2008 ANNUAL REPORT
QUESTERRE ENERGY CORPORATION

Questerre Energy Corporation is a Calgary-based petroleum and natural gas exploration and production company. The Company aims to create shareholder value through the development of scalable, high-impact projects. Questerre's common shares are listed on the Toronto Stock Exchange and Oslo Stock Exchange under the symbol QEC.

Cover image:
"All Hail the Triumphant"

Courtesy Kinsman Robinson Galleries, Toronto
in association with Master's Gallery Ltd., Calgary.

PRESIDENT'S MESSAGE

2008 was a remarkable year for Questerre.

Our business plan to find a large gas field onshore Canada came to fruition with a giant shale gas discovery in Quebec. Currently in pre-pilot commercialization, we believe this discovery will ultimately become a major shale play in North America. Shale gas is creating historic changes in North American energy markets and, through our discovery in Quebec, Questerre is participating in these changes.

Although eclipsed by the success in Quebec, we had good results with our entire portfolio during the year. We generated cash flow of over $17 million on average daily production of 1,178 boe/d and exited the year with no debt, positive cash flow and working capital in excess of $54 million, consisting mainly of cash and equivalents. This financial strength will be invaluable in current markets, allowing us to fully evaluate our discovery in Quebec without any need for additional capital.

Highlights

- Major shale gas discovery in Quebec
- Early success with Liard shale gas play at Beaver River
- Continued growth in conventional assets - successful drilling programs conducted in Antler and Greater Sierra
- Cash flow of over $17 million reflecting improved light oil weighting and higher commodity prices
- Replaced over 150% of production and increased proved plus probable reserves by 24%
- Increased financial strength with net working capital of over $54 million at year end

St. Lawrence Lowlands, Quebec

The Yamaska test results released in early April provided the stimulus to accelerate appraisal of the shale gas potential of the Lowlands. These wells confirmed the key technical characteristics of the Utica shale as a viable resource play with multi-Tcf potential, in particular, the ability to be successfully hydraulically fractured.

Multi-well programs were subsequently announced by our partners, Forest and Talisman, to test the Utica, the shallower Lorraine shale and the deeper Trenton Black-River group. Fracability of the Utica shale was further substantiated by exceptional results from Gentilly #1. The stimulation of a single interval by Talisman in this vertical well yielded sustained rates of over 800 mcf/d on an 18-day test.

We believe the stabilized flow rates from Gentilly #1 and rates between 100-800 mcf/d from prototype horizontal wells by Forest are remarkable. When measured against more established shale plays, these results place us well up the first year learning curve for a new shale play. The next steps involve analyzing the technical data from these initial wells, adding further results and testing one variable at a time to establish a commercially successful completion design.

Forest and Questerre have completed an initial analysis of the extensive data gathered on the pre-pilot horizontal wells. We are currently planning to re-enter and stimulate one of these wells this summer. We have also been working with Talisman on a plan to drill pre-pilot test wells in advance of a multi-well commercial pilot pad. These wells will likely be multi-stage fractured horizontals situated near existing vertical wells. This would allow for microseismic monitoring of the fracs to verify the stimulated rock volume and indirectly, recoverable reserves.

Recent market conditions have caused a more cautious approach which is slowing the original timeline for commercial development. Our partners continue to proceed with further work in the Lowlands to develop optimal drilling and completion techniques. We are confident that with the scale of this project, the potential for stacked shale plays, and a competitive fiscal environment it remains a priority for all participants.

Beaver River Field

The shale expertise gleaned from Quebec gave us new ideas to test the Liard shales at Beaver River.

A focus on mechanical rock properties led us to re-enter the A-5 well and test a brittle interval at the top one of the three organic-rich shale sequences. Initial production rates of approximately 5 mmcf/d are encouraging; however, an extensive testing period is necessary to verify contribution from the shale interval along with further technical analysis.

We were disappointed with the results from the A-8 Nahanni well as it represented over six years' technical work. We did, however, successfully mitigate the financial impact of this well through a farmout agreement that funded the majority of our portion of costs with partner capital.

Conventional Oil and Gas Assets

The acquisition of Magnus Energy and the farm-in at Greater Sierra late 2007 were validated by our work in 2008.

We successfully drilled 15 wells and stage fractured 17 wells at Antler, Saskatchewan targeting light oil from the Bakken/Torquay formation. On average, the higher initial rates and production to date from these wells are positive signs for both acceleration of and increases in ultimate recovery. Notwithstanding the returns on capital invested in Antler at current oil prices continue to meet internal hurdle rates, we postponed our winter program because the time for the return of our capital was too long. In the interim, we continue to add to our inventory of drill-ready locations.

Two horizontal Jean Marie wells and a 46 square mile 3-D seismic survey earned us a 50% interest in a contiguous land block of over 50 sections at Greater Sierra in northeast BC. With multiple locations for the primary Jean Marie resource play, we see this acreage as a call on future natural gas prices. Further upside remains in the deeper horizons, where we have identified several leads on the 3-D survey.

Modifying drilling and completion techniques could have a material impact on recoveries and economics at both these projects. At Antler, we are looking into changing the perforation and cluster design along with the size of the fracs. We plan to gather pressure data from our wells at Greater Sierra to assess the benefits of newer completion methods, particularly gas-fracturing.

Corporate

The acquisition of our founding shareholder, Terrenex, was highly accretive. Terrenex and its predecessors have been involved in natural gas exploration in the Lowlands since the late 1980s and were among the first to identify the fractured Utica shale as a prospective play.

Through this acquisition we consolidated our interest in the Lowlands by adding a net 27,000 acres and ownership of an invaluable seismic database of over 5,000 kms. Total consideration was a net 8.2 million Questerre shares and $0.5 million in cash.

The addition of Pierre Boivin to the Board strengthened our presence in Quebec. With a strong entrepreneurial background in the province, Mr. Boivin currently serves as President of the Montreal Canadiens, the Gillette Entertainment Group and the Bell Centre. We are certain he will play a vital role in the development of our acreage as we establish its strategic value to the province.

Operational and Financial

The production and reserve improvements over the year reflect the successful development of our conventional oil and gas assets.

The drilling program in Antler largely contributed to the growth in our proved and probable reserves to 2.9 mmboe from 2.3 mmboe and a 44% increase in the reserve life index to just over six years. Light oil from Antler and higher oil production from Vulcan positively impacted our product mix with oil and natural gas liquids representing 33% of total volumes, up from 13% last year. We also disposed of non-core assets that included medium grade crude and short-life gas production in the Grand Forks and Westlock areas of Alberta.

Despite lower volumes compared to last year, the oil weighting and operating netbacks benefited from higher prices and materially improved our cash flow to $17.29 million. This cash flow and existing working capital funded gross capital expenditures of approximately $44 million.

Outlook

We have established the following objectives for 2009:

- Maintain financial flexibility
- Obtain additional results from Quebec and establish a statistically meaningful set of results
- Streamline operations and reduce operating costs

Michael Binnion
President and Chief Executive Officer

AREAS OF OPERATIONS

St. Lawrence Lowlands, Quebec

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

The area is prospective for natural gas in several horizons with primary targets in the Lorraine and Utica shale/siltstone at a depth of 500m to 2000m and the Ordovician Trenton Black-River carbonates ("TBR") at approximately 2000m.

The majority of Questerre's landholdings of over one million gross acres lie in the heart of the fairway between two major geological features – a subsurface thrust fault known as Logan's Line to the east and the Yamaska growth fault to the west. This acreage is comprised of three separate blocks.

The largest block of 719,788 acres is subject to a farm-in and participation agreement with Talisman Energy. Upon Talisman completing their farm-in obligations in 2009, Questerre will hold an approximate 25% working interest and a 4 1/4% royalty on production.

The 113,453-acre Yamaska acreage is governed by a royalty and joint venture agreement with Gastem Inc. and Forest Oil and lies adjacent to the Talisman farm-in lands. Questerre recently converted its 7.5% gross overriding royalty into a 20% working interest in this block in the fourth quarter of 2008.

Questerre's third exploration block, St. Jean, covers 181,255 acres close to the US border. Questerre holds an average of a 56% working interest in this block with Gastem.

During 2008, work was conducted on all three blocks following the announcement of a significant Utica shale gas discovery by Forest Oil on the Yamaska permits in April.

Forest drilled and completed several horizontal wells in the Lowlands during the year with two on the Yamaska permits. Initial flow rates from these frac'd wells of 4 mmcf/d compare favorably to rates of up to 1 mmcf/d from the stimulated vertical wells with final rates ranging between 100 mcf/d and 800 mcf/d. Questerre anticipates Forest will expand this program in 2009 with future work to include the re-stimulation of the horizontal wells.

Drilling operations at Yamaska permits

Completion operations on St. David

A new focus on unconventional assets coupled with their extensive technical work on Questerre's acreage led Talisman to also announce plans to appraise the shale gas horizons in the Lowlands. A multi-well program included a commitment to drill the remaining three farm-in wells that would also test the Trenton Black-River.

Talisman's appraisal program began with the re-entry and re-completion of the Gentilly #1 discovery well. Stabilized results from a single Utica interval in this well of 800 mcf/d on an 18-day test exceeded expectations. Additional intervals were frac'd, though testing of these intervals was hampered by downhole obstructions and unavailability of equipment.

Two of the three earning wells, La Visitation #1 and St. David #1, were drilled prior to year-end with the third well, St. Edouard #1, drilled in early 2009. Multiple prospective shale intervals on the first two wells have been stimulated with preliminary results expected in mid 2009.

Notwithstanding current market conditions, Questerre believes that Talisman and Forest will continue the appraisal programs in the Lowlands albeit on a more measured basis by thoroughly analyzing results prior to conducting new operations.

