2013

ANNUAL REPORT

QUESTERRE ENERGY CORPORATION

2013

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

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

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

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

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

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

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

President's Message

We had a very good year focused on building our new core area in the Montney.

Following our discovery well in mid-2012, we aggressively acquired a land position to give us the scale needed for development. We now hold 59 net sections in a condensate-rich fairway that is being proven up by drilling, both by Questerre and others. This drilling has established economic contingent and prospective resources on about one third of this acreage with a best estimate of 32 million boe and 100 million boe respectively. Condensate and other liquids account for half of these volumes.

Disappointing last year was the control of well incident in Kakwa South. It highlights the risks of operating in the deep basin in Alberta. To mitigate these risks and execute our development plan, we strengthened our management team with a COO and VP Drilling with a proven track record in the Montney.

We also executed our infrastructure strategy, reducing the capital required for development and guaranteeing market access for our products. We now have take-or-pay contracts for production of over 6,000 boe/d. Our development plan is underway to ramp up production and meet this target by mid-late 2015.

By mid-late 2015, we expect to see the early results from Red Leaf's first commercial scale capsule that could unlock the potential of oil shale. The work successfully completed in 2013 by the Red Leaf/Total joint venture to finalize the capsule design and secure the necessary regulatory permits allows them to begin construction this summer and fire the capsule within nine months thereafter. The success of this project could materially impact our own oil shale acreage in Wyoming and Pasquia Hills, Saskatchewan. We analyzed our own core data at Pasquia Hills in 2013 with promising results and our goal for this year is to finalize our resource assessment.

Highlights

- Development drilling delineates Montney resource with best estimates of economic contingent resources of 32 million boe and prospective resources of 100 million boe with over 40% as condensate
- Concluded market access agreements for approximately 6,000 boe/d of Montney natural gas and liquids production
- Red Leaf receives permits for commercial scale capsule and is scheduled to commence construction in mid-late 2014
- Proved and probable reserve grew by 40% to 9.04 MMboe with oil, condensate and liquids accounting for 65% of volumes
- Cash flow from operations of $13.19 million with average daily production of 885 boe/d for the year

Kakwa-Resthaven, Alberta

With condensate rates driving the economics of this liquids-rich gas play, we are very encouraged by the rates from our early wells that continue to exceed expectations. They have averaged 140 bbls/MMcf to 180 bbls/MMcf of condensate, in line with results from other operators including Paramount and Seven Generations. It substantiates that our acreage lies in the one of the sweet spots in this over-pressured fairway.

In addition to targeting the sweet spot, we have the potential to scale up this play. All our wells to date have produced from one of three intervals in the Upper Montney. Our partners and other operators are producing wells from a second interval at rates of 100 bbls/MMcf. We are currently completing our first joint venture well in this second interval. Based on four wells per interval per section and two tested intervals, this means we could drill close to 90 wells on our main 11 net section block with expected ultimate recoveries of 1,000 Mboe per well on a proven and probable basis.

As we begin ramping up development, maximizing recoveries and improving capital efficiencies will be essential to meeting and exceeding the type well economics. The core we took from our 05-23 Well this summer is essential to model our fracs and improve completion designs. We have been experimenting with different completion techniques including foam fracs, slick water fracs and hybrids and expect to analyze the results from these in the next six to nine months.

Drilling and completion costs are beginning to trend downward from $10 million to about $8 million per well last year. As we move to drilling multiple wells from pads and laterals of longer than one mile, we expect to see further improvements in costs on a relative basis. We recently spud the 08-20 Well, our first well from a multi-well pad, with a planned one and a half mile lateral. The next well will be drilled from this same pad and, subject to weather, a third well could be drilled off this pad before all wells are completed.

Our main focus for 2014 is to execute the development plan.

This plan is designed to grow our production to over 6,000 boe/d by the second half of 2015 and meet our ten-year take-or-pay commitments for firm processing and transportation capacity. If we are able to secure additional capacity either on an interruptible or firm basis, we may be able to accelerate this plan to grow production to 12,000 boe/d by 2018. Based on the current type curves, the acreage to support this development is our main block where we hold just over 11 net sections.

Another operator recently released data on an offsetting Montney well to the west of our main block. During the last day of a four day test, the well reported rates of 189 bbls/MMcf, 2.5 MMcf/d and no sour gas. This test alone is insufficient to establish contingent resources or reserves for our adjacent 100% acreage and we will be drilling our first well here after breakup.

In 2014, we plan to drill up to five wells on our 100% acreage with our first well drilling in the lateral section now. We also plan to drill up to 7 wells on our joint venture block with partners. Subject to the results from our 100% acreage, we expect to drill a similar number of wells in 2015. We estimate a capital requirement of approximately $100 million for 2015, which we expect to fund through debt facilities.

Antler, Saskatchewan and Pierson, Manitoba

We continued to build our conventional light oil production as a source of reserve value that could service the credit facility necessary for our 2015 Kakwa development plan.

This mainly involves expanding the pilot waterflood at Antler to increase recovery of the oil in place. We believe a successful waterflood has the potential to double the existing 2P reserves of approximately 1.8 million barrels for less than $3 million in incremental capital.

We are behind schedule on this waterflood as we were not timely in converting wells to injectors. We have also been very cautious with the injection volumes to minimize damage to this low energy reservoir. As a result we have not yet begun to replace the voidage or produced volumes. Based on the positive results, we have increased these volumes in early 2014 and expect to begin replacing the voidage later this year.

Oil Shale Mining

We are very pleased with the progress made by the Red Leaf and Total joint venture to commercialize the EcoShale process to produce oil from shale. Although it has taken almost two years longer than we originally expected when we made our investment in March 2012, we believe it has been needed for a robust design.

The design of the capsule was finalized and validated by a series of construction tests this year. The engineering for the capsule and the associated processing facilities has also been optimized to further reduce costs and emissions to meet the requirements of existing EPA permits. We expect these improvements will accelerate the transition from the Early Production System (EPS) phase to commercial development.

As we monitor the progress on EPS, we have been advancing our oil shale acreage at Pasquia Hills.

We conducted field work this year to determine the best approach to mine the shale for use in the EcoShale process. Our core data from our 2012 drilling program was analyzed and will form the basis of a resource assessment. We expect this report will be ready by the summer. Recently, we have also submitted shale samples for bulk testing by Red Leaf to determine the oil quality and composition expected under the EcoShale process.

Operational & Financial

During the year, we averaged 885 boe/d with early production from Kakwa contributing over a quarter of these volumes. We did not see a material contribution from our Antler drilling program as this was delayed into the fourth quarter. Similarly, our drilling program in Kakwa was weighted to the fourth quarter and production was dependent on the completion of our central facilities. Our current production is about 1,300 boe/d.

Our drilling program in Manitoba and the condensate production from Kakwa maintained our oil and liquids weighting at over 75% for the year. With higher commodity prices, we increased cash flow to $13 million from $10 million in 2012.

We reallocated capital from Antler to Kakwa to reinforce our success in the year.

Of our total capital expenditures of $52 million, more than 85% was invested in Kakwa, with approximately 60% in drilling, completions and infrastructure and 40% on land acquisition. The remainder was invested in Antler and Manitoba targeting light oil production. We financed our capital budget for 2013 mainly with our cash flow and working capital on hand of $32 million.

We also closed two equity placements at year-end for net proceeds of $37 million to provide some of the capital needed for our 2014 drilling program. The balance of our $85 million program for 2014 will come from cash flow and our existing conventional debt facility.

Outlook

It has been three years since the development of our Utica gas discovery was suspended by the Quebec government while they studied the impacts of shale gas development. We used this time and the cash on hand to diversify the portfolio to include assets that can create value in the near, medium and long term. We are very pleased with the success of our shift in strategy caused by external circumstances.

Our investment in oil shale represents an opportunity to participate with a supermajor in commercializing one of the world's largest untapped oil resources. The oil shale acreage we have acquired allows us to leverage this new technology and add significant oil resources that complement our shale gas discovery.

The investment in the condensate-rich Montney in Alberta will be the primary driver for value creation in the near and medium term. We are executing the first year of a two-year plan to target over 6,000 boe/d of production by the second half of 2015. With access to additional infrastructure and continued success, we may be able to increase this further.

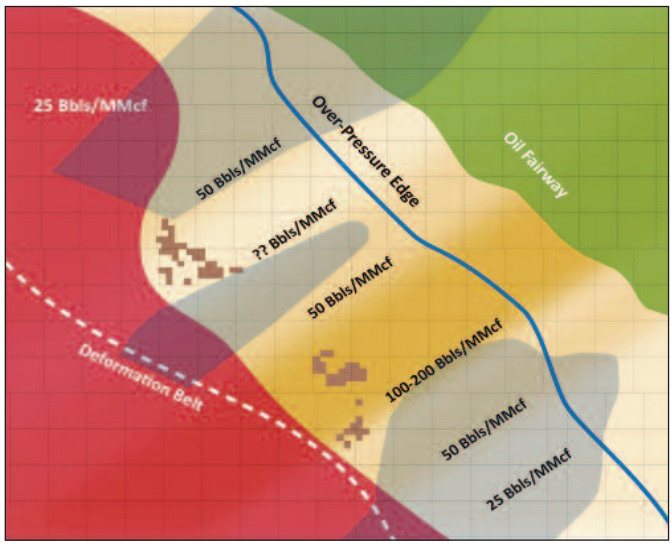
Our investment of time and minimal capital in Quebec to communicate the benefits of local resource development is slowly paying off. The government recently announced a $100 million direct investment in to oil exploration in the province signalling a substantive shift in attitude to hydrocarbons. We were also pleased with the results of the comprehensive environmental study, the first of its kind in Canada, which concluded the risks of development are manageable. We look forward to being a part of the upcoming public hearings and working with the government for the necessary legislation to develop our discovery.

Michael Binnion
President and Chief Executive Officer

Kakwa-Resthaven, Alberta

The Kakwa-Resthaven area is situated approximately 75 kilometres south of Grand Prairie in west central Alberta. Among other zones of interest, the area is prospective for liquids-rich natural gas in the deep, over-pressured fairway of the Montney shale at a depth of approximately 3,100m to 3,600m. Questerre's wells are targeting one of three prospective intervals in the upper Montney formation. Economics for the Montney are enhanced by relatively high liquids content, particularly condensate, and Crown royalty incentives for new deep horizontal gas wells with initial royalty rates of 5%. The Company holds an average 83% working interest in 45,920 gross acres in this area.

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



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

In 2013, Questerre increased its land holdings in this area to 21,600 (13,560 net) acres through Crown land sales, acquisitions and farm-in agreements. Of this acreage, the Company currently holds a 100% working interest and operates 10,880 acres. In addition, Questerre increased its land holdings to 24,320 net acres prospective for the Montney formation in the Wapiti area approximately 20 miles northeast of its acreage at Kakwa-Resthaven.

Questerre participated in the drilling of three (0.75 net) wells and the completion of four (1.0 net) wells on its joint venture acreage where it holds a 25% working interest. Consistent with the initial wells drilled in 2012, the two wells tested in 2013, the 03-19 Well and the 05-23 Well, flowed at initial rates averaging approximately 4.77 MMcf/d and 821 bbls/d of condensate in the last twenty four hours of their respective tests. For more information on these well tests, please refer to the Company's press releases filed on SEDAR on March 21, 2013 and October 16, 2013.

Joint venture central compression and condensate stabilization facility at Kakwa-Resthaven

To address the productivity constraints associated with these relatively high condensate yields and the high line pressures, the Company has been working with the operator to install central compression facilities and additional well head equipment. A central compression and condensate stabilization facility was constructed in the fourth quarter of 2013 and commissioned in early 2014. The facility has a capacity of 15 MMcf/d of natural gas and 3,000 bbls/d of condensate.

In addition to activities on its joint venture acreage, the Company tested the 09-01 Well on its operated acreage approximately 6 miles to the south of its joint venture acreage. During initial testing and clean-up, equipment failure resulted in an uncontrolled release of completion fluids and gas for approximately 24 hours. Subsequent operations re-established gas flows and high pressure on surface that included anomalous hydrogen sulphide rates.

The 09-01 Well was suspended due to a lack of critical sour processing facilities and pipelines in the immediate area. At year-end, the Company incurred a write-off of $19.24 million for costs associated with drilling, completing and testing of the 09-01 Well that were not covered by the Company's insurance policy. In the first quarter of 2014, the Company spud a horizontal well, the 16-07 well, offsetting the 09-01 Well to validate the condensate rates in this area. Subject to equipment availability and results, the Company anticipates that it will put the well on production late in the third quarter of this year.

Drilling operations currently underway on 16-07 well in Kakwa South

The Company commissioned an independent assessment of its Montney resources. The report evaluated the resources associated with the in-place petroleum and natural gas on 12,800 net acres or less than half of its acreage in the Kakwa Resthaven/Wapiti area.

The assessment by McDaniel & Associates Consultants Ltd. ("McDaniel") estimates prospective resources net to Questerre to range between a low of 291 Bcfe (49 MMboe) and a high of 774 Bcfe (129 MMboe) with a best estimate of 598 Bcfe (100 MMboe) that includes over 40% condensate. There is no certainty that any portion of the prospective resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources.

In addition, economic contingent resources ("ECR"), have been assigned a best estimate of 190 Bcfe (32 MMboe) with a range from a low of 95 Bcfe (16 MMboe) to a high of 245 Bcfe (41 MMboe). Approximately 50% of this best estimate or 16 million barrels of oil equivalent are natural gas liquids with condensate accounting for over 83% of this amount. Using their April 2013 price forecast, McDaniel's best estimate of ECR has a net present value discounted at 10% before tax of $267 million.

