



Management's Discussion and Analysis

Torque Energy Inc. ("Torque" or the "Company") is a Canadian-based oil and natural gas company whose common shares are traded on the TSX Venture Exchange (TSX-V) under the symbol "TQE".

The Company's business is the acquisition, exploration, development and operation of oil and gas properties. During 2008 it conducted its activities in the provinces of Ontario and Alberta, Canada.

The following Management's Discussion and Analysis (MD&A) should be read in conjunction with the audited consolidated financial statements and MD&A for the years ended November 30, 2008 and 2007 contained in the 2008 consolidated financial statements of Torque and is based on information to March 28, 2009. The reader should be aware that historical results are not necessarily indicative of future performance. Additional information relating to Torque can be found at www.sedar.com and www.torqueenergy.com

This MD&A may contain forward-looking statements including expectations of future capital programs and commodity prices. These statements are based on current expectations that involve a number of risks and uncertainties, which could cause actual results to differ from those anticipated. These risks include, but are not limited to: operational risk in development, exploration and production; delays or changes in plans with respect to exploration or development projects or capital expenditures; and commodity price and exchange rate fluctuation and uncertainties.

The financial data contained herein is presented in Canadian dollars and has been prepared in accordance with Canadian Accepted Accounting Principles ("GAAP"). In conformity with Canadian Securities Administrators National Instrument 51-101, natural gas volumes have been converted to equivalent barrels of oil ("boe") using a conversion ratio of six thousand cubic feet ("Mcf") to one boe. Readers are cautioned that boes may be misleading, particularly if used in isolation.

NON-GAAP MEASURES

The Company uses certain measures of financial reporting in the MD&A that are commonly used as benchmarks within the oil and natural gas production industry. They are widely accepted measures of performance and value within the industry, and are used by investors and analysts to compare and evaluate oil and natural gas exploration and producing entities.

These measures and their underlying calculations are not defined by Generally Accepted Accounting Principles ("GAAP") in Canada and consequently are referred to as non-GAAP measures. These measures may not be comparable to a similarly titled measure of another entity. When these measures are used, they should be given careful consideration by the reader.

Included in the MD&A are references to the following non GAAP terms:

Funds flow from operations, which is determined before changes in non-cash working capital is used as a key measure of performance and liquidity

Field level cash flow refers to oil and gas sales revenue less royalties, and less operating expenses. It does not include other income or any of the other company expenses that are used to calculate net income.

Operating netback is a benchmark used in the crude oil and natural gas industry to measure the BOE contribution of oil and natural gas sales subsequent to the deduction of royalties, operating and transportation costs.

RESULTS OF OPERATIONS

Operating highlights:

- Net profit increase of \$0.09 per share to \$0.12 per share
- 39% reduction in total bank indebtedness
- 86% increase in *funds flow from operations*
- 45% increase in *field level cash flow*
- 50% increase in *operating netbacks*

Total bank indebtedness at November 30, 2008 declined to \$2,485,409 from \$4,042,545 at November 30, 2007. The reduction of \$1,557,136 was due to the cash provided by profitable operations. The difference in the amount reported as total bank indebtedness versus the bank loan represents the timing in the clearance of outstanding cheques together with the funding of current account balances from the loan account.

The Company averaged 148 boe (barrels of oil equivalent) sold per day for the period compared to 153 boe per day for the same period in 2007. Same well production for the year was approximately 141 boe/day while new production from the Mikwan project contributed approximately 21 boe/day for the final 4 months of the fiscal period. The decline in same well production represented a normal and expected rate of approximately 9%.

SELECTED QUARTERLY INFORMATION

	2008				2007			
(\$000s, except per share amounts)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Revenue (net of royalties)	978.7	1,235.0	1,108.3	845.0	804.4	840.9	849.7	649.2
Funds flow from operations	226.5	820.5	733.4	462.9	353.1	375.4	371.0	169.3
Per share - basic & diluted (\$)	0.02	0.06	0.05	0.03	0.02	0.03	0.03	0.01
Net earnings (loss)	180.9	659.1	549.1	294.3	127.5	175.6	117.2	(50.6)
Per share - basic & diluted (\$)	0.01	0.05	0.04	0.02	0.01	0.01	0.01	--
Total assets	11,159.8	11,449.4	11,224.2	10,963.8	11,077.4	11,217.1	11,170.5	11,037.1
Bank indebtedness	2,485	2,885	3,238	3,663	4,043	4,332	4,308	4,416

SELECTED ANNUAL INFORMATION

Year ending November 30	2008	2007	2006
Revenue (net of royalties) - (\$)	4,167,040	3,144,335	3,017,603
Funds flow from operations (\$)	2,359,945	1,268,751	1,034,953
Per share - basic & diluted (\$)	0.16	0.09	0.07
Net earnings (loss) - (\$)	1,683,415	369,742	(55,328)
Per share - basic & diluted (\$)	0.12	0.03	-
Total assets (\$)	11,159,785	11,077,423	11,321,107
Bank indebtedness (\$)	2,485,409	4,042,545	4,412,173

