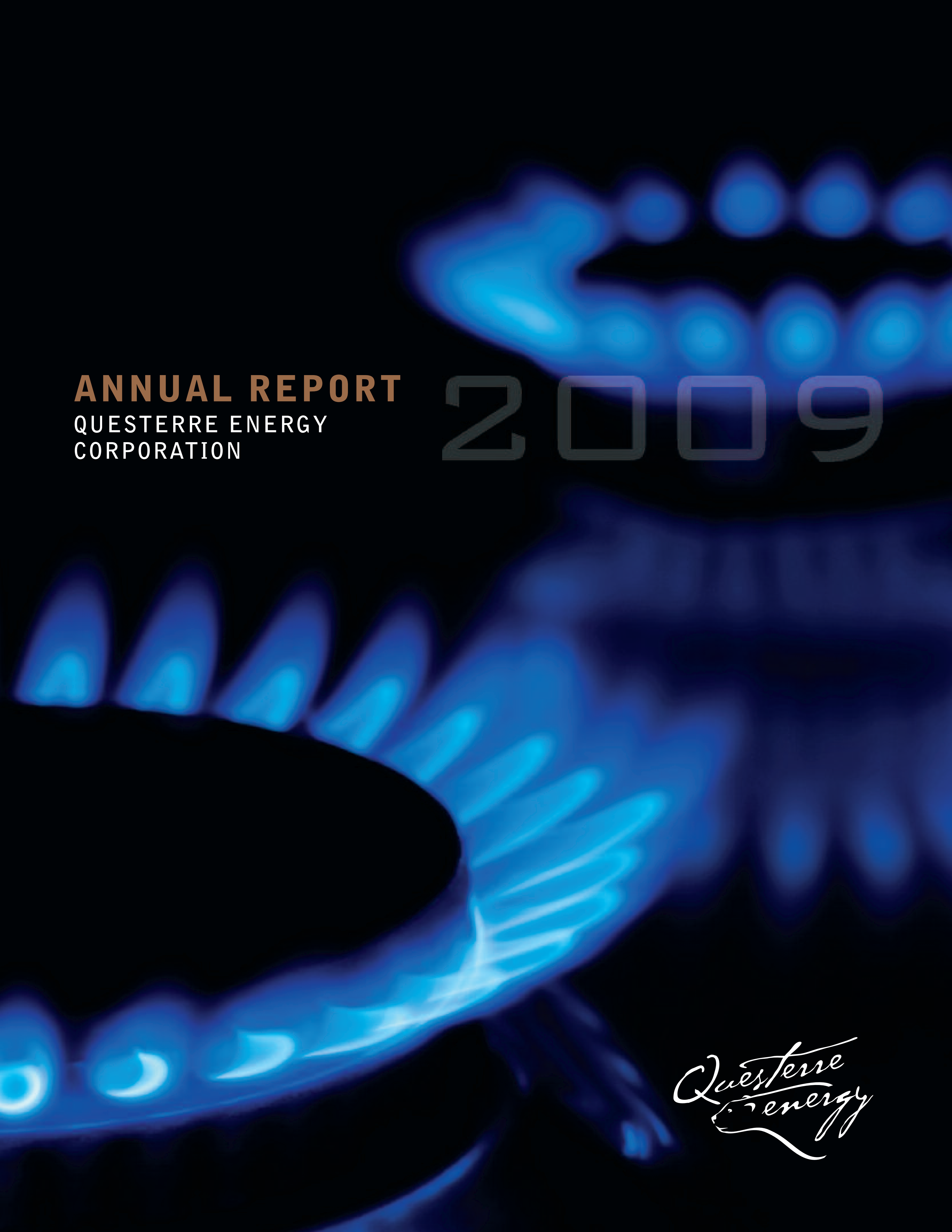


ANNUAL REPORT 2009

QUESTERRE ENERGY CORPORATION

Questerre Energy Corporation is an independent energy company focused on shale gas in North America. The company is concentrated on establishing commerciality of its Utica shale gas discovery in the St. Lawrence Lowlands, Québec.

Questerre's common shares trade on the Toronto Stock Exchange and Oslo Stock Exchange under the symbol QEC.

Completion operations on St. Edouard No. 1A horizontal well

President's Message

We had another remarkable year.

Our first horizontal well in the middle Utica exceeded our expectations. It validated the technical work over the last two years and brought us closer to commercializing our giant Utica shale gas discovery in the St. Lawrence Lowlands, Québec.

Shale gas has created a new paradigm in the North American and global energy markets. It represents an abundant, clean, efficient and secure energy source. We believe it will ultimately be the bridge to alternative energy in the future. Through our discovery in Québec, we are participating in this historic change.

We preserved our balance sheet strength in 2009 with limited investment in our conventional assets. This ensured we were fully funded for our appraisal program in Québec. We completed an equity issue in early 2010 to further strengthen our financial position as we move into commercializing this significant discovery.

Highlights

- Consistent repeatable results from Utica pilot vertical well program in the St. Lawrence Lowlands, Québec
- Independent resource assessment of Utica shale estimates potential recoverable resource at 4.36 Tcf to Questerre's net working interest
- Horizontal well program underway in Lowlands to assess commerciality; first well tests at approximately 6 MMcf/d
- Evaluated new drilling and completion techniques in Antler, Saskatchewan with encouraging results
- Minimal capital investment and higher oil weighting generated cash flow of $2.88 million with average daily production of 810 boe/d
- Maintained financial strength with over $46 million in positive working capital and no debt

St. Lawrence Lowlands, Québec

The vertical test well program completed in 2009 was critical to the success of St. Edouard No. 1A, the first full-length horizontal well.

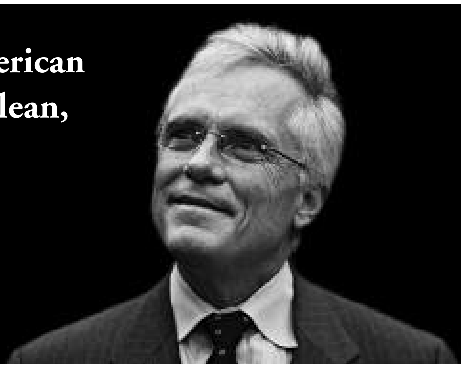
This program identified the target middle Utica interval and demonstrated that it can be consistently and effectively fracture stimulated over a large area. It also provides a base of technical data from which we can work to further optimize results.

We utilized this modern data along with data from other wells in the basin to quantify the scale of the resource. An independent assessment attributed a best estimate of prospective recoverable resources, net to our interest, at 4.36 Tcf. This implies a 10% recovery factor based on comparison to the counties outside the core in the Barnett shale. We expect the actual average recovery rate will prove to be higher over time with actual results.

Our assertion about recoveries is based in part on the micro-seismic data from the St. Edouard No. 1A horizontal well completion. Early indications are we were successful in stimulating the entire Utica interval. The well is currently on a long-term production test with results continuing in line with expectation. Consistent with the overpressuring and significant natural fracturing encountered by this well, the initial production data may point to a Haynesville shale type curve. The type curve generated from this well and others in the pilot program, as compared to proxies from other shale plays, will be a meaningful indicator of the ultimate recovery of this resource.

We are currently reviewing both the completion program for the second horizontal well, Gentilly No. 2, and the drilling program for the next well. These operations should begin after spring break-up. Subject to results, we plan to participate in a minimum of 2-3 more horizontals this year. Additional activities in the planning stages are added wells, a 3-D seismic survey over proposed pilot pad locations and a pipeline to tie-in the St. Edouard location to the gathering system.

Shale gas has created a new paradigm in the North American and global energy markets. It represents an abundant clean, efficient and secure energy source. We believe it will ultimately be the bridge to alternative energy in the future. Through our discovery in Québec, we are participating in this historic change.



The pace and scope of this appraisal program and early commercial development will be dependent on our partners. We are very pleased by the results to date and are confident they are too. With strategic commitments to developing their unconventional gas resources, we anticipate that our continued success will favorably position the Utica among their other projects.

Variability in well results is inherent in shale gas and we expect individual wells in this pilot program could surprise to the positive and negative. Of interest, production data from the Barnett, one of the more developed plays, still demonstrates substantial variability in results with initial rates ranging from under 100 Mcf/d to over 6 MMcf/d. Due to the statistical nature of these plays, the average rate from the entire program remains our focus. St. Edouard No. 1A horizontal was a spectacular result. It leads us to believe that we could achieve and possibly exceed our benchmark of 1.5 MMcf/d to 2.5 MMcf/d for an initial stabilized rate. This leaves us room to further improve rates with optimization of completion techniques and longer reach horizontals with greater frac stages.

While progress was made on the technical learning curves, we are beginning to work our way up other learning curves to set the stage for development. We helped form a new industry organization, the Québec Oil & Gas Association, to achieve these objectives.

One of the primary objectives for the Association has been to work collaboratively with government. We are very encouraged by the commitment from the provincial government to partner with industry in developing this strategic resource for the province.

A stable fiscal regime and single window approach will provide the incentive and regulatory framework necessary for industry to invest in commercialization and development. We are hopeful this new legislation will be presented at the National Assembly later this year and approved by year-end.

Open and consistent communication with the local municipalities and their constituents is equally important as is their participation in development.

In a province with abundant hydroelectricity, we see natural gas as a clean and efficient alternative for heating and industrial demand. Our operations are conducted to rigorous environmental standards and, as an industry, our aim is to meet and exceed these requirements. We must communicate these facts and address any misconceptions about shale gas development and its impact on the environment. We must also ensure that these parties benefit economically from this development.

Northeast British Columbia

The learning curve for the Liard shale at Beaver River proved more demanding.

Amid production shut-ins for unusually cold weather, plant turnarounds and operational issues, we continued testing of the A-5 shale gas well during the year. The production data indicates minimal contribution from the shale and more work is necessary to develop a predictive model.

This would involve gathering and analyzing additional data including core and logs to validate thermal maturity and mechanical rock properties as well as identifying prospective intervals for fracture stimulation. We are optimistic that a joint venture with a more experienced partner will help us move up the learning curve and realize the potential of this asset.

The variability in well results at Beaver River, ranging from 10 MMcf/d to under 100 Mcf/d, underscores the importance of the learning curve in developing shale plays. Without the rigor, it is virtually impossible to consistently repeat the successful wells and avoid the unsuccessful ones.

Our recently acquired acreage in the Horn River area of northeast BC will also benefit from this approach of methodical technical work and leveraging partner expertise. The 17.5 net sections of land offsets the main Horn River shale fairway to the southeast and lies north of the Sierra and Yoyo natural gas fields. Prospective reef anomalies in the Pine Point and Keg River have been identified on this acreage, as well as locations to assess the Horn River shale.

The announcement last year that the Kitimat LNG terminal, originally an import terminal four years ago, is being developed as an export terminal for Asian markets is encouraging for northeast BC. It accentuates the global impact of unconventional natural gas in North America. It could possibly strengthen realized prices for this region that have been traditionally challenged by higher transportation fees.

Antler, Saskatchewan

Low crude oil prices in early 2009 and a focus on capital preservation led us to defer our drilling program at Antler, Saskatchewan.

We evaluated existing wells and made changes to both our drilling and completion techniques, as well as production practices. New techniques, including a monobore design with tubing conveyed fracs, showed promising results. We also electrified the majority of our wells to reduce fuel and generator expenses and expanded our water disposal facilities to minimize third party costs.

Light oil in Saskatchewan remained in the financial markets' spotlight with sustained corporate activity. Over $6.5 billion in mergers and acquisitions were announced in 2009 with an estimated $1.9 billion in equity capital raised for companies in this area over the last year. This activity, coupled with our ongoing work, bodes well to realize the full value of these assets in the future.

Operational and Financial

Our results reflect the limited investment in development drilling and, to a lesser extent, production shut-ins in British Columbia.

Production averaged 810 boe/d and we reported positive cash flow from operations of $2.88 million. Our oil weighting increased to approximately one half from one third in 2008. This helped mitigate the growing disparity between commodity prices as natural gas traded at approximately a 60% discount to oil on a boe basis in 2009.

Capital investment totaled just under $12 million with over half spent on the Utica shale appraisal in the Lowlands. The remainder was principally incurred in Antler developing our oil pool and acquiring land in northeast BC prospective for the Horn River shale.

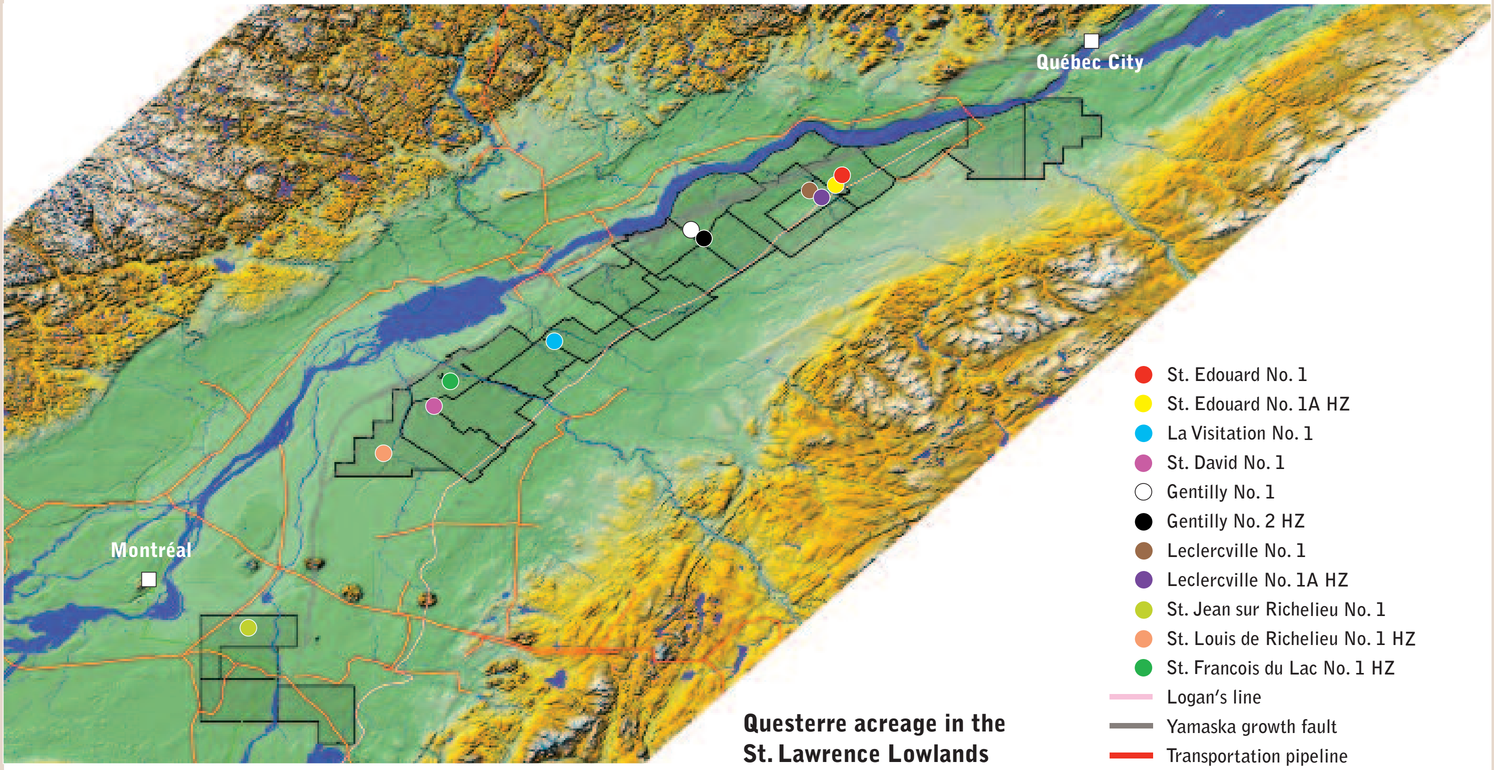
Outlook

Following the excellent results from St. Edouard No. 1A, we look forward to the expansion of the pilot program this year. Additional horizontal wells will contribute to a statistically meaningful data set and establish the commercial parameters of this emerging play. We strengthened our balance sheet in the first quarter of 2010 and are well positioned to participate in this program and early field development.

