

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 November 11, 2009. This MD&A should be read in conjunction with the unaudited interim consolidated financial statements for the three and nine months ended September 30, 2009 and the audited consolidated financial statements for the year ended December 31, 2008. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). All amounts are in Canadian dollars unless otherwise noted. Additional information relating to Questerre, including Questerre's Annual Information Form for December 31, 2008 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; and
- geological, technical, drilling and processing problems and other difficulties in producing oil, natural gas liquids and natural gas reserves.

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

Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward-looking statements contained in this MD&A and the documents incorporated by reference herein are expressly qualified by this cautionary statement. We do not undertake any obligation to publicly update or revise any forward-looking statements except as required by applicable securities law.

Non-GAAP Terms

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

As an indicator of Questerre's performance, cash flow from operations should not be considered as an alternative to, or more meaningful than, cash flows from operating activities as determined in accordance with Canadian GAAP. Questerre's determination of cash flow from operations may not be comparable to that reported by other companies. Questerre considers cash flow from operations to be a key measure as it demonstrates the Company's ability to generate the cash necessary to fund operations and future capital investment. It is also used by research analysts to value and compare oil and gas companies.

Cash Flow from Operations Reconciliation

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2009	2008	2009	2008
Cash flows from operating activities	\$ 2,506,708	\$ 6,019,866	\$ 952,845	\$ 15,859,374
Net change in non-cash working capital	(2,004,351)	(608,312)	1,330,014	(1,369,868)
Cash flow from operations	\$ 502,357	\$ 5,411,554	\$ 2,282,859	\$ 14,489,506

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.

Working capital, which term represent current assets less current liabilities is used to assess efficiency, liquidity and general financial strength. There is no GAAP measure that is reasonably comparable to working capital.

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 Information

<i>As at/for the period ended September 30</i>	<i>Three months ended</i>		<i>Nine months ended</i>	
	2009	2008	2009	2008
Financial (\$)				
Petroleum and Natural Gas Sales	2,786,384	8,892,160	9,486,144	25,161,344
Cash Flow from Operations	502,357	5,411,554	2,282,859	14,489,506
Per share – Basic	–	0.03	0.01	0.08
Per share – Diluted	–	0.03	0.01	0.08
Net Earnings (Loss)	(1,581,718)	292,647	(9,824,800)	(1,725,238)
Per share – Basic	(0.01)	–	(0.05)	(0.01)
Per share – Diluted	(0.01)	–	(0.05)	(0.01)
Capital Expenditures, net of acquisitions and dispositions	3,259,938	7,352,744	8,551,336	28,113,879
Working Capital Surplus	49,016,405	67,826,776	49,016,405	67,826,776
Total Assets	148,581,048	162,756,977	148,581,048	162,756,977
Shareholders' Equity	132,216,221	145,328,700	132,216,221	145,328,700
Common Shares Outstanding	199,184,643	197,290,420	199,184,643	197,290,420
Weighted average – basic	197,827,758	197,250,522	197,501,393	182,806,201
Weighted average – diluted	206,723,239	208,686,342	205,709,978	192,042,814
Operations (units as noted)				
Average Production				
Crude Oil and Natural Gas Liquids (bbls/d)	352	502	391	372
Natural Gas (mcf/d)	1,680	4,744	2,623	5,382
Total (boe/d)	632	1,292	828	1,269
Average Sales Price				
Crude Oil and Natural Gas Liquids (\$/bbl)	70.72	116.45	60.21	112.55
Natural Gas (\$/mcf)	3.21	8.05	4.29	9.26
Total (\$/boe)	47.92	74.74	41.97	72.28
Netback (\$/boe)				
Total Revenue	47.92	74.80	41.97	72.34
Royalties (credits)	(1.29)	12.71	2.20	12.30
Percentage	(3%)	17%	5%	17%
Field Operating Expense	16.50	13.58	13.65	13.86
Operating Netback	32.71	48.51	26.12	46.18
Net Cash G&A	19.91	8.96	15.95	6.39
Cash Netback	12.80	39.55	10.17	39.79
Wells Drilled				
Gross	2.00	3.00	3.00	11.00
Net	1.25	2.30	1.50	6.80

