

QUESTERRE ENERGY CORPORATION



**on course
on target
on going**

2004 ANNUAL REPORT

CORPORATE PROFILE

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



PRESIDENT'S MESSAGE

We are a much stronger Company at the end of 2004 than we were at the beginning with excellent prospects for 2005.

We established the following objectives for 2004:

- Complete our corporate restructuring;
- Complete a \$1 – \$3 million common equity financing; and
- Complete re-processing of the Beaver River 3-D seismic survey and secure financing to re-drill the Beaver River Field.

We achieved virtually all these objectives and more during 2004. We have also developed a new business plan for 2005.

We will maintain our focus on high impact projects in North America. These projects are mainly naturally fractured and hydrothermally dolomitized reservoirs. These types of unconventional reservoirs are only recently being understood from a technical perspective. We believe only a minority of larger companies are pursuing these types of reservoirs and there remain opportunities for Questerre to acquire new projects.

Questerre owns significant land positions prospective for these types of reservoir and we plan to add more to this during 2005.

We plan to diversify our risks in 2005 in two ways.

Firstly, we will participate in conventional junior oil and gas plays to provide a source of near-term cash flow and growth. We believe this cash flow will help our Company weather any delays or other unforeseen problems with our high-impact projects. In addition, these plays will provide significant base value for our Company.

In late 2004, we implemented this strategy through participation in drilling in the Parkland and Vulcan areas of Alberta. Our initial test wells were both discoveries and we expect to follow this up with further drilling in 2005.

The second way we plan to diversify risk is to work with partners on our primary projects. We were able to partner with two large independents on our Simonette project, acquired in late 2004. As a result we had a total budgeted risk capital of \$1.1 million on a project with unrisks potential of 10-15 million barrels of oil recoverable. While this well was unsuccessful it is a model of how we will approach our high impact projects in future.

We have partners in place for our St. Lawrence Lowlands acreage and hope they will be in a position to proceed with a test well before summer 2005. We continue to believe that significant recoverable gas remains at the Beaver River Field. We are currently in discussions with potential partners and will proceed once we have secured sufficient financing.

We plan to add another conventional junior oil and gas project as well as an additional high-impact project during the year.

We will require additional financing in order to drill follow-up wells in Vulcan and Parkland and to add new projects. To this end, we plan to apply for a secondary listing on the Oslo Stock Exchange in Norway. We have entered into an agreement with DnB NOR Bank ASA, the largest bank in Norway, to sponsor Questerre and raise additional equity of approximately \$5 million.

We have set the following objectives for 2005:

- Participate in exploration drilling programs at Parkland and Vulcan;
- Commence drilling and/or seismic operations in the St. Lawrence Lowlands, Quebec;
- Secure a partner for the Beaver River Field;
- Apply for a secondary listing on the Oslo Stock Exchange and complete an equity financing;
- Add an additional high impact project; and
- Add a conventional junior oil and gas project

We exited 2004 with production of approximately 100 boe per day. We are targeting an exit production rate of 500 boe per day from our conventional junior oil and gas projects in 2005. Success with any of our high-impact projects could enhance our exit production significantly.

I am optimistic that we can achieve these objectives in 2005. We are, of course, hoping for a success in one of our high-impact projects this year. However, while we do hope for early success, we have implemented a business plan that moderates financial risk while building cash flowing assets.

Ultimately, we think the projects we have assembled will create significant equity value for our shareholders.



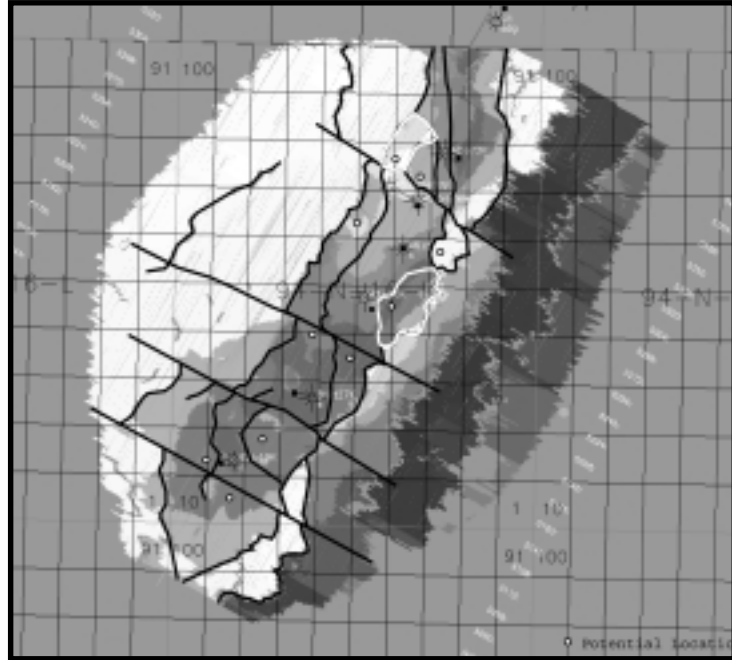
Michael Binnion
President and Chief Executive Officer

AREAS OF OPERATION

Beaver River Field, British Columbia

Discovered in 1961, the Beaver River Field is a natural gas field with an estimated 1.2 Tcf of original gas in place ("OGIP"). Recovery rates for the field were estimated at 90% of OGIP; however, the field recovered only 12%, or 178 Bcf.

Similar active water drive reservoirs typically experience recovery rates between 25-60% of the OGIP. This indicates remaining recoverable reserves for the Beaver River Field could range between 120 Bcf and 540 Bcf, with individual wells averaging daily production of 35-50 mmcf. Questerre believed it could tap this potential and acquired a controlling interest in the field in 2001.



Nahanni time structure map

Our interpretation of the Beaver River

Field is based on the theory of compartmentalization and coning – the majority of the recoverable reserves are trapped in undrilled fault blocks or compartments within the field and the remainder behind water cones in existing compartments. This theory is founded on comprehensive technical work that includes hydrodynamic pressure studies, material balance analysis, pressure transient analysis and gas isotope analysis. It was corroborated by a 3-D seismic survey acquired over the field in 2002. A review by our independent reservoir engineers, McDaniel & Associates, confirms our field interpretation and has assigned possible reserves of 120 Bcf to these undrilled compartments.

A-5 Re-entry

The objective of this re-entry was to generate sufficient cash flow to spud a new compartment well at the Field. The target, clearly defined on a 3-D seismic survey, was 130m of relatively low risk reservoir structure up-dip from the highest producing well in the Field.

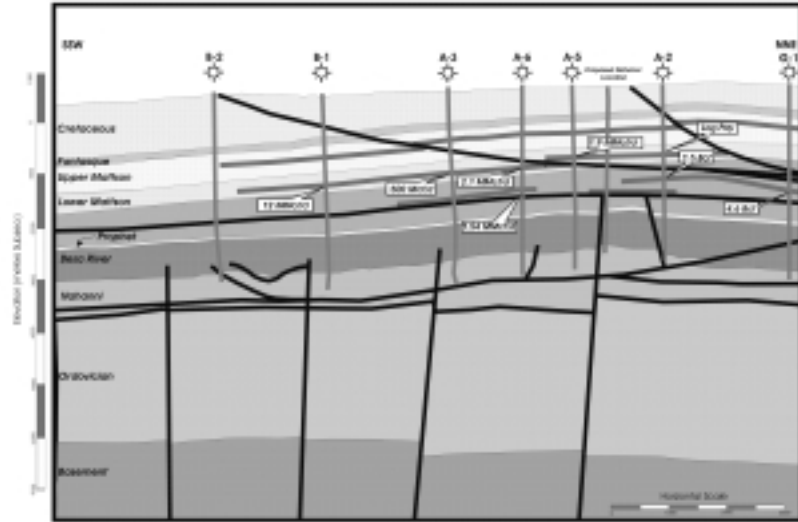
Operations commenced in August 2003 and were completed in March 2004 with the tie-in of the well. The A-5 re-entry did not encounter any up-dip structure and intersected the reservoir at the same subsea level as the old well. It is currently producing from a previously drained section of an existing compartment at rates of approximately 600 mcf of raw gas and 700 cubic meters of formation water per day, substantially below expectations.

The unsuccessful results of the well were exacerbated by the cost overruns. Budgeted at \$6.5 million, the total drilling, completion and tie-in costs were over \$19 million. Problems unrelated to downhole conditions account for a majority of these cost overruns. Notwithstanding, actual drilling took 41 days at an approximate cost of \$3.3 million.

Seismic Reprocessing

In light of the results from the A-5 well, we reprocessed our 3-D seismic survey.

Based on the re-processed data, it appears the Nahanni has more potentially undrilled compartments than originally expected. Management believes this could translate into a higher recovery factor for the Field. The reprocessing has also identified a new compartment that appears to contain up-dip structure less than 500 meters away from the existing A-5 well. A new well into this compartment could test both the new compartment and up-dip hypothesis.



Shallow zone potential at Beaver River Field

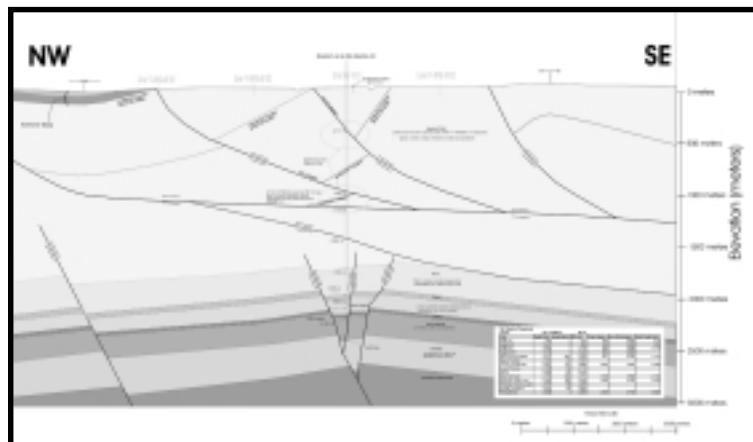
The reprocessing has also resulted in better imaging of the horizons above the Nahanni at a depth of 1600m – 2800 m TVD. An analysis of these horizons has indicated these could be tight gas zones, or non-conventional reservoir, where proper completion techniques play an important role in achieving commercial production. The Company continues to evaluate these new targets.

