

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

The following Management's Discussion and Analysis of Financial Condition and Results of Operations ("MD&A") was prepared at, and is dated, March 28, 2008. This MD&A is provided by management of Questerre Energy Corporation ("Questerre" or the "Company") to review 2007 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, 2007 and 2006. Additional information relating to Questerre, including Questerre's Annual Information Form is available on SEDAR at [www.sedar.com](http://www.sedar.com).

Questerre is a junior oil & gas company involved in the exploration and development of scalable, high-impact projects primarily targeting the Canadian frontier. To mitigate the risks associated with these projects, the Company has secured partners to assist in their development. To further diversify risk, the Company is also developing a portfolio of conventional exploration and production assets.

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

### Forward Looking Statements

This MD&A contains forward-looking statements. Management's assessment of future plans and operations, production estimates, drilling inventory and wells to be drilled, timing of drilling and tie in of wells, productive capacity of new wells, capital expenditures and the timing thereof, may constitute forward-looking statements under applicable securities laws and necessarily involve risks including, without limitation, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, inability to retain drilling rigs and other services, the timing and length of plant turnarounds and the impact of such turnarounds and the timing thereof, delays resulting from or inability to obtain required regulatory approvals and ability to access sufficient capital from internal and external sources. As a consequence, the Company's actual results could differ materially from those expressed in, or implied by, the forward-looking statements. Readers are cautioned that the foregoing list of factors is not exhaustive. The forward-looking statements contained in this MD&A are made as at the date of this MD&A and the Company does not undertake any obligation to update publicly or to revise any of the included forward looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities laws.

### Non-GAAP Terms

This document contains the terms "funds generated from operations", "netbacks", "working capital" and "average sales price" which are non-GAAP terms. The Company uses these measures to help evaluate its performance. The Company considers netbacks a key measure as it demonstrates its profitability relative to current commodity prices and the Company's ability to generate funds necessary to repay debt and to fund future growth through capital investment. As an indicator of Questerre's performance, funds generated from operations should not be considered as an alternative to, or more meaningful than, cash flow from operating activities as determined in accordance with Canadian GAAP. Questerre's determination of funds generated from operations may not be comparable to that reported by other companies. The reconciliation between net income and funds generated from operations can be found in the consolidated statements of cash flows in the consolidated financial statements.

### BOE Conversions

Barrel of oil equivalent ("boe") amounts may be misleading, particularly if used in isolation. A boe conversion ratio has been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil and is based on an energy equivalent conversion method application at the burner tip and does not necessarily represent an economic value equivalency at the wellhead.

## SELECT ANNUAL INFORMATION

Item	Year Ended December 31,	
	2007	2006
<b>Financial (\$)</b>		
Petroleum and natural gas sales	<b>23,785,489</b>	12,030,736
Funds generated from operations	<b>10,229,020</b>	5,076,419
Per share – Basic	<b>0.065</b>	0.04
Per share – Fully Diluted	<b>0.063</b>	0.04
Net Earnings (loss)	<b>(1,281,671)</b>	(876,835)
Per share – Basic	<b>(0.008)</b>	(0.01)
Per share – Fully Diluted	<b>(0.008)</b>	(0.01)
Capital Expenditures (including acquisitions)	<b>38,775,201</b>	29,790,006
Working Capital	<b>10,007,846</b>	22,696,421
Total Assets	<b>93,074,767</b>	71,039,440
Shareholders' Equity	<b>71,627,841</b>	59,163,470
Common shares Outstanding		
Basic	<b>168,930,470</b>	155,171,750
Fully Diluted	<b>181,994,640</b>	168,041,336
<b>Operations (units as noted)</b>		
Average Production		
Crude oil and Natural Gas Liquids (bbls/d)	<b>176</b>	113
Natural Gas (mcf/d)	<b>7,282</b>	3,984
Total (boe/d)	<b>1,390</b>	778
Average Sales Price		
Crude oil and Natural Gas Liquids (C\$/bbl)	<b>71.42</b>	63.08
Natural Gas (C\$/mcf)	<b>7.17</b>	6.46
Total (\$/boe)	<b>46.63</b>	42.29
Netback (\$/boe)		
Total Revenue	<b>46.63</b>	42.29
Royalties	<b>11.06</b>	9.93
Percent	<b>23.58%</b>	23.42%
Field Operating Expense	<b>12.08</b>	9.86
Operating Netback	<b>23.49</b>	22.51
Net cash G&A	<b>5.44</b>	5.64
Cash netback	<b>18.05</b>	16.87
Wells drilled		
Gross	<b>17</b>	20
Net	<b>10.32</b>	10.21

