2015 ANNUAL REPORT

QUESTERRE ENERGY CORPORATION

2015

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

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

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

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

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

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

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

President's message

Geology still matters.

Our results in 2015 reflect the importance of being in the right rock. Despite weak prices, our top tier Montney assets delivered meaningful production and cash flow growth. We drilled longer wells and optimized completions to increase recovery and returns on developing this condensate-rich resource.

Proving up our oil shale resources was setback as Red Leaf and Total delayed their first commercial-scale capsule by two to three years. As they re-engineer the capsule design to be profitable at US$55-$60/bbl, we high-graded our portfolio. We relinquished the rights to our Wyoming acreage, deferred work in Saskatchewan and acquired a new project in the Kingdom of Jordan. Early work suggests this project might have the best rock and right scale to be among the top oil shale resources in the world.

For 2016, our capital program will remain restricted to maintain liquidity. We are participating in additional wells on our Montney acreage selectively. At Antler, we are optimizing wells and our pilot waterflood to incrementally grow production. Limited capital will be invested to evaluate our Jordanian oil shale project and possible development. Lastly, our public and government relations work will continue in Quebec to achieve social acceptability for our Utica shale discovery.

Highlights

- Recognized as top publicly traded emerging producer by the Explorers and Producers Association of Canada for 2015
- Cash flow from operations of $9.78 million and average daily production of 1,582 boe/d for the year
- Corporate total gross proved plus probable reserves of 12.9 MMboe with a before income tax NPV-10% of $119.34 million
- Kakwa development continued with joint venture facility expansion and extended-reach horizontals using optimized completions
- Rationalized oil shale portfolio with new MOU for acreage in Jordan and terminated agreement for Wyoming acreage

Kakwa-Resthaven, Alberta

We spud the first well at Kakwa four years ago this February.

Within the Montney fairway covering over 50,000 square miles, we targeted a sweet spot that was between underlying reefs, where condensate rates were likely to be 50 bbls/MMcf or better, the reservoir sufficiently overpressured and not too deep that drilling would be too expensive. Due to the premium value, condensate production rates were very important as natural gas was below $3/Mcf.

The discovery well, 13-17, tested at almost 140 bbls/MMcf of condensate and subsequent wells have produced at similar or higher rates over the last two years. Currently averaging about 180 bbls/MMcf, our rates are in line with our competitors in the vicinity and endorse our ideas that we are in the right rock.

Although condensate rates have been high, payouts with existing recoveries have been challenged by lower prices. In 2015, we made material efficiency gains by optimizing completions and drilling longer wells.

The new completions use a sliding sleeve system that discretely places frac treatments and places them closer together. This is supposed to increase the stimulated reservoir and the volume of gas and condensate produced. The longer horizontals allow us to place more frac treatments at a lower marginal cost. The combination of the longer wells and more effective completions should translate into a higher recovery at a lower overall cost.

Early indications are positive. On section 25, our three recent wells have horizontals averaging 2200m and new completions. We have one well on this section drilled in 2013 that has a horizontal of 1200m using a more dated completion design. Initial production rates over the first thirty days for the newer wells are almost 75% higher and the best estimate of Expected Ultimate Recoveries, as evaluated by our reserve engineers, are almost double at one million boe. Drilling costs per metre of horizontal for the three newer wells are about 40% lower, averaging $1,800/m. Our last well, 03-18, has a horizontal of 2900m and an estimated cost of $1,700/m. We hope to continue this trend of longer horizontals and lower costs with future wells this year.

In addition to drilling longer wells at a lower cost, we could drill more wells than initially planned on the same acreage. The lack of pressure communication between frac treatments, thus far, implies spacing between wells can be reduced further, down to 200m. This means that on our 16 section joint venture block we now estimate there are over 75 gross locations remaining, of which 90% have horizontals of over 2200m.

Based on the results and progress on our joint venture acreage, our offsetting seven net sections could be just as prospective. It has the potential to triple our net locations from 19 above to 58. As the land is held till 2021, we are conserving capital and monitoring the activity around us, including two wells that were recently tied-in.

Oil Shale Mining

While much less mature than our Montney assets, our oil shale assets, particularly the acreage in Jordan, are orders of magnitude larger. They are important to our business plan of capturing large scale and high quality resources early.

Like other large scale oil projects, such as the oil sands, they require higher prices. We are improving the chances for development in the 'lower for longer' price environment by high grading projects and focusing on acreage with the right rock. This right rock for oil shale is rich, thick, areally extensive and reasonably close to surface to ensure mining costs are not too expensive.

Our new project in Jordan, covering over 140 square miles, met these criteria. Core we took last fall fits with existing core data, indicating average yields of 25 gallons/ton over a 40m interval. As noted last fall, we are benchmarking against the Green River shale in Utah, the largest oil shale resource in the world, where we estimate the average yield on a selective sweet spot is 21 gallon/ton over an 18m interval.

We are in the very early stages of assessing this resource, and the ore, specifically its suitability for retorting and processing the products from the process - water, sulphur, oil, gas and other minerals. This work is essential to evaluating commercial development under Red Leaf's EcoShale process and other existing retorting technologies.

The work by Red Leaf to make the EcoShale process profitable at lower prices is encouraging, both from our perspective as a licensee and a shareholder. As detailed in their fourth quarter 2015 report, Red Leaf's CEO commented that the move from indirect heating, using a series of pipes to circulate heat in the capsule, to direct heating, injecting hot gas directly into the capsule, has enabled them to greatly simplify design and reduce material and construction costs. We are looking forward to the results from the next phase of engineering for the associated oil processing and recovery plant due later this year.

Operational & Financial

The commissioning of the central facility expansion at Kakwa contributed to a 47% increase in production over the prior year to 1,582 boe/d in 2015. Kakwa represented just over 75% of Company volumes in the year compared to just under 50% last year.

Despite the higher production volumes, materially lower realized prices resulted in cash flow from operations of $9.78 million, down from $14.89 million in 2014.

Net income for the year was impacted by impairment charges of $69.6 million. Of this amount, about 40% relates to the carrying value of producing assets which declined due to lower prices, 40% relates to the impairment of its exploration assets, primarily Quebec due to external views on the risk of new legislation, and the remainder relates to the further impairment of our investment in Red Leaf.

Consistent with 2014, Kakwa represented approximately 90% of capital investment that totaled $20.52 million in the year.

Outlook

Capital for 2016 will be restricted to maintain financial flexibility in the current pricing environment.

Our limited investment at Kakwa could see net declines in production but will help maintain producing reserves that underpin the credit facility. This will build on the successful optimization work last year and is essential to improving our returns. While the economics of the Montney at Kakwa are top decile, we are mindful of over capitalizing this asset with long payouts and our existing balance sheet capability.

Investing in our Jordanian oil shale assets will not add reserves or production in the near term; but we believe the work is warranted relative to its prospectivity.

We are still optimistic about our Quebec Utica shale discovery and eventually resuming the work to prove commerciality.

This has taken considerably longer than we hoped. Our sustained optimism is in part due to the growing coalition of support and the government's commitment to release its ten-year energy policy and hydrocarbon legislation this spring. Though there have been delays to the original timeline, the government has, for the most part, remained on track.

We are also optimistic that this could be better than we have expected. A Canadian Energy Research Institute report notes that the Utica shale could have the second lowest supply costs for Quebec at C$3.72/Mcf, behind only the Marcellus shale. More interesting are the results from the dry gas window of the same Utica shale in Ohio and Pennsylvania. The US EIA estimates Utica production has grown to approximately 3 Bcf/d in nearly three years and recent wells are reported testing at IP30s of over 30 MMcf/d. We are confident that our acreage has the potential to deliver similar results.

Michael Binnion
President and Chief Executive Officer

Kakwa-Resthaven, Alberta

The Kakwa-Resthaven area is situated approximately 75 kilometres south of Grande Prairie in west central Alberta. Among other zones of interest, the area is prospective for condensate-rich natural gas in the deep, over-pressured fairway of the Montney formation, at a depth of approximately 3,100 metres to 3,600 metres. Questerre's wells are currently targeting one of three prospective intervals in the Upper Montney formation. Economics are enhanced by relatively high liquids content, particularly condensate, and Crown royalty incentives for new deep horizontal gas wells with initial royalty rates of up to 5%.

Questerre currently holds 19,040 (11,000 net) acres in the area, including a 100% working interest and operatorship of 8,320 net acres. In addition, the Company holds a further 24,320 net acres in the Wapiti area, approximately 20 miles to the northwest also prospective for the Montney formation.

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

In 2015, on its joint venture acreage, Questerre participated in the drilling of one (0.25 net) well and the completion of six (1.5 net) wells. The Company also participated in an expansion of existing infrastructure on this acreage where it holds a 25% working interest.

Production from this area averaged 1,200 boe/d in 2015 with liquids, primarily condensate, accounting for 50% of this amount.

The wells completed in 2015 benefitted from enhanced completion programs designed to place between 60 and 85 individual slickwater fracture treatments in the horizontal sections that ranged in length from approximately 2000m to 2400m. Based on the preliminary production results, it is expected that future wells will be completed using similar programs optimized further for inter treatment spacing and sand tonnage.

Infrastructure was expanded early in the year to tie-in recently completed wells and plan for future development. Approximately 11 miles of additional pipeline was constructed for the local gathering system. The capacity of the central compression and condensate stabilization facility was also increased from 15 MMcf/d to 30 MMcf/d plus associated liquids. Concurrently, a tie-in was constructed to a third party pipeline to mitigate the cost of trucking condensate to the injection station for this pipeline.

During the year, limited activity was conducted on the Company's operated acreage in light of low commodity prices.

Questerre expects to participate selectively in additional wells drilled on the joint venture acreage in 2016. The Company anticipates that these additional wells will support production to meet the joint venture's take or pay commitments for processing and transportation.

Antler, Saskatchewan

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

Production from this area averaged 200 bbl/d in 2015.

In 2015, activities at Antler focused on optimization of existing production and the pilot waterflood to increase recovery of the oil in place. The waterflood pilot consists of four horizontal wells on two sections injecting approximately 1,100 bbl/d of water into the oil pool. Injection pressures were increased during the year and initial responses suggest an improvement in production rates from offsetting horizontal and vertical wells.

In 2016, the Company plans to increase injection volumes to further accelerate the production response and continue work to optimize production.