For more information about the resource assessment, please refer to the Kakwa-Resthaven section of the Management's Discussion and Analysis.

To facilitate market access for its future production from this area, the Company entered into a series of agreements with certain midstream companies in the second half of 2013. These included firm transportation and processing as well as marketing for condensate, natural gas and the associated natural gas liquids. Production volumes under these take-or-pay contracts are approximately 6,000 boe/d and represent approximately 20 MMcf/d of natural gas and 3,000 bbls/d of condensate and liquids. The in-service date for these contracts is mid-late 2015 with terms of between three and ten years.

The Company plans to invest approximately $80 million in the Kakwa-Resthaven area in 2014. This will include up to seven (1.75 net) wells with the joint venture, up to five wells on its 100% operated acreage and associated facilities and pipelines. The 2014 capital program is the first of a two-year development plan to achieve production of approximately 6,000 boe/d by mid-late 2015 to satisfy the Company's infrastructure commitments.

Antler, Southeast 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.

During 2013, Questerre continued development of its light oil pool in Antler through drilling and the expansion of a waterflood pilot to increase recovery of the oil in place.

Two additional horizontal wells were converted to water injection wells in the third quarter of the year and a third was converted in the first quarter of 2014. This follows the positive results from the first horizontal well that was converted into an injector in the third quarter of 2012. The Company currently has two sections that are under waterflood. Production and pressure data in the offsetting wells is being monitored and based on results, Questerre plans to expand this to additional sections in mid-late 2014.

At Antler, the Company also drilled two horizontal and one vertical well targeting the Torquay/Bakken formation. The two (2.0 net) horizontal wells were brought on production in 2014 and the vertical (1.0 net) well was abandoned.

Oil Shale Mining

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

Initial field capsule construction at Seep Ridge, Utah

In 2013, Red Leaf continued its work with a US affiliate of the French-based supermajor, Total S.A. ("Total"), to jointly develop their oil shale assets in Utah. The joint venture began an Early Production System ("EPS") phase to prove the technical and environmental attributes of the process at large scale in Utah. It follows the successful field pilot conducted by Red Leaf in 2009. Total will fund an 80% share of the EPS expenses estimated at US$200 million. Red Leaf and Total subsequently plan to launch an advanced commercial pilot on their jointly held acreage for oil shale in Utah. Total will also fund an 80% share of the first US$200 million of this commercial production phase of operations.

During the year, the joint venture worked to optimize the design and engineering for the construction of the first commercial scale capsule. This work was validated by a series of constructability tests that were successfully completed. Engineering was also completed on the associated mining and production facilities. In December, the Company also received a key regulatory permit to facilitate field work commencing in 2014.

Concurrently, the Company has been working with Red Leaf to progress their joint oil shale acreage in Wyoming. Preliminary permitting and engineering is ongoing for a work program to assess this acreage. Questerre will participate for a 20% interest and Red Leaf will hold the remaining 80% interest in this joint venture. The work program will include a series of core holes on the acreage to validate an existing resource assessment. Subject to regulatory approval and equipment availability, the work program is scheduled to commence in mid-late 2015.

Red Leaf oil shale joint ventures in Utah and Wyoming

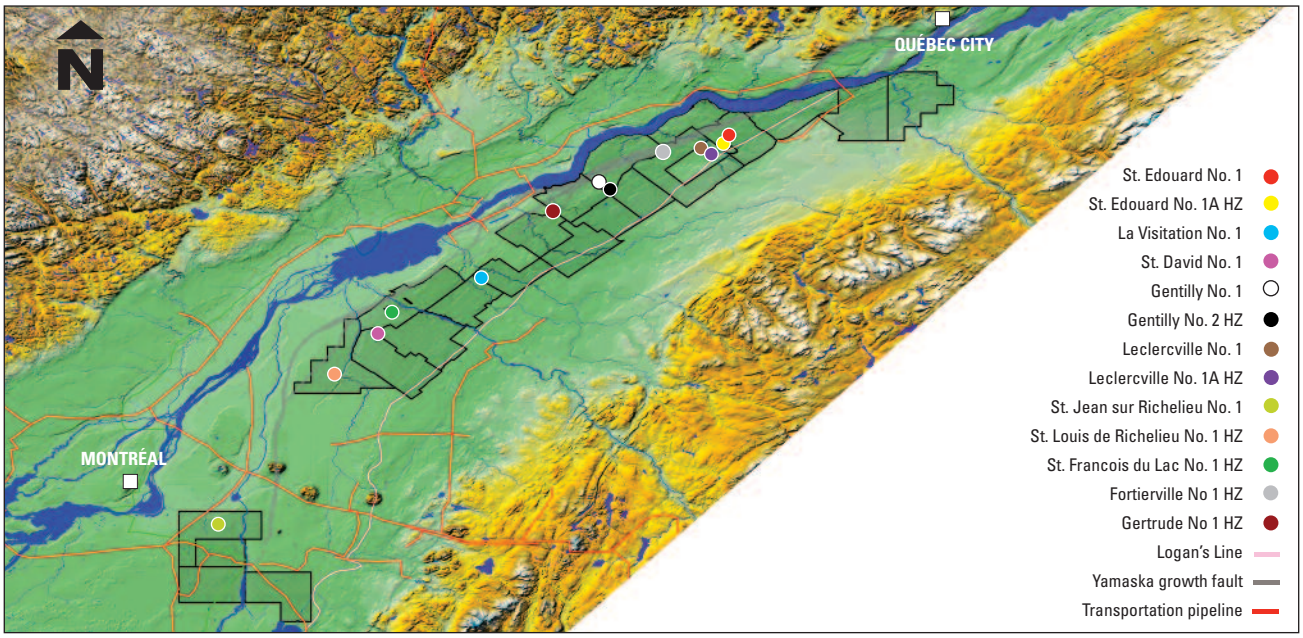
Questerre also completed the analysis of data from its second core program at its oil shale acreage at Pasquia Hills, Saskatchewan. The six-well core program was completed in the fall of 2012 on the eastern block of Questerre's acreage. 653m of good quality core was cut as well as a full suite of drilling logs over the target Second White Specks shale.

All the wells drilled encountered the target formation with a minimum thickness of 26m and a maximum of 59m. This follows the first 10-well program on the western block where over 30m of the shale was cored in all the wells drilled. In line with expectations, preliminary analysis indicates grades of 10-17 gallons/ton with select intervals from some wells averaging 15-18 gallons/ton in an interval of up to 10m and individual samples of over 26 gallons/ton.

Outcrop of oil shale at Pasquia Hills, Saskatchewan

Further testing is scheduled in 2014 and will include characterization of the oil quality. Utilizing the data from the core program, the Company expects to commission an independent resource assessment of this acreage later this year.

St. Lawrence Lowlands, Quebec



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

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

Following a successful vertical test well program in 2008 and 2009, Questerre and its partner, Talisman, began a pilot horizontal well program to assess commerciality of the Utica shale in 2010. The initial results from the first two wells, St. Edouard and Gentilly, drilled in different parts of the fairway met or exceeded Management's expectations. Two additional horizontal wells, Fortierville and St. Gertrude were also drilled and are awaiting completion.

In 2011, the pilot program was suspended while the government initiated a strategic environmental assessment of shale gas development in Quebec ("SEA").

In 2013, the Minister of Sustainable Development, Environment and Parks in Quebec ("MDDEP") announced its plans to refer the study of shale gas development to the province's environmental assessment agency, the Bureau d'audiences publiques sur l'environment ("BAPE"). The Minister also announced plans to table legislation that would introduce a moratorium on modern hydraulic fracturing operations and shale gas development in the province pending the introduction of new hydrocarbon legislation.

The committee responsible for conducting the SEA completed their assessment during the year. The summary report from the assessment was released in February 2014 and confirmed that the risks associated with development are manageable. The findings from this report will lay the groundwork for the next stage, which will be a series of public consultations to be held by the BAPE. The consultations are expected to commence in the second quarter of 2014.

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 27, 2013. 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, 2013 and 2012. Additional information relating to Questerre, including Questerre's Annual Information Form for the year ended December 31, 2013, is available on SEDAR under Questerre's profile at www.sedar.com.

Questerre is an independent energy company focused on non-conventional oil and gas resources. The Company is currently developing a portfolio of oil shale assets in North America. It is securing a social license to commercialize its Utica natural gas discovery in Quebec. The Company is underpinned by light oil and other conventional assets. Questerre is committed to the economic development of its resources in an environmentally conscious and socially responsible manner.

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

Basis of Presentation

Questerre presents figures in the MD&A using accounting policies within the framework of International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board. All financial information is reported in Canadian dollars, unless otherwise noted. Certain amounts in prior years have been reclassified to conform to the current year's presentation.

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 "seek", "anticipate", "budget", "plan", "continue", "estimate", "expect", "forecast", "may", "will", "project", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe" 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, contain forward-looking statements pertaining to the following:

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

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

In particular, this MD&A contains the following forward-looking statements pertaining to the following:

- production volumes;
- the future ability to alleviate field processing constraints;
- timing of drilling programs and resulting cash flows;
- future oil, natural gas liquids and natural gas prices;
- the size of the Company's oil, natural gas liquids and natural gas resource;
- the timing related to the Company's processing, transportation and marketing agreements;
- operating costs;
- royalty rates;
- future development, exploration and acquisition activities and related expenditures;
- the amount of future asset retirement obligations; and
- future liquidity and future financial capacity.

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

- future oil, natural gas liquids and natural gas prices;
- the continued availability of capital, undeveloped lands and skilled personnel;
- the costs of expanding our property holdings;
- the ability to obtain equipment in a timely manner to carry out exploration, development and exploitation activities;
- the ability to obtain financing on acceptable terms;
- the ability to add production and reserves through exploration, development and exploitation activities; and

- the continuation of the current tax and regulatory regime.

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

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

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

Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward-looking statements contained in this MD&A and the documents incorporated by reference herein are expressly qualified by this cautionary statement. We do not undertake any obligation to publicly update or revise any forward-looking statements except as required by applicable securities law. The information set out herein with respect to forecasted 2014 and 2015 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 for 2014 and 2015. 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)		2013		2012
Net cash from operating activities	$	14,406	$	10,117
Change in non-cash operating working capital		(1,214)		128
Cash flow from operations	$	13,192	$	10,245

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

The Company considers netbacks a key measure as it demonstrates its profitability relative to current commodity prices. Operating netbacks have been defined as revenue less royalties, transportation and operating costs. Cash netbacks have been defined as operating netbacks less general and administrative costs. Netbacks are generally discussed and presented on a per boe basis.

The Company also uses the term "working capital surplus". Working capital surplus, 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, as used by the Company, is calculated as current assets less current liabilities excluding the current portion of the share based compensation liability, risk management contracts and the flow-through share liability.

Select Annual Information

As at/for the years ended December 31,	**2013**	2012	2011
Financial ($ thousands, except as noted)			
Petroleum and Natural Gas Sales	**24,359**	18,842	18,273
Cash Flow from Operations	**13,192**	10,244	10,063
Basic ($/share)	**0.06**	0.04	0.04
Diluted ($/share)	**0.06**	0.04	0.04
Net Income (Loss)	**(19,354)**	(19,472)	3,901
Basic ($/share)	**(0.08)**	(0.08)	0.02
Diluted ($/share)	**(0.08)**	(0.08)	0.02
Capital Expenditures, net of			
Acquisitions and Dispositions	**52,133**	42,350	40,766
Working Capital Surplus	**31,909**	33,216	104,481
Total Assets	**273,108**	243,365	258,410
Shareholders' Equity	**241,197**	217,456	232,878
Common Shares Outstanding (thousands)	**264,657**	230,804	231,300
Weighted average - basic (thousands)	**236,691**	230,914	233,026
Weighted average - diluted (thousands)	**237,210**	232,774	235,975
Operations (units as noted)			
Average Production			
Crude Oil and Natural Gas Liquids (bbl/d)	**682**	580	491
Natural Gas (Mcf/d)	**1,219**	590	930
Total (boe/d)	**885**	678	646
Average Sales Price			
Crude Oil and Natural Gas Liquids ($/bbl)	**91.53**	86.14	94.57
Natural Gas ($/Mcf)	**3.57**	2.65	3.91
Total ($/boe)	**75.41**	75.95	77.50
Netback ($/boe)			
Petroleum and Natural Gas Revenue	**75.41**	75.95	77.50
Royalties Expense	**(5.78)**	(5.14)	(6.60)
Percentage	**8%**	7%	9%
Operating Expense	**(15.04)**	(18.04)	(11.93)
Operating Netback	**54.59**	52.77	58.97
General and Administrative Expense	**(13.68)**	(17.00)	(20.83)
Cash Netback	**40.91**	35.77	38.14
Wells Drilled			
Gross	**11.00**	15.00	21.00
Net	**5.50**	8.50	14.77

Highlights

- Development drilling delineates Montney resource with best estimate economic contingent resources of 32 MMboe and prospective resources of 100 MMboe with over 40% as condensate
- Concluded market access agreements for approximately 6,000 boe/d of Montney natural gas and liquids production
- Red Leaf finalizes design for commercial scale capsule and scheduled to commence construction in mid-2014
- Proved and probable reserves grew by 40% to 9.04 MMboe with oil, condensate and liquids accounting for 65% of volumes
- Cash flow from operations of $13.19 million with average daily production of 885 boe/d for the year

2013 Activities

Western Canada

Kakwa-Resthaven, Alberta

In 2013, the Company began developing this new core area in west central Alberta targeting condensate-rich natural gas from the Montney formation.