## QUARTERLY FINANCIAL INFORMATION

	December 31, 2007	September 30, 2007	June 30, 2007	March 31, 2007
<b>Production (boe/d)</b>	<b>1,216</b>	<b>1,206</b>	<b>1,443</b>	<b>1,702</b>
<b>Average Realized Price (\$/boe)</b>	<b>47.70</b>	<b>38.74</b>	<b>49.83</b>	<b>48.98</b>
<b>Petroleum and natural gas sales</b>	<b>5,387,298</b>	<b>4,339,265</b>	<b>6,555,860</b>	<b>7,502,436</b>
<b>Funds generated from operations</b>	<b>1,584,590</b>	<b>2,414,613</b>	<b>3,183,088</b>	<b>3,046,729</b>
Per share - Basic	0.009	0.016	0.021	0.020
Per share - Fully Diluted	0.009	0.015	0.020	0.020
<b>Net Earnings (loss)</b>	<b>(2,066,084)</b>	<b>(676,499)</b>	<b>980,543</b>	<b>480,366</b>
Per share - Basic	(0.013)	(0.004)	0.006	0.00
Per share - Fully Diluted	(0.013)	(0.004)	0.006	0.00
<b>Capital Expenditures (including acquisitions)</b>	<b>9,355,590</b>	<b>5,646,625</b>	<b>3,297,067</b>	<b>7,163,179</b>
<b>Working Capital</b>	<b>10,007,846</b>	<b>26,476,203</b>	<b>29,911,344</b>	<b>20,427,261</b>
<b>Total Assets</b>	<b>93,074,767</b>	<b>77,241,283</b>	<b>80,758,475</b>	<b>77,279,174</b>
<b>Shareholders' Equity</b>	<b>71,627,841</b>	<b>62,100,834</b>	<b>62,412,993</b>	<b>60,688,283</b>
<b>Weighted Average Common Shares Outstanding</b>				
Basic	162,650,245	155,211,741	155,198,536	155,190,861
Fully Diluted	166,729,098	160,919,586	161,897,966	162,242,898

	December 31, 2006	September 30, 2006	June 30, 2006	March 31, 2006
Production (boe/d)	1,148	1,037	635	292
Average Realized Price (\$/boe)	44.85	41.66	36.86	44.16
Petroleum and natural gas sales	4,737,331	3,974,412	2,158,396	1,160,597
Funds generated from operations	2,069,818	1,676,537	1,083,075	287,367
Per share - Basic	0.014	0.012	0.008	0.00
Per share - Fully Diluted	0.013	0.012	0.008	0.00
Net Earnings (loss)	(1,164,811)	(1,954,289)	2,842,727	(599,982)
Per share - Basic	(0.010)	(0.014)	0.022	(0.01)
Per share - Fully Diluted	(0.010)	(0.014)	0.021	(0.01)
Capital Expenditures (including acquisitions)	26,024	6,073,406	10,345,506	6,601,918
Working Capital	22,696,421	8,740,261	13,092,540	10,302,085
Total Assets	71,039,440	50,327,193	52,606,238	32,267,594
Shareholders' Equity	59,163,470	42,418,992	44,077,413	28,681,694
Weighted Average Common Shares Outstanding				
Basic	142,969,567	141,116,660	129,681,964	117,536,816
Fully Diluted	149,144,137	145,333,504	133,483,848	121,338,700

## HIGHLIGHTS

- Two wells drilled to test emerging shale gas play in St. Lawrence Lowlands, Quebec
- Talisman acquires 2-D seismic to follow-up Gentilly #1 discovery well in Quebec
- Acquired a light oil resource style play through the purchase of Magnus Energy Inc.
- Concluded a 54 square mile farm-in with EnCana for established Jean Marie play in BC
- Drilled two non-commercial wells at Beaver River Field
- Cash flow from operations doubled to \$10.23 million from \$5.08 million in 2006
- Established reserves of 2.34 mmbœ in 2007 – replaced 100% of 2007 production volumes with higher value oil reserves

## 2007 ACTIVITIES

### St. Lawrence Lowlands, Quebec

Exploration work continued on Questerre's acreage in the Lowlands over the year.

The largest block of 711,000 acres is subject to a farm-in and participation agreement with Talisman Energy Inc. ("Talisman"). Subject to Talisman earning in the entire block, Questerre will hold a 25% working interest and a 4 1/4% royalty on production.

Talisman tested the first well on this acreage, Gentilly #1, during the first quarter of 2007. Gentilly #1 initially flowed at rates between 4.5 mmcf/d and 9.5 mmcf/d with final flow rate ranging between 340 mcf/d and 630 mcf/d from the primary Trenton Black-River ("TBR") formation. While these results do not warrant a tie-in to the local distribution system, Questerre believes the results validate its exploration model for the TBR in the Lowlands.

Based on these final test results and additional technical work, Talisman elected to acquire a 2-D seismic survey over two additional Questerre prospects. The seismic survey was completed in early 2008. Contingent upon Talisman's commitment to earn, Questerre plans to participate in the drilling of between two to three wells on this acreage this year.

The 102,000-acre Yamaska block lies adjacent to Questerre's acreage with Talisman and is subject to a royalty and joint venture agreement with Gastem Inc. ("Gastem"). Questerre currently holds a 7.5% gross overriding royalty convertible into a 20% working interest on this block.

In the summer of 2007, Gastem spud two wells, St. Francois du Lac and St. Louis de Richelieu, on this block to evaluate the Utica shale potential. The two back-to-back wells were successfully drilled to a vertical depth of approximately 1800m. Gastem's partner, Forest Oil, subsequently elected to stimulate and test the wells. Questerre expects the test results will remain confidential as Forest completes its analysis of the data.

Questerre's third exploration block, St. Jean, covers approximately 200,000 acres proximal to the US border. Questerre holds a 50% working interest in this block jointly with Gastem.

A high-resolution aeromagnetic survey was acquired over this block during the first quarter of 2007. Interpretation of this survey integrated with other technical work indicates the acreage is prospective for both the TBR and Utica at depths shallower than 1000m. Questerre is conducting further technical work to identify a potential drilling location for 2008.

## Northeast British Columbia

### Greater Sierra

In December 2007, Questerre entered into a seismic and farm-in agreement with EnCana Corporation ("EnCana") covering 54 square miles in the Greater Sierra region of northeast British Columbia. The acreage is prospective for natural gas from multiple horizons with the primary target of the Devonian Jean Marie at a depth of approximately 1400m.