FUNDS FLOW FROM OPERATIONS

Funds flow from operations increased 86% in 2008 to \$2.4 million, or \$0.16 per share on a diluted basis from \$1.3 million, or \$0.09 per share on a diluted basis for 2007. This is primarily a result of profitable operations due to increased commodity prices. Funds flow from operations is calculated as follows:

Year ending November 30 (\$)	2008	2007	2006
Cash provided by operating activities	2,490,531	1,119,645	1,364,025
Change in non-cash working capital	(130,586)	149,106	(329,072)
Funds flow from operations	2,359,945	1,268,751	1,034,953

FIELD LEVEL CASH FLOW

Year ending November 30 (\$)	2008	2007	2006
Oil and natural gas sales	4,706,154	3,512,953	3,377,403
Royalty expense	(615,169)	(452,566)	(436,741)
Net sales	4,090,985	3,060,387	2,940,662
Operating expenses (incl. Transportation)	(728,014)	(747,992)	(804,179)
Field level cash flow	3,362,971	2,312,395	2,136,483
Per share - basic & diluted (\$)	0.24	0.17	0.15

OPERATING NETBACKS

Year ending November 30 (\$/boe)	2008	2007	2006
Oil sales	99.22	67.79	63.69
Natural gas sales	58.74	49.63	52.82
Total sales	87.09	62.98	60.80
Royalty expense - (\$/boe)	(11.38)	(8.11)	(7.86)
%	13.1	12.9	12.9
Operating expenses (incl. transportation)	(13.47)	(13.41)	(14.48)
Netback	62.24	41.46	38.46

PETROLEUM AND NATURAL GAS SALES

All of the Company's production is sold within Canada, and revenues are received in Canadian dollars. The commodities produced and sold are sensitive to both worldwide (crude oil) and North American (natural gas) price fluctuations and the Canada/U.S. exchange rate. An increase in the value of the Canadian dollar negatively impacts price realizations. There was a marginal increase in the value of the Canadian dollar versus the U.S. dollar in 2008 compared to 2007. The average Canada/U.S. exchange rate was \$1.05/\$1.00 in fiscal 2008 compared to \$1.09 during fiscal 2007.

Production sales of petroleum and natural gas in 2008 averaged 148 boe/day, and realized an average gross price/boe of \$87.09. This compares to 152 boe/day in 2007 with an average price/boe of \$62.98, an increase of 38%. The overall increase in realized price/boe can be primarily attributed to the significant increase in the price/barrel (bbl) of worldwide crude oil prices during most of 2008. This contributed to a 46% increase in the realized price/bbl of oil compared to 2007. At the same time, the price/boe of natural gas production increased 18% from 2007 levels. Oil revenues were tempered by normal declines in production volumes in 2008 of approximately 9%. Production volumes of natural gas increased by 9% in 2008 compared to 2007 due to new production volumes from the Mikwan project in Alberta. Three new wells were tied-in and commenced production in late July of 2008 and are currently contributing at an average rate of 21 boe/day.

Year ending November 30	2008	2007	2006
Oil volumes - bbl	37,851	40,991	40,783
Oil price - \$/bbl	99.22	67.80	63.69
Gross oil sales (\$)	3,755,510	2,778,841	2,597,510
Natural gas volumes - Mcf	97,099	88,748	88,590
Natural gas price - \$/Mcf	9.79	8.27	8.80
Gross natural gas sales (\$)	950,644	734,112	779,893

bbl = one barrel of oil cf = ft³ of natural gas M = one thousand

ROYALTIES

Royalty burdens are predominantly freehold and overriding, along with some Crown royalties related specifically to the Mikwan Alberta production. Crown royalties commenced in July 2008 coincident with the commencement of production from the Mikwan project. For the year ended November 30, 2008, royalty rates remained relatively flat at approximately 13%.

Year ending November 30	2008	2007	2006
Royalties (\$)	615,169	452,566	436,741
- \$/boe	11.38	8.11	7.86
- rate %	13.1	12.9	12.9

CASH COSTS

Cash costs (operating, general and administrative and interest) decreased by 7% to \$29.93/boe in 2008 from \$32.05/boe in 2007 due primarily to reduced interest costs as a result of lower bank indebtedness throughout the year.

Operating Expenses

Operating expenses for 2008 decreased to \$728,014 compared to \$747,992 for the same period in 2007 representing, a 3% decrease. The decrease resulted primarily from lower repairs and maintenance related expenditures. On a boe basis, 2008 operating costs were \$13.47/boe compared to \$13.41/boe in 2007. Operating expenses are anticipated to increase during fiscal 2009 as the costs related to the Mikwan project are reflected for a full 12 month period.