Questerre increased its land holdings in this area to 21,600 (13,560 net) acres through Crown land sales, acquisitions and farm-in agreements. Of this acreage, the Company currently holds a 100% working interest and operates 10,880 acres. In addition, Questerre increased its land holdings to 24,320 net acres prospective for the Montney formation in the Wapiti area approximately 20 miles northeast of its acreage at Kakwa-Resthaven.

Questerre participated in the drilling of three (0.75 net) wells and the completion of four (1.0 net) wells on its joint venture acreage where it holds a 25% working interest. Consistent with the initial wells drilled in 2012, the two wells tested in 2013, the 03-19 Well and the 05-23 Well, flowed at initial rates averaging approximately 4.77 MMcf/d and 821 bbls/d of condensate in the last twenty four hours of their respective tests. For more information on these well tests, please refer to the Company's press releases filed on SEDAR on March 21, 2013 and October 16, 2013.

To address the productivity constraints associated with these relatively high condensate yields and the high line pressures, the Company has been working with the operator to install central compression facilities and additional wellhead equipment. A central compression and condensate stabilization facility was constructed in the fourth quarter of 2013 and commissioned in early 2014. The facility has a capacity of 15 MMcf/d of natural gas and 0 bbls/d of condensate.

In addition to activities on its joint venture acreage, the Company tested the 09-01 Well on its operated acreage approximately six miles to the south. During initial testing and clean-up, equipment failure resulted in an uncontrolled release of completion fluids and gas for approximately 24 hours. Subsequent operations re-established gas flows and high pressure on surface that included anomalous hydrogen sulphide rates.

The 09-01 Well was suspended due to a lack of critical sour processing facilities and pipelines in the immediate area. At year-end, the Company incurred a write-off of $19.24 million for costs associated with

drilling, completing and testing of the 09-01 Well that were not covered by it's insurance policy. In the first quarter of 2014, the Company spud a horizontal well offsetting the 09-01 Well to validate the condensate rates in this area. Subject to equipment availability and results, the Company anticipates that it will put the well on production late in the third quarter of this year.

The Company commissioned an independent assessment of its Montney resources. The resource assessment was conducted by McDaniel & Associates Consultants Ltd. ("McDaniel"), which assessed the resources associated with the in place petroleum and natural gas on a portion of Questerre's net acreage in the area. Specifically, the assessment was conducted on 12,800 net acres or approximately 44% of the Company's total acreage in the area as of the date of the assessment. No assessment was conducted of the Company's acreage held in the Wapiti area.

The report estimates prospective resources ("PR") net to Questerre to range between a low of 291 Bcfe (49 MMboe) and a high of 774 Bcfe (129 MMboe) with a best estimate of 598 Bcfe (100 MMboe) that includes over 40% condensate. There is no certainty that any portion of the prospective resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources.

In addition, economic contingent resources ("ECR"), have been assigned a best estimate of 190 Bcfe (32 MMboe) with a range from a low of 95 Bcfe (16 MMboe) to a high of 245 Bcfe (41 MMboe). Approximately 50% of this best estimate or 16 million barrels of oil equivalent are natural gas liquids with condensate accounting for over 83% of this amount. Using their April 2013 price forecast, McDaniel's best estimate of ECR has a net present value discounted at 10% before tax of $267 million. There is no certainty that it will be commercially viable to produce any portion of the contingent resources.

The assessment of the resources by McDaniel includes Discovered and Undiscovered Petroleum Initially In Place (PIIP), PR (a subset of Undiscovered PIIP) and ECR (a subset of Discovered PIIP). The evaluation was performed in accordance with NI 51-101 and the Canadian Oil and Gas Evaluation Handbook and is effective April 1, 2013. For information on commodity prices used in the evaluation, refer to the Company's Annual Information Form for the year ended December 31, 2013, which is available on SEDAR under Questerre's profile at www.sedar.com.

The evaluation conducted by McDaniel included detailed geological and petrophysical analysis of Questerre's Montney acreage in the Kakwa-Resthaven area and adjacent industry Montney wells. It focused on the Upper and Middle Montney intervals. McDaniel assumed a Montney development plan based on an average of eight wells per section (four wells for each of the Upper and Middle Montney intervals). Total PIIP on average was estimated at approximately 60 Bcf per section with recovery factors estimated to range from 20% to 55% with a best estimate of approximately 40%.

The recoveries of natural gas liquids estimated by the resource assessment are based on the Company securing shallow cut processing capacity. Contingent resources were assigned to the Company's acreage within a three mile radius of a tested or producing Montney well.

The primary contingencies which prevent the classification of the ECR as reserves are classified as non-technical as follows: the current early stage of development, timing of development, regulatory requirements for government spacing and land expiries. Additional drilling, completion, and testing data will be required before Questerre can commit to the development of the ECR. Proven and probable reserves are assigned to areas in proximity to proven producing Montney wells. ECR are assigned to areas that extend beyond the limits of reserves and are interpreted to be less certain. As continued delineation drilling occurs, more ECR are expected to be re-classified as reserves.

All unrisked estimates of resources above represent Questerre's gross resources before the deduction of any royalties.

To facilitate market access for its future production from this area, the Company entered into a series of agreements with certain midstream companies in the second half of 2013. These included firm transportation and processing as well as marketing for condensate, natural gas and the associated natural gas liquids. Production volumes under these take or pay contracts are approximately 6,000 boe/d and represent approximately 20 MMcf/d of natural gas and 3,000 bbls/d of condensate and liquids. The in-service date for these contracts is mid-late 2015 with terms of between three and ten years.

The Company plans to invest approximately $80 million in the Kakwa-Resthaven area in 2014. This will include up to seven (1.75 net) wells with the joint venture, up to five wells on its 100% operated acreage and associated facilities and pipelines. The 2014 capital program is the first of a two-year development plan to achieve production of approximately 6,000 boe/d by mid-late 2015 to satisfy the Company's infrastructure commitments.

Antler, Saskatchewan and Pierson, Manitoba

During 2013, Questerre continued development of its light oil pool in Antler, Saskatchewan through drilling and the expansion of a waterflood pilot to increase recovery of the oil in place.

Two additional horizontal wells were converted to water injection wells in the third quarter of the year and a third was converted in the first quarter of 2014. This follows the positive results from the first horizontal well that was converted into an injector in the third quarter of 2012. The Company currently has two sections that are under waterflood. Production and pressure data in the offsetting wells is being monitored and based on results, Questerre plans to expand this to additional sections in mid-late 2014.

At Antler, the Company also drilled two horizontal wells and one vertical well targeting the Torquay/Bakken formation. The two (2.0 net) horizontal wells were brought on production in 2014 and the vertical (1.0 net) well was abandoned.

Following the results of an initial two (0.70 net) well program in Pierson, Manitoba in late 2012 targeting light oil from the Spearfish formation, Questerre participated in a five (1.75 net) well program during the year. The wells were drilled on schedule and under budget. The Company plans to participate in up to four (1.40 net) additional wells in this area in 2014 and the installation of associated facilities and pipelines.

Oil Shale Mining

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

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

In 2013, Red Leaf continued its work with a US affiliate of the French-based supermajor, Total S.A. ("Total"), to jointly develop their oil shale assets in Utah. The joint venture began an Early Production System ("EPS") phase to prove the technical and environmental attributes of the process at large scale in Utah. It follows the successful field pilot conducted by Red Leaf in 2009. Total will fund an 80% share of the EPS expenses estimated at US$200 million. Red Leaf and Total subsequently plan to launch an advanced commercial pilot on their jointly held acreage for oil shale in Utah. Total will fund an 80% share of the first US$200 million of this commercial production phase of operations.

During the year, the joint venture worked to optimize the design and engineering for the construction of the first commercial scale capsule. This work was validated by a series of constructability tests that were successfully completed. Engineering was also completed on the associated mining and production facilities. In December, the Company received a key regulatory permit to facilitate field work commencing in 2014.

Concurrently, the Company has been working with Red Leaf to progress their joint oil shale acreage in Wyoming. Preliminary permitting and engineering is ongoing for a work program to assess this acreage. Questerre will participate for a 20% interest and Red Leaf will hold the remaining 80% interest in this joint venture. The work program will include a series of core holes on the acreage to validate an existing resource assessment. Subject to regulatory approval and equipment availability, the work program is scheduled to commence in mid-late 2015.

Questerre also completed the analysis of data from its second core program at its oil shale acreage at Pasquia Hills, Saskatchewan. The six-well core program was completed in the fall of 2012 on the eastern block of Questerre's acreage. 653m of good quality core was cut as well as a full suite of drilling logs over the target Second White Specks shale.

All the wells drilled encountered the target formation with a minimum thickness of 26m and a maximum of 59m. This follows the first 10-well program on the western block where over 30m of the shale was cored in all the wells drilled. In line with expectations, preliminary analysis indicates grades of 10-17 gallons/ton with select intervals from some wells averaging 15-18 gallons/ton in an interval of up to 10m and individual samples of over 26 gallons/ton.

Further testing is scheduled in 2014 and will include characterization of the oil quality. Utilizing the data from the core program, the Company expects to commission an independent resource assessment of this acreage later this year.

St. Lawrence Lowlands, Quebec

The pilot program to assess the commerciality of the Utica shale remained suspended in 2013 while the government conducted its strategic environmental assessment ("SEA") on shale gas development in Quebec.

In 2013, the Minister of Sustainable Development, Environment and Parks in Quebec ("MDDEP") announced its plans to refer the study of shale gas development to the province's environmental assessment agency, the Bureau d'audiences publiques sur l'environment ("BAPE"). The Minister also announced plans to table legislation that would introduce a moratorium on modern hydraulic fracturing operations and shale gas development in the province pending the introduction of new hydrocarbon legislation.

The committee responsible for conducting the SEA completed their assessment during the year. The summary report from the assessment was released in February 2014 and concluded that the risks associated with the development are manageable. The findings from this report will lay the groundwork for the next stage, which will be a series of public consultations to be held by the BAPE. The consultations are expected to commence in the second quarter of 2014.

Questerre expects that any further operations, including the completion of the Fortierville and St. Gertrude horizontal wells will be deferred pending completion of the BAPE's assessment of the shale gas industry and release of the proposed hydrocarbon legislation.

Corporate

In July, the Company secured a $26.50 million credit facility with a Canadian chartered bank. Structured as a revolving operating demand loan, any borrowing under the facility, 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 facility is secured by a $50 million debenture with a first floating charge over all assets of the Company and a general assignment of books debts.

Drilling Activities

In 2013, Questerre participated in the drilling of 11.0 (5.50 net) wells, comprising three (3.0 net) oil wells in Antler, Saskatchewan, three (0.75 net) liquids-rich natural gas wells in Kakwa-Resthaven, Alberta and five (1.75 net) oil wells in Pierson, Manitoba.

Production

	2013			2012		
	Oil and Liquids (bbl/d)	Natural Gas (Mcf/d)	Equivalent (boe/d)	Oil and Liquids (bbl/d)	Natural Gas (Mcf/d)	Equivalent (boe/d)
Saskatchewan	396	-	396	530	-	530
Alberta	182	1,105	366	36	525	124
Manitoba	104	-	104	13	-	13
British Columbia	-	114	19	-	65	11
	682	1,219	885	579	590	678

In 2013, early production from the Kakwa-Resthaven area of Alberta of about 250 boe/d increased the Company's daily volumes to 885 boe/d from 678 boe/d in the prior year. Crude oil and liquids, as a percentage of total volumes, decreased to 77% from 85% in 2012 as production from this area is split approximately 50% natural gas and 50% liquids.

While the majority of Questerre's capital program for 2013 was focused on developing the condensate-rich Montney in Alberta, the Company continued to invest in its light oil assets in Saskatchewan and Manitoba.

In Manitoba, Questerre participated in a five (1.75 net) well program in the third quarter that increased production from 13 bbls/d to 104 bbls/d. Production from this area was shut-in for a material portion of the year as wet weather impeded access to truck production from the single well batteries. To mitigate this downtime, Questerre will participate in the construction of a satellite battery and local gathering system. In conjunction with the operator, Questerre also plans to drill up to four (1.40 net) additional wells in this area in 2014.

With development in Antler, Saskatchewan, focusing mainly on the expansion of a pilot waterflood, production largely reflected natural declines and the conversion of two additional producing wells to injectors. The drilling and completion of three (3.0 net) wells and the recompletion of an existing well in the area were delayed by unseasonably wet weather this summer and an early winter. The Company was able to complete the majority of the work late in the fourth quarter and early in the first quarter of 2014. The wells have since been tied-in and placed on production. In 2014, Questerre's plans for this area will continue to target the expansion of the waterflood pilot with the conversion of two additional horizontal wells. Based on results, the waterflood will be expanded to additional sections.

Production from Kakwa-Resthaven in the year was primarily from two wells drilled on the joint venture acreage in 2012. Growth was constrained by limited drilling in the first half of the year and a lack of compression and access to third party processing capacity. The relatively high condensate rates associated with these natural gas wells also required additional wellhead production facilities that were only installed in early 2014. Furthermore, limited third party pipeline capacity resulted in an apportionment of the condensate volumes.

The field processing constraints were alleviated in early 2014 with the commissioning of a central compression and condensate stabilization facility on its joint venture acreage in the area. The facility has a capacity of 15 MMcf/d and 3,000 bbls/d of associated condensate. Questerre has a 25% working interest in this facility. Questerre anticipates this facility will be essential to its development plans for the upcoming year.