Positive well results are a pre-requisite to commercial development. Equally important is a concerted commitment and the active participation of all stakeholders – public, government, service sector and industry. We are confident that with the support of these partners, we will be able to develop this multi-Tcf resource for the benefit of our shareholders and the province of Québec.

Michael Binnion
President and Chief Executive Officer

Areas of Operations



Questerre acreage in the St. Lawrence Lowlands

St. Lawrence Lowlands, Québec

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

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 the discovery in 2008, the appraisal of the Utica shale remained the focus for Questerre.

A joint vertical test well program with its partner Talisman Energy was completed during the year. Targeting the Utica, this included the drilling and completion of St. Edouard No. 1 and the completion and testing of two wells drilled in 2008 — La Visitation No. 1 and St. David No. 1.

The drilling and completion of St. Edouard No. 1, the fourth and final well in the program, marked the end of the earn-in program by Talisman. Talisman currently holds a 75% working interest in approximately 720,000 joint acres. Questerre holds an approximate 25% working interest in this acreage and also retains a 4¼% gross overriding royalty on production from Talisman.

The stabilized initial rates from these wells ranged between 300 Mcf/d and 700 Mcf/d. Production logging indicates the majority of the flow is attributable to an interval within the middle Utica. These rates are in line with the middle Utica flow rates of over 800 Mcf/d from Gentilly No. 1, the first well in the program, and 900 Mcf/d from Leclercville No. 1, drilled offsetting the joint acreage.

Gentilly No. 2 horizontal well drilling operations

Consistent results over a large geographic area provided the momentum to begin a pilot horizontal well program for the middle Utica to assess commerciality. Two horizontal wells were spud in the second half of 2009. The wells were situated next to existing verticals for micro-seismic monitoring of frac effectiveness. The first, St. Edouard No. 1A, was successfully drilled and the horizontal leg was completed with eight stage fracture stimulations in early 2010. Initial flow rates were over 12 MMcf/d with an average stabilized rate of approximately 6 MMcf/d. The well is currently on a long-term test. Drilling operations on the second horizontal well, Gentilly No. 2, were completed in early 2010 and the well will be fracture stimulated later this year.

Subject to results and partner participation, Questerre anticipates this pilot program could be expanded to include several other horizontal wells, a 3-D seismic survey and a pipeline tie-in to the local distribution system.

The evaluation of the Utica included the testing of other prospective intervals within this horizon. Targeting the upper Utica, Questerre's partner, Forest Oil, completed the testing of two prototype horizontal wells on the Yamaska permits earlier in the year. Stabilized rates of between 100 Mcf/d and 800 Mcf/d were achieved with initial rates of up to 4 MMcf/d. These results reflect in part the slower than expected cleanup of the frac fluid. The companies have developed alternative completion programs to address this issue and Questerre anticipates Forest will conduct this additional work in the future. In the interim, Forest plans to acquire 2-D seismic this year in advance of further drilling on these permits.

Questerre completed the St. Jean sur Richelieu No. 1 well to evaluate the shallower Utica shale south of the main fairway on the St. Jean permits. Fracture stimulation yielded sustained gas flows at limited rates with frac efficiency less than expected. Work is ongoing to determine if gas fracturing can improve frac effectiveness and commerciality. The Company believes this acreage could be developed with vertical wells and multiple small fracs similar to other shallow tight gas projects.

In addition to the Utica, Questerre and Talisman also tested two other zones of interest in the Lowlands.

Successful fracs were completed in the shallower Lorraine shale in La Visitation No. 1 and Gentilly No. 1. Sustained gas flows resulted at rates of approximately 100 Mcf/d. Results were affected by flow-back of the proppant and frac fluid. Further work, including fluid compatibility studies, is necessary to improve the effectiveness of the stimulation.

Testing of the Trenton Black-River in St. Edouard No. 1 resulted in a final gas rate of approximately 2 MMcf/d over a three day test with no formation water. Pressure data indicates that the estimated reserves would be insufficient to support tie-in costs and the interval was suspended. With the focus on the Utica, further exploration for this zone has been deferred in the near term.

Northeast British Columbia

Greater Sierra

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, Pine Point formations as well as the Horn River shale.

Through a farm-in agreement with EnCana, Questerre established a new core area in the Greater Sierra region of northeast British Columbia early in 2008. With lower than expected natural gas prices during the year, a planned Jean Marie drilling program with EnCana was deferred.

Questerre acquired an additional 14,680 (11,680 net) acres south of its acreage with EnCana at a Crown land sale in 2009. The land is prospective for the primary Jean Marie formation in addition to the deeper Horn River shales and the Pine Point carbonates. Locations have been identified to test the deeper carbonate anomalies and assess the shale intervals.

Questerre plans to work with an industry partner to pursue these locations and develop this acreage.

Beaver River Field

The Beaver River Field is located approximately 160 km northwest of Fort Nelson, on the border of British Columbia and the Yukon. Production from the field benefits from extensive infrastructure including processing facilities, a local gathering system and a tie-in to the Spectra Energy pipeline. Questerre currently holds a 50% interest in over 23,000 acres in this area.

There are multiple zones of interest including three interbedded shale, siltstone and sandstone intervals known as the Mattson, Besa River and Golata at a depth of 1300 metres – 3300 metres and the Nahanni, a hydrothermally dolomitized carbonate sequence at a depth of approximately 3300 metres.

Testing of the shale at Beaver River in 2009 was setback with extended production shut-ins due to low natural gas prices, plant turnarounds, unusually cold weather and operational challenges.

The A-5 well, recompleted in late 2008, targeted a brittle dolomite interval above an organic rich shale sequence. The well tested at an initial gross rate of 10 MMcf/d and was on production intermittently during the year, most recently at the beginning of the fourth quarter of 2009 with initial gross rates of over 2 MMcf/d. Results to date indicate minimal contribution from the deeper shale and additional work will be required.

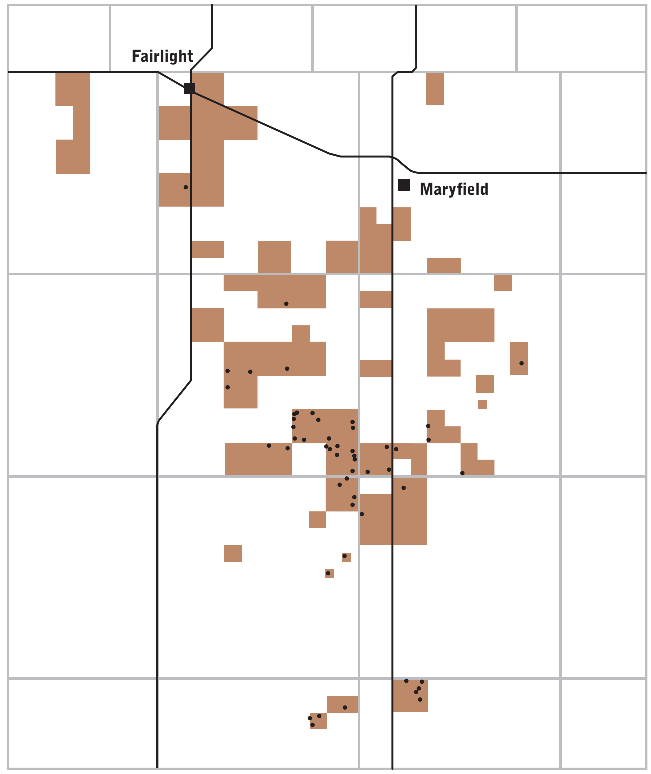
Questerre continues to explore for joint venture opportunities to further assess the shale horizons at Beaver River.

Antler, Saskatchewan

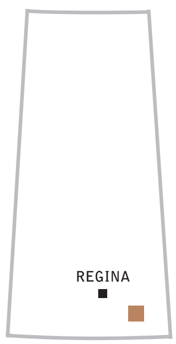
The Antler area is approximately 200 km from Regina in southeast Saskatchewan. The primary target is light oil from the Bakken/Torquay formation, a dolomitic siltstone shale sequence at a depth of between 1050 metres and 1150 metres.

Following a multi-well horizontal pilot program in 2008, a detailed review of the existing wells and drilling and completion practices was conducted this year to improve recovery of the oil in place. Modified completion techniques were tested to confine the fracture stimulation within the target Bakken/Torquay interval and minimize water production from adjacent intervals. The Company also evaluated tubing conveyed fracture stimulation as an alternative to the Packers Plus system. Preliminary results are positive and Questerre plans to implement these in its current drilling program.

The development plans for 2010 include a proposed drilling program and a 3-D seismic survey to build its inventory of locations. Early work also continues on a pilot water flood scheme to enhance recovery.



Landholdings in Antler, Saskatchewan



Vulcan, 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.

Delayed regulatory approval for a minor compressor upgrade in Vulcan, hindered production optimization from the Mannville I Pool. This in turn has set back plans for a proposed infill well into this oil pool. Subject to the timing of approvals, Questerre anticipates this well could be drilled towards the end of this year.

In the current fiscal and regulatory environment, Questerre does not anticipate conducting any other drilling in Alberta in 2010.

Environmental Stewardship

Questerre is committed to the economic development of our resources in an environmentally conscious and socially responsible manner.

Local participation and involvement is vital to the success of our projects.

We are investigating innovative solutions to efficiently manage water resources. We believe in a prudent approach to the sourcing, use and disposal of water for drilling and completion operations in compliance with strict environmental regulations. Wherever possible, we plan to recycle and reuse water. Where produced water cannot be recycled, we plan to dispose it responsibly.

Our surface rights are shared with stakeholders including the landowners and the government. We aim to leverage improvements in technology to manage our surface footprint. Horizontal drilling and multi-well pads will keep disturbance to a minimum. Commercial development will utilize central facilities for drilling, completion and production operations to further mitigate surface issues.

Our focus is on cleaner burning natural gas. 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.

Minimizing the environmental footprint
St. David No. 1 location

Drilling operations

Completion operations

Post cleanup

Management's Discussion and Analysis of Financial Condition and Results of Operations

The following Management's Discussion and Analysis of Financial Condition and Results of Operations ("MD&A") was prepared as of March 25, 2010. This MD&A is provided by Management of Questerre Energy Corporation ("Questerre" or the "Company") to review 2009 activities and results as compared to the previous year. This MD&A should be read in conjunction with the audited consolidated financial statements for the years ended December 31, 2009 and 2008. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). All amounts are in Canadian dollars unless otherwise noted. Additional information relating to Questerre, including Questerre's Annual Information Form is available on SEDAR at www.sedar.com.

Questerre is an independent energy company focused on shale gas in North America. The Company is concentrated on establishing commerciality of its Utica shale gas discovery in the St. Lawrence Lowlands, Québec. The Company also continues to develop a portfolio of conventional assets in Western Canada.

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

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 the Company 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 and other assumptions contained in this MD&A and the documents incorporated by reference herein.

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-GAAP Terms

This document contains the terms "cash flow from operations" and "netbacks" which are non-GAAP 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 Canadian GAAP. 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 future capital investment. It is also used by research analysts to value and compare oil and gas companies.

Cash Flow from Operations Reconciliation

	2009	2008
Cash flows from operating activities	**$ (26,529)**	$ 23,466,056
Net change in non-cash working capital	**2,905,105**	(6,176,758)
Cash flow from operations	**$ 2,878,576**	$ 17,289,298

The Company considers netbacks a key measure as it demonstrates its profitability relative to current commodity prices and its ability to generate cash flow to fund future growth through capital investment and repay any debt outstanding. Operating netbacks per boe equal total petroleum and natural gas revenue per boe adjusted for royalties per boe and operating expenses per boe. Cash netbacks per boe are calculated as operating netbacks less general and administrative expenses per boe. Operating and cash netbacks are a useful measure to compare the Company's operations with those of its peers.