To assess the potential of the shallower Utica shale to the south of the main fairway, Questerre spud the St. Jean sur Richelieu #1 well in the third quarter of 2008. Early results from a stimulation in 2009 were positive with sustained flow rates established. However, further work is required to improve the effectiveness of the stimulation to increase stabilized flow rates.

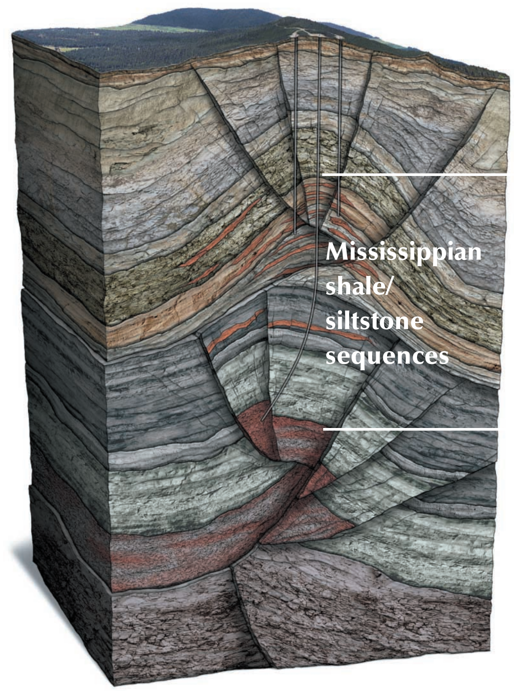
Northeast British Columbia

Beaver River

The Beaver River Field (the "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 1300m – 3300m and the Nahanni, a hydrothermally dolomitized carbonate sequence at a depth of approximately 3300m.

The 2008 winter work program completed the drilling and testing of the A-8 well that targeted a potential undrained compartment in the Nahanni formation. With final well results of less than 400 mcf/d and 900 bbl/d of formation water, Questerre has deferred further exploration work on the Nahanni in the near term.



Schematic cross section of Beaver River

Questerre revisited the prospective shale gas intervals at Beaver River during the summer to gather additional technical data. The program included a minor stimulation of a brittle dolomitic sequence which tested at a stabilized rate of 10 mmcf/d on a three-day test.

The well was placed on a long-term production test to determine the contribution from the underlying shale. Subject to results, Questerre has identified up to three additional recompletion candidates to further evaluate this shale interval.

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 1400m. The region is also prospective for shallower zones including the Mississippian Debolt and deeper Devonian Keg River and Slave Point formations.

In early 2008, Questerre earned a 50% interest in 34,560 acres through the acquisition of a 3-D seismic survey and the successful drilling and completion of two horizontal wells for the Jean Marie. The wells were completed and tied in to its partner's extensive gathering system that winter.

Early interpretations of the 3-D seismic survey have identified numerous prospects for the Jean Marie and several leads for the deeper formations. A 2010 drilling program is contingent upon improved natural gas prices and will initially pursue locations proximate to existing infrastructure to minimize tie-in costs. In conjunction with its partner, Questerre plans to assess different completion techniques for the Jean Marie to improve recovery.

Antler, Saskatchewan


Oil battery at Antler

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 1050m and 1150m.

Questerre conducted a pilot program in early 2008 to evaluate the benefits of stage fractured horizontal wells to maximize recovery of the underlying oil pool at Antler.

The pilot program was expanded during the summer and over the year 15 wells were drilled and 17 stimulated. The stabilized rates from these horizontal wells on average are 2 to 3 times the unstimulated rates. Based on these results, the Company estimates the stimulated horizontal wells could ultimately improve primary recovery of the oil in place up to 10%.

Utilizing a 3-D seismic survey acquired last winter, Questerre has established a drilling inventory of over 50 locations with in excess of 100 additional drilling locations remaining unevaluated. An initial 20 well program for this winter has been deferred pending a recovery in commodity prices. In the current environment, Questerre's project economics will focus on improving the payout of capital on a well by well basis.

The Company is evaluating refinements to the existing completion programs for the horizontal wells and further work on a water flood scheme to enhance recovery.

Alberta

Questerre's assets in Alberta are primarily located in Vulcan, southern Alberta.

The Vulcan area 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 1900m. Questerre participated in the discovery of two adjacent Manville pools in Vulcan in 2005 and 2006 and holds a 50% interest in both pools.

Development of the oil Mannville I Pool was a priority for Questerre in 2008. With its partner, Questerre drilled the first horizontal well into this pool that was subsequently stage fracture stimulated. Production rates were significantly higher than the existing vertical well with a test rate of 750 bbl/d and associated gas. Subject to the optimization of production facilities to alleviate facility constraints, Questerre is reviewing plans for two additional infill locations.

The proposed sale of non-core assets in Alberta was completed during year. Approximately 130 boe/d of medium crude and natural gas production primarily from the Grand Forks and Westlock areas respectively was sold to focus on developing operated properties with higher netbacks.

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 30, 2009. This MD&A is provided by Management of Questerre Energy Corporation ("Questerre" or the "Company") to review 2008 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, 2008 and 2007. 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 a junior oil and gas company involved in the exploration and development of scalable high-impact projects in Canada. To mitigate the risks associated with these projects, the Company has secured partners to assist in their development. To further diversify risk, the Company continues to develop a portfolio of conventional exploration and production 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;
- geological, technical, drilling and processing problems and other difficulties in producing oil, natural gas liquids and natural gas reserves; and
- the other factors discussed under "Risk Management" in this Management's Discussion and Analysis.

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.

Non-GAAP Terms

This document contains the terms "cash flow from operations", "netbacks", "working capital" and "average sales price" which are non-GAAP terms. The Company uses these measures to help evaluate its performance. 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. 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

	2008	2007
Cash flows from operating activities	**$ 23,466,056**	$ 2,275,299
Net change in non-cash working capital	**(6,176,758)**	7,953,721
Cash flow from operations	**$ 17,289,298**	$ 10,229,020

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.

Select Annual Information

As at/for the years ended December 31	**2008**	2007	2006
Financial ($)			
Petroleum and Natural Gas Sales	**29,805,568**	23,785,489	12,030,736
Cash Flow from Operations	**17,289,298**	10,229,020	5,076,419
Per share – Basic	**0.09**	0.07	0.04
Per share – Diluted	**0.09**	0.06	0.04
Net Earnings (Loss)	**(9,212,614)**	(1,281,674)	(876,835)
Per share – Basic	**(0.05)**	(0.01)	(0.01)
Per share – Diluted	**(0.05)**	(0.01)	(0.01)
Capital Expenditures, net of acquisitions and dispositions	**42,490,941**	15,462,461	29,328,854
Working Capital Surplus	**54,307,989**	10,007,846	22,596,421
Total Assets	**165,531,133**	93,074,767	71,039,440
Shareholders' Equity	**137,189,444**	71,627,841	59,163,470
Common Shares Outstanding	**197,299,642**	168,930,470	155,171,750
Weighted average – basic	**186,447,776**	157,078,211	132,918,644
Weighted average – diluted	**196,593,333**	163,260,612	137,493,898
Operations (units as noted)			
Average Production			
Crude Oil and Natural Gas Liquids (bbls/d)	**385**	176	113
Natural Gas (mcf/d)	**4,761**	7,282	3,984
Total (boe/d)	**1,178**	1,390	778
Average Sales Price			
Crude Oil and Natural Gas Liquids ($/bbl)	**99.42**	71.42	63.08
Natural Gas ($/mcf)	**8.99**	7.17	6.46
Total ($/boe)	**69.13**	46.88	42.37
Netback ($/boe)			
Total Revenue	**69.13**	46.88	42.37
Royalties	**11.55**	11.06	9.92
Percentage	**17**	24	23
Field Operating Expense	**14.05**	12.07	9.86
Operating Netback	**43.53**	23.75	22.59
Net Cash G&A	**6.66**	5.44	5.64
Cash Netback	**36.87**	18.31	16.95
Wells Drilled			
Gross	**19.0**	17.0	20.0
Net	**12.1**	10.3	10.2

Quarterly Financial Information

	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

Highlights

- Major shale gas discovery in Quebec
- Early success with Liard shale play at Beaver River
- Continued growth in conventional assets — successful drilling programs conducted in Antler and Greater Sierra
- Cash flow of over $17 million reflecting improved light oil weighting and higher commodity prices
- Increased financial strength with net working capital of over $54 million at year end

2008 Activities

St. Lawrence Lowlands, Quebec

In 2008, activity in the Lowlands focused on the Utica and Lorraine shale horizons with industry partners commencing work programs to assess their commerciality.

The announcement of a significant Utica shale gas discovery by Forest Oil ("Forest") on the Yamaska permits in April led to an initial program of multiple horizontal wells.

Forest drilled the majority of these wells on the Yamaska acreage and successfully completed each with a four-stage fracture stimulation. Initial flow rates of 4 mmcf/d compare favorably to rates of up to 1 mmcf/d from the vertical wells stimulated earlier in the year. On longer term testing, rates from the horizontals ranged between 100 mcf/d and 800 mcf/d. Questerre anticipates Forest will expand this program in 2009 with future work to include the re-stimulation of the horizontal wells. Upon the completion of the initial work program by Forest, Questerre converted its 7.5% gross overriding royalty into a 20% working interest in the Yamaska acreage in the fourth quarter of the year.

During the second quarter of the year, Talisman Energy Inc. ("Talisman") also announced plans to appraise the shale gas horizons in the Lowlands. Their multi-well program included a commitment to drill the remaining three farm-in wells and earn a 75% interest in the 719,000 acre block with Questerre. In addition to the shale horizons, these three wells also tested the deeper Trenton Black-River carbonate group.