In 2014, Questerre plans to participate in the drilling of up to seven (1.75 net) wells on its joint venture acreage. In addition, the Company plans to drill up to five wells on its 100% owned acreage. To ensure access to third party infrastructure for its future production, Questerre has secured sufficient processing and transportation capacity for approximately 6,000 boe/d of production commencing mid-late 2015.

2013 Financial Results

Petroleum and Natural Gas Sales

	2013			2012		
($ thousands)	Oil and Liquids	Natural Gas	Total	Oil and Liquids	Natural Gas	Total
Saskatchewan	$ 13,588	$ -	$ 13,588	$ 16,847	$ -	$ 16,847
Alberta	5,855	1,463	7,318	1,059	509	1,568
Manitoba	3,315	-	3,315	360	-	360
British Columbia	-	138	138	-	67	67
	$ 22,758	$ 1,601	$ 24,359	$ 18,266	$ 576	$ 18,842

Higher oil and condensate production in 2013 benefitted from higher prices to improve petroleum and natural gas revenue by almost 30% over the prior year. Approximately 20% of this increase of $5.52 million was due to higher natural gas production and stronger natural gas prices.

Pricing

	2013	2012
Benchmark prices:		
Natural Gas - AECO, daily spot ($/Mcf)	3.19	2.39
Crude Oil - Edmonton light ($/bbl)	92.92	86.12
Realized prices:		
Natural Gas ($/Mcf)	3.57	2.65
Crude Oil and Natural Gas Liquids ($/bbl)	91.53	86.14

Consistent with the prior year, crude oil prices remained relatively volatile with the benchmark WTI price trading between US$87/bbl and US$110/bbl. Concerns about the fiscal situation in the US and the global economy in the early part of 2013 saw prices fall and subsequently increase with growing unrest in the Middle East and North Africa region. Prices fell again in the fall of 2013, on the back of seasonal refinery turnarounds and pipeline constraints.

The differential between the WTI price and the Canadian Light Sweet benchmark also remained fairly volatile, trading between a premium of US$0.67/bbl and a discount of US$17.44/bbl. Although the differential narrowed mid-year due to increased volumes of oil transported by rail, and to a lesser extent refinery demand and additional pipeline capacity, Questerre expects the volatility to persist for the foreseeable future.

Questerre's condensate production attracted a premium to the Canadian Light Sweet benchmark in 2013 and the Company's realized price increased to $91.53/bbl from $86.14/bbl as compared to the benchmark pricing of $92.92/bbl in 2013 and $86.12/bbl in 2012.

Weather contributed to stronger natural gas prices in early 2013, driving higher heating demand in the winter and cooling demand in the summer. The pricing moderated in the summer with cooler temperatures and as natural gas became less price competitive with coal for power generation. With dry gas production in the US remaining relatively stable, higher industrial and power demand will likely be needed in the long-term to tighten the supply demand balance.

Higher heat content gas production from Alberta contributed to realized prices of $3.57/Mcf in 2013 (2012: $2.65/Mcf) as compared to the benchmark AECO average price of $3.19/Mcf (2012: $2.39/Mcf).

To partially mitigate the impact of further volatility in its realized prices, the Company entered into a $94.70/bbl WTI swap for 150 bbls/d for calendar 2014, a $4.00/GJ NGX AB-NIT Month Ahead Index (7A) swap for 2000 GJ/d from February 1, 2014 to December 31, 2014 and a $3.72/GJ NGX AB-NIT Month Ahead Index (7A) swap for 2000 GJ/d from January 1, 2015 to December 31, 2015.

Royalties

($ thousands)		2013		2012
Alberta	$	813	$	56
Saskatchewan		787		1,176
Manitoba		268		42
British Columbia		-		-
	$	1,868	$	1,274
% of Revenue:				
Alberta		11%		4%
Saskatchewan		6%		7%
Manitoba		8%		12%
British Columbia		0%		0%
Total Company		8%		7%

In 2013, Questerre's effective royalty rate as a percentage of revenue increased marginally to 8% from 7% in 2012.

Partially offset by the decline in the royalty rate on production from Manitoba, the higher rate is due to production from the Kakwa-Resthaven area of Alberta which increased the royalty rate on Alberta production from 4% to 11%. Although the Company's production from the area benefits from Crown royalty incentive programs, the higher royalty rate was due to additional gross overriding royalties that are payable on its first well in the area. The Company currently holds a 37.5% interest in this well subject to the payment of an overriding royalty until payout of the capital costs incurred by Questerre. Upon achieving payout, the working interest reverts to 25% and the gross overriding royalty is no longer payable.

Operating Costs

($ thousands)		2013		2012
Alberta	$	2,206	$	1,020
Saskatchewan		2,165		3,332
Manitoba		362		56
British Columbia		125		69
	$	4,858	$	4,477
$/boe:				
Alberta		16.52		22.63
Saskatchewan		14.98		17.15
Manitoba		9.54		11.90
British Columbia		18.07		17.23
Total Company		15.04		18.05

On a unit of production basis, operating costs in the current year decreased from $18.05/boe to $15.04/boe due to operating efficiencies at Antler, Saskatchewan and the increase in production from Kakwa, where costs are lower than the Company's other Alberta assets.

At Antler, the tie-in of existing wells to the main battery and the local electrical grid during the year resulted in lower rental, fuel and trucking costs as rental diesel generators powering pumps were replaced by electricity and pipelines eliminated the trucking of emulsion.

Operating costs in Alberta decreased from $22.63/boe to $16.52/boe in the current year. In 2012, production from Alberta was primarily from the Vulcan area where the relatively large proportion of fixed costs was borne by declining production. In 2013, the majority of Alberta production was from the Kakwa-Resthaven area, which has lower per unit operating costs. The Company expects its operating costs in this area to decrease further as additional wells are brought on production through its recently commissioned joint venture central facility.

General and Administrative Expenses

($ thousands)		2013		2012
General and administrative expenses, gross	$	6,129	$	6,568
Capitalized expenses and overhead recoveries		(1,714)		(2,350)
General and administrative expenses, net	$	4,415	$	4,218

Gross general and administrative expenses ("G&A") were $6.13 million in 2013 compared to $6.57 million in 2012. The decrease was mainly due to lower staffing costs, public and government relations and legal expenses. Capitalized expenses and overhead recoveries as a percentage of gross G&A was 28% in 2013 compared to 36% in 2012. This is attributable to higher capital expenditures on operated properties in 2012, a portion of which is recoverable from its partners.

Depletion, Depreciation, Impairment and Accretion

Questerre recorded $9.40 million of depletion and depreciation expense for the year ended December 31, 2013 (2012: $9.82 million). On a per unit basis, the Company's depletion and depreciation expense decreased by over 26% to $29.10/boe in 2013 (2012: $39.57/boe). The decrease is attributable to a higher production weighting from cash generating units with lower finding and development costs. On a gross basis, this was mostly offset by an increase in production from 2012.

In 2013, the Company recorded $20.83 million for exploration and evaluation asset impairments comprising $1.59 million for lease expiries of its undeveloped land and $19.24 million relating to its 09-01 Well in the Kakwa-Resthaven area. The costs associated with the 09-01 Well represent the drilling, completion and testing costs before and after the control of well incident, which were not covered by the Company's insurance policy. The factors that led to the 09-01 Well impairment include the costs of this specific well relative to the carrying value of its assets in the area and the lack of reserves assigned.

In 2013, the Company also recorded $1.88 million for asset impairments relating to its property, plant and equipment assets. At December 31, 2013, the Company reviewed the carrying amounts of its property, plant and equipment assets for indicators of impairment such as changes in future prices, future costs and reserves. Based on this review, certain of the Company's cash generating units ("CGU's") were tested for impairment in accordance with the Company's accounting policy. The recoverable amount of the CGUs was estimated based on the fair value less costs of disposal ("FVLCD") using a discounted cash flow model. The estimate of FVLCD was determined using a discount rate of 10% and forecasted after-tax cash flows based on proved plus probable reserves, with escalating prices and future development costs obtained from the reserve report. Based on the assessment, for the year ended December 31, 2013, the Company recorded the impairment loss, which relates to its Antler, Midway, Vulcan, and Other Alberta CGUs. The factors that led to the impairment were a reduction in forecasted near-term commodity prices.

In 2012, the Company recorded $21.01 million for exploration and evaluation asset impairments comprising $19.39 million relating to its Wawota, Saskatchewan exploration and evaluation assets and $1.61 million for lease expiries of its undeveloped land. In 2012, the Company also recorded $5.32 million for asset impairments relating to its property, plant and equipment assets mainly in the Antler and Vulcan CGU's.

Share Based Compensation

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

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

The Company uses the Black-Scholes model to calculate a theoretical value of the options based on the price of its shares, its volatility, risk-free rate and expected life. Due to the increase in the Company's share price in 2013, the Black-Scholes values have increased resulting in an expense in 2013.

Deferred Taxes

For the years ended December 31, 2013 and 2012, Questerre reported a deferred tax recovery of $4.98 million and $6.71 million. The deferred tax recovery decrease in 2013 compared to 2012 is primarily related to a decreased loss before income taxes.

Questerre had sufficient tax pool deductions to offset taxable income in 2013.

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, 2013, the unrealized loss recorded for the year ended December 31, 2013 was $0.85 million compared to the unrealized gain of $0.40 million for the same period in 2012. For the Company's settled risk management contracts at December 31, 2013, the realized loss recorded for the year ended December 31, 2013 was $0.26 million compared to the realized gain of $0.48 million for the same period in 2012.

In connection with the disposition of its interest in Questerre Beaver River Inc. to Transeuro Energy Corp. ("Transeuro") in 2011, the Company invested in senior convertible bonds of Transeuro in the second quarter of 2012. During the third quarter of 2013, the Company converted the bonds into common shares of the issuer and subsequently disposed of these shares. The Company recognized a loss on its investment of $1.53 million for the year ended December 31, 2013 and $0.24 million for the year ended December 31, 2012.

Questerre reported interest income of $0.39 million for the year ended December 31, 2013 (2012: $1.09 million). The interest is from the cash invested in Guaranteed Investment Certificates issued by Canadian chartered banks and credit unions and from the Company's investment in convertible bonds. The decrease in the interest income is a result of the Company's lower cash balance in the current year.

The Company recorded a gain on foreign exchange, net of deferred tax, through other comprehensive income or loss of $2.59 million for the year ended December 31, 2013 (2012: $0.33 million loss). The changes are due to fluctuations in the exchange rate relating to its US dollar investments.

Questerre holds investments in private companies which are designated as available for sale and are stated at fair value. For 2012, the Company recorded an unrealized gain, net of deferred tax, of $1.96 million in other comprehensive income or loss related to these investments.

Total Comprehensive Income or Loss

Questerre's total comprehensive loss was $16.76 million for 2013 compared to $16.19 million in 2012. The Company's change in total comprehensive loss is mainly attributable to higher share based compensation expense in 2013, mainly offset by higher operating netbacks and lower impairment charges in 2013.

Capital Expenditures

($ thousands)		2013		2012
Alberta	$	44,730	$	20,211
Saskatchewan		4,382		20,843
Manitoba		2,253		141
Quebec		613		1,118
Wyoming		136		-
British Columbia		70		60
Corporate		2		152
		52,186		42,525
Dispositions		(175)		(175)
Total	$	52,011	$	42,350

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

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

Questerre incurred net capital expenditures of $42.35 million in 2012 as follows:

- In Saskatchewan, $17.61 million was incurred mainly drilling and completing wells in Antler. During 2012, the Company drilled eight (5.25 net) wells and completed 11.0 (7.50 net) wells. The Company also spent $3.23 million on exploratory work assessing its oil shale acreage at Pasquia Hills, Saskatchewan.
- $17.41 million was invested in the Kakwa-Resthaven participating in the drilling and completion of operated and non-operated wells, including the 09-01 Well. The Company drilled 3.0 (1.63 net) wells and completed two (0.50 net) wells. The Company also invested $2.57 million in Manyberries, Alberta to drill, complete, test and equip one oil well for production.
- In the St. Lawrence Lowlands, Quebec, $1.12 million was incurred primarily to secure the Company's social license to operate and develop its Utica shale discovery.

Liquidity and Capital Resources

Questerre had a working capital surplus of $31.91 million at December 31, 2013 as compared to a surplus of $33.22 million at December 31, 2012. The Company's capital investment program for 2014 is mainly directed to the development of its Montney assets in the Kakwa-Resthaven area. The Company believes it is sufficiently capitalized to fund this program from its working capital surplus, cash flow from operations and available conventional debt facilities.

Cash Flow from Operating Activities

Net cash from operating activities for the year ended December 31, 2013 and 2012 was $14.41 million and $10.12 million, respectively. The Company realized higher net petroleum and natural gas revenue, which was partially offset by increased operating expenditures.

Cash Flow used in Investing Activities

Cash flow used in investing activities decreased from $74.74 million in 2012 to $48.70 million in 2013. For the year ended December 31, 2013, the Company incurred capital expenditures of $52.19 million compared to $42.53 million for the same period in 2012. The higher net capital expenditures were mainly due to increased investment activity in the Kakwa-Resthaven area partially offset by less drilling and completion activity in Antler in 2013.

During 2013, the Company converted its senior convertible bonds of Transeuro into common shares of the issuer and disposed of these shares for proceeds of $0.49 million.

In 2012, Questerre acquired approximately 6% of the equity capital of Red Leaf for $43.17 million and invested in senior secured convertible bonds for $2.22 million. In 2012, the Company also disposed of its marketable securities for proceeds of $5.41 million.