Based on these results and further interpretation of the seismic data, Questerre is currently evaluating locations to test both the shallow potential and the new compartment potential of the Field.

St. Lawrence Lowlands, Quebec

The St. Lawrence Lowlands lie south of the St. Lawrence River in Quebec, between Montreal and Quebec City. The exploration potential of this acreage is underpinned by proximity to the natural gas markets in the northeastern United States and excellent fiscal terms.

Key Questerre personnel have been active in natural gas exploration in the Lowlands since the 1980s. While these early



Structural cross-section through Sainte Sophie #1 well

efforts did not encounter any commercial quantities of gas, they confirmed the existence of a deep gas source. Recognizing the significant wrench faulting in this basin and its vital role in creating hydrothermal dolomite (HTD) reservoirs, we acquired an interest in the Lowlands in 2001.

A detailed regional geological and geophysical study was subsequently completed to validate our original ideas. The study documented the development and existence of HTD in Quebec – in out crop, well bores and in the St. Flavian Field, an HTD reservoir that currently serves as a gas storage facility. South of the Lowlands in the Appalachian Basin in the United States, several significant HTD reservoir discoveries, most recently by Talisman Energy, appear to provide further endorsement of our ideas.

We have reprocessed and reinterpreted over 3,000 km of 2-D seismic data and identified several drillable prospects and leads on our acreage for this HTD play, known regionally as the Trenton-Black River. Our first prospect, Becancour, covers approximately 12 square miles and has the potential to host up to several hundred Bcf in recoverable reserves.

The Becancour prospect will be tested by the Sainte Sophie #1 well, our first well in the Lowlands. Our partners in the project will collectively earn a 60% interest in the Sainte Sophie #1 well and 2,000 surrounding hectares by funding 90% of the costs. These partners will have the option of drilling additional wells on the same terms for six months from the completion of the initial well. Questerre will be responsible for funding 6 1/4% of the costs to earn a 32 1/2 % interest in the well.

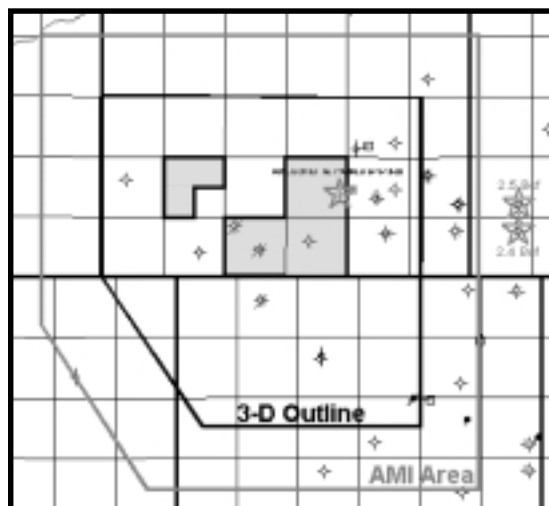
The Sainte Sophie #1 well was scheduled to spud by July 31, 2004. Due primarily to financing and rig availability, the operator has been unable to spud the well in 2004. To this end, Questerre has granted the operator an extension until July 1, 2005 to spud. In the interim, the Company has commenced discussions with other parties regarding additional exploration activities on its acreage.

Parkland and Vulcan, Alberta

The Company has recently acquired new core areas in Parkland and Vulcan, Alberta.

The lands are prospective for natural gas in multiple horizons. The primary plays are well defined on two 3-D seismic surveys covering over 49 sections of land. These plays hold the potential for 1-5 Bcf per well.

Questerre participated in the drilling of two wells in late 2004 and early 2005 to earn a 50% interest in 5 sections of land. Both these discovery wells were successful and are currently being production tested. Subject to successful test results, Questerre anticipates these wells will be tied-in and placed on production during the second quarter of 2005.



Land position in Parkland and Vulcan

Simonette, Alberta

In late 2004, Questerre acquired a 50% interest in 10 sections of land in west central Alberta prospective for a Swan Hills reef play. The acreage is adjacent to two discovered fields that have produced in excess of 15 million barrels each from the Swan Hills formation. The play was well defined by a 3-D seismic survey and supported by aeromag data.

During the first quarter of 2005, Questerre successfully farmed out a 26.667% interest in this well to a major independent exploration and production company. The well spud in early February and was completed by late March ahead of schedule and under budget at a cost of approximately \$3.7 million. Unfortunately the well did not encounter reservoir in the Swan Hills formation and was subsequently abandoned. In conjunction with its partners, Questerre continues to evaluate this acreage for additional potential.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following Management Discussion and Analysis of Financial Condition and Results of Operations ("MD&A") was prepared at, and is dated, March 28, 2005. This MD&A is provided by Management of Questerre Energy Corporation ("Questerre" or the "Company") to review 2004 activities and results as compared to the previous year and should be read in conjunction with the audited consolidated financial statements for the years ended December 31, 2004 and 2003. Additional information relating to Questerre, including Questerre's Annual Information Form is available on SEDAR at www.sedar.com.

Questerre was incorporated as a private company in October 1971. The Company initially operated as an oil and gas exploration and production company with minority interests in several producing properties in Western Canada. In November 2000, a new management team was assembled and the Company changed its focus to pursuing what Management believes will be large-scale exploration and development projects. Management intends to leverage its specialized knowledge of naturally fractured and hydrothermally dolomitized reservoirs to develop these projects.

To mitigate the financial and operational risks, the Company will seek industry partners to participate in the development of these projects. The Company plans to further temper risk through the acquisition and development of a portfolio of lower risk projects. It is expected these lower risk projects will provide near-term cash flow and growth.

In July 2003, the Company completed an initial public offering and listed its Common Shares on the Toronto Stock Exchange.

As at March 28, 2005, the Company has two projects it believes hold the potential to create significant shareholder value – the Beaver River Field in British Columbia and the St. Lawrence Lowlands in Quebec. The Company is also developing its portfolio of lower risk exploration projects that include recently acquired assets in the Parkland and Vulcan areas of Alberta. In addition, Questerre also holds minority interests in producing non-operated properties in Alberta.

This MD&A contains forward-looking statements. Forward-looking statements are based on current expectations that involve a number of risks and uncertainties which could cause events or results to differ materially from those reflected in the MD&A. Forward-looking statements are based on the estimates and opinions of Questerre's management at the time the statements were made. Questerre assumes no obligation to update forward-looking statements should circumstances or management's estimates change.

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 and is based on an energy equivalent conversion method application at the burner tip and does not necessarily represent an economic value equivalent at the wellhead.

Select Annual Information

Item	For Year Ended		
	December 31 2004	December 31 2003	December 31 2002
Total Revenues	1,636,096	2,788,701	1,821,252
Expenses	2,768,162	19,513,827	8,128,217
Net Income (Loss) before discontinued operations and extraordinary items			
– Total	693,503	(16,725,126)	(6,318,364)
– Per Share	0.02	(0.54)	(0.24)
– Per Share (Diluted)	0.02	(0.54)	(0.24)
Total Assets	9,803,679	8,240,837	9,966,445
Working Capital (Deficiency)	2,824,588	(4,557,846)	235,850
Total Long Term Debt	600,000	–	–
Total Liabilities	3,255,036	8,388,171	3,438,965
Shareholders' Equity	6,548,643	(147,334)	6,527,480
Cash Dividend per Share	0.00	0.00	0.00

Quarterly Financial Information

Period ended December 31, 2004

	Q1	Q2	Q3	Q4	Total
Production revenue, net of royalties	64,555	903,601	286,365	381,575	1,636,096
Net income (loss)	(5,523,293)	(909,815)	6,698,361	428,250	693,503
Per share – basic	(0.13)	(0.02)	0.15	0.01	0.02
Per share – diluted	(0.13)	(0.02)	0.15	0.01	0.02

Period ended December 31, 2003

	Q1	Q2	Q3	Q4	Total
Production revenue, net of royalties	491,366	490,265	124,850	242,811	1,349,292
Net loss	(254,512)	(239,813)	(532,340)	(15,698,461)	(16,725,126)
Per share – basic	(0.01)	(0.01)	(0.02)	(0.50)	(0.54)
Per share – diluted	(0.01)	(0.01)	(0.02)	(0.50)	(0.54)

2004 ACTIVITIES

A-5 Re-Entry

The Company's primary focus in early 2004 was the completion of the A-5 re-entry operation at the Beaver River Field (the "Field") in British Columbia.

The objective of this re-entry was to generate sufficient cash flow to spud a new compartment well at the Field. The target, clearly defined on a 3-D seismic survey, was 130m of relatively low risk reservoir structure up-dip from the highest producing well in the Field.

Operations commenced in August 2003 and were completed in March 2004 with the tie-in of the well. The A-5 re-entry did not encounter any up-dip structure and intersected the reservoir at the same subsea level as the old well. It is currently producing from a previously drained section of an existing compartment at rates of approximately 600 mcf of raw gas and 700 cubic meters of formation water per day, substantially below Management's expectations. This is presently the only producing well at the Field.

Corporate Restructuring

The unsuccessful results of the A-5 re-entry were compounded by significant operational delays and cost overruns. Questerre engaged a reputable drilling consultant to plan and manage the drilling of this re-entry. The cost estimate prepared by this consultant was \$5.3 million based on a multi-well program and \$6.5 million based on a single well program. The total project costs, including completion, testing and tie-in, were over \$19 million, or almost three times the original cost estimate. Despite raising a total of \$11.5 million in cash net of financing and administrative costs, over \$9 million remained unpaid to unsecured trade creditors. Accordingly, on April 1, 2004, Questerre Beaver River Inc. ("QBR"), a wholly owned subsidiary of the Company, applied for and was granted an order by the Court of Queen's Bench of Alberta providing for creditor protection under the Companies' Creditors Arrangement Act ("CCAA").