General & Administrative Expenses

Net general and administrative expenses decreased 4% to \$685,743 in 2008 from \$714,902 in 2007. In 2007, the Company changed its auditors. This change resulted in some costs being absorbed from two firms during the transition leading to higher than expected or normal levels. In 2008, the Company realized a return to normal expenditure levels for its auditing requirements and a resulting decrease of approximately \$20,000. During 2008, the Company capitalized \$122,443 (2007 - \$107,360) of general and administration expenses related to geology and the development of oil and gas properties. General and administrative expenses are not expected to change in any material amount during the fiscal 2009 period.

\$, except as indicated	2008	2007	2006
Gross	808,186	822,262	787,984
Recoveries	-	-	-
Capitalized amounts	(122,443)	(107,360)	(114,000)
Net General & Administrative Expenses	685,743	714,902	673,984
- \$/boe	12.69	12.82	12.13

INTEREST EXPENSE

Interest expense decreased to \$203,752 in 2008 from \$324,693 in 2007. The decrease is primarily a result of using cash generated from operations to reduce the bank indebtedness. Recent changes to borrowing rates may result in a continued reduction of interest costs for 2009.

\$, except as indicated	2008	2007	2006
Bank debt	201,207	321,698	284,013
Convertible debenture	-	-	80,000
Capital lease and other	2,545	2,995	2,814
Interest Expenses	203,752	324,693	366,827
- \$/boe	3.77	5.82	6.60

NET EARNINGS

The Company realized a profit of \$1,683,415 (\$0.12 per share) for the 12 months ended November 2008 compared to a profit of \$369,742 (\$0.03 per share) for the same period in 2007. Oil and gas revenues less royalties increased to \$4,090,985 in 2008 versus \$3,060,387 in 2007. The contributing factors for the increases can be attributed to higher commodity prices for both oil and natural gas throughout the year together with stable production volumes.

OTHER ITEMS

Depletion, Amortization & Accretion Expenses

The fair values of asset retirement obligations are recorded as liabilities on a discounted basis when they are incurred, which is typically when the related assets are acquired or installed. Amounts recorded for the related assets are increased by the amount of these obligations. Over time the liabilities will be accreted for the change in their present value and the initial capitalized costs will be depleted and amortized over the useful lives of the related assets. There are no asset retirement liabilities set up for those assets which have an indeterminate useful life.

Depletion, amortization and accretion decreased to \$725,760 in 2008 from \$954,053 in 2007. On a boe basis, depletion, amortization and accretion decreased 21% from \$17.10 to \$13.43.

	2008		2007		2006	
	\$	\$/BOE	\$	\$/BOE	\$	\$/BOE
Depletion and amortization	706,519	13.07	897,293	16.09	915,699	16.48
Accretion - ARO	19,241	0.36	56,760	1.01	65,016	1.18
Total	725,760	13.43	954,053	17.10	980,715	17.66

Asset retirement obligation (ARO)

The undiscounted amount of expected cash flows required to settle the asset retirement obligation is estimated at \$1,544,668 (2007 - \$1,920,279). The liability for the expected cash flows, as reflected in the consolidated financial statements, has been discounted at 9% and includes a 1.0% inflation factor (2.0% - 2007).

Asset retirement obligation, beginning of year	\$574,469
Change in estimate	(116,636)
Liabilities settled	140,356
Asset retirement costs incurred	(189,587)
Accretion	19,241
Asset retirement obligation, end of year	<u>\$427,843</u>

Costs attributable to these commitments and contingencies are expected to be incurred over an extended period of time and are to be funded primarily from the Company's cash provided by operating activities. Over the next 5 years, approximately 18% of the costs will be incurred and the remainder from 2014 to 2058. Although the ultimate impact of these matters on operations cannot be determined at this time, it could be material for any one quarter or year.

TAX POOLS

At November 30, 2008, the Company had approximately \$9.0 Million of tax pools available for deduction against future earnings (2007 - \$9.4 Million). A breakdown of the tax pool balances is as follows:

Tax Pools (\$000's)	2008	2007	2006	Maximum Annual Rate of Deduction
Canadian Development Expenses	657	657	496	30%
Canadian Oil & Gas Property Expenses	5,240	5,938	6,346	10%
Undepreciated Capital Cost Allowances	1,262	1,467	1,949	20 - 45%
Canadian Exploration Expense	1,745	1,278	1,219	100%
Share Issue Costs		0	0	5 year straight line
Non-capital Losses		0	17	100%
Loan financing fees	63	108	154	5 year straight line
TOTAL	8,967	9,448	10,181	

In addition, the Company has various successor pools in the amount of \$5,596,000 (2007 - \$6,492,000) which may be utilized under certain circumstances against certain future taxable resource income earned in Ontario.

The potential income tax benefits associated with unutilized tax pools have been recognized to the extent of reducing future tax liabilities. The Company has not recognized future income tax assets related to available and successor tax pools.