Select Annual Information

As at/for the years ended December 31	**2009**	2008	2007
Financial ($, except common shares outstanding)			
Petroleum and Natural Gas Revenue	**12,933,267**	29,805,568	23,785,489
Cash Flow from Operations	**2,878,576**	17,289,298	10,229,020
Per share – Basic	**0.01**	0.09	0.07
Per share – Diluted	**0.01**	0.09	0.06
Net Loss	**(13,722,888)**	(9,212,614)	(1,281,674)
Per share – Basic	**(0.07)**	(0.05)	(0.01)
Per share – Diluted	**(0.07)**	(0.05)	(0.01)
Capital Expenditures, net of acquisitions and dispositions	**11,989,541**	42,490,941	15,462,461
Working Capital Surplus	**46,500,671**	54,307,989	10,007,846
Total Assets	**145,272,364**	165,531,133	93,074,767
Shareholders' Equity	**129,977,202**	137,189,444	71,627,841
Common Shares Outstanding	**199,722,143**	197,299,642	168,930,470
Weighted average – basic	**197,940,390**	186,447,776	157,078,211
Weighted average – diluted	**206,729,689**	196,593,333	163,260,612

Operations (units as noted)			
Average Production			
Crude Oil and Natural Gas Liquids (bbl/d)	**378**	385	176
Natural Gas (Mcf/d)	**2,591**	4,761	7,282
Total (boe/d)	**810**	1,178	1,390
Average Sales Price			
Crude Oil and Natural Gas Liquids ($/bbl)	**63.88**	99.42	71.42
Natural Gas ($/Mcf)	**4.34**	8.99	7.17
Total ($/boe)	**43.75**	69.13	46.88
Netback ($/boe)			
Petroleum and Natural Gas Revenue	**43.75**	69.13	46.88
Royalties Expense	**(3.32)**	(11.55)	(11.06)
Percentage	**8%**	17%	24%
Operating Expense	**(13.86)**	(14.05)	(12.07)
Operating Netback	**26.57**	43.53	23.75
General and Administrative Expense	**(15.94)**	(6.72)	(5.44)
Cash Netback	**10.63**	36.81	18.31
Wells Drilled			
Gross	**4.00**	19.00	17.00
Net	**1.71**	12.10	10.30

Highlights

- Consistent repeatable results from Utica pilot vertical well program in the St. Lawrence Lowlands, Québec
- Independent resource assessment of Utica shale estimates potential recoverable resource at 4.36 Tcf to Questerre's net working interest
- Horizontal well program underway in Lowlands to assess commerciality; first well tests at approximately 6 MMcf/d
- Evaluated new drilling and completion techniques in Antler, Saskatchewan with encouraging results
- Minimal capital investment and higher oil weighting generated cash flow of $2.88 million with average daily production of 810 boe/d
- Maintained financial strength with over $46 million in positive working capital and no debt

2009 Activities

St. Lawrence Lowlands, Québec

The appraisal of the Utica shale potential remained the focus for the Company in the St. Lawrence Lowlands.

During the year, Questerre finalized a joint vertical test well program with its partner, Talisman Energy Canada Inc. ("Talisman"). Targeting the Utica, this included the drilling and completion of St. Edouard No. 1 and the completion and testing of two wells drilled in 2008 – La Visitation No. 1 and St. David No. 1.

The drilling and completion of St. Edouard No. 1, the fourth and final well in the program, marked the end of the earn-in program by Talisman. Talisman currently holds a 75% working interest in approximately 720,000 joint acres. Questerre holds an approximate 25% working interest in this acreage and also retains a 4¼% gross overriding royalty on production from Talisman.

The stabilized initial rates from these wells ranged between 300 Mcf/d and 700 Mcf/d. Production logging indicates the majority of the flow is attributable to an interval within the middle Utica. These rates are in line with the middle Utica flow rates of over 800 Mcf/d from Gentilly No. 1, the first well in the program, and 900 Mcf/d from Leclercville No. 1, drilled offsetting the joint acreage.

Consistent results over a large geographic area provided the momentum to begin a pilot horizontal well program for the middle Utica to assess commerciality. Two horizontal wells were spud in the second half of 2009. The wells were located next to existing verticals for micro-seismic monitoring of frac effectiveness. The first, St. Edouard No. 1A, was successfully drilled and the horizontal leg was completed with eight stage fracture stimulations in early 2010. Initial flow rates were over 12 MMcf/d with an average stabilized rate of approximately 6 MMcf/d. The well is currently on a long-term test. Drilling operations on the second horizontal well, Gentilly No. 2, were completed in 2010 and the well will be fracture stimulated later this year.

Subject to results and partner participation, Questerre anticipates this pilot program could be expanded to include several other horizontal wells, a 3-D seismic survey and a pipeline tie-in to the local distribution system.

The evaluation of the Utica included the testing of other prospective intervals within this horizon. Targeting the upper Utica interval, Questerre's partner, Forest Oil Corporation ("Forest"), completed the testing of two prototype horizontal wells on the Yamaska permits earlier in the year. Stabilized rates of between 100 Mcf/d and 800 Mcf/d were achieved and reflect the slower than expected cleanup of the frac fluid. While the companies have identified alternative completion programs to address this issue, Questerre anticipates Forest will conduct this additional work in the future. In the interim, Forest plans to acquire 2-D seismic this year in advance of further drilling on these permits.

In early 2009, Questerre completed the St. Jean sur Richelieu No. 1 well to evaluate the shallower Utica shale south of the main fairway. Fracture stimulation yielded sustained gas flows at limited rates with frac efficiency less than expected. Additional work is ongoing to determine if gas fracturing can improve frac effectiveness and commerciality. The Company believes this acreage could be developed with vertical wells and multiple small fracs similar to other shallow tight gas projects.

The Company commissioned Netherland, Sewell & Associates, Inc., an independent reservoir engineering firm, to assess the Utica's potential. Utilizing the extensive technical data from the test wells, the report estimates prospective gas in place for the Utica shale in the deep fairway at 158 Bcf per square mile. Using a range of recovery factors based on more established shale plays, the report estimates prospective resources recoverable for Questerre's interest to range between 1.33 Tcf and 13.78 Tcf with a best estimate of 4.36 Tcf.

In addition to the Utica, Questerre and Talisman also tested two other zones of interest in the Lowlands.

Successful fracs were completed in the shallower Lorraine shale in La Visitation No. 1 and Gentilly No. 1. Sustained gas flows resulted at rates of approximately 100 Mcf/d. Results were affected by flow-back of the proppant and frac fluid. Further work, including fluid compatibility studies, is necessary to improve the effectiveness of the stimulation.

Testing of the deeper Trenton Black-River carbonate in the St. Edouard No. 1 well resulted in a final gas rate of approximately 2 MMcf/d over a three day test with no formation water. Pressure data indicates that the estimated reserves would be insufficient to support tie-in costs and the interval was suspended. With the focus on the Utica, further exploration for this zone has been deferred in the near term.

Northeast British Columbia

<u>Beaver River Field</u>

Testing of the Liard shale at Beaver River was setback with extended production shut-ins due to low natural gas prices, plant turnarounds, unusually cold weather and operational challenges.

The A-5 well, recompleted in late 2008, targeted a brittle dolomite interval above an organic rich shale sequence. The well tested at an initial gross rate of 10 MMcf/d and has been on production intermittently during the year most recently at the beginning of the fourth quarter with initial gross rates of over 2 MMcf/d. Results to date indicate minimal contribution from the deeper shale and further work will be required.

Testing during the winter was hampered by unexpected drilling mud from previous operations produced concurrently with the natural gas. This damaged surface facilities and required substantial rehabilitation and modification. Production was shut-in in the second quarter for a turnaround of the main processing plant. This was subsequently extended during a period of low natural gas prices. In the fourth quarter, unseasonably cold weather subsequently froze up facilities and shut-in production from this well.

Questerre continues to explore for joint venture opportunities to further assess and develop the Liard shale.

<u>Greater Sierra</u>

A planned drilling program with its partner, EnCana Corporation ("EnCana") was deferred with lower than expected natural gas prices in the year.

Through participation in a Crown land sale, Questerre acquired an additional 14,680 (11,680 net) acres south of its acreage with EnCana. The land is prospective for the primary Jean Marie formation in addition to the deeper Horn River shales and the Pine Point carbonates. Locations have been identified to test the deeper carbonate anomalies and assess the shale intervals. Questerre plans to work with an industry partner to pursue these locations and develop this acreage.

Antler, Saskatchewan

Low crude oil prices in the first quarter also impacted drilling in Antler with the suspension of a planned 20-well program.

A detailed review of the existing wells and drilling and completion practices was conducted during the year to improve recovery of the oil in place. Modified completion techniques were tested to confine the fracture stimulation within the target Bakken/Torquay interval and minimize water production from adjacent intervals. The Company also evaluated tubing conveyed fracture stimulation as an alternative to the Packers Plus system. Preliminary results are positive and Questerre plans to implement these in its current drilling program.

Field work in 2009 also focused on improving operating efficiencies with the installation of a pipeline to tie-in wells to the central battery facility and the electrification of the existing wells.

Southern Alberta

Minimal activity was conducted in Alberta in the current fiscal and regulatory environment.

Delayed regulatory approval for a minor compressor upgrade in Vulcan, Southern Alberta hindered production optimization from the Mannville I Pool. This in turn has setback plans for a proposed infill well into this oil pool. Subject to the timing of approvals, Questerre anticipates this well could be drilled towards the end of 2010.

Drilling Activities

In 2009, Questerre participated in the drilling of four (1.71 net) wells, comprising of one (1.00 net) oil well in Antler and three (0.71 net) natural gas wells in Québec. In 2008, Questerre participated in the drilling of 19 (12.10 net) wells, comprising of 15 (10.00 net) oil wells and four (2.10 net) natural gas wells.

Production

Production volumes in 2009 reflect the focus on capital preservation with minimal investment by the Company in development drilling. Daily production averaged 810 boe/d during the year with oil and liquids representing 47% of total volumes. By comparison, in 2008, Questerre reported daily production of 1,178 boe/d with oil and liquids accounting for 33% of total volumes.

Lower natural gas production from Alberta and BC coupled with the completion of several oil wells in Antler, southeast Saskatchewan contributed to the improved oil weighting during the year. Light oil from Antler accounted for 73% of the oil and liquids volumes during the year (2008: 64%) with light oil and liquids from Vulcan, Southern Alberta making up the difference. Notwithstanding this increased production in Antler, total oil and liquids volumes decreased marginally to 378 bbl/d from 385 bbl/d in 2008 as a result of lower production in Vulcan.

Questerre's assets in Alberta remained the largest contributor to corporate production, adding 365 boe/d or 45% of total volumes down from 645 boe/d and 55% in the prior year. Unchanged from prior periods, Vulcan was the majority of these volumes at 312 boe/d or 85% during the year (2008: 476 boe/d and 74%). The decrease from the prior year mirrors the natural production profile of the Company's Mannville pools in Vulcan. Production from minor properties of 53 boe/d (2008: 169 boe/d) excludes assets acquired through the purchase of Stride Energy, a private E&P company, in 2006. These assets added approximately 120 boe/d in 2008 before being sold. Other than a proposed infill location at Vulcan, Questerre has no plans for additional drilling in Alberta in 2010.

Extended production shut-ins at the Beaver River Field significantly lowered volumes from British Columbia. Production averaged 170 boe/d (2008: 286 boe/d) or 21% of total volumes (2008: 24%). Production from Beaver River for the year of 130 boe/d (2008: 197 boe/d) was largely from the testing of the A-5 shale gas well which was hampered by operational challenges, cold weather and plant turnarounds. The higher flowing pressure of this well backed out production from the other two wells, A-2 and A-7, which accounted for the majority of production in the prior year. Questerre's interest in two gas wells at Greater Sierra, BC, was responsible for the other 40 boe/d (2008: 89 boe/d) of production from the province.

Light oil from Antler, Saskatchewan added the remaining 275 boe/d (2008: 247 boe/d). A deferred winter drilling program and reduced field activity during the year translated into minor production gains. Preliminary results from new drilling and completion approaches are positive and Questerre plans to implement these in a planned program in 2010.

Questerre anticipates its production in 2010 will continue to reflect prudent capital investment in the current financial market. Capital will be directed to establishing commerciality of the Utica shale in Québec and maximizing the value of its assets in Antler. In Antler, this will include the continued assessment of new completion ideas and early work for a water flood to improve recovery. Based on the timing of additional drilling in Antler, Questerre expects production to average between 400-600 boe/d.

2009 Financial Results

Revenue

Petroleum and natural gas revenue for the fiscal year declined to $12.93 million from $29.81 million in 2008. Materially higher production volumes and commodity prices in 2008 were responsible for the higher revenue compared to the current year. Total production volumes were 31% lower in 2009 with oil and natural gas prices lower by 36% and 52% respectively.

Crude oil prices recovered during the year on the expectation of a global economic recovery and as a financial hedge against the value of the US dollar and inflation. This was in spite of inventory levels above their five-year averages that illustrated weaker demand growth and potential oversupply largely by OPEC. Canadian crude prices experienced a similar increase as the appreciation of the Canadian dollar offset a decrease in the differential between the Canadian and US crude prices.

Realized prices mirrored the developments in the benchmark price during the year. The Edmonton Light price averaged $65.90/bbl with Questerre receiving a net price of $63.88/bbl in 2009. In the prior year, Questerre realized an average price of $99.42/bbl while the benchmark averaged $102.16/bbl.

Natural gas prices remained challenged for most of the year and staged a minor recovery in the fourth quarter on the back of colder than forecasted weather. A delayed supply side response from the significantly lower rig counts in 2009 and reduced industrial demand contributed to storage levels that approached maximum capacity. This was compounded by a cooler summer that tempered residential cooling demand and a less active hurricane season than anticipated.

Higher heat content gas production from Vulcan continued to positively impact realized natural gas prices. Consistent with prior years, Questerre received a premium to the reference AECO price. Sales prices averaged $4.34/Mcf (2008: $8.99/Mcf) in comparison to an AECO daily index price of $3.96/Mcf (2008: $8.16/Mcf).

Questerre did not enter into any risk management contracts in 2009 and all production was sold on the spot market.

Royalties

Royalty credits in Alberta and British Columbia along with lower prices and production volumes resulted in a significant decrease in royalties on an absolute and relative basis in 2009. Year over year, crown, freehold and overriding royalties declined 80% from $4.98 million to $0.98 million in 2009.

Royalties on production in Alberta averaged 13% of revenue during the year (2008: 22%). This takes into account a $0.47 million Alberta Royalty Tax Credit from 2006 received in the third quarter of the year. Excluding the credits, the effective royalty rate remained unchanged at 22% from the prior year. The Company expects the New Royalty Framework ("NRF") that came into effect in Alberta on January 1, 2009 to have a minimal effect on the Company's royalty rate. With limited drilling in Alberta, the Company does not expect to benefit from the incentive programs announced in March 2009. For the changes to the Alberta royalty structure announced in March 2010 see the risk management section of this MD&A.

Royalty credits on BC production during the year exceeded royalties payable by $0.12 million. This includes a credit of $0.18 million for 2008 production from the Company's wells in Greater Sierra that qualified under the Crown's ultra marginal gas well royalty program. The wells currently attract a royalty rate of approximately 3%. Questerre also benefits from a deep re-entry credit to offset any royalties payable on production from the A-5 well at the Beaver River Field during the year. Questerre incurred royalties of approximately 15% on production from the other two producing wells, A-2 and A-7, at Beaver River. With current natural gas prices, Questerre anticipates no further drilling in British Columbia in the near term. As such, the Company will not avail itself of the royalty incentives announced by the BC government in August 2009.