Highlights

- St. Edouard #1 vertical well tests at an initial rate of 2.6 mmcf/d and a stabilized rate of 700 mcf/d from the middle Utica interval in the Lowlands
- First pilot horizontal well targeting middle Utica spuds in the quarter
- Independent assessment of the Utica shale estimates potential recoverable resource at 4.28 Tcf or approximately 713 million barrels of oil equivalent net to Questerre
- Positive cash flow of \$0.50 million and production of 632 boe/d with lower gas prices, extended production shut-ins and minimal spending on developed assets
- Sustained financial strength with \$49 million in positive working capital and no debt

Third Quarter 2009 Activities

St. Lawrence Lowlands, Quebec

Questerre continued its appraisal of the Utica shale interval in the Lowlands with its partner Talisman Energy Canada ("Talisman").

This included the testing of the St. Edouard #1 well. Following an evaluation of the deeper Trenton Black-River carbonate formation, a zone within the middle Utica was fracture stimulated. The well initially flowed at 2.6 mmcf/d with an average rate of 700 mcf/d over a 10-day test. The well validated the middle Utica results from four other wells drilled across the partners' acreage in the Lowlands.

St. Edouard #1 is the fourth and final well in the earn-in program with Talisman. Upon drilling and testing of the four wells, Talisman has completed its earning obligations and currently holds a 75% working interest in almost 720,000 acres. Questerre currently holds an approximate 25% working interest in this acreage and also retains a 4¼% gross overriding royalty on production from Talisman.

The consistent middle Utica results from St. Edouard #1 and the other wells over a large geographic area were the impetus for a pilot program targeting this zone. The program will initially include two horizontal wells with multi-stage fracture stimulations. The first horizontal, located adjacent to the St. Edouard #1 vertical well, spud at the end of the quarter. It is expected that the second horizontal will be located proximal to the Gentilly #1 location, approximately 34 km to the southwest of St. Edouard #1. Subject to equipment availability and logistics, completion operations are scheduled for later this year with preliminary results expected in the first quarter of 2010.

With the completion of the initial work program, Questerre commissioned Netherland, Sewell & Associates, Inc., an independent reservoir engineering firm, to assess the potential of the Utica in the Lowlands. The report estimates the prospective original gas in place for the Utica shale in the deep fairway at 150 Bcf per square mile. Using a range of recovery factors based on more well established shale plays, the report estimates prospective resources recoverable for Questerre's interest to range between 2.2 Tcf to 8.0 Tcf with a best estimate of 4.28 Tcf. This does not include the royalty interest held by Questerre nor an assessment of the shallower Lorraine formation.

Northeast British Columbia

Beaver River Field

The extended production shut-in at the Beaver River Field (the "Field") further delayed the long-term test of the A-5 shale gas well.

A-5 was recompleted in late 2008 targeting a brittle, dolomite-rich interval above a deeper organic-rich shale sequence. The well tested at an initial rate of 10 mmcf/d and has been on production intermittently throughout the first half of this year, most recently at an average rate of 2.6 mmcf/d in the second quarter. Results to date indicate minimal contribution from the deeper shale and further testing will be required.

Production from the Field was suspended during June for the turnaround of the Spectra Fort Nelson Gas Plant. Materially lower gas prices in the third quarter led to an extension of the shut-in until early November when production resumed from the A-5 and A-2 wells.

The summer work program at Beaver River targeted the restoration and rehabilitation of existing leases and facilities. This included phyto-remediation as an environmentally friendly and cost-effective solution for lease cleanup where drilling and completion programs were conducted over the last two years.

Greater Sierra

Low natural gas prices also saw production from the Greater Sierra region suspended for the last third of the quarter. Based on the current outlook for natural gas prices in 2010, Questerre and its partner, EnCana, anticipate the winter drilling program in this area will likely be deferred.