Oil Shale Mining

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

Red Leaf has entered into a joint venture with a US affiliate of the French-based supermajor, Total S.A. ("Total") to develop the company's oil shale assets in Utah. In 2012, 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. In 2015, the joint venture elected to defer the construction of its first commercial-scale capsule under the EPS phase for two to three years while it optimized the capsule design. Total has agreed to make payments of up to US$85 million to Red Leaf to fund the costs related to this deferral, including contract cancellation, and the optimization of capsule design.

In June, the Company was notified by Red Leaf that due, to its limited resources, it terminated the exploration license and option to lease agreement with a US-based independent for its oil shale project in Wyoming. Questerre had the right to earn a 20% working interest in this agreement. Questerre has no further rights or obligations related to this acreage.

With the commercialization of the EcoShale process suspended and the lower yields than expected under this process from its oil shale at Pasquia Hills, the Company elected to suspend further work in Saskatchewan during the year.

In the second quarter of 2015, the Company concluded a Memorandum of Understanding ("MOU") for the appraisal and development of oil shale acreage in the Hashemite Kingdom of Jordan. The MOU covers an area of 388 square kilometers in the Isfir-Jafr area, approximately 200 km south of the capital, Amman. The initial term of the MOU is two years and it may be extended. The Company estimates its financial commitments to range between $3 million and $5 million over the initial term.

A field program began in the fall to assess this acreage. Two hydrology studies were conducted and a five well core program completed. Subject to results, the Company intends to develop a subsequent work program that would be conducted during the initial phase of a subsequent concession agreement.

In 2016, the Company will continue appraisal of its Jordanian oil shale assets. The two main objectives are the evaluation of the scale and nature of the resource and the feasibility of commercial development.

St. Lawrence Lowlands, Quebec

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

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

Following a successful vertical test well program in 2008 and 2009, Questerre and its partner, Repsol Oil & Gas Canada Inc. (formerly Talisman Energy Inc.), began a pilot horizontal well program to assess commerciality of the Utica shale in 2010. In the fall of 2010, the pilot program was suspended while the provincial government initiated the Strategic Environmental Assessment ("SEA"). In the summer of 2014, the government extended the tenure of exploration permits held to beyond 2021.

In the fourth quarter of 2015, the Government published the majority of the studies from its current environmental assessment and conducted public hearings. The final studies are expected to be released in early 2016 and followed by further public consultation. In conjunction, the Ministry of Natural Resources recently published its 'green book' outlining the requirements for social acceptability for energy projects.

Pursuant to its strategic plan for 2015-2018, the Government is scheduled to announce its energy policy followed by draft hydrocarbon legislation in 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 24, 2016. 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, 2015 and 2014. Additional information relating to Questerre, including Questerre's Annual Information Form for the year ended December 31, 2015 ("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. 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;

- appraisal plans, drilling plans, secondary recovery schemes, including waterflood, and timing and manner 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;
- treatment under governmental and other regulatory regimes and tax, environmental and other laws;
- critical accounting estimates and the potential impacts thereof; and
- 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, the Corporation’s Annual Information Form, dated March 24, 2016, and the documents incorporated by reference into this document:

- volatility in market prices for oil, natural gas liquids and natural gas;
- counterparty credit risk;
- access to capital;
- the terms and availability of credit facilities;

- changes or fluctuations in oil, natural gas liquids and natural gas production levels;
- liabilities inherent in oil and natural gas operations;
- adverse regulatory rulings, orders and decisions;
- attracting, retaining and motivating skilled personnel;
- uncertainties associated with estimating oil and natural gas reserves;
- 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.

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

Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward-looking statements contained in this MD&A and the documents incorporated by reference herein are expressly qualified by this cautionary statement. We do not undertake any obligation to publicly update or revise any forward-looking statements except as required by applicable securities law. 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)	2015	2014 (1)
Net cash from operating activities	$ 8,957	$ 14,248
Interest paid (received)	225	(504)
Change in non-cash operating working capital	596	1,146
Cash flow from operations	$ 9,778	$ 14,890

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

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 and cash netbacks as presented do not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures for other entities. Operating netbacks have been defined as revenue less royalties, transportation and operating costs. Cash netbacks have been defined as operating netbacks less general and administrative costs. Netbacks are generally discussed and presented on a per boe basis.

The Company also uses the term “working capital surplus (deficit)”. Working capital surplus (deficit), as presented, does not have any standardized meaning prescribed by 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 and risk management contracts.

Select Annual Information

As at/for the years ended December 31,	**2015**	2014 [(1)]	2013
Financial ($ thousands, except as noted)			
Petroleum and Natural Gas Sales	**22,015**	28,577	24,359
Cash Flow from Operations	**9,778**	14,890	13,192
Basic and Diluted ($/share)	**0.04**	0.06	0.06
Net Loss	**(73,534)**	(36,738)	(19,354)
Basic and Diluted ($/share)	**(0.28)**	(0.14)	(0.08)
Capital Expenditures, net of			
Acquisitions and Dispositions	**20,524**	56,646	52,133
Working Capital Surplus (Deficit)	**(21,478)**	(9,247)	31,909
Total Non-Current Financial Liabilities	**9,370**	8,235	8,086
Total Assets	**161,894**	232,770	273,108
Shareholders' Equity	**127,453**	200,641	241,197
Common Shares Outstanding (thousands)	**264,932**	264,932	264,657
Weighted average - basic (thousands)	**264,932**	264,890	236,691
Weighted average - diluted (thousands)	**264,932**	265,703	237,210
Operations (units as noted)			
Average Production			
Crude Oil and Natural Gas Liquids (bbls/d)	**913**	749	682
Natural Gas (Mcf/d)	**4,012**	1,959	1,219
Total (boe/d)	**1,582**	1,076	885
Average Sales Price			
Crude Oil and Natural Gas Liquids ($/bbl)	**51.75**	90.84	91.53
Natural Gas ($/Mcf)	**3.26**	5.25	3.57
Total ($/boe)	**38.13**	72.76	75.41
Netback ($/boe)			
Petroleum and Natural Gas Revenue	**38.13**	72.76	75.41
Royalties Expense	**(2.16)**	(5.80)	(5.78)
Percentage	**6%**	8%	8%
Operating Expense	**(13.97)**	(14.36)	(15.04)
Operating Netback	**22.00**	52.60	54.59
General and Administrative Expense	**(6.14)**	(12.11)	(13.68)
Cash Netback	**15.86**	40.49	40.91
Wells Drilled			
Gross	**1.00**	16.00	11.00
Net	**0.25**	5.80	5.50

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

Highlights

- Recognized as top publicly traded emerging producer by the Explorers and Producers Association of Canada for 2015
- Cash flow from operations of $9.78 million and average daily production of 1,582 boe/d for the year
- Corporate total gross proved plus probable reserves of 12.9 MMboe with a before income tax NPV-10% of $119.34 million
- Kakwa development continued with joint venture facility expansion and extended-reach horizontals using improved completions
- Rationalized oil shale portfolio with new MOU for acreage in Jordan and terminated agreement for Wyoming acreage

2015 Activities

Western Canada

Kakwa-Resthaven, Alberta

In 2015, development continued in this core area targeting condensate rich natural gas from the Montney formation. Questerre currently holds 19,040 (11,000 net) acres in the area, including a 100% working interest and operatorship of 8,320 net acres. In addition, the Company holds a further 24,320 net acres in the Wapiti area, approximately 20 miles to the northwest also prospective for the Montney formation.

On its joint venture acreage, Questerre participated in the drilling of one (0.25 net) well and the completion of six (1.5 net) wells. The Company also participated in an expansion of existing infrastructure.

The wells completed in 2015 benefitted from enhanced completion programs designed to place between 60 and 85 individual slickwater fracture treatments in the horizontal sections that ranged in length from approximately 2000m to 2400m. These wells were the 13-25-63-6W6M Well (the "13-25 Well"), the 14-25-63-6W6M Well, the 15-25-63-6W6M Well, the 01-11-63-6W6M Well, the 08-11-63-6W6M Well and the 01-14-63-6W6M Well. The Company holds a 25% working interest in these wells. Based on the preliminary production results, it is expected that future wells will be completed using similar programs optimized further for inter-treatment spacing and sand tonnage.

During its first thirty days of production in the fourth quarter of 2015, gross production from the 13-25 Well averaged 3.5 MMcf/d of gas and 750 bbls/d of condensate and other liquids (1,333 boe/d). For initial production rates on the other wells, please refer to the Company's MD&A filed as part of its second quarter 2015 and third quarter 2015 reports on August 13, 2015 and November 12, 2015 respectively. While the initial rates from these wells are encouraging, the results are not necessarily indicative of long-term performance or ultimate recovery from these wells.

Infrastructure was expanded early in the year to tie-in these wells and plan for future development. Approximately 11 miles of additional pipeline was constructed for the local gathering system. The capacity of the central compression and condensate stabilization facility was also increased from 15 MMcf/d to 30 MMcf/d plus associated liquids. Concurrently, a tie-in was constructed to a third party pipeline to mitigate the cost of trucking condensate to the injection station for this pipeline. Questerre holds a 25% working interest in the central facility and associated infrastructure.

Subsequent to year-end, drilling operations were completed on the 03-18-63-5W6M Well (the "03-18 Well"). The 03-18 Well was drilled with a lateral of 2900m in the Montney formation. Completion operations are scheduled for after spring breakup and programmed with approximately 67 frac stages in the horizontal section.

During the year, limited activity was conducted on the Company's operated acreage in light of commodity prices.

Questerre expects to participate selectively in additional wells drilled on the joint venture acreage in 2016. The Company anticipates that these additional wells will support production to meet the joint venture's take or pay commitments for processing and transportation.

<u>Antler, Saskatchewan</u>

Activities at Antler focused on optimization of existing production and the pilot waterflood to increase recovery of the oil in place.

The waterflood pilot consists of four horizontal wells on two sections injecting approximately 1,100 bbls/d of water into the oil pool. Injection pressures were increased during the year and initial responses suggest an improvement in production rates from offsetting horizontal and vertical wells.

In 2016, the Company plans to increase injection volumes to further accelerate the production response and continue work to optimize production subject to partner participation.

Oil Shale Mining

The deferral of the commercial-scale pilot project by Red Leaf Resources Inc. ("Red Leaf") led Questerre to high grade its portfolio of oil shale projects during the year.

Questerre's oil shale mining assets include prospective oil shale acreage in the Hashemite Kingdom of Jordan ("Jordan") and Saskatchewan. Questerre also holds licensing rights to a proprietary process to produce oil from shale developed by 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 state of Utah. Questerre currently holds approximately 6% of the equity capital of Red Leaf.