The realized royalty rate in Saskatchewan increased slightly from 6% in 2008 to 7% in 2009. This includes the Saskatchewan Capital Surcharge estimated at 1.7% of total revenue. Subject to the timing of additional drilling throughout the year, Questerre expects its royalty rate to increase as additional wells are drilled on freehold lands where the royalty rate averages 17%. By comparison, drilling on crown land benefits from an incentive program with a royalty rate of 2.5% on the first 100,000 barrels of production.

Operating Costs

Aggregate operating expenses fell 32% to $4.10 million from $6.06 million in 2008, mirroring the decline in production volumes. On a per unit basis, this resulted in a more muted decline from $14.05/boe to $13.86/boe.

Field operating expenses in Alberta decreased to $9.78/boe from $12.46/boe in the prior year. Operating costs in Vulcan remained relatively flat at $10.90/boe (2008: $10.86/boe) with reduced gathering and processing costs offsetting the higher proportion of fixed costs. The sale of its higher cost assets in Central Alberta in 2008 saw the operating costs on its other properties in Alberta decline to $3.20/boe in the current year from $16.99/boe in the prior year.

Operating expenses at Beaver River are also primarily fixed and the lower costs during the year of $1.29 million (2008: $1.54 million) reflect the lower gathering and processing charges for smaller production volumes. At Greater Sierra with a higher proportion of variable costs saw expenses fall to $0.20 million from $0.48 million in the prior year with the 55% decrease in production volumes.

Lifting costs in Antler saw a marginal increase to $12.84/bbl from $11.94/bbl in 2008. Questerre expects these costs on boe basis to improve in 2010 as a result of 2009 field work and additional anticipated 2010 volumes. The recent tie-in of several wells to the electrical grid is expected to eliminate the higher costs for generators and associated fuel. Furthermore, the installation of a pipeline to tie-in several wells to the central battery and expanded water disposal facilities should reduce trucking and disposal charges going forward.

General and Administrative Expenses

Gross general and administrative expenses ("G&A") saw a minor increase to $5.35 million from $5.20 million in the prior year.

With capital spending substantially lower in 2009, capitalized expenses and overhead recoveries totaled $0.64 million (2008: $2.30 million). This resulted in an increase in net G&A to $4.71 million from $2.90 million in 2009.

($ thousands)	**2009**	2008
General and administrative expenses	**$ 5,354**	$ 5,195
Capitalized expenses and overhead recoveries	**(642)**	(2,295)
General and administrative expenses, net	**$ 4,712**	$ 2,900

Stock-based Compensation

Stock-based compensation expense for the year ended December 31, 2009 totaled $5.23 million (2008: $4.08 million). As mandated by existing accounting standards, this represents the estimated fair value of stock options granted using the Black Scholes pricing model amortized over the vesting period.

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. The higher expense is due to the increased volatility in Questerre's share price, higher exercise prices and the number of options granted in the last 18 months. The expense is a non-cash item, and, upon exercise of options in fact results in increased cash.

The weighted average fair value of the options granted in 2009 using the Black Scholes pricing model was $1.53 (2008: $1.27) and the weighted average exercise price was $2.26 (2008: $1.80).

Other Income and Expenses

In 2009, Questerre reported interest income of $0.48 million (2008: $1.50 million). The income was earned on the net proceeds of the $75 million equity issue completed by Questerre in the second quarter of 2008. Lower cash balances and declining interest rates account for the reduction in interest income in the current year. Cash is invested in Guaranteed Investment Certificates issued by Canadian chartered banks with a maturity of less than one year.

With no draw downs during the year, Questerre did not incur any interest expense under its term credit facility (2008: $0.12 million). As at December 31, 2009, Questerre did not have any amounts outstanding under this facility.

Questerre realized an immaterial gain on the disposition of marketable securities during 2009 compared to a realized loss of $0.71 million in 2008. The marketable securities held by the Company represent investments in junior exploration and production companies. In accordance with the financial instruments accounting guidelines, the Company has classified these securities as held for trading and marks these securities to market value at the end of each fiscal period. This 'mark to market' adjustment is recorded as an unrealized gain or loss on the statements of operations. In 2009, the Company recorded a $0.02 million unrealized gain compared to a $0.09 million unrealized loss in 2008. At December 31, 2009, Questerre holds marketable securities with a market value of $0.20 million (2008: $0.20 million).

In 2008, Questerre recorded an allowance for doubtful accounts of $1.73 million for amounts due from a joint venture partner. No allowance was recorded in 2009.

Depletion, Depreciation and Accretion

In 2009, Questerre's depletion and depreciation provision decreased 8% to $15.87 million, compared to $17.23 million in 2008. A 31% decrease in production volumes was offset by a 34% increase in the charge on a per boe basis from $39.97 in 2008 to $53.69 in 2009. Increased capital expenditures during the year without a corresponding increase in reserves accounts for this difference.

At December 31, 2009, Questerre excluded costs of $23.62 million (December 31, 2008: $19.89 million) relating to unproved properties and included $6.15 million (December 31, 2008: $5.36 million) of future development costs in the depletion calculation.

Questerre applies a two-stage ceiling test to determine if the value of its petroleum and natural gas properties is impaired. The carrying value of the Company's petroleum and natural gas properties at December 31, 2009 was determined to be in excess of the undiscounted net cash flow from the proved reserves. However, since the carrying value of these properties is less than the net cash flow from the proved and probable reserves using a risk free discount rate, as currently prescribed by accounting standards, no impairment loss is recognized in 2009. The Company also did not incur a writedown of its assets in 2008.

The net cash flow from reserves is based on future prices forecasted by the Company's independent reserve engineers as of December 31, 2009. These prices are incorporated by reference from Note 4 of the Company's audited consolidated financial statements for the year ended December 31, 2009.

For the year ended December 31, 2009, the non-cash accretion expense for asset retirement obligations is $0.42 million compared to $0.25 million in 2008. The increase is due to the obligations for wells drilled in 2009 and the second half of 2008 and revisions to the estimates used to determine the asset retirement obligations in the fourth quarter of 2008. Furthermore, the credit adjusted risk free rate was changed to 12% for obligations incurred post October 1, 2008. The estimated net present value of the total asset retirement obligation is $4.76 million as at December 31, 2009 based on a total future undiscounted liability of $9.58 million.

Income Taxes

The recovery of future taxes for 2009 was $4.19 million compared to an expense of $2.41 million in the prior year. The future tax recovery in the current year is due to an $11.15 million increase in the net loss before income taxes. It also includes a decrease in the potential future tax liability related to the Questerre common shares that were held by a wholly owned foreign subsidiary that was dissolved in 2009.

Net Loss

Questerre recorded a net loss of $13.72 million for the year (2008: $9.21 million). The loss in the current year was attributable to substantially lower commodity prices and reduced production volumes coupled with proportionately higher expenses. In the prior year, significantly higher revenue and comparatively lower expenses resulted in a smaller loss.

Capital Expenditures

Excluding acquisitions and dispositions, Questerre incurred capital expenditures of $11.99 million in 2009 a marked decrease from $43.96 million in 2008. The Company's significant 2009 capital expenditures consisted of the following:

- $6.28 million was invested in the St. Lawrence Lowlands, Québec where the Company participated in the drilling and completion of multiple wells to assess the Utica shale.
- In Saskatchewan $4.46 million was incurred in Antler primarily evaluating new drilling and completion techniques and tying-in and completing wells drilled in the prior year.
- In British Columbia the majority of the $0.84 million was spent acquiring acreage prospective for multiple horizons including the Horn River shale.

For comparison, the company's 2008 capital program consisted of the following:

- $20.44 million in Antler with the majority incurred drilling and completing several horizontal wells and the associated facilities;
- $10.68 million in Greater Sierra that included $5.58 million for the acquisition of a 3-D seismic survey with the balance spent finishing the drilling and completion of two horizontal Jean Marie wells;
- $4.45 million at the Beaver River Field to finalize the drilling and completion of the A-8 Nahanni well and recompleting the A-5 well for shale gas potential;
- $4.80 million in Québec participating in the drilling of four wells and the recompletion of the Gentilly No. 1 well;
- $3.37 million in Alberta mainly in Vulcan to drill and complete one horizontal well, tie-in two others and the associated facilities.

($ thousands)		**2009**		2008
Expenditures on Property, Plant and Equipment				
Alberta	**$**	**376**	$	3,373
British Columbia		**837**		15,126
Saskatchewan		**4,457**		20,437
Québec		**6,279**		4,795
Corporate		**41**		226
		11,990		43,957
Dispositions		**–**		(2,146)
Acquisitions (cash portion)		**–**		680
Acquisitions (non-cash portion)		**–**		84
Asset Retirement Obligations		**56**		168
Total	**$**	**12,046**	$	42,743

Liquidity and Capital Resources

Questerre reported a working capital surplus of $46.50 million at December 31, 2009 as compared to a surplus of $54.31 million at December 31, 2008.

The Company's current assets consist of cash and cash equivalents of $51.40 million, $0.20 million of marketable securities, $4.51 million of accounts receivable, $0.30 million of inventory and $0.62 million in prepaids and deposits. Current liabilities of $10.53 million represent accounts payable and accrued liabilities.

In March 2010, Questerre closed an equity issuance of 30,000,000 Common Shares at a price of $4.30 per share for gross proceeds of approximately $129 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.

The Company believes it is sufficiently capitalized with the proceeds from the financing, a working capital surplus of $46.50 million at December 31, 2009, positive cash flow from operations and no debt. The majority of future planned capital spending will be incurred in Québec and is in part contingent upon the results of the pilot programs conducted by Questerre's partners. The Company does not anticipate utilizing its existing credit facility in the foreseeable future. The credit facility is believed to provide adequate contingency for unanticipated changes in capital spending or market conditions.

Cash Flow from Operations and Cash Flows from Operating Activities

Cash flow from operations for 2009 was $2.88 million or 83% lower than the 2008 cash flow from operations of $17.29 million. The decrease from the prior year is primarily due to lower realized prices for both oil and natural gas of 36% and 52%, respectively, and a 31% decrease in production volumes.

Cash flows from operating activities for 2009 was a negative $0.03 million compared to $23.47 million in 2008. The change in the non-cash working capital of $9.08 million represents the difference from the change in the cash flow from operations.

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, 2009, 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 25 2010	December 31 2009	December 31 2008
Common shares	229,722,143	199,722,143	197,299,642
Stock options	18,528,753	18,618,753	17,655,421
Weighted average common shares			
Basic		197,940,390	186,447,776
Diluted		206,729,689	196,593,333

On September 30, 2009, 10,698,785 Questerre common shares that were acquired in the Terrenex acquisition were cancelled. The cancellation has been recorded as $10,315,647 being deducted from common shares and $12,793,729 as an increase to the deficit. Due to the pending cancellation of the 10,698,785 Questerre common shares at the time of acquisition in 2008, the cancellation has already been factored into the opening number of shares outstanding and therefore no outstanding share amounts need to be adjusted for in 2009.

A total of 2,422,501 common shares were issued pursuant to the exercise of stock options by directors, officers and employees during the year.

In March 2010, Questerre closed an equity issuance of 30,000,000 Common Shares at a price of $4.30 per share.

Off-Balance Sheet Arrangements

Questerre has no off-balance sheet arrangements.

Related Party Transactions

Questerre had no related party transactions in 2009.

Contractual Obligations and Commitments

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

	Total	Less than 1 year	1 – 3 years	4 – 5 years	After 5 years
Equipment rentals	$125,462	$115,811	$9,651	–	–
Office lease	333,241	333,241	–	–	–
	$458,703	$449,052	$9,651	–	–

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 a result of global economic conditions, the Corporation may have restricted access to capital, bank debt and equity, and is likely to face increased borrowing costs. Although the Corporation's business and asset base have not changed, the lending capacity of many financial institutions has diminished and risk premiums have increased. 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.
- Debt may be utilized to expand capital programs, including acquisitions, when it is deemed appropriate and where debt retirement can be controlled.
- Equity, including flow-through shares, if available on acceptable terms, may be raised to fund acquisitions and capital expenditures.
- 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 arises from the potential loss resulting from a counterparty failing to meet its obligations in accordance with the agreed terms. The Company may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production and other parties. 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 customers 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. In many cases, the Company has offsetting receivables and payables with its partners and makes use of these offsets to mitigate any payment risk. Wherever possible, the Company requires cash calls from its partners on capital projects before they commence.

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

The Company has issued and may continue 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.

Although Questerre has no formal hedging policy, the Company may use financial instruments to reduce corporate risk in certain situations. Questerre currently has no hedges or other financial instruments in place.

Environmental Regulation and Risk

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. The Company mitigates the potential financial exposure of environmental risks by maintaining adequate insurance.

Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nationwide emissions of carbon dioxide, methane, nitrous oxide and other so-called "greenhouse gases". The Government of Canada is in the process of developing future regulatory requirements that are expected to set greenhouse gas emission reduction requirements for various industrial activities, including oil and gas exploration and production. Questerre's exploration and production facilities and other operations and activities emit a small amount of greenhouse gases which will likely subject Questerre to federal law regulating emissions of greenhouse gases if and when such requirements come into force. Future federal legislation, together with provincial emission reduction requirements, such as those contained in Alberta's Climate Change and Emissions Management Act, British Columbia's Greenhouse Gas Reduction (Cap and Trade) Act, and proposed in Saskatchewan's Bill 126: Management and Reduction of Greenhouse Gases Act, may require the reduction of emissions or emissions intensity with Questerre's operations and facilities.

Although Questerre is not a large emitter of greenhouse gases, the Company continues to monitor developments in this area. Although environmental legislation is evolving in a manner which could result in stricter standards and enforcement, larger fines and liability, and potentially increased capital expenditures and operating costs, at this time it is not possible to predict the impact of these requirements on the Company and its operations and financial condition.

Alberta Royalty and Tax Regime

On February 16, 2007, the Alberta Government announced that a review of the Province's royalty and tax regime (including income tax and freehold mineral rights tax) pertaining to oil and gas resources, including oil sands, conventional oil and gas and coalbed methane, would be conducted by a panel of experts with the assistance of individual Albertans and key stakeholders. On September 18, 2007, the Royalty Review Panel delivered its final report and recommendations to the Government of Alberta. The report titled "Our Fair Share", recommended significant increases to royalties levied on natural gas, conventional oil and oil sands produced in Alberta. On October 25, 2007, the Alberta Government released details of its planned implementation of the final Royalty Review Panel report, titled "The New Royalty Framework" ("NRF").