INCOME TAXES

The effective rate of income tax varies from the statutory rate as follows:

	2008	2007	2006
Combined tax rate	33.72%	36%	38%
Expected income tax recovery at statutory rate	\$ 567,400	\$143,919	\$(21,036)
Recognition of benefit of oil and gas property pools	(567,400)	(143,919)	
Accreted interest			
Resource related adjustments			(51,523)
Stock based compensation			39,992
Unrecognized future tax assets/Other			32,567
Actual income tax provision	-	-	-

CAPITAL EXPENDITURES

Net capital expenditures totalled \$852,000 in 2008 compared to \$495,000 in 2007. The change in oil and gas properties for the period 2006 through 2008 is summarized below:

(\$000')	2008	2007	2006
Balance, November 30	17,282	16,787	16,303
Canadian expenditures:			
Lease and land acquisitions	187	242	234
Geological & geophysical	205	59	114
Drilling, completion and workovers	251	194	81
Equipping and facilities	208	(14)	39
Capitalized amounts and other	118	107	-
Subtotal	969	588	468
Asset retirement obligation adjustment	(117)	(93)	16
Disposition of oil and gas properties	0	0	0
Net Canadian Expenditures	852	495	484
Total	18,134	17,282	16,787

The Company's capital expenditures were primarily related to the drilling, completion and tie-in costs of the Mikwan project in Alberta together with continued geological and geophysical assessments of the projects in S.W. Ontario.

FOURTH QUARTER

Net revenues decreased in the fourth quarter compared to the preceding quarter due to the impact of declining commodity prices for both oil and natural gas. Sales volumes increased due to the introduction of Mikwan production. Operating costs increased slightly on a boe basis due to higher anticipated unit costs for the Alberta production. There were no extraordinary items or unusual year end adjustments other than those that occur following the annual and independent reserves evaluation.

LIQUIDITY AND CAPITAL RESOURCES

The Company's working capital deficiency decreased to \$2,592,128 at November 30, 2008 from \$3,980,641 at November 30, 2007. This decrease is a result of utilizing cash flow from operations to retire a portion of the bank debt during the year. In the short term, the Company is able to meet its liabilities as they come due. Additional financing may be required to rectify the working capital deficiency.

The loan facility provides Torque with a revolving demand loan bearing interest payable monthly at the bank's prime lending rate plus 1.00%. At November 30, 2008, the bank's prime lending rate was 4.00%. The loan is collateralized by a General Assignment of Book Debts together with a fixed and floating \$20,000,000 debenture over all Torque's assets.

At November 30, 2008, \$2,485,409 of funds had been drawn against the facility as follows:

	<u>2008</u>	<u>2007</u>
Opening balance	\$4,042,545	\$4,412,173
Repaid to November 30	(1,557,136)	(369,628)
Ending balance	<u>\$2,485,409</u>	<u>\$4,042,545</u>

The bank has not waived its right to demand repayment of the outstanding principal balance prior to November 30, 2008. Consequently, the entire balance has been shown as a current liability. At November 30, 2008, the credit facility was \$6,100,000 and, the available credit was \$3,775,000 (2007 - \$2,050,000).

	<u>2008</u>	<u>2007</u>
Authorized	\$6,100,000	\$6,100,000
Bank loan at November 30	2,325,000	4,050,000
Available credit at November 30	<u>\$3,775,000</u>	<u>\$2,050,000</u>

In 2008, the Company funded its capital expenditure program from cash flow from operations and existing cash. It expects to be able to continue to do so during the short term.

At November 30, 2008, the Company's market value of common shares was \$1,107,016 based on the closing price of \$0.08 per share and 13,837,698 shares outstanding. The number of common shares outstanding at March 28, 2009 remains at 13,837,698.

COMMITMENTS AND CONTRACTUAL OBLIGATIONS

Subsequent to year end 2008, the Company has the following commitments and contractual obligations:

The Company has committed to drill, complete and tie-in one additional development well in the Mikwan area with an approximate cost of completion of \$122,300.

The Company is further committed to leased office premises and office equipment with future lease payments, plus common area costs as follows:

<u>Year</u>	<u>\$</u>
2009	48,846
2010	49,089
2011	16,553
2012	5,707
2013	5,707

Other Indemnifications

In the ordinary course of business, the Company and its subsidiaries enter into contracts which contain indemnification provisions, such as loan agreements, confidentiality agreements, purchase contracts, service agreements, licensing agreements, asset purchase and sale agreements, joint venture agreements, operating agreements, leasing agreements, land use agreements, and others. In such contracts, the Company may indemnify counterparties to the contracts if certain events occur. These indemnification provisions vary on an agreement by agreement basis. In some cases, there are no pre-determined amounts or limits included in the indemnification provisions and the occurrence of contingent events that will trigger payment under them is difficult to predict. Therefore, the maximum potential future amount that the Company could be required to pay cannot be estimated.

OFF-BALANCE SHEET ARRANGEMENTS

The Company does not have and is not expected to have during its 2009 fiscal year any off-balance sheet arrangements.