Questerre's commitments under this agreement were to fund the drilling and completion of two horizontal Jean Marie wells and a 46-square mile 3-D seismic survey to earn a 50% interest in this acreage. In early 2008, the two horizontal wells were successfully drilled, completed and tied-in to the local gathering system at a total cost of nearly \$6.0 million. In March 2008, acquisition of the 3-D survey was also completed ahead of schedule and under budget.

Subject to the interpretation of the seismic survey, Questerre expects to participate with EnCana in drilling 6-8 wells at Greater Sierra in 2009.

### Beaver River Field

The 2007 work program at the Beaver River Field (the "Field") targeted both prospective horizons — the shallow Mattson and deeper Nahanni.

The appraisal of the A-2 Mattson discovery included the drilling and completion of two wells — A-7 and B-3. A-7 was drilled at the northern end of the Field approximately 1.3 km away from the A-2 well to a depth of 1950m. The B-3 well was drilled to delineate the Mattson in the southern part of the Field, nearly 6.0 km from the A-2 well to a depth of 2115m. While neither well had access to the same producing interval as the A-2 well, they encountered several other potentially productive Mattson intervals.

Several stimulation techniques were evaluated to maximize recovery from the Mattson - nitrogen-based, CO<sub>2</sub>-based and slick-water. The results indicate that natural fracturing and predominantly sand intervals resulted in better deliverability more than any specific stimulation technique. A-7, drilled into a naturally fractured section of the Mattson tested at rates of up to 1.9 mmcf/d and is currently producing at 1 mmcf/d. B-3 was drilled into a fault block without an open fracture system and tested at 300 mcf/d, well below management's expectations.

An independent study on the Mattson commissioned by Questerre and its partner, Transeuro Energy Corp. ("Transeuro"), confirms the discovered resource of the Mattson shale interval ranges between 495 Bcf – 750 Bcf per square mile. The report further corroborates the test results indicating that development should initially focus on areas of pervasive natural fracturing and sand intervals. Notwithstanding the magnitude of this resource, Questerre anticipates future work on the Mattson will be highly selective and targeted to take advantage of higher natural gas prices.

Questerre and Transeuro spud the A-8 Nahanni well on August 7, 2007. The primary target was a potential undrained Nahanni fault block identified on a reprocessed 3D seismic survey. Additional targets included the Mattson, Mississippian fracture carbonate and Devonian shale. The well reached target depth of 4112m at year-end. Challenging mobilization and drilling through extensively fractured and faulted zones resulted in drilling costs of just over \$19 million or \$4 million over budget with Questerre's responsible for 50% of total costs.

Well results were substantially less than anticipated. On initial cleanup A-8 flowed at rates in excess of 5 mmcf/d with final test rates of 400 mcf/d of gas and over 900 bbls/d of formation water. Though the pressure data suggests the well is not in communication with the adjacent A-5 well and in a partially sealed fault block, the presence of formation water indicates a different sealing mechanism than originally expected.

Further Nahanni exploration and evaluation of the shallower zones in A-8 will be contingent upon capital, equipment availability and weather.

In April 2007, Questerre received a cash payment of \$10 million from Transeuro to complete its earn-in obligations at the Field. In consideration of this payment, Transeuro was released from its obligations to drill additional wells at its sole cost. Questerre and Transeuro each hold a 50% interest in all producing and prospective horizons in the Field and the associated infrastructure.

During the first quarter of 2007, the Company doubled its landholdings in the Beaver River area to over 23,000 acres including the exploration rights to all horizons in acreage surrounding the Field. It also acquired the rights to additional horizons at the Field, including the Prophet carbonate and the Devonian shales. The majority of this acreage was validated with its 2007 work program.

### **Antler, Saskatchewan**

Questerre established a new core area in southeast Saskatchewan through the acquisition of Magnus Energy Inc. ("Magnus") See "Acquisition of Magnus Energy Inc."

Magnus' principal asset was a 50% working interest in over 80 square miles of land prospective for light sweet oil from the productive Devonian Bakken/Torquay formation. To maximize the recovery of the oil in place, Questerre is currently evaluating long reach horizontal wells and selective fracture stimulation techniques.

During 2007 and early 2008, Questerre participated in the drilling and completion of 7 (4.5 net) successful oil wells. The Company plans to drill an additional 5 (2.5) net horizontal wells during the balance of 2008.

### **Southern and Central Alberta**

Questerre's activities in Southern and Central Alberta were focused in the areas of Vulcan and Westlock respectively.

In January, the Company received approval from the Energy Resources Conservation Board ("ERCB") to commence full field production from its Mannville G Pool ("G Pool") at Vulcan. Questerre has a 50% interest in the G Pool. Production commenced at over 2,000 boe/d and is currently 1,200 boe/d.

Questerre also holds a 50% interest in an adjacent oil pool, the Mannville I Pool (the "I Pool"). In the third quarter, the operator submitted a Good Production Practice Plan for this pool to the ERCB. Subject to approval, full production is expected to begin in late 2008. In the interim, the Company commenced drilling its first horizontal well into this pool with plans to drill one more horizontal well this year.

Through a farm-in and participation agreement executed at the end of the first quarter, Questerre expanded its land holdings in Vulcan. Questerre and its partners would each earn a one-third interest in 4,480 acres for drilling two wells, subject to the payment of a 15% gross overriding royalty ("GORR") on production. The partners have an option to earn on the same terms an additional 1,920 acres by drilling a third well.

Questerre contributed a further 1,280 acres of its land in Vulcan to this joint venture. In consideration of a 15% GORR payable to Questerre, its partners will each earn a one-third interest in this land by funding their proportionate share of costs to drill a minimum of one well on this acreage.