Questerre reviewed the modifications by the Government of Alberta to its royalty program, which took effect on January 1, 2009, and provides the following observations:

- In 2009, approximately 55% of Questerre's production is from properties located outside Alberta and is therefore not affected by the NRF.
- Royalties determined under the NRF will be determined based on commodity prices, well productivity and depth of wells. A significant portion of Questerre's wells are lower productivity wells that, on a relative basis, are less impacted by the NRF than higher productivity wells.
- The NRF will have a negative impact on the economics of any future drilling.

On March 3, 2009, the Government of Alberta announced a three-point incentive program to stimulate new and continued economic activity in Alberta, which included a drilling royalty credit for new conventional oil and natural gas wells and a new well royalty incentive program. The new well incentive program applies to wells commencing production of conventional oil and natural gas between April 1, 2009 and March 31, 2011 and provides for a maximum 5% royalty rate for the first twelve months of production, up to a maximum of 50,000 barrels of oil or 500 million cubic feet of natural gas. Questerre has not drilled any wells in Alberta to take advantage of this incentive.

On March 11, 2010, the government of Alberta announced that the following will become permanent features of the royalty structure, effective with the January 2011 production month:

Permanent 5% Front-end Royalty

- The current incentive program rate of 5% on new natural gas and conventional oil wells will become a permanent feature of the royalty system, with the current time and volume limits.

Lower Maximum Rates

- The maximum royalty rate for conventional oil will be reduced at higher price levels from 50% to 40% to provide better risk-reward balance to investors.
- Recognizing the fundamental changes to the North American supply/demand balance and increased competition from other jurisdictions, the maximum royalty rate for conventional and unconventional natural gas will be reduced at higher price levels from 50% to 36%.

Implementation/Transition

- All royalty curves will be finalized and announced by May 31, 2010 and be effective for all production January 1, 2011.
- The transitional royalty framework for oil and gas introduced in November 2008 will continue until its original announced expiration on December 31, 2013. Effective January 1, 2011, no new wells will be allowed to select the transitional royalty rates. Wells that have already selected the transitional royalty rates will have the option to stay with those rates or switch to the new rates effective January 1, 2011.
- The drilling royalty credit will continue until expiry on March 31, 2011 and all other programs will continue as designed.

As part of the recognition of the significant changes in the North American natural gas market, the government will continue to analyze various components of natural gas royalties. The conclusion of this analysis will be included in the final royalty curve revisions to be announced on May 31st. Once Questerre receives the final royalty curves then the impact of the changes can be analyzed at that time.

Critical Accounting Estimates

Management is required to make judgments, assumptions and estimates in the application of generally accepted accounting principles that have a significant impact on the financial results of the Company. The following discussion outlines the accounting estimates that are critical to determining Questerre's financial results.

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.

Full Cost Accounting

Questerre follows the full cost method of accounting for petroleum and natural gas operations as outlined in the Canadian Institute of Chartered Accountants ("CICA") accounting guideline "Oil and Gas Accounting – Full Cost" (AcG-16). Under this accounting method, all costs related to the exploration for and development of petroleum and natural gas reserves are capitalized. Capitalized costs, as well as the estimated future expenditures to develop proved reserves, are depleted using the unit-of-production method based on estimated proved petroleum and natural gas reserves.

In applying the full cost method, Questerre calculates a ceiling test at each annual balance sheet date, or earlier if circumstances or events indicate impairment may have occurred. This is done to ensure that the net carrying value of petroleum and natural gas assets does not exceed the estimated undiscounted future net cash flow from production of proved reserves. Accordingly, the Company must base this calculation of future net cash flow on estimated forecasted sales prices, costs and regulations in effect at the period end. AcG-16 limits the carrying value of petroleum and natural gas properties to their fair value. The fair value is equal to estimated future cash flow from proved and probable reserves using future price forecasts and costs discounted at a risk-free rate.

Asset Retirement Obligations

Questerre follows CICA Section 3110, "Asset Retirement Obligations", which requires liability recognition for retirement obligations associated with the Company's property, plant and equipment. Determination of the asset retirement obligations is based on internal estimates using current costs and technology in accordance with existing legislation and industry practice and must also estimate timing, a credit adjusted 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 earnings. 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 earnings in the period. The associated asset 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. Revisions to the estimated timing of cash flows or to the original estimated undiscounted cost also result in an increase or decrease to the asset retirement obligation and asset.

Goodwill

Goodwill of $2.47 million represents the excess purchase price over the fair value of identifiable assets and liabilities acquired from Stride Energy Ltd. in 2006. Goodwill is not amortized. However, in accordance with accounting standards, goodwill impairment is assessed annually at December 31, or more frequently as economic events dictate. Impairment is determined by comparing the fair value of the reporting unit to its carrying value, including goodwill. If it is determined that the fair value of the reporting units assets and liabilities is less than its carrying value, an impairment amount is determined. The impairment is charged to earnings.

Stock-based Compensation

The Company has a stock-based compensation plan enabling employees, officers and directors to purchase common shares at exercise prices equal to the market price or above on the date the option is granted. The Company uses the fair value method for valuing stock option grants. Compensation costs attributable to share options granted are measured at their fair value at the grant date and expensed over the vesting period with a corresponding increase to contributed surplus. Upon exercise of the stock options, the consideration paid by the option holder, together with the amount previously recognized in contributed surplus, is credited to share capital. The assumptions used in calculating its stock based compensation expense are: the volatility of the stock price, risk-free rates of return and the expected lives of the options.

Financial Instruments

Handbook Section 3855 sets out comprehensive requirements for recognition and measurement of financial instruments. Under this standard, an entity would recognize a financial asset or liability only when the entity becomes a party to the contractual provisions of the financial instrument. Financial assets and financial liabilities would, with certain exceptions, be initially measured at fair value.

Income Tax Accounting

The determination of the Company's income and other tax 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 liability may differ significantly from that estimated and recorded by management.

Other Estimates

The accrual method of accounting will require management to incorporate certain estimates of revenues, royalties, production costs and other costs as at a specific reporting date. In addition, the Company must estimate capital expenditures on capital projects that are in progress or recently completed where actual costs have not been received as of the reporting date.

Accounting Standards Changes

On January 1, 2009, the Company adopted Canadian Institute of Chartered Accountants ("CICA") Handbook Section 3064, "Goodwill and Intangible Assets". The new standard replaces the previous goodwill and intangible asset standard and revises the requirement for recognition, measurement, presentation and disclosure of intangible assets. The adoption of this standard was applied retroactively and has had no material impact on Questerre's consolidated financial statements.

In June 2009, the CICA issued amendments to CICA Handbook Section 3862, Financial Instruments – Disclosures. The amendments include enhanced disclosures related to the fair value of financial instruments and the liquidity risk associated with financial instruments. The amendments will be effective for annual financial statements for fiscal years ending after September 30, 2009 and are consistent with recent amendments to financial instrument disclosure standards in International Financial Reporting Standards (IFRS). The adoption of this section required enhanced disclosures on Questerre's consolidated financial statements.

This section was amended to require disclosures about the inputs to fair value measurements, including their classification within a hierarchy that prioritizes the inputs to fair value measurement.

The three levels of the fair value hierarchy are:

- Level 1 – Unadjusted quoted prices in active markets for identical assets or liabilities;
- Level 2 – Inputs other than quoted prices that are observable for the asset or liability either directly or indirectly; and
- Level 3 – Inputs that are not based on observable market data.

Questerre's marketable securities are recorded at fair value using quoted market prices and are classified as level 1 in the fair value hierarchy.

Future Accounting Pronouncements

International Financial Reporting Standards ("IFRS")

Questerre's IFRS Changeover Plan

In February 2008, the CICA's Accounting Standards Board confirmed that IFRS will replace Canadian GAAP in 2011 for profit-oriented Canadian publicly accountable enterprises. Questerre will be required to report its results in accordance with IFRS beginning in 2011. The Company has developed a changeover plan to complete the transition to IFRS by January 1, 2011, including the preparation of 2010 required comparative information.

The key elements of Questerre's changeover plan include:

- determine appropriate changes to accounting policies and required amendments to financial disclosures;
- identify and implement changes in associated processes and information systems;
- comply with internal control requirements;
- communicate collateral impacts to internal business groups; and
- educate and train internal and external stakeholders.

During 2009, Questerre made significant progress on its changeover plan. The Company analyzed accounting policy alternatives and preliminarily drafted its IFRS accounting policies. Process and system changes have been designed for significant areas of impact, with internal control requirements taken into account. IFRS education sessions have been held with internal stakeholders.

Process and system changes will be implemented in early 2010 to ensure IFRS comparative data is captured. Questerre's IFRS accounting policies are expected to be finalized mid-2010. Quantification of IFRS impacts will then be determined utilizing previously captured data. Communication of impacts to external stakeholders is expected to occur in the latter half of 2010.

Questerre will continue to update its IFRS changeover plan to reflect new and amended accounting standards issued by the International Accounting Standards Board.

Expected Accounting Policy Impacts

Questerre's significant areas of impact continue to include property, plant and equipment ("PP&E"), asset retirement obligations ("ARO"), impairment testing and income taxes. These areas of impact have the greatest potential impact to the Company's financial statements. The following discussion provides an overview of these areas, as well as the exemptions available under IFRS 1, First-time Adoption of International Financial Reporting Standards. In general, IFRS 1 requires first time adopters to retrospectively apply IFRS, although it does provide optional and mandatory exemptions to these requirements.

Property, Plant and Equipment

Under Canadian GAAP, Questerre follows the CICA's guideline on full cost accounting in which all costs directly associated with the acquisition of, the exploration for, and the development of natural gas and crude oil reserves are capitalized on a country-by-country cost centre basis. Costs accumulated within each country cost centre are depleted using the unit-of-production method based on proved reserves determined using estimated future prices and costs. Upon transition to IFRS, Questerre will be required to adopt new accounting policies for upstream activities, including pre-exploration costs, exploration and evaluation costs and development costs.

Pre-exploration costs are those expenditures incurred prior to obtaining the legal right to explore and must be expensed under IFRS. Currently, Questerre capitalizes and depletes pre-exploration costs within the country cost centre. In 2008 and 2009, these costs were not material to Questerre.

Exploration and evaluation costs are those expenditures for an area or project for which technical feasibility and commercial viability have not yet been determined. Under IFRS, Questerre will initially capitalize these costs as Exploration and Evaluation assets on the balance sheet. When the area or project is determined to be technically feasible and commercially viable, the costs will be transferred to PP&E. Unrecoverable exploration and evaluation costs associated with an area or project will be expensed.

Development costs include those expenditures for areas or projects where technical feasibility and commercial viability have been determined. Under IFRS, Questerre will continue to capitalize these costs within PP&E on the balance sheet. However, the costs will be depleted on a unit-of-production basis over an area level (unit of account) instead of the country cost centre level currently utilized under Canadian GAAP. Questerre has not finalized the areas or the inputs to be utilized in the unit-of-production depletion calculation.

Under IFRS, upstream divestures will generally result in a gain or loss recognized in net earnings. Under Canadian GAAP, proceeds of divestitures are normally deducted from the full cost pool without recognition of a gain or loss unless the deduction would result in a change to the depletion rate of 20% or greater, in which case a gain or loss is recorded.

Questerre expects to adopt the IFRS 1 exemption, which allows the Company to deem its January 1, 2010 IFRS upstream asset costs to be equal to its Canadian GAAP historical upstream net book value. On January 1, 2010, the IFRS exploration and evaluation costs will be equal to the Canadian GAAP unproved properties balance and the IFRS development costs will be equal to the full cost pool balance. Questerre will allocate this upstream full cost pool over reserves to establish the area level depletion units.

Asset Retirement Obligation

Under Canadian GAAP, ARO is measured as the estimated fair value of the retirement and decommissioning expenditures expected to be incurred. Existing liabilities are not re-measured using current discount rates. Under IFRS, ARO is measured as the best estimate of the expenditure to be incurred and requires the use of current discount rates at each remeasurement date. Generally, the change in discount rates results in a balance being added to or deducted from PP&E.

As a result of Questerre's intended use of the IFRS 1 upstream assets exemption, the Company is required to revalue its January 1, 2010 ARO balance and recognize the adjustment in retained earnings.

Impairment

Under Canadian GAAP, Questerre is required to recognize an upstream impairment loss if the carrying amount exceeds the undiscounted cash flows from proved reserves for the country cost centre. If an impairment loss is to be recognized, it is then measured at the amount the carrying value exceeds the sum of the fair value of the proved and probable reserves and the costs of unproved properties.

Under IFRS, Questerre is required to recognize and measure an upstream impairment loss if the carrying value exceeds the recoverable amount for a cash-generating unit. Under IFRS, the recoverable amount is the higher of fair value less cost to sell and value in use. Impairment losses, other than goodwill, are reversed under IFRS when there is an increase in the recoverable amount. Questerre will group its upstream assets into cash-generating units based on the independence of cash inflows from other assets or other groups of assets.

Income Taxes

In transitioning to IFRS, the Company's future tax liability will be impacted by the tax effects resulting from the IFRS changes discussed above. Questerre continues to assess the impact that the IFRS income tax principles may have on the Company.

Other IFRS 1 Considerations

Business combinations and joint ventures entered into prior to January 1, 2010 will not be retrospectively restated using IFRS principles.

<u>Other Recent Accounting Pronouncements</u>

As of January 1, 2011, Questerre will be required to adopt the following CICA Handbook sections:

"Business Combinations", Section 1582, which replaces the previous business combinations standard. The standard requires assets and liabilities acquired in a business combination, contingent consideration and certain acquired contingencies to be measured at their fair values as of the date of acquisition. In addition, acquisition-related and restructuring costs are to be recognized separately from the business combination and included in the statement of operations. The adoption of this standard will impact the accounting treatment of future business combinations.

"Consolidated Financial Statements", Section 1601, which, together with Section 1602 below, replace the former consolidated financial statements standard. Section 1601 establishes the requirements for the preparation of consolidated financial statements. The adoption of this standard should not have a material impact on Questerre's Consolidated Financial Statements.

"Non-controlling Interests", Section 1602, which establishes the accounting for a non-controlling interest in a subsidiary in the consolidated financial statements subsequent to a business combination. The standard requires a non-controlling interest in a subsidiary to be classified as a separate component of equity. In addition, net earnings and components of other comprehensive income are attributed to both the parent and non-controlling interest. The adoption of this standard should not have a material impact on Questerre's Consolidated Financial Statements.

Design and Evaluation of Internal Control 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 Control 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, 2009.