Subsequent to QBR filing for protection under CCAA, several parties who provided goods and services in respect of the A-5 re-entry filed statements of claim against the Company with respect to those services. Several other parties indicated that they intended to advance similar claims, either jointly against the Company or, as an alternative to settlement from QBR. Although Questerre disputed liability for most of the claims advanced by parties who worked on the A-5 re-entry, and in some cases both Questerre and QBR disputed the amounts claimed, the Company believed that the cost of defending the actions could exceed its available cash resources. As well, the existence of claims and the possibility of further potential claims against the Company seriously restricted its ability to raise capital in the public markets.

On June 22, 2004, the Company sought and was granted protection under the CCAA and was added as a petitioner in QBR's CCAA proceedings.

On August 9, 2004, Plans of Compromise or Arrangement for the Company and QBR (the "Plans" or "Plans of Arrangement") were filed under the CCAA for the settlement of all outstanding claims. The Plans were approved by the requisite majority of unsecured creditors at meetings of creditors of QBR and the Company held on August 31, 2004. The Plans were subsequently sanctioned by the Court of Queen's Bench of Alberta on September 9, 2004. Questerre and QBR subsequently emerged from Court protection on October 8, 2004.

Pursuant to the Plans proposed by Questerre and QBR, unsecured creditors received either the lesser of the amount of their claim or \$2,000. Alternatively, unsecured creditors elected to receive a cash dividend of \$0.05 plus one Common Share of Questerre for each dollar of their claims. The Common Shares of Questerre issued under the Plans are subject to a contractual escrow and released in two equal instalments on the fourth and eighth month anniversary of the date the Plans received final Court approval.

In addition to the proposed settlement, Questerre arranged for a liquidity option. Under this liquidity option, unsecured creditors received \$0.05 for each dollar of their claims, and also received an additional \$0.07 for each dollar of their claim in exchange for foregoing each Common Share they would have otherwise received. This resulted in a cash settlement of \$0.12 per dollar of claim outstanding.

The Common Shares that would otherwise have been issued to these unsecured creditors were issued to Terrenex Acquisition Corporation ("Terrenex"), a related party, pursuant to the terms of a Liquidity Option Agreement. See "Related Party Transactions." Under the Liquidity Option Agreement, Terrenex established a fund to finance the liquidity option up to a maximum of \$668,500.

A total of \$0.56 million in cash and 9,623,012 Common Shares of Questerre were issued on the implementation of these Plans. 6,756,102 Common Shares were issued to Terrenex pursuant to the Liquidity Option Agreement.

Seismic Reprocessing

The results of the A-5 re-entry necessitated a reassessment of the seismic data over the Field. The review confirmed that the false imaging of the up-dip structure was due to improper processing of the seismic data, not the interpretation.

A new processing company and geophysicist were engaged to re-process the seismic survey during the year. This reprocessing was required to correct velocity anomalies responsible for the false imaging and more accurately image the Nahanni reservoir. Two key stages of the reprocessing were completed during the year. The reprocessing has dramatically reduced the noise associated with the data and resulted in more clearly defined imaging of the Nahanni reservoir.

Based on the new interpretation, it appears the Nahanni has more potentially undrilled compartments than originally expected. Management believes this could translate into a higher recovery factor for the Field. The reprocessing has also identified a new compartment that appears to contain up-dip structure less than 500 meters away from the existing A-5 well. A new well into this compartment could test both the new compartment and up-dip hypothesis.

The reprocessing has also resulted in better imaging of the horizons above the Nahanni at a depth of 1600m – 2800 m TVD. An analysis of these horizons has indicated these could be tight gas zones, or non-conventional reservoir, where proper completion techniques play an important role in achieving commercial production. The Company continues to evaluate these new targets.

Based on these results and further interpretation of the seismic data, Questerre is currently evaluating locations to test both the shallow potential and the new compartment potential of the Field.

In early 2005, Questerre filed a statement of claim in the Court of Queen's Bench of Alberta against the company that processed the 3-D seismic survey over the Field. The statement of claim can be viewed on the Company's web site. Questerre anticipates the seismic processing company will file its statement of defense during the second quarter of 2005.

St. Lawrence Lowlands

The Company successfully concluded a farm-in and participation agreement covering its exploration acreage in the St. Lawrence Lowlands during the year. The farm-in partners, including a director of the Company (See "Related Party Transactions"), will collectively earn a 60% interest in the Sainte Sophie #1 well and 2,000 surrounding hectares by funding 90% of the costs. These partners will have the option of drilling additional wells on the same terms for six months from the completion of the initial well. Questerre will be responsible for funding 6 1/4% of the costs to earn a 32 1/2% interest in the well.

The Sainte Sophie #1 well was scheduled to spud by July 31, 2004. Due primarily to financing and rig availability, the operator has been unable to spud the well in 2004. To this end, Questerre has granted the operator an extension until July 1, 2005 to spud. In the interim, the Company has commenced discussions with other parties regarding additional exploration activities on its acreage.

New Projects

During the fourth quarter of 2004, the Company began evaluating and acquiring additional projects to diversify its existing portfolio.

Questerre acquired a 50% interest in 10 sections of land in west central Alberta prospective for a Swan Hills reef play. The acreage is adjacent to two discovered fields that have produced in excess of 15 million barrels each from the Swan Hills formation. During the first quarter of 2005, Questerre successfully farmed out a 26.667% interest in this well to a major independent exploration and production company. The well spud in early February and was completed by late March ahead of schedule and under budget at a cost of approximately \$3.7 million. The well did not encounter reservoir in the Swan Hills formation and was subsequently abandoned. Questerre does not have any additional financial commitments with regard to this project.

The Company also concluded a farm-in and participation agreement in the Parkland and Vulcan areas of Alberta in the fourth quarter. Prospective for natural gas in multiple horizons, Questerre participated in the drilling of two wells in late 2004 and early 2005 to earn a 50% interest in 5 sections of land. Questerre has also acquired a 50% interest in two additional sections in these areas.

In early 2005, the Company participated in the drilling of an additional well in the Vulcan area to earn a 50% interest in an additional 2 sections of land. All three wells are currently being completed and tested. Subject to successful production testing, the wells will be tied in and placed on production during the second quarter of 2005. Questerre anticipates drilling additional wells in these areas in 2005.

In conjunction with its farm-in partners in the St. Lawrence Lowlands, Questerre participated in the drilling of an exploration well in the Gaspé Peninsula of Quebec in November 2004. The well was targeting three oil and/or gas targets, characterized by seismic anomalies and structural/stratigraphic traps. Total well costs are estimated at \$1.6 million, with the Company share estimated at \$0.2 million. The well did not encounter commercial hydrocarbons and was subsequently abandoned.

To finance the drilling of wells in Alberta, the Company completed a \$3.6 million financing in the fourth quarter of 2004. The financing consisted of the issuance of a total of 12.4 million common shares on a private placement basis.

Production

The Company's production is primarily natural gas from the Field and its minority interests in non-operated producing properties in Alberta.

Production from the Field in 2004 is solely attributable to the A-5 re-entry that was placed on production in April 2004. In 2003, production from the Field is attributable to two wells – B-2 and A-5. Both these wells were shut in by year-end 2003 – the A-5 well was shut in July to drill the A-5 re-entry and the B-2 well was shut in October due to pipeline pressures and water disposal constraints.

For the year ended December 31, 2004, the Field averaged 758 mcf/d of raw gas (126 boe/d). Production peaked at 3870 mcf/d (645 boe/d) in April and gradually declined to 575 mcf/d (96 boe/d) year-end. By comparison, gross production from the Field for 2003 averaged 704 mcf/d of raw gas (117boe/d). Questerre conducted the A-5 re-entry operation on a sole risk basis; as such 100% of the production from the Field in 2004 is attributable to Questerre. In 2003, Questerre was attributed 60% of gross production from the Field.

Production from the Company's interest in non-operated producing properties in Alberta for 2004 remained unchanged from the previous year at 25 boe/d of natural gas and associated natural gas liquids.

The Company plans to grow its production base in 2005 through further exploration and development drilling in Parkland and Vulcan and the acquisition of additional lower-risk projects. Questerre expects that further drilling at the Field will commence once the Company secures a joint venture partner and sufficient financing.

2004 FINANCIAL RESULTS

Revenue

Questerre reported petroleum and natural gas revenues of \$1.94 million in 2004 (2003 – \$1.5 million). 2004 revenues included \$1.53 million (2003 – \$1.11 million) in natural gas sales from the Field and \$0.40 million (2003 – \$0.39 million) from its interest in non-operated Alberta properties. Questerre's realized natural gas prices decreased by 8% to \$6.25/mcf in 2004 from \$6.79/mcf in 2003. Decreased pricing in 2004 marginally offset increases in revenue associated with increased production.

Royalties

Crown royalties for the Field are governed by a royalty agreement with the Crown that provides for the deferral of all royalties until the earlier of June 30, 2004 and cumulative production of 13 bcf from the Field. Repayment of deferred royalties was contingent on both the commercial success of the experimental project for which the deferral was granted and on monthly production exceeding volumes established by the Crown.

In December 2003, Questerre reported a royalty recovery which included the reversal of 2003 and prior years' royalty expense recognized under the royalty agreement. Based on the limited production and disappointing results to date, the Company adjusted the liability for Crown royalties to Nil at December 31, 2003 on the basis that the conditions for repayment no longer existed. On the same basis, the Company did not accrue Crown royalties on its Field production in the first and second quarters of 2004.

The Company has accrued Crown royalties of \$0.14 million for the second half of 2004 on production from the Field. Payment of this royalty is contingent on the Company reaching an agreement with the Ministry of Energy and Mines in British Columbia regarding its qualification for a deep royalty credit of \$2.2 million for the A-5 re-entry. Discussions are ongoing with the Ministry regarding the Company's qualification for this credit.

Due to increased natural gas revenue from the Field in 2004, overriding royalties on production in 2004 increased 50% to \$0.06 million from \$0.03 million in 2003.