Talisman's appraisal program began with the re-entry and re-completion of the Gentilly #1 discovery well. Following a slick-water fracture stimulation of a single interval in the Utica, the well flowed at a stabilized rate of 800 mcf/d on an 18-day test. Additional intervals were stimulated, though testing of these intervals was hampered by downhole obstructions and unavailability of equipment.

Two of the three Talisman earning wells, La Visitation #1 and St. David #1, were drilled to target depth in the second half of the year with the final well, St. Edouard #1 spud in the first quarter of 2009. Prospective sequences in the Lorraine and Utica in the first two wells have been stimulated. The operator, Talisman, is expected to report on preliminary test results from this program during the second and third quarter of 2009.

Notwithstanding current market conditions, Questerre believes that Talisman and Forest will continue the appraisal programs in the Lowlands albeit on a more measured basis by thoroughly analyzing results prior to conducting new operations.

To assess the potential of the shallower Utica shale to the south of the main fairway, Questerre spud the St. Jean sur Richelieu #1 well in the third quarter of 2008. The well was drilled to a target depth of approximately 500m and fracture stimulated in early 2009. Early results are that the well is gas bearing and reasonable pressures were encountered. Following the stimulation, sustained gas flow rates were established. However, the stimulation was marginally successful and further work is required to improve its effectiveness to increase sustained flow rates.

Northeast British Columbia

Beaver River Field

Work programs were conducted during the year for the two prospective horizons at the Field.

The winter work program centered on the completion and testing of the A-8 well for the deep Nahanni formation.

With a significant fault identified on a reprocessed 3-D seismic survey, the primary target for this well was a potentially undrained Nahanni fault block. Final test results for the A-8 well of 400 mcf/d and 900 bbl/d of formation water were well below expectations. The results are indicative of the fault not sealing as originally predicted. Further testing of this horizon will be contingent on capital and equipment availability.

The summer work program was planned to re-evaluate the shale intervals at the Field based on an analysis of the mechanical rock properties.

Following the stimulation of a brittle interval overlying an organic rich shale sequence in the A-5 well, the well flowed natural gas at a stabilized rate of 10 mmcf/d over a three day test. The well is currently on a long-term production test to determine the contribution from the underlying shale. Subject to results, Questerre has identified up to three additional recompletion candidates to further evaluate this shale interval.

Greater Sierra

Through a farm-in agreement with EnCana Corporation ("EnCana"), Questerre established a new core area in the Greater Sierra region of northeast British Columbia early in the year.

Questerre committed to the drilling and completion of two horizontal wells for the primary Jean Marie formation and the acquisition of a 46 square mile 3-D seismic survey to earn a 50% interest in 54 sections of land. Total costs for the program were approximately $12 million.

Drilling and completion operations on the two horizontal wells were finalized in the first quarter and the wells were subsequently tied-in by EnCana to their local gathering system. Questerre holds a 50% interest in these wells.

The seismic acquisition program was operated by EnCana and completed in March ahead of schedule and under budget. An early interpretation of the 3-D seismic survey has identified numerous prospects in the target Jean Marie and several leads in the deeper Keg River and Slave Point formations.

Low commodity prices coupled with significant infrastructure costs for the primary Jean Marie locations led Questerre and EnCana to cancel their proposed 6-8 well winter drilling program for 2009. Future drilling at Greater Sierra will leverage higher commodity prices and initially target locations proximate to existing infrastructure.

Antler, Saskatchewan

Questerre conducted a pilot program in early 2008 to evaluate the benefits of stage fractured horizontal wells to maximize recovery of the underlying oil pool at Antler.

Over the year a total of 15 (10.0 net) horizontal wells were drilled and 17 (10.5 net) fracture stimulated. The stabilized rates from the stimulated horizontal wells on average are 2 to 3 times the unstimulated rates and 10 to 15 times the rates from stimulated vertical wells. These rates are consistent with the experience of other operators in the area. Based on these results, the Company estimates the stimulated horizontal wells could increase primary recovery of the oil in place up to 10%.

Utilizing a 3-D seismic survey acquired last winter, Questerre has established a drilling inventory of over 50 locations. An initial 20 well drilling program for this winter has been suspended pending a recovery in commodity prices to improve the payout of capital on a per well basis.

The Company is also evaluating refinements to the existing completion techniques for the horizontal wells and a possible water flood scheme to further enhance recovery.

Southern and Central Alberta

Questerre rationalized its assets in the province through development drilling in southern Alberta and the sale of non-core assets in central Alberta.

During the winter of 2008, Questerre finalized the drilling of its first horizontal well into the Mannville I Pool (the "I Pool"). The Company has a 50% interest in the well and the I Pool. The well was stimulated with a four stage selective frac and tested at a facility constrained rate of 750 bbl/d with associated gas and less than a 10% water cut. The well was placed on production during the summer at a restricted rate of approximately 300 boe/d.

With receipt of Good Production Practice status for the I Pool in July, a plan to optimize production facilities is being formulated. Once finalized, Questerre will evaluate its participation in up to two additional infill locations for the I Pool.

Questerre disposed of approximately 130 boe/d of production in the Hector, Grand Forks and Westlock areas of Alberta. These dispositions reflect the Company's objective to improve the netbacks and reserve life of its assets.

Drilling Activities

In 2008, Questerre participated in the drilling of 19 (12.1 net) wells, comprising of 15 (10.0 net) oil wells and four (2.1 net) natural gas wells. In 2007, Questerre participated in the drilling and testing of 17 (10.3 net) wells resulting in three (1.2 net) natural gas wells, five (3.0 net) oil wells, three (2.3 net) dry holes and six (3.8 net) suspended wells.

Corporate

Equity Offerings

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.

Acquisition of 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 Quebec 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.

Restructuring

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. Final Court approval for this proposal is expected in the first half of 2009. No adjustments have been made to the carrying values of the liabilities pending receipt of this approval.

Production

For its conventional assets, Questerre achieved its objectives for 2008 with an increase in higher quality oil production. Despite a 15% decrease in daily production volumes to 1,178 boe/d in 2008 from 1,390 boe/d in the prior year, light oil and natural gas liquids grew to represent approximately 33% of sales volumes as compared to just under 13% in 2007.

The increased oil weighting in Questerre's product mix largely reflects the Company's successful drilling program in the Antler area of southeast Saskatchewan where it participated in the drilling and fracture stimulation of multiple horizontal wells. Oil production also benefited from the development of the Company's light oil Mannville I Pool in Vulcan, Alberta during the year. Contingent on improved commodity prices, Questerre expects that further drilling in Antler will increase the oil weighting to approximately 50% in 2009.

As a proportion of Questerre's daily production volumes in 2008, Alberta remained the largest contributor. Production from operated and non-operated properties accounted for 645 boe/d, or nearly 55% of total volumes in 2008, down markedly from 1,131 boe/d and 81% in 2007. Production from the Mannville G and I Pools in Vulcan added 476 boe/d in 2008 and 860 boe/d in 2007, approximately three quarters of the Alberta volumes in both years. Subject to further development drilling of the I Pool, production from Alberta is likely to be under 50% for the Company in 2009. Questerre also disposed of approximately 130 boe/d of Alberta production acquired through the purchase of Stride Energy in 2006. This consisted mainly of medium crude production in Grand Forks and comparatively short-life natural gas production in Westlock.

Production from British Columbia of 286 boe/d (2007: 249 boe/d) was split between the Beaver River Field and the new core area at Greater Sierra. Shale gas at Beaver River from the A-2 and A-7 wells declined to 197 boe/d (2007: 249 boe/d) due to both natural production profile and a shut-in during the second half of the year during a period of low natural gas prices. Questerre commenced test production from a third shale well, A-5, in December with startup delayed by unseasonably cold weather. Overall production gains at Beaver River in 2009 will be limited as the high flowing pressure from A-5 will back out the existing wells. Questerre also completed the drilling of two horizontal Jean Marie natural gas wells in 2008 at Greater Sierra that added the remaining 89 boe/d over the year.

The acquisition of Magnus in late 2007 added Antler as a new core area targeting light oil production from the Torquay/Bakken formation. A successful pilot program to test stage fractured horizontal wells was expanded during the summer and resulted in production growth from 10 boe/d in 2007 to 247 boe/d in 2008. Questerre continues to build its inventory of locations in Antler for future drilling in a higher pricing environment.

Excluding the disposition of approximately 130 boe/d, daily production in 2008 remained relatively unchanged from the prior year, consistent with the Company's guidance. A higher proportion of light oil production capitalized on stronger commodity prices and materially improved the company's netbacks on a boe basis. In the context of the current financial and commodity markets, the Company has scaled back its entire development drilling program for this year. Subject to changes to its drilling program for higher commodity prices, production for 2009 is expected to average between 800 boe/d and 1,000 boe/d.

2008 Financial Results

Revenue

Year over year, petroleum and natural gas revenue increased by approximately 25% to $29.81 million from $23.79 million in 2007. Significantly higher oil and natural gas prices during the majority of 2008 offset the decline in production volumes from the prior year. Gross revenue also benefited from the increased oil weighting in 2008 which leveraged the higher oil prices.

Crude oil prices in 2008 mirrored the dramatic changes in the global economy during the year. Concerns about growing demand from emerging economies and 'peak oil' in the first half of the year contributed to oil prices averaging a high of $138/bbl in July. The global credit crisis and ensuing demand destruction in the latter part of the year saw prices subsequently fall to average $41/bbl in December.

With the disposition of its medium crude assets in Grand Forks early in the second quarter, Questerre's oil production for 2008 was light sweet oil from Antler and light oil and natural gas liquids from Vulcan. The improvement in product quality translated into a realized price of $99/bbl that was on par with the Edmonton Light average of $102/bbl for the year. In comparison, in 2007, Questerre's realized price averaged $71/bbl with the reference price averaging $77/bbl.

