2011

ANNUAL REPORT

QUESTERRE ENERGY CORPORATION

2011

QUESTERRE ENERGY CORPORATION 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 ALSO SECURING A SOCIAL LICENSE TO COMMERCIALIZE ITS UTICA NATURAL GAS DISCOVERY IN QUEBEC. THE COMPANY IS UNDERPINNED BY LIGHT OIL ASSETS AND A STRONG BALANCE SHEET. QUESTERRE IS COMMITTED TO THE ECONOMIC DEVELOPMENT OF ITS RESOURCES IN AN ENVIRONMENTALLY CONSCIOUS AND SOCIALLY RESPONSIBLE MANNER. QUESTERRE'S COMMON SHARES TRADE ON THE TORONTO AND OSLO STOCK EXCHANGE UNDER THE SYMBOL QEC.

PRESIDENT'S MESSAGE

We started Questerre with the mission of 'looking where others had looked; seeing what no one had seen.' We believed that to find big gas fields in North America you had to look in a new kind of rock. In Quebec that new kind of rock turned out to be the Utica shale. Our resource discovery in the Utica is estimated to be 25 Tcf or more of recoverable gas making it one of the top ten natural gas discoveries in North America. By being very early with these ideas, our lands control the heart of the discovery.

However, with the pilot program to test commerciality deferred during the environmental assessment in Quebec, we once again began looking for a new project. We began the search for a high-impact project by keeping to our original mission. Our belief today is to find big oil fields in North America you have to look in a new kind of rock and see what no one has seen.

We believe that new kind of rock turns out to be an idea so old, few have heard of it. Mining of oil shales has been done for close to 1,000 years but, since discovering how to refine crude oil in the 19th century, it has been uneconomic. Conventional wisdom is unlocking oil shales, one of the world's largest untapped resources, is not economic at today's oil prices.

The US Geological Survey estimates that there is more than ten times the resource in oil shales than in oil sands. Rather than being measured in billions of barrels, oil shale resources are measured in trillions of barrels.

Late in the year, we assembled a portfolio of projects to participate in this emerging resource opportunity. For oil sands, shale oil and shale gas changes in pricing along with engineering innovations unlocked previously uneconomic resources. We believe the same is possible for mining of oil shales by discarding the traditional mining model. The Red Leaf EcoShale process does just that. Rock handling is the biggest expense in mining and is the key to economically mining oil shales today. By moving the process to the rocks instead of the rocks to the process, the EcoShale process reduces the biggest cost of mining dramatically.

Subsequent to our commitment to this project some of the largest resource companies in the world have also become interested to join our resource project.

Mindful of the challenges and time lines associated with developing large resource projects, we also continued to build our portfolio of conventional assets in 2011 as a reserve of capital and to underpin near-term value for our shareholders. This included expanding our light oil assets in Saskatchewan and a new project in the liquids-rich Montney shale gas in Alberta.

Highlights

- Executed on new oil shale strategy through Letter of Intent with Red Leaf Resources Inc., obtained an option to license the EcoShale process, and acquired 100,000 net acres for oil shale in Saskatchewan
- Grew conventional asset base with successful light oil drilling program in Antler, Saskatchewan
- Exploration licenses in St. Lawrence Lowlands, Quebec extended by up to three years to 2021 during strategic environmental assessment for shale gas development
- Increased oil production leveraged higher prices and generated cash flow from operations of $10.06 million with average daily production of 646 boe/d
- Maintained financial strength with over $104 million in positive working capital and no debt

Oil Shale

We see oil shale today as the next major resource play - an early-stage opportunity to capture large resources that require innovative processes to be commercial.

Hosting oil resources that are orders of magnitude larger than the oil sands and shale oil, oil shale has significant potential. Oil shales are rich in organic material or kerogen that converts to oil through the application of heat. Oil has been produced for centuries from oil shale through retorting, a process that involves mining the shale, flash heating

in the absence of oxygen and then disposing of the spent shale. Large-scale commercial production however has traditionally been challenged by costs and environmental concerns.

Relatively simple enhancements to existing processes that involve complex engineering were key to overcoming these hurdles in other resource plays like the oil sands and shale oil and gas. For example, allowing multiple fracture stimulations to be conducted in a horizontal well through advances in packer design, was key to producing oil and gas commercially from shale oil and gas formations like the Bakken and the Barnett. We believe the Red Leaf EcoShale process, that brings the process to the rock instead of the rocks to the process, is a simple yet dramatic improvement to retorting oil shales.

While the process is key, having the right rock is equally if not more important. Not unlike shale oil and gas, geology still matters. The oil shale must have the organic content to produce sufficient oil measured in gallons per ton of rock. Among other criteria, the shale also needs the right mineral content and be sufficiently close to surface to be mined economically. Of the estimated 2.8 trillion barrels of oil shale resources globally, approximately 1.5 trillion barrels are in the Green River formation in Utah, Wyoming and Colorado according to the US Geological Survey. Questerre has a direct and indirect interest in two projects in Wyoming and Utah with Red Leaf. Geography is important too. Both Utah and Wyoming are resource friendly jurisdictions with surface mineable oil shale deposits situated away from populated areas.

In addition to the minority interest in the projects with Red Leaf, we have also acquired 100,000 net acres in Saskatchewan where we potentially have a larger land position for a less studied oil shale deposit.

Our transaction with Red Leaf is expected to close imminently and we look forward to beginning work on all three of these projects.

Western Canada

While we were assembling our oil shale assets and evaluating new opportunities, we were also developing our Torquay/Bakken oil assets in Antler into a new core area for the Company. The goal is to grow this base of production and other conventional assets to over 1,500 boe/d by the end of the assessment in Quebec in 2013.

Building on our experience over the last two years with new drilling, completion and production practices, we drilled 13 wells to develop the existing pool in 2011. This included a number of step-out locations to delineate the edges of the pool. We expanded our asset base with a tuck-in acquisition that added approximately 100 bbl/d with several follow-on locations.

For 2012, our focus will be increasing recovery from the main pool. Along with infill drilling, we will begin preliminary field work on a secondary recovery scheme, subject to partner approvals and landowner consents. Based on analogous pools and a reservoir simulation study, the modeling indicates recoveries could materially increase to about 240,000 incremental barrels per section. Though our economic returns were very strong in 2011, we are monitoring domestic oil prices and will adjust our program accordingly to ensure this continues in 2012.

In addition to Antler, our early stage projects in Wawota and Pierson, Manitoba will be important in meeting our production target in 2013. We plan to complete an exploration well in Wawota this summer after breakup. In Pierson, we are continuing to evaluate offsetting wells to determine the optimal drilling and completion practices.

We also looked, opportunistically, at several acquisition and farm-in prospects in other areas during the year. We closed late in the year on a 16 (4 net) section farm-in in the liquids-rich window of the Montney shale in Alberta. With strong liquids prices and favorable fiscal terms, this area has seen considerable activity recently. Our first well is currently drilling and we expect to test it this summer.

St. Lawrence Lowlands, Quebec

The recommendations of the BAPE report in early 2011 highlighted the lack of oil and gas expertise in Quebec and the growing importance of social acceptability for large-scale resource projects.

We view the mandate of the oversight committee for this assessment as too ambitious given the timeframe and resources available. We had hoped that successful shale gas projects in North America would have served as a valuable precedent for the BAPE to narrow its scope to the unique aspects of Quebec. Moreover there is increasing independent research that established industry practices, particularly in Western Canada, are safely developing non-conventional natural gas.

To the extent we are allowed, we will work with the government to deepen their understanding of our industry during the assessment. While the committee has not called for demonstration projects, we expect they will at some point. Accordingly we do not expect any field activity in 2012. We were pleased that they recognized the impact of the assessment on our plans by extending the term of our exploration licenses by up to three years.

In the interim, we are expanding our public relations efforts to gain our social license to operate. We retained Mr. Andre Boisclair, a former Minister of the Environment in Quebec to advise us on socio-political and energy issues in Quebec. We also sponsored the creation of the Oil & Gas Services Association of Quebec to develop the local service sector that will be essential for commercial development. In less than three months, the association has grown to over 50 members representing over 5,000 individuals. Although much work remains, we are optimistic that this support builds and Quebecers realize that the significant local economic benefits of natural gas development outweigh the manageable impacts.

Operational & Financial

Record flooding in Saskatchewan and completion equipment availability delayed the planned growth in our production volumes in Antler during the year. Fourth quarter volumes grew to 743 boe/d from 605 boe/d in 2010.

We invested over $34 million in Antler which included the drilling of 15 (10.27 net) wells and a $13.25 million asset acquisition. This largely contributed to improving our oil weighting to 76% from 53% in the prior year. With netbacks of almost $80 per barrel in Antler, these volumes leveraged higher oil prices and generated cash flow from operations of $10.06 million for the year. We saw an increase in the NPV-10 of proven and probable reserves from $67 million to $102 million.

Outlook

We plan to continue investing in our conventional assets in 2012. Success this year will put us on track to achieve our production goal in 2013. These assets and our strong financial position will provide a source of capital for future development of our entire portfolio.

Our assets in Quebec remain an important part of our portfolio. We plan to invest limited capital in 2012; however, our investment in management effort will increase as we work on our social license to operate in the province.

Advancing our oil shale assets will be our main priority this year. We expect to conclude our letter of intent with Red Leaf shortly as they begin field work on the Utah project this summer. Work will also begin this summer to update the existing resource assessment for Wyoming. In Saskatchewan, we plan to commence a program to evaluate the oil shale potential on our 100,000 acre block.

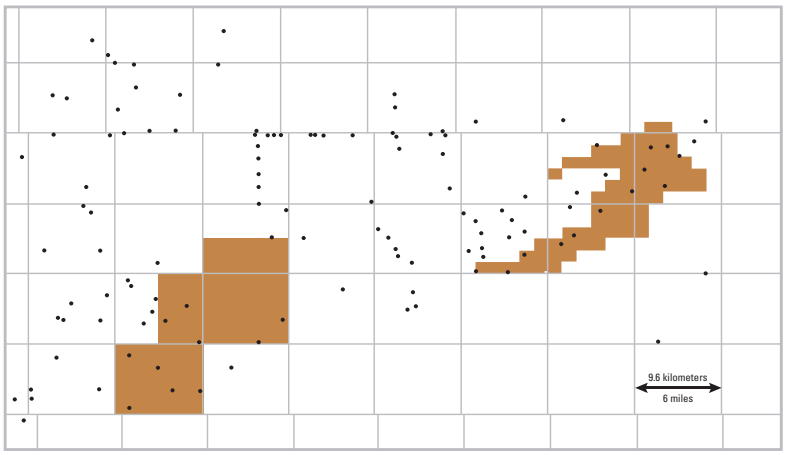
Through our Utica shale discovery, Questerre participated early in the shale gas revolution. Oil shale and the new process to unlock these resources could create a similar, if not larger, impact than shale oil and shale gas. We believe our oil shale assets will allow us, once again, to capitalize on another paradigm shift in energy markets.

Michael Binnion
President and Chief Executive Officer

Oil Shale Mining

In early 2011, the announcement of a strategic environmental assessment in Quebec led Questerre to pursue unconventional oil opportunities as part of its strategy to create shareholder value. To this end, in the fall of 2011, the Company assembled a portfolio of oil shale mining opportunities including licensing rights to a proprietary technology to produce oil from shale.

By participation at Crown landsales, the Company acquired a 100% interest in two licenses covering approximately 100,000 acres in the Pasquia Hills area of east central Saskatchewan. The acreage overlies an identified oil shale deposit. Over the next two years, Questerre plans to conduct an extensive work program including drilling wells for core data, modified Fisher assay analysis and geomechanical testing of the oil shale at an estimated cost of $2 million to $4 million.



Oil shale acreage in Pasquia Hills, Saskatchewan

In addition to its acreage in Saskatchewan, Questerre plans to also acquire an interest in two additional oil shale projects in Wyoming and Utah in the United States through its letter of intent with Red Leaf Resources Inc. ("Red Leaf"). Red Leaf is a private Utah-based oil shale technology and resource company. Red Leaf's principal assets are its proprietary EcoShale In-Capsule Technology to recover oil from shale and mineral leases in the states of Wyoming and Utah prospective for oil shale. The letter of intent also outlines the terms under which Questerre will acquire an equity interest in Red Leaf through a subscription for common shares.

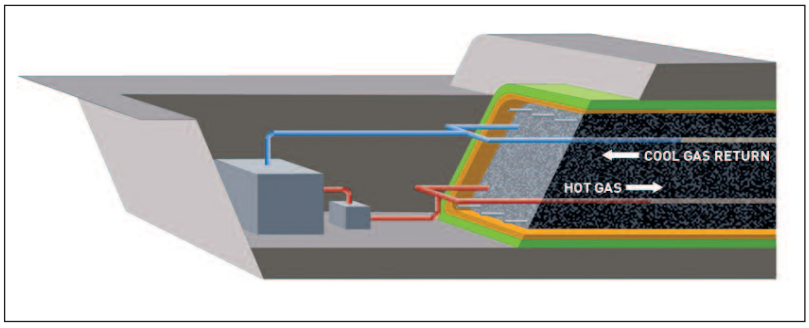
Pursuant to the letter of intent with Red Leaf, Questerre will participate for a 10% working interest in the development of 5,120 acres licensed by Red Leaf in the Washakie Basin in southwestern Wyoming. Upon execution of a joint venture farm-in and operating agreement, Red Leaf and Questerre plan to carry out a work program to update an existing resource assessment of the oil shale potential of these lands. Questerre's anticipated share of this program for 2012-2013 will be $0.25 million.

Surface topography in Washakie Basin, Wyoming

Through its equity interest in Red Leaf, Questerre will also acquire an indirect interest in Red Leaf's principal oil shale project covering approximately 17,000 acres in the Uinta Basin in southeastern Utah. Red Leaf recently completed a successful pilot on a portion of this acreage recovering high quality oil as expected. With the direct participation of a supermajor, Red Leaf plans to advance this pilot to early commercialization beginning in 2012. The supermajor is expected to invest up to US$320 million in this project to acquire a 50% interest in Red Leaf's Utah assets.

Red Leaf is currently conducting an equity offering for a minimum of US$100 million to primarily finance its share of costs for the project in Utah. Subject to the participation of the supermajor in the Utah project and the equity offering, Questerre is expected to invest US$25 million in this offering. Closing is scheduled prior to the end of the first quarter of 2012.

The EcoShale process is designed to extract high quality light oil from mined oil shale in an environmentally sustainable manner. The process involves the mining of shale that is placed in a large clay lined and covered capsule. Expendable heat pipe loops are strategically placed in the capsule with the oil shale. External blowers are used to force the hot flue gas from natural gas burners through the pipe loops to heat the oil shale. Collection pipes are located at the top and bottom of the capsule to recover the natural gas and oil respectively. Produced natural gas from heating the oil shale fuels the burners used to heat other capsules. Upon completion, the pipes in the capsule are sealed and the surface of the capsule is covered with top soil and seeded with native vegetation.



Schematic of EcoShale Process

The potential benefits of the process include low capital costs relative to other processes, energy efficiency, a high quality refined oil product, negligible water usage, scalability and limited reclamation.

Questerre has also entered into a ten-year non-exclusive option agreement to license the Red Leaf processes and technology for any project identified by Questerre. Subject to the project meeting the criteria for commerciality, Questerre will pay Red Leaf a fee of US$2 million for each license issued. Red Leaf will receive a gross overriding royalty on the project on mutually acceptable terms.

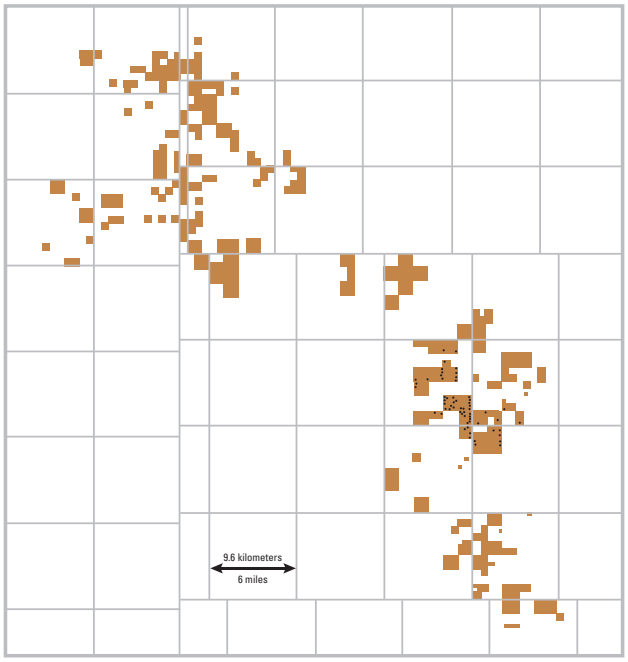
Western Canada

Antler, Saskatchewan

The Antler area is approximately 200 km from Regina in southeast Saskatchewan. The primary target is high quality light oil from the Bakken/Torquay formation, a dolomitic siltstone shale sequence at a depth of between 1050 metres and 1150 metres. Secondary targets include the Souris Valley, a carbonate sequence at a depth of approximately 900 metres to 1000 metres.

