become one of the low cost producers of oil and compete favorably with other large oil resource plays including the oil sands. The work done by Red Leaf last year on developing a line of sight to commercial production has been very encouraging. They estimate that by implementing already planned evolutions of the process and the benefits of the learning curve, they should be able to reduce the capsule costs from an estimated US$75 million for the EPS phase to about US$35 million. This translates to all in cost of production between US$30-US$40/barrel.

Based on the budget cuts being implemented worldwide by supermajors, we expect that Total S.A. and Red Leaf will slow the construction of the first capsule this year. This will push back first oil. We believe this will provide an opportunity for Red Leaf to assess additional improvements in the capsule design that could further reduce costs and accelerate the transition to commercial development.

To leverage the results from the EPS phase, we have been evaluating our oil shale acreage at Pasquia Hills and selectively looking for additional opportunities.

The first phase of our resource assessment at Pasquia Hills was completed with an estimate of oil initially in place in excess of two billion barrels. We have been assessing the resource that can be developed commercially under the Red Leaf process and have sent our shale for bulk sampling. We continue to work with Red Leaf and refining consultants for upgrading options for the oil produced under the EcoShale process to maximize the realized price and improve our economics.

Operational and Financial

Notwithstanding the downtime at Kakwa, early production from the area averaged 511 boe/d and contributed to daily production of 1,076 boe/d in 2014. The Kakwa drilling program was weighted towards the last half of the year with 6 (1.5 net) wells awaiting completion and tie-in at year end. We estimate our behind pipe volumes to be approximately 1,000 boe/d in this area.

The natural declines in Antler and growing volumes from Kakwa marginally lowered our weighting of oil and liquids to 67% for the year. This benefitted from higher prices and we increased cash flow to $15.49 million from $13.29 million in 2013.

Our financial results reflect the estimated $33.7 million impairment of our Red Leaf equity investment based on current oil prices and the performance of peer group of similar companies. Oil prices also impact the carrying value of our Antler asset and resulted in an additional impairment of $22.7 million.

Of our total capital expenditures of $63.6 million, more than 90% or $59.4 million was invested in Kakwa. The remainder was invested in Antler and Manitoba on our light oil assets. We financed our capital expenditures with our working capital surplus of $32 million and our cash flow from operations.

Outlook

We have been successful in building a portfolio of resources with significant scale and balanced exposure to both oil and gas prices. In light of current prices, we are prudently investing capital to preserve our options for the future.

High-grading the Montney assets is our top priority for 2015. We intend to capitalize on the established reserves to finance further delineation of our operated acreage. With ~9 million boe in 2P reserves and 14 million boe in economic contingent resources assigned to four sections or less than 10% of our acreage, our goal is to grow these numbers in the next 12-18 months.

During this time, we will continue our government and public relations work in Quebec for our Utica shale gas discovery. Although slower than expected, we are seeing meaningful results with the extension of the holiday on our licenses beyond 2021 and public associations like the Federation of Chambers of Commerce of Quebec publicly supporting our efforts. We are looking forward to the new hydrocarbon legislation and engaging the new operator, Repsol S.A. who has considerable international experience with social acceptability issues around oil and gas development.

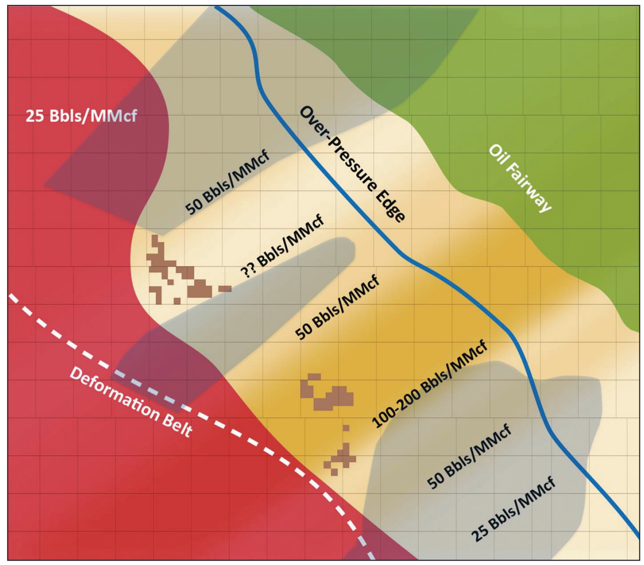
Much like Quebec, our oil shale assets will ultimately be larger than most people think but will also take longer than most people think. These assets represent an opportunity of several hundred million barrels and we are selectively looking to grow this further. Current oil prices will delay the construction and firing of the first EcoShale commercial-size capsule, but we remain very encouraged by its potential to begin development of this massive resource.

Michael Binnion
President and Chief Executive Officer

(1) With respect to discovered resources, or any sub category other than reserves, there is no certainty that it will be commercially viable to produce any portion of the resources.

Kakwa-Resthaven, Alberta

The Kakwa-Resthaven area is situated approximately 75 kilometres south of Grand 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 3100m to 3600m. Questerre's wells are currently targeting one of three prospective intervals in the Montney formation. Economics for the Montney are enhanced by relatively high liquids content, particularly condensate, and Crown royalty incentives for new deep horizontal gas wells with initial royalty rates of up to 5%.



Questerre's acreage in the liquids-rich fairway for Montney shale in Alberta

The Company currently holds 21,600 (13,560 net) acres in the area including a 100% working interest and operatorship of 10,880 net acres. In addition, in the Wapiti area, approximately 20 miles northeast of its acreage in the Kakwa-Resthaven area, the Company holds 24,320 net acres prospective for the Montney formation.

Development of the Montney has historically focused on areas of dry gas or relatively low liquids of approximately 25 bbls/MMcf in British Columbia. Recent activity has targeted a sweet spot where natural gas liquids range between 50 bbls/MMcf to greater than 100 bbls/MMcf. With test rates from its wells as high as 200 bbls/MMcf, the Company's acreage appears to be in the sweet spot of this liquids-rich fairway. More importantly, liquids from these wells are mainly condensate which retains a premium to light oil and liquids prices as a diluent for heavy oil production in Alberta.

In 2014, Questerre participated in the drilling of 11 (2.75 net) wells and the completion of 7 (1.75 net) wells on its joint venture acreage where it holds a 25% working interest. The joint venture is realizing improvements in drilling time with reduced costs per metre of horizontal drilled. Additionally, progress is also being made in enhancing completion practices.

Included in the 2014 program were the first wells drilled with laterals of approximately 2000m from a single surface location. These were the 08-20-63-5-W6M (the "08-20 Well"), the 09-20-63-5-W6 (the "09-20 Well") and the 02-18-63-5-W6M (the "02-18 Well"). The operator reported the average natural gas and condensate production during the first thirty days (excluding downtime) for the 08-20 Well was 4.08 MMcf/d and 561 bbls/d, for the 09-20 Well was 4.05 MMcf/d and 736 bbls/d and for the 02-18 Well was 2.89 MMcf/d and 585 bbls/d. Although the initial rates from these wells are encouraging, they are not indicative of long-term performance or ultimate recovery. Based on these results, the Company expects that the majority of future wells will be drilled with laterals of 1.5 miles.

With all wells to date targeting a Middle Montney interval, the joint venture drilled and completed its first well in the Upper Montney in 2014. During the last 24 hours of a 119 hour test period, the 02/14-30-63-5W6M (the "02/14-30 Well") averaged 2.73 MMcf/d of natural gas and 621 bbls/d of condensate. No sour gas was observed during testing. Although the initial rates from this well are encouraging, they are not indicative of long-term performance or ultimate recovery.

To address the productivity constraints associated with these relatively high condensate yields and line pressures, the joint venture commissioned its central compression and condensate stabilization facility in the first quarter of 2014. The facility has a capacity of 15 MMcf/d of natural gas and approximately 3,000 bbls/d of condensate. In the fall of 2014, the joint venture began work to expand this central facility to 30 MMcf/d and 6,000 bbls/d of condensate. Questerre has a 25% working interest in this facility. Additionally, the joint venture is evaluating wellhead production facilities to address liquid loading.

Joint venture completion operations on three-well pad

The Company also spud two wells in 2014 to delineate its operated acreage in the area.

The first well, the 16-07-62-5-W6M (the "16-07 Well"), was drilled on its acreage six miles south of its joint venture acreage. The Company has a 100% working interest in this well and ten sections of land.

Completion operations on 16-07 well at Kakwa South

The 16-07 Well was completed with a ten-stage slick water fracture stimulation in the approximately 1000m horizontal leg. Over the last 24 hour period of the cleanup and flow back, the well averaged 3.5 MMcf/d of natural gas with condensate rates of approximately 50 bbls/MMcf. Based on gas analysis, the Company expects to recover an additional 15-20 bbls/MMcf of natural gas liquids through processing at a shallow-cut facility. Sour gas was measured at less than 0.003% during testing. While the initial test rates from the 16-07 Well are encouraging, they are not indicative of the long-term performance or ultimate recovery from this well. The 16-07 Well was tied-in to the local gathering system and put on production late in the fourth quarter.

The second well, the 06-29-63-5W6M (the "06-29 Well"), formerly the 14-29 Well, was spud in the second quarter. The Company holds a 100% working interest in this well and seven sections of land offsetting its joint venture acreage to the east.

The 06-29 Well was successfully drilled to a measured depth of 5828m with a lateral leg of approximately 2100m. During the completion operations, a leak was discovered in the casing in the horizontal section. As a result, work was suspended and the Company is evaluating options to repair this leak.

The Company commissioned an independent assessment of its Montney resources on its joint venture acreage of 2,675 acres or approximately 20% of its net land holdings in the Kakwa Resthaven area (the “Joint Venture Acreage”). Conducted by McDaniel & Associates Consultants (“McDaniel”), the resource report assessed the contingent resources associated with the in place petroleum and natural gas on the Joint Venture Acreage. The Resource Report evaluation was performed in accordance with National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* (“NI 51-101”) and the Canadian Oil and Gas Evaluation Handbook (“COGE Handbook”) and is effective December 31, 2014.

The report estimates Economic Contingent Resources (“ECR”) to range between a low of 9.67 MMboe and a high of 18.30 MMBoe with a best estimate of 14.34 MMboe that includes approximately 45% condensate. Using their January 2015 price forecast, McDaniel’s best estimate of ECR has a NPV-10% of $149.62 million.

In addition to the ECR, the proved plus probable reserves for the Kakwa-Resthaven area estimated by McDaniel is 11.92 MMBoe (72 Bcfe) as at December 31, 2014. Using their January 2015 price forecast, these reserves have a NPV-10% of $175.40 million.

The evaluation conducted by McDaniel included detailed geological and petrophysical analysis of Questerre and adjacent industry Montney wells. It focused on the Upper and Middle Montney intervals. McDaniel assumed a Montney development plan based on an average of eight wells per section in the two intervals. Total Petroleum Initially In Place on average was estimated at approximately 52 Bcf per section with recovery factors estimated to range from 25% to 45% with a best estimate of approximately 37%. The recoveries of natural gas liquids estimated by the report are based on the Company’s existing shallow cut processing, transportation and fractionation capacity. Contingent resources were assigned to the Company’s acreage within a three mile radius of a tested or producing Montney well exhibiting commercial production rates.

In light of the decline in commodity prices, Questerre has adopted a conservative capital program for its operated and non-operated Montney acreage in 2015. The Company plans to invest approximately $12 million on its non-operated acreage to participate in the completion and tie-in of existing wells and the expansion of its central facility and local gathering system. On its operated acreage, Questerre intends to defer the completion of the 06-29 Well and the spud of its next well until prices improve.

In conjunction with this reduced capital budget, the Company entered into agreements with the operator of its joint venture acreage and another industry operator to assign, on a temporary and permanent basis, over 75% of its interest in the infrastructure agreements for the processing, transportation and fractionation of natural gas and associated liquids in the area. The agreements are subject to receipt of all requisite approvals and formal documentation.

Antler, Saskatchewan


Producing oil well at Antler

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 1050 metres and 1150 metres. Secondary targets include the Souris Valley, a carbonate sequence at a depth of approximately 900 metres to 1000 metres.

In 2014, Questerre expanded the pilot waterflood for its light oil pool at Antler to increase recovery of the oil in place. The waterflood pilot consists of four horizontal wells on two sections injecting approximately 1,000 bbls/d of water into the oil pool. The fourth well was converted to an injector in the first quarter of the year based on the initial responses from the first three injectors. The Company continues to monitor production and pressure in the offsetting producing wells as injection pressures are increased. Plans are underway to expand this pilot further in 2015.

Oil Shale Mining

Questerre's oil shale assets include prospective acreage in Saskatchewan and Wyoming and the licensing rights to a proprietary process to produce oil from shale developed by Red Leaf Resources Inc. ("Red Leaf"). Questerre currently holds approximately 6% of the equity capital of Red Leaf. Red Leaf is a private Utah-based oil shale and technology company. Its principal assets are its proprietary EcoShale In-Capsule process to recover oil from shale in addition to oil shale leases in the states of Utah and Wyoming. Questerre has partnered with Red Leaf to develop its acreage in Wyoming and has an option to obtain licenses to utilize the Red Leaf process.