Cash Flow provided by (used in) Financing Activities

Cash flow provided by financing activities was $39.21 million in 2013 and used in financing activities was $0.40 million in 2012. The increase in 2013 is due to the net proceeds received on the issue of Common Shares of $39.21 million from the Company's private placement, flow-through share offering and option exercises. In 2012, the Company repurchased Common Shares for $0.52 million under its normal course issuer bid.

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, 2013, 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 27, 2014	December 31, 2013	December 31, 2012
Common Shares	264,907	264,657	230,804
Stock options	17,938	18,188	21,349
Weighted average Common Shares			
Basic		236,691	230,914
Diluted		237,210	232,774

In December 2013, pursuant to a private placement, the Company issued 23.49 million Common Shares at a

price of $1.29 per share, for gross proceeds of $30.24 million. The issue costs including underwriter' fees were approximately $1.43 million ($1.06 million net of tax effect) with net proceeds being $28.81 million.

In December 2013, pursuant to a bought deal flow-through share equity offering, the Company issued 5.87 million Common Shares at a price of $1.55 per share, for gross proceeds of $9.09 million. The issue costs including underwriter' fees were approximately $0.71 million ($0.53 million net of tax effect) with net proceeds being $8.38 million. A premium of $1.76 million related to the issuance of the Common Shares on a flow-through basis was recorded as a short-term liability on the consolidated statement of financial position. The liability is derecognized, with a corresponding deferred tax expense, as the Company incurs qualifying exploration expenditures. The Company has an obligation to incur $9.09 million in qualifying exploration expenditures by December 31, 2014 to satisfy the terms of this flow-through Common Share issuance. The Company intends to use the offering proceeds primarily to accelerate its capital program for its liquids-rich Montney acreage in the Kakwa-Resthaven area of west central Alberta, Canada.

A summary of the Company's stock option activity during the years ended December 31, 2013 and 2012 follows:

	December 31, 2013		December 31, 2012	
	Number of Options *(thousands)*	Weighted Average Exercise Price	Number of Options *(thousands)*	Weighted Average Exercise Price
Outstanding, beginning of year	21,349	$2.24	22,674	$2.27
Forfeited	(1,766)	1.67	(1,950)	2.09
Expired	(2,480)	4.66	(255)	0.90
Exercised	(4,493)	0.45	(260)	0.45
Granted	5,578	0.96	1,140	0.68
Outstanding, end of year	18,188	$2.02	21,349	$2.24
Exercisable, end of year	9,352	$2.89	12,973	$2.48

Commitments and Contingencies

The Company has commitments under a lease for office space of $0.32 million per year for 2014 and $0.27 million in 2015. In 2011, Questerre entered into a data licensing agreement. The Company has commitments under the agreement of $0.10 million per year for 2014.

In August 2013, the Company entered into a 10 year agreement for 20 MMcf/d of natural gas and associated liquids processing at a new propane-plus (C3+) shallow cut gas plant located in the Kakwa-Resthaven area in west central Alberta. The agreement is expected to begin in 2015 and has an annual commitment of $3.65 million.

In August 2013, the Company entered into a 3-year transportation agreement for the delivery of approximately 19 MMcf/d of natural gas. The agreement is expected to begin in 2015 and has an annual commitment of $1.74 million.

In October 2013, the Company entered into a 10-year agreement for fractionation and marketing for natural gas liquids. The agreement is expected to begin in 2015 and has an annual commitment of $0.69 million.

In November 2013, the Company entered into a 10-year transportation agreement for the delivery of condensate and natural gas liquids. The agreement is expected to begin in 2015 and has an annual commitment of $3.61 million.

The Company is a defendant in two legal actions arising in the normal course of business. The Company considers the likelihood of cash outflows relating to such actions to be remote and believes that any liabilities that might arise pertaining to any such matters would not have a material effect on its consolidated financial position.

In 2011, a joint venture partner filed a statement of claim with respect to amounts formally disputed by Questerre. Questerre has filed its statement of defense and counterclaim with respect to this issue. The claim is for $3.91 million and the entire amount is accounted for in the consolidated financial statements.

Risk Management

Companies engaged in the petroleum and natural gas industry face a variety of risks. For Questerre, these include risks associated with exploration and development drilling as well as production operations, commodity prices, exchange and interest rate fluctuations. Unforeseen significant changes in such areas as markets, prices, royalties, interest rates and government regulations could have an impact on the Company's future operating results and/or financial condition. While management realizes that all the risks may not be controllable, they can be monitored and managed.

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

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

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

The Company uses the following guidelines to address financial exposure:

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

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

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

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

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

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.

Environmental Regulation and Risk

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

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

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

Critical Accounting Estimates

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

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

Petroleum and Natural Gas Reserves

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

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

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

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 with respect to the way in which management monitors the operations.

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

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

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

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

Asset Retirement Obligation

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

Share Based Compensation

The Company has a stock option plan enabling employees, officers and directors to receive common shares or cash at exercise prices equal to the market price or above on the date the option is granted. At each reporting date, the Company uses the Black-Scholes option pricing model as the fair value method for valuing

stock options. The assumptions used in the calculation are: the volatility of the stock price, risk-free rates of return and the expected lives of the options. A forfeiture rate is estimated on the grant date and is adjusted to reflect the actual number of options that vest. Changes to assumptions may have a material impact on the amounts presented.

Income Tax Accounting

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

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

Investment in Red Leaf

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

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

Investment in Convertible Bonds

Questerre had an investment in convertible bonds, which was classified as fair value through profit and loss and carried at fair value. The Company uses its judgment to select the method of valuation and make assumptions that are primarily based on market conditions existing at the end of each reporting period. The

Company uses directly and indirectly observable inputs in measuring the fair value of the convertible debt, including quoted commodity prices, volatility, credit spreads and foreign exchange rates.

Accounting Standards Changes

Changes in Accounting Policies for 2013

Effective January 1, 2013, the Company adopted the following new standards and interpretations:

IFRS 10 *Consolidated Financial Statements*

IFRS 10 revised the definition of control and requires an entity to consolidate an investee when it has power over the investee, is exposed, or has rights, to variable returns from its involvement with the investee and has the ability to affect those returns through its power over the investee. It also included guidance related to an investor with decision making rights to determine if it is acting as a principal or agent. IFRS 10 replaced SIC-12 *Consolidation—Special Purpose Entities* and parts of IAS 27 *Consolidated and Separate Financial Statements*.

IAS 27 was amended to conform to the changes made in IFRS 10 but retains the current guidance for separate financial statements.

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

IFRS 11 *Joint Arrangements*

IFRS 11 requires a venturer to classify its interest in a joint arrangement as a joint venture or joint operation. Joint ventures will be accounted for using the equity method of accounting whereas for a joint operation the venturer will recognize its share of the assets, liabilities, revenue and expenses of the joint operation. IFRS 11 supersedes IAS 31 *Interests in Joint Ventures*, and SIC-13 *Jointly Controlled Entities—Non-Monetary Contributions by Venturers*.

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

IFRS 12 *Disclosure of Interest in Other Entities*

IFRS 12 establishes disclosure requirements for interests in other entities, such as subsidiaries, joint arrangements, associates and unconsolidated structured entities. The standard carries forward existing disclosures and also introduces significant additional disclosure requirements that address the nature of, and risks associated with, an entity's interests in other entities. IFRS 12 replaces disclosure requirements previously included in IAS 27, IAS 31 and IAS 28 *Investments in Associates*.

IAS 28 has been amended to conform to the changes made in IFRS 10 and IFRS 11.

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

IFRS 13 *Fair Value Measurement*

IFRS 13 establishes a single framework for fair value measurement and disclosures when fair value is required or permitted under IFRS. Adoption of the standard did not require adjustments to the valuation techniques used by the Company to measure fair value and did not result in any measurement adjustments as at January 1, 2013. The adoption of this standard resulted in additional disclosures in the Company's

financial statements.

IAS 1 *Presentation of Financial Statements*

Amendments to IAS 1 require companies preparing financial statements in accordance with IFRS to group together items within other comprehensive income that may be reclassified to the profit or loss section of the income statement. The amendment affected presentation only and had no impact on the Company's financial position or performance.

IAS 36 *Impairment of Assets*

In May 2013, the IASB released an amendment to IAS 36 *Impairment of Assets* regarding disclosures on recoverable amounts of non-financial assets. This amendment removed certain disclosures of the recoverable amounts of CGUs which had been included in IAS 36 by the issue of IFRS 13. The amendment is not mandatory until January 1, 2014, however the Company has decided to early adopt the amendment as of January 1, 2013. The amendment affected presentation only and had no impact on the Company's financial position or performance.

Future Accounting Pronouncements

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

IFRS 9 *Financial Instruments*

As at January 1, 2015, the Company will be required to adopt IFRS 9 *Financial Instruments*. IFRS 9 was issued in November 2009 and replaces the current multiple classification and measurement models for debt instruments with a new mixed measurement model having only two classification categories: amortized cost and fair value through profit and loss. IFRS 9 also replaces the models for measuring investments in equity instruments, and such instruments are either recognized at fair value through profit or loss or at fair value through other comprehensive income or loss. Where such equity instruments are measured at fair value through other comprehensive income or loss, dividends are recognized in profit or loss to the extent they do not clearly represent a return of investment, however, other gains and losses (including impairments) associated with such instruments remain in accumulated other comprehensive income or loss indefinitely.

Requirements for financial liabilities were added in October 2010 and they largely carried forward existing requirements in IAS 39 *Financial Instruments: Recognition and Measurement*, except that fair value changes due to credit risk for liabilities designated at fair value through profit or loss would generally be recorded in other comprehensive income or loss.

In November 2013, the IASB issued the third phase of IFRS 9 which details the new general hedge accounting model. Hedge accounting remains optional and the new model is intended to allow reporters to better reflect risk management activities in the financial statements and provide more opportunities to apply hedge accounting. The Company does not use hedge accounting for its existing risk management contracts.

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

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

- The Company has designed and evaluated the effectiveness of Disclosure Controls and Procedures ("DC&P"). The President and Chief Executive Officer and the Chief Financial Officer have concluded that DC&P are designed appropriately and are operating effectively as at December 31, 2013.
- The Company has designed and evaluated the effectiveness of Internal Controls over Financial Reporting ("ICFR"). The President and Chief Executive Officer and the Chief Financial Officer completed an assessment of the ICFR and during the process of the assessment, it was determined that certain weaknesses existed in ICFR. The weaknesses are the result of the Company's size and limited number of staff and include: (i) the inability to achieve complete segregation of duties; and (ii) having insufficient staff with the required technical tax knowledge to deal with complex and non-routine matters. The Company believes that these weaknesses are mitigated by: (i) the President and Chief Executive Officer and the Chief Financial Officer overseeing all material transactions; (ii) the audit committee, comprised of independent members of the Board of Directors, reviewing the quarterly interim and annual audited financial statements with management; (iii) the Board of Directors' approval of the financial statements based on the audit committee's recommendation after its review; and (iv) the Company consulting with its third party expert advisors as needed in connection with the recording and reporting of complex and non-routine transactions.
- The Company reports that no changes were made to ICFR during 2013 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 2013 Results

Questerre's cash flow from operations increased from $2.90 million for the quarter ended December 31, 2012 to $2.94 million for the same period in 2013. The increase in cash flow from operations is mainly due to higher operating netbacks in 2013 than 2012.

Oil and natural gas liquids revenue increased to $5.76 million for the three months ended December 31, 2013 compared to $5.23 million for the same period in 2012. The Company's realized price for oil and natural gas liquids was $85.44/bbl for the fourth quarter of 2013 compared with $83.26/bbl for the fourth quarter of 2012. Oil and natural gas liquids production increased from 658 bbls/d in the fourth quarter of 2012 to 692 bbls/d in the fourth quarter of 2013. The increased production was mainly from the Pierson wells that were brought on stream in the fourth quarter of 2013. The increased production was partially offset by natural declines from existing assets.

Operating costs were $1.02 million or $13.18/boe for the three months ended December 31, 2013 compared to $1.40 million or $19.87/boe for the same period in 2012. The decrease in operating costs is mainly due lower rental, fuel and trucking in Antler as a result of the tie-in of existing wells to the main battery and the local electrical grid.

The Company's G&A was $0.95 million for the fourth quarter of 2012 compared to $1.19 million for the fourth quarter of 2013 mainly due to lower capitalized expenses and overhead recoveries. This is attributable to higher capital expenditures on operated properties in 2012, a portion of which is recoverable from its partners.

Total comprehensive loss for the three months ended December 31, 2013 was $14.89 million compared to $17.16 million for the same period in 2012. The comprehensive loss decrease from 2012 is due to lower impairment charges recorded in 2013.

Net capital expenditures were $12.95 million and $12.98 million for the three months ended December 31, 2013 and 2012, respectively. In 2013, the Company spent $9.50 million relating to its Kakwa-Resthaven assets and $2.87 million relating to its Antler assets. In 2012, the Company spent $10.63 million relating to its Kakwa-Resthaven assets and $1.37 million relating to its other Alberta assets.