Red Leaf has entered into a joint venture with a US affiliate of the French-based supermajor, Total S.A. ("Total") to develop the company's oil shale assets in Utah. In 2012, 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. In 2015, due to low commodity prices, the joint venture elected to defer the construction of its first commercial-scale capsule under the EPS phase for two to three years while it optimized the capsule design. Total has agreed to make payments of up to US$85 million to Red Leaf to fund the costs related to this deferral, including contract cancellation, and the optimization of capsule design.

In June, the Company was notified by Red Leaf that due, to its limited resources, it terminated the exploration license and option to lease agreement with a US-based independent for its oil shale project in Wyoming. Questerre had the right to earn a 20% working interest in this agreement. Questerre has no further rights or obligations related to this acreage.

With the commercialization of the EcoShale process delayed and the lower yields than expected under this process from its oil shale at Pasquia Hills, the Company elected to suspend further work in Saskatchewan during the year.

In the second quarter of 2015, the Company concluded a Memorandum of Understanding ("MOU") for the appraisal and development of oil shale acreage in Jordan. The MOU covers an area of 388 square kilometers in the Isfir-Jafr area, approximately 200 km south of the capital, Amman. The initial term of the MOU is two years and may be extended. The Company estimates its financial commitments to range between $3 million to $5 million over the initial term.

A field program began in the fall to assess this acreage. Two hydrology studies were conducted and a five well core program completed. Subject to results, the Company intends to develop a further work program that would be conducted during the initial phase of a subsequent concession agreement.

In 2016, the Company will continue appraisal of its Jordanian oil shale assets. The two main objectives are the evaluation of the scale and nature of the resource and the feasibility of commercial development.

St. Lawrence Lowlands, Quebec

The pilot program to assess the commerciality of the Utica shale remained suspended in 2015 while the Government of Quebec completed its strategic environmental assessment ("SEA") of oil and gas development.

In the fourth quarter, the Government published the majority of the studies from the SEA and conducted public hearings. The final studies are expected to be released in early 2016 and followed by public consultation. In conjunction with the SEA, the Ministry of Natural Resources recently published its 'green book' outlining the requirements for social acceptability for energy projects.

Pursuant to its strategic plan for 2015-2018, the Government is scheduled to announce its energy policy followed by draft hydrocarbon legislation in 2016.

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

Corporate

In November 2015, the Company's credit facilities with a Canadian chartered bank were renewed at $50 million. The credit facilities consist mainly of a revolving operating demand loan and a non-revolving acquisition and development demand loan. Any borrowings under the facility, except letters of credit, are subject to interest at the bank's prime interest rate and applicable basis point margins based on the ratio of debt to cash flow, measured quarterly.

The facility is secured by a revolving credit agreement, a debenture including a first floating charge over all assets of the Company and a general assignment of book debts. The next scheduled review of these credit facilities is in the second quarter of 2016.

Drilling Activities

In 2015, Questerre participated in the drilling of one (0.25 net) well in the Kakwa-Resthaven area.

Production

	2015			2014		
	Oil and Liquids (bbls/d)	Natural Gas (Mcf/d)	Total (boe/d)	Oil and Liquids (bbls/d)	Natural Gas (Mcf/d)	Total (boe/d)
Saskatchewan	201	-	201	307	-	307
Alberta	627	3,932	1,283	296	1,870	608
Manitoba	85	-	85	146	-	146
British Columbia	-	80	13	-	89	15
	913	4,012	1,582	749	1,959	1,076

The commissioning of the Kakwa facility expansion increased production from the area, resulting in higher corporate production over the prior year.

The oil and liquids production represents light crude oil and natural gas liquids and natural gas production represents primarily shale gas. The oil and liquids weighting declined from 70% to 58% during the year as production from the Kakwa area is split approximately equally between liquids, primarily condensate, and natural gas. The lower weighting also reflects the natural declines experienced in Antler and Manitoba. The Company anticipates these declines will be partially offset in 2016 by the optimization and waterflood work at Antler and the planned drilling of one (0.35 net) oil well in Manitoba.

Kakwa remained the largest contributor to Company volumes. Production from Kakwa was 1,200 boe/d or 76% of total volumes in 2015 compared to 511 boe/d or 48% in the prior year. Subject to commodity prices and continued results, Questerre expects these volumes could decline marginally in 2016 as fewer additional wells are brought on to fulfill its contractual commitments.

2015 Financial Results

Petroleum and Natural Gas Sales

	2015			2014		
($ thousands)	Oil and Liquids	Natural Gas	Total	Oil and Liquids	Natural Gas	Total
Saskatchewan	$ 4,114	$ -	$ 4,114	$ 10,659	$ -	$ 10,659
Alberta	11,574	4,620	16,194	9,427	3,619	13,046
Manitoba	1,644	-	1,644	4,733	-	4,733
British Columbia	-	63	63	-	139	139
	$ 17,332	$ 4,683	$ 22,015	$ 24,819	$ 3,758	$ 28,577

Petroleum and natural gas revenue declined by 23% over the prior year due to materially lower commodity prices. This reflects a 32% increase in revenue due to higher volumes offset by a 56% decline due to lower prices.

Pricing

	2015	2014
Benchmark prices:		
Natural Gas - AECO, daily spot ($/Mcf)	2.73	4.50
Crude Oil - Canadian Light Sweet Blend ($/bbl)	58.68	93.38
Realized prices:		
Natural Gas ($/Mcf)	3.26	5.25
Crude Oil and Natural Gas Liquids ($/bbl)	51.75	90.84

Crude oil prices continued their decline from the second half of 2014. The benchmark West Texas Intermediate ("WTI") averaged US$48.76/bbl over the year (2014: US$92.99/bbl) with an average price of US$37.33/bbl in December (2014: US$59.29/bbl).

Record production from OPEC, particularly Saudi Arabia, the potential for increased production from Iran and the impact of a weakening Chinese economy on demand contributed to this decline. In North America, prices were affected by growing domestic production despite declining rig counts and concerns about growing oil inventories. The declining Canadian dollar and improving differentials partially mitigated this decline in 2015. The differential between WTI and the benchmark Canadian Light Sweet blend ("MSW") declined from US$6.15/bbl in 2014 to US$1.46/bbl in 2015.

As the majority of its liquids production is light crude oil and condensate, Questerre's realized price tracks the MSW price. Condensate production from Kakwa receives a small premium to this price. This is offset by the materially lower price for other natural gas liquids, particularly propane.

Natural gas prices experienced a similar decline as the benchmark Henry Hub averaged US$2.68/Mcf during the year compared to an average price of US$4.37/Mcf in 2014.

These prices reflect the persistent supply demand imbalance. Dry gas production in the United States grew 4 Bcf/d over the year to average approximately 74 Bcf/d as increases in the Marcellus and Utica shale offset declines in associated gas production from liquids-rich plays. While demand has increased for power generation due to low prices, the retirement of coal fired plants and exports to Mexico, further increases will be required to offset the growth in supply. In Canada, the prospect for reduced demand from the United States resulted in the differential with the AECO price increasing from US$0.28/Mcf in 2014 to US$0.52/Mcf in 2015.

Higher heat content production from Kakwa contributed to a realized price of $3.26/Mcf in 2015 (2014: $5.25/Mcf) compared to an average AECO price of $2.73/Mcf (2014: $4.50/Mcf).

To mitigate the impact of further volatility in prices, the Company has entered into a $2.54/GJ swap for 2000 GJ/d and a $70/bbl swap for 200 bbls/d in 2016.

Royalties

($ thousands)		**2015**		2014
Alberta	**$**	**816**	$	1,063
Saskatchewan		**213**		661
Manitoba		**217**		554
British Columbia		**-**		1
	$	**1,246**	$	2,279
% of Revenue:				
Alberta		**5%**		8%
Saskatchewan		**5%**		6%
Manitoba		**13%**		12%
British Columbia		**0%**		1%
Total Company		**6%**		8%

Consistent with the decline in revenue, gross royalties decreased from $2.28 million to $1.25 million in 2015. As a percentage of revenue, royalties decreased from 8% in 2014 to 6% in 2015.

The main contributor to the decrease is the lower overall rate on production from Kakwa which accounts for the majority of production from Alberta. The lower rate is attributable to the higher credits for processing the Crown's share of production through the Company's facilities. Production in Kakwa also benefits from several incentive programs including the New Well Royalty Rate and the Natural Gas Deep Drilling Program that provides for royalties of up to 5%.

In Saskatchewan and Manitoba, royalty rates changed marginally during the year. In Saskatchewan, rates declined by 1% to 5%. In Manitoba, rates increased by 1% to 13% due to the higher proportion of production from freehold lands that attract a higher royalty rate.

Operating Costs

($ thousands)		**2015**		2014
Alberta	**$**	**6,226**	$	3,377
Saskatchewan		**1,313**		1,813
Manitoba		**341**		359
British Columbia		**187**		92
	$	**8,067**	$	5,641
$/boe:				
Alberta		**13.28**		15.24
Saskatchewan		**17.99**		16.15
Manitoba		**10.98**		6.74
British Columbia		**39.43**		16.96
Total Company		**13.97**		14.37

Driven by higher production volumes in the year, operating costs increased to $8.07 million from $5.64 million in 2014.

On a unit of production basis, operating costs averaged slightly lower than the prior year at $13.97/boe from $14.37/boe. This is due to the higher proportion of fixed costs in Kakwa being apportioned to greater production volumes. Similarly, the higher proportion of fixed costs in Saskatchewan apportioned over smaller volumes resulted in an increase on a boe basis. Additionally, the operating costs in Saskatchewan were higher because of workovers conducted during the year.

General and Administrative Expenses

($ thousands)		**2015**		2014
General and administrative expenses, gross	**$**	**4,938**	$	7,017
Capitalized expenses and overhead recoveries		**(1,392)**		(2,261)
General and administrative expenses, net	**$**	**3,546**	$	4,756

Gross general and administrative expenses ("G&A") in 2015 declined by 30% to $4.94 million from $7.02 million in the prior year.

Given lower activity levels in the year, the Company implemented several corporate restructuring measures, including reductions in personnel, salaries and directors' fees. The lower personnel costs were also responsible for the reduction in capitalized expenses and overhead recoveries.