In 2014, Red Leaf continued its work with a US affiliate of the French-based supermajor, Total S.A. ("Total"), to jointly develop their oil shale assets in Utah. The joint venture began an Early Production System ("EPS") phase to prove the technical and environmental attributes of the process at large scale in Utah. It follows the successful field pilot conducted by Red Leaf in 2009. Total will fund an 80% share of the EPS phase expenses estimated at US$300 million. Red Leaf and Total subsequently may launch an advanced commercial pilot on their jointly held oil shale acreage in Utah.

During the year, the joint venture completed the front end engineering and design for the construction of the capsule and the associated mining and production facilities. It also approved a supplemental AFE for the EPS phase at an estimated total cost of approximately US$300 million. The final construction permit was secured and field work began in the third quarter of last year.

Field work underway for construction of the first commercial scale capsule at Seep Ridge, Utah

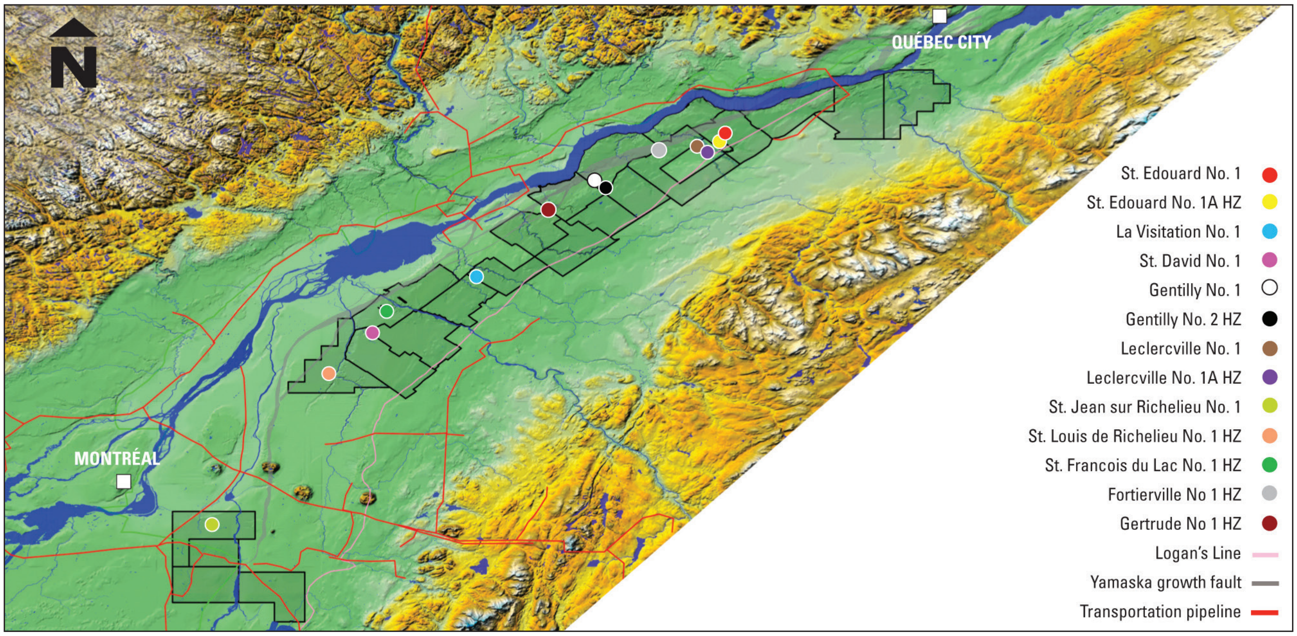
In the current oil price environment, the joint venture is scaling back field work in 2015. While this will delay the completion and firing of the capsule, the joint venture expects that the total costs of the EPS phase will remain within the original budget.

Concurrently, the Company has been working with Red Leaf to progress their joint oil shale acreage in Wyoming. Preliminary permitting and engineering is ongoing for a work program to assess this acreage. Questerre will participate for a 20% interest and Red Leaf will hold the remaining 80% interest in this joint venture. The work program will be postponed in 2015 pending the results of the EPS phase and an improvement in commodity prices.

Red Leaf oil shale joint venture acreage in Utah and Wyoming

The Company continues to assess the potential of its oil shale acreage at Pasquia Hills, Saskatchewan. A resource report was commissioned and the first phase completed during the year. It confirmed a discovered oil initially in place in excess of two billion barrels. The second phase of this report will assess the in place resource that can be commercially developed with the EcoShale process. Concurrently, the Company is assessing treating facilities to upgrade the quality of produced oil from this process and improve realized prices.

St. Lawrence Lowlands, Quebec



Questerre acreage in the 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 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, Talisman, began a pilot horizontal well program to assess commerciality of the Utica shale in 2010. The initial results from the first two wells, St. Edouard and Gentilly, drilled in different parts of the fairway met or exceeded Management's expectations. Two additional horizontal wells, Fortierville and St. Gertrude were also drilled and are awaiting completion.

In 2011, the pilot program to assess the commerciality of the Utica shale was suspended while the government initiated a strategic environmental assessment ("SEA") of shale gas development in the province. In the summer of 2014, the government extended the tenure of exploration permits held to beyond 2021.

The committee responsible for the SEA released their report in the first quarter of 2014. The report concluded that the risks associated with development are manageable. The findings were referred to the province's advisory office for environmental hearings, the Bureau d'audiences publiques sur l'environment ("BAPE"). The BAPE subsequently conducted a series of public consultations and concluded that social acceptability, economic benefits and legislation were the main challenges associated with development in the near term.

The government has since commissioned an inter-ministerial committee to conduct a study on the entire oil and gas sector in the province with results due by the end of 2015. Furthermore, the Ministry of Natural Resources intends to study the conditions that foster social acceptability with the aim of establishing guidelines and best practices. The government has also committed to introduce new hydrocarbon legislation by early 2016.

Questerre expects that further operations, including the completion of the Fortierville and St. Gertrude horizontal wells will be deferred pending the introduction of proposed hydrocarbon legislation.

Environmental Stewardship

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

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

Management's Discussion and Analysis ("MD&A") was prepared as of March 26, 2015. This MD&A should be read in conjunction with the audited consolidated financial statements of Questerre Energy Corporation ("Questerre" or the "Company") as at and for the years ended December 31, 2014 and 2013. Additional information relating to Questerre, including Questerre's Annual Information Form for the year ended December 31, 2014 ("AIF"), is available on SEDAR under Questerre's profile at www.sedar.com.

Questerre is an independent energy company focused on non-conventional oil and gas resources. The Company is currently developing a portfolio of oil shale assets in North America. It is securing a social license to commercialize its Utica natural gas discovery in Quebec. The Company is underpinned by light oil and other conventional assets. 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. All financial information is reported in Canadian dollars, unless otherwise noted.

Forward-Looking Statements

Certain statements contained within this MD&A, and in certain documents incorporated by reference into this document, 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", "budget", "plan", "continue", "estimate", "expect", "forecast", "may", "will", "project", "predict", "potential", "intend", "could", "might", "believe", "assume", "future", "ultimate" 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. We believe 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, or incorporated by reference into, this MD&A should not be unduly relied upon. These statements speak only as of the date of this MD&A or as of the date specified in the documents incorporated by reference into this MD&A, as the case may be.

This MD&A, and the documents incorporated by reference, if any, contain forward-looking statements including, but not limited to, those pertaining to the following:

- oil and natural gas properties;
- oil, natural gas liquids and natural gas reserves and/or resources and production levels;
- estimates of future net revenues;
- projections of prices and costs;
- drilling plans and timing of drilling, completion and tie-in of wells by Questerre and its partners;

- the implementation of processing, transportation, fractionation and marketing agreements;
- weighting of production between different commodities;
- commodity prices, exchange rates and interest rates;
- expected levels of royalty rates, operating costs, general and administrative costs, costs of services and other costs and expenses;
- timing and extent of work programs to be performed by Red Leaf;
- capital expenditure programs and other expenditures and the timing and method of financing thereof;
- supply of and demand for oil, natural gas liquids and natural gas;
- expectations regarding our ability to raise capital and to continually add to reserves through acquisitions and development;
- our ability to grow or sustain production and reserves through prudent management;
- the emergence of accretive growth opportunities and continued access to capital markets;
- our future operating and financial results;
- schedules and timing of certain projects and our strategy for future growth; and
- treatment under governmental and other regulatory regimes and tax, environmental and other laws.

The following forward-looking statements in this MD&A include, but are not limited to:

- oil and natural gas properties;
- oil, natural gas liquids and natural gas reserves and resources and production and recovery levels in respect thereof;
- estimates of future net revenues;
- projections of prices, costs and royalties;
- drilling, completion and tie-in of wells by Questerre and its partners;
- the Company's infrastructure and use of third party infrastructure;
- Questerre's use of waterflood;
- the joint venture with Red Leaf (as defined herein);
- the Company's financial position;
- Questerre's contractual commitments and benefits;
- commodity prices, price differentials, sales prices, exchange rates and interest rates;
- the Company's capital expenditure program;
- Questerre's risks and risk management strategy;
- governmental and regulatory regimes and laws;
- critical accounting estimates and the potential impacts thereof;
- future accounting pronouncements and the expected form and impacts thereof; the amount of future asset retirement obligations; and liquidity and capital resources.

With respect to forward-looking statements contained in this MD&A and the documents incorporated by reference herein, we have made assumptions regarding, among other things:

- future oil, natural gas liquids and natural gas prices;
- the continued availability of capital, undeveloped lands and skilled personnel;

- the costs of expanding our property holdings;
- the ability to obtain equipment in a timely manner to carry out exploration, development and exploitation activities;
- the ability to obtain financing on acceptable terms;
- the ability to add production and reserves through exploration, development and exploitation activities; and
- the continuation of the current tax and regulatory regime.

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 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;
- 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;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands, and services;
- incorrect assessments of the value of acquisitions and targeted exploration and development assets;
- fluctuations in foreign exchange or interest rates;
- stock market volatility, market valuations and the market value of the securities of Questerre;
- failure to realize the anticipated benefits of acquisitions;
- actions by governmental or regulatory authorities including changes in royalty structures and programs and income tax laws or changes in tax laws and incentive programs relating to the oil and gas industry;
- limitations on insurance;
- changes in environmental or other legislation applicable to our operations, and our 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.

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. The 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.

Additional IFRS and Non-IFRS Measures

This document contains the term "cash flow from operations", which is an additional IFRS measure. The Company uses this measure to help evaluate its performance.

As an indicator of Questerre's performance, cash flow from operations should not be considered as an alternative to, or more meaningful than, net cash flow from operating activities as determined in accordance with IFRS. Questerre's determination of cash flow from operations may not be comparable to that reported by other companies. Questerre considers cash 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.

Cash Flow from Operations Reconciliation

($ thousands)		2014		2013
Net cash from operating activities	$	14,248	$	14,406
Change in non-cash operating working capital		1,146		(1,214)
Cash flow from operations	$	15,394	$	13,192

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

The Company considers netbacks a key measure as it demonstrates its profitability relative to current commodity prices. 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 IFRS and may not be comparable with the calculation of similar measures for other entities. Working capital surplus (deficit), as used by the Company, is calculated as current assets less current liabilities excluding the current portion of the share based compensation liability, risk management contracts and the flow-through share liability.

Select Annual Information

As at/for the years ended December 31,	2014	2013	2012
Financial ($ thousands, except as noted)			
Petroleum and Natural Gas Sales	28,577	24,359	18,842
Cash Flow from Operations	15,394	13,192	10,244
Basic ($/share)	0.06	0.06	0.04
Diluted ($/share)	0.06	0.06	0.04
Net Loss	(40,521)	(19,354)	(19,472)
Basic ($/share)	($0.15)	($0.08)	($0.08)
Diluted ($/share)	($0.15)	($0.08)	($0.08)
Capital Expenditures, net of			
Acquisitions and Dispositions	56,646	52,133	42,350
Working Capital Surplus (Deficit)	(9,247)	31,909	33,216
Total Assets	234,174	273,108	243,365
Shareholders' Equity	196,858	241,197	217,456
Common Shares Outstanding (thousands)	264,932	264,657	230,804
Weighted average - basic (thousands)	264,890	236,691	230,914
Weighted average - diluted (thousands)	265,703	237,210	232,774
Operations (units as noted)			
Average Production			
Crude Oil and Natural Gas Liquids (bbls/d)	749	682	580
Natural Gas (Mcf/d)	1,959	1,219	590
Total (boe/d)	1,076	885	678
Average Sales Price			
Crude Oil and Natural Gas Liquids ($/bbl)	90.84	91.53	86.14
Natural Gas ($/Mcf)	5.25	3.57	2.65
Total ($/boe)	72.76	75.41	75.95
Netback ($/boe)			
Petroleum and Natural Gas Revenue	72.76	75.41	75.95
Royalties Expense	(5.80)	(5.78)	(5.14)
Percentage	8%	8%	7%
Operating Expense	(14.36)	(15.04)	(18.04)
Operating Netback	52.60	54.59	52.77
General and Administrative Expense	(12.11)	(13.68)	(17.00)
Cash Netback	40.49	40.91	35.77
Wells Drilled			
Gross	16.00	11.00	15.00
Net	5.80	5.50	8.50

Highlights

- Corporate proved plus probable reserves increased from 9.04 MMBoe to 13.88 MMBoe with an NPV-10% of $231.6 million
- Best estimate of economic contingent resources for the Company's Montney joint venture acreage is an additional 14.3 MMBoe with an NPV-10% of $149.6 million
- Delineation of operated Montney acreage underway with success at Kakwa South, although Kakwa North completion delayed with mechanical failure
- Red Leaf and Total joint venture secured final permit and began construction of commercial scale capsule
- Cash flow from operations of $15.4 million with average daily production of 1,076 boe/d

2014 Activities

Western Canada

<u>Kakwa-Resthaven, Alberta</u>

In 2014, the Company continued development of this new core area in west central Alberta, targeting condensate rich natural gas from the Montney formation.