Crown and gross overriding royalties on production from the Company's minor properties in Alberta in 2004 remained unchanged at \$0.1 million or 28% of gross resource revenue attributable to these properties.

Operating Costs

Total operating expenses increased 50% from \$1.1 million in 2003 to \$1.7 million in 2004. Gas processing and transportation fees, which account for 17% of operating expenses in 2004, are directly proportionate to production from the Field. These fees are based on interruptible service rates at the Duke Fort Nelson plant.

Due to the fixed nature of operating costs at the Beaver River Field, the remainder of the increase in 2004 is attributed to the Company bearing responsibility for 100% of operating costs associated with the Field, as compared to 60% in 2003.

Marketing fees in 2003 were charged at 5% of gross revenue pursuant to an existing marketing contract. This contract was terminated in 2003 and a daily spot price contract was negotiated for 2004 with substantially reduced marketing fees.

General & Administrative Expenses

General and administrative expenses of \$0.74 million in 2004 included \$0.14 million of bad debt expense recorded against amounts receivable from partners on the Beaver River Field. Overhead capitalization of \$0.4 million associated with the increased capital expenditures in the first six months of 2004 offset a significant portion of 2004 expenses.

<i>(\$ thousands)</i>	2004	2003
General & administrative expenses	\$ 1,010	\$ 1,023
Bad debt expense	139	650
Overhead recoveries	(411)	(671)
General & administrative expenses, net	\$ 738	\$ 1,002

Other Income and Expenses

During the year ended December 31, 2004, Questerre recorded restructuring expenses of \$0.43 million representing professional services associated with the Company's filings under the CCAA.

Questerre recorded a gain of \$7.63 million during the year representing the net forgiveness of outstanding amounts owing by the Company to its unsecured trade creditors. \$7.3 million of this amount related to amounts settled under the Plans.

Stock Based Compensation

Effective January 1, 2004, the Company adopted the new accounting standard for stock based compensation. See "Changes in Accounting Policies – Stock Based Compensation." This resulted in stock based compensation expense of (\$0.03) million for the year ended December 31, 2004. This was due to a recovery realized on the cancellation of share options previously expensed during the year, partially offset by the expense for share options subsequently issued.

The new accounting standard was applied retroactively without restatement of prior periods, therefore no corresponding expense was recorded in 2003.

Interest Expense

Interest expense of \$0.07 million in 2004 was relatively unchanged from 2003. In 2004, this comprised primarily of \$0.02 million in interest payable on the term bank loan and \$0.04 million in interest payable on the promissory note to Rupert's Crossing, an Investment Corporation ("Rupert's"). Rupert's is a private investment holding company controlled by Michael Binnion, the Company's President. See "Related Party Transactions". The interest expense in 2003 relates solely to the interest payable on the term bank loan.

Depletion, Depreciation and Site Restoration

Questerre recognized \$7.4 million in depletion and depreciation in 2004 compared to \$17.3 million in 2003. Included in 2004 depletion is a \$7.0 million "ceiling test" write-down and depletion charge recorded by the Company on its Field petroleum and natural gas assets. The write-down reflects the majority of the costs incurred to finish the drilling, completion and tie-in of the A-5 re-entry in 2004. Depletion for 2004 also includes \$0.2 million relating to the Company's costs of an unsuccessful well in the Gaspé Peninsula, Quebec. As of December 31, 2004, all costs associated with the Beaver River Field, net of salvage values, have been written down and included in depletion, except \$2.9 million of geological and geophysical costs.

Included in 2003 depletion is a \$16.7 million "ceiling test" write-down recorded by the Company on its Field petroleum and natural gas assets. Based on the reserve evaluation, the Company had no proved or probable reserves associated with the Field at December 31, 2003.

Questerre does not include costs associated with its St. Lawrence Lowlands acreage in Quebec in the calculation of depletion or in costs subject to the ceiling test calculation. This asset remains unproved at December 31, 2004.

The Company's estimated undiscounted asset retirement cost for the Beaver River Field at December 31, 2004 was \$1.8 million (2003 - \$0.89 million). The increase of \$0.9 million during the year was based on Management's revised assessment of asset retirement costs associated with the Field. Accretion of asset retirement obligations for the year ended December 31, 2004 was \$0.09 million (2003 - 0.06 million). Questerre did not acquire any new properties in 2003 or 2004 that would result in additional asset retirement obligations.

Taxes

Consistent with prior years, Questerre had sufficient tax pool deductions to offset taxable income in 2004 resulting in no income taxes payable for the current year. In addition, the Company's tax assets continue to significantly exceed tax liabilities. No tax asset is recognized at December 31, 2004 as there is no certainty that the Company will be able to realize the value of the tax assets in the future.

The Company recorded a \$1.8 million recovery in recognition of the tax benefit of flow-through shares issued in 2004.

The Company has non-capital loss carryforwards at December 31, 2004 of \$0.71 million. This represents non-capital losses created in 2004 and, therefore, expire in 2011. The non-capital losses accumulated to December 31, 2003 were used to offset the taxable income related to the gain on settlement of obligations.

Net Loss and Cash Flow

Questerre recorded net income of \$0.07 million (\$0.02 per share) in 2004 compared to a net loss of \$16.7 million (\$0.54 per share) in 2003. The net income for the year is primarily due to the gain on settlement of all outstanding obligations under the Plans and the recovery due to future tax on flow-through shares offset by higher depletion including a \$6.2 million ceiling test write-down.

LIQUIDITY AND CAPITAL RESOURCES

Capital Expenditures

Questerre incurred capital expenditures of \$7.48 million in 2004 compared to \$14 million in 2003.

The majority of capital spending in 2004 at the Field related to the drilling, completion and tie-in of the A-5 re-entry. In Quebec, approximately \$0.2 million was spent on the drilling of the Miguasha #1 well with the remainder incurred in the St. Lawrence Lowlands. In Alberta, Questerre incurred approximately \$0.8 million in drilling costs in the Parkland area with the remainder spent on land acquisition in the Vulcan and Simonette areas.

The majority of 2003 capital spending related to the Field – primarily the drilling of the A-5 re-entry. Capital expenditures on the Company's Lowlands acreage were largely directed to the acquisition of exploration licenses. In May 2003, the Company issued 750,000 common shares at a deemed price of \$1.00 per share, to Terrenex on the termination of a farmout agreement covering the St. Lawrence Lowlands licenses. Subsequent to terminating the agreement, Questerre successfully obtained the exploration licenses previously covered by this agreement.

<i>(\$ thousands)</i>	2004	2003
Capital Expenditures		
Beaver River Field, British Columbia	\$ 6,271	13,090
St. Lawrence Lowlands & Gaspé, Quebec	287	876
Alberta Properties	917	72
Total	\$ 7,475	14,038

Working Capital Position

Questerre reported a working capital surplus of \$2.76 million at December 31, 2004 as compared to a working capital deficiency of \$4.56 million as of December 31, 2003.

Questerre's current assets at December 31, 2004 primarily consist of cash of \$2.7 million, accounts receivable of \$0.22 million and field inventory of \$0.14 million. It also includes \$0.4 million placed in trust with the operator for the drilling of the Sainte Sophie #1 well on the Company's acreage in the St. Lawrence Lowlands in Quebec. Due to delays in spudding this well, this amount was refunded to the Company during the first quarter of 2005. In addition \$0.12 million is held as a deposit with the Crown in British Columbia as deposits for reclamation and abandonment costs at the Beaver River Field.

Questerre's current liabilities consist of trade payables of \$0.57 million and \$0.23 million representing the term bank loan that has been classified as a current liability.

The majority of the Company's cash holdings were used to finance drilling and completion activities in Alberta during the first quarter of 2005. The Company incurred expenditures of approximately \$2.4 million to finance the drilling and completion of wells in the Parkland, Vulcan and Simonette areas of Alberta. The Company anticipates it will need to raise additional capital to finance further exploration and development work in the Parkland and Vulcan areas and new project acquisition in 2005.

Revenue from the Field and its non-operated properties in Alberta does not generate sufficient cash to maintain the Company's current level of expenditures. The Company expects that, based on successful testing, its recently drilled wells in Parkland and Vulcan will significantly improve near-term cash flow. The Company plans to further enhance cash flow through additional drilling in these areas in conjunction with the acquisition of lower-risk exploration and development projects.

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, 2004, there were no Class B common voting shares or preferred shares outstanding.

On February 13, 2004, the Company completed a private placement for 642,860 common shares and 1,878,791 flow-through common shares for gross proceeds of \$3.16 million. Proceeds from this offering were primarily used to finance the drilling and completion of the A-5 re-entry at the Field.

On September 21, 2004, the Company issued a total of 9,623,012 common shares on the implementation of the Plans of Arrangement under the CCAA.

On December 22, 2004 the Company completed a private placement for 2,638,000 common shares and 9,825,000 flow-through common shares for gross proceeds of \$3.61 million. Proceeds from this placement were primarily used to finance acquisition and drilling of new projects in Alberta.

At December 31, 2004, there were no Class B common voting shares or preferred shares outstanding, a total of 66,751,904 common shares outstanding and 3,365,000 stock options outstanding. An additional 2,000,000 common shares have been reserved for the conversion of the \$0.6 million promissory note.

Contractual Obligations

Questerre is party to an Office Rental Agreement with a related party for the provision of offices, office equipment and support personnel. Either party may terminate the agreement with six months written notice. Questerre's annual commitment under this agreement is \$126,000 for 2005.

The Company is responsible for principal payments on its bank loan in the amount of \$80,400 annually in 2005 and 2006 and \$73,700 in 2007.

Off-Balance Sheet Arrangements

Questerre has no off-balance sheet arrangements.