Depletion, Depreciation, Impairment and Accretion

For the year ended December 31, 2015, the Company reported depletion and depreciation expense of $9.73 million compared to $8.48 million in 2014. The higher expense reflects the increased production in the current year. On a per unit basis, depletion decreased to $16.85/boe from $21.58/boe in 2014 with higher production volumes in the current year from cash generating units ("CGUs") with lower finding and development costs.

In 2015, the Company recorded impairment charges of $69.62 million (2014: $47.63 million) to net loss. Of this amount, $27.15 million is for property, plant and equipment, $26.63 million relates to exploration and evaluation assets and $15.85 million relates to investments.

At December 31, 2015, the Company reviewed the carrying amounts of its property, plant and equipment and exploration and evaluation assets for indicators of impairment such as changes in future prices, future costs and reserves.

Based on this review, the Company's CGUs were tested for impairment in accordance with the Company's accounting policy. The recoverable amount of the CGUs was estimated based on the fair value less costs of disposal ("FVLCD") using a discounted cash flow model. Based on the assessment, for the year ended December 31, 2015, the Company recorded an impairment loss of $27.15 million which relates to its Montney, Antler, Midway, Vulcan and Other Alberta CGUs. The factor that led to the impairment was a reduction in forecasted commodity prices.

The impairment of exploration and evaluation assets relates primarily to the impairment of the Quebec CGU of $23.50 million. The recoverable amount of this CGU was estimated based on a FVLCD. The estimate of

FVLCD was determined using prospective resources attributable to the Quebec CGU to develop an after tax cash flow forecast associated with a potential development program. The resources and associated cash flows were discounted to reflect: a) the chance of discovery given the early stage nature of the project, b) the chance of development given current prices and market conditions, the status of oil and gas development and regulations in the province, and c) the expected return.

Although the Government of Quebec has delayed the release of its energy policy, a precursor to the new hydrocarbon legislation required for development, the Company is optimistic it will be introduced in 2016. However, based on external views, the Company increased the risk factors associated with the adoption of new legislation favorable to development and the expected return which resulted in the impairment expense for 2015.

At December 31, 2015, an impairment loss of $18.70 million was recognized relating to the Company's investments. This largely represents the difference between the carrying value of its investment in Red Leaf and its estimated fair value. The estimated fair value was determined using the net asset value method. The Company recorded $15.51 million of the impairment in net loss and $2.67 million in other comprehensive loss.

Share Based Compensation

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

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 and 2015, the Black-Scholes values have decreased resulting in a recovery of stock based compensation.

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

The Company revised its December 31, 2014 comparative financial statements to reflect an overstatement of its share based payment liability of $5.19 million and an overstatement of its share based compensation expense and capitalized share based payment of $3.3 million and $1.89 million, respectively. Refer to Note 2 of the consolidated financial statements for the year ended December 31, 2015 for the impacts of the revision.

Deferred Taxes

The Company reported a deferred tax expense of $2.12 million for 2015 compared to a deferred tax recovery of $3.65 million for the prior year.

The expense reflects the de-recognizing of $18.21 million of its deferred tax asset at year end. The Company changed its methodology of assessing its deferred tax asset in 2015 due to commodity prices and the impairments recorded in the current year.

In 2015, the Company assessed the recoverability of this asset using the estimate of before tax cash flows associated with its proved reserves using escalating pricing and future development costs as outlined in its independent reserve report. In prior years, the Company utilized the before tax cash flows associated with its proved and probable reserves using escalating pricing and future development costs as outlined in its independent reserve report.

Questerre had sufficient tax pools to offset taxable income in 2015.

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, 2015, the unrealized loss recorded for the year ended December 31, 2015 was $0.33 million (2014: unrealized gain of $1.20 million). For the Company's settled risk management contracts at December 31, 2015, the realized gain recorded for the year ended December 31, 2015 was $0.80 million (2014: realized loss of $0.57 million).

Questerre reported interest expense of $1.49 million for the year ended December 31, 2015 and interest income of $0.50 million for the prior year. The interest expense primarily relates to the interest charged on an outstanding joint venture billing and borrowings under its credit facility. In 2014, the interest income was from cash invested in Guaranteed Investment Certificates issued by Canadian chartered banks and credit unions.

The Company recorded a gain on foreign exchange, net of deferred tax, through other comprehensive income (loss) of $2.42 million for the year ended December 31, 2015 (2014: $3.65 million). 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 $73.45 million for 2015 compared to $40.87 million in 2014. The Company's change in total comprehensive loss is attributable mainly to higher impairment charges and lower petroleum and natural gas revenue.

Net Loss Per Share

Questerre's basic net loss per share increased from $0.14 per share to $0.28 per share in 2015. Questerre's net loss was $73.53 million in 2015 and $36.74 million in 2014.

Capital Expenditures

($ thousands)		2015		2014
Alberta	$	18,372	$	59,445
Saskatchewan		526		1,904
Manitoba		-		1,695
Jordan		825		-
Quebec		172		326
Wyoming		-		93
British Columbia		629		61
Corporate		-		51
		20,524		63,575
Dispositions		-		(6,929)
Total	$	20,524	$	56,646

In 2015, Questerre incurred capital expenditures of $20.52 million as follows:

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

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 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.

Liquidity and Capital Resources

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

In November 2015, the Company's credit facilities were renewed at $50 million. The facility is determined by, among other things, the Company's current reserve report, results of operations and forecasted commodity prices. The next scheduled review is expected to be completed in the second quarter of 2016. At December 31, 2015, $14.54 million (December 31, 2014: $nil) was drawn on the credit facility and the Company is in compliance with all its covenants under the credit facility.

Questerre had a working capital deficit of $21.48 million at December 31, 2015 as compared to a deficit of $9.25 million at December 31, 2014. Management believes that with its current credit facility and expected positive operating cash flows from operations, the Company will generate sufficient cash flows to meet its foreseeable obligations in the normal course of operations. With improving commodity prices, Questerre anticipates liquidity to increase over time as cash flow from operations exceeds planned capital expenditures in the future and debt is reduced. On an ongoing basis, while the Company will utilize flexibility relating to commitments for future capital expenditures in order to maintain liquidity, it cannot provide any assurance that sufficient cash flows will be generated from operating activities to reduce its working capital deficiency and to carry out its planned capital expenditure program. 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 Company's AIF.

Cash Flow from Operating Activities

Net cash from operating activities for the year ended December 31, 2015 and 2014 was $8.96 million and $14.25 million, respectively. The Company realized materially lower netbacks in 2015, which was partially offset by changes in non-cash working capital.

Cash Flow used in Investing Activities

Cash flow used in investing activities decreased to $34.16 million in 2015 from $50.80 million in 2014. For the year ended December 31, 2015, the Company incurred capital expenditures of $20.52 million compared to $63.58 million for the same period in 2014. The lower net capital expenditures were mainly due to lower investment activity in the Kakwa-Resthaven area.

Cash Flow provided by Financing Activities

Cash flow provided by financing activities was $14.54 million in 2015 and $0.10 million in 2014. The increase in 2015 reflects the drawdowns under the Company's credit facility. In 2014, the amount relates to the proceeds on 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, 2015, there were no Class "B" common voting shares or preferred shares outstanding.

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

(thousands)	**March 24, 2016**	**December 31, 2015**	December 31, 2014
Common Shares	**264,932**	**264,932**	264,932
Stock options	**16,154**	**19,982**	17,792
Weighted average Common Shares			
Basic		**264,932**	264,890
Diluted		**264,932**	265,703

A summary of the Company's stock option activity during the years ended December 31, 2015 and 2014 follows:

	December 31, 2015		December 31, 2014	
	Number of Options *(thousands)*	**Weighted Average Exercise Price**	Number of Options *(thousands)*	Weighted Average Exercise Price
Outstanding, beginning of period	**17,792**	**$1.96**	18,188	$2.02
Granted	**10,532**	**0.29**	1,250	1.04
Forfeited	**(2,819)**	**1.10**	(1,333)	2.26
Expired	**(5,523)**	**3.68**	-	-
Exercised	**-**	**-**	(313)	0.67
Outstanding, end of period	**19,982**	**$0.72**	17,792	$1.96
Exercisable, end of period	**6,808**	**$0.97**	11,201	$2.56

Commitments

A summary of the Company's net commitments at December 31, 2015 follows:

($ thousands)	2016	2017	2018	2019	2020	Thereafter	Total
Transportation, Marketing and Processing	$ 2,726	$ 4,728	$ 4,728	$ 3,990	$ 3,990	$ 23,942	$ 44,104
Office Leases	142	137	86	86	79	-	530
	$ 2,868	$ 4,865	$ 4,814	$ 4,076	$ 4,069	$ 23,942	$ 44,635

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

Questerre has no capital commitments in 2016. In order to maintain its capacity to execute its business strategy, the Company expects that it will need to continue the development of its producing assets. There will also be expenditures in relation to G&A and other operational expenses. These expenditures are not yet commitments, but Questerre expects to fund such amounts primarily out of cash flow from operations and its existing credit facilities.

Risk Management

Companies engaged in the petroleum and natural gas industry face a variety of risks. For Questerre, these include risks associated with exploration and development drilling as well as production operations, commodity prices, exchange and interest rate fluctuations. Unforeseen significant changes in such areas as markets, prices, royalties, interest rates and government regulations could have an impact on the Company's future operating results and/or financial condition. While management realizes that all the risks may not be controllable, Questerre believes that they can be monitored and managed. For more information, please refer to the "Risk Factors" and "Industry Conditions" sections of the AIF and Note 6 to the audited consolidated financial statements for the year ended December 31, 2015.

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, borrowings and possible future equity sales, the Company's ability to do so is dependent on, among other factors, the overall state of capital markets and investor appetite for investments in the energy industry and the Company's securities in particular. To the extent that external sources of capital become limited or unavailable or available but on onerous terms, the Company's ability to make capital investments and maintain existing assets may be impaired, and its assets, liabilities, business, financial condition and results of operations may be materially and adversely affected as a result. Based on current funds available and 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. In the past, the Company manages credit risk exposure by investing in Canadian banks and credit unions. Management does not expect any counterparty to fail to meet its obligations.