Three wells (1.0 net) were drilled under this agreement with two wells on the farm-in lands and one of Questerre's land. The program resulted in two (0.66 net) successful gas wells and one (0.33 net) dry and abandoned well. The two wells were tied-in and placed on production during the first quarter of 2008.

At Westlock, the Company drilled five (4.65 net) wells resulting in three (2.65 net) suspended wells and (2.0 net) dry and abandoned wells. A further evaluation of the suspended wells indicates the economics do not justify a tie-in and the wells will be abandoned. Questerre has no planned capital expenditures for this area in 2008 and plans to divest of this and other non-core assets.

### **Drilling Activities**

In 2007, Questerre participated in the drilling and testing of 17 gross wells (10.32 net wells) resulting in 3 (1.16 net) gas wells, 5 (3.0 net) oil wells, 3.0 (2.3 net) dry holes and 6.0 (3.85 net) suspended wells.

## Corporate

### Equity Offerings

In 2007, the Company completed two equity issuances on a private placement basis through the issuance of 3,500,000 common shares for gross proceeds of \$3 million as follows:

- 2,500,000 common shares were issued, on a flow-through basis, at \$0.80 per common share for gross proceeds of \$2 million; and
- 1,000,000 common shares were issued, on a flow-through basis, at \$1.00 per common share for gross proceeds of \$1 million.

### Acquisition of Magnus Energy Inc.

In November 2007, Questerre acquired Magnus Energy Inc. ("Magnus"), a public exploration and production company with land and production focused in the Antler area of southeast Saskatchewan.

Total consideration was 7,840,804 common shares at a deemed price of \$0.94 per common share and the assumption of a working capital deficit of \$13.37 million. Questerre subsequently satisfied Magnus' secured debt of \$17.4 million through a cash payment of \$15.4 million and the issuance of 2.25 million Questerre common shares.

Magnus shareholders received 7,840,804 Questerre common shares representing 0.015316 of a Questerre common share for each Magnus Class A share. Each Magnus Class B share was exchanged for 10 Magnus Class A shares prior to the exchange of Magnus Class A shares for Questerre common shares. Upon closing, Magnus became a wholly owned subsidiary of Questerre.

## PRODUCTION

Questerre's production for the year averaged 1,390 boe/d, a 78% increase from production of 778 boe/d in 2006.

The Company's gas weighting was over 87% for 2007, a slight increase from 85% in 2006. Excluding 45 boe/d of 25° API from the Grand Forks area in Eastern Alberta, Questerre's oil production for 2007 was principally light oil and associated natural gas liquids from Vulcan. Post the acquisition of Magnus in November, this also included light oil from Antler. With development drilling in Antler and Vulcan planned for 2008, Questerre expects oil to account for close to 30% of its product mix in the current year.

Production growth in 2007 reflected the successful development of the Mannville G Pool in Vulcan during 2006. With receipt of Good Production Practice ("GPP") approval in January and the commencement of production, Vulcan represented 860 boe/d or 62% of the Company's production, an increase from 327 boe/d and 42% in 2006. Questerre's ancillary assets in Alberta contributed 281 boe/d or 20% of the Company's production during the year. Net of natural declines, this production was relatively unchanged from 265 boe/d in 2006.

Beaver River represented 249 boe/d or 18% of Questerre's production for the year. A-2 was the only producing well at the Field until October when the A-7 was placed on production. While A-2 experienced natural declines during the year from a peak of 640 boe/d (gross) in January to 406 boe/d (gross) in December, Questerre plans to install both wellhead and boost compression in early 2008 to improve productivity from this well. By comparison in 2006, A-2 averaged 186 boe/d (net) with production increasing from 332 boe/d in April to 667 boe/d in December.

The acquisition of Magnus completed in the fourth quarter added production of 120 boe/d effective November 1, 2007. Antler contributed 40 boe/d or 33% of this production in 2007 with the remainder from a non-core asset in the Kakwa area of central Alberta. With additional drilling planned for 2008, Questerre expects Antler to become more significant to the Company's production profile.

Questerre's exit production for 2007 of 1,330 boe/d is approximately 870 boe/d less than predicted production of 2,200 boe/d. The unsuccessful results from the A-7 and B-3 wells at Beaver River and delays in drilling development wells for the Vulcan oil pool each account for approximately 20% of the difference. Furthermore, Questerre budgeted to spend \$10 million in capital to add an estimated 500 boe/d in production. These funds subsequently financed the Magnus acquisition through a payout of a portion of Magnus' secured debt.

Questerre estimates its production for 2008 to average between 1,400 boe/d and 1,300 boe/d. The Company expects that its active drilling program at Antler will offset natural declines in its existing production in Alberta and Beaver River. Furthermore, the higher netbacks at Antler are expected to improve cash flow for 2008.

## 2007 FINANCIAL RESULTS

### Revenue

Petroleum and natural gas revenue for 2007 almost doubled to \$23.80 million from \$12.03 million in the preceding year. Higher production volumes in Vulcan were the largest contributor to this growth and resulted in Alberta revenue of \$19.55 million (2006: \$9.57 million). Increased production from the A-2 well also contributed with revenue from Beaver River increasing to \$3.59 million (2006: \$2.46 million). The remaining \$0.66 million represents revenue from Magnus' light oil assets in Antler for the last two months of the year.