Natural gas prices tracked changes in crude oil prices throughout the year. High oil prices and supply concerns saw prices rise to an average of $11.22/mcf in June 2008 and subsequently fall to an average of $6.62/mcf in December 2008 on concerns of industrial demand and oversupply from North American unconventional gas sources.

Representing the largest component of natural gas volumes, higher heat content production from Vulcan continued to positively impact realized natural gas prices. Unchanged from the prior year, Questerre received a premium to the reference AECO price. For 2008, Questerre sold its natural gas at an average price of $8.99/mcf (2007: $7.17/mcf) in comparison to an AECO daily index price of $8.16/mcf (2007: $6.44/mcf).

Petroleum and natural gas revenue for 2008 was supplemented by a modest realized gain on risk management activities. Questerre realized a gain of $0.11 million for the year (2007: nil). The amount was derived from a contract of 2,000 GJ/d at $8.45/GJ from April 1 to October 31, 2008. Excluding this contract, all production is sold at the spot market price. The Company did not hold any risk management contracts as of December 31, 2008.

Royalties

Crown, freehold and overriding royalties for 2008 totaled $4.98 million, a decrease of 11% from $5.61 million in 2007. As a percentage of revenue this decreased to 17% from 24%.

The royalty rate on Alberta production decreased slightly to 22% from 25% in the prior year. This reflects a 35% increase in realized prices that offset a 43% decline in daily production volumes from the province over the year. Questerre anticipates the New Royalty Framework ("NRF") in Alberta which came into effect on January 1, 2009 to have a minimal impact on the Company's royalty rates. The combination of lower expected commodity prices and existing production rates will not result in a material change to its effective royalty rate. Questerre has no current plans to drill additional wells in Alberta and will not benefit from the additional royalty incentive programs announced in November 2008 and March 2009.

Production from British Columbia attracted a royalty rate of 20% in 2008 up from 18% in 2007. The rate increase is due to the A-7 well at Beaver River and the two wells at Greater Sierra that commenced production in the current year at a base royalty rate of 27%. In 2009, Questerre expects these wells to qualify under the Crown's ultra marginal gas well royalty program that would reduce these rates by approximately 50%. Furthermore, Questerre expects to benefit from a $0.50 million deep re-entry royalty credit for production from the A-5 well.

Questerre's production in Antler, Saskatchewan benefits from the lowest royalty rate of all the Company's producing areas. Including the Saskatchewan Capital Surcharge, royalties as a percentage of revenue were 6%. With a majority of wells in 2008 drilled on Crown acreage, Questerre participated in an incentive program that includes royalty rates of 2.5% up to cumulative production of 100,000 barrels per horizontal well.

Operating Costs

On an aggregate basis, Questerre's operating costs decreased marginally to $6.06 million in 2008 from $6.13 million in 2007. On a per unit of production basis, the decrease in production volumes resulted in operating costs increasing 16% to $14.05/boe from $12.07/boe in 2007.

The lower production volumes and the relatively fixed nature of costs at the Company's core areas in Antler, Vulcan and Beaver River account for a portion of the increase. Processing and transportation of natural gas at Midway through third party processing plants coupled with higher water disposal charges at Antler were also key contributors. More importantly, generally higher costs in 2008 illustrate the industry wide conditions during the year.

General and Administrative Expenses

Gross general and administrative expenses ("G&A") increased 20% in 2008 to $5.17 million from $4.30 million in 2007. On a boe basis, net G&A expenses increased 22% to $6.66/boe compared to $5.44/boe in 2007.

G&A expenses in 2008 reflect the additional staff and consulting expense to support an increase in operating activity in Antler and Quebec, professional fees incurred in evaluating several acquisition opportunities and higher office lease costs. The shale gas discovery in Quebec generated increased market activity with a corresponding increase in transfer agent fees, investor relations and travel expenses.

Consistent with prior years, the Company capitalizes expenses directly related to exploration and development activities. In 2008, Questerre capitalized $2.09 million (2007: $0.80 million) of G&A expenses and recorded overhead recoveries of $0.21 million (2007: $0.74 million) for capital projects it operated.

($ thousands)	**2008**	2007
General and administrative expenses	**$ 5,166**	$ 4,302
Capitalized expenses and overhead recoveries	**(2,295)**	(1,545)
General and administrative expenses, net	**$ 2,871**	$ 2,757

Stock-Based Compensation

Stock-based compensation expense for the year ended December 31, 2008 totaled $4.08 million (2007: $1.47 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 options life.

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. For Questerre, the expense mirrors the increased volatility of the Company's shares in 2007 and 2008. The expense is a non-cash item, and, upon exercise of options in fact results in increased cash.

The significantly higher amount is attributable to 9,045,000 options granted in 2008 which represents 51% of the outstanding options. The remainder of the outstanding options relate to option grants in the preceding four years. The weighted average fair value of these options granted in 2008 using the Black Scholes pricing model was $1.27 and the weighted average exercise price was $1.80. By comparison, in 2007 the Company issued 445,000 options at a weighted average fair value of $0.45 and an average exercise price of $0.96.

Other Income and Expenses

The net proceeds of the $75.79 million equity offering completed by Questerre in June earned interest income of $1.50 million in 2008 (2007: $1.06 million). The proceeds are invested in Guaranteed Investment Certificates issued by Canadian chartered banks with a maturity of less than one year.

Interest expense of $0.15 million (2007: $0.07 million) was incurred by the Company under its term credit facility during the year. The outstanding balance was paid down in the second quarter from the proceeds of the equity offering. As at December 31, 2008, Questerre did not have any amounts outstanding under this facility.

Questerre realized a loss of $0.71 million on the disposition of marketable securities during 2008 compared to a realized gain of $0.90 million in 2007. 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 2008, the Company recorded an unrealized loss of $0.09 million (2007: $0.79 million). At December 31, 2008, Questerre holds marketable securities with a market value of $0.20 million (2007: $1.98 million).

Questerre recorded an allowance for doubtful accounts of $1.73 million for amounts due from a joint venture partner. The Company is the operator of the joint property and amounts due to Questerre are secured by a first charge operators' lien on the property.

Depletion and Depreciation

Questerre recognized $17.23 million in depletion and depreciation in 2008 (2007: $13.55 million). This equates to $39.97 on a boe basis (2007: $26.70).

The primary reason for the increase on a gross and boe basis is the unsuccessful drilling results from the Beaver River field in 2007 which contributed to a significantly higher depletion cost base in 2008. Mitigating some of this increase is the reserve additions from the successful drilling program in Antler.

At December 31, 2008, Questerre excluded costs of $19.89 million (December 31, 2007: $11.90 million) relating to unproved properties and included $5.36 million (December 31, 2007: $2.70 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, 2008 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 of 3.45%, as currently prescribed by accounting standards, no impairment loss is recognized in 2008. The Company also did not incur a writedown of its assets in 2007.

The net cash flow from reserves is based on future prices forecasted by the Company's independent reserve engineers as of December 31, 2008. These prices are incorporated by reference from Note 4 of the Company's audited consolidated financial statements for the year ended December 31, 2008. Actual prices to date in 2009 have been less than this forecast. If this is revised downwards, there could be an impairment recognized as of March 31, 2009.

Accretion of Asset Retirement Obligations

For the year ended December 31, 2008, the non-cash accretion expense for asset retirement obligations is $0.25 million compared to $0.14 million in 2007. The increase is due to the obligations for wells drilled during 2008 and revisions to the estimates used to determine the asset retirement obligations. 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 $4.99 million as at December 31, 2008, based on a total future undiscounted liability of $9.84 million.

Income Taxes

For the year ended December 31, 2008, Questerre recorded a future income tax expense of $2.41 million compared to a recovery of $2.02 million in 2007. This represents the additional valuation allowance on new future income tax assets created in the year as they are not more likely than not to be realized offset by the reversal of previously unrecognized future income tax assets that are now likely to be realized.

Net Loss

Questerre recorded a net loss of $9.21 million for the year (2007: $1.28 million). The higher loss in 2008 is due to the increased non-cash expenses of stock-based compensation, depletion and depreciation, allowance for doubtful accounts and future income tax expense. In 2007, the loss includes a gain of $1.50 million on the sale of a working interest at Beaver River and a future income tax recovery of $2.02 million.

Capital Expenditures

In 2008, Questerre's capital expenditures, prior to acquisitions and dispositions, increased by 75% to $43.96 million from $25.16 million in 2007.

The majority of the capital expenditures in the year were incurred in the Antler area developing the assets acquired in the fourth quarter of 2007. Questerre was also active in the Greater Sierra drilling two wells and acquiring a 3-D seismic survey and at Beaver River with the completion and testing of the A-8 and A-5 wells. In the prior year, Questerre's capital expenditures targeted development of the Vulcan and Beaver River areas coupled with the acquisition of Magnus Energy in the fourth quarter. Questerre financed its capital expenditures largely through its cash flow and cash on hand at the beginning of the year.

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 Quebec participating in the drilling of four wells and the recompletion of the Gentilly #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.

In 2008, Questerre also disposed of some non-core assets in Alberta for $2.15 million.

($ thousands)	**2008**	2007
Capital Expenditures		
Alberta	**3,373**	8,332
British Columbia	**15,126**	13,118
Saskatchewan	**20,437**	2,708
Quebec	**4,795**	734
Corporate/Other	**226**	270
Expenditures on Property, Plant and Equipment	**43,957**	25,162
Dispositions (net of gain)	**(2,146)**	(8,499)
Acquisitions (cash portion)	**680**	301
Acquisitions (non-cash portion)	**84**	21,266
Asset Retirement Obligations	**168**	545
Total	**42,743**	38,775

Liquidity and Capital Resources

Questerre reported a working capital surplus of $54.31 million at December 31, 2008 as compared to a surplus of $10.01 million at December 31, 2007.