Following the positive results from the 2010 drilling program, Questerre continued the development of its main Torquay/Bakken pool in Antler, Saskatchewan in 2011.

During the year, the Company drilled 15 (10.27 net) horizontal wells targeting light oil from this formation. The wells were primarily stepout locations to delineate the boundaries of the existing pool. Despite delays due to record flooding, heavy rainfall and a shortage of completion equipment, the Company successfully



Landholdings in Antler, Saskatchewan

completed and tied in all wells drilled during the year as well as its backlog of wells from 2010. The Company also evaluated the potential of the Souris Valley, a shallower oil bearing zone. Two (1.00 net) wells were drilled and one (0.50 net) well was recompleted for this interval resulting in two oil producers and one suspended well.

Questerre also completed a complementary asset acquisition in the Antler area in 2011. It included approximately 100 bbl/d of production from the Torquay/Bakken formation and 6,942 net acres of undeveloped land proximate to its existing main pool. The proved and probable reserves assigned to these assets as of March 31, 2011 by an independent engineering firm is 419 Mbbls representing six percent of the oil in place. The cash consideration for this acquisition was $13.25 million.

To assess the potential of its recently acquired exploration acreage in the Wawota area, approximately 20 miles northeast of its main pool in Antler, the Company drilled three vertical exploration wells. The wells have identified nearly one third of the acreage or 8,000 net acres as prospective. Further appraisal work is planned for 2012 and will include the stimulation and testing of one of the vertical wells.

For 2012, Questerre intends to drill up to 20 (12 net) additional horizontal wells in Antler. The proposed program will target infill and step out wells to further delineate the northern and southern extent of the main pool. The Company also plans to implement a secondary recovery scheme with preliminary field work scheduled for the first half of 2012.

Resthaven, West-Central Alberta

To diversify its portfolio of conventional assets in Western Canada, the Company acquired acreage prospective for the liquids-rich window of the Montney shale in the Kakwa-Resthaven area of west central Alberta in the fourth quarter of 2011.

Questerre's acreage for this play is located in the deep over-pressured fairway of the Montney shale in Alberta. Economics are materially enhanced by the relatively high liquids content and the Crown royalty incentives for new deep horizontal wells with initial royalty rates of 5%. The most recent offset wells, located approximately twelve miles away tested at average rates of 10 MMcf/d to 15 MMcf/d of natural gas and 300 bbl/d to 600 bbl/d of natural gas liquids or between approximately 2,000 boe/d to 3,100 boe/d per well.

Drilling operations on first horizontal well at Resthaven

Drilling operations are underway on the first horizontal well with operations scheduled to be completed by mid to late April 2012. Stimulation and testing is planned for post spring breakup. Questerre will have a 37.5% interest in the well before payout and a 25% interest in this well after payout. Upon drilling and completion of this well, Questerre will have a 25% working interest in 16 contiguous sections of land in this area.

Vulcan, Southern Alberta

The Vulcan area in Southern Alberta is prospective for natural gas and oil in multiple horizons with the Mannville Sunburst formation as the main zone of interest at a depth of approximately 1900 metres. Questerre participated in the discovery of two adjacent Mannville pools in Vulcan in 2005 and 2006 and holds a 50% interest in both pools.

Questerre participated in the drilling of one (0.50 net) infill oil well for its Mannville oil pool in 2011. The well was placed on production in the third quarter at an initial rate for the first thirty days of approximately 50 bbl/d. The Company is evaluating up to three other infill locations for this oil pool.

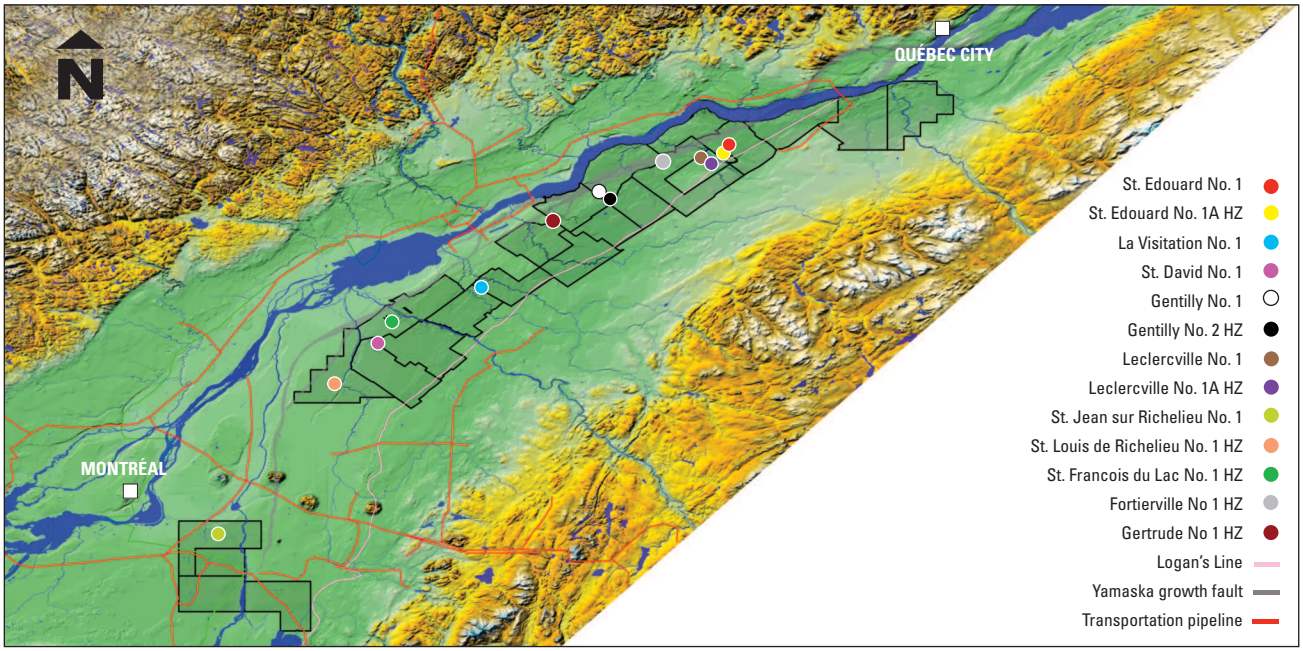
Greater Sierra, Northeast British Columbia

The Greater Sierra region lies approximately 100 km east of Fort Nelson, British Columbia. The primary zone of interest is the Devonian Jean Marie at a depth of approximately 1400 metres. The region is also prospective for shallower zones including the Mississippian Debolt and deeper Devonian Keg River, Slave Point and Pine Point formations as well as the Horn River shale.

In addition to its non-operated producing assets in this area, Questerre holds 29,313 net acres of undeveloped land in this region prospective for multiple intervals.

Low natural gas prices and material third party gathering and processing charges led to Questerre suspending activity in this area in 2011. In light of continued weakness in natural gas prices, the Company has no plans to invest additional capital in this area in 2012.

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 Energy Inc. ("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.

Based on the preliminary results of the pilot program, Questerre updated the independent resource assessment of the Utica shale conducted by Netherland, Sewell & Associates, Inc. ("NSAI"). Using a range of recovery factors based on more established shale plays, as at December 31, 2010, NSAI estimates prospective resources recoverable for Questerre's net interest to range between 1.46 Tcf and 15.45 Tcf with a best estimate of 4.43 Tcf. This does not include the royalty interest held by Questerre nor an assessment of the Lorraine formation.

In 2011, the pilot program to assess the commerciality of the Utica shale was suspended while the government initiated its strategic environment assessment on shale gas development in Quebec ("SEA").

The SEA was the principal recommendation from the report of the Bureau d'audiences publiques sur l'environment ("BAPE") that was published in early 2011 by the Ministry of Sustainable Development, Environment and Parks ("MDDEP"). The report advocated increasing the understanding of shale gas by all stakeholders, promoting social acceptability by consultation and enhancing the existing regulations. The recommendations from the BAPE report also included provisions for controlled piloting that would include the drilling and completion of a limited number of wells while the SEA is underway. Questerre anticipates these wells will be part of the pilot program to assess commerciality.

BAPE report published in March 2011 mandated a strategic environmental assessment

In June 2011, MDDEP introduced interim regulations to govern operations during the SEA. The interim regulations required operators to inform and consult the public prior to commencing operations. To enhance the understanding of shale gas, MDDEP may have representatives observe the drilling and completion operations. Operators will also be required to provide MDDEP with technical information including drilling and completion methods and technology, water management programs, proposed completion fluid composition and volumes and sampling water wells within a one kilometer radius from proposed operations.

Due to the timing of the announcement of these regulations and the narrow window on equipment availability, the operator of the St. Gertrude and Fortierville horizontal wells was unable to contract the necessary equipment to complete the wells in 2011. Questerre believes that these completion operations will likely be deferred again and minimal activity conducted in 2012 pending equipment availability, further clarification on the interim regulations and mandate of the SEA.

The mandate and membership of the oversight committee for the SEA was established by MDDEP in the second quarter of 2011. The committee has a total of 11 members including representatives from the ministries of public affairs and natural resources and the education, sustainable development, environmental and private sectors. It is chaired by MDDEP. The committee's mandate will include delivery of a report on the SEA to address the issues identified and provide recommendations to develop the legislative and regulatory framework to govern shale gas development. Preliminary reports updating progress on the committee's activities are due in May 2012 and May 2013 with the final report scheduled for delivery to MDDEP by November 2013. Upon the completion of the assessment over the next two to three years, the Ministry of Natural Resources ("MNRF") has confirmed it plans to introduce new hydrocarbon legislation that is expected to facilitate commercial development.

MNRF introduced new legislation suspending the term of the exploration licenses for petroleum, natural gas and underground reservoirs in the province of Quebec for a period of up to three years as determined by the Minister. Holders of these licenses are also exempted from performing the work required under the Mining Act for this period.

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 ensure that our footprint is minimized. Questerre believes in a prudent approach to the sourcing, use and disposal of water for drilling and completions 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.

We look forward to actively participate in the planned strategic environmental assessment of shale gas in the province of Quebec.

Management's Discussion and Analysis ("MD&A") was prepared as of March 28, 2012. 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, 2011 and 2010. Additional information relating to Questerre, including Questerre's Annual Information Form for the year ended December 31, 2011 is available on SEDAR 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 also securing a social license to commercialize its Utica natural gas discovery in Quebec. The Company is underpinned by light oil assets and a strong balance sheet. Questerre is committed to the economic development of its resources in an environmentally conscious and socially responsible manner.

The Company's common shares are listed on the Toronto Stock Exchange and Oslo Stock Exchange under the symbol "QEC".

Basis of Presentation

This is Questerre's first year presenting figures in the MD&A using accounting policies within the framework of International Financial Reporting Standards ("IFRS"). In previous periods, the Company prepared its consolidated financial statements in accordance with Canadian generally accepted accounting principles in effect prior to January 1, 2011 ("previous GAAP"). Comparative figures presented in this MD&A pertaining to Questerre's 2010 results have been restated to be in accordance with IFRS. A reconciliation of comparative figures from previous GAAP to IFRS is provided in the notes to the December 31, 2011 consolidated financial statements. Comparative figures presented in this MD&A pertaining to Questerre's 2009 results were prepared in accordance with previous GAAP and were not required to be restated.

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 production levels;
- estimates of future cash flow;
- projections of prices and costs;
- drilling plans and timing of drilling, recompletion and tie-in of wells by Questerre and its partners;
- 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;
- 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;
- timing of drilling programs and resulting cash flows;
- future oil and gas prices;
- 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 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.

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.

Non-IFRS Terms

This document contains the terms "cash flow from operations" and "netbacks" which are non-IFRS terms. The Company uses these measures 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, cash flows 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

		2011		2010
Cash flows from operating activities	**$**	**10,595,507**	$	3,629,524
Net change in non-cash operating working capital		**(532,570)**		1,115,036
Cash flow from operations	**$**	**10,062,937**	$	4,744,560

The Company considers netbacks a key measure as it demonstrates its profitability relative to current commodity prices. Operating netbacks per boe equal total petroleum and natural gas sales per boe adjusted for royalties per boe and operating expenses per boe.

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.

Select Annual Information

As at/for the years ended December 31,	**2011**	2010	2009
Financial ($, except common shares outstanding)			
Petroleum and Natural Gas Sales	**18,273,083**	11,989,713	12,933,267
Cash Flow from Operations	**10,062,937**	4,744,560	2,878,576
Per share - Basic	**0.04**	0.02	0.01
Per share - Diluted	**0.04**	0.02	0.01
Net Profit (Loss) [(1)]	**3,901,396**	(10,933,885)	(14,979,202)
Per share - Basic	**0.02**	(0.05)	(0.08)
Per share - Diluted	**0.02**	(0.05)	(0.08)
Capital Expenditures, net of acquisitions and dispositions	**40,765,871**	38,406,524	11,989,541
Working Capital Surplus	**104,480,657**	136,076,978	46,500,671
Total Assets	**258,409,889**	260,548,991	145,272,364
Shareholders' Equity	**232,877,970**	238,686,128	129,977,202
Common Shares Outstanding	**231,300,028**	234,131,728	199,722,143
Weighted average - basic	**233,025,712**	227,181,288	197,940,390
Weighted average - diluted	**235,975,196**	234,326,194	206,729,689
Operations (units as noted)			
Average Production			
Crude Oil and Natural Gas Liquids (bbl/d)	**491**	329	378
Natural Gas (Mcf/d)	**930**	1,738	2,591
Total (boe/d)	**646**	619	810
Average Sales Price			
Crude Oil and Natural Gas Liquids ($/bbl)	**94.57**	77.46	63.88
Natural Gas ($/Mcf)	**3.91**	4.24	4.34
Total ($/boe)	**77.50**	53.07	43.75
Netback ($/boe)			
Petroleum and Natural Gas Sales	**77.50**	53.07	43.75
Royalties Expense	**(6.60)**	(6.89)	(3.32)
Percentage	**9%**	13%	8%
Operating Expense	**(11.93)**	(14.44)	(13.86)
Operating Netback	**58.97**	31.74	26.57
Wells Drilled			
Gross	**21.00**	15.00	4.00
Net	**14.77**	6.96	1.71

(1) The net loss for the year ended December 31, 2009 has been restated. See the "Restatement" section in this MD&A for further details.
Note: The 2009 period above is presented in accordance with previous GAAP.

Highlights

- Executed on new oil shale strategy through Letter of Intent with Red Leaf Resources Inc., obtained an option to license the EcoShale process, and acquired 100,000 net acres for oil shale in Saskatchewan
- Grew conventional asset base with successful light oil drilling program in Antler, Saskatchewan
- Exploration licenses in St. Lawrence Lowlands, Quebec extended by up to three years to 2021 during strategic environmental assessment for shale gas development
- Increased oil production leveraged higher prices and generated cash flow from operations of $10.06 million with average daily production of 646 boe/d
- Maintained financial strength with over $104 million in positive working capital and no debt

2011 Activities

Oil Shale Mining

In early 2011, the announcement of a strategic environmental assessment in Quebec led Questerre to pursue unconventional oil opportunities as part of its strategy to create shareholder value. To this end, in the fall of 2011, the Company assembled a portfolio of oil shale mining opportunities including licensing rights to a proprietary technology to produce oil from shale.

By participation at Crown landsales, the Company acquired a 100% interest in two licenses covering approximately 100,000 acres in the Pasquia Hills area of east central Saskatchewan. The acreage overlies an identified oil shale deposit. Over the next two years Questerre plans to conduct an extensive work program including drilling wells for core data, modified Fisher assay analysis and geomechanical testing of the oil shale at an estimated cost of between $2 million to $4 million.

In addition to its acreage in Saskatchewan, Questerre plans to also acquire an interest in two additional oil shale projects in Wyoming and Utah in the United States through its letter of intent with Red Leaf Resources Inc. ("Red Leaf"). Red Leaf is a private Utah-based oil shale technology and resource company. Red Leaf's principal assets are its proprietary Eco-Shale In-Capsule Technology to recover oil from shale and mineral leases in the states of Wyoming and Utah prospective for oil shale. The letter of intent also outlines the terms under which Questerre will acquire an equity interest in Red Leaf through a subscription for common shares.