The Company currently holds 21,600 (13,560 net) acres in the area including a 100% working interest and operatorship of 10,880 net acres. In addition, in the Wapiti area, approximately 20 miles northeast of its acreage in the Kakwa-Resthaven area, the Company holds 24,320 net acres prospective for the Montney formation.

Questerre participated in the drilling of 11 (2.75 net) wells and the completion of 7 (1.75 net) wells on its joint venture acreage where it holds a 25% working interest. Included in the 2014 program were the first wells drilled with laterals of approximately 2000m from a single surface location. These wells were the 08-20-63-5-W6M (the "08-20 Well"), the 09-20-63-5-W6M (the "09-20 Well") and the 02-18-63-5-W6M (the "02-18 Well"). The operator reported the average natural gas and condensate production during the first thirty days (excluding downtime) for the 08-20 Well was 4.08 MMcf/d and 561 bbls/d, for the 09-20 Well was 4.05 MMcf/d and 736 bbls/d and for the 02-18 Well was 2.89 MMcf/d and 585 bbls/d. Although the initial rates from these wells are encouraging, they are not indicative of long-term performance or of ultimate recovery. Based on these results, the Company expects that the majority of future wells will be drilled with laterals of 1.5 miles.

With all wells drilled to date targeting the Middle Montney interval, the joint venture drilled and completed its first well in the Upper Montney interval in 2014. During the last 24 hours of a 119 hour test period, the 02/14-30-63-5W6M (the "02/14-30 Well") well averaged 2.73 MMcf/d of natural gas and 621 bbls/d of condensate. No sour gas was observed during testing. Although the initial rates from this well are encouraging, they are not indicative of long-term performance or ultimate recovery. For more information on the 02/14-30 Well test, please refer to the Company's press release filed on SEDAR on April 7, 2014.

To address the productivity constraints associated with the relatively high condensate yields and line pressures experienced on its existing wells, the joint venture commissioned its central compression and condensate stabilization facility in the first quarter of 2014. The facility has a capacity of 15 MMcf/d of natural gas and approximately 3,000 bbls/d of condensate. In the fall of 2014, the joint venture began work to expand this central facility to 30 MMcf/d and 6,000 bbls/d of condensate. Questerre has a 25% working interest in this facility. Furthermore, the joint venture is evaluating additional wellhead production facilities to address liquid loading.

In 2014, the Company spud two wells in 2014 to delineate its operated acreage in the area.

The first well, the 16-07-62-5-W6M (the "16-07 Well") well, was drilled on its acreage six miles to the south of its joint venture acreage. The Company has a 100% working interest in this well and ten sections of land.

The 16-07 Well was completed with a ten-stage slick water fracture stimulation in the approximately 1000m horizontal leg. Over the last 24 hour period of the cleanup and flow back, the well averaged 3.5 MMcf/d of natural gas with condensate rates of approximately 50 bbls/MMcf. Based on gas analysis, the Company expects to recover an additional 15-20 bbls/MMcf of natural gas liquids through processing at a shallow-cut facility. Sour gas was measured at less than 0.003% during testing. While the initial test rates from the 16-07 Well are encouraging, they are not indicative of the long-term performance or ultimate recovery. The 16-07 Well was tied-in to the local gathering system and put on production late in the fourth quarter. Production from this well has been intermittent in part due to access to third party water disposal facilities. For more information on the 16-07 Well test, please refer to the Company's press release filed on SEDAR on August 22, 2014.

The second well, the 06-29-63-5W6M (the "06-29 Well"), formerly the 14-29 Well, was spud in the second quarter. The Company holds a 100% working interest in this well and seven sections of land offsetting its joint venture acreage to the east.

The 06-29 Well was successfully drilled to a measured depth of 5828m with a lateral leg of approximately 2100m. During the completion operations, a leak was discovered in the casing in the horizontal section. As a result, work was suspended and the Company is evaluating options to repair this leak.

The Company commissioned an independent assessment of its Montney resources on its joint venture acreage of 2,675 acres or approximately 20% of its net land holdings in the Kakwa-Resthaven area (the "Joint Venture Acreage"). Conducted by McDaniel & Associates Consultants ("McDaniel"), the resource report assessed the contingent resources associated with the Joint Venture Acreage (the "Resource Report"). The Resource Report evaluation was performed in accordance with National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101") and the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook") and is effective December 31, 2014 with a preparation date of February 13, 2015. (See AIF).

The report estimates Economic Contingent Resources ("ECR") to range between a low of 9.67 MMboe and a high of 18.30 MMBoe with a best estimate of 14.34 MMboe that includes approximately 45% condensate. Using their January 2015 price forecast, McDaniel's best estimate of ECR has a NPV-10% of $149.62 million.

In addition to the ECR, the proved plus probable reserves for the Kakwa-Resthaven area estimated by McDaniel is 11.92 MMBoe as at December 31, 2014. Using their January 2015 price forecast, these reserves have a NPV-10% of $175.40 million.

The Resource Report evaluation conducted by McDaniel included detailed geological and petrophysical analysis of Questerre and adjacent industry Montney wells. It focused on the Upper and Middle Montney intervals. McDaniel assumed a Montney development plan based on an average of eight wells per section in the two intervals. The recoveries of natural gas liquids estimated by the report are based on the Company's existing shallow cut processing, transportation and fractionation capacity. Contingent resources were assigned to the Company's acreage within a three mile radius of a tested or producing Montney well exhibiting commercial production rates.

An estimate of net present value of future net 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 required investment. It includes contingent resources that are considered to be not commercially recoverable and therefore these resources cannot be classified as reserves. There is uncertainty that the net present value of future net revenue will be realized.

The primary contingencies which prevent the classification of the Company's ECR as reserves are classified as non-technical, and are as follows: market access, facility constraints, timing of development, and internal and external approvals for commitment to project development. Additional drilling, completion, and testing data will be required before Questerre can commit to the development of its ECR.

In light of the decline in crude oil prices during the fourth quarter of 2014, Questerre has adopted a conservative capital program for its operated and non-operated Montney acreage in 2015. The Company plans to invest approximately $12 million on its non-operated acreage to participate in the completion and tie-in of existing wells and the expansion of its central facility and local gathering system. On its operated acreage, Questerre intends to defer the completion of the 06-29 Well and the spud of its next well until prices improve.

In conjunction with this reduced capital budget, the Company entered into agreements with the operator of its joint venture acreage and industry operators to assign, on a temporary and permanent basis, over 75% of its interest in the infrastructure agreements for the processing, transportation and fractionation of natural gas and associated liquids in the area. The agreements are subject to receipt of all requisite approvals and formal documentation.

Antler, Saskatchewan and Pierson, Manitoba

Questerre expanded the pilot waterflood for its light oil pool at Antler, Saskatchewan to increase recovery of the oil in place.

The waterflood pilot consists of four horizontal wells on two sections injecting approximately 1,000 bbls/d of water into the oil pool. The fourth well was converted to an injector in the first quarter of the year based on the initial responses from the first three injectors. The Company continues to monitor production and pressure in the offsetting producing wells as injection pressures are increased. Plans are underway to expand this pilot further in 2015.

In December, the Company concluded the disposition of its South Antler assets for $7 million. Production from the property was approximately 77 bbls/d of light oil and the disposition had an effective date of November 1, 2014.

Additional development drilling was conducted on the Company's acreage in the Pierson, Manitoba area targeting light oil from the Spearfish formation. Three (1.05 net) wells were drilled and completed in the year. To mitigate the downtime associated with spring breakup, the operator completed the installation of a satellite battery and local gathering system.

Oil Shale Mining

Questerre's oil shale assets include prospective acreage for oil shale in Saskatchewan and Wyoming and the licensing rights to a proprietary process to produce oil from shale developed by Red Leaf Resources Inc. ("Red Leaf"). Questerre currently holds approximately 6% of the equity capital of Red Leaf.

Red Leaf is a private Utah-based oil shale and technology company. Its principal assets are its proprietary EcoShale® In-Capsule process to recover oil from shale in addition to oil shale leases in the states of Utah and Wyoming. The Company has partnered with Red Leaf to develop its oil shale acreage in the state of Wyoming and has an option to obtain licenses to utilize the Red Leaf process.

In 2014, Red Leaf continued its work with a US affiliate of the French-based supermajor, Total S.A. ("Total"), to jointly develop their oil shale assets in Utah. The joint venture began an Early Production System ("EPS") phase to prove the technical and environmental attributes of the process at large scale in Utah. It follows the successful field pilot conducted by Red Leaf in 2009. Red Leaf and Total subsequently may launch an advanced commercial pilot on their jointly held oil shale acreage in Utah.

During the year, the joint venture completed the front end engineering and design for the construction of the capsule and the associated mining and production facilities. It also approved a supplemental AFE for the EPS phase at an estimated total cost of approximately US$300 million. Total will fund an 80% share of these EPS phase expenses. The final construction permit was secured and field work began in the third quarter of last year.

In the current crude oil price environment, the joint venture is scaling back field work in 2015. While this will delay the completion and firing of the capsule, the joint venture expects that the total costs of the EPS phase will remain within the original budget.

Questerre has been working with Red Leaf to progress their joint oil shale acreage in Wyoming. Preliminary permitting and engineering is ongoing for a work program to assess this acreage. Questerre will participate for a 20% interest and Red Leaf will hold the remaining 80% interest in this joint venture. The work program will be postponed in 2015 pending the results of the EPS phase and an improvement in commodity prices.

The Company continues to assess the potential of its oil shale acreage at Pasquia Hills, Saskatchewan. A resource report was commissioned and the first phase completed during 2014. The second phase of this report will assess the in-place resource that can be commercially developed with the EcoShale® process. Concurrently, the Company is assessing treating facilities to upgrade the quality of produced oil from this process and improve realized prices.

St. Lawrence Lowlands, Quebec

The pilot program to assess the commerciality of the Utica shale remained suspended in 2014 while the government continued its strategic environmental assessment ("SEA") of shale gas development in the province. In the summer of 2014, the government extended the tenure of the exploration permits held by Questerre and other operators in the St. Lawrence Lowlands to beyond 2021.

The committee responsible for the SEA released their report in the first quarter of 2014. The report concluded that the risks associated with development are manageable. The findings were referred to the province's advisory office for environmental hearings, the Bureau d'audiences publiques sur l'environment ("BAPE"). The BAPE subsequently conducted a series of public consultations and concluded that social acceptability, economic benefits and legislation were the main challenges associated with development in the near term.

The government has since commissioned an inter-ministerial committee to conduct a study on the entire oil and gas sector in the province with results due by the end of 2015. Furthermore, the Ministry of Natural Resources has indicated an intention to study the conditions that foster social acceptability with the aim of establishing guidelines and best practices. The government has also committed to introduce new hydrocarbon legislation by early 2016.

Questerre expects that further operations, including the completion of the Fortierville and St. Gertrude horizontal wells, will be deferred pending the introduction of proposed hydrocarbon legislation.

Corporate

In June, the Company's credit facilities were increased to $50 million. The next scheduled review of these facilities is in April 2015. The credit facilities include a revolving operating demand loan and a non-revolving acquisition and development demand loan. Any borrowings under the facilities, with the exception of letters of credit, bear interest at the bank's prime interest rate and applicable basis point margins based on the Company's ratio of debt to cash flow, measured quarterly. The Company intends to maintain this ratio at no more than 2.0. The bank's current prime rate is 3% per annum. The facility is secured by a revolving credit agreement, a debenture with a first floating charge over all assets of the Company and a general assignment of books debts.

Drilling Activities

In 2014, Questerre participated in the drilling of 16 (5.80 net) wells, comprising 3 (1.05 net) oil wells in Pierson, Manitoba and 13 (4.75 net) gas wells in the Kakwa-Resthaven area, Alberta.

Production

	2014			2013		
	Oil and Liquids (bbls/d)	Natural Gas (Mcf/d)	Equivalent (boe/d)	Oil and Liquids (bbls/d)	Natural Gas (Mcf/d)	Equivalent (boe/d)
Saskatchewan	307	-	307	396	-	396
Alberta	296	1,870	608	182	1,105	366
Manitoba	146	-	146	104	-	104
British Columbia	-	89	15	-	114	19
	749	1,959	1,076	682	1,219	885

In 2014, early production from the Kakwa-Resthaven area of 511 boe/d contributed to an increase in the Company's daily volumes from 885 boe/d to 1,076 boe/d in 2014. As a percentage of volumes, crude and liquids decreased to 70% from 77% in 2013 as production from this area is split approximately equally between liquids and natural gas.

The lower oil and liquids weighting also reflects the natural declines experienced in Antler and, to a lesser extent, the disposition of the South Antler assets in the fourth quarter. This was partially offset by three (1.05 net) new wells drilled in Pierson, Manitoba during the year. Consistent with the prior year, approximately 143 boe/d of production in these areas was shut-in during spring break-up due to limited road access to truck produced oil and to workover wells. To mitigate the impact of these weather related shut-ins at Pierson, the operator constructed a satellite battery and gathering system in the first half of this year.