South of its acreage with EnCana, the Company recently acquired additional land prospective for multiple targets including the Jean Marie and the deeper Horn River shale and the Pine Point carbonates. Locations have been identified to test the deeper Pine Point carbonate anomalies and assess the shale intervals. Consistent with its business strategy, Questerre plans to work with a joint venture partner to pursue these locations and further develop these land holdings.

Antler, Saskatchewan

Operations at Antler resumed in the third quarter to assess new drilling and completion techniques.

Two wells drilled in 2008 were fracture stimulated in the third quarter using a modified completion program. The program was designed to contain frac effectiveness within the target Bakken/Torquay formation while minimizing water production from deeper intervals. Questerre also drilled and completed a horizontal well to assess the benefits of tubing conveyed fracture stimulation as an alternative to the Packers Plus system. Initial results from these wells are positive and they have been placed on a long-term production test.

Subject to final test results, Questerre is evaluating a drilling program for 2010.

Drilling Activities

Questerre participated in the drilling of one (1.0 net) oil well and one (0.25 net) gas well during the third quarter of 2009.

Production

Production volumes in the third quarter of 2009 continued to reflect the minimal investment in developing assets and extended shut-ins in B.C. Daily production averaged 632 boe/d for the quarter as compared to 806 boe/d in the preceding quarter and 1,292 boe/d for the third quarter of 2008. On a year to date basis, production was 828 boe/d in 2009 and 1,269 boe/d in 2008.

With natural gas production from B.C. suspended in the low price environment, oil and natural gas liquids represented 56% of Questerre's product mix in the quarter (2008: 39%). This increased from 44% in the first two quarters of this year. Light oil from Antler accounted for over three quarters of these volumes with light oil and liquids from Vulcan accounting for the remainder.

Consistent with the prior year, Questerre's Alberta assets added just over one-half of total production or 327 boe/d in the third quarter (2008: 689 boe/d). Unchanged from the prior quarters in 2009, Vulcan contributed approximately 85% of these volumes or 280 boe/d (2008: 72% and 499 boe/d). The decrease in Alberta volumes over the prior year and the second quarter volumes of 379 boe/d largely reflects the natural production profile of the Company's Mannville pools in Alberta. In the current year, production from minor

properties of 47 boe/d (2008: 190 boe/d) excluded producing assets in Westlock, Central Alberta that represented 124 boe/d in the third quarter of 2008 and were sold in the fourth quarter of 2008. Notwithstanding a potential infill location at the Mannville oil pool in Vulcan, Questerre has no plans for further drilling in Alberta.

Shut-ins at B.C. resulted in minimal production of 29 boe/d in the quarter (2008: 296 boe/d) that accounted for 5% of total volumes for the quarter (2008: 23%). In the preceding quarter, B.C. added 190 boe/d or 24% of Company volumes. Production from the Beaver River Field historically accounts for the majority of production from the province. For the first half of 2009, production from the A-5 well accounted for 152 boe/d or 80% of these volumes. In the prior year third quarter, the A-2 and A-7 wells at Beaver River added 209 boe/d or 71% of production from the province. Questerre recently resumed production from the Field with initial volumes of approximately 150 boe/d net to the Company. Questerre's interest in two gas wells at Greater Sierra, B.C. were responsible for the 29 boe/d in the quarter (2008: 87 boe/d). These wells were subsequently shut-in by the operator for the last third of the quarter and were brought online in early October.

Light oil from Antler, southeast Saskatchewan, contributed the remaining 276 boe/d (2008: 307 boe/d) in the third quarter. The recompletion of two wells using a modified completion program in the quarter helped improve volumes from 237 boe/d in the second quarter. Questerre continues to evaluate new drilling and completion techniques in advance of a potential 2010 drilling program.

Third Quarter 2009 Financial Results

Revenue

Petroleum and natural gas revenue for the quarter ended September 30, 2009 was \$2.79 million (2008: \$8.89 million) and \$9.49 million for the first nine months of the year (2008: \$25.16 million).

Significantly higher production volumes and commodity prices in 2008 were largely responsible for the higher revenue compared to the current year. In the third quarter of this year, production volumes were 51% lower. Oil and gas prices were lower by 39% and 60% respectively.