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

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

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

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

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

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

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

As at December 31, 2015, the Company had the following outstanding commodity risk management contract in place:

Risk Management Contract	Volumes	Average Price	Term	Fair Value Asset (Liability) *($ thousands)*
Crude oil swap	200 bbls/d	$70/bbl	Jan. 1, 2016 - Dec. 31, 2016	933
Natural gas swap	2,000 gj/d	$2.54/gj	Jan. 1, 2016 - Dec. 31, 2016	99
AECO - call option sale	3,000 gj/d	$2.70/gj	Jan. 1, 2017 - Dec. 31, 2017	(334)
WTI Nymex - call option sale	200 bbls/d	$80/bbl	Jan. 1, 2017 - Dec. 31, 2017	(284)

Please Refer to Note 6 e) of the audited consolidated financial statements for the year ended December 31, 2015.

Environmental Regulation and Risk

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

Critical Accounting Estimates

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

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

Petroleum and Natural Gas Reserves

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 *Standards of Disclosure for Oil and Gas Activities* and the COGE Handbook. For further information, please refer to "Statement of Reserves Data and Other Oil and Gas Information" in the AIF.

The estimation of reserves 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, future operating and development costs and recent land transactions. Changes to these assumptions will affect the recoverable amounts of the CGUs and may require a material adjustment to their related carrying value.

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

Asset Retirement Obligation

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

Share Based Compensation

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

Income Tax Accounting

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

The Company has revised its estimate related to deferred tax assets in the year. As at December 31, 2015, the recoverability of deferred tax assets was assessed using proved reserves instead of proved and probable reserves, which were used in the prior year. This change was the result of lower forecasted commodity prices.

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

Investment in Red Leaf

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

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

Revision of prior period comparatives

The Company revised its December 31, 2014 comparative financial statements to reflect an overstatement of its share based payment liability of $5.19 million and an overstatement of its share based compensation expense and capitalized share based payment of $3.3 million and $1.89 million, respectively. The Company assessed the materiality of this adjustment and concluded that it was not material to any of the previously issued consolidated financial statements. As a result, the Company revised these statements for these changes. The factors that it considered when assessing materiality were that there is no cash or credit facility impact to these changes and that there was no changes in amounts paid to employees upon exercise of options. Refer to Note 2 of the consolidated financial statements for the year ended December 31, 2015 for the impacts of the revision.

Accounting Standards Changes

Changes in Accounting Policies for 2015

There were no new or amended accounting standards or interpretations adopted during the year ended December 31, 2015.

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.

<u>IFRS 16 Leases</u>

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

IFRS 15 Revenue From Contracts With Customers

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

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

IFRS 9 Financial Instruments

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

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

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

- The Company has designed and evaluated the effectiveness of Disclosure Controls and Procedures ("DC&P"). The President and Chief Executive Officer and the Chief Financial Officer have concluded that DC&P are designed appropriately and are operating effectively as at December 31, 2015.
- 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, 2015 and have concluded that such ICFR have been designed appropriately and are operating effectively.
- The Company reports that no changes were made to ICFR during the quarter ended December 31, 2015 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 2015 Results

Questerre's cash flow from operating activities decreased from $4.15 million for the quarter ended December 31, 2014 to $1.78 million for the same period in 2015, mainly due to lower cash flow from operations. The decrease in cash flow from operations is due to lower operating netbacks in 2015, which were partially offset by higher volumes in the year.

Petroleum and natural gas revenue decreased from $7.61 million for the three months ended December 31, 2014 to $5.31 million for the same period in 2015. The Company's realized price for oil and natural gas liquids was $48.08/bbl for the fourth quarter of 2015 compared with $71.84/bbl for the fourth quarter of 2014. In the fourth quarter, production increased from 1,468 boe/d in 2014 to 1,648 boe/d in 2015. The increased production was from the Company's Kakwa-Resthaven area wells that were brought on production through 2015. The increased production at Kakwa was partially offset by natural declines from other producing assets.

Operating costs were $2.22 million or $14.69/boe for the three months ended December 31, 2015 compared to $1.60 million or $11.81/boe for the same period in 2014. The increase in operating costs is mainly due to higher production in 2014. On a per unit basis, operating costs increased due to higher workovers in the Antler area.

Impairment of assets was $48.25 million for the three months ended December 31, 2015 compared to $47.04 million for the same period in 2014. In the fourth quarter of 2015, the Company recorded impairment charges, including $18.15 million for its property, plant and equipment, $23.50 million relating to its Quebec Exploration and Evaluation assets and $5.7 million for its investments. 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.

Total comprehensive loss for the three months ended December 31, 2015 was $55.96 million compared to $45.41 million for the same period in 2014. The comprehensive loss increase from 2014 is due to higher deferred tax expenses recorded in 2015. In the fourth quarter of 2015, the Company assessed the recoverability of this asset using the estimate of before tax cash flows associated with its proved reserves using escalating pricing and future development costs as outlined in its independent reserve report. In prior periods, the Company utilized the before tax cash flows associated with its proved and probable reserves using escalating pricing and future development costs as outlined in its independent reserve report.

Capital expenditures were $1.01 million and $16.60 million for the three months ended December 31, 2015 and 2014, respectively. In 2015, capital expenditures included $0.52 million for its Jordan assets, $0.33 million for its Kakwa-Resthaven assets and $0.11 million for its Antler assets. 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 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, 2015	September 30, 2015 [1]	June 30, 2015 [1]	March 31, 2015 [1]
Production (boe/d)	**1,648**	1,934	1,480	1,257
Average Realized Price ($/boe)	**35.03**	36.69	44.90	36.49
Petroleum and Natural Gas Sales	**5,311**	6,528	6,048	4,128
Cash Flow from Operations	**2,269**	3,182	3,067	1,308
Basic and Diluted ($/share)	**0.01**	0.01	0.01	-
Net Profit (Loss)	**(56,044)**	(18,169)	1,333	(656)
Basic and Diluted ($/share)	**(0.21)**	(0.07)	0.01	-
Capital Expenditures, net of acquisitions and dispositions	**1,014**	6,213	5,095	8,203
Working Capital Surplus (Deficit)	**(21,478)**	(21,334)	(18,202)	(16,165)
Total Assets	**161,894**	217,794	233,627	230,905
Shareholders' Equity	**127,453**	183,151	202,220	201,147
Weighted Average Common Shares Outstanding				
Basic (thousands)	**264,932**	264,932	264,932	264,932
Diluted (thousands)	**264,932**	264,932	264,936	264,934

($ thousands, except as noted)	December 31, 2014 [1]	September 30, 2014	June 30, 2014	March 31, 2014
Production (boe/d)	1,468	849	849	1,133
Average Realized Price ($/boe)	56.37	76.34	82.08	84.92
Petroleum and Natural Gas Sales	7,613	5,963	6,342	8,659
Cash Flow from Operations [1]	4,157	2,448	2,925	5,360
Basic and Diluted ($/share)	0.02	0.01	0.01	0.02
Net Profit (Loss)	(39,117)	680	520	1,179
Basic and Diluted ($/share)	(0.15)	-	-	-
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	232,770	289,928	274,625	278,908
Shareholders' Equity	200,641	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

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

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

- Cash flow from operations has fluctuated due to changes in production levels and a general decrease in average realized commodity prices.
- Production has increased to 1,648 boe/d for the three months ended December 31, 2015 as compared with 1,468 boe/d for the same period in the prior year. Production has been generally increasing over the quarters primarily due to the development of the Company's Kakwa-Resthaven assets.
- The working capital deficit has grown as capital expenditures have been higher than the cash flow from operations.
- Capital expenditures decreased in the current year due to a reduced capital program in light of lower commodity prices. The level of capital expenditures over the quarters has varied primarily due to the number of wells drilled and completed on the Kakwa-Resthaven asset.
- Shareholders' equity has decreased due to impairment charges recorded in the fourth quarters of 2014 and 2015 and the third quarter of 2015. The impairment charges relate to its property, plant and equipment and exploration and evaluation assets and its investment in Red Leaf.
- In September 2015 and December 2014 and 2015, the Company recorded a net loss per share due to impairment expenses.

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 24, 2016

Independent Auditor's Report

To the Shareholders of Questerre Energy Corporation

We have audited the accompanying consolidated financial statements of Questerre Energy Corporation, which comprise the consolidated balance sheets as at December 31, 2015 and December 31, 2014 and the consolidated statements of net profit or loss and comprehensive income or loss, changes in equity and cash flows for the years then ended, and the related notes, which comprise a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements

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

Auditor's responsibility

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

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

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

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Questerre Energy Corporation as at December 31, 2015 and December 31, 2014 and its financial performance and its cash flows for the years then ended in accordance with International Financial Reporting Standards.

PricewaterhouseCoopers LLP

Chartered Professional Accountants

Calgary, Alberta

March 24, 2016

Consolidated Balance Sheets

($ thousands)	Note	December 31, 2015	December 31, 2014
			Revised (See Note 2)
Assets			
Current Assets			
Cash and cash equivalents	5	$ 343	$ 11,005
Accounts receivable	6	2,668	2,607
Current portion of risk management contracts	6	1,032	748
Deposits and prepaid expenses		582	789
		4,625	15,149
Investments	7	632	16,541
Property, plant and equipment	8	87,547	96,007
Exploration and evaluation assets	9	47,917	81,900
Goodwill		2,346	2,346
Deferred tax assets	10	18,827	20,827
		$ 161,894	$ 232,770
Liabilities			
Current Liabilities			
Accounts payable and accrued liabilities		$ 10,529	$ 23,648
Credit facilities	13	14,542	-
Current portion of share based compensation liability	11	-	246
		25,071	23,894
Unrealized risk management contracts	6	618	-
Asset retirement obligation	12	8,752	8,133
Share based compensation liability	11	-	102
		34,441	32,129
Shareholders' Equity			
Share capital	14	347,345	347,345
Contributed surplus	11	16,951	16,686
Accumulated other comprehensive income		209	128
Deficit		(237,052)	(163,518)
		127,453	200,641
		$ 161,894	$ 232,770

Commitments (note 19)