The Company's current assets consist of cash and short term investments of $65.38 million, $0.20 million of marketable securities, $8.05 million of accounts receivable, $0.35 million of inventory and $0.97 million in prepaids and deposits. Current liabilities of $20.64 million represent accounts payable and accrued liabilities. Questerre improved its working capital surplus through the equity issue and dispositions of non-core assets.

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 $54 million, consisting mainly of cash and cash equivalents.

The majority of planned capital spending in 2009 will be incurred in Quebec 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 credit facility to fund capital expenditures in 2009 or 2010. The line of credit is believed to provide adequate contingency for unanticipated changes in capital spending or market conditions.

The recent change in commodity prices will 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. Development of the Company's proved and probable undeveloped reserves as outlined in its Form 51-101 F1 "Statement of Reserves Data and Other Oil and Gas Information" will likely be funded from its existing working capital and timing is contingent on commodity prices.

Cash Flow from Operations and Cash Flows from Operating Activities

Cash flow from operations for 2008 was $17.29 million or 69% higher than the 2007 cash flow from operations of $10.23 million. Higher realized prices for both oil and natural gas is the primary reason for the significant year-over-year increase.

Cash flows from operating activities for 2008 was $23.47 million compared to $2.28 million in 2007. The change in the non-cash working capital of $14.13 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, 2008, 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 30 2009	December 31 2008	December 31 2007
Common shares	197,299,642	197,299,642	168,930,470
Stock Options	18,710,421	17,655,421	13,064,170
Weighted average common shares			
Basic		186,447,776	157,078,211
Diluted		196,593,333	163,260,612

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.

Pending the cancellation of 10,698,785 Questerre common shares held by Terrenex, the Company also issued a net 8,211,618 common shares for the acquisition of Terrenex.

A total of 4,032,554 common shares were issued pursuant to the exercise of stock options by directors, officers and employees during the year.

Off-Balance Sheet Arrangements

Questerre has no off-balance sheet arrangements.

Related Party Transactions

Questerre incurred fees of $63,000 for the year ended December 31, 2008 (2007: $122,430) to Rupert's Crossing Ltd. ("Rupert's"). The payment was made for the termination of an Office Rental Agreement between Questerre and Rupert's 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.

Effective April 30, 2008, Questerre acquired all the outstanding common shares and preferred shares of 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 Quebec 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.

Contractual Obligations and Commitments

Questerre has certain contractual obligations relating to the lease of office space and equipment rentals that extend for longer than one year as set out in the table below:

	Total	Less than 1 year	1 – 3 years	4 – 5 years	After 5 years
Equipment rentals	$241,273	$115,811	$125,462	–	–
Office lease	651,107	339,708	311,399	–	–
	$892,380	$455,519	$436,861	–	–

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.

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, have caused significant volatility to commodity prices. These conditions worsened in 2008 and are continuing in 2009, causing a loss of confidence in the broader U.S. and global credit and financial markets and resulting in the collapse of, and government intervention in, major banks, financial institutions and insurers and creating a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. These factors have negatively impacted company valuations and will impact the performance of the global economy going forward. Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and demand of these commodities due to the current state of the world economies, OPEC actions and the ongoing global credit and liquidity concerns.

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.

Receivables related to the sale of the Company's petroleum and natural gas production are from major marketing companies who have strong credit ratings. These revenues are normally collected on the 25th day of the month following delivery.

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.

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. Facilities are modern and are well maintained complying with environmental and safety regulations. The Company also mitigates the potential financial exposure of environmental risks by maintaining adequate insurance.

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. In 2002, the Government of Canada ratified the Kyoto Protocol (the "Protocol"), which calls for Canada to reduce its greenhouse gas emissions to specified levels. There has been much public debate with respect to Canada's ability to meet these targets and the Government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. Implementation of strategies for reducing greenhouse gases whether to meet the limits required by the Protocol or as otherwise determined could have a material impact on the nature of oil and natural gas operations, including those of the Company.

The Federal Government released on April 26, 2007, its Action Plan to Reduce Greenhouse Gases and Air Pollution (the "Action Plan"), also known as ecoACTION and which includes the Regulatory Framework for Air Emissions. This Action Plan covers not only large industry, but regulates the fuel efficiency of vehicles and the strengthening of energy standards for a number of energy-using products. Regarding large industry and industry related projects the Government's Action Plan intends to achieve the following: (i) an absolute reduction of 150 megatonnes in greenhouse gas emissions by 2020 by imposing mandatory targets; and (ii) air pollution from industry is to be cut in half by 2015 by setting certain targets. New facilities using cleaner fuels and technologies will have a grace period of three years. In order to facilitate the companies' compliance of the Action Plan's requirements, while at the same time allowing them to be cost-effective, innovative and adopt cleaner technologies, certain options are provided. These are: (i) in-house reductions; (ii) contributions to technology funds; (iii) trading of emissions with below-target emission companies; (iv) offsets; and (v) access to Kyoto's Clean Development Mechanism.

On March 8, 2008, the Alberta Government introduced Bill 3, the Climate Change and Emissions Management Amendment Act, which intends to reduce greenhouse gas emission intensity from large industries. Bill 3 states that facilities emitting more than 100,000 tonnes of greenhouse gases a year must reduce their emissions intensity by 12% starting July 1, 2008; if such reduction is not initially possible the companies owning the large emitting facilities will be required to pay a minimum of $15 per tonne for every tonne above the 12% target. These payments will be deposited into an Alberta-based technology fund that will be used to develop infrastructure to reduce emissions or to support research into innovative climate change solutions. As an alternate option, large emitters can invest in projects outside of their operations that reduce or offset emissions on their behalf, provided that these projects are based in Alberta. Prior to investing, the offset reductions, offered by a prospective operation, must be verified by a third party to ensure that the emission reductions are real.

Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact of those requirements on the Company and its operations and financial condition.

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 coal bed methane, would be conducted by a panel of experts with the assistance of individual Albertans and key stakeholders. The review panel produced its report and recommendations on September 18, 2007. The Government of Alberta considered these recommendations and obtained input from the public and the oil and gas sector on the recommendations and on October 25, 2008 issued its decision on the direction of royalties in the province. A summary of the Alberta Government's framework, which will impact Questerre is as follows:

Conventional Oil

Price-sensitive and volume-sensitive conventional oil royalty rates will become separate elements within a single sliding rate formula. New royalty rates will range from 0% to 50%, up from the current maximums of 30% and 35% for new and old vintages. Royalties will be calculated on a monthly production rate as is done currently and as collected, reported and used by industry.

The following royalty programs will be eliminated:

- Third Tier Exploratory Well Royalty Exemption
- Re-activated Well Royalty Reduction
- Low Productivity Well Royalty Reduction
- Horizontal Re-entry Well Royalty Program
- Experimental Project Petroleum Royalty

Oil project royalty programs like Enhanced Oil Recovery and the Innovative Energy Technology Program will be retained to encourage research and additional oil recovery. The tiers in conventional oil that distinguish vintages based on the discovery date will be eliminated. Rate caps on price will be raised for conventional oil to $120/bbl. Previously, maximum rates were reached at around $30/bbl for conventional oil.

Natural Gas

New royalty rates will range from 5% to 50%, up from ranges of 5% to 30% for new and 5% to 35% for old vintages.

The government plans to revamp the Deep Gas Drilling Program. The Government announced that royalty reductions will be available for deep gas wells. Deep gas wells included those over 2,000 metres of drilling length. Included in the deep well regime will be entire length of horizontal wells. The government will raise rate caps on the price of natural gas to $16.59/GJ. The cap will ensure the royalty system is sensitive over a broad range of prices. Previously maximum royalty rates were reached at around $3.70/GJ for natural gas.

Royalties for natural gas liquids will now be set at 40% for pentanes, a change from 22-50% for old tiers and 22-35% for new. The new royalties for butanes and propane will be 30%, up from 15-30%. The government will eliminate the option to use the Corporate Average Price to determine natural gas royalties.

For gas processing facilities, the government will move from using corporate effective royalty rates to calculate costs of the Crown's share of capital to establishing facility effective royalty rates. This will improve the link of capital costs for natural gas to a particular facility. The Alberta Royalty Review Panel had recommended going to deemed or set fees, an approach tried before in Alberta, but it does not recognize significant actual cost differences in processing plants. For gathering and compression, the government will continue to use set fees which recognize actual costs. The government will eliminate the tiers in conventional natural gas that distinguish vintages based on the discovery date to simplify the system. The Government views that under current economic conditions the difference between tiers is minimal. The government will retain the Otherwise Flared Solution Gas Royalty (OFSG) Waiver Program and extend it to bitumen wells. This program encourages solution gas conservation, rather than venting the gas, resulting in improved air quality.

In response to the significant reduction in activity and the global economic crisis, on November 19, 2008 the Alberta Government announced that for wells that commenced drilling after this date companies can elect, on a well by well basis to either have the NRF apply to the production from that well or have the old, pre-NRF rates apply for new wells between 1,000 and 3,500 metres in depth. This five-year transitional royalty system is designed to help stimulate drilling in Alberta. Questerre will make a determination on each well to see which method is most advantageous.

On March 3, 2009 the Alberta Government released a three-point incentive program aimed at stimulating new and continued economic activity for conventional producers. The highlights of the province's three-point plan include the following:

- A drilling royalty credit for new, conventional, oil and natural gas wells drilled between April 1, 2009 and March 31, 2010. This one-year program will provide a $200-per-metre-drilled royalty credit to companies on a sliding scale based on their production levels from the prior year.
- A new well incentive program, which offers a maximum five percent royalty rate for the first year of production from new oil or natural gas wells. This program also commences on April 1, 2009 and runs for one year.
- To encourage the clean-up of inactive oil and gas wells, the province will invest $30 million in a fund committed to abandoning and reclaiming old well sites.