Pursuant to the letter of intent with Red Leaf, Questerre will participate for a 10% working interest in the development of 5,120 acres licensed by Red Leaf in Washakie Basin in southwestern Wyoming. Upon execution of a joint venture farm-in and operating agreement, Red Leaf and Questerre plan to carry out a work program to update an existing resource assessment of the oil shale potential of these lands. Questerre's anticipated share of this program for 2012-2013 will be $0.25 million.

Through its equity interest in Red Leaf, Questerre will also acquire an indirect interest in Red Leaf's principal oil shale project covering approximately 17,000 acres in the Uinta Basin in southeastern Utah. Red Leaf recently completed a successful pilot on a portion of this acreage. With the direct participation of a supermajor, Red Leaf plans to advance this pilot to early commercialization beginning in 2012. The supermajor is expected to invest up to US$320 million in this project to acquire a 50% interest in Red Leaf's Utah assets.

Red Leaf is conducting an equity offering for a minimum of US$100 million to primarily finance its share of costs for the project in Utah. Subject to the participation of the supermajor in the Utah project and the equity offering, Questerre is expected to invest US$25 million in this offering. Closing is scheduled prior to the end of the first quarter of 2012.

Questerre has also entered into a ten year non-exclusive option agreement to license the Red Leaf processes and technology for any project identified by Questerre. Subject to the project meeting the criteria for commerciality, Questerre will pay Red Leaf a fee of US$2 million for each license issued. Red Leaf will receive a gross overriding royalty on the project on mutually acceptable terms.

Western Canada

Following the positive results from the 2010 drilling program, Questerre continued the development of its main Torquay/Bakken pool in Antler, Saskatchewan.

During the year, the Company drilled 15 (10.27 net) horizontal wells targeting light oil from this formation. The wells were primarily stepout locations to delineate the boundaries of the existing pool. Despite delays due to record flooding, heavy rainfall and a shortage of completion equipment, the Company successfully completed and tied in all wells drilled during the year as well as its backlog of wells from 2010. The Company also evaluated the potential of the Souris Valley, a shallower oil bearing zone. Two (1.00 net) wells were drilled and one (0.50 net) well was recompleted for this interval resulting in two oil producers and one suspended well.

Questerre also completed a complementary asset acquisition in the Antler area in 2011. It included approximately 100 bbl/d of production from the Torquay/Bakken formation and 6,942 net acres of undeveloped land proximate to its existing main pool. The proved and probable reserves assigned to these assets as of March 31, 2011 by an independent engineering firm is 419 Mbbls representing six percent of the oil in place. The cash consideration for this acquisition was $13.25 million.

To assess the potential of its recently acquired exploration acreage in the Wawota area, approximately 20 miles northeast of its main pool in Antler, the Company drilled three vertical exploration wells. The wells have identified nearly one third of the acreage or 8,000 net acres as prospective. Further appraisal work is planned for 2012 and will include the stimulation and testing of one of the vertical wells.

For 2012, Questerre intends to drill up to 20 (12 net) additional horizontal wells in Antler. The proposed program will target infill and step out wells to further delineate the northern and southern extent of the main pool. The Company also plans to implement a secondary recovery scheme with preliminary field work scheduled for the first half of 2012.

In Southern Alberta, Questerre participated in the drilling of one (0.50 net) infill oil well for its Mannville pool in the Vulcan area. The well was placed on production in the third quarter at an initial rate for the first thirty days of approximately 50 bbl/d. The Company is evaluating up to three other infill locations for this oil pool.

To diversify its portfolio of conventional assets in Western Canada, the Company acquired acreage prospective for the liquids-rich window of the Montney shale in the Kakwa-Resthaven area of west central Alberta in the fourth quarter of 2011.

Drilling operations are underway on the first horizontal well with operations scheduled to be completed by mid to late April 2012. Stimulation and testing is planned for post spring breakup. Questerre will have a 37.5% interest in the well before payout and a 25% interest in this well after payout. Upon drilling and completion of this well, Questerre will have a 25% working interest in 16 contiguous sections of land in this area.

St. Lawrence Lowlands, Quebec

In 2011, the pilot program to assess the commerciality of the Utica shale was suspended while the government initiated its strategic environment assessment on shale gas development in Quebec ("SEA").

The SEA was the principal recommendation from the report of the Bureau d'audiences publiques sur l'environment ("BAPE") that was published in early 2011 by the Ministry of Sustainable Development, Environment and Parks ("MDDEP"). The report advocated increasing the understanding of shale gas by all stakeholders, promoting social acceptability by consultation and enhancing the existing regulations. The recommendations from the BAPE report also included provisions for controlled piloting that would include the drilling and completion of a limited number of wells while the SEA is underway. Questerre anticipates these wells will be part of the pilot program to assess commerciality.

In June 2011, MDDEP introduced interim regulations to govern operations during the SEA. The interim regulations required operators to inform and consult the public prior to commencing operations. To enhance the understanding of shale gas, MDDEP may have representatives observe the drilling and completion operations. Operators will also be required to provide MDDEP with technical information including drilling and completion methods and technology, water management programs, proposed completion fluid composition and volumes and sampling water wells within a one kilometer radius from proposed operations.

Due to the timing of the announcement of these regulations and the narrow window on equipment availability, the operator of the St. Gertrude and Fortierville horizontal wells was unable to contract the necessary equipment to complete the wells in 2011. Questerre believes that these completion operations will likely be deferred again and minimal activity conducted in 2012 pending equipment availability, further clarification on the interim regulations and mandate of the SEA.

The mandate and membership of the oversight committee for the SEA was established by MDDEP in the second quarter of 2011. The committee has a total of 11 members including representatives from the ministries of public affairs and natural resources and the education, sustainable development, environmental and private sectors. It is chaired by MDDEP.

The committee's mandate will include delivery of a report on the SEA to address the issues identified and provide recommendations to develop the legislative and regulatory framework to govern shale gas development. Preliminary reports updating progress on the committee's activities are due in May 2012 and May 2013 with the final report scheduled for delivery to MDDEP by November 2013. Upon the completion of the assessment over the next two to three years, the Ministry of Natural Resources ("MNRF") has confirmed it plans to introduce new hydrocarbon legislation that is expected to facilitate commercial development.

MNRF introduced new legislation suspending the term of the exploration licenses for petroleum, natural gas and underground reservoirs in the province of Québec for a period of up to three years as determined by the Minister. Holders of these licenses are also exempted from performing the work required under the Mining Act for this period.

Corporate

In May 2011, Questerre concluded an agreement with Transeuro Energy Corp. ("Transeuro") for Transeuro to acquire the remaining 50% interest in the Beaver River Field (the "Field").

Pursuant to the agreement, Transeuro acquired all the issued and outstanding shares of Questerre Beaver River Inc. ("QBR"), a wholly owned subsidiary of the Company that owned the other 50% interest in the Field.

In consideration, Questerre received 8 million common shares (after a 5 for 1 consolidation in August 2011) of Transeuro. Questerre subsequently acquired an additional 38,782,399 common shares through an investment of $2.33 million in Transeuro's equity offering completed in December 2011. Subsequent to 2011, Questerre has liquidated a portion of the shares held and currently holds 27,682,399 common shares representing approximately 9% of the issued and outstanding common shares of Transeuro.

Normal Course Issuer Bid

Pursuant to the Normal Course Issuer Bid, a total of 3,598,700 common shares were purchased at a weighted average price of $0.92 per common share during the year. 1,057,700 common shares were purchased through the facilities of the TSX at an average price of $0.97 per share and 2,541,000 common shares were purchased through the facilities of Oslo Bors at an average price of $0.89 per share.

Drilling Activities

In 2011, Questerre participated in the drilling of 21 (14.77 net) wells, comprising of 20 (14.27 net) oil wells in Antler and Wawota in Saskatchewan and one (0.50 net) oil well in Vulcan, Alberta. In 2010, Questerrre participated in the drilling of 15 (6.96 net) wells, comprising of 13 (6.50 net) oil wells in Antler and two (0.46 net) natural gas wells in Quebec.

Production

	2011			2010		
	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	**434**	**-**	**434**	258	-	258
Alberta	**57**	**636**	**163**	71	1,054	247
British Columbia	**-**	**294**	**49**	-	684	114
	491	**930**	**646**	329	1,738	619

Consistent with the prior year, Questerre's production volumes in 2011 reflect the Company's strategy to develop its light oil assets in Saskatchewan while deferring investment in conventional, dry natural gas assets in the current commodity price environment.

With activity in Saskatchewan hampered by inclement weather and equipment availability for the first nine months the year, production volumes for the year increased marginally over 2010. Average daily production in 2011 grew to 646 boe/d from 619 boe/d a year ago. In contrast, average production in the fourth quarter of the year was 743 boe/d as compared to 605 boe/d in the prior year.

The increased activity in Antler translated into oil and natural gas liquids representing a larger proportion of the Company's product mix. This included the drilling of 15 (10.27 net) horizontal wells and an asset acquisition. As a result, oil and liquids accounted for 76% of total production as compared to 53% in 2010. Questerre also participated in the drilling of one (0.50 net) oil well in Alberta which partially replaced the declining natural gas production with higher value oil production.

Gas production from the Company's non-operated assets in Alberta and British Columbia reflected natural production declines. The disposition in the second quarter of its interest in the Beaver River natural gas field coupled with an oil focused drilling program further accentuated this decrease in natural gas volumes.

For 2012, Questerre has plans for a phased drilling program in Antler, Saskatchewan that could include up to 20 (12 net) horizontal wells. The Company is also participating in the exploration and potential development of its new acreage in Alberta that is prospective for liquids-rich natural gas. Contingent upon the results of drilling operations, weather and equipment availability, Questerre expects production for 2012 to average between 800 boe/d to 1,000 boe/d while maintaining its higher oil and liquids weighting.

2011 Financial Results

Petroleum and Natural Gas Sales

	2011			2010		
	Oil and Liquids	**Natural Gas**	**Total**	Oil and Liquids	Natural Gas	Total
Saskatchewan	**$ 15,016,788**	**$ -**	**$ 15,016,788**	$ 7,355,878	$ -	$ 7,355,878
Alberta	**1,923,212**	**959,571**	**2,882,783**	1,947,568	1,750,231	3,697,799
British Columbia	**-**	**373,512**	**373,512**	-	936,036	936,036
	$ 16,940,000	**$ 1,333,083**	**$ 18,273,083**	$ 9,303,446	$ 2,686,267	$ 11,989,713

Petroleum and natural gas sales increased materially over the prior year with higher oil prices leveraging Questerre's improved oil weighting. This was offset by decreases in natural gas revenue reflecting lower volumes and natural gas prices.

Pricing

	2011	2010
Benchmark prices		
Natural Gas - AECO, daily spot ($/Mcf)	**3.63**	4.01
Crude Oil - Edmonton par ($/bbl)	**95.03**	77.50
Realized prices		
Natural Gas ($/Mcf)	**3.91**	4.24
Crude Oil and Natural Gas Liquids ($/bbl)	**94.57**	77.46

Despite the increase over the prior year, crude oil prices were fairly volatile during 2011 with the benchmark WTI price trading between US$75/bbl and US$115/bbl. This volatility was largely driven by concerns about potential supply disruptions in the Middle East and North Africa, the European debt crisis and the pace of the recovery in the United States. In North America, these impacts were partially muted by the widening differential between the Brent price and the WTI price that reflected growing domestic production and infrastructure constraints. This also impacted the differential between the WTI and Edmonton Light price which traded between a premium of $3/bbl to a discount of $9/bbl during the year.

Questerre's realized price for 2011 increased to $94.57/bbl from $77.46/bbl in 2010, mirroring the increase in the Edmonton Light price to $95.03/bbl from $77.50/bbl in 2010.

Natural gas prices continue to be challenged by sustained supply growth and limited demand growth in the United States. During the year, US dry natural gas production increased from approximately 58 Bcf/d to 64 Bcf/d. Although natural gas has become highly competitive with coal for power generation, more substantial increases in demand from this sector as well as transportation and industrial usage will be required to restore the supply demand balance.

Higher heat content gas production from Questerre's assets in Vulcan, Southern Alberta contributed to realized prices of $3.91/Mcf in 2011 (2010: $4.24/Mcf) as compared to the benchmark AECO average price of $3.63/Mcf (2010: $4.01/Mcf).

Royalties

		2011		2010
Saskatchewan	**$**	**892,492**	$	405,191
Alberta		**650,332**		1,169,084
British Columbia		**14,514**		(18,204)
	$	**1,557,338**	$	1,556,071
% of Revenue				
Saskatchewan		**6%**		6%
Alberta		**23%**		32%
British Columbia		**4%**		-2%
Total Company		**9%**		13%

In 2011, Questerre's effective royalty rate decreased to 9% from 13% in 2010. Excluding prior period amounts for production from Alberta in 2010, this decline was less pronounced from 10% in 2010 to 9% in 2011.

This is mainly due to the increasing proportion of petroleum and natural gas sales from Saskatchewan where the royalty rate is currently 7%. This includes the Saskatchewan Resource Surcharge of 1.7% of gross revenue from the province. Furthermore, the majority of the Company's wells are located on Crown lands where it benefits from a royalty incentive rate of up to 2.5% of revenue on the first 100,000 barrels of production from horizontal wells.

Operating Costs

		2011		2010
Saskatchewan	**$**	**1,493,475**	$	984,876
Alberta		**803,613**		1,160,853
British Columbia		**514,869**		1,116,540
	$	**2,811,957**	$	3,262,269
$/boe				
Saskatchewan		**9.43**		10.46
Alberta		**13.51**		12.88
British Columbia		**28.79**		26.83
Total Company		**11.93**		14.44

In Saskatchewan, continued investment in improving operating efficiency through electrification of well sites and tie-ins to the main battery has contributed to lower operating costs on a per barrel basis over the prior year. Furthermore, increased volumes cover the relatively fixed operating costs associated with this area, lowering the unit of production costs.

In Alberta, the increased operating expense on a unit of production basis is mainly due to the declining natural gas production and the relatively fixed proportion of costs in Vulcan, Southern Alberta.

With the disposition of the Company's interest in the Field at the end of May 2011, field operating costs in BC have experienced a significant decline. Coupled with the increasing proportion of corporate volumes from the lower operating cost environment in Saskatchewan, this disposition has been responsible for the improvement in operating costs, on a corporate basis, from $14.44/boe in 2010 to $11.93/boe in 2011.

General and Administrative Expenses

		2011		2010
General and administrative expenses, gross	**$**	**7,396,467**	$	6,236,148
Capitalized expenses and overhead recoveries		**(2,488,126)**		(2,113,999)
General and administrative expenses, net	**$**	**4,908,341**	$	4,122,149

Gross general and administrative expenses ("G&A") increased in 2011 to $7.40 million from $6.24 million in the prior year. Increases in public and government relations expenses, legal fees and staffing costs account for the higher expenses in 2011.

With the increase in the gross expense partially offset by the increase in the capitalized expenses and overhead recoveries, net G&A increased to $4.91 million in 2011 from $4.12 million in 2010.

Other Income and Expenses

In 2011, Questerre reported interest income of $1.74 million (2010: $1.51 million). The interest was earned principally on the net proceeds of the equity issuance completed by Questerre in the first quarter of 2010. Notwithstanding the lower cash balances in 2011, the interest is higher in this year with the proceeds being invested for the entire year compared to only a portion of 2010 after the financing was closed. The cash is invested in Guaranteed Investment Certificates issued by Canadian chartered banks and credit unions.

The Company recorded other income in 2011 of $0.05 million (2010: $0.19 million) comprised of $0.17 million (2010: $0.19 million) relating to the net gain on the purchase of Alberta drilling royalty credits offset by a payment of $0.12 million on the settlement of legal proceedings.

In 2011, the Company recorded a gain on sale of subsidiary of $4.68 million relating to the sale of its wholly owned subsidiary QBR in the second quarter of the year. Also related to this property was bad debt expense of $0.35 million (2010: $1.43 million). These represent amounts due from the joint venture partner at the Field.

Marketable securities represent investments in shares of public companies which are designated as available for sale and are stated at fair value. Any unrealized gain or loss is recognized in other comprehensive income (loss) for the period in which they arise. The Company recorded an unrealized loss, net of deferred tax of $1.61 million in 2011 (2010: $nil). At December 31, 2011, Questerre holds marketable securities with a market value of $3.27 million.