Revenue for the quarter decreased by only 6% from the preceding quarter revenue of \$2.97 million despite a 22% decline in production volumes. With oil volumes relatively stable over the two periods and gas volumes 38% lower, the 11% improvement in oil prices offset the 12% decline in realized gas prices.

Natural gas prices remained challenged, reaching seven-year lows during the quarter. Prices reflected storage levels that approached maximum capacity as domestic North American production continued to increase despite a reduction in drilling activity earlier in the year. The absence of a strong recovery in demand, particularly from the industrial sector, and a cooler summer that limited residential cooling demand also contributed to the growing inventory levels.

In the third quarter natural gas prices declined further with the reference AECO price averaging \$2.94/mcf down from \$3.46/mcf in the second quarter and \$3.78/mcf for the year to date. Questerre continued to realize natural gas prices at a premium to the index with an average sales price of \$3.21/mcf for the quarter and \$4.29/mcf for the nine months ended September 30, 2009.

Crude oil prices in the quarter were buoyed by market optimism about a global economic recovery and financial interest as a hedge against the value of the US dollar. In spite of inventory levels at five year highs, concerns about OPEC's compliance with quota curtailments and reduced demand, prices improved from the second quarter.

The increase in the benchmark Edmonton Light price from \$65.90/bbl in the second quarter to \$71.50/bbl in the third quarter was tempered by the strengthening in the Canadian dollar. Questerre experienced a similar increase in its net sales price from \$63.98/bbl to \$70.72/bbl.

Questerre currently does not have any hedges, physical or financial, in place and all production is sold on the spot market.

Royalties

Questerre reported a royalty credit of \$0.08 million for the third quarter (2008: expense: \$1.51 million) and royalty expense of \$0.50 million for the nine months ended September 30, 2009 (2008: \$4.28 million).

The credit relates to a corporate tax assessment for Alberta Royalty Tax Credit of \$0.47 million from 2006 that was received and recorded during the quarter. Excluding the credit, royalties were \$0.40 million for the third quarter and \$0.97 million for the year to date. Prior to the credit the effective royalty rate was 14% for the quarter (2008: 17%) and 10% for the year (2008: 17%).

Royalties incurred on production in Alberta remained flat at 21% (2008: 26%) for the second and third quarters of 2009. The rate decreased from 26% in the third quarter of 2008 with the lower production volumes and prices, particularly from the oil and gas pools in Vulcan. The Company expects the New Royalty Framework ("NRF") that came into effect in Alberta on January 1, 2009 to have a minimal effect on the Company's royalty rate.

Questerre recorded a royalty credit of \$0.01 million for the period on production from B.C. The credit relates to production from the Greater Sierra region which attracted a royalty rate of approximately 3% in the quarter when excluding the credit (2008: 20%). The Company utilizes a deep re-entry credit to offset any royalties payable on production from the A-5 well at the Beaver River Field. In 2008, Questerre incurred royalties of 20% on production from the A-2 and A-7 wells at Beaver River that were shut in for the first nine months of 2009. With no drilling planned in B.C. in 2010, Questerre anticipates it will not be accessing the royalty incentives announced by the B.C. Government in August 2009.

The realized royalty rate in Saskatchewan increased to 12% in the quarter from 2% in the previous quarter and 5% for the same period in 2008. The higher royalties year over year relate to an increase in production from wells drilled on freehold lands which have an average royalty rate of approximately 16% as compared to 2.5% on Crown acreage. In the second quarter of 2009, the lower rate is due to a royalty credit based on an assessment from the provincial government.

Operating Costs

Aggregate operating expenses for the three months ended September 30, 2009 fell 41% to \$0.96 million from \$1.61 million in the same period in 2008 mirroring the decline in production volumes. For the nine months ended September 30, 2009, these costs decreased by 36% to \$3.09 million from \$4.82 million in 2008. Compared to the preceding quarter with operating costs of \$0.89 million, operating expenses in the third quarter were 7% higher.