Related Party Transactions

In August 2004, the Company entered into a Liquidity Option Agreement with Terrenex to facilitate acceptance of the Plans by the unsecured creditors of Questerre and QBR. Pursuant to the Liquidity Option Agreement, Terrenex funded a payment of \$0.07 per Common Share to those unsecured creditors that did not wish to hold the Common Shares received under the Plans (the "Liquidity Option"). In consideration for this payment, Terrenex was issued that number of Common Shares that, but for their election to participate in the Liquidity Option, would have been issued to the unsecured creditors. The Common Shares issued to Terrenex are subject to the same contractual hold period were they issued to these unsecured creditors. For fulfilling its obligations under the Liquidity Option Agreement, Terrenex was issued 300,000 Common Shares of the Company.

On the approval of the Plans on August 31, 2004, unsecured creditors of Questerre and QBR with claims totalling \$6.7 million elected to participate in the Liquidity Option. Terrenex funded a payment of \$0.47 million to these unsecured creditors and was issued 6,756,102 Common Shares.

Questerre incurred fees of \$126,000 for the years ended December 31, 2004 and 2003 to a company with common directors and officers. The transactions were in the normal course of business paid pursuant to an Office Rental Agreement for the provision of office space, office equipment and support personnel. The agreement may be terminated by either party with six months' written notice.

In June 2004, Questerre entered into a farmout agreement with a director of the Company. The farmout agreement covers the Company's exploration acreage in the St. Lawrence Lowlands, Quebec utilizing the same terms and conditions of a farmout agreement with independent arms-length parties.

In June 2004, the Company obtained \$0.5 million on the issue of a \$0.5 million promissory note to Rupert's. Rupert's is a private investment holding company controlled by the President and Chief Executive Officer of Questerre. The promissory note was originally due on November 14, 2004 with interest calculated at 12% per annum, payable monthly. The promissory note is secured by a General Security Agreement over the assets of the Company and the hypothecation of the Company's exploration licenses in Quebec.

In August 2004, the Company amended its \$0.5 million financing agreement with Rupert's when Rupert's advanced an additional \$0.1 million which was placed in trust with the Company's legal counsel. Upon the approval of the Plans, these funds were advanced to the Company on the same terms as the original \$0.5 million. The funds were used to finance a portion of the cash component of the Plans.

In October 2004, the Company further amended the terms of the \$0.5 million financing agreement with Rupert's when Rupert's advanced an additional \$0.08 million to the Company for general working capital. The advance was made on the same terms as the original advance of \$0.5 million. The \$0.08 million was repaid in December 2004.

In November 2004, the Company and Rupert's amended the terms of the financing agreement extending the due date of the promissory note from November 14, 2004 to November 14, 2006 and reducing the interest rate from 12% per annum to 8% per annum. The Company has been granted the right to prepay the entire amount or any portion thereof with 30 days' notice in writing to Rupert's. Rupert's has been granted an option, subject to regulatory approval, to convert the entire amount into Common Shares of the Company at a conversion rate of \$0.30 per Common Share. As at December 31, 2004, a total of \$0.6 million is due to Rupert's under this financing agreement.

Financial Instruments

The Company's financial instruments included in the balance sheet are comprised of accounts receivable, accounts payable, accrued liabilities, bank loan and promissory note payable. The fair value of the financial instruments classified as current assets approximate their carrying amounts due to the short-term maturity of these instruments. The fair value of the bank loan and promissory note approximate their carrying amount as the interest rate approximates market.

Virtually all of the Company's accounts receivable are for revenue due on production from the Field and the Company's minority interest in non-operated properties in Alberta. The Company is not exposed to significant credit risks.

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.

Going Concern

Questerre's financial statements have been prepared using Canadian generally accepted accounting principles ("GAAP") and, accordingly, have been prepared using the same principles as those for a going concern.

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 depreciated, depleted and amortized 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 depreciation, depletion and amortization ("DD&A"). A downward revision in a reserve estimate could result in a higher DD&A 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 charged against earnings.

Certain costs related to unproved properties and major development projects may be excluded from costs subject to depletion until proved reserves have been determined or their value is impaired. These properties are reviewed quarterly to determine if proved reserves should be assigned or if impairment has occurred. If reserves can be assigned, the cost of the properties would be included in the depletion calculation. If impairment has occurred, any write-down would be included in depletion and depreciation expense for the period.

Oil and Gas Reserves

Questerre's proved oil and gas reserves are evaluated and reported on by an independent petroleum engineering consultant. 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 and depreciation. A revision to the reserve estimate could result in a higher or lower DD&A 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 Obligation

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 policies.

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. In the second quarter of 2004, the Company increased its estimated undiscounted asset retirement cost for the Field from 0.9 million to \$1.8 million. The \$0.9 million increase was added to the asset retirement obligation and also capitalized as part of the carrying amount of the related 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 income for asset retirement obligations.

CHANGE IN ACCOUNTING POLICIES

The following new and amended standards were implemented by the Company in 2004 with the following impact on the 2004 financial statements.

Stock Based Compensation

In January 2004, the Company adopted the amended CICA Handbook Section 3870 "Stock-based Compensation and Other Stock-based Payments". This change in accounting policy has been applied retroactively without restatement of prior periods presented.

Under this amended standard, the Company must account for compensation expense based on the fair value of rights granted under its stock-based compensation plan. Compensation cost attributable to share options granted to employees or directors is measured at fair value at the grant date and expensed over the expected exercise time frame with a corresponding increase to contributed surplus. Upon exercise of the stock options, consideration paid by the unit holder together with the amount previously recognized in contributed surplus is recorded as an increase to share capital.

As a result of adopting this change in accounting policy, the consolidated financial statements at January 1, 2004 were changed as follows: contributed surplus increased by \$70,527 and the opening deficit was increased by \$70,527.

Asset Retirement Obligations

In January 2004, the Company adopted CICA Handbook Section 3110 “Asset Retirement Obligations”. This change in accounting policy has been applied retroactively with restatement of prior periods presented.

Utilizing the new accounting policy, 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 as accretion expense is recorded. 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 policies. Revisions to the estimated timing of cash flows or to the original estimated undiscounted cost would also result in an increase or decrease to the asset retirement obligation. 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.

The previously reported amounts for 2003 have been restated due to the retroactive application of this new standard. Adoption of this standard had the following effects on the Company’s consolidated balance sheet and statement of income and deficit for the year ended December 31, 2003:

Increase in petroleum and natural gas properties:	\$ 20,600
Decrease in future site restoration and abandonment liability:	878,833
Increase in asset retirement obligation	(848,134)
Increase in opening deficit	408,201
Decrease in site restoration expense	(525,285)
Increase in depletion and depreciation expense	10,300
Increase in asset retirement obligation accretion expense	55,485

Full Cost Accounting Guideline

In January 2004, the Company prospectively adopted the new Accounting Guideline 16 “Oil and Gas Accounting – Full Cost” issued by the Canadian Institute of Chartered Accountants (“CICA”).

Consistent with the former guideline, the net carrying cost of the Company’s petroleum and natural gas properties is limited to an estimated net recoverable amount (“ceiling test”). Under the new guideline, the ceiling test calculation is a two step process. First, the Company determines whether a write-down is required by comparing the carrying value of the properties to the undiscounted cash flow of its proved reserves (based on management’s best estimate of future prices) plus the lower of cost and market value for unproved properties. If there is an impairment calculated under the first step, the carrying value of properties is written down to the discounted value of the proved plus probable reserves (based on management’s best estimate of future prices) plus the lower of cost and market of unproved properties.

The Company recorded a \$6.2 million ceiling test write-down for the year ended December 31, 2004 related to the Field and a \$0.2 million write-down relating to the Company’s share of an unsuccessful well drilled in Quebec. The write-downs are included in the depletion and depreciation provision on the income statement.

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.

The Company has issued and will continue to issue flow through shares to investors. The Company uses its best efforts to ensure that qualifying expenditures of CEE are incurred in order to meet its flow through obligations. However, in the event that the Company incurs qualifying expenditures of 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. Being the operator and maintaining a high working interest in its properties allows the Company to best manage operational risk by giving the Company control over costs and timing of expenditures, and the method and sales of production. Where the Company is not the operator of a property, it strives to develop a good working relationship with the operator and the other partners in the property 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.

Interest rates on long-term debt float with the Bank of Canada rate. The Company does not have any US\$ denominated debt. If strong indications arise that interest rates would be increasing significantly, steps would be taken where possible to fix the rate for a period of time.

Potential risks to the environment are inherent in some of the business activities of the Company. Questerre intends 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.

MANAGEMENT'S REPORT

To the Shareholders of Questerre Energy Corporation

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

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

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

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

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



Michael Binnion
President and Chief Executive Officer



David Mallory
Interim Chief Financial Officer

Calgary, Alberta, Canada
March 22, 2005

AUDITORS' REPORT

To the Shareholders of Questerre Energy Corporation

We have audited the consolidated balance sheets of Questerre Energy Corporation as at December 31, 2004 and 2003 and the consolidated statements of loss and deficit and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2004 and 2003 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

Chartered Accountants

Calgary, Alberta Canada
March 22, 2005

CONSOLIDATED BALANCE SHEETS

	December 31 2004	December 31 2003
		(as restated – note 3)
Assets		
Current assets		
Cash	2,701,477	\$ 1,678,611
Accounts receivable	218,249	623,544
Inventory	141,373	680,036
Deposits and cash calls paid	502,522	–
	3,563,621	2,982,191
Restricted Cash (note 7)	100,000	100,000
Petroleum and natural gas properties – net of accumulated depletion and depreciation (note 5)		
British Columbia	3,346,186	3,262,696
Alberta	1,024,584	182,387
Quebec	1,769,288	1,713,563
	6,140,058	5,158,646
	9,803,679	8,240,837
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	572,033	\$ 7,225,137
Bank loan (note 7)	234,500	314,900
	806,533	7,540,037
Promissory note payable (note 8)	600,000	–
Asset retirement obligation (notes 2 and 10)	1,848,503	848,134
	3,255,036	8,388,171
Shareholders' Equity		
Common shares (note 11)	31,339,389	25,308,340
Contributed surplus (note 11)	41,952	–
Deficit	(24,832,698)	(25,455,674)
	6,548,643	(147,334)
Going Concern Matters (notes 1 and 2)		
	9,803,679	\$ 8,240,837

See accompanying notes to consolidated financial statements.