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

Signed on behalf of the Board of Directors

Dennis Sykora
Director

Bjorn Inge Tonnessen
Director

Consolidated Statements of net profit or Loss and Comprehensive Income or Loss

($ thousands, except per share amounts)	Note		For the years ended December 31, 2015		2014
					Revised (See Note 2)
Revenue					
Petroleum and natural gas sales	15	$	22,015	$	28,577
Royalties			(1,246)		(2,279)
Petroleum and natural gas revenue, net of royalties			20,769		26,298
Expenses					
Direct operating			8,067		5,641
General and administrative			3,546		4,756
Depletion and depreciation	8		9,730		8,476
Impairment of assets	7,8,9		69,620		47,628
Loss on sale of property, plant and equipment			-		2,928
Gain on risk management contracts	6		(468)		(628)
Share based compensation (recovery)	11		(54)		(2,057)
Accretion of asset retirement obligation	12		115		135
Interest (income) expense	20		1,487		(504)
Other expense			139		325
Loss before taxes			(71,413)		(40,402)
Deferred tax expense (recovery)	10		2,121		(3,664)
Net Loss			(73,534)		(36,738)
Other Comprehensive (Income) Loss, Net of Tax					
Items that may be reclassified subsequently to profit or loss:					
Gain on foreign exchange	7		2,422		3,645
Foreign currency translation adjustment			22		-
Reclass to net loss on write-down of investments	7		(2,363)		(7,776)
			81		(4,131)
Total Comprehensive Loss		$	(73,453)	$	(40,869)
Net Loss per Share					
Basic and diluted	14	$	(0.28)	$	(0.14)

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

Consolidated Statements of Changes in Equity

		For the years ended December 31,	
($ thousands)	Note	2015	2014
			Revised (See Note 2)
Share Capital			
Balance, beginning of year		$ 347,345	$ 347,059
Issue of common shares		-	350
Share issue costs (net of tax)		-	(64)
Balance, end of year		347,345	347,345
Contributed Surplus			
Balance, beginning of year		16,686	16,659
Reclassification of share based compensation		265	27
Balance, end of year		16,951	16,686
Accumulated Other Comprehensive Income			
Balance, beginning of year		128	4,259
Other comprehensive income (loss)		81	(4,131)
Balance, end of year		209	128
Deficit			
Balance, beginning of year		(163,518)	(126,780)
Net loss		(73,534)	(36,738)
Balance, end of year		(237,052)	(163,518)
Total Shareholders' Equity		$ 127,453	$ 200,641

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

Consolidated Statements of Cash Flows

($ thousands)	Note	For the years ended December 31, 2015	2014
			Revised (See Note 2)
Operating Activities			
Net loss		$ (73,534)	$ (36,738)
Adjustments for:			
Depletion and depreciation	8	9,730	8,476
Impairment of assets	7,8,9	69,620	47,628
Loss on sale of property, plant and equipment	8	-	2,928
Unrealized (gain) loss on risk management contracts	6	334	(1,201)
Share based compensation (recovery)	11	(54)	(2,057)
Accretion of asset retirement obligation	12	115	135
Deferred tax expense (recovery)	10	2,121	(3,664)
Interest (income) expense	20	1,487	(504)
Other items not involving cash		19	(24)
Abandonment expenditures	12	(60)	(89)
Cash flow from operations		9,778	14,890
Interest (paid) received		(225)	504
Change in non-cash working capital	18	(596)	(1,146)
Net cash from operating activities		8,957	14,248
Investing Activities			
Property, plant and equipment expenditures	8	(2,241)	(2,865)
Exploration and evaluation expenditures	9	(18,283)	(60,710)
Sale of property, plant and equipment		-	6,929
Change in non-cash working capital	18	(13,637)	5,848
Net cash used in investing activities		(34,161)	(50,798)
Financing Activities			
Proceeds from issue of share capital		-	184
Increase in credit facilities		33,767	-
Repayment of credit facilities		(19,225)	-
Share issue costs		-	(88)
Net cash from financing activities		14,542	96
Change in cash and cash equivalents		(10,662)	(36,454)
Cash and cash equivalents, beginning of year		11,005	47,459
Cash and cash equivalents, end of year		$ 343	$ 11,005

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, 2015 and 2014 comprise the Company and its wholly-owned subsidiaries in those periods owned. The Company wholly owns Questerre Energy Corporation/Jordan, which holds interests in the oil shale assets located in Jordan.

Questerre is incorporated under the laws of the Province of Alberta and is domiciled in Canada. The address of its registered office is 1650, 801 – 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 24, 2016, the date the Board of Directors approved the statements.

b) Basis of measurement

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

c) Functional and presentation currency

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

d) Jointly controlled assets

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

e) Use of estimates and judgments

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

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

Petroleum and natural gas reserves

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

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

Reserve estimates impact a number of areas, in particular, the valuation of property, plant and equipment 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, future operating and development costs and recent land transactions. Changes to these assumptions will affect the recoverable amounts of CGUs and may require a material adjustment to their related carrying value.

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

Refer to Note 8 for the sensitivity analysis related to impairments 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 12 for the carrying amounts related to the asset retirement obligation.

Share based compensation

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

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

Income tax accounting

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

The Company has revised its estimate related to deferred tax assets in the year. As at December 31, 2015, the recoverability of deferred tax assets was assessed using proved reserves instead of proved and probable reserves, which were used in the prior year. This change was the result of lower commodity prices.

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

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

Investment in Red Leaf Resources

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

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

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

Revision of prior period comparatives

The Company revised its December 31, 2014 comparative financial statements to reflect an overstatement of its share based payment liability of $5.19 million and an overstatement of its share based compensation expense and capitalized share based payments of $3.3 million and $1.89 million, respectively. The Company assessed the materiality of this adjustment and concluded that it was not material to any of the previously issued consolidated financial statements. As a result, the Company revised comparative balances in these statements for these changes. The factors that it considered when assessing materiality were that there is no cash or credit facility impact to these changes and that there was no changes in amounts paid to employees upon exercise of options.

The following tables present the effect of this correction on individual line items within the Company's consolidated balance sheet, statement of net profit or loss and statement of comprehensive loss and statement of cash flow as at and for the three and twelve months ended December 31, 2014. The Company also made certain presentation changes to the cash flow statement so as to exclude interest paid or received to better reflect its cash flow from operations, which are reflected below.

Balance Sheet Revisions

($ thousands)	As Previously Reported	Adjustment	As Revised
Exploration and evaluation assets	83,789	(1,889)	81,900
Deferred tax assets	20,342	486	20,827
Share based payment liability	5,535	(5,187)	348
Deficit	(167,301)	3,783	(163,518)

Statement of Profit or Loss Revisions

($ thousands)	As Previously Reported	Adjustment	As Revised
Share based compensation (recovery)	1,240	(3,297)	(2,057)
Deferred tax recovery	(3,178)	(486)	(3,664)
Net Loss	(40,521)	3,783	(36,738)
Total comprehensive loss	(44,652)	3,783	(40,869)
Basic and diluted loss per share	(0.15)	0.01	(0.14)

Cash Flow Statement Revisions

($ thousands)	As Previously Reported	Presentation Change	Adjustment	As Revised
Net loss	(40,521)	-	3,783	(36,738)
Share based compensation (recovery)	1,240	-	(3,297)	(2,057)
Deferred tax recovery	(3,178)	-	(486)	(3,664)
Interest (income) expense	-	(504)	-	(504)
Cash flow from operations	15,394	(504)	-	14,890
Interest (paid) received	-	504	-	504
Change in non-cash working capital	(1,146)	-	-	(1,146)
Net cash from operating activities	14,248	-	-	14,248

3. Significant Accounting Policies

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

a) Basis of consolidation

Subsidiaries

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

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

Transactions eliminated on consolidation

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

b) Financial instruments

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

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

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

Financial assets and liabilities at fair value through profit or loss

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

Available for sale

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

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

Loans and receivables

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

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

c) Share capital

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

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

Recognition and measurement

Exploration and evaluation expenditures

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

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

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

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

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

Development and production costs

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

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

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

Other property, plant and equipment

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

Depletion and depreciation

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

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

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

e) Goodwill

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

f) Impairment

Non-financial assets

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

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

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

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

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

Financial assets

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

(i) significant financial difficulty of the obligor;

(ii) delinquencies in interest or principal payments; and

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

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

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

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

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

g) Share based compensation

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

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

h) Provisions

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

Asset retirement obligation

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

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

i) Revenue

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

j) Income tax

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

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

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

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

k) Net profit or loss per share

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

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

4. Changes in Accounting Policies and Disclosures

Changes in Accounting Policies for 2015

There were no new or amended accounting standards or interpretations adopted during the year ended December 31, 2015.

Future Accounting Pronouncements

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

IFRS 16 *Leases*

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

IFRS 15 *Revenue From Contracts With Customers*

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

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

IFRS 9 *Financial Instruments*

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

5. Cash and Cash Equivalents

($ thousands)	**December 31, 2015**	December 31, 2014
Bank balances	**$ -**	$ 2,431
Short-term bank deposits	**343**	8,574
	$ 343	$ 11,005

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, 2015 included cash and cash equivalents, accounts receivable, risk management contracts, deposits, investments, credit facilities and accounts payable and accrued liabilities. As at December 31, 2015, the fair values of the Company's financial assets and liabilities equaled their carrying values due to the short-term maturity, except for the Company's investments and the risk management contracts, which are recorded at fair value.

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

Level 1 Fair Value Measurements

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

Level 2 Fair Value Measurements

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

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

Level 3 Fair Value Measurements

Level 3 fair value measurements are based on unobservable information.

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

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

c) Credit risk

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

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

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

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

The Company's accounts receivables are aged as follows:

($ thousands)	**December 31, 2015**	December 31, 2014
Current	**$ 2,162**	$ 2,366
31 - 60 days	**221**	97
61 - 90 days	**101**	71
>90 days	**332**	167
Allowance for doubtful accounts	**(148)**	(94)
	$ 2,668	$ 2,607

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

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

d) Liquidity risk

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

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

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

e) Market risk

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

<u>Commodity price risk</u>

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

As at December 31, 2015, the Company had the following outstanding commodity risk management contracts in place:

Risk Management Contract	Volumes	Average Price	Term	Fair Value Asset (Liability) *($ thousands)*
Crude oil swap	200 bbls/d	$70/bbl	Jan. 1, 2016 - Dec. 31, 2016	933
Natural gas swap	2,000 gj/d	$2.54/gj	Jan. 1, 2016 - Dec. 31, 2016	99
AECO - call option sale	3,000 gj/d	$2.70/gj	Jan. 1, 2017 - Dec. 31, 2017	(334)
WTI Nymex - call option sale	200 bbls/d	$80/bbl	Jan. 1, 2017 - Dec. 31, 2017	(284)

The net risk management position is as follows:

($ thousands)	**December 31, 2015**	December 31, 2014
Risk Management Assets:		
Current portion	**$ 1,032**	$ 748

($ thousands)	**December 31, 2015**	December 31, 2014
Risk Management Liabilities:		
Non-current portion	**$ 618**	$ -

The Company recorded an unrealized loss of $0.33 million for the year ended December 31, 2015 and an unrealized gain of $1.2 million for the same period in 2014. The Company also recorded a realized gain of $0.8 million for the year ended December 31, 2015 and a realized loss of $0.57 million for the same period in 2014.