RELATED PARTY TRANSACTIONS

During the year ended November 30, 2008, \$30,000 (2007 - \$31,878) was paid for office facilities and administrative services to Ionic Management Corp., a company related by virtue of a common director (Brian E. Bayley).

During the year ended November 30, 2008, \$27,300 (2007 - \$133,750) was paid to an officer of the Company (John K. Thomson) for management fees. Of this amount, \$21,840 (2007 - \$107,360) is included in petroleum and natural gas properties and equipment.

BUSINESS RISKS

The Company is engaged in the exploration, development and production of crude oil and natural gas. The oil and natural gas industry is highly competitive. In addition, the Company is exposed to a number of risks including:

Commodity Pricing - The Company is exposed to the risk from fluctuations in both worldwide (crude oil) and North American (natural gas) prices. All production is sold within Canada and revenues are received in Canadian dollars. The Company does not manage price risk on its production by entering into forward sales and fixed price contracts.

Foreign exchange risks - The Company is exposed to the risk related to fluctuations in the rate of exchange between the Canadian dollar and the U.S. dollar. Crude oil and natural gas revenues are based upon reference prices denominated in U.S. dollars. The Company does not have any derivative financial instruments in place to manage this risk

Exploration Risks - Oil and natural gas exploration involves a high degree of risk which even a combination of experience, knowledge and careful evaluation may not be able to overcome. The cost of drilling, completing and operating wells may vary significantly from initial estimates. Torque's drilling operations may be unsuccessful or may be curtailed, delayed or cancelled as a result of numerous factors not within its control. These factors include, but are not limited to, title problems, weather conditions, compliance with governmental requirements, shortage of capital, mechanical difficulties and shortages or delays in the

delivery of drilling rigs or other equipment. Accordingly, there can be no assurance that Torque's acquisition, development, exploitation and exploration activities will result in reserves being added at acceptable costs. There is no assurance that additional oil or natural gas reserves in commercial quantities will be discovered by the Company.

The Company mitigates these risks by contracting experienced and qualified consultants and using sound business practices. The Company follows all government regulations and has an up-to-date emergency response plan. Property and liability insurance in place provides a reasonable amount of protection from risk of loss due to a variety of insurable events.

Operating Hazards - The oil and gas business involves a variety of operating risks, including the risk of fire, explosion, blow-out, pipe failure, casing collapse, stuck tools, abnormally pressured formations and environmental hazards such as oil spills, gas leaks, pipeline ruptures and discharges of toxic gases, the occurrence of any of which could result in substantial losses to Torque due to injury and loss of life, loss of or damage to wellbores and drilling or production equipment, costs of overcoming downhole problems, severe damage to and destruction of property, natural resources and equipment, pollution and other environmental damage, clean-up responsibilities, regulatory investigation and penalties and suspension of operations. Gathering systems and processing facilities are subject to many of the same hazards and any significant problems related to those facilities could adversely affect Torque's ability to market its production. Insurance may not cover downhole operating risks, such as the costs of retrieving stuck equipment. Furthermore, Torque cannot predict whether insurance will continue to be available at premium levels that justify its purchase or whether insurance will be available at all to cover the risks faced by the Company.

Estimates of Reserves and Related Data - Numerous uncertainties are inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures including many factors beyond the control of the producer. The reserve data set forth in this MD&A represents only estimates based on available geological, geophysical, production and engineering data, the extent, quality and reliability of which vary. Oil and gas reserve engineering is a subjective process of estimating accumulations of oil and gas that cannot be measured in an exact manner and estimates of other engineers might differ materially from those shown. The accuracy of any reserve estimate is a function of the quality and quantity of available data, engineering and geological interpretation and judgment. In addition, the estimates of future net cash flow from proved reserves of the Company and the present value thereof are based upon certain assumptions about future production levels, prices, costs and participation, if any, by third parties in the development of the Company's reserves that may not prove correct over time for reasons which may or may not be under the control of or known to the Company. Any significant variance from these assumptions could materially affect the quantity and value of the Company's reserves as compared to the estimates contained in this MD&A.

Environmental Regulation - The drilling for and production, handling, transportation and disposal of oil and gas and by-products are subject to extensive regulation under federal, provincial and local environmental laws. In most instances, the applicable regulatory requirements relate to water and air pollution control and solid waste management measures, permitting requirements, or restrictions on operations in environmentally sensitive areas. Environmental assessments have not been performed on all of Torque's properties. To date, expenditures for environmental control facilities and for remediation have not been significant in relation to the results of operations of Torque. Torque believes, however, that the trend toward stricter standards in environmental legislation and regulation is likely to continue.

Political Risks - The Company's operations are subject to business risk inherent to the oil and natural gas industry. These risks can involve matters arising out of government policies, imposition of special taxes or similar charges by government bodies, foreign exchange fluctuations and controls, access to capital markets, civil disturbances, deprivation or unenforceability of contract rights or the taking of property without fair compensation.

