

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

<i>As at/for the years ended December 31</i>	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 Gently #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.

<i>(\$ thousands)</i>	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.

<i>(\$ thousands)</i>	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 depletion 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.