The higher heat content of natural gas production from Vulcan translated into a realized gas price above the industry average for the year. For 2007, Questerre sold its natural gas at an average price of \$7.17/mcf (2006: \$6.46/mcf) in comparison to an AECO daily index price of \$6.44/mcf (2006: \$6.51/mcf).

Questerre's realized price for oil and liquids in 2007 increased by 13% from \$63.08/barrel in 2006 to \$71.42/barrel. With oil and NGLs from Vulcan accounting for approximately two thirds of Company's oil production, Questerre's realized price grew closer to the Edmonton Light average price of \$77.02/barrel in 2007 (2006: \$73.29/barrel). The Company expects this to continue as light oil from Antler forms a larger portion of its production for the coming year.

Questerre sold all its production on the spot market in 2007. To capitalize on current natural gas and oil prices, Questerre is evaluating a risk management program for 2008.

### Royalties

Questerre recorded \$5.61 million in royalty expense for the year ended December 31, 2007 (2006: \$2.82 million).

This represents an effective royalty rate of 23.58%, virtually unchanged from 23.42% in the prior year. Crown royalties decreased marginally to 17.19% (2006: 18.23%) while freehold and overriding royalties increased to 6.39% (2006: 5.17%).

Royalties on Alberta production decreased by approximately 5% to 24.65% from 25.84% in 2006. Higher than expected deductions for allowable operating costs and gas cost allowance resulted in a lower royalty rate on Vulcan production of 27.64% during the year (2006: 31.54%). Furthermore, the royalty rate on the Company's other assets in Alberta was just under 14% (2006: 20.00%).

The effective royalty rate for production from Beaver River averaged 17.50% in 2007 (2006: 14.00%). The higher rate reflects the prices realized and increased production from A-2 during the year. The base royalty rate of 27% for the A-7 well also contributed to the increase in the overall rate.

In 2008, Questerre expects its royalty rate to decrease reflecting the favourable fiscal terms for exploration and development in Saskatchewan. New horizontal wells in Antler attract a royalty rate of 2.5% on the first 100,000 barrels with freehold royalty rates of approximately 12-18%.

The New Royalty Framework ("NRF") for Alberta was announced in the fourth quarter and is expected to become effective in 2009. The NRF is highly geared towards production rates and gas prices. Subject to the results from its new horizontal well in Vulcan, Questerre anticipates this well and its minority interest in a deep gas well in Kakwa will be the only wells to be affected by these new rates. However, the amount of this impact will ultimately be determined by the actual regulations implemented, actual production rates and prices. Furthermore, the majority of the Company's projects are situated outside Alberta and will not be affected by the NRF.

## Operating Costs

Total operating expenses for the year ended December 31, 2007 increased just under 120% to \$6.13 million from \$2.80 million in 2006. Processing and gathering charges for the Company's production through third party processing plants and pipelines comprised of \$2.12 million (2006: \$0.87 million).

Operating expenses for the Company's Alberta production were \$4.22 million in total or \$10.13 on a boe basis as compared to \$1.81 million and \$8.39 per boe in the preceding year. The increase in aggregate reflects the 93% increase in production volumes. The per boe rate increase is primarily due to the higher operating costs in Vulcan, reflecting the full year of operation of the main battery and compressor station.

Beaver River operating expenses totaled \$1.91 million for 2007 (2006: \$0.99 million) and included gathering and processing charges of \$0.68 million (2006: \$0.45 million). The higher costs in 2007 reflect the increased activity at the Field supporting the drilling and completion operations. The operating expenses related to production from Saskatchewan were less than \$0.1 million.

## General and Administrative Expenses

General and administrative expenses ("G&A") for 2007, prior to capitalization and overhead recoveries, were \$4.30 million (2006: \$2.72 million). The increase over the prior year is due to a higher staff count, including five new employees and legal and advisory costs relating to evaluation of new projects.

The Company capitalizes overhead expenses based on its capital expenditures for the year. These expenses represent amounts directly related to exploration and development activities.

During the year, the Company's capital expenditures of \$38.24 million including the acquisition of Magnus, resulted in capitalized G&A expenses of \$0.8 million (2006: \$1.12 million). As the majority of these capital projects were operated by Questerre, the Company recorded overhead recoveries of \$0.74 million (2006: \$nil).

The higher production volumes for 2007 offset the increased general and administrative expenses resulting in a 4% decrease on a per boe basis to \$5.43 from \$5.64 in 2006. For the coming year, Questerre expects its G&A expenses to remain at these levels.

(\$ thousands)	<b>2007</b>	2006
General and administrative expenses	<b>\$ 4,302</b>	\$ 2,719
Capitalized expenses and overhead recoveries	<b>(1,545)</b>	(1,117)
General and administrative expenses, net	<b>\$ 2,757</b>	\$ 1,602

## Stock-based Compensation

Stock-based compensation expense for the year ended December 31, 2007 totaled \$1.47 million (2006: \$1.35 million). The expense in 2007 relates primarily to the recognition of the compensation expense for options granted in 2006. In 2006, the Company issued 3.92 million options at an average exercise price of \$0.93. The weighed average fair value of these options, using the Black Scholes pricing model was \$0.45 per option. By comparison, in 2007 the Company issued 445,000 options at an average exercise price of \$0.96 with a weighted average fair value of \$0.45 per option.

## Other Income and Expenses

Questerre realized a gain of \$0.90 million on the disposition of marketable securities during the year compared to a realized loss of \$0.02 million in 2006. The marketable securities held by the Company represent investments in junior exploration and production companies.