Credit Risk - The Company's trade accounts receivable are from companies in the oil and gas industry, and as such the Company is exposed to all the risks associated with that industry. Substantially all of the Company's oil revenues are from one customer and all of the Company's gas revenues are from one other customer. Approximately 71% of accounts receivable are from these two customers (2007 - 82% were from these same two customers).

Liquidity Risk - Liquidity risk represents the risk that the Company will not be in a position to meet its financial obligations as they come due. As at November 30, 2008, the Company had \$3,775,000 available from its revolving credit facility. The Company's accounts payable and accrued liabilities will come due within 60 days of the balance sheet date. Given the available liquid resources, management anticipates having sufficient funds to meet the Company's short term commitments.

Dependence on Key Personnel - The Company is highly dependent on the continued service of and its ability to attract and retain qualified engineering and management personnel. The competition for such personnel is intense and the loss of particular persons, as well as the failure to recruit additional key personnel in a timely manner, could have a material adverse effect on the Company's business.

Changing Business Conditions - The Company's future operating results will substantially depend on the ability of its officers and key employees to manage changing business conditions and to implement and improve its operational, financial control and reporting systems. If the Company is unable to respond to and manage changing business conditions, the quality of the Company's services, its ability to retain key personnel and its results of operations could be materially adversely affected.

CRITICAL ACCOUNTING ESTIMATES

Oil and Gas Properties

The preparation of consolidated financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the amounts reported in the consolidated financial statements and accompanying notes. Actual results could differ from those estimates.

The Company follows the full cost method of accounting for oil and gas operations whereby all costs of exploring for and developing oil and gas reserves are initially capitalized. Such costs include land acquisition costs, geological and geophysical expenses, carrying charges on non-producing properties, costs of drilling and overhead charges directly related to acquisition and exploration activities.

Costs capitalized, together with the costs of production equipment, are depleted and amortized on the unit-of-production method based on the estimated gross proved reserves as determined by independent petroleum engineers. Petroleum products and reserves are converted to a common unit of measure, using 6 Mcf of natural gas to 1 Bbl of oil.

Costs of acquiring and evaluating unproved properties are initially excluded from depletion calculations. These unevaluated properties are assessed periodically to ascertain whether impairment has occurred. When proved 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 calculations.

Proceeds from sale of petroleum and natural gas properties are applied against capitalized costs, with no gain or loss recognized, unless such a sale would alter the rate of depletion by more than 20%.

The Company applies an impairment test ("ceiling test") to determine if capitalized costs are not recoverable and exceed their fair value. Capitalized costs are not recoverable if they are greater than estimated undiscounted cash flows from future production of proved reserves plus the cost (net of impairment) of unproved properties. Commodity prices used in calculating estimated cash inflows are based on quoted benchmark prices. Costs used in estimating cash outflows are based on expected future production and other costs and include abandonment and site restoration costs. An impairment loss is recognized if capitalized costs are greater than their recoverable amount. The impairment loss is measured as the amount by which capitalized costs exceed the fair value of proved reserves plus the cost (net of impairment) of unproved properties. Fair value is determined based on the present value of future cash flows, after deducting abandonment and site restoration costs, discounted at a risk free interest rate. Any impairment loss is charged to earnings.

Changes in Accounting Policy including Initial Adoption

As stated in Note 3 of the financial statements.

Measured Uncertainty

The amounts recorded for depletion and depreciation of oil and gas properties, the provision for future site restoration and abandonment costs and the ceiling test calculation are based on estimates of proven reserves, production rates, oil and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the consolidated financial statements of changes in such estimates in future years could be significant.

SUMMARY OF SECURITIES AT THE END OF THE PERIOD

Authorized

Unlimited common voting shares without par value
100,000,000 Class 'A' preference shares, par value \$10
100,000,000 Class 'B' preference shares, par value \$50

Issued and outstanding

	<u>2008</u>		<u>2007</u>	
	Shares	Amount	Shares	Amount
Common shares outstanding	13,837,698	\$12,143,910	13,837,698	\$12,143,910

Stock Options

The Company has a stock option plan (the "Plan") for its directors, officers, employees and consultants to purchase common shares. Under the terms of the Plan, the Board of Directors may authorize the granting of options to purchase common shares. The option price per common share granted under the plan may not be less than the closing market price on the date the option is granted less allowable discounts as permitted under the policies of the TSX Venture Exchange.

The maximum term of any option is five years from the date the option is granted. Options may be immediately exercisable upon grant.

The status of the Company's common share purchase option plan is as follows:

<u>Options outstanding at November 30</u>	<u>Common shares</u>	<u>Weighted Average Exercise Price</u>
2006	1,180,000	\$0.10
2007	1,180,000	\$0.10
2008	1,180,000	\$0.10

In 2008, there were no new stock purchase options granted, exercised or forfeited.