- 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 have concluded that the ICFR are designed appropriately and are operating effectively as at December 31, 2009.
- The Company reports that no changes were made to ICFR during 2009 that have materially affected, or are reasonably likely to materially affect the Company's ICFR.

Because of their inherent limitations, disclosure controls and procedures and internal controls over financial reporting may not prevent or detect misstatements, errors or fraud. Control systems, no matter how well conceived or operated, can provide only reasonable, not absolute assurance that the objectives of the control systems are met.

Fourth Quarter 2009 Results

In the St. Lawrence Lowlands, operations in the quarter focused on the pilot horizontal well program to assess commerciality of the Utica shale. The first well, St. Edouard No. 1A, was successfully drilled and cased to a measured depth of 3181m with a 1000m horizontal leg in the target middle Utica interval. The horizontal well was successfully completed with 8 stage fracture stimulations. Clean-up and flow back commenced January 29, 2010. Initial rates were over 12 MMcf/d. During the test, the well flowed natural gas at an average rate of over 6 MMcf/d. The well is currently still flowing on an extended production test. The second well, Gentilly No. 2, spud in December. Operations were completed on schedule and budget in January 2010. Total measured depth for the well was 2693m with an approximate 700m horizontal leg. Completion operations are expected to commence after spring break-up.

Improving commodity prices and test production from Beaver River strengthened our financial and operating performance in the fourth quarter of the year. The focus on capital preservation resulted in a strong working capital position of $46.50 million at year end with cash and cash equivalents of $51.40 million.

Production for the period averaged 759 boe/d as compared to 632 boe/d in the preceding quarter and 907 boe/d for the fourth quarter of 2008.

New drilling and completion techniques at Antler, Saskatchewan continued to show promise during the quarter. Based on these results, Questerre and its partners finalized plans to implement these in a winter drilling program consisting of three (1.50 net) wells. Production from Beaver River, northeast British Columbia, resumed early in the quarter at initial rates of up to 3 MMcf/d (gross) from three wells – A-5, A-7 and A-2. Extended periods of unseasonably cold weather subsequently froze production facilities at two of the wells. Current production is approximately 500 Mcf/d (gross) from the A-2 well.

Crude oil prices in the quarter reflected the growing optimism about the economic recovery and the weakness in the US dollar. Late in the quarter, natural gas prices staged a recovery with colder than expected weather positively impacting the record storage levels. As a result, oil and liquids prices increased 8% to $76.30/bbl and natural gas prices increased by 41% to $4.53/Mcf from $3.21/Mcf in the previous quarter. The improved prices and higher volumes translated into petroleum and natural gas revenue of $3.45 million or 24% higher than third quarter revenue of $2.79 million.

With the cash flow from operations largely unchanged compared to the prior quarter, Questerre's net loss for the period increased with higher non-cash expenses, particularly stock based compensation and depletion and depreciation and a smaller future tax recovery. For the quarter, Questerre reported a net loss of $3.90 million and positive cash flow from operations of $0.60 million. This compares to a net loss of $1.58 million and positive cash flow from operations of $0.50 million in the preceding quarter.

Capital expenditures of $3.44 million in the quarter focused on the pilot horizontal program in Québec. Of this amount, $2.54 million was spent drilling two (0.46 net) horizontal wells in the Lowlands and $0.71 million in Antler completing and tying in one (1.00 net) horizontal well.

Quarterly Financial Information

	December 31 2009	September 30 2009	June 30 2009	March 31 2009
Production (boe/d)	**759**	**632**	**806**	**1,049**
Average Realized Price ($/boe)	**49.37**	**47.92**	**40.56**	**39.46**
Petroleum and Natural Gas Sales	**3,447,123**	**2,786,384**	**2,974,761**	**3,724,999**
Cash Flow from Operations	**595,717**	**502,357**	**717,151**	**1,063,351**
Per share – Basic	**–**	**–**	**–**	**0.01**
Per share – Diluted	**–**	**–**	**–**	**0.01**
Net Loss	**(3,898,088)**	**(1,581,718)**	**(3,835,057)**	**(4,408,025)**
Per share – Basic	**(0.02)**	**(0.01)**	**(0.02)**	**(0.02)**
Per share – Diluted	**(0.02)**	**(0.01)**	**(0.02)**	**(0.02)**
Capital Expenditures, net of acquisitions and dispositions	**3,438,205**	**3,259,938**	**1,732,487**	**3,558,911**
Working Capital Surplus	**46,500,671**	**49,016,405**	**50,953,325**	**51,756,719**
Total Assets	**145,272,364**	**149,304,238**	**149,650,802**	**154,599,633**
Shareholders' Equity	**129,977,202**	**132,216,221**	**131,820,858**	**134,190,125**
Weighted Average Common Shares Outstanding				
Basic	**199,243,068**	**197,827,758**	**197,370,978**	**197,299,642**
Diluted	**208,653,009**	**206,723,239**	**205,065,933**	**205,069,693**

	December 31 2008	September 30 2008	June 30 2008	March 31 2008
Production (boe/d)	907	1,292	1,241	1,274
Average Realized Price ($/boe)	55.65	74.81	80.03	62.38
Petroleum and Natural Gas Sales	4,644,224	8,892,160	9,037,355	7,231,829
Cash Flow from Operations	2,799,792	5,411,554	5,138,828	3,939,125
Per share – Basic	0.01	0.03	0.03	0.02
Per share – Diluted	0.01	0.03	0.03	0.02
Net Earnings (Loss)	(7,487,376)	292,647	(2,670,086)	652,201
Per share – Basic	(0.04)	–	(0.01)	–
Per share – Diluted	(0.04)	–	(0.01)	–
Capital Expenditures, net of acquisitions and dispositions	14,377,062	7,352,744	3,066,281	17,694,854
Working Capital Surplus (Deficiency)	54,307,989	67,826,776	68,450,058	(4,506,141)
Total Assets	165,531,133	162,756,977	160,395,379	102,606,756
Shareholders' Equity	137,189,444	145,328,700	143,603,481	72,783,296
Weighted Average Common Shares Outstanding				
Basic	197,293,327	197,250,522	181,275,421	169,733,932
Diluted	206,230,961	208,686,342	194,380,878	172,902,492

	December 31 2007	September 30 2007	June 30 2007	March 31 2007
Production (boe/d)	1,216	1,206	1,443	1,702
Average Realized Price ($/boe)	48.16	39.11	49.93	48.98
Petroleum and Natural Gas Sales	5,387,928	4,339,265	6,555,860	7,502,436
Cash Flow from Operations	1,584,590	2,414,613	3,183,088	3,046,729
Per share – Basic	0.01	0.02	0.02	0.02
Per share – Diluted	0.01	0.02	0.02	0.02
Net Earnings (Loss)	(2,066,084)	(676,499)	980,543	480,366
Per share – Basic	(0.01)	–	0.01	–
Per share – Diluted	(0.01)	–	0.01	–
Capital Expenditures, net of acquisitions and dispositions	9,355,590	5,646,625	(6,702,933)	7,163,179
Working Capital Surplus	10,007,846	26,476,203	29,911,344	20,427,261
Total Assets	93,074,767	77,241,283	80,758,475	77,279,174
Shareholders' Equity	71,627,841	62,100,834	62,412,993	60,688,283
Weighted Average Common Shares Outstanding				
Basic	162,650,245	155,211,741	155,198,536	155,190,861
Diluted	166,729,098	160,919,586	161,897,966	162,242,898

Management's Report

To the Shareholders of Questerre Energy Corporation

The accompanying consolidated financial statements of Questerre Energy Corporation and all the information in this Annual Report are the responsibility of management and have been approved by the Board of Directors.

The consolidated financial statements have been prepared by management in accordance with generally accepted accounting principles. When alternative accounting methods exist, management has chosen those it deems most appropriate in the circumstances. Financial statements are not precise since they include certain amounts based on estimates and judgments. Management has determined such amounts on a reasonable basis in order to ensure that the consolidated financial statements are presented fairly, in all material respects. The financial information contained elsewhere in this report has been reviewed to ensure consistency with the consolidated financial statements.

Management has established systems of internal controls, which are designed to provide reasonable assurance that assets are safeguarded from loss or unauthorized use and to produce reliable accounting records for the preparation of financial information.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. It exercises its responsibilities primarily through the Audit Committee, which is comprised of non-management directors. The Audit Committee has reviewed the consolidated financial statements with management and the auditors and has reported to the Board of Directors which have approved the consolidated financial statements.

The consolidated financial statements have been audited by PricewaterhouseCoopers LLP, the external auditors, in accordance with auditing standards generally accepted in Canada on behalf of the shareholders.

Michael Binnion
President and Chief Executive Officer

Jason D'Silva
Chief Financial Officer

Calgary, Alberta, Canada
March 25, 2010

Auditors' Report

To the Shareholders of Questerre Energy Corporation

We have audited the consolidated balance sheets of Questerre Energy Corporation (the "Company") as at December 31, 2009 and December 31, 2008 and the consolidated statements of operations, comprehensive loss and deficit, and cash flows for the years then ended. These consolidated financial statements are the responsibility of the Company's management. 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 plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2009 and December 31, 2008 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Alberta
March 25, 2010

Consolidated Balance Sheets

	December 31 2009	December 31 2008
Assets		
Current assets		
Cash and cash equivalents	**$ 51,396,052**	$ 65,379,340
Marketable securities (note 5)	**204,336**	198,080
Accounts receivable (note 10)	**4,509,203**	8,049,421
Inventory (note 12)	**301,599**	352,127
Prepaids and deposits	**619,990**	970,003
	57,031,180	74,948,971
Future income taxes (note 9)	**1,486,533**	–
Goodwill	**2,467,816**	2,467,816
Property, plant and equipment, net (note 4)	**84,286,835**	88,114,346
	$ 145,272,364	$ 165,531,133
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	**$ 10,530,509**	$ 20,640,982
Future income taxes (note 9)	–	2,705,845
Asset retirement obligations (note 7)	**4,764,653**	4,994,862
	15,295,162	28,341,689
Shareholders' Equity		
Common shares (note 8)	**183,706,643**	191,991,012
Questerre shares held by subsidiary (notes 3 & 8 (b))	–	(23,109,376)
Contributed surplus (note 8 (f))	**11,218,598**	6,739,230
Deficit	**(64,948,039)**	(38,431,422)
	129,977,202	137,189,444
	$ 145,272,364	$ 165,531,133

Contractual obligations and commitments (note 15).

See accompanying notes to the consolidated financial statements.

Approved by the Board of Directors

R Hammond

Consolidated Statements of Operations, Comprehensive Loss and Deficit

For the years ended December 31,		**2009**		2008
Revenue				
Petroleum and natural gas revenue	**$**	**12,933,267**	$	29,805,568
Royalties		**(980,719)**		(4,979,101)
		11,952,548		24,826,467
Expenses				
Operating		**4,097,207**		6,057,492
General and administrative		**4,711,526**		2,900,189
Interest expense		**–**		122,900
Interest income		**(478,060)**		(1,501,223)
Realized (gain) loss on sale of marketable securities (note 5)		**(106)**		711,929
Unrealized (gain) loss on marketable securities (note 5)		**(18,208)**		90,632
Realized gain on risk management activities		**–**		(109,749)
Allowance for doubtful accounts		**–**		1,730,462
Stock-based compensation (note 8 (e))		**5,225,313**		4,076,503
Depletion and depreciation		**15,873,155**		17,234,553
Accretion of asset retirement obligations (note 7)		**424,335**		248,481
		29,835,162		31,562,169
Net loss before income taxes		**(17,882,614)**		(6,735,702)
Income Taxes				
Current (note 9)		**32,652**		67,560
Future (recovery) (note 9)		**(4,192,378)**		2,409,352
		(4,159,726)		2,476,912
Net loss and comprehensive loss		**(13,722,888)**		(9,212,614)
Deficit, beginning of period		**(38,431,422)**		(29,218,808)
Cancellation of shares (note 8 (b))		**(12,793,729)**		–
Deficit, end of period	**$**	**(64,948,039)**	$	(38,431,422)
Net loss per share (note 8 (c))				
Basic and diluted	**$**	**(0.069)**	$	(0.049)

See accompanying notes to the consolidated financial statements.

Consolidated Statements of Cash Flows

For the years ended December 31,	**2009**	2008
Operating Activities		
Net loss	**$ (13,722,888)**	$ (9,212,614)
Items not affecting cash and cash equivalents:		
Depletion and depreciation	**15,873,155**	17,234,553
Stock-based compensation (note 8 (e))	**5,225,313**	4,076,503
Accretion of asset retirement obligations (note 7)	**424,335**	248,481
Realized (gain) loss on sale of marketable securities (note 5)	**(106)**	711,929
Unrealized (gain) loss on marketable securities (note 5)	**(18,208)**	90,632
Allowance for doubtful accounts	**–**	1,730,462
Future income taxes (recovery) (note 9)	**(4,192,378)**	2,409,352
Abandonment expenditures	**(710,647)**	–
	2,878,576	17,289,298
Net change in non-cash working capital	**(2,905,105)**	6,176,758
	(26,529)	23,466,056
Financing Activities		
Issue of common shares	**1,285,333**	77,301,878
Share issue costs	**–**	(5,267,071)
	1,285,333	72,034,807
Investing Activities		
Expenditures on property, plant and equipment	**(11,989,541)**	(43,956,604)
Acquisition of Terrenex Ltd. (note 3)	**–**	(680,161)
Sale of property, plant and equipment	**–**	2,145,824
Sale of marketable securities (note 5)	**12,058**	1,274,551
Purchase of marketable securities (note 5)	**–**	(295,942)
	(11,977,483)	(41,512,332)
Net change in non-cash working capital	**(3,264,609)**	(2,508,467)
	(15,242,092)	(44,020,799)
Increase (decrease) in cash and cash equivalents	**(13,983,288)**	51,480,064
Cash and cash equivalents, beginning of period	**65,379,340**	13,899,276
Cash and cash equivalents, end of period	**$ 51,396,052**	$ 65,379,340

See supplemental cash flow information contained in note 13.

See accompanying notes to the consolidated financial statements.

Notes to the Consolidated Financial Statements

For the years ended December 31, 2009 and 2008

1. Basis of Presentation and Nature of Operations

The consolidated financial statements include the accounts of Questerre Energy Corporation and its subsidiaries ("Questerre" or the "Company") and have been prepared by management in accordance with Canadian generally accepted accounting principles. Preparation of the consolidated financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the period. Actual results may differ from these estimates.

Questerre 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.