The pre-exploration expense relates to activities before the legal right to explore is acquired. The 2011 charges relate primarily to geological and geophysical expenditures.

In 2010, the Company finalized the assignment into bankruptcy of its wholly-owned subsidiary, Magnus Energy Inc. ("Magnus") and its wholly-owned subsidiary, Magnus One Energy Corp. (collectively the "Magnus entities"). This transaction resulted in a gain on extinguishment of liabilities related to Magnus entities of $1.13 million. Other 2010 activity related to a $0.34 million gain on divestitures relating to a minor property sale and a gain on marketable securities of $0.32 million.

Share Based Compensation

During the first quarter of 2011, the Company amended its stock option plan to include a put right. Pursuant to the put right, 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 net profit (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. The prior period numbers before the modification remain unchanged.

The Black-Scholes model calculates a theoretical value of the options based on the price of the Company's shares, its volatility, risk free rate and expected life. Due to the significant decrease in the Company's share price in 2011, the Black-Scholes values have decreased and a recovery has been recorded in the year.

Share based compensation for 2011 was a recovery of $2.26 million as compared to an expense of $9.22 million in 2010. As mandated by existing accounting standards, this represents the change in the estimated fair value of stock options outstanding using the Black-Scholes pricing model.

Depletion, Depreciation, Impairment and Accretion

Questerre's depletion and depreciation provision in 2011 increased 26% to $7.27 million, compared to $5.75 million in 2010. The increase is attributable to a 4% increase in production volumes and a 21% increase in the charge on a per boe basis from $25.46 in 2010 to $30.83 in 2011.

In 2011, Questerre had $6.99 million (2010: $1.36 million) in impairments in both of its property, plant and equipment ("PP&E") and exploration and evaluation ("E&E") assets as follows:

PP&E - Natural gas prices continued to decline in 2011. As a result, the Company tested the Midway, Other Alberta and Vulcan cash generating units ("CGUs") for impairment. The recoverable amount of the CGU was estimated based on the higher of the value in use ("VIU") and the fair value less costs to sell ("FVLCTS"). The estimate of FVLCTS was determined using a discount rate of 10% and forecasted cash flows based on proved plus probable reserves, with escalating prices and future development costs obtained from the reserve report after tax. Based on the assessment, an impairment loss of $0.61 million was recognized.

During the year ended December 31, 2010, due to declining natural gas prices, the Company tested the Midway, Kakwa, Other Alberta, Vulcan and Beaver River CGUs for impairment. Based on the assessment, the carrying amount of the CGUs was determined to be $1.36 million lower than its recoverable amount, and an impairment loss was recognized.

E&E - An assessment of the indicators of impairment was completed on the E&E properties in 2011. Based on the assessment, the E&E related to the Midway CGU was determined to be impaired as a result of declining natural gas prices and expiring licenses. The Company has no future plans for this area and as a result $6.38 million of costs related to Midway was recognized as impairment.

Questerre recognized $0.16 million in accretion expense in 2011 compared to $0.17 million in 2010. The decrease relates to the sale of QBR in May 2011 offset by the new liabilities incurred relating to drilling and acquisitions. The estimated net present value of the total asset retirement obligation is $5.81 million as at December 31, 2011 based on a total future undiscounted liability of $8.18 million.

Deferred Taxes

The recovery of deferred taxes for 2011 was $1.03 million compared to a recovery of $0.46 million in 2010. The higher recovery in 2011 corresponds with the higher impairment expense in the year. Consistent with prior periods, Questerre had sufficient tax pool deductions to offset taxable income in 2011.

Total Comprehensive Income (Loss)

Questerre recorded total comprehensive income in 2011 of $2.29 million compared to a $10.93 million total comprehensive loss in 2010. There are five significant changes from the prior year with respect to the total comprehensive income (loss). In 2011, the adoption of the liability method of accounting for share based compensation and the decrease in the fair value of the stock options created a share based compensation recovery of $2.26 million compared to a $9.22 million expense in 2010. Also contributing to the increase in the total comprehensive income in 2011 was the $4.68 million gain on the sale of QBR whereas the gain on extinguishment of liabilities related to Magnus entities in 2010 was $1.13 million. The higher sales from the increased oil and liquids production and realized pricing further helped contribute to the total comprehensive income in 2011. Two significant items that decreased the 2011 total comprehensive income was a $1.61 million unrealized loss, net of deferred tax, on marketable securities and impairment of assets of $6.99 million in 2011 compared to $1.36 million in 2010.

Capital Expenditures

		2011		2010
Saskatchewan	**$**	**34,599,678**	$	30,184,692
Quebec		**3,055,528**		7,371,181
Alberta		**2,689,156**		7,565
Manitoba		**150,599**		1,562,032
British Columbia		**89,671**		117,728
Corporate		**181,239**		13,326
		40,765,871		39,256,524
Dispositions		**-**		(850,000)
Total	**$**	**40,765,871**	$	38,406,524

Questerre incurred net capital expenditures of $40.77 million in 2011 (2010: $38.41 million) primarily on its light oil assets in Saskatchewan. The Company's significant capital expenditures for 2011 consisted of the following:

- In Saskatchewan, $12.89 million was the amount spent on a property acquisition, net of adjustments, and $21.71 million was incurred mainly to drill, complete and tie-in several wells. In 2011, the Company spud a total of 20 (14.27 net) wells in the province.
- $3.06 million was invested in the St. Lawrence Lowlands, Quebec primarily working to securing the Company's social license to operate to commercialize its Utica shale discovery.
- The $2.69 million spent in Alberta is comprised of the drilling, completing and tie-in of one (0.50 net) oil well and the farm-in on sixteen sections (four net) prospective for the liquids rich window of the Montney shale in Alberta.
- The $0.15 million incurred in Manitoba primarily relates to acquiring land rights.

The Company's significant capital expenditures for 2010 consisted of the following:

- In Saskatchewan, $12.98 million was incurred in Antler primarily to drill, complete and tie-in several wells. In 2010, the Company spud a total of 13 (6.50 net) wells. The remaining $17.20 million was spent on increasing and evaluating new landholdings particularly in the Wawota area of the province.
- $7.37 million was invested in the St. Lawrence Lowlands, Quebec where the Company finished the drilling of Gentilly No. 2 and subsequently completed the well. The Company also spud two wells, Fortierville No. 1 and St. Gertrude No. 1 and continued the completion and testing of St. Edouard No. 1A. The Company concluded a pipeline agreement and preliminary work for a 3-D seismic program.
- The $1.56 million incurred in Manitoba primarily relates to acquiring land rights.
- The disposition of $0.85 million relates to the sale of a non-core property in Alberta.

Liquidity and Capital Resources

Questerre reported a working capital surplus of $104.48 million at December 31, 2011 as compared to a surplus of $136.08 million at December 31, 2010.

The Company's current assets consist of cash and cash equivalents of $107.57 million, $3.27 million of marketable securities, $10.43 million of accounts receivable and $0.35 million in prepaids and deposits. Current liabilities of $17.14 million represent accounts payable and accrued liabilities.

The Company believes it is sufficiently capitalized with a working capital surplus of $104.48 million at December 31, 2011, positive cash flow from operations and no debt to fund its capital investment program for 2012. This is expected to include investments in the Antler area of Saskatchewan, and subject to conditions precedent, its investment in Red Leaf.

The majority of future capital spending that may be incurred in Quebec over the next 3-5 years is contingent upon the results of the strategic environmental assessment, the introduction of new hydrocarbon legislation and the results of the pilot program conducted by Questerre and its partners. Subject to these considerations, Questerre anticipates the ongoing development of its light oil assets will provide a further source of capital for future activities in Quebec or any of the Company's other assets, including its oil shale assets.

Cash Flow from Operations and Cash Flows from Operating Activities

Cash flow from operations in 2011 of $10.06 million was $5.32 million or 112% higher than the 2010 cash flow from operations of $4.74 million. The increase from the prior year is mainly due to significantly higher petroleum and natural gas sales and interest income along with lower operating expenses offset by higher G&A expenses and cash paid on the exercise of stock options. The petroleum and natural gas sales increase is due to the increased oil weighting that leveraged higher oil prices.

Cash flows from operating activities for 2011 was $10.60 million compared to $3.63 million in 2010. The increased cash flows from operating activities of $6.97 million is due to the positive change in the non-cash working capital of $1.65 million and the increase in the cash flow from operations of $5.32 million as discussed above.

Share Capital

The Company is authorized to issue an unlimited number of Class A common voting 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, 2011, 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.

	March 28 2012	December 31 2011	December 31 2010
Common shares	231,109,028	231,300,028	234,131,728
Stock options	22,505,419	22,674,169	20,035,835
Weighted average common shares			
Basic		233,025,712	227,181,288
Diluted		235,975,196	234,326,194

In December 2010, the Company announced its intention to conduct a Normal Course Issuer Bid ("NCIB") through the facilities of the TSX and the Oslo Stock Exchange. Under the terms of the NCIB, Questerre was authorized to acquire up to an aggregate of 11,706,586 of its common shares over the next 12-month period representing approximately 5% of its issued and outstanding common shares as at December 16, 2010. The NCIB commenced on December 22, 2010 and terminated on December 21, 2011.

In December 2011, the Company announced its renewal of the NCIB. Under the terms of the NCIB, Questerre is 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 will terminate on December 21, 2012, or the earlier of the date all common shares which are subject to the NCIB are purchased.

At December 31, 2011, 3,598,700 common shares have been purchased under the NCIB with a par value of $4,791,348 and consideration of $3,312,404. At December 31, 2011, 815,500 common shares had not been cancelled or settled. These shares are considered treasury stock, resulting in $1,085,418 included in share capital and $521,236 recognized in accounts payable at December 31, 2011. Subsequent to year end, the transaction has been settled and the common shares have been cancelled and returned to Treasury.

In 2011, there have been 6,220,000 options granted, 767,000 options exercised by issue of common shares, 703,000 options purchased by the Company pursuant to the put right, 1,006,666 options forfeited and 1,105,000 options expired.

Off-Balance Sheet Arrangements

Questerre has no off-balance sheet arrangements.

Related Party Transactions

Questerre had no related party transactions in 2011.

Commitments and Contingencies

Questerre has certain contractual obligations relating to the lease of office space and data licensing as set out in the table below:

	Total	Less than 1 year	1 - 3 years	4 - 5 years	After 5 years
Office lease	$ 1,191,605	$ 304,240	$ 608,479	$ 278,886	$ -
Data licensing	400,000	100,000	200,000	100,000	-
	$ 1,591,605	$ 404,240	$ 808,479	$ 378,886	$ -

The Company is a defendant and plaintiff in a number of legal actions arising in the normal course of business. The Company believes that any liabilities that might arise pertaining to any such matters would not have a material effect on its consolidated financial position.

In the second quarter of 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.

The Company is committed to a $0.50 million secured loan to Transeuro, subject to certain terms and conditions. No amount has been drawn under the credit facility at December 31, 2011.

In the fourth quarter of 2011, the Company also entered into work commitments to spend $4.17 million over the next two years on two oil shale exploratory permits in Saskatchewan.

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 rate 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 farm-in participants to participate in 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 Corporation'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 Corporation's securities in particular. To the extent that external sources of capital become limited or unavailable or available on onerous terms, the Corporation's ability to make capital investments and maintain existing assets may be impaired, and its assets, liabilities, business, financial condition and results of operations may be materially and adversely affected as a result. Based on current funds available and expected cash flow from operations, the Corporation 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 Corporation 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 Corporation's capital expenditure plans may result in a delay in development or production on the Corporation'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.
- Farmouts 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 principally 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.

Poor credit conditions in the industry and of joint venture partners 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 against this risk by obtaining pre-approval of significant capital expenditures. Wherever possible, the Company requires cash calls from its partners on capital projects before they commence.

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 Expenditures ("CEE") are incurred in order to meet its flow through obligations. However, in the event that the Company incurs qualifying expenditures of Canadian Development Expenditures ("CDE") or has CEE expenditures reclassified under audit by the Canada Revenue Agency, the Corporation 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. Questerre had no hedges or other financial instruments in place in 2011 but in early 2012 Questerre has entered into a CDN $103/bbl WTI swap for 150 bbl/d for February 1, 2012 – December 31, 2012 and a CDN $99.65/bbl WTI swap for 150 bbl/d for 2013.

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 and 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 Québec 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. Although Canada ratified the Kyoto Protocol, it has since announced its intention to withdraw. British Columbia, Alberta, Saskatchewan, Québec 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 ("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. There should be a 50 percent statistical probability that the actual quantity of recoverable reserves will be more than the amount estimated as proven and probable and a 50 percent statistical probability that it will be less. The equivalent statistical probabilities for the proven component of proven and probable reserves are 90 percent and 10 percent, respectively.

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

Impairment of assets and Goodwill

A cash generating unit ("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.

The recoverable amounts of CGUs have been determined based on the higher of value in use ("VIU") and the fair value less costs to sell ("FVLCTS"). The key assumptions the Company uses in estimating future cash flows for recoverable amounts are anticipated future commodity prices, expected production volumes, 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 judgment 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/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/liability may differ significantly from that estimated and recorded by management.

Accounting Standards Changes

Questerre has completed its adoption of IFRS for the year beginning on January 1, 2011. As a result, the Company's financial results for 2011 and comparative periods are reported under IFRS while figures presented in this MD&A pertaining to Questerre's 2009 results were prepared in accordance with previous GAAP and were not required to be restated.

The key areas of adjustment to the January 1, 2010 and December 31, 2010 balance sheets as a result of the transition to IFRS were as follows:

- Impairment of Property, Plant and Equipment ("PP&E") under IFRS was tested as required on initial transition to IFRS based on discounted cash flows for each CGU, which is a more granular level than required under previous GAAP. Also, under previous GAAP, a discounted cash flow analysis was not required if the undiscounted cash flows from proved reserves exceeded the carrying amount. As at January 1, 2010, the Company recorded an impairment of $18.52 million, which reduced PP&E with a corresponding charge to deficit. For the year ended December 31, 2010, additional impairment of natural gas assets of $1.36 million was recorded in net profit (loss), with a corresponding decrease to PP&E.

- Under previous GAAP, asset retirement obligations were discounted at a credit adjusted risk fee rate of 7 and 12 percent. The estimated cash flow to abandon and remediate the wells and facilities was risk adjusted under previous GAAP; therefore, the obligation is discounted at a risk free rate under IFRS. The risk free rate is based on the Government of Canada bonds rates based on the remaining life to abandon each well. At January 1, 2010 the Company used a risk free rate that ranged from 1.45 to 4.10 percent. Upon transition to IFRS this resulted in a $1.89 million increase in the asset retirement obligation with a corresponding increase in the deficit.
- Under previous GAAP, the Company followed the full cost method of accounting for oil and gas properties whereby all costs of acquisition, exploration for and development of oil and gas reserves were capitalized at the cost-centre level. Under IFRS, pre-exploration costs are expensed as incurred. After the legal right to explore is acquired, exploration costs are capitalized as exploration and evaluation assets. Once the exploration area achieves technical feasibility and commercial viability, exploration and evaluation costs are moved to PP&E. Upon transition to IFRS, the Company reclassified $23.62 million of PP&E to exploration and evaluation assets. As at December 31, 2010, the Company reclassified $49.76 million of PP&E to exploration and evaluation assets.
- Nearly all the previous GAAP to IFRS differences have an impact on deferred taxes as the adjustments change the accounting balance and the amount of the temporary or permanent differences. The impact of these changes increased the deferred tax asset by $5.69 million as at January 1, 2010 and by $3.56 million as at December 31, 2010 under IFRS.

The additional impacts of the IFRS transition on the Company's net profit (loss) are as follows:

- Upon transition to IFRS, the Company adopted a policy of depleting oil and natural gas interests on a unit of production basis over proved plus probable reserves. The depletion policy under previous GAAP was based on units of production over proved reserves. In addition depletion was calculated at a Canadian cost-centre level under previous GAAP. IFRS requires depletion and depreciation to be calculated based on individual components. For the year ended December 31, 2010 transition differences resulted in a decrease to depletion of $7.33 million with a corresponding change to PP&E.
- Under previous GAAP, proceeds from divestitures were deducted from the full cost pool without recognition of a gain or loss unless the deduction resulted in a change to the depletion rate of 20% or greater. Under IFRS, gains or losses are recorded on divestitures and calculated as the difference between the proceeds and the net book value of the asset disposed. For the year ended December 31, 2010, the Company recognized a $0.34 million gain on divestitures in net profit (loss).
- Under previous GAAP, the Company's equity-settled stock options were measured at their fair value at the grant date. This amount was expensed to stock based compensation on the income statement over the vesting period using graded vesting. Forfeitures were accounted for as they occurred. Under IFRS, an estimate of forfeitures must be factored into the calculation of the expense at the grant date and any difference between the estimates and actual is recognized in the period when actual forfeitures are incurred. The effect on net profit (loss) for the year ended December 31, 2010 is to reduce share based compensation expense by $0.32 million with a corresponding decrease to contributed surplus.
- Future income taxes are now referred to as deferred taxes.