Quarterly Financial Information

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

($ thousands, except as noted)	December 31, 2012	September 30, 2012	June 30, 2012	March 31, 2012
Production (boe/d)	766	696	525	725
Average Realized Price ($/boe)	74.22	75.64	72.10	80.68
Petroleum and Natural Gas Sales	5,232	4,843	3,444	5,323
Cash Flow from Operations	2,898	2,834	1,221	3,291
Basic ($/share)	0.01	0.01	0.01	0.01
Diluted ($/share)	0.01	0.01	0.01	0.01
Net Profit (Loss)	(17,659)	(111)	131	(1,833)
Basic ($/share)	(0.08)	-	-	(0.01)
Diluted ($/share)	(0.08)	-	-	(0.01)
Capital Expenditures, net of acquisitions and dispositions	12,981	9,389	5,188	14,792
Working Capital Surplus	33,216	40,597	47,350	55,052
Total Assets	243,365	257,814	256,759	267,006
Shareholders' Equity	217,456	234,846	233,860	233,137
Weighted Average Common Shares Outstanding				
Basic (thousands)	230,804	230,793	230,946	231,114
Diluted (thousands)	232,665	232,420	232,955	232,695

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

- Production has increased from 678 boe/d for the year ended December 31, 2012 to 885 boe/d for the same period in 2013. Liquids production has decreased as a percentage of total production from 86% in 2012 to 77% in 2013.
- The Company's net loss for the fourth quarter of 2013 increased due to higher impairment charges.
- The working capital surplus has decreased as the capital expenditures and investment in Red Leaf has been higher than the cash flow from operations. This was partially offset by the proceeds received in 2013 from share issuances.

Management's Report

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

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

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

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

Michael Binnion

President and Chief Executive Officer

Jason D'Silva

Chief Financial Officer

Calgary, Alberta, Canada

March 27, 2014

Independent Auditor's Report

To the Shareholders of Questerre Energy Corporation

We have audited the accompanying consolidated financial statements of Questerre Energy Corporation (the "Company"), which comprise the consolidated balance sheets as at December 31, 2013 and December 31, 2012 and the consolidated statements of net profit or loss and comprehensive income or loss, changes in equity and cash flows for the years ended December 31, 2013 and December 31, 2012, and the related notes, which comprise a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements

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

Auditor's responsibility

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

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

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

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2013 and December 31, 2012 and its financial performance and its cash flows for the years ended December 31, 2013 and December 31, 2012 in accordance with International Financial Reporting Standards.

PricewaterhouseCoopers LLP

Chartered Accountants

Calgary, Alberta

March 27, 2014

Consolidated Balance Sheets

($ thousands)	Note	December 31, 2013	December 31, 2012
Assets			
Current Assets			
Cash and cash equivalents	5	$ 47,459	$ 42,541
Investment in convertible bonds	7	-	2,064
Accounts receivable	8	2,630	4,945
Current portion of risk management contracts	8	-	399
Deposits and prepaid expenses		607	546
		50,696	50,495
Investments	9	46,078	43,101
Property, plant and equipment	10	99,267	88,818
Exploration and evaluation assets	11	56,442	45,477
Goodwill		2,346	2,346
Deferred tax assets	12	18,279	13,128
		$ 273,108	$ 243,365
Liabilities			
Current Liabilities			
Accounts payable and accrued liabilities		$ 18,787	$ 16,881
Current portion of risk management contracts	8	453	-
Flow-through share obligation	16	1,760	-
Current portion of share based compensation liability	13	2,825	1,945
		23,825	18,826
Asset retirement obligation	14	7,136	6,644
Share based compensation liability	13	950	439
		31,911	25,909
Shareholders' Equity			
Share capital	16	347,059	307,035
Contributed surplus		16,659	16,179
Accumulated other comprehensive income or loss		4,259	1,668
Deficit		(126,780)	(107,426)
		241,197	217,456
		$ 273,108	$ 243,365

Commitments and contingencies (note 21)

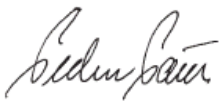
Subsequent events (note 22)

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

Signed on behalf of the Board of Directors

Dennis Sykora

Director



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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, 2013	2012
Revenue			
Petroleum and natural gas sales	17	$ 24,359	$ 18,842
Royalties		(1,868)	(1,274)
Petroleum and natural gas revenue, net of royalties		22,491	17,568
Expenses			
Direct operating		4,858	4,477
General and administrative		4,415	4,218
Depletion and depreciation	10	9,395	9,818
Impairment of assets	10,11	22,714	26,333
Loss (gain) on risk management contracts	8	1,112	(882)
Loss on investment in convertible bonds	7	1,525	240
Share based compensation	13	2,825	953
Accretion of asset retirement obligation	14	156	130
Reclass from OCI relating to marketable securities and investments		-	(248)
Interest income		394	1,092
Other income (expense)		(221)	199
Loss before taxes		(24,336)	(26,180)
Deferred tax recovery	12	(4,982)	(6,708)
Net Loss		(19,354)	(19,472)
Other Comprehensive Income or Loss, Net of Tax			
Items that may be reclassified subsequently to profit or loss:			
Gain on marketable securities and investments	6,9	-	3,857
Gain (loss) on foreign exchange	9	2,591	(328)
Reclass to profit (loss) relating to marketable securities and investments		-	(248)
		2,591	3,281
Total Comprehensive Loss		$ (16,763)	$ (16,191)
Net Loss per Share			
Basic and diluted	16	$ (0.08)	$ (0.08)

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

Consolidated Statements of Changes in Equity

($ thousands)	Note	For the years ended December 31, 2013	2012
Share Capital			
Balance, beginning of year		$ 307,035	$ 307,857
Issue of common shares	16	41,612	184
Repurchase of shares under normal course issuer bid		-	(1,006)
Share issue costs (net of tax)	16	(1,588)	-
Balance, end of year		347,059	307,035
Contributed Surplus			
Balance, beginning of year		16,179	14,588
Reclassification of share based compensation	13	480	1,106
Repurchase of shares under normal course issuer bid	16	-	485
Balance, end of year		16,659	16,179
Accumulated Other Comprehensive Income or Loss			
Balance, beginning of year		1,668	(1,613)
Other comprehensive income (loss)		2,591	3,281
Balance, end of year		4,259	1,668
Deficit			
Balance, beginning of year		(107,426)	(87,954)
Net loss		(19,354)	(19,472)
Balance, end of year		(126,780)	(107,426)
Total Shareholders' Equity		$ 241,197	$ 217,456

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

Consolidated Statements of Cash Flows

($ thousands)	Note	For the years ended December 31, 2013	2012
Operating Activities			
Net loss		$ (19,354)	$ (19,472)
Adjustments for:			
Depletion and depreciation	10	9,395	9,818
Impairment of assets	10,11	22,714	26,333
Unrealized (gain) loss on risk management contracts	8	852	(399)
Loss on investment in convertible bonds	7	1,525	240
Share based compensation	13	2,825	953
Accretion of asset retirement obligation	14	156	130
Deferred tax recovery	12	(4,982)	(6,708)
Other items not involving cash		121	(548)
Abandonment expenditures	14	(60)	(102)
Cash flow from operations		13,192	10,245
Change in non-cash working capital	20	1,214	(128)
Net cash from operating activities		14,406	10,117
Investing Activities			
Property, plant and equipment expenditures	10	(20,240)	(17,162)
Exploration and evaluation expenditures	11	(31,946)	(25,363)
Sale of property, plant and equipment		53	175
Purchase of investments	9	-	(43,171)
Proceeds from sale of marketable securities and investments	6,9	490	7,850
Purchase of convertible bonds	7	-	(2,224)
Change in non-cash working capital	20	2,948	5,156
Net cash used in investing activities		(48,695)	(74,739)
Financing Activities			
Proceeds from issue of share capital	16	41,349	117
Share issue costs	16	(2,142)	-
Shares repurchased	16	-	(520)
Net cash from (used in) financing activities		39,207	(403)
Change in cash and cash equivalents		4,918	(65,025)
Cash and cash equivalents, beginning of year		42,541	107,566
Cash and cash equivalents, end of year		$ 47,459	$ 42,541
Cash interest received		$ 902	$ 1,151

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, 2013 and 2012 comprise the Company and its wholly-owned subsidiary in those years owned.

Questerre is incorporated under the laws of the Province of Alberta and is domiciled in Canada. The address of its registered office is 1650, 801 – 6th Avenue SW, Calgary, Alberta.

2. Basis of Preparation

a) Statement of compliance

The Company prepares its consolidated financial statements in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Boards ("IASB"). The policies applied in these consolidated financial statements are based on IFRS issued and outstanding as at March 27, 2014, the date the Board of Directors approved the statements.

b) Basis of measurement

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

c) Functional and presentation currency

These consolidated financial statements are presented in Canadian dollars, which is the Company's functional currency.

d) Jointly controlled assets

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

e) Reclassification

Certain amounts in prior years have been reclassified to conform to the current year's presentation.

f) Use of estimates and judgments

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

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

Petroleum and natural gas reserves

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

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

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

Refer to Note 10 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 with respect to the way in which management monitors the operations.

Refer to Note 10 for carrying amounts of property, plant and equipment.

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

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

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

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

Refer to Note 10 for the sensitivity analysis related to impairments and to Note 11 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 credit-adjusted 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 14 for the carrying amounts related to the asset retirement obligation.

Share based compensation

The Company has a stock option plan enabling employees, officers and directors to receive common shares or cash at exercise prices equal to the market price or above on the date the option is granted. At each reporting date, the Company uses the Black-Scholes option pricing model as the fair value method for valuing stock options. The assumptions used in the calculation are: the volatility of the stock price, risk-free rates of return and the expected lives of the options. A forfeiture rate is estimated on the grant date and is adjusted to reflect the actual number of options that vest. Changes to assumptions may have a material impact on the amounts presented.

For further detail on carrying amounts and assumptions refer to Note 13.

Income tax accounting

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

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

Refer to Note 12 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. The Company also assesses factors that might indicate that the corporate transaction price might not be representative of fair value at the measurement date. These factors include significant changes in the performance of the investee compared with budgets, plans or milestones, changes in management or strategy and significant changes in the price of oil. Considerable judgment is required in measuring the fair value of the Company's investment in Red Leaf, which may result in material adjustments to its related carrying value.

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

Refer to Note 9 for the carrying amounts and further detail on the recoverability related to the Company's investment in Red Leaf.

Investment in convertible bonds

Questerre had an investment in convertible bonds, which was classified as fair value through profit and loss and carried at fair value. The Company uses its judgment to select the method of valuation and make assumptions that are primarily based on market conditions existing at the end of each reporting period. The Company uses directly and indirectly observable inputs in measuring the fair value of the convertible debt, including quoted commodity prices, volatility, credit spreads and foreign exchange rates.

Refer to Note 7 for the carrying amounts related to the Company's investment in convertible bonds.

3. Significant Accounting Policies

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

a) Basis of consolidation

Subsidiaries

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

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

Transactions eliminated on consolidation

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

b) Financial instruments

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

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

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

Financial assets and liabilities at fair value through profit or loss

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

Available for sale

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

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

Loans and receivables

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

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

Financial liabilities at amortized cost

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

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

c) Share capital

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

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

Recognition and measurement

Exploration and evaluation expenditures

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

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

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

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

Every reporting period, the company evaluates individually significant exploration and evaluation wells for impairment, if there are specific impairment indicators evident at the well level. If technical feasibility and commercial viability of the well is not established, the well costs are written off. For insignificant wells, overall E&E 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. As at January 24, 2011, the Company modified its stock option plan.

Prior to the modification, the Company accounted for its stock option plan using the fair value method. Under this method, compensation costs attributable to stock options granted to employees, officers or directors was measured at fair value at the grant date and expensed over the vesting period with a corresponding increase to contributed surplus. The exercise of stock options was recorded as an increase in common shares with a corresponding reduction in contributed surplus.

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

Under both plans, a forfeiture rate is estimated on the grant date and is adjusted to reflect the actual number of options that vest.

h) Provisions

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

Asset retirement obligation

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

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

i) Marketable securities

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

j) Inventory

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

k) Revenue

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

l) Income tax

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

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

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

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

m) Net profit or loss per share

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

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

n) Flow-through shares

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

4. Changes in Accounting Policies and Disclosures

Changes in Accounting Policies for 2013

Effective January 1, 2013, the Company adopted the following new standards and interpretations:

IFRS 10 *Consolidated Financial Statements*

IFRS 10 revised the definition of control and requires an entity to consolidate an investee when it has power over the investee, is exposed, or has rights, to variable returns from its involvement with the investee and has the ability to affect those returns through its power over the investee. It also included guidance related to an investor with decision making rights to determine if it is acting as a principal or agent. IFRS 10 replaced SIC-12 *Consolidation—Special Purpose Entities* and parts of IAS 27 *Consolidated and Separate Financial Statements*.

IAS 27 was amended to conform to the changes made in IFRS 10 but retains the current guidance for separate financial statements.

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

IFRS 11 *Joint Arrangements*

IFRS 11 requires a venturer to classify its interest in a joint arrangement as a joint venture or joint operation. Joint ventures will be accounted for using the equity method of accounting whereas for a joint operation the venturer will recognize its share of the assets, liabilities, revenue and expenses of the joint operation. IFRS 11 supersedes IAS 31 *Interests in Joint Ventures*, and SIC-13 *Jointly Controlled Entities—Non-Monetary Contributions by Venturers*.

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

IFRS 12 *Disclosure of Interest in Other Entities*

IFRS 12 establishes disclosure requirements for interests in other entities, such as subsidiaries, joint arrangements, associates and unconsolidated structured entities. The standard carries forward existing disclosures and also introduces significant additional disclosure requirements that address the nature of, and risks associated with, an entity's interests in other entities. IFRS 12 replaces disclosure requirements previously included in IAS 27, IAS 31 and IAS 28 *Investments in Associates*.

IAS 28 has been amended to conform to the changes made in IFRS 10 and IFRS 11.

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

IFRS 13 *Fair Value Measurement*

IFRS 13 establishes a single framework for fair value measurement and disclosures when fair value is required or permitted under IFRS. Adoption of the standard did not require adjustments to the valuation techniques used by the Company to measure fair value and did not result in any measurement adjustments as at January 1, 2013. The adoption of this standard resulted in additional disclosures in the Company's financial statements.