Approved by the Board of Directors


Director


Director

CONSOLIDATED STATEMENTS OF INCOME AND DEFICIT

	For the years ended December 31,	
	2004	2003
	(as restated – note 3)	
Revenue		
Petroleum and natural gas revenue	1,942,523	1,495,702
Royalties	(306,427)	(146,410)
Recovery of deferred crown royalties (note 9)	–	1,439,409
	1,636,096	2,788,701
Expenses		
Operating	1,718,803	1,141,527
General and administrative, net of overhead	737,600	1,001,874
Restructuring costs	430,219	–
Stock-based compensation (note 3)	(28,575)	–
Interest expense	69,984	64,754
Interest income	(25,033)	(53,022)
Gain on settlement of obligations (note 1)	(7,630,778)	–
Foreign exchange gain	1,803	–
Depletion and depreciation	7,402,949	17,303,209
Accretion on asset retirement obligation (notes 3 and 10)	91,190	55,485
	2,768,162	19,513,827
Net income (loss) before income taxes	(1,132,066)	(16,725,126)
Taxes		
Future tax recovery	1,825,569	–
	1,825,569	–
Net income (loss)	693,503	(16,725,126)
Deficit, beginning of period	(25,455,674)	(8,322,347)
Restatement for changes in accounting policies		
Stock-based compensation (note 3)	(70,527)	–
Asset retirement obligation (note 3)	–	(408,201)
Deficit, end of period	(24,832,698)	(25,455,674)
Net income (loss) per share		
Basic and diluted (note 11 (c))	0.02	(0.54)

See accompanying notes to consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the years ended December 31,	
	2004	2003
	(as restated – note 3)	
Cash provided by (used in):		
Operating Activities		
Net income (loss)	693,503	(16,725,126)
Items not affecting cash		
Depletion and depreciation	7,402,949	17,303,209
Accretion on asset retirement obligation	91,190	55,485
Gain on settlement of obligations	(7,630,778)	–
Stock-based compensation expense	(28,575)	–
Future tax recovery	(1,825,569)	–
	(1,297,280)	633,568
Deferral of crown royalties	–	(1,439,409)
Net change in non-cash working capital	377,459	(18,382)
	(919,821)	(824,223)
Financing Activities		
Issue of common shares	8,238,452	10,355,593
Share issue costs	(353,234)	(1,056,032)
Proceeds of promissory note	600,000	–
Repayment of bank loan	(80,400)	(51,600)
Net change in non-cash working capital	7,602,180	–
	16,006,998	9,247,961
Investing Activities		
Expenditures on petroleum and natural gas properties	(7,475,182)	(13,287,416)
Net change in non-cash working capital	(6,589,129)	5,987,285
	(14,064,311)	(7,300,131)
Increase in cash	1,022,866	1,123,607
Cash, beginning of period	1,678,611	555,004
Cash, end of period	2,701,477	1,678,611

See accompanying notes to consolidated financial statements.

During the year ended December 31, 2004, the Company paid \$69,984 (2003 – \$64,754) of cash interest and \$Nil in cash taxes (2003 – \$Nil).

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

For the years ended December 31, 2004 and 2003

1 Corporate Restructuring

On April 1, 2004, Questerre Beaver River Inc. ("QBR"), a wholly owned subsidiary of Questerre Energy Corporation ("Questerre" or the "Company") was granted an Order by the Court of Queen's Bench of Alberta providing for creditor protection under the Companies' Creditors Arrangement Act ("CCAA"). On June 22, 2004, Questerre also applied for and was granted an Order by the Court of Queen's Bench of Alberta providing for creditor protection under CCAA.

QBR's financial difficulty was the result of significant problems and cost overruns associated with a re-entry operation undertaken at the Beaver River natural gas field (the "Beaver River Field" or the "Field") that is located approximately 100 miles northwest of Fort Nelson, British Columbia. QBR holds a 60% working interest and a 100% priority right to cash flow (subject to payouts) in the Field. QBR held a 100% working interest in the operation as a result of joint venture partners choosing to forego participation under penalty. The CCAA filing by Questerre was necessary due to claims advanced or threatened by certain parties that provided goods and services in connection with the re-entry operation and was intended to allow the Company to restructure its affairs while continuing operations on a normalized basis.

On August 9, 2004, the Company filed Plans of Compromise or Arrangement (the "Plans") under the CCAA for the settlement of all outstanding claims. The Plans were approved by the requisite majority of unsecured creditors at meetings of creditors held on August 31, 2004 and sanctioned by the Court of Queen's Bench of Alberta on September 9, 2004. Questerre and QBR subsequently emerged from Court protection under the CCAA on October 8, 2004.

Pursuant to the Plans proposed by Questerre and QBR, unsecured creditors received either the lesser of the amount of their claim or \$2,000. Alternatively, unsecured creditors elected to receive a cash dividend of \$0.05 plus one Common Share of Questerre for each dollar of their claims. The Common Shares of Questerre issued under the Plans are subject to a contractual escrow and released in two equal instalments on the fourth and eighth month anniversary of the date the Plans received final Court approval.

In addition to the proposed settlement, Questerre arranged for a liquidity option. Under this liquidity option, unsecured creditors received \$0.05 for each dollar of their claims, and also received an additional \$0.07 for each dollar of their claim in exchange for foregoing each Common Share they would have otherwise received. This resulted in a cash settlement of \$0.12 per dollar of claim outstanding.

The Common Shares that would otherwise have been issued to these unsecured creditors were issued to Terrenex Acquisition Corporation ("Terrenex"), a related party, pursuant to the terms of the Liquidity Option Agreement (See Note 14). In consideration, Terrenex established a fund to finance the liquidity option up to a maximum of \$668,500.

A total of \$0.56 million in cash and 9,623,012 Common Shares were issued on the implementation of these plans. 6,756,102 Common Shares were issued to Terrenex pursuant to the Liquidity Option Agreement.

2 Nature of Operations and Basis of Presentation

Questerre is primarily involved in the exploration and development of naturally fractured and hydrothermally dolomitized reservoirs. As at December 31, 2004, the Company has four primary projects – the Beaver River Field in British Columbia (note 5), the St. Lawrence Lowlands in Quebec, Simonette, and Parkland and Vulcan areas in Alberta. Questerre also holds minority interests in producing, non-operated properties in Alberta.

The St. Lawrence Lowlands, Simonette and Parkland and Vulcan projects remained unproved at December 31, 2004.

Subsequent to year-end, the Company participated in the drilling of an exploration well at Simonette for an estimated net cost of \$1.0 million. The well did not encounter any commercial hydrocarbons and was subsequently abandoned. The Company does not have any further financial commitments with regard to this project.

The Company has participated in the drilling of three wells in the Parkland and Vulcan areas at a cost of \$1.4 million during the last quarter of 2004 and first quarter of 2005. Subject to successful production testing, the Company anticipates these wells will be tied in and placed on production. Questerre plans to participate in further drilling in these areas in 2005.

The Company's efforts and resources are directed at developing a portfolio of projects and ultimately realizing the value of these projects. Due to the numerous risks inherent in these projects, there can be no assurance the Company will be successful. While the Company seeks to mitigate risks by joint venture partners and developing a stable production base, the Company's success will, to a large extent, depend on its continued ability to finance the development of existing projects and the acquisition and development of new projects.

These financial statements have been prepared using Canadian generally accepted accounting principles ("GAAP") and, accordingly, have been prepared using the same principles as those for a going concern. Should the Company be unsuccessful in realizing the value of its current and future projects, it may not be able to realize its assets and discharge its liabilities in the normal course of business.

3 Change in Accounting Policies

a) Full cost accounting guideline

In January 2004, the Company prospectively adopted the new Accounting Guideline 16 "Oil and Gas Accounting – Full Cost" issued by the Canadian Institute of Chartered Accountants ("CICA").

Consistent with the former guideline, the net carrying cost of the Company's petroleum and natural gas properties is limited to an estimated net recoverable amount ("ceiling test"). Under the new guideline, the ceiling test calculation is a two step process. First, the Company determines whether a write-down is required by comparing the carrying value of the properties to the undiscounted cash flow of its proved reserves (based on management's best estimate of future prices) plus the lower of cost and market value for unproved properties. If there is an impairment calculated under the first step, the carrying value of properties is written down to the discounted value of the proved plus probable reserves (based on management's best estimate of future prices) plus the lower of cost and market of unproved properties.

The Company recorded a \$6.2 million ceiling test write-down for the year ended December 31, 2004 related to the Field. In addition, the Company recorded a \$0.2 million write-down relating to its share of an unsuccessful well drilled in Quebec. The write-down is included in the depletion and depreciation provision on the income statement.

b) Asset retirement obligation

In January 2004, the Company adopted CICA Handbook Section 3110 "Asset Retirement Obligations". This change in accounting policy has been applied retroactively with restatement of prior periods presented.

Utilizing the new accounting policy, 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 as accretion expense is recorded. 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 policies. Revisions to the estimated timing of cash flows or to the original estimated undiscounted cost would also result in an increase or decrease to the asset retirement obligation. 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.

The previously reported amounts for 2003 have been restated due to the retroactive application of this new standard. Adoption of this standard had the following effects on the Company's consolidated balance sheet and statement of income and deficit for the year ended December 31, 2003 :

Increase in petroleum and natural gas properties	\$ 20,600
Decrease in future site restoration and abandonment liability	878,833
Increase in asset retirement obligation	(848,134)
Increase in opening deficit	408,201
Decrease in site restoration expense	(525,285)
Increase in depletion and depreciation expense	10,300
Increase in asset retirement obligation accretion expense	55,485

c) Stock based compensation plan

In January 2004, the Company adopted the amended CICA Handbook Section 3870 "Stock-based Compensation and Other Stock-based Payments". This change in accounting policy has been applied retroactively without restatement of prior periods presented.