Refer to the notes of the consolidated financial statements for further details on the impacts of the transition to IFRS.

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*, which is the result of the first phase of the International Accounting Standards Board's ("IASB") project to release IAS 19 *Financial Instruments: Recognition and Measurement*. 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 equity instruments, and such instruments are either recognized at fair value through net profit (loss) or at fair value through other comprehensive income (loss). Where such equity instruments are measured at fair value through other comprehensive income (loss), dividends are recognized in net profit (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 (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 net profit (loss) would generally be recorded in other comprehensive income (loss).

IFRS 10 Consolidated Financial Statements

IFRS 10 revises 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 includes guidance related to an investor with decision making rights to determine if it is acting as a principal or agent. Under existing IFRS, consolidation is required when an entity has the power to govern the financial and operating policies of an entity so as to obtain benefits from its activities. IFRS 10 replaces SIC-12 *Consolidation—Special Purpose Entities* and parts of IAS 27 *Consolidated and Separate Financial Statements*.

IAS 27 has been amended to conform to the changes made in IFRS 10 but retains the current guidance for separate 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. Under existing IFRS, entities have the choice to proportionately consolidate or equity account for interests in joint ventures. IFRS 11 supersedes IAS 31 *Interests in Joint Ventures*, and SIC-13 *Jointly Controlled Entities—Non-monetary Contributions by Venturers*.

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.

IFRS 13 Fair Value Measurement

IFRS 13 is a comprehensive standard for fair value measurement and disclosure requirements for use across all IFRS standards. The new standard clarifies that fair value is the price that would be received to sell an asset, or paid to transfer a liability in an orderly transaction between market participants, at the measurement date. It also establishes disclosures about fair value measurement. Under existing IFRS, guidance on measuring and disclosing fair value is dispersed among the specific standards requiring fair value measurements and in many cases does not reflect a clear measurement basis or consistent disclosures.

The above four standards are effective for annual periods beginning on or after January 1, 2013. Early adoption is permitted, providing the standards are adopted concurrently.

IAS 1 Presentation of Financial Statements

In June 2011, the IASB issued an amendment to IAS 1 *Presentation of Financial Statements* requiring companies to group items presented within other comprehensive income (loss) based on whether they may be subsequently reclassified to net profit (loss). Entities that choose to present other comprehensive income (loss) items before tax will be required to show the amount of tax related to the two groups separately. This amendment to IAS 1 is effective for annual periods beginning on or after July 1, 2012 with full retrospective application. Early adoption is permitted.

IFRS 7 Financial Instruments: Disclosures

IFRS 7 has been amended to include additional disclosure requirements in the reporting of transfer transactions and risk exposures relating to transfers of financial assets and the effect of those risks on an entity's financial position, particularly those involving the securitization of financial assets. The amendment is applicable for annual periods beginning on or after July 1, 2011, with earlier adoption permitted.

Restatement

The net loss for the year ended December 31, 2009 has been restated. Questerre acquired Terrenex Ltd. and its wholly owned foreign subsidiary Cabernet Holdings Ltd. ("Cabernet") on April 28, 2008. The only significant asset Cabernet owned was Questerre common shares. On July 22, 2009, Cabernet was dissolved and a taxable event was deemed to have occurred. The result was presented on the December 31, 2009 consolidated financial statements as a $1,256,314 increase to the future tax asset on the balance sheet. The offset was initially recorded to the future tax recovery line on the statements of operations and as a result the deficit line on the balance sheet. Upon subsequent review, since the recovery related to an equity item it should have been booked to common shares in the shareholders' equity section.

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, 2011.
- 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 2011 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 2011 Results

With the increase in the oil and liquids realized price and volumes, Questerre strengthened its financial performance in the fourth quarter of the year. Questerre ended the year with a strong working capital position of $104.48 million with cash and cash equivalents of $107.57 million.

Production for the quarter averaged 743 boe/d as compared to 604 boe/d in the preceding quarter and 605 boe/d for the fourth quarter of 2010. In the fourth quarter of 2011 the production increases at Antler translated into oil and liquids representing 84% of the Company's product mix compared to 81% in the prior quarter and 62% in the fourth quarter of 2010. Light oil from Antler accounted for 91% of the Company's oil and liquids volumes. The remaining oil and liquids are largely from its Mannville pools in Vulcan, Southern Alberta.

Due entirely to growth in Antler, oil and liquids production averaged 625 bbl/d in the fourth quarter of 2011, increasing by 66% from the prior year and 28% from the prior quarter.

By contrast, natural gas production averaged 708 Mcf/d in the fourth quarter of this year, declining 48% from the corresponding period in 2010. The decrease year over year is due to the disposition of the Beaver River field in the second quarter of 2011, coupled with natural declines in its remaining assets.

Realized oil and liquids prices increased 8% to $97.47/bbl from the prior quarter and 22% from the fourth quarter of 2010. Questerre's realized natural gas price decreased 13% to $3.66/Mcf from the prior quarter and 3% from the fourth quarter of 2010. The increased oil production and pricing translated into petroleum and natural gas sales of $5.84 million or 35% higher than the third quarter revenue of $4.33 million.

Cash flow from operations increased to $3.15 million in the fourth quarter of 2011 (2010: $2.60 million) compared to $3.01 million in the prior quarter. The increase in the fourth quarter is due to the increased petroleum and natural gas sales offset by higher royalties, operating costs and other expense items.

Questerre's total comprehensive loss in the fourth quarter of 2011 was $3.90 million (2010: $3.01 million) compared to $1.41 million of total comprehensive income in the prior quarter. The higher total comprehensive loss in the fourth quarter of 2011 is mainly due to $6.99 million in impairments offset by a $0.61 million share based compensation recovery and the increase in the cash flow from operations.

Net capital expenditures of $12.49 million in the quarter were primarily focused on our light oil assets in Saskatchewan to drill, complete and tie-in several wells and we also farmed in on sixteen sections (four net) prospective for the liquids rich window of the Montney shale.

Quarterly Financial Information

	December 31 2011	September 30 2011	June 30 2011	March 31 2011
Production (boe/d)	**743**	604	586	650
Average Realized Price ($/boe)	**85.42**	77.93	77.60	67.78
Petroleum and Natural Gas Sales	**5,839,520**	4,330,124	4,138,050	3,965,389
Cash Flow from Operations	**3,149,746**	3,008,565	2,267,676	1,636,950
Per share - Basic	**0.01**	0.01	0.01	0.01
Per share - Diluted	**0.01**	0.01	0.01	0.01
Net Profit (Loss)	**(4,030,018)**	1,758,768	4,938,387	1,234,259
Per share - Basic	**(0.02)**	0.01	0.02	0.01
Per share - Diluted	**(0.02)**	0.01	0.02	0.01
Capital Expenditures, net of acquisitions and dispositions	**12,490,404**	19,726,206	1,305,781	7,243,480
Working Capital Surplus	**104,480,657**	114,194,728	131,312,369	130,616,809
Total Assets	**258,409,889**	258,890,553	250,973,021	261,365,161
Shareholders' Equity	**232,877,970**	236,592,124	234,312,816	232,275,278
Weighted Average Common Shares Outstanding				
Basic	**232,055,963**	232,115,528	233,610,707	234,434,615
Diluted	**233,991,289**	234,382,606	236,472,552	238,509,767

	December 31 2010	September 30 2010	June 30 2010	March 31 2010
Production (boe/d)	605	649	620	600
Average Realized Price ($/boe)	58.33	49.47	49.87	55.10
Petroleum and Natural Gas Sales	3,246,637	2,953,980	2,813,743	2,975,353
Cash Flow from Operations	2,599,486	1,438,666	190,017	516,391
Per share - Basic	0.01	0.01	-	-
Per share - Diluted	0.01	0.01	-	-
Net Loss	(3,011,526)	(1,652,678)	(4,535,629)	(1,734,052)
Per share - Basic	(0.01)	(0.01)	(0.02)	(0.01)
Per share - Diluted	(0.01)	(0.01)	(0.02)	(0.01)
Capital Expenditures, net of acquisitions and dispositions	20,916,846	8,606,402	3,806,236	5,077,040
Working Capital Surplus	136,076,978	154,531,153	160,932,087	165,597,791
Total Assets	260,548,991	261,433,625	258,023,289	261,952,906
Shareholders' Equity	238,686,128	239,189,258	237,989,679	239,742,030
Weighted Average Common Shares Outstanding				
Basic	234,126,067	234,021,347	233,809,187	206,388,591
Diluted	238,754,183	240,363,560	240,694,908	216,789,825

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

- The increased capital spending in 2010 and 2011 in Saskatchewan is beginning to generate production and cash flow growth but production decreases in both Beaver River and Vulcan have generally offset the Saskatchewan production gains. This was compounded with the sale of QBR in the second quarter of 2011.
- With an increasing percentage of Questerre's volumes being comprised of oil and liquids and the corresponding increase of the realized oil and liquids pricing, petroleum and natural gas sales has increased in recent quarters.
- Following the same trend as the petroleum and natural gas sales, the cash flow from operations has increased in recent quarters due to the increase in higher netback oil and liquids volumes.
- In the second quarter of 2010, the net loss increased due to additional share based compensation expense and bad debt expense. The decreased net loss in the third quarter of 2010 is primarily due to the gain on extinguishment of liabilities related to Magnus entities. In the first quarter of 2011, with the adoption of the liability method of accounting for stock options, the decrease in the fair value of the stock options at the end of the quarter created a gain for share based compensation and overall a net profit. In the second quarter of 2011, the higher profit is primarily due to the gain on the sale of the QBR subsidiary. In the fourth quarter of 2011, an impairment loss of $6.99 million was recorded creating the only quarterly loss in 2011.
- The working capital surplus, total assets and shareholders' equity all increased significantly in the first quarter of 2010 when a financing was closed for gross proceeds of $127.91 million. In general, the working capital surplus has decreased as the capital expenditures have been higher then the cash flow from operations since that time.

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 28, 2012

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, 2011, December 31, 2010 and January 1, 2010 and the consolidated statements of net profit (loss) and comprehensive income (loss), changes in equity and cash flows for the years ended December 31, 2011 and December 31, 2010, 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, 2011, December 31, 2010 and January 1, 2010 and its financial performance and its cash flows for the years ended December 31, 2011 and December 31, 2010 in accordance with International Financial Reporting Standards.

PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Alberta
March 28, 2012

Consolidated Balance Sheets

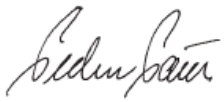
(Canadian dollars)	Note	**December 31 2011**	December 31 2010 *(Note 21)*	January 1 2010 *(Note 21)*
Assets				
Current Assets				
Cash and cash equivalents		**$ 107,566,398**	$ 141,974,856	$ 51,396,052
Marketable securities	6	**3,274,768**	-	204,336
Accounts receivable		**10,431,385**	7,894,381	4,509,203
Inventory	7	**-**	344,138	301,599
Deposits and prepaid expenses		**349,375**	507,124	619,990
		121,621,926	150,720,499	57,031,180
Investments	6	**494,506**	-	-
Property, plant and equipment	8	**75,462,470**	48,249,407	42,145,349
Exploration and evaluation assets	10	**51,582,526**	49,762,437	23,621,537
Goodwill		**2,345,944**	2,467,816	2,467,816
Deferred tax assets		**6,902,517**	9,348,832	7,180,344
		$ 258,409,889	$ 260,548,991	$ 132,446,226
Liabilities				
Current Liabilities				
Accounts payable and accrued liabilities		**$ 17,141,269**	$ 14,643,521	$ 10,530,509
Current portion of share based compensation liability	14	**2,097,637**	-	-
		19,238,906	14,643,521	10,530,509
Asset retirement obligation	12	**5,805,972**	7,219,342	6,655,654
Share based compensation liability	14	**487,041**	-	-
		25,531,919	21,862,863	17,186,163
Shareholders' Equity				
Share capital	13	**307,856,902**	311,652,770	184,962,957
Contributed surplus		**14,588,016**	18,888,735	11,218,598
Accumulated other comprehensive income (loss)		**(1,612,967)**	-	-
Deficit		**(87,953,981)**	(91,855,377)	(80,921,492)
		232,877,970	238,686,128	115,260,063
		$ 258,409,889	$ 260,548,991	$ 132,446,226

Commitments and contingencies (note 17).

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

Signed on behalf of the Board of Directors:

Russ Hammond
Director



Peder Paus
Director

Consolidated Statements of net profit (loss), and comprehensive income (loss)

(Canadian dollars)	Note	For the years ended December 31, **2011**	2010
Revenue			
Petroleum and natural gas sales		**$ 18,273,083**	$ 11,989,713
Royalties		**(1,557,338)**	(1,556,071)
Petroleum and natural gas revenue, net of royalties		**16,715,745**	10,433,642
Expenses			
Operating		**2,811,957**	3,262,269
General and administrative		**4,908,341**	4,122,149
Pre-exploration		**90,151**	-
Gain on marketable securities	6	**-**	(321,524)
Gain on sale of subsidiary	1	**(4,682,182)**	-
Gain on divestitures		**-**	(337,031)
Gain on extinguishment of liabilities related to Magnus entities	1	**-**	(1,130,345)
Bad debt expense		**347,834**	1,429,691
Depletion and depreciation	8, 10	**7,268,902**	5,753,146
Impairment of assets	8, 10	**6,991,632**	1,360,685
Accretion of asset retirement obligation	12	**155,667**	170,113
Share based compensation (recovery)	14	**(2,259,924)**	9,224,010
		15,632,378	23,533,163
Interest income		**1,741,758**	1,509,498
Other income		**49,940**	192,500
Profit (loss) before taxes		**2,875,065**	(11,397,523)
Deferred taxes (recovery)		**(1,026,331)**	(463,638)
Net profit (loss)		**3,901,396**	(10,933,885)
Other comprehensive income (loss), net of tax			
Unrealized loss on marketable securities	6	**(1,612,967)**	-
Total comprehensive income (loss)		**$ 2,288,429**	$ (10,933,885)
Net profit (loss) per share			
Basic and diluted	13	**$ 0.02**	$ (0.05)

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

Consolidated Statements of Changes in Equity

	Note	For the years ended December 31, 2011	2010
Share Capital			
Balance, beginning of period		**$ 311,652,770**	$ 184,962,957
Options exercised	13	**995,480**	4,162,250
Normal course issuer bid	13	**(4,791,348)**	-
Issue of common shares	13	**-**	127,907,414
Share issue costs, net of tax of $1,704,850	13	**-**	(5,379,851)
Balance, end of period		**307,856,902**	311,652,770
Contributed Surplus			
Balance, beginning of period		**18,888,735**	11,218,598
Reclassification of share based compensation	14	**(5,779,663)**	-
Normal course issuer bid	13	**1,478,944**	-
Share based compensation	14	**-**	9,224,010
Options exercised	14	**-**	(1,553,873)
Balance, end of period		**14,588,016**	18,888,735
Accumulated Other Comprehensive Income (Loss)			
Balance, beginning of period		**-**	-
Other comprehensive loss	6	**(1,612,967)**	-
Balance, end of period		**(1,612,967)**	-
Deficit			
Balance, beginning of period		**(91,855,377)**	(80,921,492)
Net profit (loss)		**3,901,396**	(10,933,885)
Balance, end of period		**(87,953,981)**	(91,855,377)
Total Shareholders' Equity		**$ 232,877,970**	$ 238,686,128

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

Consolidated Statements of Cash Flows

(Canadian dollars)	Note	For the years ended December 31, **2011**	2010
Operating Activities			
Net profit (loss)		**$ 3,901,396**	$ (10,933,885)
Adjustments for:			
Depletion and depreciation	8, 10	**7,268,902**	5,753,146
Impairment of assets	8, 10	**6,991,632**	1,360,685
Accretion of asset retirement obligation	12	**155,667**	170,113
Share based compensation (recovery)	14	**(2,259,924)**	9,224,010
Gain on marketable securities	6	**-**	(321,524)
Gain on sale of subsidiary	1	**(4,682,182)**	-
Gain on divestitures		**-**	(337,031)
Gain on extinguishment of liabilities related to Magnus entities	1	**-**	(1,130,345)
Bad debt expense		**347,834**	1,429,691
Deferred taxes (recovery)	16	**(1,026,331)**	(463,638)
Cash paid on exercise of stock options	14	**(597,070)**	-
Abandonment expenditures		**(36,987)**	(6,662)
		10,062,937	4,744,560
Change in non-cash working capital	18	**532,570**	(1,115,036)
Net cash from operating activities		**10,595,507**	3,629,524
Investing Activities			
Property, plant and equipment expenditures		**(21,422,475)**	(13,115,196)
Exploration and evaluation expenditures		**(6,449,488)**	(26,141,328)
Expenditures on acquisitions	9	**(12,893,908)**	-
Sale of property, plant and equipment		**-**	850,000
Disposition of subsidiary		**(705,986)**	-
Proceeds from sale of marketable securities		**-**	525,860
Purchase of marketable securities	6	**(2,326,944)**	-
Purchase of investments		**(494,506)**	-
Change in non-cash working capital	18	**2,064,696**	1,398,854
Net cash used in investing activities		**(42,228,611)**	(36,481,810)
Financing Activities			
Proceeds from issue of share capital		**537,050**	130,515,791
Repurchase of shares under normal course issuer bid	13	**(3,312,404)**	-
Share issuance costs		**-**	(7,084,701)
Net cash from (used in) financing activities		**(2,775,354)**	123,431,090
Change in cash and cash equivalents		**(34,408,458)**	90,578,804
Cash and cash equivalents, beginning of period		**141,974,856**	51,396,052
Cash and cash equivalents, end of period		**$ 107,566,398**	$ 141,974,856
Cash interest received		**$ 1,599,923**	$ 1,130,588

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 period ended December 31, 2011 and 2010 comprise the Company and its wholly-owned subsidiaries in those periods owned.