Production in the Kakwa-Resthaven area benefitted from the commissioning of the central compression facility on its joint venture acreage. The facility was constructed to address the high line pressures associated with access to third party processing facilities. Additionally, the operator has been installing wellhead facilities to improve lifting of the relatively high condensate volumes associated with the gas production and improve uptime. In conjunction with the operator, we continue to evaluate additional facilities such as gas lift that could further enhance liquids lifting and uptime.

Growth in Montney production was weighted towards the last quarter of the year with the tie-in of four (1.0 net) wells on the joint venture acreage and one well on its operated acreage. Production in the area increased from 470 boe/d in the first quarter to 865 boe/d in the last quarter. Furthermore, at year end, 6 (1.5 net) wells were awaiting completion and tie-in. The Company expects that, subject to the completion and tie-in of these wells by the end of the first half of 2015, it's behind pipe volumes are approximately 1,000 boe/d.

With current commodity prices and the deferral of future work on its operated acreage, the Company has budgeted a relatively conservative capital program for 2015. The Company plans to participate in the completion and tie in of the 6 (1.5 net) wells on its joint venture acreage and the expansion of the central facility and associated pipelines to tie-in this production.

2014 Financial Results

Petroleum and Natural Gas Sales

	2014			2013		
($ thousands)	Oil and Liquids	Natural Gas	Total	Oil and Liquids	Natural Gas	Total
Saskatchewan	$ 10,659	$ -	$ 10,659	$ 13,588	$ -	$ 13,588
Alberta	9,427	3,619	13,046	5,855	1,463	7,318
Manitoba	4,733	-	4,733	3,315	-	3,315
British Columbia	-	139	139	-	138	138
	$ 24,819	$ 3,758	$ 28,577	$ 22,758	$ 1,601	$ 24,359

Petroleum and natural gas revenue grew by 17% over the prior year largely due to higher volumes of oil and liquids and higher natural gas prices in 2014. Higher production volumes were responsible for over 75% of this increase with pricing accounting for the remainder of the increase.

Pricing

	2014	2013
Benchmark prices:		
Natural Gas - AECO, daily spot ($/Mcf)	4.50	3.19
Crude Oil - Edmonton light ($/bbl)	93.38	92.92
Realized prices:		
Natural Gas ($/Mcf)	5.25	3.57
Crude Oil and Natural Gas Liquids ($/bbl)	90.84	91.53

Crude oil prices remained relatively strong for the first three quarters of 2014 and then declined significantly in the last quarter. The geopolitical instability in Ukraine, North Africa and the Middle East contributed to the benchmark West Texas Intermediate ("WTI") price trading between US$90 and US$110 per barrel between January and September 2014. In the last quarter of the year, oil prices declined to US$59 per barrel in December driven by the rapidly increasing oil inventories in the United States and the decision by the Organization of the Petroleum Exporting Countries in November to maintain production levels.

Despite increasing volumes transported by rail and pipelines, the differential between the WTI and Canadian Mixed Sweet Blend ("MSW") remained volatile during the year, averaging US$6 per barrel, and trading between US$11 per barrel and US$2 per barrel. Questerre expects this volatility to persist in 2015.

The benchmark MSW price increased marginally from $92.92 per barrel in 2013 to $93.38 per barrel in 2014. By comparison, Questerre's realized price declined to $90.84 per barrel in 2014 from $91.53 per barrel in 2013. This reflects the penalty associated with the relatively higher proportion of other natural gas liquids, including propane and butane, in the Company's condensate production volumes. The Company anticipates these volumes and the associated penalty will decrease substantially in the second half of this year once production is processed at a shallow cut processing facility that extracts these other liquids.

Consistent with prior years, weather was an important factor in natural gas pricing in 2014. A very cold winter in the northeastern United States drove record demand for heating and drew natural gas storage levels to well below the five year average. As a result, the benchmark AECO price averaged over $5 per MMBtu for the first half of 2014. With a cooler summer and the continued growth in US dry natural gas production, prices declined in the last quarter of the year and averaged $3.60 per MMBtu. Natural gas prices will likely remain challenged in 2015 and require increased industrial and export demand to tighten the supply demand balance.

Higher heat content production from the Kakwa-Resthaven area contributed to realized prices of $5.25/Mcf in 2014 (2013: $3.57/Mcf) as compared to the average AECO price of $4.50/Mcf (2013: $3.19/Mcf).

To mitigate the impact of further volatility in prices, the Company entered into a $4.00/GJ swap for 2000 GJ/d from February 1, 2014 to December 31, 2014 and a $3.72/GJ swap for 2000 GJ/d for 2015.

Royalties

($ thousands)		2014		2013
Alberta	$	1,063	$	813
Saskatchewan		661		787
Manitoba		554		268
British Columbia		1		-
	$	2,279	$	1,868
% of Revenue:				
Alberta		8%		11%
Saskatchewan		6%		6%
Manitoba		12%		8%
British Columbia		1%		0%
Total Company		8%		8%

Royalties as a percentage of revenue remained stable at 8% in 2014 and 2013.

In Alberta, this percentage declined from 11% to 8% in 2014. In 2013, the majority of production was from the Kakwa-Resthaven area where one of two producing wells attracted a gross overriding royalty until payout. In 2014, with additional wells brought on production, this single well accounted for a materially lower portion of total revenue. Production from this area benefits from several Crown incentives including the New Well Royalty Rate and the Natural Gas Deep Drilling Program that provide for royalties of up to 5%.

In Manitoba, royalties increased with the majority of new wells drilled on freehold acreage, which attracts a higher royalty rate than production from Crown lands.

Operating Costs

($ thousands)	2014	2013
Alberta	$ 3,377	$ 2,206
Saskatchewan	1,813	2,165
Manitoba	359	362
British Columbia	92	125
	$ 5,641	$ 4,858
$/boe:		
Alberta	15.24	16.52
Saskatchewan	16.15	14.98
Manitoba	6.74	9.54
British Columbia	16.96	18.07
Total Company	14.37	15.04

On a unit of production basis, operating costs decreased marginally to $14.37/boe in 2014 from $15.04/boe in 2013.

Operating costs in Saskatchewan reflect the relatively high proportion of fixed costs associated with the property and incremental costs to workover producing wells. With the natural decline and shut-in volumes during spring break-up, the fixed costs were borne by lower volumes in the year.

In Alberta, the Company's operating costs declined marginally with the higher fixed costs being borne by increasing production volumes. Questerre expects that these costs on a boe basis will decline in 2015 as additional volumes are brought on production in Kakwa-Resthaven. Furthermore, the Company expects that transportation costs associated with its condensate production will decrease further as a planned pipeline will replace the trucking of product to the injection station of a third party pipeline.

General and Administrative Expenses

($ thousands)	2014	2013
General and administrative expenses, gross	$ 7,017	$ 6,129
Capitalized expenses and overhead recoveries	(2,261)	(1,714)
General and administrative expenses, net	$ 4,756	$ 4,415

Gross general and administrative expenses ("G&A") were $7.02 million in 2014 compared to $6.13 million in 2013. The increase was mainly due to additional personnel costs related to the development of the Company's Kakwa-Resthaven area. Capitalized expenses and overhead recoveries as a percentage of gross G&A was 32% in 2014 compared to 28% in 2013. This is attributable to additional staff employed in the current year to develop this area. This was partially offset by lower capital expenditures on operated properties in 2014, a portion of which is recoverable from its partners.

Depletion, Depreciation, Impairment and Accretion

Questerre recorded $8.48 million of depletion and depreciation expense for the year ended December 31, 2014 (2013: $9.40 million). On a per unit basis, the Company's depletion and depreciation expense decreased by approximately 26% to $21.58/boe in 2014 (2013: $29.10/boe). The decrease is attributable to a higher production weighting from cash generating units with lower finding and development costs.

In 2014, the Company recorded impairment charges of $47.63 million, including $22.13 million for its property, plant and equipment, $24.78 million for its investments and $0.72 million for lease expiries of its undeveloped land. The Company recorded $22.71 million to impairment charges in 2013, mainly relating to costs associated with its 09-01 Well in the Kakwa-Resthaven area.

At December 31, 2014, the Company reviewed the carrying amounts of its property, plant and equipment assets for indicators of impairment such as changes in future prices, future costs and reserves. Based on this review, the Company's cash generating units ("CGU's") 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. The estimate of FVLCD was determined using a discount rate of 10% and forecasted after-tax cash flows based on proved plus probable reserves, with escalating prices and future development costs obtained from an independent reserve evaluation report. Based on the assessment, for the year ended December 31, 2014, the Company recorded the impairment loss, which relates to its Antler, Midway and Vulcan CGUs. The factor that led to the impairment was a reduction in forecasted near-term commodity prices.

At December 31, 2014, an impairment loss of $33.72 million was recognized relating to the Company's investments. This represents the difference between the carrying value of its investment in Red Leaf and its estimated fair value. The Company recorded $24.78 million of the impairment in net loss and $8.93 million in other comprehensive income (loss) net of deferred tax of $1.16 million.

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. As there have been no equity issuances by Red Leaf since 2012 that serve as a proxy for the estimate of fair value, fair value was determined using discounted future after-tax cash flows. The estimate reflects the recent crude oil price environment and the corresponding decline in public equity markets for comparable oil and gas companies. The Company used a discount rate of 22%, which incorporated volatility measured by public companies similar to Red Leaf, considered the early stage of Red Leaf and applied a discount for liquidity. The Company also assigned a probability of economic or technical failure of 14.5% in measuring fair value.

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 a put right at any time. Once the put options are cash settled, the options are cancelled.

Under the plan, fair values are determined at each reporting date using the Black-Scholes option pricing model. Periodic changes in fair value are recognized in profit or loss as share based compensation expense or recovery with a corresponding change to the liability. Obligations for cash payments are recorded as a share based compensation liability based on the fair value of the liability at the reporting date.

The Company uses the Black-Scholes model to calculate a theoretical value of the options based on the price of its shares, its volatility, risk-free rate and expected life. Due to the decrease in the Company's share price in 2014, the Black-Scholes values have decreased in 2014 resulting in a lower expense.

Deferred Taxes

For the years ended December 31, 2014 and 2013, Questerre reported a deferred tax recovery of $3.18 million and $4.98 million. The decrease in deferred tax recovery from 2013 to 2014 is primarily related to a lower loss before income taxes and investment impairments. The Company did not recognize a deferred tax asset relating to its investment impairment charge of $24.78 million as it does not consider it probable that it will realize the related tax benefit through future taxable profits.

Questerre had sufficient tax pool deductions to offset taxable income in 2014.

Other Income and Expenses

Changes to the fair value of the Company's risk management contracts are recorded through net profit or loss. For the Company's outstanding risk management contracts at December 31, 2014, the unrealized gain recorded for the year ended December 31, 2014 was $1.20 million compared to the unrealized loss of $0.85 million for the same period in 2013. For the Company's settled risk management contracts at December 31, 2014, the realized loss recorded for the year ended December 31, 2014 was $0.57 million and $0.26 million for the same period in 2013.

In December 2014, the Company disposed of certain Antler assets for net proceeds of $6.93 million and recorded a loss on disposition of $2.93 million.

Questerre reported interest income of $0.50 million for the year ended December 31, 2014 (2013: $0.39 million). The interest is from the cash invested in Guaranteed Investment Certificates issued by Canadian chartered banks and credit unions and from the Company's investment in convertible bonds. The increase in the interest income is a result of the Company's higher average cash balance in the current year.

The Company recorded a gain on foreign exchange, net of deferred tax, through other comprehensive income (loss) of $3.65 million for the year ended December 31, 2014 (2013: $2.59 million gain). The changes are due to fluctuations in the exchange rate relating to its US dollar investments.

Total Comprehensive Loss

Questerre's total comprehensive loss was $44.65 million for 2014 compared to $16.76 million in 2013. The Company's change in total comprehensive loss is mainly attributable to higher impairment charges, partially offset by higher operating netbacks in 2014.

Net Loss Per Share

Questerre's basic net loss per share increased from $0.08 per share to $0.15 per share in 2014. Questerre's net loss was $19.35 million in 2013 compared to $40.52 million in 2014. The impact of the increased loss in 2014 on a per share basis was partially lowered due to the higher number of weighted average shares outstanding in 2014 of 264.89 million versus 236.69 million in 2013.

Capital Expenditures

($ thousands)	2014	2013
Alberta	$ 59,445	$ 44,730
Saskatchewan	1,904	4,382
Manitoba	1,695	2,253
Quebec	326	613
Wyoming	93	136
British Columbia	61	70
Corporate	51	2
	63,575	52,186
Dispositions	(6,929)	(175)
Total	$ 56,646	$ 52,011

Questerre incurred net capital expenditures of $63.58 million in 2014 as follows:

- In Alberta, the Company spent $59.45 million mainly for drilling, completions and facilities targeting condensate-rich natural gas from the Montney. The Company drilled 11 (2.75 net) and completed seven (1.75 net) wells in 2014.
- In Saskatchewan, the Company spent $1.90 million, comprising $1.62 million incurred in Antler and $0.28 million for work relating to the Pasquia Hills oil shale acreage. In Antler, capital expenditures were focused on completing and tying in wells drilled in the prior year.
- In Manitoba, the Company spent $1.70 million to drill and complete three (1.05 net) wells and expand facilities in the Pierson area.