RESERVES

VON Resource Management Ltd. (VON) of Calgary, Alberta, independent petroleum consultants prepared a report dated March 20, 2009 in which VON evaluated, effective November 30, 2008, the quantity and estimated future cash flow of the Company's total estimated proved and probable Canadian reserves.

This evaluation was prepared in accordance with procedures and standards contained in the Canadian Oil and Gas Evaluation (COGE) Handbook. Reserve estimates of the properties were determined in accordance with the reserve classification, definitions and procedures outlined under the National Instrument 51-101 Policy which is a guide for Engineers and Geologists submitting oil and gas reports to Canadian Provincial Securities Administrators.

It should be noted that the remaining reserves assigned to the properties are based on the discounted cash flow analysis. This results in some wells having lower remaining reserves than derived through engineering calculations. The difference is a direct consequence of properties encountering their economic limit prior to recovering all the technically available reserves.

Provision for abandonment and site reclamation costs has been included in the cash flow analysis, as well as the offsetting salvage value of tangible equipment after the well abandonment, based on data provided by the company. However, no provision has been made for facility abandonment, reclamation and salvage value. In addition to the abandonment and reclamation liability for Proved Producing wells, the abandonment and reclamation costs and offsetting salvage value was included in the Total Proved Reserves for non-producing wells in which Torque has an interest, as reported by the company. Abandonment costs have been allocated at \$30,000 per well, site reclamation costs at \$10,000 per well and salvage values have been depreciated to the forecast economic life (max 50 years).

The results of the evaluations contained in the VON Report, based on both forecast and constant cost and price assumptions, are summarized in the tables below. The present worth of estimated future cash flows contained in the following tables may not be representative of the fair market value of the reserves. Assumptions relating to costs, prices for future production and other matters are summarized in the notes following the tables. There is no assurance that such prices and cost assumptions will be attained and variances could be material.

The Company's estimated gross proved reserves at November 30, 2008 were 830 MBOE (November 30, 2007 were 727 MBOE). The increase of 14% is due to positive revisions of 158 MBOE based on well performance taken into account during the decline curve analysis, and the addition of 4 wells that came on production during the year. Company gross probable additional reserves of 99 MBOE were also assigned to these producing properties, for a Proved plus Probable (2P) total of 929 MBOE.

The following tables summarize the Company's reserves volumes and net present values of future net revenue, before and after tax, as at November 30, 2008, using forecast prices and costs.

***Oil, Natural Gas and Natural Gas Liquids Reserves and Present Worth Value of
Estimated Future Cash Flows Based on Forecast Price and Cost Assumptions
Effective as of November 30, 2008***

	Oil		Gas		MBOE	
	<i>(Mstb)</i>		<i>(MMcf)</i>			
	Gross	Net	Gross	Net	Gross	Net
Proved Producing	582	503	1421	1246	819	711
Proved Developed Non-Producing			66	59	11	10
Proved Undeveloped					0	0
Total Proved	582	503	1487	1305	830	721
Probable	75	65	144	127	99	86
Total Proved plus Probable	657	568	1631	1432	929	807

Mstb = Thousand stock tank barrels

Reserve Category	Net Present Values of Future Net Revenue									
	Before Income Taxes Discount at (%/year)					After Income Taxes Discounted at (%/year)				
	0% (MM\$)	5% (MM\$)	10% (MM\$)	15% (MM\$)	20% (MM\$)	0% (MM\$)	5% (MM\$)	10% (MM\$)	15% (MM\$)	20% (MM\$)
PP	44.908	24.954	17.399	13.545	11.199	35.509	21.316	15.579	12.496	10.543
PDNP *	0.084	0.062	0.045	0.030	0.019	(0.088)	(0.062)	(0.048)	(0.039)	(0.035)
PUD										
Proved	44.992	25.016	17.444	13.575	11.218	35.421	21.254	15.531	12.457	10.508
Probable	8.220	2.515	1.156	0.689	0.477	5.625	1.739	0.816	0.499	0.356
Total Proved Plus Probable	53.212	27.531	18.600	14.264	11.695	41.046	22.993	16.347	12.956	10.864

* Includes one PDNP well plus Abandonment and Surface Reclamation Liability net of Salvage Value for all non-producing wells

PP = Proved Producing

PDNP = Proved Developed Non-Producing

PUD = Proved Undeveloped

**Total Future Net Revenue (Undiscounted) effective as of November 30, 2008
Forecast Prices and Costs**

Reserves Category	Revenue (M\$)	Royalties (M\$)	Operating Costs (M\$)	Development Costs (M\$)	Abandonment and Reclamation Costs (M\$)	Future Net Revenue Before Income Taxes (M\$)	Income Taxes (M\$)	Future Net Revenue After Taxes (M\$)
Proved Reserves	70,826	9,389	15,285	21	1139	44,992	9,571	35,421
Proved Plus Probable Reserves	80,576	10,621	15,572	21	1150	53,212	12,166	41,046