Field operating expenses in Alberta averaged \$11.14/boe up almost 20% from \$9.31/boe in the second quarter and down 8% from \$12.10/boe for the third quarter of 2008. The variance from the second quarter is primarily due to the relatively fixed proportion of costs in Vulcan. The variance from the prior year relates to higher cost properties in Central Alberta that were sold at the end of 2008.

The higher percentage of fixed costs and shut-in production at Beaver River resulted in operating costs of \$0.22 million for the third quarter. This compares to operating costs, excluding gathering and processing charges, of \$0.29 million in the second quarter and \$0.31 million in the third quarter of 2008. Expenses were higher in 2008 due to the ancillary costs related to the two producing wells, A-2 and A-7. In the

second quarter of this year, additional costs were incurred in operating the A-5 well that was subsequently shut-in in the third quarter. With variable costs representing a larger percentage of expenses at Greater Sierra, the lower production volumes in 2009 reduced operating costs to \$0.04 million from \$0.10 million in 2008 and unchanged from \$0.04 million in the second quarter of 2009.

Lifting costs in Antler increased to \$14.87/bbl in the third quarter from \$10.67/bbl in the second quarter and \$12.11/bbl in the third quarter of 2008. Excluding a workover of an existing well for \$0.10 million, operating costs actually declined to \$10.94/bbl during the quarter. Questerre expects operating costs to decrease further with the recent tie-in of several producing wells to the electrical grid eliminating the higher costs for generators and the associated fuel costs.

General and Administrative Expenses

For the third quarter of 2009, Questerre recorded general and administrative expenses (“G&A”) net of capitalized overhead and recoveries of \$1.16 million (2008: \$1.07 million) and \$3.61 million for the year to date (2008: \$2.23 million).

Gross G&A expenses of \$1.32 million declined marginally from the prior quarter expenses of \$1.41 million and from the third quarter 2008 expenses of \$1.42 million. Higher capitalized expenses and overhead recoveries were also responsible for the decrease in net G&A to \$1.16 million from \$1.32 million in the second quarter. In the third quarter of 2008, higher gross expenses offset by higher capitalization and recovery deductions accounted for the G&A of \$1.07 million.

On a per unit basis, the lower production volumes in the quarter translated to G&A per boe of \$19.91 from \$18.00 in the prior quarter (2008: \$8.96).

(\$ thousands)	Three months ended Sept. 30		Nine months ended Sept.30	
	2009	2008	2009	2008
General and administrative expenses	\$ 1,323	\$ 1,424	\$ 4,073	\$ 3,708
Capitalized expenses and overhead recoveries	(165)	(358)	(468)	(1,480)
General and administrative expenses, net	\$ 1,158	\$ 1,066	\$ 3,605	\$ 2,228

Stock-Based Compensation

Stock-based compensation expense was \$3.88 million for the nine months of 2009 (2008: \$1.85 million) and \$1.20 million for the quarter ended September 30, 2009 (2008: \$1.00 million). This represents the estimated fair value of stock options granted using the Black Scholes pricing model amortized over the vesting period.

The significantly higher expense is due to the increased volatility in Questerre’s share price and higher exercise prices coupled with the number of options granted in the last 15 months. The weighted average fair value of the options granted in the first nine months of 2009 using the Black Scholes pricing model was \$1.21 (2008: \$1.27) and the weighted average exercise price was \$1.80 (2008: \$1.81).

Other Income and Expenses

For the first nine months of the year, Questerre reported interest income of \$0.40 million (2008: \$0.90 million) and \$0.11 million (2008: \$0.51 million) for the third quarter. The income was earned on the net proceeds of the \$75 million equity issue completed by Questerre in the second quarter of 2008. Lower cash balances and declining interest rates account for the reduction in interest income in the current year. Cash is invested in Guaranteed Investment Certificates issued by Canadian chartered banks with a maturity of less than one year.

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. For the first nine months of 2009, the Company recorded an unrealized gain of \$0.01 million. At September 30, 2009, Questerre holds marketable securities with a market value of \$0.19 million.