On June 18, 2008, Magnus Energy Inc. ("Magnus") and its wholly-owned subsidiary Magnus One Energy Corp. (collectively the "Magnus entities") applied for protection under the *Bankruptcy and Insolvency Act (Canada).* Magnus was a wholly-owned subsidiary of Questerre. In the third quarter of 2010, the Company finalized the assignment of the Magnus entities into bankruptcy. This transaction resulted in a gain on extinguishment of liabilities related to Magnus entities of $1,130,345.

In May 2011, Questerre concluded its agreement with Transeuro Energy Corp. ("Transeuro") for Transeuro to acquire the remaining 50% interest in the Beaver River field.

Pursuant to the agreement, Transeuro acquired all the issued and outstanding shares of Questerre Beaver River Inc. ("QBR"), a wholly owned subsidiary of the Company that owned the other 50% interest in the Beaver River field. In consideration, Questerre received 40 million common shares of Transeuro valued at $2,800,000. The sale of QBR resulted in a gain on the sale of the subsidiary of $4,804,054 and a derecognition of goodwill of $121,872.

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 Canadian generally accepted accounting principles as set out in the Handbook of the Canadian Institute of Chartered Accountants ("CICA Handbook"). In 2010, the CICA Handbook was revised to incorporate International Financial Reporting Standards ("IFRS"), and require publicly accountable enterprises to apply such standards effective for years beginning on or after January 1, 2011. Accordingly, these are the Company's first annual consolidated financial statements prepared in accordance with IFRS as issued by the International Accounting Standards Board ("IASB"). In these consolidated financial statements, the term "previous GAAP" refers to Canadian GAAP before the adoption of IFRS.

These consolidated financial statements have been prepared in accordance with IFRS. Subject to certain transition elections and exceptions disclosed in Note 21, the Company has consistently applied the accounting policies used in the preparation of its opening IFRS balance sheets at January 1, 2010 throughout all periods presented, as if these policies had always been in effect. Note 21 discloses the impact of the transition to IFRS on the Company's reported financial position, financial performance and cash flows, including the nature and effect of significant changes in accounting policies from those used in the Company's consolidated financial statements for the year ended December 31, 2010 prepared under previous GAAP.

The policies applied in these consolidated financial statements are based on IFRS issued and outstanding as at March 28, 2012, the date the Board of Directors approved the statements.

b) Basis of measurement

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

Many of the Company's oil and natural gas activities involve jointly controlled assets. The consolidated financial statements include the Company's share of these jointly controlled assets and a proportionate share of the relevant revenue and related costs.

d) 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 ("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. There should be a 50 percent statistical probability that the actual quantity of recoverable reserves will be more than the amount estimated as proven and probable and a 50 percent statistical probability that it will be less. The equivalent statistical probabilities for the proven component of proven and probable reserves are 90 percent and 10 percent, respectively.

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

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

Impairment of assets and Goodwill

A cash generating unit ("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.

The recoverable amounts of CGUs have been determined based on the higher of value in use ("VIU") and the fair value less costs to sell ("FVLCTS"). The key assumptions the Company uses in estimating future cash flows for recoverable amounts are anticipated future commodity prices, expected production volumes, 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 judgment and assumptions noted above for impairment of assets.

Refer to Note 8 for the sensitivity analysis related to impairments. Refer to Note 11 for the carrying amounts related to goodwill.

Asset retirement obligation

Determination of 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.

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

Share Based Compensation

The Company has a stock option plan enabling employees, officers and directors to receive common shares or cash at exercise prices equal to the market price or above on the date the option is granted. 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 14.

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/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/liability may differ significantly from that estimated and recorded by management.

Refer to Note 16 for the carrying amounts related to deferred taxes.

3. Significant Accounting Policies

The accounting policies set out below have been applied consistently to all periods presented in these consolidated financial statements, except where specific exemptions permitted an alternative treatment upon transition to IFRS in accordance with IFRS 1 as disclosed in Note 21.

(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.

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 designed its marketable securities 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 (loss). When an available for sale investment is sold or impaired, the accumulated gains or losses are moved from accumulated other comprehensive income (loss) to net profit (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 three months 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 ("E&E") 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.

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

The carrying amounts of the Company's non-financial assets, other than E&E assets and 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, Canada. E&E 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 FVLCTS. FVLCTS is determined using discounted future cash flows of proved and probable reserves using an after tax discount rate for FVLCTS. In determining FVLCTS, 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.

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 that is reclassified to net income.

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/decreases due to changes in the estimated future cash flows and risk free rates are adjusted through PP&E or E&E. 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 (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. 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 (loss) per share

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

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

4. Changes in Accounting Policies and Disclosures

a) New and amended accounting standards and interpretations

Accounting standards effective for periods beginning on or after January 1, 2011 have been adopted as part of the transition to IFRS.

b) Accounting Standards and amendments issued but not yet effective

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*, which is the result of the first phase of the International Accounting Standards Board's ("IASB") project to release IAS 19 *Financial Instruments: Recognition and Measurement*. 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 equity instruments, and such instruments are either recognized at fair value through net profit (loss) or at fair value through other comprehensive income (loss). Where such equity instruments are measured at fair value through other comprehensive income (loss), dividends are recognized in net profit (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 (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 net profit (loss) would generally be recorded in other comprehensive income (loss).

IFRS 10 Consolidated Financial Statements

IFRS 10 revises 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 includes guidance related to an investor with decision making rights to determine if it is acting as a principal or agent. Under existing IFRS, consolidation is required when an entity has the power to govern the financial and operating policies of an entity so as to obtain benefits from its activities. IFRS 10 replaces SIC-12 *Consolidation—Special Purpose Entities* and parts of IAS 27 *Consolidated and Separate Financial Statements*.

IAS 27 has been amended to conform to the changes made in IFRS 10 but retains the current guidance for separate 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. Under existing IFRS, entities have the choice to proportionately consolidate or equity account for interests in joint ventures that are jointly controlled entities. IFRS 11 supersedes IAS 31 *Interests in Joint Ventures*, and SIC-13 *Jointly Controlled Entities—Non-monetary Contributions by Venturers*.

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.

IFRS 13 Fair Value Measurement

IFRS 13 is a comprehensive standard for fair value measurement and disclosure requirements for use across all IFRS standards. The new standard clarifies that fair value is the price that would be received to sell an asset, or paid to transfer a liability in an orderly transaction between market participants, at the measurement date. It also establishes disclosures about fair value measurement. Under existing IFRS, guidance on measuring and disclosing fair value is dispersed among the specific standards requiring fair value measurements and in many cases does not reflect a clear measurement basis or consistent disclosures.

The above four standards are effective for annual periods beginning on or after January 1, 2013. Early adoption is permitted, providing the standards are adopted concurrently.

IAS 1 Presentation of Financial Statements

In June 2011, the IASB issued an amendment to IAS 1 *Presentation of Financial Statements* requiring companies to group items presented within other comprehensive income (loss) based on whether they may be subsequently reclassified to net profit (loss). Entities that choose to present other comprehensive income (loss) items before tax will be required to show the amount of tax related to the two groups separately. This amendment to IAS 1 is effective for annual periods beginning on or after July 1, 2012 with full retrospective application. Early adoption is permitted.

IFRS 7 Financial Instruments: Disclosures

IFRS 7 has been amended to include additional disclosure requirements in the reporting of transfer transactions and risk exposures relating to transfers of financial assets and the effect of those risks on an entity's financial position, particularly those involving the securitization of financial assets. The amendment is applicable for annual periods beginning on or after July 1, 2011, with earlier adoption permitted.

5. 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, 2011 included cash and cash equivalents, marketable securities, investments, accounts receivable, deposits, accounts payable and accrued liabilities. As at December 31, 2011, all the Company's financial assets and liabilities are recorded at their carrying value which approximates fair value.

The 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.

Marketable securities – 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. As the marketable securities are recorded at fair value using quoted market prices they are classified as Level 1 of the hierarchy.

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.

Level 3 Fair Value Measurements

Level 3 fair value measurements are based on unobservable information.

Investments – The fair value is determined using valuation models where significant inputs are not derived from observable market data.

As at each reporting period, the Company will assess whether a financial asset, other than those classified as held-for-trading is impaired. Any impairment loss will be included in net profit (loss) for the period.

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 against this risk by obtaining pre-approval of significant capital expenditures. Wherever possible, the Company requires cash calls from its partners on capital projects before they commence.

The Company's accounts receivables are aged as follows:

		December 31 2011		December 31 2010
Current	**$**	**4,242,644**	$	4,772,869
31 - 60 days		**1,974,946**		1,587,619
61 - 90 days		**1,757,635**		1,048,305
>90 days		**2,549,874**		5,725,622
Allowance for doubtful accounts		**(93,714)**		(5,240,034)
	$	**10,431,385**	$	7,894,381

The following table provides a reconciliation of the Company's allowance for doubtful accounts:

		December 31 2011		December 31 2010
Balance, beginning of period	**$**	**5,240,034**	$	2,899,112
Joint venture partner allowance		**761,201**		2,340,922
Sale of subsidiary		**(5,907,521)**		-
Balance, end of period	**$**	**93,714**	$	5,240,034

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

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

d) Liquidity risk

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

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

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

e) Market risk

Market risk is the risk that changes in market prices, such as commodity prices, foreign exchange rates and interest rates will affect the Company's net profit (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 by not only 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, 2011, the Company had no oil and natural gas risk management contracts in place.

Currency risk

Even though all of Questerre's petroleum and natural gas sales are denominated in Canadian dollars, the underlying market prices for these commodities are impacted by the exchange rate between Canada and the United States. As at December 31, 2011, 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, 2011.

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) of $104.48 million consisting mainly of cash and cash equivalents.

The volatility of commodity prices have 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.

	December 31 2011	December 31 2010	January 1 2010
Shareholders' equity	**$ 232,877,970**	$ 238,686,128	$ 115,260,063

6. Marketable Securities & Investments

		December 31 2011		December 31 2010		January 1 2010
Current investments:						
Marketable securities	**$**	**3,274,768**	$	-	$	204,336
Long-term investments:						
Other equity investment		**494,506**		-		-
	$	**3,769,274**	$	-	$	204,336

Marketable securities represent investments in shares of public companies and the other equity investment represents shares held in a private company.

The following table sets out the changes in marketable securities:

		December 31 2011		December 31 2010
Balance, beginning of period	**$**	**-**	$	204,336
Proceeds on sale of subsidiary		**2,800,000**		-
Purchase of marketable securities		**2,326,944**		-
Sale of marketable securities		**-**		(525,860)
Realized gain on sale of marketable securities		**-**		241,870
Unrealized gain (loss) on marketable securities		**(1,852,176)**		79,654
	$	**3,274,768**	$	-

The unrealized loss on marketable securities of $1,852,176 was recorded net of deferred tax of $239,209 in other comprehensive income (loss) for the year ended December 31, 2011.

7. Inventory

In 2011, $130,275 in fuel inventory was purchased (2010: $331,803) and $142,656 (2010: $289,264) was recognized as an expense. At December 31, 2011, the inventory balance is nil, as it solely related to QBR, which was sold in the second quarter of 2011.

8. Property, Plant and Equipment

		Oil and Natural Gas Assets		Other Assets		Total
Cost or deemed cost:						
Balance at January 1, 2010	$	60,217,761	$	1,565,779	$	61,783,540
Additions		13,674,217		13,326		13,687,543
Transfers from exploration and evaluation assets		43,316		-		43,316
Disposals		(1,392,046)		-		(1,392,046)
Balance at December 31, 2010		72,543,248		1,579,105		74,122,353
Additions		23,240,878		181,239		23,422,117
Acquisitions		11,338,805		-		11,338,805
Transfer from exploration and evaluation assets		241,741		-		241,741
Disposals		(3,780,304)		(631,464)		(4,411,768)
Balance at December 31, 2011	**$**	**103,584,368**	**$**	**1,128,880**	**$**	**104,713,248**
Depletion, depreciation and impairment losses:						
Balance at January 1, 2010	$	18,519,949	$	1,118,242	$	19,638,191
Depletion and depreciation		5,486,912		266,234		5,753,146
Impairment		1,360,685		-		1,360,685
Disposals		(879,076)		-		(879,076)
Balance at December 31, 2010		24,488,470		1,384,476		25,872,946
Depletion and depreciation		7,048,579		126,353		7,174,932
Impairment		614,668		-		614,668
Disposals		(3,780,304)		(631,464)		(4,411,768)
Balance at December 31, 2011	**$**	**28,371,413**	**$**	**879,365**	**$**	**29,250,778**

		Oil and Natural Gas Assets		Other Assets		Total
Net book value:						
At January 1, 2010	$	41,697,812	$	447,537	$	42,145,349
At December 31, 2010	$	48,054,778	$	194,629	$	48,249,407
At December 31, 2011	**$**	**75,212,955**	**$**	**249,515**	**$**	**75,462,470**

During the year ended December 31, 2011, the Company capitalized administrative overhead charges of $658,689 (December 31, 2010: $629,900) directly related to development activities. Included in the depletion calculation are future development costs of $18,896,000 (December 31, 2010: $7,857,000).

In 2011, natural gas prices continued to decline. As a result, the Company tested the Midway, Other Alberta and Vulcan CGUs for impairment. The recoverable amount of the CGU was estimated based on the higher of the VIU and the FVLCTS. The estimate of FVLCTS was determined using a discount rate of 10% and forecasted cash flows based on proved plus probable reserves, with escalating prices and future development costs obtained from the reserve report after tax. Based on the assessment, an impairment loss of $614,668 was recognized.

The benchmark reference prices used to determine the FVLCTS are those determined by independent industry reserve engineers as follows:

	Alberta Average Plantgate ($C/MMBtu)
2012	3.30
2013	4.00
2014	4.50
2015	4.90
2016	5.35
2017	5.70
2018	6.00
2019	6.20
2020	6.45
2021	6.60
2022	6.70
2023	6.80
2024	6.95
2025	7.15
2026	7.30
Thereafter	+2%/yr

The estimates used to determine the FVLCTS are particularly sensitive in the following areas:

- An increase of 1 percentage point in the discount rate used would have increased the impairment loss by $186,832. A decrease of 1 percentage point in the discount rate used would have decreased the impairment loss by $202,233.
- A 10 percent decrease in the future planned revenue would have increased the impairment loss by $478,788.

During the year ended December 31, 2010, due to declining natural gas prices, the Company tested the Midway, Kakwa, Other Alberta, Vulcan and Beaver River CGUs for impairment. Based on the assessment, the recoverable amount of the CGUs was determined to be $1,360,685 lower than its carrying amount, and an impairment loss was recognized.

The benchmark reference prices used to determine the FVLCTS are those determined by independent industry reserve engineers as follows.