IAS 1 *Presentation of Financial Statements*

Amendments to IAS 1 require companies preparing financial statements in accordance with IFRS to group together items within other comprehensive income that may be reclassified to the profit or loss section of the income statement. The amendment affected presentation only and had no impact on the Company's financial position or performance.

IAS 36 *Impairment of Assets*

In May 2013, the IASB released an amendment to IAS 36 *Impairment of Assets* regarding disclosures on recoverable amounts of non-financial assets. This amendment removed certain disclosures of the recoverable amounts of CGUs which had been included in IAS 36 by the issue of IFRS 13. The amendment is not mandatory until January 1, 2014, however the Company has decided to early adopt the amendment as of January 1, 2013. The amendment affected presentation only and had no impact on the Company's financial position or performance.

Future Accounting Pronouncements

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

IFRS 9 *Financial Instruments*

As at January 1, 2015, the Company will be required to adopt IFRS 9 Financial Instruments. IFRS 9 was issued in November 2009 and replaces the current multiple classification and measurement models for debt instruments with a new mixed measurement model having only two classification categories: amortized cost and fair value through profit and loss. IFRS 9 also replaces the models for measuring investments in equity instruments, and such instruments are either recognized at fair value through profit or loss or at fair value through other comprehensive income or loss. Where such equity instruments are measured at fair value through other comprehensive income or loss, dividends are recognized in profit or loss to the extent they do not clearly represent a return of investment, however, other gains and losses (including impairments) associated with such instruments remain in accumulated other comprehensive income or loss indefinitely.

Requirements for financial liabilities were added in October 2010 and they largely carried forward existing requirements in IAS 39 *Financial Instruments: Recognition and Measurement*, except that fair value changes due to credit risk for liabilities designated at fair value through profit or loss would generally be recorded in other comprehensive income or loss.

In November 2013, the IASB issued the third phase of IFRS 9 which details the new general hedge accounting model. Hedge accounting remains optional and the new model is intended to allow reporters to better reflect risk management activities in the financial statements and provide more opportunities to apply hedge accounting. The Company does not use hedge accounting for its existing risk management contracts.

5. Cash and Cash Equivalents

($ thousands)	December 31, 2013	December 31, 2012
Bank balances	$ 6,668	$ 3,423
Short-term bank deposits	40,791	39,118
	$ 47,459	$ 42,541

6. Marketable Securities

Marketable securities represent investments in shares of public companies. The following table sets out the changes in marketable securities:

($ thousands)	December 31, 2013	December 31, 2012
Balance, beginning of year	$ -	$ 3,275
Conversion of debenture into common shares	490	-
Sale of marketable securities	(490)	(5,412)
Gain on marketable securities	-	2,137
Balance, end of year	$ -	$ -

In 2013, the Company converted its senior convertible bonds of Transeuro Energy Corp. into 15.29 million common shares of the issuer and subsequently sold these shares for proceeds of $0.49 million.

For the year ended December 31, 2012, the gain on marketable securities of $2.14 million was recorded in other comprehensive income or loss net of deferred tax expense of $0.24 million.

7. Investment in Convertible Bonds

The following table sets out the changes in the investment in convertible bonds:

($ thousands)	December 31, 2013	December 31, 2012
Balance, beginning of year	$ 2,064	$ -
Purchase of convertible bonds	-	2,224
Conversion into common shares	(490)	-
Loss on investment in convertible bonds	(1,525)	(240)
Gain (loss) on foreign exchange	(49)	80
Balance, end of year	$ -	$ 2,064

In May 2012, Questerre invested in senior secured convertible bonds. They were to mature May 22, 2015 and had a coupon rate of 12%. This financial asset had been designated to be measured as fair value through profit or loss. In September 2013, the Company converted the Transeuro bonds into 15.29 million common shares of the issuer. Refer to Note 6.

8. 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, 2013 included cash and cash equivalents, accounts receivable, risk management contracts, deposits, investments and accounts payable and accrued liabilities. As at December 31, 2013, 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.

The Company's marketable securities are considered a level 1 instrument. The fair value of marketable securities are determined by the closing bid price per share as at the balance sheet date multiplied by the number of shares.

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 by reference to recent corporate transactions of the investee.

The following table sets forth a reconciliation of changes in the fair value of the assets classified as level 3 in the fair value hierarchy during 2013:

($ thousands)	December 31, 2013	December 31, 2012
Balance, beginning of year	$ 45,166	$ 495
Purchases	-	45,395
Conversion into common shares	(490)	-
Subscription refund	-	(2,438)
Gain recognized through other comprehensive income	2,977	1,836
Loss recognized through net profit (loss)	(1,575)	(122)
Balance, end of year	$ 46,078	$ 45,166

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, 2013	December 31, 2012
Current	$ 1,979	$ 2,297
31 - 60 days	245	501
61 - 90 days	57	204
>90 days	443	2,037
Allowance for doubtful accounts	(94)	(94)
	$ 2,630	$ 4,945

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.

At December 31, 2013, the Company had fully collected amounts outstanding of $10.53 million from insurers relating to a control of well incident that occurred in January 2013. The claim was made for costs to bring the well to the condition existing prior to the incident.

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

d) Liquidity risk

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

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

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

e) Market risk

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

Commodity price risk

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

possible, its cash flow on future sales. The contracts reduce the volatility in sales revenue by locking in prices with respect to future deliveries of oil and natural gas.

As at December 31, 2013, the Company had the following outstanding commodity risk management contracts in place:

	Volumes	Average Price	Term	Fair Value Liability *($ thousands)*
WTI NYMEX oil swap	150 bbls/d	$94.70/bbl	Jan. 1, 2014 - Dec. 31, 2014	$ 453

The net risk management position is as follows:

($ thousands)	December 31, 2013	December 31, 2012
Risk Management Assets:		
Current portion	$ -	$ 399
	$ -	$ 399

($ thousands)	December 31, 2013	December 31, 2012
Risk Management Liabilities:		
Current portion	$ 453	$ -
	$ 453	$ -

In net profit or loss, the Company recorded an unrealized loss of $0.85 million for the year ended December 31, 2013 and an unrealized gain of $0.40 million in 2012. The Company also recorded a realized loss of $0.26 million for the year ended December 31, 2013 and a realized gain of $0.48 million for the same period in 2012.

The value of Questerre's commodity price risk management contracts fluctuate with changes in the underlying market price of crude oil. An increase or decrease of $5 to the Canadian dollar West Texas Intermediate ("WTI") price, with all other variables being held constant, would result in a $0.27 million increase or decrease to net profit or loss, respectively.

Currency risk

All of Questerre's petroleum and natural gas sales are denominated in Canadian dollars, however; the underlying market prices for these commodities are impacted by the exchange rate between Canada and the United States. As at December 31, 2013, the Company had no forward foreign exchange contracts in place.

Interest rate risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Company has had no debt outstanding, interest rate swaps or financial contracts in place at or during the period ended December 31, 2013.

f) Capital management

The Company believes it is well capitalized with positive cash flow from operations (a non-IFRS measure defined as cash flows from operating activities before changes in non-cash operating working capital), no debt and a working capital surplus (defined as current assets less current liabilities excluding the current portion of the share based compensation liability, risk management contracts and the flow-through share liability) of $31.91 million consisting mainly of cash and cash equivalents.

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 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, 2013	December 31, 2012
Shareholders' equity	$ 241,197	$ 217,456

9. Investments

The investments balance comprises the following private company investments:

($ thousands)	December 31, 2013	December 31, 2012
Red Leaf	$ 45,535	$ 42,593
Investment in other private company	543	508
	$ 46,078	$ 43,101

The following table sets out the changes in investments:

($ thousands)	December 31, 2013	December 31, 2012
Balance, beginning of year	$ 43,101	$ 495
Purchase of investments	-	43,171
Subscription refund	-	(2,438)
Gain on investments	-	2,250
Gain (loss) on foreign exchange	2,977	(377)
Balance, end of year	$ 46,078	$ 43,101

In March 2012, pursuant to an equity offering, Questerre acquired US$40 million of common shares of Red Leaf. Red Leaf is a private Utah based oil shale and technology based company whose principal assets are its proprietary EcoShale In-Capsule Technology to recover oil from shale in addition to its oil shale leases in the states of Wyoming and Utah. In June 2012, the Company purchased an additional US$3 million of common shares of Red Leaf from a private investor.

In October 2012, pursuant to a backstop agreement between the Company and Red Leaf, Red Leaf refunded US$2.44 million of Questerre's US$40 million subscription in its equity offering completed in March 2012. This was based on the gross proceeds of the equity offering completed by Red Leaf exceeding the minimum offering size.

For the year ended December 31, 2013, the gain on foreign exchange relating to investments was $2.98 million, which was recorded in other comprehensive income or loss net of deferred tax of $0.39 million. For the year ended December 31, 2012, the loss on foreign exchange relating to investments was $0.38 million, which was recorded in other comprehensive income or loss net of deferred tax of $0.05 million. For the year ended December 31, 2012, the gain on investments of $2.25 million was recorded in other comprehensive income or loss net of deferred tax of $0.29 million.

The Company measured the fair market value of Red Leaf by reference to recent corporate transactions and assessed other factors that might indicate that the transaction price might not be representative of fair value at the measurement date. These factors included significant changes in the performance of Red Leaf compared with budgets, plans or milestones, changes in management or strategy and significant changes in the price of oil. Based on this assessment, a price of US$1,500/share was used to value the Red Leaf investment as at December 31, 2013 and 2012. No items were identified in this analysis that would indicate a different valuation.

Red Leaf is currently in the early production phase ("EPS") of commercializing its EcoShale process. As part of this phase, it is finalizing the design and engineering and in 2014 is expected to proceed with constructing and operating a commercial scale pilot. Pending the results of the EPS, Red Leaf and its joint venture partner will then make a final investment decision to commence commercial oil shale production on its existing leases. If Red Leaf's EcoShale In-Capsule technology is not technically feasibility or commercially viability, then the Company's investment in Red Leaf could be impaired.

10. 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, 2011	$ 103,584	$ 1,128	$ 104,712
Additions	17,762	153	17,915
Transfer from exploration and evaluation assets	10,583	-	10,583
Balance, December 31, 2012	131,929	1,281	133,210
Additions	21,226	2	21,228
Transfer from exploration and evaluation assets	496	-	496
Balance, December 31, 2013	**$ 153,651**	**$ 1,283**	**$ 154,934**
Accumulated depletion, depreciation and impairment losses:			
Balance, December 31, 2011	$ 28,371	$ 879	$ 29,250
Depletion and depreciation	9,713	105	9,818
Impairment	5,324	-	5,324
Balance, December 31, 2012	43,408	984	44,392
Depletion and depreciation	9,295	100	9,395
Impairment	1,880	-	1,880
Balance, December 31, 2013	**$ 54,583**	**$ 1,084**	**$ 55,667**

($ thousands)	Oil and Natural Gas Assets	Other Assets	Total
Net book value:			
At December 31, 2012	$ 88,521	$ 297	$ 88,818
At December 31, 2013	**$ 99,068**	**$ 199**	**$ 99,267**

During the year ended December 31, 2013, the Company capitalized administrative overhead charges of $2.14 million (December 31, 2012: $0.56 million) including $0.86 million in capitalized stock based compensation expense directly related to development activities (December 31, 2012: $0.06 million). Included in the December 31, 2013 depletion calculation are future development costs of $73.41 million (December 31, 2012: $56.44 million).

At December 31, 2013, 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 certain of the Company's CGUs were tested for impairment in accordance with the Company's accounting policy. The recoverable amount of the CGUs was estimated based on the FVLCD using a discounted cash flow model. The estimate of FVLCD was determined using a discount rate of 10% and forecasted after-tax cash flows from 2014 to 2050 based on proved plus probable reserves, with escalating prices and future development costs obtained from the reserve report.

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

	2014	2015	2016	2017	2018	Average Annual % Change Thereafter
WTI (US$/barrel)	95.00	95.00	95.00	95.00	95.30	0.02
AECO ($/mmbtu)	4.00	4.25	4.55	4.75	5.00	0.02

Based on the assessment, for the year ended December 31, 2013, the Company recorded an impairment loss of $1.88 million relating to its Antler, Midway, Vulcan, and Other Alberta CGUs. The factors that led to the impairment were a reduction in forecasted near-term commodity prices. The recoverable amounts at December 31, 2013 for these CGUs are as follows:

($ thousands)	Antler	Midway	Vulcan	Other Alberta
Recoverable amounts	$ 60,347	$ 119	$ 1,044	$ 934

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	$ (627)	$ 4,603	$ (740)	$ 6,415

11. 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, 2013	December 31, 2012
Balance, beginning of year	$ 45,477	$ 51,583
Additions	32,420	25,486
Transfers to property, plant and equipment	(496)	(10,583)
Dispositions	(125)	-
Impairment	(20,834)	(21,009)
Balance, end of year	$ 56,442	$ 45,477

During the year ended December 31, 2013, the Company capitalized administrative overhead charges of $0.63 million (December 31, 2012: $1.52 million) including $0.21 million of capitalized stock based compensation expense directly related to exploration and evaluation activities (December 31, 2012: $(0.04) million).

In December 2013, the Company recorded an impairment charge of $19.24 million relating to the Company's 09-01 Well in Kakwa, Alberta. The factors that led to the 09-01 Well impairment include the costs of this specific well relative to the carrying value of its assets in the area and the lack of reserves assigned. The Company also recorded an impairment charge of $1.59 million for lease expiries of its undeveloped land in 2013.