Depletion, Depreciation and Accretion

Depletion and depreciation expense for the third quarter of 2009 decreased 20% to \$3.07 million from \$3.83 million in the prior quarter. With minimal additions to the depletable base in the third quarter, the decrease in gross expense is due to the 22% decrease in production volumes. On a boe basis, this remained relatively stable at rates of \$52.83 and \$52.20 for the third and second quarters of 2009 respectively.

The higher depletable base in the current year explains the 35% increase, on a unit of production basis, from \$39.19/boe in the prior year. The 51% decrease in production volumes offset this to some extent and resulted in a 34% decrease in gross depletion and depreciation expense from \$4.66 million in the third quarter of 2008 to \$3.07 million in the third quarter of 2009.

At September 30, 2009, property, plant and equipment included \$21.24 million (December 31, 2008: \$19.89 million) relating to seismic expenditures and unproved properties which have been excluded from the depletion calculation. Included in the depletion calculation are future development costs of \$5.36 million (December 31, 2008: \$5.36 million).

Questerre recognized \$0.11 million in accretion expense for the three months ended September 30, 2009 (2008: \$0.05 million) and \$0.32 million for the first nine months of 2009 (2008: \$0.15 million). The increases are due to the obligations for wells drilled in 2009 and the second half of 2008 and revisions to the estimates used to determine the asset retirement obligations in the fourth quarter of 2008. Furthermore, the credit adjusted risk free rate was changed to 12% for obligations incurred post October 1, 2008. The estimated net present value of the total asset retirement obligation is \$4.97 million as at September 30, 2009 based on a total future undiscounted liability of \$10.04 million.

Net Earnings/(Loss)

Questerre realized a loss, before income taxes, of \$3.48 million for the three months ended September 30, 2009 (2008: earnings: \$0.59 million) and a loss of \$13.22 million for the nine months ended September 30, 2009 (2008: \$1.07 million). The loss in the current year was attributable to substantially lower commodity prices and reduced production volumes coupled with proportionately higher expenses. In the prior year, significantly higher revenue and comparatively lower expenses resulted in a smaller loss.

Income Taxes

The recovery of future taxes for the third quarter of 2009 was \$1.90 million when compared to a recovery of \$0.64 million in the prior quarter and an expense of \$0.29 million in the third quarter of 2008. The 2009 third quarter increase in the future tax recovery, when compared to the 2009 second quarter recovery, is primarily related to a decrease in the potential future tax liability related to the Questerre common shares initially held by Cabernet Holdings Ltd. prior to it being dissolved July 23, 2009.

Capital Expenditures

Questerre incurred capital expenditures of \$3.26 million in the third quarter of 2009 (2008: \$7.35 million) and \$8.55 million for the first three quarters of the year (2008: \$28.40 million).

Current year expenditures focused on the shale gas appraisal program in Quebec where the Company incurred \$3.74 million participating in the drilling and completion of several wells. An additional \$3.75 million was spent in Antler primarily to complete and tie-in wells. The majority of the Company's investment in the Greater Sierra region of B.C. was to acquire additional exploration acreage.

In 2008, a total of \$28.40 million was invested in the Company's portfolio of assets. Just over 50% of this amount or \$14.93 million was invested in northeast B.C. at Greater Sierra and the Beaver River Field primarily in the first quarter of the year. An expanded pilot horizontal program in Antler saw almost \$9.00 million spent in Saskatchewan. The remaining expenditures were incurred in Alberta to drill and complete one well into the oil pool and in Quebec to drill two shale wells and recomplete one well.

(\$ thousands)	Three months ended Sept. 30		Nine months ended Sept. 30	
	2009	2008	2009	2008
Expenditures on Property, Plant and Equipment				
Alberta	\$ 120	\$ 659	\$ 236	\$ 2,411
British Columbia	51	955	826	14,933
Saskatchewan	2,084	3,710	3,751	8,999
Quebec	1,005	2,022	3,738	2,052
	3,260	7,346	8,551	28,395
Dispositions	–	–	–	(890)
Acquisitions (cash portion)	–	7	–	609
Acquisitions (non-cash portion)	–	(7)	–	155
Asset Retirement Obligations	24	106	41	–
Total	\$ 3,284	\$ 7,452	\$ 8,592	\$ 28,269

Liquidity and Capital Resources

Questerre reported a working capital surplus of \$49.02 million at September 30, 2009 as compared to a surplus of \$54.31 million at December 31, 2008.