	Alberta Average Plantgate ($C/MMBtu)
2011	4.05
2012	4.70
2013	5.20
2014	5.70
2015	6.15
2016	6.55
2017	6.85
2018	7.15
2019	7.35
2020	7.50
2021	7.60
2022	7.80
2023	7.95
2024	8.15
2025	8.25
Thereafter	+2%/yr

The estimates used to determine the FVLCTS are particularly sensitive in the following areas:

- An increase of 1 percentage point in the discount rate used would have increased the impairment loss by $178,639. A decrease of 1 percentage point in the discount rate used would have decreased the impairment loss by $193,243.
- A 10 percent decrease in the future planned revenue would have increased the impairment loss by $466,406.

9. Property Acquisition

On July 7, 2011, Questerre acquired certain interests in oil properties located in southeast Saskatchewan for total cash consideration of $12,893,908. The consolidated financial statements include the results of operations for the period following the close of the transaction on July 7, 2011. If the properties had been acquired as of January 1, 2011, an additional $1,580,854 in petroleum and natural gas revenue, net of royalties and $212,663 in operating expenses would have been recognized for the year ended December 31, 2011. Following the close of the transaction $1,537,378 in petroleum and natural gas revenue, net of royalties and $188,280 in operating expenses have been recognized in 2011. The impact on net profit (loss) is not readily determinable.

The transaction was accounted for as a business combination using the acquisition method of accounting under IFRS 3, whereby the net assets acquired are recorded at fair value.

The following table summarizes the net assets acquired pursuant to the acquisition:

Fair value of net assets acquired:		
Property, plant and equipment	**$**	**11,590,123**
Exploration and evaluation assets		**1,555,103**
Asset retirement obligation		**(251,318)**
Net assets acquired	**$**	**12,893,908**
Cash consideration	**$**	**12,893,908**

10. Exploration and Evaluation ("E&E") Assets

Reconciliation of the movements in E&E assets:

		December 31 2011		December 31 2010
Carrying amount, beginning of period	**$**	**49,762,437**	$	23,621,537
Additions		**6,977,661**		26,184,216
Acquisitions		**1,555,103**		-
Transfers to property, plant and equipment		**(241,741)**		(43,316)
Undeveloped land expiries		**(93,970)**		-
Impairment		**(6,376,964)**		-
Carrying amount, end of period	**$**	**51,582,526**	$	49,762,437

During the year ended December 31, 2011, the Company capitalized administrative overhead charges of $1,619,542 (December 31, 2010: $1,256,800) directly related to E&E activities.

In 2011, an assessment of the indicators of impairment was completed on the E&E properties. Based on the assessment, the E&E related to the Midway CGU was determined to be impaired as a result of declining natural gas price and expiring licenses. The Company has no future plans for this area and as a result $6,376,964 of costs related to Midway was recognized as impairment.

An impairment test was also performed on its Quebec E&E assets. The impairment test was based on the average value ascribed on a per acre basis in several comparable non-conventional gas farm-in and acquisition transactions in North America. Using the average value attributed to acreage in these transactions and applying conservative discount rates due to the early stage nature of the Quebec acreage and political considerations, no impairment was recognized as the attributed value exceeds the carrying value of the Quebec E&E assets. A VIU impairment test was also performed and also resulted in no impairment as the value exceeded the Quebec E&E carrying value of $25,245,822.

Undeveloped land expiries within E&E assets are recognized as additional depletion and depreciation expense in net profit (loss).

E&E 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 E&E assets during the period.

11. Goodwill

Carrying Amount:		
Balance at January 1, 2010	$	2,467,816
Balance at December 31, 2010	$	2,467,816
Derecognition of goodwill	$	(121,872)
Balance at December 31, 2011	**$**	**2,345,944**

In 2011, the sale of QBR resulted in a derecognition of goodwill of $121,872.

12. Asset Retirement Obligation

The Company's asset retirement and abandonment obligations result from its ownership interest in oil and natural gas assets. The total asset retirement obligation is estimated based on the Company's net ownership interest in all wells and facilities, estimated costs to reclaim and abandon these wells and facilities and the estimated timing of the costs to be incurred in future periods. The Company has estimated the net present value of the asset retirement obligation to be $5,805,972 as at December 31, 2011 (December 31, 2010: $7,219,342) based on an undiscounted total future liability of $8,184,477 (December 31, 2010: $9,661,749). These payments are expected to be made over the next 35 years. The discount factor, being the risk free rate related to the liability, is between 0.95 and 2.49 percent (2010: 1.67 and 3.52 percent). An inflation rate of three percent 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:

		December 31 2011		December 31 2010
Balance, beginning of period	**$**	**7,219,342**	$	6,655,654
Revisions due to change in discount rate		**1,029,172**		273,903
Revisions due to change in estimates		**201,290**		(247,823)
Liabilities incurred		**925,596**		374,157
Liabilities acquired		**251,318**		-
Liabilities settled		**(36,987)**		(6,662)
Sale of subsidiary		**(3,939,426)**		-
Accretion		**155,667**		170,113
Balance, end of period	**$**	**5,805,972**	$	7,219,342

13. Share Capital

The Company is authorized to issue an unlimited number of Class A common voting 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, 2011, there were no Class B common voting shares or preferred shares outstanding.

a) Issued and outstanding – Class A Common Shares

	Number		Amount
Balance, January 1, 2010	199,722,143	$	184,962,957
Issue of common shares	30,000,000		127,907,414
Issued on exercise of options	4,409,585		4,162,250
Shares issue costs, net of tax			(5,379,851)
Balance, December 31, 2010	234,131,728		311,652,770
Issued on exercise of options	767,000		995,480
Repurchased under normal course issuer bid	(3,598,700)		(4,791,348)
Balance, December 31, 2011	**231,300,028**	**$**	**307,856,902**

In March 2010, Questerre closed an equity issuance of 30,000,000 common shares for gross proceeds of $127.91 million. This was comprised of 19,972,000 common shares on a private placement basis in Norway and 10,028,000 common shares by way of a short-form prospectus offering in Canada.

b) Normal course issuer bid

In December 2010, the Company announced its intention to conduct a Normal Course Issuer Bid ("NCIB") through the facilities of the TSX and the Oslo Stock Exchange. Under the terms of the NCIB, Questerre was authorized to acquire up to an aggregate of 11,706,586 of its common shares over the next 12-month period representing approximately 5% of its issued and outstanding common shares as at December 16, 2010. The NCIB commenced on December 22, 2010 and terminated on December 21, 2011.

In December 2011, the Company announced its renewal of the NCIB. Under the terms of the NCIB, Questerre is 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 will terminate on December 21, 2012, or the earlier of the date all common shares which are subject to the NCIB are purchased.

All common shares purchased by Questerre under the NCIB will be returned to treasury and cancelled. When common shares are repurchased, the amount of consideration paid, net of the excess of the purchase price of the common shares over their average carrying value, is recognized as a reduction of share capital. The excess of the average carrying value over the purchase price is recorded as contributed surplus. Repurchased shares that are not cancelled at the balance sheet date are recorded in share capital as treasury shares. Common shares transactions are recognized on a trade date basis.

At December 31, 2011, 3,598,700 common shares have been purchased under the NCIB for consideration of $3,312,404 and an adjustment to share capital on an average cost basis of $4,791,348. At December 31, 2011, 815,500 of common shares had not been cancelled or settled. These shares are considered treasury stock, resulting in $1,085,418 included in share capital and $521,236 recognized in accounts payable at December 31, 2011. Subsequent to year end, the transaction has been settled and the common shares have been cancelled and returned to Treasury.

c) Per share amounts

Basic net profit (loss) per share is calculated as follows:

		2011		2010
Net profit (loss)	**$**	**3,901,396**	$	(10,933,885)
Issued common shares at beginning of period		**234,131,728**		199,722,143
Effect of shares issued (private placement)		**-**		16,223,712
Effect of shares issued (prospectus offering)		**-**		7,967,452
Effect of options exercised for shares		**572,131**		3,267,981
Effect of treasury stock reacquired		**(1,678,147)**		-
Weighted average number of common shares outstanding (basic)		**233,025,712**		227,181,288
Basic net profit (loss) per share	**$**	**0.02**	$	(0.05)

Diluted net profit per share is calculated as follows:

		2011		2010
Net profit (loss)	**$**	**3,901,396**	$	(10,933,885)
Weighted average number of common shares outstanding (basic)		**233,025,712**		227,181,288
Effect of outstanding options		**2,949,484**		7,144,906
Weighted average number of common shares outstanding (diluted)		**235,975,196**		234,326,194
Diluted profit per share	**$**	**0.02**	$	-

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. Diluted per share amounts are not calculated when there is a net loss. 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.

14. 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, over a three-year period starting one year from the grant date or at the end of three years. The grants generally expire five years from the date of grant or five years from the commencement of the vesting.

As at January 24, 2011, the Company modified its stock option plan. Under the modified option plan, a put right was included that allows the optionee to settle options with cash or equity. The Corporation 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. At the time of the plan modification, $9,231,368 of contributed surplus was transferred to the share based compensation liability on the Company's consolidated balance sheet.

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

	December 31, 2011		December 31, 2010	
	Number of Options	**Weighted Average Exercise Price**	Number of Options	Weighted Average Exercise Price
Outstanding, beginning of period	**20,035,835**	**$2.47**	18,618,753	$1.53
Forfeited	**(1,006,666)**	**1.71**	(136,668)	2.72
Expired	**(1,105,000)**	**1.27**	-	-
Exercised	**(1,470,000)**	**0.72**	(4,409,585)	0.59
Granted	**6,220,000**	**0.99**	5,963,335	4.03
Outstanding, end of period	**22,674,169**	**$2.27**	20,035,835	$2.47
Exercisable, end of period	**10,196,237**	**$2.12**	9,142,702	$1.32

The following table summarizes information about stock options outstanding and exercisable at December 31, 2011:

	Options Outstanding			Options Exercisable		
	Number of Options	Weighted Average Years to Expiry	Weighted Average Exercise Price	Number of Options	Weighted Average Years to Expiry	Weighted Average Exercise Price
$0.45 - $0.53	4,753,334	1.15	$0.45	4,753,334	1.15	$0.45
$0.54 - $1.39	4,180,000	4.56	0.73	255,000	0.66	0.90
$1.40 - $2.79	5,372,500	3.66	2.04	1,654,158	3.03	2.22
$2.80 - $4.22	5,893,335	3.24	4.03	1,471,251	3.23	4.03
$4.23 - $4.70	2,475,000	1.45	4.70	2,062,494	1.45	4.70
	22,674,169	**2.95**	**$2.27**	**10,196,237**	**1.80**	**$2.12**

The fair value of the liability was estimated at December 31, 2011 using the Black-Scholes valuation model with the weighted average assumptions as follows:

	December 31 2011	December 31 2010
Weighted average fair value per award ($)	**0.22**	2.66
Volatility (%)	**83**	108
Forfeiture rate (%)	**2.31**	2.14
Expected life (years)	**2.62**	3.01
Risk free interest rate (%)	**1.25**	1.20

Note - The 2010 comparative period is the weighted average assumptions for each option granted during the year as the Company previously reported under an equity plan.

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

The modification to the option plan was accounted for prospectively. Share based compensation of $2,259,924 was recovered during the year ended December 31, 2011 and $9,224,010 was expensed during the comparable period in 2010 prior to the modification. In addition, share based compensation expense of $120,439 (2010: $nil) was capitalized during the year ended December 31, 2011.

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

		December 31 2011
Balance, beginning of period	$	-
Amount transferred on modification of option plan		**9,231,368**
Amount transferred from contributed surplus		**(3,451,705)**
Share based compensation expense (recovery)		**(2,259,924)**
Capitalized share based compensation expense		**120,439**
Reclassification to share capital on exercise of stock options		**(458,430)**
Cash payment for options surrendered		**(597,070)**
Share based compensation liability	$	**2,584,678**
Current portion	$	**2,097,637**
Non-current portion		**487,041**
	$	**2,584,678**

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.

15. Employee Salaries and Benefits

		2011		2010
Salaries, bonuses and other short-term benefits	$	**3,525,131**	$	3,054,793
Share based compensation (recovery)		**(2,139,485)**		9,224,010
	$	**1,385,646**	$	12,278,803

16. Deferred Income Taxes

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

		2011		2010
Profit (loss) before taxes	$	**2,875,065**	$	(11,397,523)
Combined federal and provincial tax rate		**27.32%**		28.63%
Computed "expected" deferred taxes (recovery)		**785,468**		(3,263,111)
Increase (decrease) in deferred taxes resulting from:				
Non-deductible differences		**(5,128,457)**		2,327,232
Rate adjustments		**182,104**		483,522
Valuation allowance		**3,009,043**		(42,926)
Other		**125,511**		31,645
Deferred taxes (recovery)	$	**(1,026,331)**	$	(463,638)

The statutory tax rate decreased to 27.32% in 2011 from 28.63% in 2010 as a result of tax legislation enacted in 2007.

The movement of the deferred tax asset is as follows:

		2011		2010
Balance, January 1	**$**	**(9,348,832)**	$	(7,180,344)
Credit to statement of net profit (loss)		**(1,026,331)**		(463,638)
Tax credit relating to components of other comprehensive income (loss)		**(239,209)**		-
Tax credit related to Shareholders' Equity		**-**		(1,704,850)
Sale of subsidiary		**3,711,855**		-
Balance, December 31	**$**	**(6,902,517)**	$	(9,348,832)

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

		Asset retirement obligation		Share issue costs		Marketable securities		Non-Capital Losses
Deferred tax asset:								
Balance, January 1, 2010	$	(1,626,988)	$	(1,425,977)	$	(23,530)	$	(3,867,860)
Charged (credited) to statement of net profit (loss)		(200,039)		949,889		23,530		(3,847,654)
Credited to Shareholders' Equity		-		(1,704,850)		-		-
Balance, December 31, 2010		(1,827,027)		(2,180,938)		-		(7,715,514)
Charged (credited) to statement of net profit (loss)		(657,985)		875,557		-		(3,576,699)
Credited to comprehensive income (loss)		-		-		(239,209)		-
Sale of subsidiary		985,239		152		-		1,053,058
Balance, December 31, 2011	**$**	**(1,499,773)**	**$**	**(1,305,229)**	**$**	**(239,209)**	**$**	**(10,239,155)**

		Petroleum and natural gas properties		Unrealized gain on investments
Deferred tax liability:				
Balance, January 1, 2010	$	(1,864,089)	$	1,628,100
Charged to statement of net profit (loss)		2,610,636		-
Balance, December 31, 2010		746,547		1,628,100
Charged to statement of net profit (loss)		2,332,796		-
Sale of subsidiary		1,673,406		-

Non-capital loss carryforwards at December 31, 2011 expire from 2014 to 2031.

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

		December 31 2011		December 31 2010
Petroleum and natural gas properites	**$**	**56,668**	$	-
Capital losses		**4,525,613**		1,818,202
	$	**4,582,281**	$	1,818,202

The Company has temporary differences in respect of its investments in Canadian subsidiaries for which no deferred taxes have been recorded. As no taxes are expected to be paid in respect of the temporary differences related to its Canadian subsidiaries, the Company has not determined the amount of those temporary differences.

17. Commitments and Contingencies

The Company has commitments under a lease for office space of $304,240 per year for 2012 to 2014 and $278,885 in 2015. In the first quarter of 2011, Questerre entered into a data licensing agreement. The Company has commitments under the agreement of $100,000 per year for 2012 to 2015.

The Company is a defendant and plaintiff in a number of legal actions arising in the normal course of business. The Company believes that any liabilities that might arise pertaining to any such matters would not have a material effect on its consolidated financial position.

In the second quarter of 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.

The Company is committed to a $0.50 million secured loan to Transeuro, subject to certain terms and conditions. No amount has been drawn under the credit facility at December 31, 2011.

In the fourth quarter of 2011, the Company also entered into work commitments to spend $4.17 million over the next two years on two oil shale exploratory permits in Saskatchewan.

During 2011, the Company reached settlements related to legal proceedings resulting in a receipt of $375,000 and payment of $500,000. The settlements are recorded in other income. Questerre also had other income of $149,940 relating to the net gain on the purchase of Alberta drilling royalty credits.