Questerre incurred net capital expenditures of $52.01 million in 2013 as follows:

- In Alberta, the Company spent $44.73 million, including $24.66 million on drilling, completions and facilities targeting condensate-rich natural gas from the Montney, $0.65 million to acquire 3-D seismic data and the remainder to acquire acreage in the Kakwa-Resthaven and Wapiti areas prospective for this formation.
- In Saskatchewan, the Company spent $4.38 million, comprising $4.14 million incurred in Antler and $0.24 million for work relating to the Pasquia Hills oil shale acreage. In Antler, capital expenditures were focused on drilling, completing and tying in wells, conversions for the pilot waterflood and the acquisition of 3-D seismic data.
- In Manitoba, the Company spent $2.25 million to drill and complete five (1.75 net) wells in the Pierson area.

Liquidity and Capital Resources

In June 2014, the Company's credit facilities were increased to $50 million. The facility is determined based on, among other things, the Company's current reserve report, results of operations, current and forecasted commodity prices and the current economic environment The next scheduled review of the Company's credit facilities is in April 2015. At December 31, 2014 no amount has been drawn on the credit facility and the financial covenants relating to the facility were met.

Questerre had a working capital deficit of $9.25 million at December 31, 2014 as compared to a surplus of $31.91 million at December 31, 2013. Management believes with its current credit facility and positive expected operating cash flows from operations in the near future that the Company will generate sufficient cash flows to meet its foreseeable obligations in the normal course of operations. On an ongoing basis the Company will review its capital expenditures to ensure that cash flow from operations or access to credit facilities are available to fund these capital expenditures. The Company has the flexibility to adjust capital expenditures based on cash flow from operations to manage debt levels. To this end, in early 2015, the Company reported a conservative capital program for 2015 and has and continues to work on strategies to reduce general and administrative costs subsequent to December 31, 2014. The Company also intends to maintain a debt to cash flow ratio at no more than 2.0. The Company 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. For a detailed discussion of the risks and uncertainties associated with the Company's business and operations, see the Risk Management section of this MD&A and the AIF.

Cash Flow from Operating Activities

Net cash from operating activities for the year ended December 31, 2014 and 2013 was $14.25 million and $14.41 million, respectively. The Company realized higher netbacks in 2014, which was partially offset by changes in non-cash working capital.

Cash Flow used in Investing Activities

Cash flow used in investing activities increased to $50.80 million in 2014 from $48.70 million in 2013. For the year ended December 31, 2014, the Company incurred capital expenditures of $63.58 million compared to $52.19 million for the same period in 2013. The higher net capital expenditures were mainly due to increased investment activity in the Kakwa-Resthaven area partially offset by less drilling and completion activity in Antler and Pierson in 2014.

In December 2014, the Company disposed of certain Antler assets for net proceeds of $6.93 million.

Cash Flow provided by Financing Activities

Cash flow provided by financing activities was $0.10 million in 2014 and $39.21 million in 2013. In 2013, the Company received $39.21 million from its private placement, flow-through share offering and option exercises.

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, 2014, 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 26, 2015	December 31, 2014	December 31, 2013
Common Shares	264,932	264,932	264,657
Stock options	16,665	17,792	18,188
Weighted average Common Shares			
Basic		264,890	236,691
Diluted		265,703	237,210

In 2014, the Company issued 275,000 Common Shares on option exercises for proceeds of $0.18 million.

A summary of the Company's stock option activity during the years ended December 31, 2014 and 2013 follows:

	December 31, 2014		December 31, 2013	
	Number of Options *(thousands)*	Weighted Average Exercise Price	Number of Options *(thousands)*	Weighted Average Exercise Price
Outstanding, beginning of year	18,188	$2.02	21,349	$2.24
Forfeited	(1,333)	2.26	(1,766)	1.67
Expired	-	-	(2,480)	4.66
Exercised	(313)	0.67	(4,493)	0.45
Granted	1,250	1.04	5,578	0.96
Outstanding, end of year	17,792	$1.96	18,188	$2.02
Exercisable, end of year	11,201	$2.56	9,352	$2.89

Commitments and Contingencies

Commitments

A summary of the Company's net commitments at December 31, 2014 follows:

($ thousands)	2015	2016	2017	2018	2019	Thereafter	Total
Transportation, Marketing and Processing	$ -	$ 2,726	$ 4,728	$ 4,728	$ 3,990	$ 27,932	$ 44,105
Office Lease	295	-	-	-	-	-	295
	$ 295	$ 2,726	$ 4,728	$ 4,728	$ 3,990	$ 27,932	$ 44,400

In the fall of 2013, the Company entered into a series of take or pay agreements for the processing, transportation, fractionating and marketing of 20 MMcf/d of raw gas and associated liquids production in the Kakwa-Resthaven area (the "Infrastructure Contracts"). The in-service date for the agreements is estimated to be late-2015/early-2016. In December 2014, the Company assigned a 57.5% interest in the Infrastructure Contracts on a permanent basis to third parties. Concurrently, the Company also assigned an 18.75% interest in the Infrastructure Contracts on a temporary basis to a third party until December 2016.

The Company has commitments under a lease for office space of $0.30 million in 2015.

Contingencies

On May 30, 2011, Talisman Energy Inc. filed a statement of claim at the Court of Queen's Bench of Alberta with respect to amounts formally disputed by Questerre. Questerre has filed its statement of defense and counterclaim with respect to this issue. The claim is for $3.91 million and the entire amount is accounted for in Questerre's consolidated financial statements.

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, they can be monitored and managed.

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 cash flow from operations, current cash balances, 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 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 as a result. Based on current funds available, expected cash flow from operations, the Company believes it has sufficient funds available to fund its projected capital expenditures. However, if cash flow from operations are lower than expected or capital costs for these projects exceed current estimates, or if the Company incurs major unanticipated expense related to development or maintenance of its existing properties, it may be required to seek additional capital to maintain its capital expenditures at planned levels. Failure to obtain any financing necessary for the Company's capital expenditure plans may result in a delay in development or production on the Company's properties.

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

The Company uses the following guidelines to address financial exposure:

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

Credit risk represents the potential financial loss to the Company if a customer or counterparty to a financial instrument fails to meet or discharge their obligation to the Company. Credit risk arises from the Company's receivables from joint venture partners and oil and gas marketers. In the event such entities fail to meet their contractual obligations to the Company, such failures may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. Credit risk also arises from the Company's cash and cash equivalents. 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.

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

Accounts receivable related to the sale of the Company's petroleum and natural gas production is paid in the following month from major oil and natural gas marketing companies and the Company has not experienced any credit loss relating to these sales 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, 2014, the Company had the following outstanding commodity risk management contract in place:

	Volumes	Average Price	Term	Fair Value Asset *($ thousands)*
Natural gas swap	2,000 gj/d	$3.72/gj	Jan. 1, 2015 - Dec. 31, 2015	$ 748

Environmental Regulation and Risk

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

Applicable provincial environmental laws in British Columbia, Alberta, Saskatchewan and Quebec are primarily found in the *Environmental Management Act*, *Environmental Protection and Enhancement Act*, *Environmental Management and Protection Act* 2002, and *Environmental Quality Act*, respectively. Environmental standards and compliance for releases, clean-up and reporting in each province are strict, and there is a range of enforcement actions available, with often severe penalties. All of these provinces review energy projects through environmental assessment processes, which may be held in conjunction with a federal assessment. These review processes involve public participation. Federal environmental laws such as the *Canadian Environmental Protection Act*, 1999 and the *Fisheries Act* also apply in a variety of circumstances. Potential risks to the environment are inherent in some of the business activities of the Company. Questerre endeavors to conduct its operations in a manner consistent with environmental regulations as stipulated in provincial and federal legislation.

Climate change is an issue that is increasingly subject to government regulation. In 2012, Canada withdrew from the Kyoto Protocol, established under the United Nations Framework Convention on Climate Change, which set legally binding targets to reduce nationwide emissions of carbon dioxide, methane, nitrous oxide and other so-called "greenhouse gases". Under the Copenhagen Accord, the intended successor to the Kyoto Protocol, which represents a broad political consensus rather than a binding international treaty like the Kyoto Protocol, Canada has committed to reducing its greenhouse gases emissions by 17% from 2005 levels by 2020. British Columbia, Alberta, Saskatchewan, Quebec and the federal Government have all introduced climate change action plans that include various means of achieving emissions or emissions intensity reductions, which may include direct reductions, emissions trading, carbon capture and storage, technology fund contributions, taxes on greenhouse gas emissions and credit for early action. Coordination between these plans has not yet been developed and remains a source of uncertainty. Given the evolving regulatory schemes related to climate change and the control of greenhouse gases and resulting requirements, it is not currently possible to predict the final form these requirements will take or the impact on Questerre and its operations and financial condition at this time.

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

All of Questerre's petroleum and natural gas reserves are evaluated and reported on by independent petroleum engineering consultants in accordance with NI 51-101. The estimation of reserves 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 the areas, in particular, the valuation of property, plant and equipment and the calculation of depletion.

Cash Generating Units

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

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

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

The recoverable amounts of CGUs have been determined based on the higher of value in use ("VIU") and the FVLCD. The key assumptions the Company uses in estimating future cash flows for recoverable amounts are anticipated future commodity prices, expected production volumes, the discount rate and future operating and development costs. 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 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 liability is recorded at fair value and is adjusted to its present value in subsequent periods and the amount of the accretion is charged to profit or loss in the period. 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. At each reporting date, the Company uses the Black-Scholes option pricing model as the fair value method for valuing stock options. 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 determination of the Company's income and other tax assets and 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 and liability may differ significantly from that estimated and recorded by management.

Investment in Red Leaf

Questerre has investments in certain private companies, including Red Leaf, which it classifies as an available for sale financial instrument and carries at fair value. The Company measures the fair market value of Red Leaf by reference to recent corporate transactions of Red Leaf or, in the absence of such transactions, other valuation techniques such as discounted cash flow analysis. The Company also assesses factors that might indicate that the corporate transaction price might not be representative of fair value at the measurement date. These factors include significant changes in the performance of the investee compared with budgets, plans or milestones, changes in management or strategy and significant changes in the price of oil. Considerable judgment is required in measuring the fair value of the Company's investment in Red Leaf, which may result in material adjustments to its related carrying value.

The Company also exercises judgment in its accounting for Red Leaf and the determination that the Company does not have significant influence over Red Leaf. Significant influence under IFRS represents the power to participate in the financial and operating policy decisions of the investee but is not control or joint control of those policies. Although the Company holds less than 20% of the equity of Red Leaf, the threshold for presumption of significant influence under IFRS, the Company's President and Chief Executive Officer is a member of Red Leaf's board of directors, which is considered a potential indicator of significant influence. The Company's accounting determination considered certain factors including the fact that the Company holds only one out of nine board seats, other board member composition and representation and Red Leaf's joint venture relationship with another company. Consequently, it was determined that the Company did not have significant influence and this investment has been accounted for as an available for sale financial instrument.

Accounting Standards Changes

Changes in Accounting Policies for 2014

Effective January 1, 2014, the Company adopted the following new standards and interpretations:

IAS 32 *Financial Instruments*

IAS 32 has been amended to clarify the requirements for offsetting financial assets and liabilities. The amendment clarifies that the right to offset must be available on the current date and cannot be contingent on a future event.

Adopting this accounting change had no impact on the Company's financial statements.

IFRIC 21 *Accounting for Levies*

IFRIC 21 was issued which clarifies that the obligating event giving rise to a liability to pay a levy is the activity described in the relevant legislation that triggers payment of the levy.

Adopting this accounting change had no impact on the Company's financial statements.

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 9 *Financial Instruments*

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

IFRS 15 *Revenue From Contracts With Customers*

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

The new standard is effective for annual periods beginning on or after January 1, 2017, with earlier adoption permitted. The standard may be applied retrospectively or using a modified retrospective approach. The Company is currently evaluating the impact of adopting IFRS 15 on the consolidated financial statements.

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" 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, 2014.
- 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, 2014 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 2014 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 2014 Results

Questerre's cash flow from operations increased from $2.94 million for the quarter ended December 31, 2013 to $4.29 million for the same period in 2014. The increase in cash flow from operations is mainly due to higher volumes and operating netbacks in 2014 than 2013.

Petroleum and natural gas revenue increased to $7.61 million for the three months ended December 31, 2014 compared to $5.76 million for the same period in 2013. The Company's realized price for oil and natural gas liquids was $71.84 per barrel for the fourth quarter of 2014 compared with $85.44 per barrel for the fourth quarter of 2013. Oil and natural gas liquids production increased from 692 bbls/d in the fourth quarter of 2013 to 982 bbls/d in the fourth quarter of 2014. The increased production was from the Company's Kakwa-Resthaven area wells that were brought on production through 2014. The increased production was partially offset by natural declines from existing assets.

Operating costs were $1.60 million or $11.81/boe for the three months ended December 31, 2014 compared to $1.02 million or $13.18/boe for the same period in 2013. The increase in operating costs is mainly due to higher production in 2014. On a per unit basis, operating costs decreased due to higher production from Kakwa-Resthaven, which has lower operating costs per boe.