It is envisaged for 2009 that both the NRF, in combination with low natural gas prices plus the new initiative announced on March 3, 2009 will have a negligible impact on Questerre's Crown royalty rates.

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.

Full Cost Accounting

Questerre follows the Canadian Institute of Chartered Accountants ("CICA") guideline on full cost accounting to account for its oil and natural gas properties. Under this method, all costs associated with the acquisition of, exploration for and development of natural gas and crude oil reserves are capitalized and costs associated with production are expensed. The capitalized costs are depleted using the unit-of-production method based on estimated proved reserves. Reserve estimates can have a significant impact on earnings, as they are a key component in the calculation of depletion. A downward revision in a reserve estimate could result in a higher depletion charge to earnings. In addition, if net capitalized costs are determined to be in excess of the calculated ceiling, which is based largely on reserve estimates, the excess must be written off as an expense and charged against earnings.

Oil and Gas Reserves

Questerre's proved oil and gas reserves are evaluated and reported on by an independent reservoir engineering firm. The estimation of reserves is a subjective process. Forecasts are based on engineering data, projected future rates of production, estimated commodity price forecasts and the timing of future expenditures, all of which are subject to a number of uncertainties and various interpretations. These estimates are the basis for the determination of the fair market value and the estimated net revenue stream of these reserves. The Company expects that its estimate 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 economics of recovery based on cash flow forecasts. Reserve estimates can have a significant impact on net earnings, as they are a key component in the calculation of depletion. A revision to the reserve estimate could result in a higher or lower deletion charge to net earnings. Downward revisions to reserve estimates could also result in a write-down of oil and natural gas property, plant and equipment under the ceiling test.

Asset Retirement Obligations

The Company recognizes asset retirement obligations in the period in which they are incurred if a reasonable estimate of fair value can be determined. 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.

Actual costs incurred upon settlement of the obligation are charged against the liability to the extent the liability is recorded. Any difference between actual costs incurred upon settlement of the asset retirement obligation and the recorded liability is recognized as a gain or loss in the Company's earnings in the period in which settlement occurs.

Determination of the original undiscounted retirement obligations and timing of these obligations are based on internal estimates using current costs and technology in accordance with existing legislation and industry practice. These estimates are subject to change over time and, as such, may impact the charge against earnings.

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 officers, directors and employees 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 expected exercise time 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 given that some will be forfeited upon termination of employment.

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 and production costs as at a specific reporting date but for which actual revenue, royalties and other costs have not yet been received. 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

Section 1535, "Capital Disclosures". This section establishes standards for disclosing information about an entity's objectives, policies and processes for how it manages its capital. A company must also disclose qualitative data about what the entity regards as capital; and whether the company has complied with any capital requirements and if not, the consequences of such non-compliance. The Company adopted this standard effective January 1, 2008.

Section 3862, "Financial Instruments – Disclosures". This section describes the required disclosures to evaluate the significance of financial instruments for the entity's financial position and performance as well as the nature and extent of risks arising from both recognized and unrecognized financial instruments to which the entity is exposed and how the entity manages those risks. The Company adopted this standard effective January 1, 2008.

Section 3863, "Financial Instruments – Presentation". This section establishes standards for presentation of financial instruments and non-financial derivatives. It details the presentation of the standards described in Section 3861, "Financial Instruments – Disclosure and Presentation". The Company adopted this standard effective January 1, 2008.

Section 3031, "Inventories". This section establishes standards for presentation of inventories. The new standard replaces the previous inventories standard and requires inventory to be valued on a first-in, first-out or weighted average basis, which is consistent with Questerre's former accounting policy. The new standard allows the reversal of previous write-downs to net realizable value when there is a subsequent increase in the value of inventories. The adoption of this standard has had no material impact on the Company's financial statements.

Future Accounting Pronouncements

In February 2008, the CICA's Accounting Standards Board confirmed that International Financial Reporting Standards ("IFRS") will replace Canadian generally accepted accounting principles 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 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.

The Company is currently analyzing accounting policy alternatives and identifying implementation options for the corresponding process changes. Questerre will update its IFRS changeover plan to reflect new and amended accounting standards issued by the International Accounting Standards Board. As IFRS is expected to change prior to 2011, the impact of IFRS on the Company's consolidated financial statements is not reasonably determinable at this time.

In February 2008, the AcSB issued Handbook Section 3064, "Goodwill and Intangible Assets" and amended Section 1000, "Financial Statement Concepts" clarifying the criteria for the recognition of assets, intangible assets and internally developed intangible assets. Items that no longer meet the definition of an asset are no longer recognized with assets. The standard is effective for fiscal years beginning on or after October 1, 2008 and early adoption is permitted. The adoption of this standard is not expected to have a material impact on Questerre's consolidated financial statements.

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

The Company's Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") are responsible for establishing and maintaining disclosure controls and procedures ("DC&P") and internal controls over financial reporting ("ICFR"). Questerre has documented and distributed to staff its policies, controls and procedures with respect to disclosure to third parties of information concerning the Company's operations and results. In addition, DC&P are designed to provide reasonable assurance that material information is made known to the CEO and CFO on a timely basis and that information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in securities legislation. The CEO and CFO have concluded such controls are effective.

ICFR have been designed by the CEO and CFO, either directly or under their supervision, to provide reasonable assurance regarding the reliability of financial reporting, including financial reporting for external purposes under GAAP.

As at December 31, 2008, the CEO and CFO evaluated the design and operating effectiveness of the Company's ICFR. In part, this evaluation was based on the work of third party specialists who were engaged by the Company to update documentation and provide a testing plan performed by Questerre management. Based on this documentation and testing the CEO and CFO conclude that the design of ICFR is appropriate and the controls are operating effectively as at December 31, 2008 to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements for external purposes in accordance with Canadian GAAP.

The only significant change to the company's internal controls was the recruitment of the VP Finance in the fourth quarter of 2008. There were no other material changes in the Company's internal controls and there were no circumstances suggesting a possible breach of disclosure controls.

It should be noted that a control system, including the Company's disclosure and internal controls and procedures, no matter how well conceived can provide only reasonable, but not absolute, assurance that the objectives of the control system will be met and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud.

Fourth Quarter 2008 Results

Questerre's results for the fourth quarter of 2008 reflect the lower commodity prices and production volumes during the period.

Production in the fourth quarter averaged 907 boe/d as compared to 1,292 boe/d during the preceding quarter and 1,216 boe/d for the same period in 2007.

Unseasonably cold weather set back operations at the Company's core areas of Beaver River and Antler. The tie-in and commissioning of the A-5 well was hindered by severe winter storms and only commenced production in the latter part of December. Cold weather also slowed down the completion and tie-in of several horizontal wells in Antler. In Alberta, the operator at Vulcan shut-in production from the oil pool during the second half of the quarter to optimize wellhead facilities. Questerre also completed the disposition of approximately 80 boe/d of production from the Westlock area at the beginning of the quarter.

The impact of lower production volumes was compounded by lower prices. The rapid decline in worldwide demand for commodities precipitated by the financial crisis saw Questerre's realized oil and natural gas prices decrease by 44% and 9% respectively to $65/bbl and $7.35/mcf over the quarter. This resulted in petroleum and natural gas revenue for the fourth quarter of $4.64 million or 48% lower than third quarter revenue of $8.89 million.

Despite lower operating expenses, royalties and general and administrative expenses, Questerre's net loss for the period was affected by higher expenses in the following categories: stock based compensation, allowance for doubtful accounts and future income tax expense. For the quarter, Questerre reported a net loss of $7.49 million and cash flow from operations of $2.80 million. This compares to a net income of $0.29 million and cash flow from operations of $5.41 million in the prior quarter.

The Company incurred capital expenditures of $15.56 million primarily representing its participation in the drilling of seven (5.0 net) oil wells in Antler and one (0.3 net) well in Quebec. Also included in this amount is Questerre's share of completion operations on three (0.6 net) wells in Quebec. In the quarter, Questerre realized $1.26 million in proceeds from the sale of its assets in the Westlock area of Alberta.

Fourth quarter financial results are incorporated by reference from the report filed on February 27, 2009.

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 23, 2009

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, 2008 and 2007 and the consolidated statements of operations, comprehensive loss and deficit, and cash flows for each of the years ended December 31, 2008 and 2007. 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, 2008 and 2007 and the results of its operations and its cash flows for the years ended December 31, 2008 and 2007 in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers

Chartered Accountants

Calgary, Alberta, Canada
March 23, 2009

CONSOLIDATED BALANCE SHEETS

	December 31 2008	December 31 2007
Assets		
Current assets		
Cash and cash equivalents	**$ 65,328,078**	$ 13,091,476
Short term investments	**51,262**	807,800
Marketable securities (note 5)	**198,080**	1,979,250
Accounts receivable (note 10)	**8,049,421**	8,028,997
Inventory (note 12)	**352,127**	204,462
Prepaids and deposits	**970,003**	2,764,647
	74,948,971	26,876,632
Goodwill	**2,467,816**	2,467,816
Future income tax (note 9)	**–**	1,124,731
Property, plant and equipment, net (note 4)	**88,114,346**	62,605,588
	$ 165,531,133	$ 93,074,767
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	**$ 20,640,982**	$ 16,868,786
Future income tax (note 9)	**2,705,845**	–
Asset retirement obligations (note 7)	**4,994,862**	4,578,140
	28,341,689	21,446,926
Shareholders' Equity		
Common shares (note 8)	**191,991,012**	97,341,561
Questerre shares held by subsidiary (note 3)	**(23,109,376)**	–
Contributed surplus (note 8 (f))	**6,739,230**	3,505,088
Deficit	**(38,431,422)**	(29,218,808)
	137,189,444	71,627,841
	$ 165,531,133	$ 93,074,767

Contractual obligations and commitments (note 15)

See accompanying notes to the consolidated financial statements.