18. Supplemental Cash Flow Information

Changes in non-cash working capital:

		December 31 2011		December 31 2010
Accounts receivable	**$**	**(2,537,004)**	$	(3,385,178)
Deposits and prepaid expenses		**157,749**		112,866
Inventory		**344,138**		(42,539)
Accounts payable and accrued liabilities		**2,497,747**		4,113,012
Amounts removed related to the extinguishment of Magnus entities		**-**		(514,343)
Amounts removed related to sale of subsidiary		**2,134,636**		-
Change in non-cash working capital	**$**	**2,597,266**	$	283,818
Related to:				-
Operating activities	**$**	**532,570**	$	(1,115,036)
Investing activities		**2,064,696**		1,398,854
	$	**2,597,266**	$	283,818

19. Subsequent Events

In early 2012, Questerre has entered into a CDN $103/bbl WTI swap for 150 bbl/d for February 1, 2012 – December 31, 2012 and a CDN $99.65/bbl WTI swap for 150 bbl/d for 2013.

20. Key Management Compensation

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

		2011		2010
Salaries, bonuses, director fees and other short-term benefits	**$**	**2,409,844**	$	2,462,665
Share based compensation		**1,759,430**		14,833,418
	$	**4,169,274**	$	17,296,083

21. Transition to IFRS

As stated in Note 2, these consolidated financial statements are for the period covered by the first annual consolidated financial statements prepared in accordance with IFRS as at and for the year ended December 31, 2011. Previously, the Company prepared its consolidated financial statements in accordance with previous GAAP.

The Company adopted IFRS on January 1, 2011 with a transition date of January 1, 2010. Under IFRS 1 *First Time Adoption of International Financial Reporting Standards*, IFRS is applied retrospectively at the transition date with the offsetting adjustments to assets and liabilities generally included in the deficit.

The effect of the Company's transition to IFRS is summarized as follows:

- Transition elections
- Reconciliations as previously reported under previous GAAP to IFRS
- Adjustments to the statements of cash flows

Transition elections

IFRS 1 *First Time Adoption of International Financial Reporting Standards* allows first-time adopters certain exemptions from the retrospective application of certain IFRSs. The Company has applied the following exemptions:

a) Business combinations

IFRS 1 indicates that a first-time adopter may elect not to apply IFRS 3 *Business Combinations* retrospectively to business combinations that occurred prior to the date of transition to IFRS. The Company has elected to apply IFRS relating to business combinations prospectively from January 1, 2010. As such, previous GAAP balances relating to business combinations entered into before that date, including goodwill, have been carried forward without adjustment.

b) Election for full cost oil and gas entities

The Company elected an IFRS 1 exemption whereby the previous GAAP full cost pool was measured upon transition to IFRS as follows:

(i) E&E assets consist of the Company's exploration projects which are pending the determination of technical feasibility and commercial viability. Under previous GAAP these costs were grouped with the full cost pool. Upon transition to IFRS, the Company reclassified unproved properties from the full cost pool under previous GAAP to E&E assets; and

(ii) the remaining full cost pool was allocated to producing and development assets and components on a pro rata basis to the underlying assets using proved reserve volumes as at January 1, 2010.

c) Asset retirement obligation

Since the Company has elected to apply the IFRS 1 full-cost as deemed cost exemption, asset retirement obligation must be measured as at January 1, 2010 in accordance with IAS 37. The difference between that amount and the carrying amount of those liabilities at the date of transition is recognized directly in deficit.

d) Share based compensation

IFRS 1 encourages, but does not require, first-time adopters to apply IFRS 2 *Share-based payments* to equity instruments that were granted on or before November 7, 2002, or equity instruments that were granted subsequent, to November 7, 2002 and vested before the later of the date of transition to IFRS and January 1, 2005. The Company has elected not to apply IFRS 2 to awards that vested prior to January 1, 2010.

IFRS 1 also outlines specific guidelines that a first-time adopter must adhere to under certain circumstances. The Company has applied the following guidelines to its opening balance sheet dated January 1, 2010:

e) Estimates

In accordance with IFRS 1, an entity's estimates under IFRS at the date of transition to IFRS must be consistent with estimates made for the same date under previous GAAP, unless there is objective evidence that those estimates were in error. The Company's IFRS estimates as at January 1, 2010 are consistent with its previous GAAP estimates for the same date.

Restatement of equity from previous GAAP to IFRS

IFRS employs a conceptual framework that is similar to previous GAAP. However, significant differences exist in certain matters of recognition, measurement and disclosure. While adoption of IFRS has not changed the Company's actual cash flows, it has resulted in changes to the Company's reported financial position and results of operations. In order to allow the users of the consolidated financial statements to better understand these changes, the Company's previous GAAP statement of comprehensive income (loss) and balance sheets for the year ended December 31, 2010 have been reconciled to IFRS, with the resulting differences explained.

Reconciliation of Equity at the date of IFRS transition – January 1, 2010

	Notes	Restated Canadian GAAP *(note h)*	Effect of transition to IFRS	IFRS
Assets				
Current assets				
Cash and cash equivalents		$ 51,396,052	$ -	$ 51,396,052
Marketable securities		204,336	-	204,336
Accounts receivable		4,509,203	-	4,509,203
Inventory		301,599	-	301,599
Deposits and prepaid expenses		619,990	-	619,990
		57,031,180	-	57,031,180
Property, plant and equipment	(a,b)	84,286,835	(42,141,486)	42,145,349
Exploration and evaluation assets	(b)	-	23,621,537	23,621,537
Goodwill		2,467,816	-	2,467,816
Deferred tax assets	(g)	1,486,533	5,693,811	7,180,344
		$ 145,272,364	$ (12,826,138)	$ 132,446,226
Liabilities and Equity				
Current liabilities				
Accounts payable and accrued liabilities		$ 10,530,509	$ -	$ 10,530,509
Asset retirement obligation	(e)	4,764,653	1,891,001	6,655,654
		15,295,162	1,891,001	17,186,163
Shareholders' Equity				
Share capital	(h)	184,962,957	-	184,962,957
Contributed surplus		11,218,598	-	11,218,598
Deficit	(a,e,g,h)	(66,204,353)	(14,717,139)	(80,921,492)
		129,977,202	(14,717,139)	115,260,063
		$ 145,272,364	$ (12,826,138)	$ 132,446,226

Reconciliation of Equity at the end of the last reporting year under previous GAAP – December 31, 2010

	Notes	Canadian GAAP	Effect of transition to IFRS	IFRS
Assets				
Current assets				
Cash and cash equivalents		$ 141,974,856	$ -	$ 141,974,856
Accounts receivable		7,894,381	-	7,894,381
Inventory		344,138	-	344,138
Deposits and prepaid expenses		507,124	-	507,124
		150,720,499	-	150,720,499
Property, plant and equipment	(a,b,c,d)	109,983,549	(61,734,142)	48,249,407
Exploration and evaluation assets	(b)	-	49,762,437	49,762,437
Goodwill		2,467,816	-	2,467,816
Deferred tax assets	(g)	5,784,127	3,564,705	9,348,832
		$ 268,955,991	$ (8,407,000)	$ 260,548,991
Liabilities and Equity				
Current liabilities				
Accounts payable and accrued liabilities		$ 14,643,521	$ -	$ 14,643,521
Asset retirement obligation	(e)	5,365,096	1,854,246	7,219,342
		20,008,617	1,854,246	21,862,863
Shareholders' Equity				
Share capital	(h)	311,652,770	-	311,652,770
Contributed surplus	(f)	19,208,740	(320,005)	18,888,735
Deficit	(a,c,d,e,f,g,h)	(81,914,136)	(9,941,241)	(91,855,377)
		248,947,374	(10,261,246)	238,686,128
		$ 268,955,991	$ (8,407,000)	$ 260,548,991

Reconciliation of Total Comprehensive Loss for the year ended December 31, 2010

	Notes	Canadian GAAP	Effect of transition to IFRS	IFRS
Revenue				
Petroleum and natural gas sales		$ 11,989,713	$ -	$ 11,989,713
Royalties		(1,556,071)	-	(1,556,071)
Petroleum and natural gas revenue, net of royalties		10,433,642	-	10,433,642
Expenses				
Operating		3,262,269	-	3,262,269
General and administrative		4,122,149	-	4,122,149
Gain on marketable securities		(321,524)	-	(321,524)
Gain on divestitures	(c)	-	(337,031)	(337,031)
Gain on extinguishment of liabilities related to Magnus entities		(1,130,345)	-	(1,130,345)
Bad debt expense		1,429,691	-	1,429,691
Depletion and depreciation	(d)	13,087,318	(7,334,172)	5,753,146
Impairment of assets	(a)	-	1,360,685	1,360,685
Accretion of asset retirement obligation	(e)	444,594	(274,481)	170,113
Share based compensation	(f)	9,544,015	(320,005)	9,224,010
		30,438,167	(6,905,004)	23,533,163
Interest income		1,509,498	-	1,509,498
Other income		192,500	-	192,500
Loss before taxes		(18,302,527)	6,905,004	(11,397,523)
Deferred taxes (recovery)	(g)	(2,592,744)	2,129,106	(463,638)
Total comprehensive loss for the period		$ (15,709,783)	$ 4,775,898	$ (10,933,885)

Notes to the Reconciliation of Equity and Total Comprehensive Loss from previous GAAP to IFRS

a) Impairment

Under previous GAAP, the Company applied a two part impairment test (the "ceiling test") to the net carrying amount, of oil and gas assets, whereby the first step compared the net carrying value of the asset to their relative recoverable amount. The recoverable amount is calculated as the undiscounted cash flow from the properties using proved reserves and expected future prices and costs. If the carrying amount of the properties exceeds their recoverable amount, then an impairment loss, equal to the amount by which the carrying amount of the properties exceeds the discounted cash flow from those properties using proved and probable reserves and expected future prices and costs, is recognized.

Under IFRS, the recoverable amounts have been determined based on the higher of VIU and FVLCTS at the level of CGUs. If the carrying amount of the asset exceeds its recoverable amount, the asset is impaired and an impairment loss is charged to net profit (loss) to reduce the carrying amount in the balance sheet to its recoverable amount.

With the adoption of IAS 36, the Company recorded impairments on its natural gas assets in Western Canada that were grouped into CGUs based on similar geological structure. Declining long-term natural gas prices resulted in the carrying amounts for these CGUs exceeding their recoverable amounts. The recoverable amount was calculated using a FVLCTS valuation based on a 25 year cash flow projection discounted at a rate of 10%. Discounted future cash flows were based on proved plus probable reserves using forecast prices and costs. As at January 1, 2010, the Company recorded an impairment of $18,519,949 which reduced property, plant and equipment with a corresponding charge to deficit. For the year ended December 31, 2010, additional impairment of natural gas assets of $1,360,685 was recorded in net profit (loss), with a corresponding decrease to property, plant and equipment.

For the purpose of impairment testing, goodwill is allocated to all the Company's CGUs and is tested at an operating segment level. The recoverable amount, based on the higher of VIU and the FVLCTS was determined to be higher than the carrying amount of all the CGUs and an impairment loss was not recorded as at January 1, 2010 and December 31, 2010.

b) Oil and gas properties

Under previous GAAP, the Company followed the full cost method of accounting for oil and gas properties whereby all costs of acquisition, exploration for and development of oil and gas reserves were capitalized at the cost-centre level. Under IFRS, pre-exploration costs are expensed as incurred. After the legal right to explore is acquired, exploration costs are capitalized as E&E assets. Once the exploration area achieves technical feasibility and commercial viability, E&E costs are moved to property, plant and equipment. Upon transition to IFRS, the Company reclassified $23,621,537 of property, plant and equipment to E&E assets.

As at December 31, 2010, the Company reclassified $49,762,437 of property, plant and equipment to E&E assets.

c) Divestitures

Under previous GAAP, proceeds from divestitures were deducted from the full cost pool without recognition of a gain or loss unless the deduction resulted in a change to the depletion rate of 20 percent or greater. Under IFRS, gains or losses are recorded on divestitures and calculated as the difference between the proceeds and the net book value of the asset disposed.

For the year ended December 31, 2010, the Company recognized a $337,031 gain on divestitures in net profit (loss).

d) Depletion

Upon transition to IFRS, the Company adopted a policy of depleting oil and natural gas interests on a unit of production basis over proved plus probable reserves. The depletion policy under previous GAAP was based on units of production over proved reserves. In addition depletion was calculated at a Canadian cost-centre level under previous GAAP. IFRS requires depletion and depreciation to be calculated based on individual components.

There was no impact of this difference on adoption of IFRS at January 1, 2010 as a result of the IFRS 1 election as discussed above.

For the year ended December 31, 2010 transition differences resulted in a decrease to depletion of $7,334,172 with a corresponding change to property, plant and equipment.

e) Asset retirement obligation

Under previous GAAP, asset retirement obligations were discounted at a credit adjusted risk fee rate of 7 and 12 percent. The estimated cash flow to abandon and remediate the wells and facilities was risk adjusted under previous GAAP; therefore, the obligation is discounted at a risk free rate under IFRS. The risk free rate is based on the government of Canada bonds rates based on the remaining life to abandon each well. At January 1, 2010, the Company used risk free rates that ranged from 1.45 to 4.10 percent. Upon transition to IFRS this resulted in a $1,891,001 increase in the asset retirement obligation with a corresponding increase in the deficit.

The following table provides a reconciliation of the Company's asset retirement obligation as at December 31, 2010:

		As reported December 31 2010		Adjustment upon transition to IFRS		IFRS December 31 2010
Balance, beginning of period	$	4,764,653	$	1,891,001	$	6,655,654
Revisions due to change in discount rate		-		273,903		273,903
Revisions due to change in estimates		45,206		(293,029)		(247,823)
Net liabilities incurred		117,305		256,852		374,157
Liabilities settled		(6,662)		-		(6,662)
Accretion		444,594		(274,481)		170,113
Balance, end of period	$	5,365,096	$	1,854,246	$	7,219,342

During 2010, there was downward movement in the risk free rate. The change in the liability is due to the decreased risk free rates, net liabilities incurred and revisions related to changes in estimates during the year. With the lower risk free rate accretion decreased by $274,481 for the year ended December 31, 2010.

f) Share based compensation

Under previous GAAP, the Company's equity-settled share based payments were measured at their fair value at the grant date. This amount was expensed to stock based compensation on the income statement over the vesting period using graded vesting. Forfeitures were accounted for as they occurred. Under IFRS, an estimate of forfeitures must be factored into the calculation of the expense at the grant date and any difference between the estimates and actuals is recognized in the period when actual forfeitures are incurred.

The effect on net profit (loss) for the year ended December 31, 2010 is to reduce share based compensation expense by $320,005 with a corresponding decrease to contributed surplus.

g) Deferred taxes

Nearly all the previous GAAP to IFRS differences have an impact on deferred taxes as the adjustments change the accounting balance and the amount of the temporary or permanent differences. The tax impact of the above changes increased the deferred tax assets as follows:

	Note		As at January 1 2010		As at December 31 2010
Property, plant and equipment	(a,c,d)	$	5,266,821	$	3,093,018
Asset retirement obligation	(e)		426,990		471,687
Balance, end of period		$	5,693,811	$	3,564,705

The impact of these changes increased the deferred tax asset by $5,693,811 as at January 1, 2010 and $3,564,705 as at December 31, 2010 under IFRS.

For the year ended December 31, 2010, the Company decreased the deferred tax recovery by $2,129,106, which resulted in a deferred tax recovery of $463,638 which was recorded in net profit (loss).

h) Restatement of previous GAAP

Questerre acquired Terrenex Ltd. and its wholly owned foreign subsidiary Cabernet Holdings Ltd. ("Cabernet") on April 28, 2008. The only significant asset Cabernet owned was Questerre common shares. On July 22, 2009, Cabernet was dissolved and a taxable event was deemed to have occurred. The result was presented on the September 30, 2009 financial statements as a $1,256,314 increase to the future tax asset on the balance sheet. The offset was initially recorded to the future tax recovery line on the statements of operations and as a result the deficit line on the balance sheet. Upon subsequent review, since the recovery related to an equity item it should have been booked to common shares in the shareholders' equity section.

The previous GAAP consolidated statements of operations, comprehensive loss and deficit have been amended and restated as follows:

		Year ended December 31 2009		Adjustment		Restated Year ended December 31 2009
Future tax recovery	$	(4,192,378)	$	1,256,314	$	(2,936,064)
Net loss and comprehensive loss	$	(13,722,888)	$	(1,256,314)	$	(14,979,202)
Net loss per share						
Basic and diluted	$	(0.07)			$	(0.08)

The previous GAAP consolidated balance sheets have been amended and restated as follows:

		Year ended December 31 2009		Adjustment		Restated Year ended December 31 2009
Common shares	$	183,706,643	$	1,256,314	$	184,962,957
Deficit	$	(64,948,039)	$	(1,256,314)	$	(66,204,353)

Adjustments to the statements of cash flows

The adoption of IFRS did not have a significant impact on the amounts reported as the operating, investing and financing cash flows in the consolidated statements of cash flows.

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