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

Risk Management Contract	Sensitivity Range	Increase	Decrease
Crude oil swap	$1/bbl increase or decrease to WTI price	73,000	(73,000)
Natural gas swap	$1/bbl increase or decrease to WTI price over $80/bbl	73,000	(73,000)
AECO futures sale	$0.50/GJ increase or decrease to AECO price	365,000	(365,000)
WTI Nymex futures sale	$0.50/GJ increase or decrease to AECO price over $2.7/GJ	547,500	(547,500)

Currency risk

All of Questerre's petroleum and natural gas sales are denominated in Canadian dollars, however; the underlying market prices for these commodities are impacted by the exchange rate between Canada and the United States. The Company also incurs expenditures in its Jordanian subsidiary that are denominated in Jordanian Dinar and United States dollars. As at December 31, 2015, the Company had no forward foreign exchange contracts in place.

Interest rate risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. At December 31, 2015, the Company had credit facilities outstanding of $14.54 million (December 31, 2014 – nil).

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 and interest paid or received) in the near future that the Company will be able to meet its foreseeable obligations in the normal course of operations. On an ongoing basis the Company reviews its capital expenditures to ensure that cash flow from operations or access to credit facilities are available to fund these capital expenditures. Refer to Note 13.

The volatility of commodity prices has a material impact on Questerre's 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.

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, 2015**		December 31, 2014
				Revised (See Note 2)
Credit facilities	**$**	**14,542**	$	-
Shareholders' equity		**127,453**		200,641

7. Investments

The investments balance comprises the following private company investments:

($ thousands)		**December 31, 2015**		December 31, 2014
Red Leaf	**$**	**500**	$	15,948
Investment in private company		**132**		593
	$	**632**	$	16,541

Questerre has an equity interest in Red Leaf, a private Utah based oil shale and technology company. Red Leaf's principal assets are its proprietary EcoShale In-Capsule Technology to recover oil from shale in addition to its oil shale leases in the Utah. Red Leaf is currently in the Early Production System ("EPS") phase of commercializing its EcoShale process and is expected to commence capsule construction in 2017-2018.

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 feasible or commercially viable, then the Company's investment in Red Leaf could be further impaired. The following table sets out the changes in investments:

($ thousands)		**December 31, 2015**		December 31, 2014
Balance, beginning of year	**$**	**16,541**	$	46,078
Gain on foreign exchange		**2,790**		4,181
Impairment		**(18,699)**		(33,718)
Balance, end of year	**$**	**632**	$	16,541

For the year ended December 31, 2015, the gain on foreign exchange relating to investments was $2.79 million (December 31, 2014: gain $4.18 million), which was recorded in other comprehensive income (loss) net of deferred tax of $0.37 million (December 31, 2014: $0.54 million).

As of December 31, 2015, the Company determined the fair value of its investment in Red Leaf using the net asset value method. This method was determined to be more representative of the value of the Company's investment in Red Leaf than the discounted cash flow model used at December 31, 2014, due to the suspension of field work by Red Leaf and the decline in crude prices among other factors. This method involves determining the fair value of all assets and liabilities of Red Leaf using the net amount to arrive at an estimated fair value. As a result, the Company recorded an impairment charge for Red Leaf of $18.18 million, of which $15.51 million was recorded in net loss and $2.67 million in other comprehensive income (loss). The remaining impairment charge relates to an investment in a private company.

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

8. Property, Plant and Equipment

Reconciliation of the property, plant and equipment assets:

($ thousands)		Oil and Natural Gas Assets		Other Assets		Total
Cost or deemed cost:						
Balance, December 31, 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
Additions		2,116		-		2,116
Transfer from exploration and evaluation assets		26,299		-		26,299
Balance, December 31, 2015	**$**	**204,101**	**$**	**1,334**	**$**	**205,435**
Accumulated depletion, depreciation and impairment losses:						
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
Depletion and depreciation		9,676		54		9,730
Impairment		27,145		-		27,145
Balance, December 31, 2015	**$**	**116,642**	**$**	**1,246**	**$**	**117,888**

($ thousands)		Oil and Natural Gas Assets		Other Assets		Total
Net book value:						
At December 31, 2014	$	95,865	$	142	$	96,007
At December 31, 2015	**$**	**87,459**	**$**	**88**	**$**	**87,547**

During the year ended December 31, 2015, the Company derecognized $0.03 million in capitalized stock based compensation expense directly related to development activities. During the year ended December 31, 2014, the Company capitalized administrative overhead charges of $0.04 million including $0.04 million in capitalized stock based compensation expense directly related to development activities. Included in the December 31, 2015 depletion calculation are future development costs of $134.74 million (December 31, 2014: $112.77 million).

In 2015, 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 estimates of FVLCD were determined using a discount rate of 10% and forecasted after-tax cash flows based on proved plus probable reserves, with escalating prices and future development costs obtained from an independent reserve evaluation report.

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

	2016	2017	2018	2019	2020	Average Annual % Change Thereafter
WTI (US$/barrel)	45.00	53.60	62.40	69.00	73.10	2
AECO ($/MMbtu)	2.70	3.20	3.55	3.85	3.95	2

Based on its assessment, the Company recorded an impairment loss of $27.15 million relating to its Montney, Antler, Midway, Vulcan and Other Alberta CGUs. The factor that led to the impairment was a reduction in forecasted commodity prices. The recoverable amounts at December 31, 2015 for these CGUs are as follows:

($ thousands)	Montney	Antler	Midway	Vulcan	Other Alberta
Recoverable amounts	$ 57,170	$ 29,186	$ 51	$ 395	$ 639

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	$ (9,121)	$ 8,149	$ (16,920)	$ 17,044

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, 2015		December 31, 2014
				Revised (See Note 2)
Balance, beginning of year	$	**81,900**	$	56,442
Additions		**18,943**		62,463
Transfers to property, plant and equipment		**(26,299)**		(36,129)
Dispositions		**-**		(159)
Impairment		**(26,627)**		(717)
Balance, end of year	$	**47,917**	$	81,900

During the year ended December 31, 2015, the Company capitalized administrative overhead charges of $1.38 million and no amount was recognized for capitalized stock based compensation expense directly related to exploration and evaluation activities. In 2014, the Company capitalized administrative overhead charges of $1.0 million including $1.20 million of capitalized stock based compensation expense that was derecognized.

At December 31, 2015, 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 Quebec CGU was tested for impairment in accordance with the Company's 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 prospective resources attributable to the Quebec CGU to develop an after-tax cash flow forecast associated with a potential development program. For its estimate of prospective resources, the Company utilized the best estimate from an assessment prepared by an independent qualified reserve evaluator in 2011 with an effective date of December 31, 2010. The assessment has a best estimate of net unrisked prospective natural gas resources of 4.43 Tcf with a low estimate of 1.46 Tcf and a high estimate of 13.45 Tcf. The assessment has not been updated since 2011 as there has been no additional technical information.

The estimate of prospective resources was discounted by 80% to reflect the chance of discovery and early stage nature of the project. The after-tax cash flows were discounted by a further 95% to reflect, among other factors, the chance of development given current commodity prices and market conditions, the status of oil and gas development and requisite regulations in the province, the Company securing its social license to operate and limited technical data. The Company forecasted a premium of $0.50/Mcf to the strip pricing to reflect the lack of local production in the province. A 25% discount rate was subsequently applied to these after tax cash flows. As a result of the impairment testing, the Company recorded an impairment expense for its Quebec CGU exploration and evaluation assets of $23.5 million for the year ended December 31, 2015.

The Quebec CGU represents $4.27 million (2014: $27.48 million) of the exploration and evaluation asset balance. The future recoverability of these assets is dependent upon, among other things, the government's continued commitment to execute its strategic plan for energy including local hydrocarbon development, the introduction of new hydrocarbon legislation and the Company securing its social license to operate in the province. Social license to operate is the acceptance or approval by a community or society of the company's operations in the area.

The asset may be derecognized if in the Company's opinion the above factors, among others, indicate that future activities may not be conducted in a timely manner. The energy policy has been delayed from the original timeline and while the Company remains optimistic, based on external views the Company has increased its risk factor related to the ultimate adoption of new legislation favorable to development.

Changes to the discount rate, chance of discovery, chance of development and forward price estimates independently would have the following impact on impairment of the Company's Quebec Exploration and Evaluation assets at December 31, 2015.

($ thousands)	One Percent Increase in the Discount Rate	Five Percent Decrease in the Chance of Discovery	Two Percent Decrease in the Chance of Development	Five Percent Decrease in the Forward Price Estimates
Impairment charge of exploration and evaluation assets	$ 533	$ 2,568	$ 1,710	$ 829

The impairment expense for December 31, 2015 includes $3.13 million for undeveloped land expiries and its investments in other areas.

10. Deferred Income Taxes

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

($ thousands)	**December 31, 2015**	December 31, 2014
		Revised (See Note 2)
Net loss before taxes	**$ (71,413)**	$ (40,402)
Combined federal and provincial tax rate	**26.13%**	25.69%
Computed "expected" deferred tax recovery	**(18,660)**	(10,379)
Increase (decrease) in deferred taxes resulting from:		
Non-deductible differences	**2,035**	2,935
Deferred tax asset not recognized in year	**20,721**	3,760
Rate adjustments	**(1,975)**	(3)
Other	**-**	23
Deferred tax expense (recovery)	**$ 2,121**	$ (3,664)

In the fourth quarter of 2015, the Company evaluated the recoverability of its deferred tax assets using forecasted before-tax cash flows based on proved reserves, with escalating prices and future development costs obtained from an independent reserve evaluation report. In previous periods, the Company evaluated its deferred tax assets using forecasted before-tax cash flows based on proved plus probable reserves, with escalating prices and future development costs obtained from an independent reserve evaluation report.

The statutory tax rate was 26.13% in 2015 and 25.69% in 2014.