In 2012, the Company performed an assessment of the indicators of impairment for its exploration and evaluation properties. Based on the assessment, the Company recorded an impairment charge of $19.39 million relating to its Wawota, Saskatchewan exploration and evaluation assets. As a result of exploratory work performed, the Company does not plan to pursue further activities in the Wawota area. During 2012, the Company also recorded an impairment charge of $1.61 million for lease expiries of its undeveloped land.

Of the exploration and evaluation asset balance, $27.30 million relates to the Company's acreage in Quebec prospective for non-conventional natural gas development. The future recoverability of these assets is dependent upon, among other things, the Quebec government's decision to permit drilling and modern completion operations, including hydraulic fracturing on this acreage for natural gas and the Company securing its social license to operate in the province. If the government disallows such activities for an extended period, or the Company decides not to further activities for this project, then the associated asset may be derecognized.

12. Deferred Income Taxes

The tax on the Company's profit or 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, 2013	December 31, 2012
Profit (loss) before taxes	$ (24,336)	$ (26,180)
Combined federal and provincial tax rate	25.69%	25.91%
Computed "expected" deferred tax recovery	(6,252)	(6,783)
Increase (decrease) in deferred taxes resulting from:		
Non-deductible differences	1,171	210
Rate adjustments	160	21
Recognition of previously unrecognized deferred tax asset	(141)	(173)
Other	80	17
Deferred tax recovery	$ (4,982)	$ (6,708)

The statutory tax rate decreased to 25.69% in 2013 from 25.91% in 2012 as a result of changes to the weighting of profit or loss to provinces with different tax rates.

The movement of the deferred tax asset is as follows:

($ thousands)	December 31, 2013	December 31, 2012
Balance, beginning of year	$ 13,128	$ 6,903
Credit to statement of net profit or loss	4,982	6,708
Tax on share issue costs	555	-
Tax charge relating to components of other comprehensive income or loss	(386)	(483)
Balance, end of year	$ 18,279	$ 13,128

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)	Asset retirement obligation	Share issue costs	Non-capital losses	Other
Deferred tax asset:				
Balance, December 31, 2011	$ 1,500	$ 1,305	$ 10,239	$ 239
Credited (charged) to net profit or loss	222	(603)	3,744	276
Charged to other comprehensive income or loss	-	-	-	(239)
Balance, December 31, 2012	1,722	702	13,983	276
Credited (charged) to net profit or loss	111	(485)	5,296	510
Credited to share capital	-	555	-	-
Balance, December 31, 2013	**$ 1,833**	**$ 772**	**$ 19,279**	**$ 786**

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

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

Non-capital loss carry-forwards at December 31, 2013 expire from 2014 to 2033.

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

($ thousands)		Petroleum and natural gas properties		Investments
Deferred tax liability:				
Balance, December 31, 2011	$	4,753	$	1,628
Charged (credited) to net profit or loss		(3,172)		103
Charged to other comprehensive income or loss		-		243
Balance, December 31, 2012		1,581		1,974
Charged (credited) to net profit or loss		558		(108)
Charged to other comprehensive income or loss		-		386
Balance, December 31, 2013	**$**	**2,139**	**$**	**2,252**

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

($ thousands)		**December 31, 2013**		December 31, 2012
Petroleum and natural gas properties	**$**	**219**	$	219
Capital losses		**31,750**		32,721
	$	**31,969**	$	32,940

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

13. Share Based Compensation

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

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

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

	December 31, 2013		December 31, 2012	
	Number of Options *(thousands)*	Weighted Average Exercise Price	Number of Options *(thousands)*	Weighted Average Exercise Price
Outstanding, beginning of year	21,349	$2.24	22,674	$2.27
Forfeited	(1,766)	1.67	(1,950)	2.09
Expired	(2,480)	4.66	(255)	0.90
Exercised	(4,493)	0.45	(260)	0.45
Granted	5,578	0.96	1,140	0.68
Outstanding, end of year	18,188	$2.02	21,349	$2.24
Exercisable, end of year	9,352	$2.89	12,973	$2.48

The following table summarizes information about stock options outstanding and exercisable at December 31, 2013:

	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
$0.61 - $0.75	2,722	2.89	$0.63	1,007	2.40	$0.63
$0.76 - $1.00	3,940	4.20	0.87	-	-	-
$1.01 - $1.50	3,645	3.64	1.26	1,049	2.10	1.44
$1.51 - $2.50	2,693	1.75	2.25	2,540	1.73	2.24
$2.51 - $4.03	5,188	1.23	4.03	4,756	1.23	4.03
	18,188	2.68	$2.02	9,352	1.59	$2.89

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 2013:

	December 31, 2013	December 31, 2012
Weighted average fair value per award ($)	0.82	0.49
Volatility (%)	68	93
Forfeiture rate (%)	6.70	5.35
Expected life (years)	4.66	4.83
Risk free interest rate (%)	1.82	1.36

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, 2013	December 31, 2012
Balance, beginning of year	$ 2,384	$ 2,585
Amount transferred to contributed surplus	(480)	(1,106)
Share based compensation expense	2,825	953
Capitalized share based compensation	1,068	19
Reclassification to share capital on exercise of stock options	(2,022)	(67)
Balance, end of year	$ 3,775	$ 2,384
Current portion	$ 2,825	$ 1,945
Non-current portion	950	439
	$ 3,775	$ 2,384

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

14. 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 $7.14 million as at December 31, 2013 (December 31, 2012: $6.64 million) based on an undiscounted total future liability of $11.27 million (December 31, 2012: $9.21 million). These payments are expected to be made over the next 37 years. The discount factor, being the risk-free rate related to the liabilities, is between 1.13% and 3.24% (December 31, 2012: 1.14% and 2.36%). An inflation rate of 3% over the varying lives of the assets is used to calculate the present value of the asset retirement obligation.

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

($ thousands)	December 31, 2013	December 31, 2012
Balance, beginning of year	$ 6,644	$ 5,806
Revisions due to change in discount rates	(725)	120
Revisions due to change in estimates	566	80
Liabilities incurred	555	655
Liabilities disposed	-	(45)
Liabilities settled	(60)	(102)
Accretion	156	130
Balance, end of year	$ 7,136	$ 6,644

15. Credit Facility

In July 2013, the Company secured a $26.50 million credit facility with a Canadian chartered bank. The credit facility is a revolving operating demand loan. Any borrowing under the facility, 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 facility is secured by a debenture with a first floating charge over all assets of the Company and a general assignment of books debts. Under the terms of the bank credit facility, the Company has provided its covenant that it will maintain an Adjusted Working Capital Ratio greater than 1.0. This ratio is defined as current assets, excluding unrealized hedging gains, to current liabilities, excluding bank debt and unrealized hedging losses. At December 31, 2013 no amount has been drawn on the credit facility.

16. Share Capital

The Company is authorized to issue an unlimited number of Class "A" common voting shares ("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, 2013, 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, 2011	231,300	$	307,857
Issued on exercise of options	260		184
Repurchased under normal course issuer bid	(756)		(1,006)
Balance, December 31, 2012	230,804		307,035
Issued on exercise of options	4,493		4,044
Issued on private placement	23,495		30,237
Issued on flow-through share offering	5,865		7,331
Share issue costs (net of tax effect)	-		(1,588)
Balance, December 31, 2013	**264,657**	**$**	**347,059**

In December 2013, pursuant to a private placement, the Company issued 23.49 million Common Shares at a price of $1.29 per share, for gross proceeds of $30.24 million. The issue costs including underwriter' fees were approximately $1.43 million ($1.06 million net of tax effect) with net proceeds being $28.81 million.

In December 2013, pursuant to a bought deal flow-through share equity offering, the Company issued 5.87 million Common Shares at a price of $1.55 per share, for gross proceeds of $9.09 million. The issue costs including underwriter' fees were approximately $0.71 million ($0.53 million net of tax effect) with net proceeds being $8.38 million. A premium of $1.76 million related to the issuance of the Common Shares on a flow through basis was recorded as a short-term liability on the consolidated statement of financial position. The liability is derecognized, with a corresponding deferred tax expense, as the Company incurs qualifying exploration expenditures. The Company has an obligation to incur $9.09 million in qualifying exploration expenditures by December 31, 2014 to satisfy the terms of this flow through Common Share issuance.

b) Normal course issuer bid

In December 2011, the Company announced its intention to conduct a Normal Course Issuer Bid ("NCIB") through the facilities of the Toronto Stock Exchange ("TSX") and the Oslo Stock Exchange ("OSE"). Under the terms of the NCIB, Questerre was authorized to acquire up to an aggregate of 11,605,776 of its Common Shares over the next 12-month period representing approximately 5% of its issued and outstanding Common Shares as at December 19, 2011. The NCIB commenced on December 22, 2011 and terminated on December 21, 2012.

Pursuant to the Company's NCIB, 755,824 Common Shares were purchased for the year ended December 31, 2012 for consideration of $0.52 million. The Company reduced share capital by $1.01 million, representing the average cost basis of the acquired shares and recorded $0.49 million to contributed surplus. All transactions have been settled and the Common Shares have been cancelled and returned to treasury as of December 31, 2012.

c) Per share amounts

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

(thousands, except as noted)	December 31, 2013	December 31, 2012
Net loss ($ thousands)	$ (19,354)	$ (19,472)
Issued Common Shares at beginning of year	230,804	231,300
Options exercised	3,891	130
Private placement of Common Shares	1,867	-
Flow-through share offering	129	-
Treasury stock reacquired	-	(516)
Weighted average number of Common Shares outstanding (basic)	236,691	230,914
Basic net loss per share	$ (0.08)	$ (0.08)

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

(thousands, except as noted)	December 31, 2013	December 31, 2012
Net loss ($ thousands)	$ (19,354)	$ (19,472)
Weighted average number of Common Shares outstanding (basic)	236,691	230,914
Effect of outstanding options	-	-
Weighted average number of Common Shares outstanding (diluted)	236,691	230,914
Diluted profit per share	$ (0.08)	$ (0.08)

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 profit 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, 2013, 16.17 million (2012: 18.75 million) options were

excluded from the diluted weighted average number of Common Shares outstanding calculation as their effect would have been anti-dilutive.

17. Petroleum and Natural Gas Sales

($ thousands)	December 31, 2013	December 31, 2012
Oil and liquids	$ 22,758	$ 18,266
Natural gas	1,601	576
	$ 24,359	$ 18,842

18. Employee Salaries and Benefits

($ thousands)	December 31, 2013	December 31, 2012
Salaries, bonuses and other short-term benefits	$ 3,195	$ 3,352
Share based compensation	3,893	972
	$ 7,088	$ 4,324

19. Key Management Compensation

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

($ thousands)	December 31, 2013	December 31, 2012
Salaries, bonuses, director fees and other short-term benefits	$ 2,236	$ 2,499
Share based compensation payable	2,973	2,071
	$ 5,209	$ 4,570

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) the amount, ranging from one to six months of the then applicable base salary, less required withholdings; and (ii) the vesting of all options to purchase common shares.

20. Supplemental Cash Flow Information

Changes in non-cash working capital:

($ thousands)	December 31, 2013	December 31, 2012
Accounts receivable	$ 2,316	$ (5,486)
Deposits and prepaid expenses	(61)	197
Accounts payable and accrued liabilities	1,907	261
Change in non-cash working capital	$ 4,162	$ (5,028)
Related to:		
Operating activities	$ 1,214	$ 128
Investing activities	2,948	(5,156)
	$ 4,162	$ (5,028)

21. Commitments and Contingencies

The Company has commitments under a lease for office space of $0.32 million per year for 2014 and $0.27 million in 2015. In 2011, Questerre entered into a data licensing agreement. The Company has commitments under the agreement of $0.10 million per year for 2014.

In August 2013, the Company entered into a 10-year agreement for 20 MMcf/d of natural gas and associated liquids processing at a new propane-plus (C3+) shallow cut gas plant located in the Kakwa-Resthaven area in west central Alberta. The agreement is expected to begin in 2015 and has an annual commitment of $3.65 million.

In August 2013, the Company entered into a 3-year transportation agreement for the delivery of approximately 19 MMcf/d of natural gas. The agreement is expected to begin in 2015 and has an annual commitment of $1.74 million.

In October 2013, the Company entered into a 10-year agreement for fractionation and marketing for natural gas liquids. The agreement is expected to begin in 2015 and has an annual commitment of $0.69 million.

In November 2013, the Company entered into a 10-year transportation agreement for the delivery of condensate and natural gas liquids. The agreement is expected to begin in 2015 and has an annual commitment of $3.61 million.

The Company is a defendant in two legal actions arising in the normal course of business. The Company considers the likelihood of cash outflows relating to such actions to be remote and believes that any liabilities that might arise pertaining to any such matters would not have a material effect on its consolidated financial position.

In 2011, a joint venture partner filed a statement of claim with respect to amounts formally disputed by Questerre. Questerre has filed its statement of defense and counterclaim with respect to this issue. The claim is for $3.91 million and the entire amount is accrued for in the consolidated financial statements.

22. Subsequent Events

In January 2014, Questerre entered into a $4.00/GJ NGX AB-NIT Month Ahead Index (7A) swap for 2000 GJ/d from February 1, 2014 to December 31, 2014.

In February 2014, Questerre entered into a $3.72/GJ NGX AB-NIT Month Ahead Index (7A) swap for 2000 GJ/d from January 1, 2015 to December 31, 2015.

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Peder Paus

Dennis Sykora

Bjorn Inge Tonnessen

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