In accordance with new accounting guidelines adopted this year, the Company has classified these securities as held for trading and marks these securities to market value at the end of each fiscal period. This 'mark to market' adjustment is recorded as an unrealized gain or loss on the income statement. In 2007, the Company recorded an unrealized loss of \$0.79 million. At December 31, 2007, Questerre holds marketable securities with a market value of \$1.98 million (2006: \$0.51 million).

Interest income of \$1.06 million for the year (2006: \$0.36 million) reflects the significantly higher cash balances held by the Company. Contributing to the higher cash balances were a private placement of \$18.76 million completed in December 2006 and the payment of \$10.00 million by Transeuro to complete its earn-in obligations at the Beaver River Field.

The payment of \$10.00 million received from Transeuro was classified as proceeds on the sale of a portion of the Company's interest in the Beaver River Field. Utilizing a cost base of \$8.50 million, Questerre realized a gain of \$1.50 million in the second quarter of 2007 for this transaction.

## Depletion, Depreciation and Site Restoration

Questerre recognized \$13.55 million in depletion and depreciation in 2007 (2006: \$7.76 million). This equates to \$26.70 on a boe basis (2006: \$27.37).

The higher aggregate depletion reflects the increased depletion base from the Company's 2007 capital program including the unsuccessful wells at the Beaver River Field and the increased production over the prior year. On a per boe basis, the marginal decrease reflects the reserve additions for the year offset by the higher capital base.

Questerre applies a two-stage ceiling test to determine if the value of its petroleum and natural gas properties is impaired. The carrying value of the Company's petroleum and natural gas properties at December 31, 2007 was determined to be in excess of the undiscounted net cash flow from the proved reserves by \$6.65 million. However, since the carrying value of these properties is less than the net cash flow from the proved and probable reserves using a risk free discount rate, no impairment loss is recognized. This is in spite of its investment in unsuccessful wells at Beaver River and reflects, in part, the addition of high value reserves in Antler. The Company did not incur a writedown of its assets in 2006.

Accretion expense increased to \$0.14 million from \$0.09 million in 2006 primarily as a result of the Company's drilling program at the Beaver River Field. The Company's estimated undiscounted asset retirement cost for 2007 is \$5.89 million. (2006: 3.99 million). During the year, the Company increased its asset retirement obligations through the acquisition of Magnus and the participation in the drilling of 17 gross wells.

## Income Taxes

For the year ended December 31, 2007, Questerre recorded an income tax recovery of \$2.02 million. This represents the previously unrecognized future income tax asset to be realized as a result of it being more likely than not that sufficient future taxable income will be available to utilize such tax assets.

## Net Loss and Cash Flow

Questerre recorded a net loss of \$1.28 million in 2007 compared to net loss of \$0.88 million in 2006. The net loss is due to the higher depletion and depreciation expense partially offset by the gain on sale of petroleum and natural gas properties and the future tax recovery.

Funds generated from operations for the twelve months ended December 31, 2007 were \$10.23 million, just over 100% higher than \$5.08 million for the same period in 2006. Higher production was principally responsible for this increase in cash flow from operations.

## LIQUIDITY AND CAPITAL RESOURCES

### Capital Expenditures

In 2007, Qwesterre's capital expenditures, net of dispositions, increased by 28% to \$38.24 million from \$29.79 million in 2006. The majority of the capital expenditures in the year of \$21.03 million were incurred on the acquisition of Magnus with \$13.93 million incurred in British Columbia, primarily at the Beaver River Field. By comparison, in 2006, the development of Vulcan and the acquisition of Stride were the focus of the Company's capital program. Qwesterre financed its capital expenditures through its existing working capital, cash flow and the disposition to Transeuro.

The company's capital program consisted of the following:

- \$8.33 million was incurred in Alberta, primarily at Vulcan and Westlock, including \$6.26 million on drilling and completions and \$1.17 million on facilities
- \$13.93 million was incurred in British Columbia, primarily at the Beaver River Field. This included \$4.39 million on the drilling of the A-8 well and \$6.13 million on the drilling and completion of the B-3 well. Pursuant to a farm-in agreement between Magnus and Qwesterre prior to the acquisition, an additional amount of approximately \$4.57 million was incurred on the A-8 well. A further \$1.03 million was spent on the first well at Greater Sierra and \$0.2 million on a seismic database in the region.
- \$2.71 million was incurred in Saskatchewan and included \$1.61 million on drilling and completion of wells in Antler and \$0.75 million on a 3-D seismic acquisition program
- \$0.73 million was incurred at in St. Lawrence Lowlands, for the completion of the Gently #1 well and the acquisition of the aeromag survey at St. Jean
- Acquisitions, net of dispositions reflect the \$21.57 million incurred on the acquisition of Magnus with \$8.50 million representing the disposition of a 50% interest in the Beaver River Field to Transeuro.

(\$ thousands)	2007	2006
Capital Expenditures		
Alberta	\$ 8,332	\$ 28,645
British Columbia	13,933	588
Saskatchewan	2,708	–
Quebec	734	557
Acquisitions, net of dispositions	13,068	–
Total	\$ 38,775	\$ 29,790

### Working Capital Position

Qwesterre reported a working capital surplus of \$10.00 million at December 31, 2007 compared to a working capital surplus of \$22.70 million as of December 31, 2006.

The Company's current assets at December 31, 2007 consisted of cash of \$13.09 million, short term investments and deposits of \$3.57 million, accounts receivable of \$8.02 million and marketable securities of \$1.98 million. Qwesterre's current liabilities consist of trade payables of \$16.87 million.

As at December 31, 2007, Qwesterre had no drawdowns against its credit facility for \$7.5 million with a major Canadian bank. The facility is secured by a general security agreement and a fixed and floating charge on the assets of the Company. Based on its year-end reserve report, the Company believes this amount may be expanded.