Impairment of assets was $47.04 million for the three months ended December 31, 2014 compared to $21.75 million for the same period in 2013. In the fourth quarter of 2014, the Company recorded impairment charges, including $22.13 million for its property, plant and equipment and $24.78 million for its investments. The Company's impairment charges in 2013 mainly relating to costs associated with its 09-01 Well.

Total comprehensive loss for the three months ended December 31, 2014 was $49.19 million compared to $14.89 million for the same period in 2013. The comprehensive loss increase from 2013 is due to higher impairment charges recorded in 2014.

Capital expenditures were $16.60 million and $12.95 million for the three months ended December 31, 2014 and 2013, respectively. In 2014, the Company spent $15.70 million relating to its Kakwa-Resthaven assets, $0.37 million relating to its Pierson assets and $0.27 million relating to its Antler assets. In 2013, the Company spent $9.50 million relating to its Kakwa-Resthaven assets and $2.87 million relating to its Antler assets. In December 2014, the Company disposed of certain Antler assets for net proceeds of $6.93 million and recorded a loss on disposition of $2.93 million.

Quarterly Financial Information

($ thousands, except as noted)	December 31, 2014	September 30, 2014	June 30, 2014	March 31, 2014
Production (boe/d)	**1,468**	849	849	1,133
Average Realized Price ($/boe)	**71.84**	76.34	82.08	84.92
Petroleum and Natural Gas Sales	**7,613**	5,963	6,342	8,659
Cash Flow from Operations	**4,286**	2,557	3,009	5,542
Basic ($/share)	**0.02**	0.01	0.01	0.02
Diluted ($/share)	**0.02**	0.01	0.01	0.02
Net Profit (Loss)	**(42,900)**	680	520	1,179
Basic ($/share)	**(0.16)**	-	-	-
Diluted ($/share)	**(0.16)**	-	-	-
Capital Expenditures, net of acquisitions and dispositions	**9,672**	23,362	11,254	12,359
Working Capital Surplus (Deficit)	**(9,247)**	(3,861)	16,945	25,173
Total Assets	**234,174**	289,928	274,625	278,908
Shareholders' Equity	**196,858**	246,049	243,361	244,237
Weighted Average Common Shares Outstanding				
Basic (thousands)	**264,932**	264,932	264,928	264,763
Diluted (thousands)	**264,934**	265,976	266,081	265,918

($ thousands, except as noted)	December 31, 2013	September 30, 2013	June 30, 2013	March 31, 2013
Production (boe/d)	841	880	820	1,000
Average Realized Price ($/boe)	74.45	81.20	74.84	71.57
Petroleum and Natural Gas Sales	5,760	6,574	5,585	6,441
Cash Flow from Operations	2,941	3,641	2,962	3,649
Basic ($/share)	0.01	0.02	0.01	0.02
Diluted ($/share)	0.01	0.02	0.01	0.02
Net Profit (Loss)	(16,213)	(894)	(678)	(1,569)
Basic ($/share)	(0.07)	-	-	(0.01)
Diluted ($/share)	(0.07)	-	-	(0.01)
Capital Expenditures, net of acquisitions and dispositions	12,946	9,428	3,798	25,961
Working Capital Surplus (Deficit)	31,909	4,729	10,608	12,844
Total Assets	273,108	245,814	246,660	251,828
Shareholders' Equity	241,197	220,046	221,696	220,578
Weighted Average Common Shares Outstanding				
Basic (thousands)	243,213	235,298	235,240	232,914
Diluted (thousands)	244,479	235,442	235,546	234,042

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

- Production has increased from 885 boe/d for the year ended December 31, 2013 to 1,076 boe/d for the same period in 2014 due to higher production from the Kakwa-Resthaven area. Liquids production has decreased as a percentage of total production from 77% in 2013 to 70% in 2014.
- The Company's net loss for the fourth quarter of 2014 increased due to higher impairment charges.
- The working capital surplus (deficit) has decreased as the capital expenditures have been higher than the cash flow from operations. This was partially offset by the proceeds received in 2013 from share issuances.

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 chartered accountant firm, 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 26, 2015

Independent Auditor's Report

To the Shareholders of Questerre Energy Corporation

We have audited the accompanying consolidated financial statements of Questerre Energy Corporation (the "Company"), which comprise the consolidated balance sheets as at December 31, 2014 and December 31, 2013 and the consolidated statements of net profit or loss and comprehensive income or loss, changes in equity and cash flows for the years ended December 31, 2014 and December 31, 2013, 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 the Company as at December 31, 2014 and December 31, 2013 and its financial performance and its cash flows for the years ended December 31, 2014 and December 31, 2013 in accordance with International Financial Reporting Standards.

PricewaterhouseCoopers LLP

Chartered Accountants

Calgary, Alberta

March 26, 2015

Consolidated Balance Sheets

($ thousands)	Note	December 31, 2014	December 31, 2013
Assets			
Current Assets			
Cash and cash equivalents	5	$ 11,005	$ 47,459
Accounts receivable	6	2,607	2,630
Current portion of risk management contracts	6	748	-
Deposits and prepaid expenses		789	607
		15,149	50,696
Investments	7	16,541	46,078
Property, plant and equipment	8	96,007	99,267
Exploration and evaluation assets	9	83,789	56,442
Goodwill		2,346	2,346
Deferred tax assets	11	20,342	18,279
		$ 234,174	$ 273,108
Liabilities			
Current Liabilities			
Accounts payable and accrued liabilities		$ 23,648	$ 18,787
Current portion of risk management contracts	6	-	453
Flow-through share obligation	10	-	1,760
Current portion of share based compensation liability	12	4,445	2,825
		28,093	23,825
Asset retirement obligation	13	8,133	7,136
Share based compensation liability	12	1,090	950
		37,316	31,911
Shareholders' Equity			
Share capital	15	347,345	347,059
Contributed surplus		16,686	16,659
Accumulated other comprehensive income		128	4,259
Deficit		(167,301)	(126,780)
		196,858	241,197
		$ 234,174	$ 273,108

Commitments and contingencies (note 20)

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

Signed on behalf of the Board of Directors

Dennis Sykora
Director

Peder Paus
Director

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

($ thousands, except per share amounts)	Note		For the years ended December 31, 2014		2013
Revenue					
Petroleum and natural gas sales	16	$	28,577	$	24,359
Royalties			(2,279)		(1,868)
Petroleum and natural gas revenue, net of royalties			26,298		22,491
Expenses					
Direct operating			5,641		4,858
General and administrative			4,756		4,415
Depletion and depreciation	8		8,476		9,395
Impairment of assets	8,9		22,844		22,714
Impairment of investment	7		24,784		-
Loss on sale of property, plant and equipment			2,928		72
Loss (gain) on risk management contracts	6		(628)		1,112
Loss on investment in convertible bonds			-		1,525
Share based compensation	12		1,240		2,825
Accretion of asset retirement obligation	13		135		156
Interest income			(504)		(394)
Other expense			325		149
Loss before taxes			(43,699)		(24,336)
Deferred tax recovery	10,11		(3,178)		(4,982)
Net Loss			(40,521)		(19,354)
Other Comprehensive Income (Loss), Net of Tax					
Items that may be reclassified subsequently to profit or loss:					
Gain on foreign exchange	7		3,645		2,591
Reclass to profit (loss) on investment impairment	7		(7,776)		-
			(4,131)		2,591
Total Comprehensive Loss		$	(44,652)	$	(16,763)
Net Loss per Share					
Basic and diluted	15	$	(0.15)	$	(0.08)

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

Consolidated Statements of Changes in Equity

($ thousands)	Note	For the years ended December 31, 2014	2013
Share Capital			
Balance, beginning of year		$ 347,059	$ 307,035
Issue of common shares	15	350	41,612
Share issue costs (net of tax)	15	(64)	(1,588)
Balance, end of year		347,345	347,059
Contributed Surplus			
Balance, beginning of year		16,659	16,179
Reclassification of share based compensation	12	27	480
Balance, end of year		16,686	16,659
Accumulated Other Comprehensive Income			
Balance, beginning of year		4,259	1,668
Other comprehensive income (loss)		(4,131)	2,591
Balance, end of year		128	4,259
Deficit			
Balance, beginning of year		(126,780)	(107,426)
Net loss		(40,521)	(19,354)
Balance, end of year		(167,301)	(126,780)
Total Shareholders' Equity		$ 196,858	$ 241,197

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

Consolidated Statements of Cash Flows

($ thousands)	Note	For the years ended December 31, 2014	2013
Operating Activities			
Net loss		$ (40,521)	$ (19,354)
Adjustments for:			
Depletion and depreciation	8	8,476	9,395
Impairment of assets	8,9	22,844	22,714
Impairment of investments	7	24,784	-
Loss on sale of property, plant and equipment	8	2,928	72
Unrealized (gain) loss on risk management contracts	6	(1,201)	852
Unrealized loss on investment in convertible bonds		-	1,525
Share based compensation	12	1,240	2,825
Accretion of asset retirement obligation	13	135	156
Deferred tax recovery	10,11	(3,178)	(4,982)
Other items not involving cash		-	49
Cash paid on exercise of stock options		(24)	-
Abandonment expenditures	13	(89)	(60)
Cash flow from operations		15,394	13,192
Change in non-cash working capital	19	(1,146)	1,214
Net cash from operating activities		14,248	14,406
Investing Activities			
Property, plant and equipment expenditures	8	(2,865)	(20,240)
Exploration and evaluation expenditures	9	(60,710)	(31,946)
Sale of property, plant and equipment	8	6,929	53
Proceeds from sale of marketable securities		-	490
Change in non-cash working capital	19	5,848	2,948
Net cash used in investing activities		(50,798)	(48,695)
Financing Activities			
Proceeds from issue of share capital	15	184	41,349
Share issue costs	15	(88)	(2,142)
Net cash from financing activities		96	39,207
Change in cash and cash equivalents		(36,454)	4,918
Cash and cash equivalents, beginning of year		47,459	42,541
Cash and cash equivalents, end of year		$ 11,005	$ 47,459
Cash interest received		$ 604	$ 902

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

1. Reporting Entity

Questerre Energy Corporation ("Questerre" or the "Company") is a full cycle exploration and production company. The Company targets scalable high-impact projects and has developed a portfolio of exploration and production assets. The consolidated financial statements of the Company as at and for the years ended December 31, 2014 and 2013 comprise the Company and its wholly-owned subsidiary in those years owned.

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 – 6th 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 26, 2015, 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, financial assets classified as fair value through profit and loss and share based payment transactions 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.

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 petroleum engineering consultants in accordance with Canadian Securities Administrators' National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101"). The estimation of reserves 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 the areas, in particular, the valuation of property, plant and equipment and the calculation of depletion.

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

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 and future operating and development costs. 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 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.

Refer to Note 8 for the sensitivity analysis related to impairments and to Note 9 for further detail on the recoverability of the Company's Quebec exploration and evaluation 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.

Refer to Note 13 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 common shares or cash at exercise prices equal to the market price or above on the date the option is granted. At each reporting date, the Company uses the Black-Scholes option pricing model as the fair value method for valuing stock options. 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 12.

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 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 11 for the carrying amounts related to deferred taxes.

Investment in Red Leaf Resources

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

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

The Company also exercises judgment in its accounting for Red Leaf and the determination that the Company does not have significant influence over Red Leaf. Significant influence under IFRS represents the power to participate in the financial and operating policy decisions of the investee but is not control or joint control of those policies. Although the Company holds less than 20% of the equity of Red Leaf, the threshold for presumption of significant influence under IFRS, the Company's President and Chief Executive Officer is a board member of Red Leaf, which is considered a potential indicator of significant influence. The Company's accounting determination considered certain factors including the fact that the Company holds only one out of nine board seats, other board member composition and representation and Red Leaf's joint venture relationship with another company. Consequently, it was determined that the Company did not have significant influence and this investment has been accounted for as an available for sale financial instrument.

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

3. Significant Accounting Policies

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

a) Basis of consolidation

Subsidiaries

Subsidiaries are entities controlled by the Company. Control exists when the Company has the power to govern the financial and operating policies of an entity so as to obtain benefits from its activities. In assessing control, potential voting rights that currently are exercisable are taken into account.

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

Transactions eliminated on consolidation

Intercompany balances and transactions, and any unrealized income and expenses arising from intercompany transactions, are eliminated in preparing the consolidated financial statements.

b) Financial instruments

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

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

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

Financial assets and liabilities at fair value through profit or loss

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

Available for sale

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

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

Loans and receivables

Loans and receivables are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market. The Company's loans and receivables comprise receivables and cash and cash equivalents, and 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 accounts payable and accrued liabilities. Accounts payable and accrued liabilities are initially recognized at the amount required to be paid, less, when material, a discount to reduce the payables to fair value. Subsequently, trade payables are measured at amortized cost using the effective interest method.

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

c) Share capital

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

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

Recognition and measurement

Exploration and evaluation expenditures

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

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

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

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

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

Development and production costs

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

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

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

Other property, plant and equipment

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

Depletion and depreciation

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

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

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

e) Goodwill

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

f) Impairment

Non-financial assets

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

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

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

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

An impairment loss in respect of goodwill is not reversed. In respect of other assets, impairment losses recognized in prior years are assessed at each reporting date for any indications that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimates used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depletion and depreciation or amortization, if no impairment loss had been recognized. Impairment reversals are recognized in profit or loss.