The movement of the deferred tax asset is as follows:

($ thousands)		**December 31, 2015**		December 31, 2014
				Revised (See Note 2)
Balance, beginning of year	**$**	**20,827**	$	18,279
Tax recorded to statement of net profit or loss		**(2,121)**		3,664
Tax on share issue costs		**-**		21
Tax charge relating to flow through shares		**-**		(1,758)
Tax charge (recovery) relating to components of other comprehensive income or loss		**121**		621
Balance, end of year	**$**	**18,827**	$	20,827

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

($ thousands)		Petroleum and natural gas properties		Asset retirement obligation		Share issue costs		Non-capital losses
Deferred tax asset:								
Balance, December 31, 2013	$	(2,139)	$	1,833	$	772	$	19,279
Credited (charged) to net profit or loss		3,036		256		(446)		13
Credited to share capital		-		-		22		-
Balance, December 31, 2014		897		2,089		348		19,292
Credited (charged) to net profit or loss		14,627		- 274		(103)		(16,920)
Balance, December 31, 2015	**$**	**15,524**	**$**	**2,363**	**$**	**245**	**$**	**2,372**

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

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

Non-capital loss carry-forwards at December 31, 2015 expire from 2026 to 2035.

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

($ thousands)		Investments		Other
Deferred tax liability:				
Balance, December 31, 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
Charged (credited) to net profit or loss		79		(79)
Charged to other comprehensive income or loss		(121)		-
Balance, December 31, 2015	**$**	**1,587**	**$**	**90**

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

($ thousands)		**December 31, 2015**		December 31, 2014
Petroleum and natural gas properties	**$**	**219**	$	219
Investments		**40,595**		24,687
Non-capital losses		**67,463**		-
Capital losses		**36,488**		36,488
	$	**144,765**	$	61,394

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

11. Share Based Compensation

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

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

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

	December 31, 2015		December 31, 2014	
	Number of Options *(thousands)*	Weighted Average Exercise Price	Number of Options *(thousands)*	Weighted Average Exercise Price
Outstanding, beginning of period	**17,792**	**$1.96**	18,188	$2.02
Granted	**10,532**	**0.29**	1,250	1.04
Forfeited	**(2,819)**	**1.10**	(1,333)	2.26
Expired	**(5,523)**	**3.68**	-	-
Exercised	**-**	**-**	(313)	0.67
Outstanding, end of period	**19,982**	**$0.72**	17,792	$1.96
Exercisable, end of period	**6,808**	**$0.97**	11,201	$2.56

The following table summarizes information about stock options outstanding and exercisable at December 31, 2015:

	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
$0.235 - $0.29	2,812	4.86	$0.24	-	-	-
$0.30 - $0.30	5,619	4.09	0.30	-	-	-
$0.31 - $0.69	3,929	2.64	0.47	1,932	1.08	0.62
$0.70 - $0.88	3,712	2.18	0.87	1,933	1.89	0.86
$0.89 - $2.47	3,910	1.08	1.78	2,943	0.29	1.97
	19,982	2.97	$0.72	6,808	0.97	$1.27

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 2015:

	December 31, 2015	December 31, 2014
Weighted average fair value per award ($)	**0.14**	0.53
Volatility (%)	**62.88**	62.48
Forfeiture rate (%)	**9.60**	8.49
Expected life (years)	**4.41**	4.48
Risk free interest rate (%)	**0.68**	1.42

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, 2015	December 31, 2014
		Revised (See Note 2)
Balance, beginning of year	$ 348	$ 3,775
Amount transferred to contributed surplus	(265)	(27)
Share based compensation expense (recovery)	(54)	(2,057)
Capitalized share based compensation	(29)	(1,153)
Cash payment for options exercised	-	(24)
Reclassification to share capital on exercise of stock options	-	(166)
Balance, end of year	$ -	$ 348
Current portion	$ -	$ 246
Non-current portion	-	102
	$ -	$ 348

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

12. Asset Retirement Obligation

The Company's asset retirement and abandonment obligations result from its ownership interest in oil and natural gas assets. The total asset retirement obligation is estimated based on the Company's net ownership interest in all wells and facilities, estimated costs to reclaim and abandon these wells and facilities and the estimated timing of the costs to be incurred in future periods. The Company has estimated the net present value of the asset retirement obligation to be $8.75 million as at December 31, 2015 (December 31, 2014: $8.13 million) based on an undiscounted total future liability of $11.31 million (December 31, 2014: $11.5 million). These payments are expected to be made over the next 40 years. The average discount factor, being the risk-free rate related to the liabilities, is 1.35% (December 31, 2014: 1.94%). An inflation rate of 2.2% (December 31, 2014: 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, 2015	December 31, 2014
Balance, beginning of year	$ 8,133	$ 7,136
Liabilities disposed	(68)	(726)
Liabilities incurred	296	1,476
Liabilities settled	(60)	(89)
Revisions due to change in discount and inflation rates	(379)	270
Revisions due to change in estimates	715	(69)
Accretion	115	135
Balance, end of year	$ 8,752	$ 8,133

13. Credit Facility

In November 2015, the Company renewed its reserve based credit facilities with a Canadian chartered bank at $50 million. The next scheduled review is expected to be completed in the second quarter of 2016. The credit facilities include a revolving operating demand facility of $31.0 million ("Credit Facility A"), a non-revolving acquisition and development facility of $18.9 million ("Credit Facility B") and a corporate credit card of $0.1 million ("Credit Facility C"). Credit Facility A can be used for general corporate purposes, ongoing operations, capital expenditures within Canada and acquisition of petroleum and natural gas assets within Canada. Credit Facility B can only be used for the acquisitions of producing reserves and/or development of existing proved non-producing/undeveloped reserves.

Any borrowing under the facilities, with the exception of letters of credit, bears interest at the bank's prime interest rate and an applicable basis point margin based on the ratio of debt to cash flow measured quarterly. The bank's prime rate currently is 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 a covenant that it will maintain an Adjusted Working Capital Ratio greater than 1.0. The ratio is defined as current assets (excluding unrealized hedging gains and including undrawn Credit Facility A availability) to current liabilities (excluding bank debt outstanding and unrealized hedging losses). The Adjusted Working Capital Ratio at December 31, 2015 was 1.90 and the covenant is met. At December 31, 2015, $14.54 million (December 31, 2014: $nil) was drawn on Credit Facility A and no amounts drawn on Credit Facility B at December 31, 2015 and December 31, 2014.

14. Share Capital

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

a) Issued and outstanding – Common Shares

	Number (thousands)		Amount ($ thousands)
Balance, December 31, 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
Balance, December 31, 2015	**264,932**	**$**	**347,345**

b) Per share amounts

Basic net loss per share is calculated as follows:

(thousands, except as noted)		**December 31, 2015**		December 31, 2014
				Revised (See Note 2)
Net loss ($ thousands)	**$**	**(73,534)**	$	(36,738)
Issued Common Shares at beginning of year		**264,932**		264,657
Options exercised		**-**		233
Weighted average number of Common Shares outstanding (basic)		**264,932**		264,890
Basic net loss per share	**$**	**(0.28)**	$	(0.14)

Diluted net loss per share is calculated as follows:

(thousands, except as noted)		**December 31, 2015**		December 31, 2014
				Revised (See Note 2)
Net loss ($ thousands)	**$**	**(73,534)**	$	(36,738)
Weighted average number of Common Shares outstanding (basic)		**264,932**		264,890
Effect of outstanding options		**-**		-
Weighted average number of Common Shares outstanding (diluted)		**264,932**		264,890
Diluted net loss per share	**$**	**(0.28)**	$	(0.14)

Under the current stock option plan, options can be exchanged for Common Shares of the Company or for cash at the Company's discretion. As a result, they are considered potentially dilutive and are included in the calculation of diluted income (loss) per share for the period. The average market value of the Company's 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, 2015 and 2014, all options were excluded from the diluted weighted average number of Common Shares outstanding calculation as their effect would have been anti-dilutive.

15. Petroleum and Natural Gas Sales

($ thousands)	December 31, 2015	December 31, 2014
Oil and liquids	$ 17,332	$ 24,819
Natural gas	4,683	3,758
	$ 22,015	$ 28,577

16. Employee Salaries and Benefits

($ thousands)	December 31, 2015	December 31, 2014
		Revised (See Note 2)
Salaries, bonuses and other short-term benefits	$ 2,096	$ 3,380
Share based compensation (recovery)	(83)	(3,210)
	$ 2,013	$ 170

17. Key Management Compensation

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

($ thousands)	December 31, 2015	December 31, 2014
		Revised (See Note 2)
Salaries, bonuses, director fees and other short-term benefits	$ 1,916	$ 2,552
Share based compensation (recovery)	(36)	(2,103)
	$ 1,880	$ 449

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 $0.98 million at December 31, 2015.

18. Supplemental Cash Flow Information

Changes in non-cash working capital:

($ thousands)		December 31, 2015		December 31, 2014
Accounts receivable	$	(61)	$	23
Deposits and prepaid expenses		207		(182)
Accounts payable and accrued liabilities		(14,379)		4,861
Change in non-cash working capital	$	(14,233)	$	4,702
Related to:				
Operating activities	$	(596)	$	(1,146)
Investing activities		(13,637)		5,848
	$	(14,233)	$	4,702

19. Commitments

Commitments

A summary of the Company's net commitments at December 31, 2015 follows:

($ thousands)	2016	2017	2018	2019	2020	Thereafter	Total
Transportation, Marketing and Processing	$ 2,726	$ 4,728	$ 4,728	$ 3,990	$ 3,990	$ 23,942	$ 44,104
Office Leases	142	137	86	86	79	-	530
	$ 2,868	$ 4,865	$ 4,814	$ 4,076	$ 4,069	$ 23,942	$ 44,635

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

20. Summary Judgement

On June 24, 2015, a joint venture partner made an application for a summary judgement with respect to amounts formally disputed by Questerre. Pursuant to a judgement issued on December 7, 2015, the Court ruled that the Company is obligated to pay the amounts outstanding of $4.72 million and interest of $1.25 million first and dispute later. In December 2015, the Company recorded the interest to interest (income) expense. Questerre has filed a Notice of Appeal of this decision and as of March 24, 2016 has paid these amounts to the partner.

Corporate Information

Directors

Michael Binnion

Alain Sans Cartier

Earl Hickok

Dennis Sykora

Bjorn Inge Tonnessen

Officers

Michael Binnion
President and
Chief Executive Officer

Keith Wilford
Chief Operating Officer

John Brodylo
VP Exploration

Peter Coldham
VP Engineering

Jason D'Silva
Chief Financial Officer

Ian Nicholson
VP Geology,
Western Canada

Rick Tityk
VP Land

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