Qwesterre's current capital program for 2008 is estimated at approximately \$32.00 million. Of this amount \$12.00 million has been allocated to the Greater Sierra project, \$12.00 million to drilling at Antler, and the remainder to other projects. This capital program will be funded by existing working capital, cash flow, planned dispositions of non-core assets in Alberta and its credit facility.

## Share Capital

The Company is authorized to issue an unlimited number of Class A common voting shares ("common shares"), an unlimited number of Class B common voting shares and an unlimited number of preferred shares, issuable in one or more series.

In 2007, the Company completed two equity issuances on a private placement basis through the issuance of 3,500,000 Common shares for gross proceeds of \$3 million as follows:

- 2,500,000 common shares were issued, on a flow-through basis, at \$0.80 per common share for gross proceeds of \$2 million; and
- 1,000,000 common shares were issued, on a flow-through basis, at \$1.00 per common share for gross proceeds of \$1 million.

The Company also issued 2,250,000 common shares in partial settlement of Magnus' secured debt.

A total of 167,916 common shares were issued on the exercise of stock options during the year.

At December 31, 2007, there were 168,930,470 common shares outstanding, 13,064,170 stock options and no Class B common voting shares or preferred shares outstanding. As at March 28, 2008, there were 170,890,470 common shares outstanding.

## Off-Balance Sheet Arrangements

Questerre has no off-balance sheet arrangements.

## Related Party Transactions

Questerre incurred fees of \$126,000 for the years ended December 31, 2007 and 2006 to Rupert's Crossing Ltd. ("Rupert's"), a related party with common directors and officers. Amounts due from Rupert's and its affiliates at December 31, 2007 were \$155,469 (2006: \$0).

In February 2008, the Company entered into an agreement to acquire Terrenex Ltd., a related party with common directors. The transaction is subject to receipt of requisite regulatory approval and Terrenex shareholder approval. Closing is scheduled to occur no later than April 30, 2008. Total consideration for this transaction is 15,892,785 common shares and a cash payment of \$0.5 million.

## Contractual Obligations and Commitments

Questerre was party to an Office Rental Agreement with a related party for the provision of offices, office equipment and support personnel in 2007. Either party had the right to terminate the agreement with six months' written notice. The agreement was terminated effective December 31, 2007. Questerre's obligation on termination is \$63,000.

As of December 31, 2007, the Company has a commitment to incur qualifying Canadian Exploration Expenses of \$6.0 million by December 31, 2008. The commitment arises from flow-through share issues completed by Questerre and Magnus in 2007. The Company expects to satisfy these commitments by March 31, 2008.

In December 2007, the Company entered into a seismic and farm-out agreement with a major Canadian independent exploration and production company. Pursuant to the agreement, Questerre has an obligation to fund the drilling and completion of two wells and a seismic acquisition program prior to March 31, 2008 to earn a 50% interest in 54 square miles of acreage. Questerre fulfilled its obligations under this agreement prior to March 27, 2008.

The Company is obligated to make total payments under an operating lease for field equipment of \$115,812 for each of 2008, 2009 and 2010. As part of the Magnus acquisition, Questerre has assumed an obligation under a lease for office space of \$322,519 for 2008, 2009 and 2010.

## 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. For its non-operated properties, the Company strives to develop a good working relationship with the operator and monitors the operational activity on the property. The Company also carries appropriate insurance coverage for risks associated with its operations.

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

Potential risks to the environment are inherent in some of the business activities of the Company. Questerre endeavors to conduct its operations in a manner consistent with environmental regulations as stipulated in provincial and federal legislation. Facilities are modern and are well maintained complying with environmental and safety regulations. The Company also mitigates the potential financial exposure of environmental risks by maintaining adequate insurance.

Questerre continues to evaluate the Alberta government's royalty changes and its impact on both the Company's current reserve base and its future opportunities. Based on publicly available information in respect of the New Royalty Framework and sensitivities conducted by Questerre's independent reserve evaluators, utilizing the December 31, 2007 reserves of the Company and the external engineer's price forecast at that date, Questerre estimates the royalty changes, if enacted in their current form, to have the following impact: a 4% to 5% reduction to the net present value of future net reserves from proved plus probable reserves (at a 10% discount rate) and a negligible change to proved plus probable reserves for both gross and net reserves.

## Critical Accounting Estimates

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

### Full Cost Accounting

Questerre follows the Canadian Institute of Chartered Accountants' ("CICA") guideline on full cost accounting to account for its oil and natural gas properties. Under this method, all costs associated with the acquisition of, exploration for and development of natural gas and crude oil reserves are capitalized and costs associated with production are expensed. The capitalized costs are 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 and 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 reservoir engineering firm. The estimation of reserves is a subjective process. Forecasts are based on engineering data, projected future rates of production, estimated commodity price forecasts and the timing of future expenditures, all of which are subject to a number of uncertainties and various interpretations. These estimates are the basis for the determination of the fair market value and the estimated net revenue stream of these reserves. The Company expects that its estimate of reserves will change to reflect updated information. Reserve estimates can be revised upward or downward based on the results of future drilling, testing, production levels and economics of recovery based on cash flow forecasts. Reserve estimates can have a significant impact on net earnings, as they are a key component in the calculation of depletion 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 and asset.

Actual costs incurred upon settlement of the obligation are charged against the liability to the extent the liability is recorded. Any difference between actual costs incurred upon settlement of the asset retirement obligation and the recorded liability is recognized as a gain or loss in the Company's earnings in the period in which settlement occurs. The Company has recorded a \$4.58 million obligation on its assets.