<u>Financial assets</u>

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. As at January 24, 2011, the Company modified its stock option plan.

Prior to the modification, the Company accounted for its stock option plan using the fair value method. Under this method, compensation costs attributable to stock options granted to employees, officers or directors was 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 was recorded as an increase in common shares with a corresponding reduction in contributed surplus.

Under the revised option plan, obligations for payments of cash or common shares under the Company's stock option plan are accrued over the vesting period using fair values. Fair values are determined at each reporting date using the Black-Scholes option pricing model. Periodic changes in fair value are recognized in profit or loss as share based compensation expense (recovery) with a corresponding change to the liability. Obligations for cash payments are recorded as a share based compensation liability based on the fair value of the liability at the reporting date. When options are surrendered for cash, the cash settlement paid reduces the outstanding liability. When options are exercised for common shares, consideration paid by the holder is recorded to share capital in shareholders' equity.

Under both plans, 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) Marketable securities

Marketable securities are carried at fair value and unrealized gains or losses are recognized in other comprehensive income or loss in the period incurred.

j) Inventory

Inventory is recorded at the lower of cost or net realizable value. Cost is determined on a weighted average basis.

k) 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.

l) 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.

m) 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.

n) Flow-through shares

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

4. Changes in Accounting Policies and Disclosures

Changes in Accounting Policies for 2014

Effective January 1, 2014, the Company adopted the following new standards and interpretations:

IAS 32 *Financial Instruments*

IAS 32 has been amended to clarify the requirements for offsetting financial assets and liabilities. The amendment clarifies that the right to offset must be available on the current date and cannot be contingent on a future event.

Adopting this accounting change had no impact on the Company's financial statements.

IFRIC 21 *Accounting for Levies*

IFRIC 21 was issued which clarifies that the obligating event giving rise to a liability to pay a levy is the activity described in the relevant legislation that triggers payment of the levy.

Adopting this accounting change had no impact on the Company's financial statements.

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 9 *Financial Instruments*

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

IFRS 15 *Revenue From Contracts With Customers*

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

The new standard is effective for annual periods beginning on or after January 1, 2017, with earlier adoption permitted. The standard may be applied retrospectively or using a modified retrospective approach. The Company is currently evaluating the impact of adopting IFRS 15 on the consolidated financial statements.

5. Cash and Cash Equivalents

($ thousands)	December 31, 2014	December 31, 2013
Bank balances	$ 2,431	$ 6,668
Short-term bank deposits	8,574	40,791
	$ 11,005	$ 47,459

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, 2014 included cash and cash equivalents, accounts receivable, risk management contracts, deposits, investments and accounts payable and accrued liabilities. As at December 31, 2014, the fair values of the Company's financial assets and liabilities equaled their carrying values due to the short-term maturity, except for the Company's investments and the risk management contracts, which are recorded at fair value.

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

Level 1 Fair Value Measurements

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

Level 2 Fair Value Measurements

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

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

Level 3 Fair Value Measurements

Level 3 fair value measurements are based on unobservable information.

The Company's investments are considered a Level 3 instrument. The fair values are determined using a discounted cash flow approach. Refer to Note 7.

c) Credit risk

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

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

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

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

The Company's accounts receivables are aged as follows:

($ thousands)	December 31, 2014	December 31, 2013
Current	$ 2,366	$ 1,979
31 - 60 days	97	245
61 - 90 days	71	57
>90 days	167	443
Allowance for doubtful accounts	(94)	(94)
	$ 2,607	$ 2,630

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

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

d) Liquidity risk

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

Since the Company operates in the upstream oil and gas industry, it requires sufficient cash to fund capital programs necessary to maintain or increase production, develop reserves and to potentially acquire strategic assets. The Company's capital programs are funded principally by cash obtained through 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, 2014, the Company had the following outstanding commodity risk management contract in place:

	Volumes	Average Price	Term	Fair Value Asset *($ thousands)*
Natural gas swap	2,000 GJ/d	$3.72/GJ	Jan. 1, 2015 - Dec. 31, 2015	$ 748

The net risk management position is as follows:

($ thousands)	**December 31, 2014**	December 31, 2013
Risk Management Assets:		
Current portion	$ 748	$ -

($ thousands)	**December 31, 2014**	December 31, 2013
Risk Management Liabilities:		
Current portion	$ -	$ 453

The Company recorded an unrealized gain of $1.20 million for the year ended December 31, 2014 and an unrealized loss of $0.85 million for the same period in 2013. The Company also recorded a realized loss of $0.57 million for the year ended December 31, 2014 and a realized loss of $0.26 million for the same period in 2013.

The value of Questerre's commodity price risk management contracts fluctuate with changes in the underlying market price of the relevant commodity. For the Company's gas swap contracts, an increase or decrease of $1 to the AECO price, with all other variables being held constant, would result in a $0.18 million increase or decrease to net loss, respectively.

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. As at December 31, 2014, 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. The Company has had no debt outstanding, interest rate swaps or financial contracts in place at or during the period ended December 31, 2014.

f) Capital management

The Company believes with its current credit facility and positive expected operating cash flows from operations (an additional IFRS measure defined as net cash from operating activities before changes in non-cash working capital) in the near future that the Company will be able to meet its foreseeable obligations in the normal course of operations. On an ongoing basis the Company reviews its capital expenditures to ensure that cash flow from operations (an additional IFRS measure defined as net cash from operating activities before changes in non-cash working capital) or access to credit facilities are available to fund these capital expenditures. Refer to Note 14.

The volatility of commodity prices has a material impact on Questerre's cash 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. To this end, in early 2015, the Company reported a conservative capital program for 2015.

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

($ thousands)	December 31, 2014	December 31, 2013
Shareholders' equity	$ 196,858	$ 241,197

7. Investments

The investments balance comprises the following private company investments:

($ thousands)	December 31, 2014	December 31, 2013
Red Leaf	$ 15,948	$ 45,535
Investment in other private company	593	543
	$ 16,541	$ 46,078

Questerre has an equity interest in Red Leaf, a private Utah based oil shale and technology based company. Red Leaf's principal assets are its proprietary EcoShale® In-Capsule Technology to recover oil from shale in addition to its oil shale leases in the states of Wyoming and Utah. Red Leaf is currently in the Early Production System ("EPS") phase of commercializing its EcoShale® process. In 2014, Red Leaf approved the cost estimate for the EPS phase and began constructing a commercial scale pilot. Pending the results of the EPS phase, Red Leaf and its joint venture partner will then make a final investment decision to commence commercial oil shale production on its existing leases. If Red Leaf's EcoShale® In-Capsule technology is not technically feasibility or commercially viability, then the Company's investment in Red Leaf could be impaired.

The following table sets out the changes in investments:

($ thousands)		December 31, 2014		December 31, 2013
Balance, beginning of year	$	46,078	$	43,101
Gain (loss) on foreign exchange		4,181		2,977
Impairment		(33,718)		-
Balance, end of year	$	16,541	$	46,078

For the twelve months ended December 31, 2014, the gain on foreign exchange relating to investments was $4.18 million (December 31, 2013: gain $2.98 million), which was recorded in other comprehensive income (loss) net of deferred tax of $0.54 million (December 31, 2013: $0.39 million).

At December 31, 2014, an impairment loss of $33.72 million was recognized relating to the Company's investments. This represents the difference between the carrying value of its investment in Red Leaf and its estimated fair value. The Company recorded $24.78 million of the impairment in net loss and $8.93 million in other comprehensive income (loss) net of deferred tax of $1.16 million. The net loss recorded in other comprehensive income mainly represents the reversal of foreign exchange gains net of deferred tax.

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.

As there have been no equity issuances by Red Leaf since 2012 that serve as a proxy for the estimate of fair value, fair value was determined using discounted future after-tax cash flows. The estimate reflects the recent crude oil price environment and the corresponding decline in public equity markets for comparable oil and gas companies. The Company used a discount rate of 22%, which incorporated volatility measured by public companies similar to Red Leaf, considered the early stage of Red Leaf and applied a discount for liquidity. The Company also assigned a probability of economic or technical failure of 14.5% in measuring fair value.

8. Property, Plant and Equipment

Reconciliation of the property, plant and equipment assets:

($ thousands)	Oil and Natural Gas Assets	Other Assets	Total
Cost or deemed cost:			
Balance, December 31, 2012	$ 131,929	$ 1,281	$ 133,210
Additions	21,226	2	21,228
Transfer from exploration and evaluation assets	496	-	496
Balance, December 31, 2013	153,651	1,283	154,934
Additions	1,586	51	1,637
Disposition	(15,680)	-	(15,680)
Transfer from exploration and evaluation assets	36,129	-	36,129
Balance, December 31, 2014	**$ 175,686**	**$ 1,334**	**$ 177,020**
Accumulated depletion, depreciation and impairment losses:			
Balance, December 31, 2012	$ 43,408	$ 984	$ 44,392
Depletion and depreciation	9,295	100	9,395
Impairment	1,880	-	1,880
Balance, December 31, 2013	54,583	1,084	55,667
Depletion and depreciation	8,368	108	8,476
Disposition	(5,257)	-	(5,257)
Impairment	22,127	-	22,127
Balance, December 31, 2014	**$ 79,821**	**$ 1,192**	**$ 81,013**

($ thousands)	Oil and Natural Gas Assets	Other Assets	Total
Net book value:			
At December 31, 2013	$ 99,068	$ 199	$ 99,267
At December 31, 2014	**$ 95,865**	**$ 142**	**$ 96,007**

During the year ended December 31, 2014, the Company capitalized administrative overhead charges of $0.04 million (December 31, 2013: $2.14 million) including $0.04 million in capitalized stock based compensation expense directly related to development activities (December 31, 2013: $0.86 million). Included in the December 31, 2014 depletion calculation are future development costs of $112.77 million (December 31, 2013: $73.41 million).

In December 2014, the Company disposed of certain Antler assets for net proceeds of $6.93 million and recorded a loss on disposition of $2.93 million.

At December 31, 2014, the Company reviewed the carrying amounts of its oil and gas assets for indicators of impairment such as changes in future prices, future costs and reserves. Based on this review, the Company's CGUs 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 estimate of FVLCD was determined using a discount rate of 10% and forecasted after-tax cash flows from 2014 to 2050 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:

	2015	2016	2017	2018	2019	Average Annual % Change Thereafter
WTI (US$/barrel)	65.00	75.00	80.00	84.90	89.30	0.02
AECO ($/MMbtu)	3.50	4.00	4.25	4.50	4.70	0.03

Based on this assessment, the Company recorded an impairment loss of $22.13 million relating to its Antler, Midway and Vulcan Alberta CGUs. The factor that led to the impairment was a reduction in forecasted commodity prices in the near-term. The recoverable amounts at December 31, 2014 for these CGUs are as follows:

($ thousands)	Antler	Midway	Vulcan
Recoverable amounts	$ 35,504	$ 143	$ 839

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 of goodwill	$ -	$ -	$ -	$ -
Impairment charge (recovery) of property, plant and equipment	$ (3,458)	$ 3,100	$ (4,451)	$ 4,451

9. Exploration and Evaluation Assets

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

Reconciliation of the movements in exploration and evaluation assets:

($ thousands)		December 31, 2014		December 31, 2013
Balance, beginning of year	$	56,442	$	45,477
Additions		64,352		32,420
Transfers to property, plant and equipment		(36,129)		(496)
Dispositions		(159)		(125)
Impairment		(717)		(20,834)
Balance, end of year	$	83,789	$	56,442

During the year ended December 31, 2014, the Company capitalized administrative overhead charges of $2.89 million (December 31, 2013: $0.63 million) including $0.69 million of capitalized stock based compensation expense directly related to exploration and evaluation activities (December 31, 2013: $0.21 million).

The Company reviewed the carrying amounts of its exploration and evaluation assets at December 31, 2014. The Quebec CGU was tested for impairment in accordance with its accounting policy. The recoverable amount of the Quebec CGU was estimated based on the higher of the value-in-use and FVLCD. The estimate of FVLCD was determined using a 20% discount rate and forecasted after-tax cash flows of a prospective development program. Additionally, the cash flows were discounted by 80% to reflect the political and associated risk that the development would not proceed. Based on this assessment, no impairment expense was recorded.

The Quebec CGU represents $27.48 million of the exploration and evaluation asset balance. The future recoverability of these assets is dependent upon, among other things, the Quebec government's decision to permit drilling and modern completion operations, including hydraulic fracturing, on this acreage and the Company securing its social license to operate in the province. If the government disallows such activities for an extended period, or the Company decides not to further activities for this project in the future, then the associated asset may be derecognized.

The impairment expense for the year ended December 31, 2014 is for undeveloped land expiries.

10. Flow-Through Share Obligation

The following table provides a reconciliation of the Company's flow-through share obligation:

($ thousands)		December 31, 2014		December 31, 2013
Balance, beginning of year	$	1,760	$	-
Liability recognized on flow-through share issuance		-		1,760
Liabilities settled		(1,760)		-
Balance, end of year	$	-	$	1,760

At December 31, 2013, a premium of $1.76 million related to the issuance of the Class "A" common voting shares ("Common Shares") on a flow-through basis was recorded as a liability on the consolidated statement of financial position. The liability is derecognized, with a corresponding decrease in deferred tax expense, as the Company incurs qualifying exploration expenditures. At December 31, 2014, the Company incurred qualifying exploration expenditures to satisfy the required $9.09 million and recorded a reduction to the flow-through share obligation of $1.76 million with a corresponding decrease to deferred tax expense.