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*. Magnus is a wholly owned subsidiary of Questerre. At meetings of the creditors of the Magnus Entities held on September 30, 2008, the creditors approved a proposal to settle amounts outstanding. Court approval of this proposal was obtained on April 2, 2009. Questerre has lost control of Magnus due to the bankruptcy and appointment of a trustee, however, because of uncertainty over responsibility for the liabilities recorded in Magnus relating to the investment in the subsidiary, the investment has been recorded as a liability equal to the full amount of the book value of Magnus's liabilities. No adjustments have been made to the carrying values of the liabilities pending confirmation of the settlement amounts. This is expected to be completed in the first half of 2010.

Cabernet Holdings Ltd., a wholly owned subsidiary of Terrenex Ltd., transferred all of its assets to Terrenex Ltd. and then was dissolved on July 23, 2009. Subsequently, on September 1, 2009, Terrenex Ltd., a wholly owned subsidiary of Questerre, was amalgamated with Questerre. See note 8(b) for further discussion.

2. Significant Accounting Policies

a) Principles of consolidation

The consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries, Questerre Beaver River Inc., 6058931 Canada Inc. and Magnus Energy Inc.

b) Cash and cash equivalents

Cash consists of cash in the bank, less outstanding cheques and short-term deposits with a maturity of less than three months at purchase.

c) Marketable securities

Marketable securities are carried at fair value and unrecognized gains or losses are recognized in the statements of operations in the period incurred.

d) Measurement uncertainty

Depletion and depreciation, amounts used for ceiling test calculations, stock based compensation, future tax, allowance for doubtful accounts, accruals and asset retirement obligations are estimates. The ceiling test is based on estimates of oil and natural gas reserves and commodity prices, production expenses and capital costs required to develop and produce those reserves. By their nature, these estimates are subject to measurement uncertainty, and the impact of differences between actual and estimated amounts on the consolidated financial statements of future periods could be material.

e) Inventory

Inventory is recorded at the lower of weighted average cost or net realizable value, measured by replacement cost.

f) Revenue recognition

Revenue from the sale of petroleum and natural gas is recorded when the title passes to a third party and collectibility is reasonably assured.

g) Property, plant and equipment

The Company follows the full cost method of accounting whereby all costs related to the acquisition, exploration and development of petroleum and natural gas reserves are capitalized. Such costs include lease acquisition costs, geological and geophysical expenses, carrying charges of non-producing property, costs of drilling both productive and non-productive wells, petroleum and natural gas production equipment and overhead charges related to exploration and development activities. Proceeds received from the disposition of property, plant and equipment are credited against the capitalized costs unless the disposition would significantly alter the rate of depletion and depreciation, in which case a gain or loss on disposal would be recorded.

All costs of acquisition, exploration and development of petroleum and natural gas reserves, associated tangible plant and equipment costs, and estimated costs of future development of proven undeveloped reserves are depleted using the unit of production method based on estimated proven reserves before royalties as determined by independent reservoir engineers. For purposes of this calculation, natural gas reserves and production are converted to equivalent units of oil based on relative energy content.

Depreciation of capital assets not related to petroleum and natural gas properties is provided using the straight line method over periods ranging from five to ten years.

Costs of unproved properties are initially excluded from petroleum and natural gas properties for the purpose of calculating depletion. These properties are assessed periodically to determine whether impairment has occurred. When proven reserves are assigned or the property is considered to be impaired, the cost of the property or the amount of the impairment is added to costs subject to depletion.

The Company reviews the carrying amount of its petroleum and natural gas properties (the "properties") relative to their recoverable amount (the "ceiling test") at each annual balance sheet date, or earlier if circumstances or events indicate impairment may have occurred. 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 in depletion.

h) Asset retirement obligations

The fair value of asset retirement obligations related to long-term assets is recognized as a liability in the period in which they are incurred. The fair value of the asset retirement obligations is estimated by discounting the expected future cash flows to settle the asset retirement obligations at the Company's credit adjusted risk free rate. Asset retirement costs equal to the discounted asset retirement obligations are capitalized as part of the cost of the associated capital asset and amortized to expense through depletion. In subsequent periods, the asset retirement obligations are adjusted for the passage of time and for any changes in the amount or timing of the underlying future cash flows.

i) Joint operations

Significant portions of the Company's exploration and production activities are conducted jointly with others and accordingly, the consolidated financial statements reflect only the Company's proportionate interest in such activities.

j) Foreign currency translation

Monetary assets and liabilities, denominated in foreign currencies, are translated into Canadian dollars at rates of exchange in effect at the balance sheet date. Other assets and revenue and expense items are translated at rates prevailing when they were acquired or incurred. Foreign exchange gains and losses are included in the statements of operations.

k) Flow-through shares

The resource expenditure deductions for income tax purposes related to exploratory and development activities funded by flow-through share arrangements are renounced to investors in accordance with tax legislation. Future tax liabilities and share capital are adjusted by the estimated cost of the renounced tax deductions at the date of renouncement.

l) Stock-based compensation plan

The company has a stock option plan for directors, officers and employees. The stock option plan is described in note 8(d). The compensation cost attributable to share options granted is measured at fair value at the grant date and expensed over the vesting period with a corresponding increase in contributed surplus.

m) Per share information

Basic per share amounts are calculated using the weighted average number of shares outstanding during the year. Diluted per share amounts are calculated based on the treasury-stock method, which assumes that any proceeds obtained on exercise of options would be used to purchase common shares at the average market price during the period. The weighted average number of shares outstanding is then adjusted by the net change.

n) Goodwill

Goodwill is the excess purchase price over the fair value of identifiable assets and liabilities acquired. Goodwill is not amortized. However, goodwill impairment is assessed annually, or as economic events dictate, by comparing the fair value of the net assets to its carrying value, including goodwill. If the fair value of the net assets is less than its carrying value, the fair value of the goodwill is compared with its carrying value to measure the amount of the goodwill impairment loss.

o) Income taxes

The Company follows the liability method of accounting for income taxes. Under this method the Company records future income tax assets and liabilities based on “temporary differences” (differences between the accounting basis and the tax basis of the assets and liabilities) measured using the enacted or substantively enacted tax rates and laws expected to apply when these differences reverse. The effect of a change in enacted or substantively enacted income tax rates on future income tax assets and liabilities is recognized in income in the period that the change occurs. Valuation allowances are assessed on the more likely than not criteria.

p) Financial instruments

i) Financial Instruments

Section 3855 establishes a framework for classifying and measuring financial instruments. Under this section all financial instruments must be initially recognized at their fair value on the balance sheet. In accordance with section 3855, the Company has classified each financial instrument into the five categories set out in the standard: financial assets and liabilities held for trading, financial assets held to maturity, loans and receivables, financial assets available for sale and other liabilities. Measurement of each of these items is contingent upon initial classification. Unrealized gains and losses on financial instruments classified as held for trading are recognized in the statements of operations in the period incurred. Gains and losses on assets available for sale are recognized in other comprehensive income, and are charged to the statements of operations when the asset is derecognized or impaired. The amortized cost using the effective interest rate method is applied to the remaining categories of financial instruments.

The Company’s marketable securities are classified as held for trading. Any changes in the fair value of the marketable securities at the end of the fiscal period are classified as unrealized gains or losses on the statement of operations.

The classification of financial instruments occurred upon adoption of the standard, and is irrevocable.

ii) Derivative instruments and hedging

To manage its exposure to the volatility in commodity prices the Company may enter into oil and natural gas risk management contracts to protect its cash flow on future sales but the Company does not designate these contracts as hedges for accounting purposes. For outstanding contracts an unrealized gain or loss is recorded based on the change in fair value (mark-to-market) of the contracts at each reporting period end. These instruments would be recorded as unrealized risk management assets/liabilities on the consolidated balance sheets.

iii) Embedded derivatives

An embedded derivative is a component of a financial instrument or other contract that has a feature similar to a derivative. Accounting section 3855 requires certain embedded derivatives be identified and recorded separately from the host contract if the economic characteristics and risks of the embedded derivative are not closely related to that of the host contract. The terms of the embedded derivatives are the same as the terms of a freestanding derivative, and the hybrid instrument is not re-measured at fair value. At December 31, 2009 Questerre had no embedded derivatives.

iv) Comprehensive income

Comprehensive income is the change in equity of the Company from the statements of operations and other comprehensive income (“OCI”). OCI consists of the change in the fair value of any financial instruments classified as available for sale. Amounts recognized in OCI must eventually be reclassified to the statements of operations when the related gains or losses are realized.

q) Changes in Accounting Policies

On January 1, 2009, the Company adopted Canadian Institute of Chartered Accountants ("CICA") Handbook Section 3064, “Goodwill and Intangible Assets”. The new standard replaces the previous goodwill and intangible asset standard and revises the requirement for recognition, measurement, presentation and disclosure of intangible assets. The adoption of this standard was applied retroactively and has had no material impact on Questerre’s consolidated financial statements.

In June 2009, the CICA issued amendments to CICA Handbook Section 3862, Financial Instruments – Disclosures. The amendments include enhanced disclosures related to the fair value of financial instruments and the liquidity risk associated with financial instruments. The amendments will be effective for annual financial statements for fiscal years ending after September 30, 2009 and are consistent with recent amendments to financial instrument disclosure standards in International Financial Reporting Standards (IFRS). The adoption of this section required enhanced disclosures on Questerre’s consolidated financial statements.

This section was amended to require disclosures about the inputs to fair value measurements, including their classification within a hierarchy that prioritizes the inputs to fair value measurement.

The three levels of the fair value hierarchy are:

- Level 1 – Unadjusted quoted prices in active markets for identical assets or liabilities;
- Level 2 – Inputs other than quoted prices that are observable for the asset or liability either directly or indirectly; and
- Level 3 – Inputs that are not based on observable market data.

Questerre’s marketable securities are recorded at fair value using quoted market prices and are classified as level 1 in the fair value hierarchy.

r) Future Accounting Pronouncements

As of January 1, 2011, Questerre will be required to adopt the following CICA Handbook sections:

"Business Combinations", Section 1582, which replaces the previous business combinations standard. The standard requires assets and liabilities acquired in a business combination, contingent consideration and certain acquired contingencies to be measured at their fair values as of the date of acquisition. In addition, acquisition-related and restructuring costs are to be recognized separately from the business combination and included in the statement of operations. The adoption of this standard will impact the accounting treatment of future business combinations.

"Consolidated Financial Statements", Section 1601, which, together with Section 1602 below, replace the former consolidated financial statements standard. Section 1601 establishes the requirements for the preparation of consolidated financial statements. The adoption of this standard should not have a material impact on Questerre's Consolidated Financial Statements.

"Non-controlling Interests", Section 1602, which establishes the accounting for a non-controlling interest in a subsidiary in the consolidated financial statements subsequent to a business combination. The standard requires a non-controlling interest in a subsidiary to be classified as a separate component of equity. In addition, net earnings and components of other comprehensive income are attributed to both the parent and non-controlling interest. The adoption of this standard should not have a material impact on Questerre's Consolidated Financial Statements.

3. Acquisitions

Terrenex Ltd.

Effective April 30, 2008, Questerre acquired all the outstanding common shares and preferred shares of Terrenex Ltd. ("Terrenex").

Terrenex was a related party with common directors and officers. Terrenex's principal assets were a working interest in sixteen exploration licenses and a seismic database in the Québec St. Lawrence Lowlands and 10,698,785 Questerre common shares. On February 22, 2008, the Company entered into an agreement to acquire Terrenex for consideration of 15,892,785 common shares and $0.50 million in cash. On April 27, 2008, the agreement was amended and the share consideration increased to 18,910,403 common shares. On April 28, 2008, the transaction received the requisite Terrenex shareholder, regulatory and Court approval. Net of the 10,698,785 Questerre common shares held by Terrenex at the time of acquisition, a total of 8,211,618 common shares were issued for the acquisition.

This related party transaction has been measured at the carrying amount of the items exchanged. Accordingly, the property, plant and equipment were recorded at a book value of $764,291. The Questerre common shares, held by Terrenex, were recorded at $23,109,376, the carrying value of the Questerre common shares at the date of acquisition. On September 30, 2009, these shares were cancelled and the cancellation has been recorded as $10,315,647 being deducted from common shares and $12,793,729 as an increase to the deficit. Cash and transaction costs were $680,161. In addition, a future income tax liability of $2,884,415 was recognized on acquisition and has subsequently been adjusted to $1,628,100 on the dissolution of Cabernet Holdings Ltd., a wholly owned subsidiary of Terrenex Ltd. Based on the carrying amount of the assets acquired, the common shares issued as part of this transaction have been assigned a value of $20,309,091.

4. Property, Plant and Equipment

December 31, 2009	**Cost**	**Accumulated Depletion and Depreciation**	**Net Book Value**
Petroleum, natural gas properties and equipment	**$ 172,880,877**	**$ (89,041,579)**	**$ 83,839,298**
Other assets	**1,565,779**	**(1,118,242)**	**447,537**
	$ 174,446,656	**$ (90,159,821)**	**$ 84,286,835**

December 31, 2008	Cost	Accumulated Depletion and Depreciation	Net Book Value
Petroleum, natural gas properties and equipment	$ 160,876,202	$ (73,445,130)	$ 87,431,072
Other assets	1,524,810	(841,536)	683,274
	$ 162,401,012	$ (74,286,666)	$ 88,114,346

During the year ended December 31, 2009, the Company capitalized administrative overhead charges of $571,651 (December 31, 2008: $2,090,419) directly relating to exploration and development activities.

At December 31, 2009, property, plant and equipment included $23,621,537 (December 31, 2008: $19,889,320) relating to unproved properties which have been excluded from the depletion calculation. Amounts are carried at the lower of cost or fair value. Included in the depletion calculation are future development costs of $6,154,700 (December 31, 2008: $5,355,000).

The Company has performed an impairment test as of December 31, 2009, using the estimated average sales price for each of the next five years as follows:

Year	**2010**	**2011**	**2012**	**2013**	**2014**
AECO Gas (C$/MMBtu)	6.05	6.75	7.15	7.45	7.80
Edmonton Light Oil (C$/bbl)	83.20	87.00	91.00	95.00	99.20

The benchmark prices are projected to increase by an average of 2% after 2014.

5. Marketable Securities

Marketable securities represent investments in shares of public companies which are designated as held for trading and are stated at fair value. Any unrealized gains or losses are recognized in the statements of operations for the period in which they arise.