Under this amended standard, the Company must account for compensation expense based on the fair value of rights granted under its stock-based compensation plan (see note 11(e)). Compensation cost attributable to share options granted to employees or directors is measured at fair value at the grant date and expensed over the expected exercise time frame with a corresponding increase to contributed surplus. Upon exercise of the stock options, consideration paid by the unit holder together with the amount previously recognized in contributed surplus is recorded as an increase to share capital.

As a result of adopting this change in accounting policy, the consolidated financial statements at January 1, 2004 were changed as follows: contributed surplus increased by \$70,527 and the opening deficit was increased by \$70,527. Net income for 2004 included stock-based compensation expense of (\$28,575) for the year ended December 31, 2004. This was due to a recovery realized on the cancellation of share options previously expensed during the year, partially offset by the expense for share options subsequently issued.

4 Significant Accounting Policies

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that effect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Accordingly, actual results could differ from estimated amounts.

a) Principles of consolidation

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

b) Cash and cash equivalents

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

c) Measurement Uncertainty

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

d) Inventory

Inventory is recorded at the lower of weighted average cost and market, measured by replacement cost.

e) Revenue recognition

Revenue from the sale of petroleum and natural gas are recorded when the title passes to a third party.

f) Oil and natural gas operations

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

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

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

Costs of unproved properties are initially excluded from oil and gas properties for the purpose of calculating depletion. These properties are assessed periodically to determine whether impairment has occurred. When

proven reserves are assigned or the property is considered to be impaired, the cost of the property or the amount of the impairment is added to costs subject to depletion.

The Company reviews the carrying amount of its oil and natural gas properties ("the properties") relative to their recoverable amount ("the ceiling test") at each annual balance sheet date, or earlier if circumstances or events indicate impairment may have occurred. The recoverable amount is calculated as the undiscounted cash flow from the properties using proved reserves and expected future prices and costs. If the carrying amount of the properties exceeds their recoverable amount, then an impairment loss, equal to the amount by which the carrying amount of the properties exceeds the undiscounted cash flow from those properties using proved and probable reserves and expected future prices and costs, is recognized in depletion.

f) Asset retirement obligation

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

g) Joint operations

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

h) Foreign currency translation

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

i) Flow-through shares

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

j) Stock based compensation plan

The company has a stock option plan for directors and employees. The stock option plan is described in note 11. The compensation cost attributable to share options granted is measured at fair value at the grant date and expensed over the expected exercise time frame with a corresponding increase in contributed surplus.

k) Per share information

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

5 Capital Assets

	December 31 2004	December 31 2003
		(as restated – note 3)
Petroleum and natural gas properties	40,075,517	31,980,355
Less: Accumulated depletion and depreciation	(33,935,459)	(26,821,709)
	<u>6,140,058</u>	<u>5,158,646</u>

During the year ended December 31, 2004, the Company capitalized administrative overhead charges of \$326,619 (year ended December 31, 2003 – \$594,911) relating to exploration and development activities.

The Company incurred a ceiling testwrite-down of \$6.2 million for the year ended December 31, 2004 (December 31, 2003 – \$16.7 million) related to the Beaver River Field (see note 1). In addition, the Company incurred a depletion charge of \$0.8 million during the second quarter of the year for production from the Beaver River Field. The Company also incurred a write-down of \$0.2 million representing its share of costs of an unsuccessful well in Quebec. These amounts are included in the depletion and depreciation provision on the income statement.

At December 31, 2004, petroleum and natural gas properties included \$5.7 million (December 31, 2003 – \$4.3 million) relating to unproved properties which have been excluded from the depletion and depreciation calculation. All costs associated with the Beaver River Field, net of estimated salvage values, have been written down and included in depletion expense except \$2.9 million of geological and geophysical costs. These costs primarily relate to the 3-D seismic survey acquired over the Field in 2002. Management does not believe these assets are impaired as the data is a key component of the Company's plan for future development of the Field. Questerre does not include costs of \$1.8 million associated with its St. Lawrence Lowlands acreage in Quebec in the calculation of depletion or in costs subject to the ceiling test calculation. The Company also does not include costs of \$1.0 million related to its exploration projects in the Simonette and Parkland/Vulcan areas in Alberta in its calculation of depletion or in costs subject to the ceiling test calculation. Both the projects in Alberta and in Quebec remain unproved at December 31, 2004.

6 Beaver River Project

On January 12, 2001, the Company executed the Beaver River Farmout and Operating Agreement (the "Beaver River Agreement") whereby the company earned a 60% interest in the Beaver River natural gas field and project (collectively, the "Project") subject to a lien until the Company completed a specified work program and spent a minimum \$5,000,000 on the Project (increased to \$9,000,000 effective June 2001). Any amounts spent by the Company under the Beaver River Agreement for the specified work program are accumulated in an account (the "Payout Amount") and cash flow is shared by the Company and the Farmers as follows:

a) 4% override payable to the Farmers until the Company receives 6 times the Payout Amount

b) then, the Company receives a priority right to cash flow as follows:

100% until 1 times Payout Amount received;

80% until 2 times Payout Amount received and an Environmental Reserve has been fully funded, such Environmental Reserve to be determined by the Company and set aside to cover future abandonment and reclamation expenses;

70% until 6 times Payout Amount received;

60% thereafter

- c) Any remaining cash flow or deficiency is subsequently shared according to the partners working interest.
- d) Effective April 1, 2002 the specified work program was completed. At December 31, 2004, the Payout Amount balance was \$10,923,075. For the year ended December 31, 2004, the Company received Snil (2003 – \$221,932) of cash flow applicable to the Payout Amount.
- e) In August 2003 QBR began the A-5 re-entry operation at the Beaver River Field. QBR held a 100% working interest in the operation as a result of joint venture partners choosing to forego participation under a 600% penalty. Operating cash flows from the well must be applied against the 600% penalty payout prior to being applied against the Payout amount noted in c) above.

7 Bank Loan

In July 2002, the Company obtained a five-year, \$400,000 term loan with a Canadian bank. Under the terms of the loan, the Company must make monthly payments of \$6,700 principal plus interest until the loan is paid out. The interest rate under the loan is the bank's floating base rate plus 2.0% and the Company may lock in the rate at any time. The loan is secured by the first assignment to the bank of a \$100,000 Guaranteed Investment Certificate and by a General Security Agreement over the assets of the Company and its subsidiary, QBR. Financial covenants include maintaining a minimum long term debt to tangible equity ratio of 0.8 to 1.0 and maintaining a working capital ratio of at least 1.0 to 1.0. While Questerre currently meets this financial covenant, the Company has not been in compliance with this covenant in the past and, therefore, the bank loan has been classified as a current liability.

8 Promissory Note Payable

In June 2004, the Company obtained \$0.5 million on the issue of a \$0.5 million promissory note to Rupert's Crossing, an Investment Corporation ("Rupert's"). Rupert's is a private investment holding company controlled by the President and Chief Executive Officer of Questerre. The promissory note was originally due on November 14, 2004 with interest calculated at 12% per annum, payable monthly. The promissory note is secured by a General Security Agreement over the assets of the Company and the hypothecation of the Company's exploration licenses in Quebec.

In August 2004, the Company amended its \$0.5 million financing agreement with Rupert's when Rupert's advanced an additional \$0.1 million which was placed in trust with the Company's legal counsel. Upon the approval of the Plans, these funds were advanced to the Company on the same terms as the original \$0.5 million. The funds were used to finance a portion of the cash component of the Plans.

In October 2004, the Company further amended the terms of the \$0.5 million financing agreement with Rupert's when Rupert's advanced an additional \$0.08 million to the Company for general working capital. The advance was made on the same terms as the original advance of \$0.5 million. The \$0.08 million was repaid in December 2004.

In November 2004, the Company and Rupert's amended the terms of the financing agreement extending the due date of the promissory note from November 14, 2004 to November 14, 2006 and reducing the interest rate from 12% per annum to 8% per annum. The Company has been granted the right to prepay the entire amount or any portion thereof with 30 days' notice in writing to Rupert's. Rupert's has been granted an option, subject to regulatory approval, to convert the entire amount into Common Shares of the Company at a conversion rate of \$0.30 per Common Share. As at December 31, 2004, a total of \$0.6 million is due to Rupert's under this financing agreement.

9 Deferred Crown Royalties

Royalties payable to the Province of British Columbia on production from the Beaver River Field are governed by a Royalty Agreement between the Province and the Joint Venture partners dated April 1, 1999 and amended October 1, 2001. Until the earlier of June 30, 2004 and cumulative production of 13 bcf from the Field, royalties payable to the Crown are deferred. Repayment of deferred royalties is contingent on the success of the experimental project for which the deferral was granted and on monthly production exceeding volumes established by the Crown. At December 31, 2003, the Company adjusted the liability to Nil on the basis that the conditions for repayment do not exist. On the same basis, the Company did not accrue crown royalties on its Beaver River production in the first and second quarters of 2004.

The Company has accrued Crown royalties of \$0.14 million for the year ended December 31, 2004 on production from the Beaver River Field during the second half of 2004. Payment of this royalty is contingent on the Company reaching an agreement with the Ministry of Energy and Mines in British Columbia regarding its qualification for a deep royalty credit of \$2.2 million. Discussions are ongoing with the Ministry regarding the Company's qualification for this credit.

10 Asset Retirement Obligation

The total future asset retirement obligation was estimated by management based on Questerre's net ownership interest in all wells and facilities, estimated costs to reclaim and abandon the wells and facilities and the estimated timing of the costs to be incurred in future periods. The Company estimates its total asset retirement obligations to be \$1,848,503 at December 31, 2004. Questerre used a credit adjusted risk free rate of seven per cent and an inflation rate of two per cent to calculate the present value of the asset retirement obligation.