11. 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, 2014		December 31, 2013
Net loss before taxes	$	(43,699)	$	(24,336)
Combined federal and provincial tax rate		25.69%		25.69%
Computed "expected" deferred tax recovery		(11,226)		(6,252)
Increase (decrease) in deferred taxes resulting from:				
Non-deductible differences		4,245		1,171
Recognition of previously unrecognized deferred tax asset		-		(141)
Deferred tax asset not recognized in year		3,760		-
Rate adjustments		(3)		160
Other		46		80
Deferred tax recovery	$	(3,178)	$	(4,982)

The statutory tax rate was 25.69% in 2013 and 2014.

The movement of the deferred tax asset is as follows:

($ thousands)		December 31, 2014		December 31, 2013
Balance, beginning of year	$	18,279	$	13,128
Credit to statement of net profit or loss		3,178		4,982
Tax on share issue costs		22		555
Tax charge relating to flow through shares		(1,758)		-
Tax charge (recovery) relating to components of other comprehensive income or loss		621		(386)
Balance, end of year	$	20,342	$	18,279

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, 2012	$	(1,581)	$	1,722	$	702	$	13,983
Credited (charged) to net profit or loss		(558)		111		(485)		5,296
Credited to share capital		-		-		555		-
Balance, December 31, 2013		(2,139)		1,833		772		19,279
Credited (charged) to net profit or loss		2,549		256		(446)		13
Credited to share capital		-		-		22		-
Balance, December 31, 2014	**$**	**410**	**$**	**2,089**	**$**	**348**	**$**	**19,292**

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 and probable reserves, will be sufficient to provide future taxable profits to utilize the deferred tax assets.

Non-capital loss carry-forwards at December 31, 2014 expire from 2026 to 2033.

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

($ thousands)		Investments		Other
Deferred tax liability:				
Balance, December 31, 2012	$	1,974	$	(276)
Charged (credited) to net profit or loss		(108)		(510)
Charged to other comprehensive income or loss		386		-
Balance, December 31, 2013		2,252		(786)
Charged (credited) to net profit or loss		(2)		955
Charged to other comprehensive income or loss		(621)		-
Balance, December 31, 2014	**$**	**1,629**	**$**	**169**

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

($ thousands)	December 31, 2014	December 31, 2013
Petroleum and natural gas properties	$ 219	$ 219
Investments	24,687	-
Capital losses	36,488	31,750
	$ 61,394	$ 31,969

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

12. Share Based Compensation

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

Under the Company's option plan, a put right is included that allows the optionee to settle options with cash or equity. The Company has the option to decline a put right exercise at any time. Under the put right, the optionee will receive the net cash proceeds that is the excess of the closing price at the day of the put notice over the exercise price. Once the options are cash settled, the options are cancelled.

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

	December 31, 2014		December 31, 2013	
	Number of Options *(thousands)*	Weighted Average Exercise Price	Number of Options *(thousands)*	Weighted Average Exercise Price
Outstanding, beginning of year	18,188	$2.02	21,349	$2.24
Forfeited	(1,333)	2.26	(1,766)	1.67
Expired	-	-	(2,480)	4.66
Exercised	(313)	0.67	(4,493)	0.45
Granted	1,250	1.04	5,578	0.96
Outstanding, end of year	17,792	$1.96	18,188	$2.02
Exercisable, end of year	11,201	$2.56	9,352	$2.89

The following table summarizes information about stock options outstanding and exercisable at December 31, 2014:

	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
$0.40 - $0.75	2,619	2.41	$0.60	1,508	2.07	$0.62
$0.76 - $1.00	3,910	3.20	0.87	906	2.21	0.86
$1.01 - $1.50	3,915	2.99	1.27	1,439	1.09	1.46
$1.51 - $2.50	2,693	0.75	2.25	2,693	0.75	2.25
$2.51 - $4.03	4,655	0.23	4.03	4,655	0.23	4.03
	17,792	1.89	$1.96	11,201	0.87	$2.56

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 2014:

	December 31, 2014	December 31, 2013
Weighted average fair value per award ($)	0.53	0.82
Volatility (%)	62.48	67.77
Forfeiture rate (%)	8.49	6.70
Expected life (years)	4.48	4.66
Risk free interest rate (%)	1.42	1.82

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

The following table provides a reconciliation of the Company's share based compensation liability:

($ thousands)	December 31, 2014	December 31, 2013
Balance, beginning of year	$ 3,775	$ 2,384
Amount transferred to contributed surplus	(27)	(480)
Share based compensation expense	1,240	2,825
Capitalized share based compensation	737	1,068
Cash payment for options exercised	(24)	-
Reclassification to share capital on exercise of stock options	(166)	(2,022)
Balance, end of year	$ 5,535	$ 3,775
Current portion	$ 4,445	$ 2,825
Non-current portion	1,090	950
	$ 5,535	$ 3,775

The current portion represents the maximum amount of the liability payable within the next 12-month period if all vested options are surrendered for cash settlement.

13. Asset Retirement Obligation

The Company's asset retirement and abandonment obligations result from its ownership interest in oil and natural gas assets. The total asset retirement obligation is estimated based on the Company's net ownership interest in all wells and facilities, estimated costs to reclaim and abandon these wells and facilities and the estimated timing of the costs to be incurred in future periods. The Company has estimated the net present value of the asset retirement obligation to be $8.13 million as at December 31, 2014 (December 31, 2013: $7.14 million) based on an undiscounted total future liability of $11.50 million (December 31, 2013: $11.27 million). These payments are expected to be made over the next 36 years. The average discount factor, being the risk-free rate related to the liabilities, is 1.94% (December 31, 2013: 2.65%). An inflation rate of 3% 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, 2014	December 31, 2013
Balance, beginning of year	$ 7,136	$ 6,644
Liabilities disposed	(726)	-
Liabilities incurred	1,476	555
Liabilities settled	(89)	(60)
Revisions due to change in discount rates	270	(725)
Revisions due to change in estimates	(69)	566
Accretion	135	156
Balance, end of year	$ 8,133	$ 7,136

14. Credit Facility

In June 2014, the Company increased its credit facilities with a Canadian chartered bank to $50 million. The next scheduled review of the Company's credit facilities is in April 2015. The credit facilities include a revolving operating demand loan and a non-revolving acquisition and development loan. 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% 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 bank credit facility, the Company has provided its covenant that it will maintain an Adjusted Working Capital Ratio greater than 1.0. This ratio is defined as current assets, excluding unrealized hedging gains, to current liabilities, excluding bank debt and unrealized hedging losses. The Adjusted Working Capital Ratio at December 31, 2014 was 2.29 and the covenant is met. At December 31, 2014 no amount has been drawn on the credit facility.

15. 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, 2014, 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, 2012	230,804	$	307,035
Issued on exercise of options	4,493	$	4,044
Issued on private placement	23,495	$	30,237
Issued on flow-through share offering	5,865	$	7,331
Share issue costs (net of tax effect)	-		(1,588)
Balance, December 31, 2013	264,657		347,059
Issued on exercise of options	275		350
Share issue costs (net of tax effect)	-		(64)
Balance, December 31, 2014	**264,932**	**$**	**347,345**

b) Per share amounts

Basic net profit or loss per share is calculated as follows:

(thousands, except as noted)		**December 31, 2014**		December 31, 2013
Net loss ($ thousands)	$	**(40,521)**	$	(19,354)
Issued Common Shares at beginning of year		**264,657**		230,804
Options exercised		**233**		3,891
Private placement of Common Shares		-		1,867
Flow-through share offering		-		129
Weighted average number of Common Shares outstanding (basic)		**264,890**		236,691
Basic net loss per share	$	**(0.15)**	$	(0.08)

Diluted net profit or loss per share is calculated as follows:

(thousands, except as noted)		**December 31, 2014**		December 31, 2013
Net loss ($ thousands)	$	**(40,521)**	$	(19,354)
Weighted average number of Common Shares outstanding (basic)		**264,890**		236,691
Effect of outstanding options		-		-
Weighted average number of Common Shares outstanding (diluted)		**264,890**		236,691
Diluted profit per share	$	**(0.15)**	$	(0.08)

Under the current stock option plan, options can be exchanged for Common Shares or for cash at the Company's discretion. As a result, they are considered potentially dilutive and are included in the calculation of diluted profit per share for the period. The average market value of 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, 2014 and 2013, all options were excluded from the diluted weighted average number of Common Shares outstanding calculation as their effect would have been anti-dilutive.

16. Petroleum and Natural Gas Sales

($ thousands)		December 31, 2014		December 31, 2013
Oil and liquids	$	24,819	$	22,758
Natural gas		3,758		1,601
	$	28,577	$	24,359

17. Employee Salaries and Benefits

($ thousands)		December 31, 2014		December 31, 2013
Salaries, bonuses and other short-term benefits	$	3,380	$	3,195
Share based compensation		1,977		3,893
	$	5,357	$	7,088

18. Key Management Compensation

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

($ thousands)		December 31, 2014		December 31, 2013
Salaries, bonuses, director fees and other short-term benefits	$	2,552	$	2,236
Share based compensation payable		4,492		2,973
	$	7,044	$	5,209

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 $1.26 million at December 31, 2014.

19. Supplemental Cash Flow Information

Changes in non-cash working capital:

($ thousands)	December 31, 2014	December 31, 2013
Accounts receivable	$ 23	$ 2,316
Deposits and prepaid expenses	(182)	(61)
Accounts payable and accrued liabilities	4,861	1,907
Change in non-cash working capital	$ 4,702	$ 4,162
Related to:		
Operating activities	$ (1,146)	$ 1,214
Investing activities	5,848	2,948
	$ 4,702	$ 4,162

20. Commitments and Contingencies

Commitments

A summary of the Company's net commitments at December 31, 2014 follows:

($ thousands)	2015	2016	2017	2018	2019	Thereafter	Total
Transportation, Marketing and Processing	$ -	$ 2,726	$ 4,728	$ 4,728	$ 3,990	$ 27,932	$ 44,105
Office Lease	295	-	-	-	-	-	295
	$ 295	$ 2,726	$ 4,728	$ 4,728	$ 3,990	$ 27,932	$ 44,400

In the fall of 2013, the Company entered into a series of take or pay agreements for the processing, transportation, fractionating and marketing of 20 MMcf/d of raw gas and associated liquids production in the Kakwa-Resthaven area (the "Infrastructure Contracts"). The in-service date for the agreements is estimated to be late-2015/early-2016. In December 2014, the Company assigned a 57.5% interest in the Infrastructure Contracts on a permanent basis to third parties. Concurrently, the Company also assigned an 18.75% interest in the Infrastructure Contracts on a temporary basis to a third party until December 2016.

The Company has commitments under a lease for office space of $0.30 million in 2015.

Contingencies

On May 30, 2011, Talisman Energy Inc. filed a statement of claim at the Court of Queen's Bench of Alberta with respect to amounts formally disputed by Questerre. Questerre has filed its statement of defense and counterclaim with respect to this issue. The claim is for $3.91 million and the entire amount is accounted for in Questerre's consolidated financial statements.

Corporate Information

Directors

Michael Binnion

Alain Sans Cartier

Earl Hickok

Peder Paus

Ted Roberts

Dennis Sykora

Bjorn Inge Tonnessen

Officers

Michael Binnion
President and
Chief Executive Officer

Frank Walsh
Chief Operating Officer

John Brodylo
VP Exploration

Peter Coldham
VP Engineering

Chris Daunhauer
VP Finance

Jason D'Silva
Chief Financial Officer

Ian Nicholson
VP Geology,
Western Canada

Rick Tityk
VP Land

Keith Wilford
VP Operations

Bankers

Canadian Western Bank
200, 606 Fourth Street SW
Calgary, Alberta
T2P 1T1

Legal Counsel

Borden Ladner Gervais LLP
1900, 520 Third Avenue SW
Calgary, Alberta
T2P 0R3

Transfer Agent

Computershare Trust
Company of Canada
600, 530 Eighth Avenue SW
Calgary, Alberta
T2P 3S8

DNB Bank ASA
Dronning Eufemias gate 30
N-0021 Oslo, Norway

Auditors

PricewaterhouseCoopers LLP
3100, 111 Fifth Avenue SW
Calgary, Alberta
T2P 5L3

Independent Reservoir Engineers

McDaniel & Associates Consultants Ltd.
2200, 255 Fifth Avenue SW
Calgary, Alberta
T2P 3G6

Netherland, Sewell & Associates, Inc.
1601 Elm Street, Suite 4500
Dallas, Texas
75201

Head Office

1650 AMEC Place
801 Sixth Avenue SW
Calgary, Alberta T2P 3W2
Telephone: (403) 777-1185
Facsimile: (403) 777-1578
Web: www.questerre.com
Email: info@questerre.com

Stock Information

Toronto Stock Exchange
Oslo Stock Exchange
Symbol: QEC

1650 AMEC Place
801 Sixth Avenue SW
Calgary, Alberta T2P 3W2
Telephone: (403) 777-1185
Facsimile: (403) 777-1578
Web: www.questerre.com
Email: info@questerre.com