Approved by the Board of Directors

CONSOLIDATED STATEMENTS OF OPERATIONS, COMPREHENSIVE LOSS AND DEFICIT

For the years ended December 31,	**2008**	2007
Revenue		
Petroleum and natural gas revenue	**$ 29,805,568**	$ 23,785,489
Royalties	**(4,979,101)**	(5,609,308)
	24,826,467	18,176,181
Expenses		
Operating	**6,057,492**	6,126,998
General and administrative	**2,871,308**	2,757,220
Realized gain on risk management activities	**(109,749)**	–
Interest expense	**151,781**	67,641
Interest income	**(1,501,223)**	(1,063,886)
Realized (gain) loss on sale of marketable securities (note 5)	**711,929**	(903,721)
Allowance for doubtful accounts	**1,730,462**	–
Unrealized loss on marketable securities (note 5)	**90,632**	785,441
Stock-based compensation (note 8 (e))	**4,076,503**	1,465,498
Depletion and depreciation	**17,234,553**	13,546,694
Accretion of asset retirement obligations (note 7)	**248,481**	142,557
	31,562,169	22,924,442
Net loss before the following	**(6,735,702)**	(4,748,261)
Gain on sale of property, plant and equipment (note 4)	**–**	1,501,044
Net loss before income taxes	**(6,735,702)**	(3,247,217)
Income Taxes		
Current taxes (note 9)	**67,560**	59,188
Future tax (recovery) (note 9)	**2,409,352**	(2,024,731)
	2,476,912	(1,965,543)
Net loss and comprehensive loss	**(9,212,614)**	(1,281,674)
Deficit, beginning of period	**(29,218,808)**	(28,715,095)
Opening deficit adjustment for changes in accounting policies		
Financial instruments	**–**	777,961
Deficit, end of period	**$ (38,431,422)**	$ (29,218,808)
Net loss per share (note 8 (c))		
Basic and diluted	**$ (0.049)**	$ (0.008)

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the years ended December 31,	**2008**	2007
Operating Activities		
Net loss	**$ (9,212,614)**	$ (1,281,674)
Items not affecting cash and cash equivalents:		
Depletion and depreciation	**17,234,553**	13,546,694
Stock-based compensation (note 8 (e))	**4,076,503**	1,465,498
Accretion of asset retirement obligations (note 7)	**248,481**	142,557
Realized (gain) loss on sale of marketable securities (note 5)	**711,929**	(903,721)
Unrealized loss on marketable securities (note 5)	**90,632**	785,441
Allowance for doubtful accounts	**1,730,462**	–
Gain on sale of property, plant and equipment (note 4)	**–**	(1,501,044)
Future tax expense (recovery) (note 9)	**2,409,352**	(2,024,731)
	17,289,298	10,229,020
Net change in non-cash working capital	**6,176,758**	(7,953,721)
	23,466,056	2,275,299
Financing Activities		
Issue of common shares	**77,301,878**	3,040,858
Share issue costs	**(5,267,071)**	(101,308)
Repayment of bank loan	**–**	(73,700)
	72,034,807	2,865,850
Investing Activities		
Expenditures on property, plant and equipment	**(43,956,604)**	(25,161,524)
Acquisition of Magnus Energy Inc. (note 3)	**–**	(300,937)
Acquisition of Terrenex Ltd. (note 3)	**(680,161)**	–
Sale of property, plant and equipment	**2,145,824**	10,000,000
Cash acquired on the acquisition of Magnus Energy Inc. (note 3)	**–**	551,294
Sale of short term investments	**807,800**	–
Purchase of short term investments	**(51,262)**	(807,800)
Sale of marketable securities (note 5)	**1,274,551**	1,049,971
Purchase of marketable securities (note 5)	**(295,942)**	(1,986,730)
Release of restricted cash	**–**	100,000
	(40,755,794)	(16,555,726)
Net change in non-cash working capital	**(2,508,467)**	(2,110,180)
	(43,264,261)	(18,665,906)
Increase (decrease) in cash and cash equivalents	**52,236,602**	(13,524,757)
Cash and cash equivalents, beginning of period	**13,091,476**	26,616,233
Cash and cash equivalents, end of period	**$ 65,328,078**	$ 13,091,476

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, 2008 and 2007

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 conventional 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. Final Court approval for this proposal is expected in the first half of 2009. No adjustments have been made to the carrying values of the liabilities pending receipt of this approval.

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., Magnus Energy Inc. and Terrenex Ltd.

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.

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 are recorded when the title passes to a third party and collectibility is reasonable 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, 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.

p) Financial Instruments

Effective January 1, 2007, the Company adopted the Canadian Institute of Chartered Accountants (“CICA”) section 3855, “Financial Instruments - Recognition and Measurement,” section 3865, “Hedges,” section 1530, “Comprehensive Income”. These standards have been adopted retroactively without restatement.

<u>i) Financial Instruments</u>

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.

As a result of adopting this change in accounting policy, the consolidated financial statements at January 1, 2007 were changed as follows: Marketable securities increased by $777,961, and the deficit decreased by the same amount. 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. New 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, 2008 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

Section 1535, "Capital Disclosures". This section establishes standards for disclosing information about an entity's objectives, policies and processes for how it manages its capital. A company must also disclose qualitative data about what the entity regards as capital; and whether the company has complied with any capital requirements and if not, the consequences of such non-compliance. The Company adopted this standard effective January 1, 2008 (see Note 11).

Section 3862, "Financial Instruments – Disclosures". This section describes the required disclosures to evaluate the significance of financial instruments for the entity's financial position and performance as well as the nature and extent of risks arising from both recognized and unrecognized financial instruments to which the entity is exposed and how the entity manages those risks. The Company adopted this standard effective January 1, 2008 (see Note 10).

Section 3863, "Financial Instruments – Presentation". This section establishes standards for presentation of financial instruments and non-financial derivatives. It details the presentation of the standards described in Section 3861, "Financial Instruments – Disclosure and Presentation". The Company adopted this standard effective January 1, 2008 (see Note 10).

Section 3031, “Inventories”. This section establishes standards for presentation of inventories. The new standard replaces the previous inventories standard and requires inventory to be valued on a first-in, first-out or weighted average basis, which is consistent with Questerre’s former accounting policy. The new standard allows the reversal of previous write-downs to net realizable value when there is a subsequent increase in the value of inventories. The adoption of this standard has had no material impact on the Company’s financial statements (see Note 12).

r) Future Accounting Pronouncements

In February 2008, the CICA’s Accounting Standards Board confirmed that International Financial Reporting Standards (“IFRS”) will replace Canadian generally accepted accounting principles 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 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.

The Company is currently analyzing accounting policy alternatives and identifying implementation options for the corresponding process changes. Questerre will update its IFRS changeover plan to reflect new and amended accounting standards issued by the International Accounting Standards Board. As IFRS is expected to change prior to 2011, the impact of IFRS on the Company’s consolidated financial statements is not reasonably determinable at this time.

In February 2008, the AcSB issued Handbook Section 3064, “Goodwill and Intangible Assets” and amended Section 1000, “Financial Statement Concepts” clarifying the criteria for the recognition of assets, intangible assets and internally developed intangible assets. Items that no longer meet the definition of an asset are no longer recognized with assets. The standard is effective for fiscal years beginning on or after October 1, 2008 and early adoption is permitted. The adoption of this standard is not expected to 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 Quebec 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. Cash and transaction costs were $680,161. In addition, a future income tax liability of $2,884,415 was recognized on acquisition. 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.

Magnus Energy Inc.

Effective November 1, 2007, Questerre acquired all the outstanding common shares of Magnus, a public exploration and production company in consideration of the issuance of 7,840,804 Questerre common shares.

The purchase price was allocated based on the fair value of the assets and liabilities as follows:

Consideration Paid:	
Common shares	$ 7,386,037
Transaction costs	300,937
	$ 7,686,974

Allocation of Purchase Price:	
Current assets	$ 11,386,250
Current liabilities	(24,754,173)
	(13,367,923)
Property, plant and equipment	21,566,975
Asset retirement obligations	(512,078)
	$ 7,686,974

4. Property, Plant and Equipment

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**

December 31, 2007	Cost	Accumulated Depletion and Depreciation	Net Book Value
Petroleum, natural gas properties and equipment	118,358,935	(56,418,242)	61,940,693
Other assets	1,298,765	(633,870)	664,895
	119,657,700	(57,052,112)	62,605,588

During the year ended December 31, 2008, the Company capitalized administrative overhead charges of $2,090,419 (December 31, 2007: $1,474,269) directly relating to exploration and development activities.

At December 31, 2008, property, plant and equipment included $19,889,320 (December 31, 2007: $11,895,668) relating to seismic expenditures and 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 $5,355,000 (December 31, 2007: $2,699,600).

The Company has performed an impairment test as of December 31, 2008, using the estimated average sales price for each of the next five years as follows:

Year	2009	2010	2011	2012	2013
Gas (C$/MMBtu)	7.40	8.00	8.45	8.80	9.05
Oil (C$/bbl)	69.60	83.00	91.40	93.90	96.30

The benchmark prices are projected to increase by an average of 2% after 2013.

In April 2007, Questerre received a payment of $10 million in settlement of earn-in obligations from a partner. The amount was treated as a disposition of interest in property, plant and equipment. Based on a cost of $8,498,956, Questerre realized a gain of $1,501,044 on this disposition.