The Company's current assets consist of cash and cash equivalents of \$54.97 million, \$0.19 million of marketable securities, \$4.88 million of accounts receivable, \$0.38 million of inventory and \$0.71 million in prepaids and deposits. Current liabilities of \$12.12 million represent accounts payable and accrued liabilities.

The Company believes it is sufficiently capitalized with positive cash flow from operations, no debt and a working capital surplus of approximately \$49 million, consisting mainly of cash and cash equivalents to weather the volatility in current commodity prices and financial markets.

The majority of future planned capital spending 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.

Cash Flow from Operations and Cash Flows from Operating Activities

Cash flow from operations in the 2009 third quarter of \$0.50 million was \$0.21 million, or 30% lower than the preceding quarter and \$4.91 million or 91% lower than the prior year third quarter. The decrease in the cash flow from operations from the preceding quarter was primarily due to lower production volumes. Compared to the prior year, lower realized prices for both oil and natural gas of 39% and 60%, respectively, and a 51% decrease in production volumes accounted for the significant decrease.

Cash flows from operating activities for the third quarter of 2009 were \$2.51 million compared to \$6.02 million in the same period in 2008. The cash flow from operations change of \$4.91 million offset by the change in the non-cash working capital of \$1.40 million represents the change in the cash flows from operating activities.

Share Capital

The following table provides a summary of the outstanding common shares and options as at the date of the MD&A, the current quarter end and the preceding year-end.

	November 11 2009	September 30 2009	December 31 2008
Common shares	199,184,643	199,184,643	197,299,642
Stock Options	18,906,253	16,701,253	17,655,421
Weighted average common shares			
Basic		197,501,393	186,447,776
Diluted		205,709,978	196,593,333

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

Risk Management

Except as detailed below, there were no changes to Questerre's risk management policies during the period from those detailed in the MD&A for the year ended December 31, 2008.

British Columbia's Royalty Incentives

On August 6, 2009, the B.C. government announced an oil and gas stimulus package to attract investment and produce immediate economic benefits to the province. The package included royalty and regulatory initiatives to enhance the province's competitiveness. Royalty initiatives include a one year 2% royalty for all wells drilled between September 2009 and June 2010, an increase of 15% in the existing royalty deductions for natural gas drilling, qualification of horizontal wells drilled between 1,900 and 2,300 metres into the Deep Royalty Credit Program and an additional \$50 million allocation for the Infrastructure Royalty

Credit Program to stimulate investment in oil and gas roads and pipelines. Regulatory initiatives are the commingling of production in the plains area and amendments to the drilling license regulation to create flexibility allowing industry to move wells to production while not losing the privileges to convert drilling licenses to leases.

Alberta's New Royalty Programs

The Alberta Government's New Royalty Framework ("NRF") and Transitional Royalty Program ("TRP") came into effect on January 1, 2009. The NRF established new royalties for conventional oil and natural gas that are linked to commodity prices, well production volumes and well depths for gas wells and oil quality for oil wells. These new rates apply to both new and existing conventional oil and gas activities in Alberta. The TRP allows for a one time option of selecting between transitional rates and the NRF rates on new natural gas or conventional oil wells drilled between 1,000 metres to 3,500 metres in depth. The TRP rates would apply until January 1, 2014, at which time all wells would be moved to the NRF.

On March 3, 2009, the Alberta Government announced an energy incentive program that focuses on keeping drilling and service crews at work. There are two components of this program that could potentially affect Questerre; the Drilling Royalty Credit and the New Well Incentive. The Drilling Royalty Credit is a depth related credit for the drilling of new conventional oil and natural gas wells between April 1, 2009 and March 31, 2011. The New Well Incentive provides a five percent royalty rate for new natural gas and conventional oil wells that come on production between April 1, 2009 and March 31, 2011 for a period of 12 months or 0.5 billion cubic feet equivalent for gas wells or 50,000 barrels of oil equivalent for oil wells, whichever comes first.