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.

### Goodwill

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

### Stock-based Compensation

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

### Financial Instruments

New Handbook Section 3855 sets out comprehensive requirements for recognition and measurement of financial instruments. Under this standard, an entity would recognize a financial asset or liability only when the entity becomes a party to the contractual provisions of the financial instrument. Financial assets and financial liabilities would, with certain exceptions, be initially measured at fair value. This section became effective from January 1, 2007 onward.

### Other Estimates

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

## Accounting Standards Changes

### Financial Instrument – Recognition and Measurement

On January 1, 2007, the Company adopted the new Canadian accounting standard for financial instruments — recognition and measurement, financial instruments — presentation and disclosures, hedging, comprehensive income and equity. As prescribed by the new standards, prior periods have not been restated.

The financial instruments standard establishes the recognition and measurement criteria for financial assets, financial liabilities and derivatives. Under the new standard, the Company must recognize all financial instruments and non-financial derivatives, including embedded derivatives, on the balance sheet initially at fair value. Measurement in subsequent periods depends on whether the financial instrument has been classified as “held-for-trading”, “available-for-sale”, “other accounts receivable or payable” or “held-to-maturity” as defined by the standard. Unrealized gains and losses on financial instruments classified as held for trading are recognized in earnings in the period incurred. Gains and losses on assets available for sale are recognized in other comprehensive income, and are charged to earnings when the

asset is derecognized or impaired. The amortized cost using the effective interest rate method is applied to the remaining categories of financial instruments.

As a result of adopting this change in accounting policy, the consolidated financial statements at January 1, 2007 were changed as follows: Marketable securities increased by \$777,961, and the deficit decreased by the same amount. The Company's marketable securities are classified as held for trading. Any changes in the fair value of the marketable securities at the end of the fiscal period are classified as unrealized gains or losses on the income statement.

Management did not identify any material embedded derivatives which required separate recognition and measurement under the new accounting standards.

The new accounting standard on hedges had no impact on the Company's financial statements as Questerre does not apply hedge accounting.

The new accounting standards require a new statement of comprehensive income (loss); however, there are no amounts that Questerre would include in other comprehensive income except net income.

### Accounting Changes

Effective January 1, 2007 Questerre adopted the recommendations of CICA Handbook Section 1506, Accounting Changes. These standards are effective for all changes in accounting policies, changes in accounting estimates and corrections of prior period errors initiated in periods beginning on or after January 1, 2007. There was no effect on the current or prior period financial statements as a result of this adoption.

### Future Accounting Pronouncements

As of January 1, 2008 Questerre will be required to adopt two new CICA standards, Section 3862 "Financial Instruments - Disclosures" and Section 3863 "Financial Instruments - Presentation", which will replace Section 3861 "Financial Instruments - Disclosure and Presentation". The new disclosure standard increases the emphasis on the risks associated with both recognized and unrecognized financial instruments and how those risks are managed. The new presentation standard carries forward the former presentation requirements. The new financial instruments presentation and disclosure requirements were issued in December 2006 and the Company is assessing the impact on its financial statements.

As of January 1, 2008, the Corporation will be required to adopt CICA 1535 "Capital Disclosures", which will require additional disclosures of objectives, policies and processes for managing capital. In addition, disclosures will include whether companies have complied with externally imposed capital requirements. The new capital disclosure requirements were issued in December 2006 and the Company is assessing the impact on its financial statements.

In January 2006, the CICA Accounting Standards Board ("AcSB") adopted a strategic plan for the direction of accounting standards in Canada. As part of the plan, accounting standards in Canada for public companies are to converge with International Financial Reporting Standards ("IFRS") by the end of 2010. The Company continues to monitor and assess the impact of the convergence of Canadian GAAP and IFRS.

In January 2008, the Corporation will be required to adopt CICA 3031, "Inventories". This section provides revised guidance on measurement and disclosures for inventories. The Company does not expect this standard to have any impact upon adoption, as its current inventory policies continue to be permitted under the revised standard. The Company will adopt this new standard effective January 1, 2008.

## **Controls and Procedures**

### **Management's Evaluation of Disclosure Controls and Procedures**

Disclosure controls and procedures have been designed to ensure that information required to be disclosed by the Company is accumulated and communicated to Questerre's management as appropriate to allow timely decisions regarding required disclosure. Questerre's Chief Executive Officer and Chief Financial Officer have concluded, based on their evaluation as of the end of the period covered by the annual filings, that the Company's disclosure controls and procedures as of the end of such period are effective to provide reasonable assurance that material information related to the Company, including its consolidated subsidiaries, is made known to them by others within those entities, particularly during the period in which the annual filings are being prepared.

### **Internal Controls Over Financial Reporting**

Questerre's Chief Executive Officer and Chief Financial Officer have designed or caused to be designed under their supervision, internal controls over financial reporting related to the Company, including its consolidated subsidiaries, to provide reasonable assurance regarding the reliability of the Company's financial reporting and the preparation of financial statements for external purposes in accordance with Canadian GAAP.

Questerre's Chief Executive Officer and Chief Financial Officer are required to cause the Company to disclose herein any change in the Company's internal controls over financial reporting that occurred during the Company's most recent interim period that has materially affected, or is reasonably likely to materially affect, the Company's internal controls over financial reporting.

No material changes in the Company's internal controls over financial reporting were identified during the year ended December 31, 2007, that have materially affected, or are reasonably likely to materially affect, the Company's internal controls of financial reporting.

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