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 2008	December 31 2007
Balance, beginning of period	**$ 1,979,250**	$ 146,250
Change in accounting policy	**–**	777,961
Purchase of marketable securities	**295,942**	1,986,730
Sale of marketable securities	**(1,274,551)**	(1,049,971)
Realized gain (loss) on sale of marketable securities	**(711,929)**	903,721
Unrealized loss on marketable securities	**(90,632)**	(785,441)
Balance, end of period	**$ 198,080**	$ 1,979,250

6. Bank Indebtedness

In July 2002, the Company obtained a five-year, $400,000 term loan with a Canadian chartered bank. Under the terms of the loan, the Company was required to make monthly payments of $6,700 principal plus interest until the loan was paid out. The interest rate under the loan was the bank's floating base rate plus 2.0% and the Company had the right to lock in the rate at any time. The loan was collateralized by the first assignment to the bank of a $100,000 Guaranteed Investment Certificate and by a General Security Agreement over the assets of the Company and its wholly owned subsidiary, Questerre Beaver River Inc. In January 2007, the term loan was paid out.

The Company has a revolving credit facility with a Canadian chartered bank. The amount of the facility was reassessed at $5 million during the fourth quarter of 2008 pending a review of the borrowing base in early 2009. The advances bear interest at bank prime rate plus 1.5%. The authorized limit is subject to a periodic review and potential revision of the borrowing base by the bank. The facility is collateralized with a $20 million fixed and floating charge debenture over the assets of the Company. As at December 31, 2008, 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. The Company estimates its total undiscounted asset retirement obligation to be $9,840,101 at December 31, 2008. These payments are expected to be made over the next 30 years. Commencing October 1, 2008, incremental asset retirement obligations are calculated using a revised 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 2008	December 31 2007
Balance, beginning of period	**$ 4,578,140**	$ 3,377,847
Revision in estimates	**829,910**	–
Liabilities assumed on corporate acquisition	**–**	512,078
Liabilities incurred	**423,934**	545,658
Accretion expense	**248,481**	142,557
Property dispositions	**(1,085,603)**	–
Balance, end of period	**$ 4,994,862**	$ 4,578,140

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, 2008, there were no Class B common voting shares or preferred shares outstanding.

b) Issued and Outstanding – Class A Common Shares

	Number	Amount
Common Shares		
Balance, December 31, 2006	155,171,750	$ 85,809,663
Issued for cash	3,500,000	3,000,000
Issued in settlement of Magnus debt	2,250,000	2,077,000
Issued for cash on exercise of options	167,916	40,857
Issued on acquisition of Magnus Energy Inc. (Note 3)	7,840,804	7,386,037
Tax effect of flow-through share issuance		(900,000)
Stock-based compensation recognized on exercise of stock options		29,312
Share issue costs		(101,308)
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
Stock-based compensation recognized on exercise of stock options		842,361
Share issue costs		(3,803,879)
Balance, December 31, 2008	**197,299,642**	**$ 191,991,012**

(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).

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 shortform prospectus in Canada.

c) Per Share Amounts

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

	2008	2007
Basic	**186,447,776**	157,078,211
Diluted	**196,593,333**	163,260,612

For the diluted amounts 10.15 million shares (2007 – 6.18 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, 2008 and 2007, incremental shares from assumed exercise of stock options are not included due to the 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.

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

	Number of Options	Weighted Average Exercise Price
Outstanding, December 31, 2006	12,869,586	$0.59
Granted	445,000	0.96
Forfeited	(82,500)	0.68
Exercised	(167,916)	0.24
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**
Exercisable, December 31, 2008	**9,467,078**	**$0.65**

The following table summarizes information about stock options outstanding and exercisable at December 31, 2008:

	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
$0.10 - $0.30	827,501	0.97	$0.30	827,501	$0.30
$0.39 - $0.65	9,075,835	3.09	0.46	5,026,667	0.46
$0.72 - $1.00	3,280,835	2.24	0.80	2,676,043	0.81
$1.23 - $1.60	1,571,250	3.36	1.36	796,242	1.34
$2.38 - $4.70	2,900,000	4.49	4.48	140,625	2.78
	17,655,421	**3.09**	**$1.26**	**9,467,078**	**$0.65**

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:

	2008	2007
Weighed average fair value per option ($)	**1.27**	0.45
Risk free interest rate (%)	**3.01**	4.00
Expected life (years)	**3.0**	3.0
Expected volatility (%)	**97**	63

f) Contributed Surplus

The following table sets forth a reconciliation of contributed surplus:

Balance, December 31, 2006	$ 2,068,902
Stock-based compensation expense	1,465,498
Stock-based compensation recognized on exercise of stock options	(29,312)
Balance, December 31, 2007	3,505,088
Stock-based compensation expense	4,076,503
Stock-based compensation recognized on exercise of stock options	(842,361)
Balance, December 31, 2008	**$ 6,739,230**

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 earnings/(losses) before income taxes. The difference results from the following items:

	2008	2007
Net loss before income taxes	**($6,735,702)**	($3,247,217)
Combined federal and provincial tax rate	**30.00%**	32.12%
Computed "expected" income tax recovery	**(2,020,711)**	(1,043,006)
Increase in income taxes resulting from:		
Non-deductible differences	**1,394,929**	325,580
Rate adjustments	**571,799**	2,149,359
Previously unrecognized future tax asset now recognized	**(1,089,141)**	(2,024,025)
Valuation allowance	**3,567,569**	–
Unrecognized tax benefit of accounting losses	**–**	(1,585,501)
Current tax	**67,560**	59,188
Other	**(15,093)**	152,862
Income tax (recovery)	**$ 2,476,912**	($1,965,543)

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

	December 31 2008	December 31 2007
Future income tax assets:		
Asset retirement obligations	**$ 1,299,165**	$ 1,281,871
Share issue costs	**2,536,440**	1,750,516
Marketable securities	**28,732**	231,705
Non-capital loss carryforwards	**5,571,530**	3,937,416
Capital loss carryforwards	**105,705**	–
Valuation adjustment	**(6,350,972)**	(2,783,403)
	3,190,600	4,418,105
Future income tax liabilities:		
Petroleum and natural gas properties	**(3,012,031)**	(1,508,374)
Unrealized gain on investments	**(2,884,414)**	–
Flow through share renouncements to be incurred	**–**	(1,785,000)
	(5,896,445)	(3,293,374)
Net future income tax (liability) asset	**($2,705,845)**	$ 1,124,731

Non-capital loss carryforwards at December 31, 2008 represent non-capital losses and expire from 2015 to 2028.

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, 2008 the Company had no oil and natural gas risk management contracts in place. The Company has estimated the impact of changing commodity prices on its net earnings/(loss) as follows: A $10/bbl change in realized oil prices would result in a $1.18 million change in net earnings/(loss). A $1.00/mcf change in realized natural gas prices would result in a $1.46 million change in net earnings/(loss).

- 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, 2008 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, 2008.

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 are from major marketing companies who have excellent credit ratings. These revenues are normally collected on the 25th day of the month following delivery. The Company has not experienced any credit loss in the collection of its accounts receivable relating to the sale of petroleum and natural gas production.

The Company's accounts receivable was aged as follows:

Aging	
Current	$ 5,943,064
31 - 60 days	635,241
61 - 90 days	594,825
> 90 days	3,253,781
Allowance for doubtful accounts	(2,377,490)
Balance, December 31, 2008	**$ 8,049,421**

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 recently 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, short term investments, 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, 2008 are as follows:

	Carrying Value	Fair Value
Financial Assets		
Held-for-trading:		
Cash and cash equivalents	$ 65,328,078	$ 65,328,078
Short term investments	51,262	51,262
Deposits	743,673	743,673
Marketable securities	198,080	198,080
Loans and receivables:		
Accounts receivable	8,049,421	8,049,421
Financial Liabilities		
Accounts payable and accrued liabilities[1]	$ 20,640,982	$ 19,070,850

(1) The fair value of the Magnus payables cannot been estimated as it is subject to receipt of final regulatory approval for its proposed settlement with its creditors (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. Questerre's line of credit bears interest at a floating market rate. As at December 31, 2008 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 $50 million consisting mainly of cash and cash equivalents.

The majority of planned capital spending in 2009 will be incurred in Quebec 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 2009. The line of credit is believed to provide adequate contingency for unanticipated changes in capital spending or market conditions.

The recent change in commodity prices will 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, bank 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 and/or adjusting its capital spending. Questerre monitors its capital based on the current and projected cash flow from operations.

	December 31 2008	December 31 2007
Shareholders' equity	**$ 137,189,444**	$ 71,627,841
Bank Debt	**–**	–
Working Capital	**54,307,989**	10,007,846
	$ 191,497,433	$ 81,635,687

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, 2008, there were no write downs or reversals of previously written down amounts. During the year, $676,724 in fuel inventory was purchased (2007: $388,564) and $529,059 (2007: $294,201) recognized as an expense.

13. Supplemental Cash Flow Information

	2008	2007
Cash interest paid	**$ 151,781**	$ 67,641
Cash taxes paid	**$ 155,946**	$ 28,334

14. Related Party Transactions

At December 31, 2008, amounts due from Rupert's Crossing Ltd. ("Rupert's"), a related party with common directors and officers, were $623 (2007: $155,469).

Questerre incurred fees of $63,000 for the year ended December 31, 2008 (2007: $122,430) to 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.

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 each of 2009 and 2010 and $9,651 in 2011. Questerre has commitments under a lease for office space of $339,708 in 2009 and $311,399 in 2010.

CORPORATE INFORMATION

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Pierre Boivin

Russ Hammond

David Mallory

Peder Paus

Bjorn Inge Tonnessen

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Executive Officer

John Brodylo
VP Exploration

Peter Coldham
VP Engineering and
Operations

Jason D'Silva
Chief Financial Officer

Paul Harrington
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