Future capital plans are being evaluated as a result of the NRF, TRP and Energy Incentive Programs which have changed the economics of operating in Alberta.

Accounting Standards Changes

On January 1, 2009, the Company adopted the following Canadian Institute of Chartered Accountants ("CICA") Handbook Section:

"Goodwill and Intangible Assets", Section 3064. The new standard replaces the previous goodwill and intangible asset standard and revises the requirement for recognition, measurement, presentation and disclosure of intangible assets. The adoption of this standard was applied retroactively and has had no material impact on Questerre's consolidated financial statements.

Future Accounting Pronouncements

In February 2008, the CICA's Accounting Standards Board confirmed that International Financial Reporting Standards ("IFRS") will replace Canadian GAAP in 2011 for profit-oriented Canadian publicly accountable enterprises. Questerre will be required to report its results in accordance with IFRS beginning in 2011. The Company has developed a changeover plan to complete the transition to IFRS by January 1, 2011, including the preparation of 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, with a focus on the areas that have been identified as having the most significant impact. The significant impact areas are those identified as having the greatest potential impact to the Company's consolidated financial statements or the greatest risk in terms of complexity to implement. Such areas identified to date include property, plant & equipment ("PP&E"), impairment testing, asset retirement obligations, stock-based compensation and income taxes.

The Company expects one of the most significant impacts of the IFRS changeover will be in the area of accounting for exploration and development costs. Questerre currently follows the CICA's guidelines on full cost accounting. In moving to IFRS, Questerre will be required to adopt new accounting policies for upstream activities, including pre-exploration costs, exploration and evaluation costs and development costs. Depletion will be calculated at a lower unit of account level than the current country cost centre basis. In addition, impairment testing will be performed at a lower level than the current country cost centre basis and the impairment test is a one step rather than a two step process.

In July 2009, the International Accounting Standards Board ("IASB") issued a document outlining additional exemptions for first-time adopters of IFRS. Included in the document is an exemption which permits full cost accounting companies to allocate their existing upstream PP&E net book value (full cost pool) over reserves or reserves values to the unit of account level upon transition to IFRS. This exemption relieves the Company from retrospective application of IFRS for upstream PP&E. Questerre intends to adopt this exemption and the Company is also evaluating the impact of other first-time adoption exemptions available upon initial transition to IFRS.

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.

Internal Control over Financial Reporting

Questerre is required to comply with National Instrument 52-109 "Certification of Disclosure in Issuers' Annual and Interim Filings", otherwise referred to as Canadian SOX ("C-Sox"). The 2009 certificate requires that the Company disclose in the interim MD&A any changes in the Company's internal controls over financial reporting that occurred during the period that have materially affected, or are reasonably likely to materially affect the Company's internal control over financial reporting.

There have been no significant changes in Questerre's internal control over financial reporting during the quarter ended September 30, 2009 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

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.

Quarterly Financial Information

	September 30 2009	June 30 2009	March 31 2009
Production (boe/d)	632	806	1,049
Average Realized Price (\$/boe)	47.92	40.56	39.46
Petroleum and Natural Gas Sales	2,786,384	2,974,761	3,724,999
Cash Flow from Operations	502,357	717,151	1,063,351
Per share – Basic	–	–	0.01
Per share – Diluted	–	–	0.01
Net Loss	(1,581,718)	(3,835,057)	(4,408,025)
Per share – Basic	(0.01)	(0.02)	(0.02)
Per share – Diluted	(0.01)	(0.02)	(0.02)
Capital Expenditures, net of acquisitions and dispositions	3,259,938	1,732,487	3,558,911
Working Capital Surplus	49,016,405	50,953,325	51,756,719
Total Assets	148,581,048	149,650,802	154,599,633
Shareholders' Equity	132,216,221	131,820,858	134,190,125
Weighted Average Common Shares Outstanding			
Basic	197,827,758	197,370,978	197,299,642
Diluted	206,723,239	205,065,933	205,069,693

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

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