The following table sets out the changes in marketable securities:

		December 31 2009		December 31 2008
Balance, beginning of period	**$**	**198,080**	$	1,979,250
Purchase of marketable securities		**–**		295,942
Sale of marketable securities		**(12,058)**		(1,274,551)
Realized gain (loss) on sale of marketable securities		**106**		(711,929)
Unrealized gain (loss) on marketable securities		**18,208**		(90,632)
Balance, end of period	**$**	**204,336**	$	198,080

6. Bank Indebtedness

The Company has a $5 million revolving credit facility with a Canadian chartered bank. The advances bear interest at the bank prime rate plus 1.5%. The authorized limit is currently under review and the Company is evaluating its requirements for this facility in light of its cash position and planned capital programs in 2010. The facility is collateralized with a $20 million fixed and floating charge debenture over the assets of the Company. As at December 31, 2009, there were no amounts outstanding under this facility.

7. Asset Retirement Obligations

The total future asset retirement obligation was estimated by management based on Questerre's net ownership interest in all wells and facilities, estimated costs to reclaim and abandon wells and facilities and the estimated timing of the costs to be incurred in future periods. At December 31, 2009, the Company estimates its total undiscounted asset retirement obligation to be $9,578,736 (December 31, 2008: $9,840,101). These payments are expected to be made over the next 30 years. Commencing October 1, 2008, incremental asset retirement obligations are calculated using a credit adjusted risk-free rate of 12 percent. Asset retirement obligations prior to this period were calculated using a credit adjusted risk-free rate of 7 percent. An inflation rate of three percent over the varying lives of the assets remains unchanged to calculate the present value of the asset retirement obligations.

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

		December 31 2009		December 31 2008
Balance, beginning of period	**$**	**4,994,862**	$	4,578,140
Revision in estimates		**–**		829,910
Liabilities incurred		**56,103**		423,934
Accretion expense		**424,335**		248,481
Liabilities settled		**(710,647)**		–
Property dispositions		**–**		(1,085,603)
Balance, end of period	**$**	**4,764,653**	$	4,994,862

8. Share Capital

a) Authorized

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, 2009, there were no Class B common voting shares or preferred shares outstanding.

b) Issued and Outstanding – Class A Common Shares

	Number	Amount
Balance, December 31, 2007	168,930,470	$ 97,341,561
Issued for cash on exercise of options	4,032,554	1,514,378
Issued on acquisition of Terrenex Ltd. [1]	8,211,618	20,309,091
Issued on private placement	7,500,000	35,250,000
Issued on prospectus offering	8,625,000	40,537,500
Reclassification to share capital on exercise of stock options		842,361
Share issue costs		(3,803,879)
Balance, December 31, 2008	197,299,642	191,991,012
Issued for cash on exercise of options	2,422,501	1,285,333
Reclassification to share capital on exercise of stock options		745,945
Cancellation of shares [2]	–	(10,315,647)
Balance, December 31, 2009	**199,722,143**	**$ 183,706,643**

(1) Net of the pending cancellation of 10,698,785 Questerre common shares held by Terrenex, a total of 8,211,618 common shares were issued for the acquisition (See Note 3).

(2) On September 30, 2009, 10,698,785 Questerre common shares that were acquired in the Terrenex Ltd. acquisition were cancelled. The cancellation has been recorded as $10,315,647 being deducted from common shares and $12,793,729 as an increase to the deficit. Due to the pending cancellation of the 10,698,785 Questerre common shares at the time of acquisition in 2008, the cancellation has already been factored into the opening number of shares outstanding and therefore no outstanding share amounts need to be adjusted for in 2009.

In the second quarter of 2008, Questerre completed a $75.79 million equity offering at $4.70 per common share. The offering consisted of the issuance of 7,500,000 common shares on a private placement basis in Norway and 8,625,000 common shares through a short form prospectus in Canada.

c) Per share amounts

The following table summarizes the weighted average common shares used in calculating the net loss per common share:

	2009	2008
Basic	**197,940,390**	186,447,776
Diluted	**206,729,689**	196,593,333

For the diluted amounts 8.79 million shares (2008 – 10.15 million) were added to the basic weighted average number of shares outstanding. These share additions represent the dilutive effect of stock options according to the treasury stock method.

For the purpose of calculating the diluted net loss per share for the years ended December 31, 2009 and 2008, incremental shares from assumed exercise of stock options are not included due to their anti-dilutive effect.

d) Stock options

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

The following table sets forth a reconciliation of the stock option plan activity:

	Number of Options	Weighted Average Exercise Price
Outstanding, December 31, 2007	13,064,170	$ 0.59
Granted	9,045,000	1.80
Forfeited	(421,195)	1.02
Exercised	(4,032,554)	0.38
Outstanding, December 31, 2008	17,655,421	1.26
Granted	3,520,000	2.26
Forfeited	(134,167)	2.40
Exercised	(2,422,501)	0.53
Outstanding, December 31, 2009	**18,618,753**	**$ 1.53**
Exercisable, December 31, 2009	**10,568,530**	**$ 0.87**

The following table summarizes information about stock options outstanding and exercisable at December 31, 2009:

	Options Outstanding			Options Exercisable	
Range of Exercise Price	Common Shares Issuable	Weighted Average Years to Expiry	Weighted Average Exercise Price	Common Shares Issuable	Weighted Average Exercise Price
$0.40 - $0.54	7,248,334	2.24	$0.44	5,201,660	$0.43
$0.65 - $0.82	3,646,669	1.21	0.77	3,556,668	0.80
$1.28 - $1.80	2,423,750	3.51	1.55	1,142,917	1.36
$2.37 - $2.78	2,765,000	5.75	2.49	219,791	2.77
$4.40 - $4.70	2,535,000	3.45	4.70	447,494	4.70
	18,618,753	2.89	$1.53	10,568,530	$0.87

e) Stock-based compensation costs

The Company accounts for its stock based compensation plan using the fair value method. Under this method, compensation cost attributable to share options granted to employees, officers or directors is measured at fair value at the grant date and expensed over the vesting period with a corresponding increase to contributed surplus. The exercise of stock options is recorded as an increase in common shares with a corresponding reduction in contributed surplus. Forfeiture of options are recorded as incurred and any unvested stock based compensation expense is recorded as a reduction in the expense.

The fair value of each option granted is estimated on the date of grant using the Black-Scholes option pricing model with weighted average assumptions for grants as follows:

	2009	2008
Weighed average fair value per option ($)	**1.53**	1.27
Risk free interest rate (%)	**2.18**	3.01
Expected life (years)	**3.7**	3.0
Expected volatility (%)	**100**	97

f) Contributed surplus

The following table sets forth a reconciliation of contributed surplus:

Balance, December 31, 2007	$ 3,505,088
Stock-based compensation expense	4,076,503
Reclassification to share capital on exercise of stock options	(842,361)
Balance, December 31, 2008	6,739,230
Stock-based compensation expense	5,225,313
Reclassification to share capital on exercise of stock options	(745,945)
Balance, December 31, 2009	**$ 11,218,598**

9. Future Income Tax

The provision for income taxes in the consolidated financial statements differs from the result which would have been obtained in applying the combined federal and provincial tax rate to the Company's net loss before income taxes. The difference results from the following items:

	2009	2008
Net loss before income taxes	**$ (17,882,614)**	$ (6,735,702)
Combined federal and provincial tax rate	**29.57%**	30.00%
Computed "expected" income tax recovery	**(5,287,889)**	(2,020,711)
Increase (decrease) in income taxes resulting from:		
Non-deductible differences	**1,545,113**	1,394,929
Change in unrealized gain on investments	**(1,160,167)**	–
Rate adjustments	**1,340,798**	571,799
Previously unrecognized future tax asset now recognized	**–**	(1,089,141)
Valuation allowance	**(426,825)**	3,567,569
Current tax	**32,652**	67,560
Other	**(203,408)**	(15,093)
Income tax (recovery)	**$ (4,159,726)**	$ 2,476,912

The components of the Company's future income tax (liability)/asset are as follows:

	December 31 2009	December 31 2008
Future income tax assets:		
Asset retirement obligations	**$ 1,199,998**	$ 1,299,165
Share issue costs	**1,777,984**	2,536,440
Marketable securities	**23,530**	28,732
Non-capital loss carryforwards	**8,452,366**	5,571,530
Capital loss carryforwards	**103,214**	105,705
Valuation adjustment	**(5,924,147)**	(6,350,972)
	5,632,945	3,190,600
Future income tax liabilities:		
Petroleum and natural gas properties	**(2,518,312)**	(3,012,031)
Unrealized gain on investments	**(1,628,100)**	(2,884,414)
	(4,146,412)	(5,896,445)
Net future income tax (liability) asset	**$ 1,486,533**	$ (2,705,845)

Non-capital loss carryforwards at December 31, 2009 represent non-capital losses and expire from 2014 to 2029.

10. Financial Instruments

a) Risks associated with financial assets and liabilities

The Company holds various forms of financial instruments. The nature of these instruments and its operations expose the Company to market risk (commodity prices, foreign exchange rates and interest rates), credit risk and liquidity risk. The Company manages its exposure to these risks by operating in a manner that minimizes this exposure.

Market risk

Market risks are generally those risks that are outside of the control of the Company. These are: commodity prices, foreign exchange rates and interest rates. The objective of the Company is to mitigate exposure to these risks while maximizing returns to the Company.

- Commodity price risk
  Due to the volatility of commodity prices the Company is potentially exposed to adverse consequences in the event of declining prices. The Company may enter into oil and natural gas contracts to protect 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, 2009 the Company had no oil and natural gas risk management contracts in place.
- Foreign currency exchange 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, 2009 the Company had no forward foreign exchange contracts in place.
- Interest rate risk
  The Company's revolving demand loan facility is subject to floating rates and is therefore exposed to fluctuations in the market rate of interest. The floating rate debt is subject to interest rate cash flow risk, as the required cash flows to service the debt will fluctuate as a result of changes in market rates. The Company had no interest rate swaps or financial contracts in place at or during the year ended December 31, 2009.

Credit risk

Substantially all of the accounts receivable are with customers 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. Wherever possible, the Company requires cash calls from its partners on capital projects before they commence. Accounts receivable related to the sale of the Company's petroleum and natural gas production is paid in the following month from major marketing companies and the Company has not experienced any credit loss relating to these revenues.

The Company's accounts receivable are aged as follows:

Aging		
Current	$	2,789,481
31 – 60 days		366,425
61 – 90 days		178,568
> 90 days		4,073,841
Allowance for doubtful accounts		(2,899,112)
Balance, December 31, 2009	**$**	**4,509,203**

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 and 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, the Company will hedge a portion of its production to protect cash flow in the event of commodity price declines. In addition, the Company has access to a revolving credit facility which allows the Company to borrow money if required.

One of the Company's subsidiaries, Magnus has sought protection under the Bankruptcy and Insolvency Act (See Note 1). See Note 11 for disclosure related to the management of the Company's capital program. The Company's goal is to prudently spend its capital while maintaining its credit reputation amongst its suppliers.

b) Fair values of financial instruments

Questerre's financial assets and liabilities are comprised of cash and cash equivalents, marketable securities, accounts receivable, deposits, accounts payable and accrued liabilities.

The carrying and fair values of the Company's financial instruments as at December 31, 2009 are as follows:

	Carrying Value	Fair Value
Financial Assets		
Held-for-trading:		
Cash and cash equivalents	$ 51,396,052	$ 51,396,052
Deposits	440,582	440,582
Marketable securities	204,336	204,336
Loans and receivables:		
Accounts receivable	4,509,203	4,509,203
Financial Liabilities		
Accounts payable and accrued liabilities [1]	$ 10,530,509	$ 8,774,604

(1) The fair value of the Magnus payables of $1,755,905 cannot be estimated as the final settlement amounts are unknown and this has been deducted above to arrive at fair value (See Note 1).

The fair value of marketable securities is 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 would be classified as level 1 in the fair value hierarchy. Questerre's line of credit bears interest at a floating market rate. As at December 31, 2009 the company has no amounts outstanding. 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 the statements of operations for the period.

11. Capital Disclosures

The Company believes it is well capitalized to weather the current volatility in financial markets with positive cash flow from operations, no debt and a working capital surplus of over $46 million consisting mainly of cash and cash equivalents.

The majority of planned capital spending in 2010 will be incurred in Québec and is in part contingent upon the results of the pilot programs conducted by Questerre's partners. The Company does not currently anticipate using its line of credit to fund capital expenditures in 2010. The line of credit is believed to provide adequate contingency for unanticipated changes in capital spending or market conditions.

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 and reallocating capital to more profitable areas or reducing capital spending based on results and other market considerations.

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

	December 31 2009	December 31 2008
Shareholders' equity	**$ 129,977,202**	$ 137,189,444
Debt	**–**	–
Working Capital	**46,500,671**	54,307,989
	$ 176,477,873	$ 191,497,433

Questerre's objectives in managing its capital structure are to:

1. Create and maintain flexibility so that Questerre can continue to meet its financial obligations; and
2. Finance its growth either through internally generated cash flows, joint venture relationships or asset/corporate acquisitions which are financed primarily through share issuances.

The Company's capital is not subject to any external restrictions as to how capital is deployed nor does it have any financial covenants in respect of its bank credit facility.

12. Inventory

Inventory is carried at the lower of weighted average cost or net realizable value. For the year ended December 31, 2009, there were no write downs or reversals of previously written down amounts. During the year, $249,979 in fuel inventory was purchased (2008: $676,724) and $300,508 (2008: $529,059) was recognized as an expense.

13. Supplemental Cash Flow Information

		2009		2008
Cash interest paid	**$**	**–**	$	122,900
Cash taxes paid	**$**	**12,002**	$	155,946

14. Related Party Transactions

Questerre incurred fees of $63,000 for the year ended December 31, 2008 to Rupert's Crossing Ltd. ("Rupert's"). The payment was made for the termination of an Office Rental Agreement for the provision of office space, office equipment and support personnel in December 2007. Related to this, Rupert's sold office furniture and equipment to Questerre in 2008 for $39,595. These payments were in the normal course of operations, made on commercial terms and recorded at their exchange amounts. There were no transactions with Rupert's in 2009.

See Note 3 "Acquisitions – Terrenex Ltd."

15. Contractual Obligations and Commitments

The Company is obligated to make total payments under an operating lease of $115,811 in 2010 and $9,651 in 2011. Questerre has commitments under a lease for office space of $333,241 in 2010.

16. Comparative Figures

Certain comparative figures have been reclassified to conform with the current year's financial statement presentation.

17. Subsequent Event

In March 2010, Questerre closed an equity issuance of 30,000,000 Common Shares at a price of $4.30 per share for gross proceeds of approximately $129 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.

Corporate Information

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Patrick Quinlan

Bjorn Inge Tonnessen

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VP Exploration

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