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

	December 31 2004	December 31 2003
		(as restated – note 2)
Balance, beginning of period	\$ 848,134	\$ 792,646
Increase in estimate of obligation	909,179	
Accretion expense	91,190	55,488
Balance, end of period	\$ 1,848,503	\$ 848,134

11 Share Capital

a) Authorized

The Company is authorized to issue an unlimited number of Class A common voting shares. The Company is also authorized to issue an unlimited number of Class B common voting shares and an unlimited number of preferred shares, issuable in one or more series. At December 31, 2004, there were no Class B common voting shares or preferred shares outstanding.

b) Issued and outstanding – Class A common shares and common share warrants

	Number	Amount
Common Shares		
Balance, December 31, 2002	26,835,000	\$ 10,758,029
Issued on termination of Terrenex farmout agreement	750,000	750,750
Issued for cash	3,478,980	3,528,333
Flow through shares issued for cash	5,038,600	5,127,356
Issued on conversion of preferred shares	4,500,000	4,500,000
Issued for cash on exercise of warrants	1,509,666	1,673,212
Share issue costs	–	(1,058,100)
Balance, December 31, 2003	42,112,246	\$ 25,279,580
Issued for cash	3,280,860	1,373,075
Flow through shares issued for cash	11,703,791	5,389,928
Issued for cash on exercise of warrants	31,995	32,155
Issued under Plans	9,623,012	1,443,454
Tax effect of flow-through share issue		(1,825,569)
Share issue costs	–	(353,234)
Balance, December 31, 2004	66,751,904	\$ 31,339,389
Warrants		
Balance, December 31, 2002	3,840,000	\$ –
Issued for cash	5,338,330	26,692
Issued for broker commission	413,592	2,068
Issued to Terrenex on extension of farmout agreement	150,000	750
Exercised for common shares	(1,509,666)	(750)
Balance, December 31, 2003	8,232,256	\$ 28,760
Exercised for common shares	(31,995)	(160)
Expired	(8,200,261)	(28,600)
Balance, December 31, 2004	–	\$ –
Total Common Share Capital		\$ 31,339,389

Common Shares

In May 2003, the Company issued Terrenex Acquisition Corporation (“Terrenex”), a related party with common directors and officers, 750,000 common shares at a deemed price of \$1.00 per common share on the termination of a farmout agreement covering the St. Lawrence Lowlands licenses.

In July 2003, the Company successfully completed its initial public offering raising gross proceeds of \$7.4 million. The offering consisted of the issuance of 4,137,700 common shares, issued on a flow-through basis and 3,269,480 common shares.

The Company also completed three additional private placements in 2003 for combined gross proceeds of \$1.275 million on the issuance of 209,500 common shares and 900,900 flow-through shares.

On December 22, 2003, Terrenex and its wholly owned subsidiary, Cabernet Holdings Limited redeemed their 4,500,000 preferred shares for common shares at a deemed price of \$1.00 per common share.

In February 2004, the Company completed a private placement of 2,521,651 common shares for gross proceeds of \$3.156 million (\$2.945 million net of expenses). The placement consisted of the issuance of 1,878,791 common shares, on a flow-through basis, at a price of \$1.30 per common share and the issuance of 642,860 common shares at a price of \$1.11 per common share.

In September 2004, a total of 9,623,012 common shares were issued in connection with the implementation of the Plans of Arrangement in connection with the implementation of the corporate restructuring at a deemed price of \$0.15 per common share.

In December 2004, the Company completed a private placement of 12,463,000 common shares for gross proceeds of \$3.6 million (\$3.414 million net of expenses). The placement consisted of the issuance of 9,825,000 common shares, on a flow-through basis, at a price of \$0.30 per common share and the issuance of 2,638,000 common shares at a price of \$0.25 per common share.

Warrants

On February 28, 2003, the Company issued 150,000 common share warrants to Terrenex in exchange for an extension under the St. Lawrence Lowlands Farmout agreement. The warrants are exercisable for a period of two years from February 28, 2003, at a price of US\$0.83 per common share. These warrants were exercised in December 2003.

On July 18, 2003 pursuant to a prospectus offering, the Company issued 5,338,330 common share warrants. The Company also issued 413,592 common share warrants to brokers as commission on the financing. Each warrant entitles the holder to acquire one common share at a price of \$1.50 per common share until December 31, 2003 and thereafter at \$2.00 per common share until December 31, 2004. 31,995 broker warrants were exercised in January 2004. The remainder broker warrants and common share warrants expired on December 31, 2004.

c) Per share amounts

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

	2004	2003
Basic	48,273,347	30,816,683
Diluted	48,817,849	30,816,683

The reconciling item between the basic and diluted average common shares is stock options.

d) Stock options

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

The following table sets forth a reconciliation of the stock option plan activity for the year ended December 31, 2004:

	Number of Options	Weighted Avg. Exercise Price
Outstanding, December 31, 2003	3,643,500	\$ 1.28
Granted		
January 2004	313,000	1.41
September 2004	2,315,000	0.10
November 2004	50,000	0.25
December 2004	1,000,000	0.30
Cancelled	(3,956,500)	1.29
Outstanding, December 31, 2004	3,365,000	\$ 0.16
Exercisable, December 31, 2004	192,917	\$ 0.10

The outstanding options have a range of exercise prices from \$0.10 to \$0.30, and a weighted average number of years to expiry of 5.0 (2003 – 3.0). The exercisable options have an exercise price of \$0.10 and 5.0 years to expiry (2003 – 2.4).

e) Stock-based compensation costs

The Company accounts for its stock based compensation plan using the fair value method. Under this method, compensation cost attributable to share options granted to employees or directors is measured at fair value at the grant date and expensed over the expected exercise time frame with a corresponding increase to contributed surplus.

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

	2004	2003
Risk free interest rate (%)	3.0	3.0
Expected life (years)	3.0	3.0
Expected volatility (%)	173	60

f) Contributed surplus

The following table sets forth a reconciliation of contributed surplus for the year ended December 31, 2004:

Balance, December 31, 2003	\$	–
Adoption of stock based compensation		70,527
Stock based compensation expense		136,350
Cancellation of options		(164,925)
Balance, December 31, 2004	\$	41,952

12 Future Income Taxes

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

	Year ended December 31,	
	2004	2003
Net loss before income taxes	(1,131,066)	\$ (16,725,126)
Combined federal and provincial tax rate	38.66%	35.22%
Computed "expected" income tax recovery	(437,657)	(5,890,589)
Increase in income taxes resulting from:		
Non-deductible crown charges and recoveries	73,451	(481,285)
Tax rate reduction	45,208	(495,148)
Unrecognized tax benefit of accounting losses	318,908	6,867,022
Recognition of future income tax in recognition of tax on flow-through shares	(1,825,569)	
Future income tax recovery	(1,825,569)	\$ —

The components of the Company's future income tax liability are as follows:

	December 31	
	2004	2003
Future income tax assets:		
Property, plant and equipment	\$ 5,214,245	\$ 5,325,981
Asset retirement obligation	626,088	234,489
Share issue expenses	401,459	293,051
Non-capital loss carryforwards (expire 2011)	276,024	1,199,865
Valuation adjustment	(4,692,247)	(6,707,186)
	—	346,200
Future income tax liabilities:		
Flow through share renouncements to be incurred	(1,825,569)	(346,200)
	(1,825,569)	(346,200)
Net future income tax liability	\$ —	\$ —

Non-capital loss carryforwards at December 31, 2004 represent non-capital losses created in 2004 and, therefore, expire in 2011. The non-capital losses accumulated to December 31, 2003 were used to partially offset the taxable income related to the gain on settlement of obligations.

13 Financial Instruments

The company's financial instruments included in the balance sheet are comprised of accounts receivable, accounts payable, accrued liabilities, bank loan and promissory note payable. The fair value of financial instruments classified as current assets approximate their carrying amounts due to the short-term maturity of these instruments. The fair value of bank loan and promissory note approximate its carrying amount as the interest rate approximates market.

Virtually all of the company's accounts receivable are for revenue due on production from the Field and the Company's minority interest in non-operated properties in Alberta. The Company is not exposed to significant credit risks.

14 Related Party Transactions

At December 31, 2004, Questerre had amounts owing to Terrenex totaling \$5,040 (December 31, 2003 - \$1,237). All of the directors of Terrenex serve as directors or officers of Questerre.

In August 2004, the Company entered into a Liquidity Option Agreement with Terrenex to facilitate acceptance of the Plans by the unsecured creditors of Questerre and QBR. Pursuant to the Liquidity Option Agreement, Terrenex funded a payment of \$0.07 per Common Share to those unsecured creditors that did not wish to hold the Common Shares received under the Plans (the "Liquidity Option"). In consideration for this payment, Terrenex was issued that number of Common Shares that, but for their election to participate in the Liquidity Option, would have been issued to the unsecured creditors. The Common Shares issued to Terrenex are subject to the same contractual hold period were they issued to these unsecured creditors. For fulfilling its obligations under the Liquidity Option Agreement, Terrenex was issued 300,000 Common Shares of the Company.

On the approval of the Plans on August 31, 2004, unsecured creditors of Questerre and QBR with claims totalling \$6.7 million elected to participate in the Liquidity Option. Terrenex funded a payment of \$0.47 million to these unsecured creditors and was issued 6,756,102 Common Shares.

Questerre incurred fees of \$126,000 for the year ended December 31, 2004 (2003 - \$126,000) to a company with common directors and officers. The transactions were in the normal course of business paid pursuant to an Office Rental Agreement for the provision of office space, office equipment and support personnel. The agreement may be terminated by either party with six months' written notice.

In June 2004, Questerre entered into a farmout agreement with a director of the Company. The farmout agreement covers the Company's exploration acreage in the St. Lawrence Lowlands, Quebec utilizing the same terms and conditions of a farmout agreement with independent arms-length parties.

See Note 8 for an additional related party transaction.

15 Subsequent Events

In January 2005, the Company filed a statement of claim against a seismic processing company in relation to seismic processing services provided to the Company and QBR. The seismic processing company is anticipated to file its statement of defence during the second quarter of 2005. At the present time, the Company is unable to ascertain the impact of this legal action on its financial position.

Directors

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Michael Binnion
Russ Hammond
Tom Landry, Jr.
David Mallory
Peder Paus
Jed Wood

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President and Chief
Executive Officer
John Brodylo
VP Exploration
David Mallory
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Stock Information

Toronto Stock Exchange
Common Shares: QEC



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