**Future Net Revenue by Production Group effective as of November 30, 2008
Forecast Prices and Costs**

Reserves Category	Production Group	Future Net Revenues Before Income Taxes (Discounted at 10%/year) (M\$)	Future Net Revenues Per Net BOE Before Income Taxes (Discounted at 10%/year) (\$/BOE)
Proved Reserves	Light and medium crude (including solution gas and other by-productions)*	14,487	27
	Natural Gas (including by-products but excluding solution gas from oil wells)	2,957	17
	Total	17,444	24
Proved Plus Probable Reserves	Light and medium crude oil (including solution gas and other by-products)*	15,504	25
	Natural Gas (including by-products but excluding solution gas from oil wells)	3,096	17
	Total	18,600	23

*The Abandonment Liability and Site Reclamation costs for non-producing wells is included In the Oil Future Net Revenue

The following tables summarize the Company's reserves volumes and net present values of future net revenue, before and after tax, as at November 30, 2008, using constant prices and costs.

Oil, Natural Gas and Natural Gas Liquids Reserves and Present Worth Value of Estimated Future Cash Flows Based on Constant Price and Cost Assumptions Effective as of November 30, 2008

	Oil		Gas		MBOE	
	<i>(Mstb)</i>		<i>(MMcf)</i>			
	Gross	Net	Gross	Net	Gross	Net
Proved Producing	576	497	1246	1093	784	679
Proved Developed Non-Producing			65	58	11	10
Proved Undeveloped					0	0
Total Proved	576	497	1311	1151	795	689
Probable	75	66	125	110	96	84
Total Proved Plus Probable	651	563	1436	1261	891	773

Reserve Category	Net Present Values of Future Net Revenue									
	Before Income Taxes Discount at (%/year)					After Income Taxes Discounted at (%/year)				
	0% (MM\$)	5% (MM\$)	10% (MM\$)	15% (MM\$)	20% (MM\$)	0% (MM\$)	5% (MM\$)	10% (MM\$)	15% (MM\$)	20% (MM\$)
PP	24.647	15.095	11.093	8.914	7.532	21.899	14.296	10.803	8.793	7.477
PDNP *	0.021	0.012	0.003	(0.005)	(0.011)	(0.127)	(0.067)	(0.040)	(0.029)	(0.026)
PUD										
Proved	24.668	15.107	11.096	8.909	7.521	21.772	14.229	10.763	8.764	7.451
Probable	4.409	1.469	0.725	0.454	0.326	3.020	1.051	0.555	0.372	0.282
Total Proved Plus Probable	29.077	16.576	11.821	9.363	7.847	24.792	15.280	11.318	9.136	7.733

* Includes one PDNP well plus Abandonment and Surface Reclamation Liability net of Salvage Value for all non-producing wells

***Total Future Net Revenue (Undiscounted) effective as of November 30, 2008
Constant Prices and Costs***

Reserves Category	Revenue M\$	Royalties M\$	Operating Costs M\$	Development Costs M\$	Abandonment and Reclamation Costs M\$	Future Net Revenue Before Income Taxes M\$	Income Taxes M\$	Future Net Revenue After Income Taxes M\$
Proved Reserves	42,253	5,554	11,118	21	892	24,668	2,896	21,772
Proved Plus Probable Reserves	47,460	6,205	11,265	21	892	29,077	4,285	24,792

**Future Net Revenue by Production Group effective as of November 30, 2008
Constant Prices and Costs**

Reserves Category	Production Group	Future Net Revenues Before Income Taxes (Discounted at 10%/year) M\$	Future Net Revenues Per Net BOE Before Income Taxes (Discounted at 10%/year) (\$/BOE)
Proved Reserves	Light and medium crude oil (including solution gas and other by-products)*	9,208	17
	Natural Gas (including by-products by excluding solution gas from oil wells)	1,888	12
	Total	11,096	16
Proved Plus Probable Reserves	Light and medium crude oil (including solution gas and other by-products)*	9,831	16
	Natural Gas (including by-products but excluding solution gas from oil wells)	1,990	12
	Total	11,821	15

**The Abandonment Liability and Site Reclamation costs for non-producing wells is included in the Oil Future Net Revenue*

ABANDONMENT, SALVAGE AND SITE RESTORATION

The following tables set out the Abandonment, Salvage, and Site Restoration Liabilities for the Company, using both a Constant Dollar and Escalated Dollar forecast, calculated without discount and using a discount rate of 10 percent.

All Abandonment Costs, Salvage Values, and Site Restoration Costs for existing producing and non-producing wells were accounted for in estimating the Future Net Revenue of the Company in the VON Evaluation of Reserves as at November 30, 2008. However, no provision was made for facility abandonment, reclamation and salvage value. Abandonment costs were allocated at \$30,000 per well, site reclamation costs at \$10,000 per well and salvage values were depreciated to the forecast economic life (max 50 years).

Abandonment, Salvage & Site Restoration Summary (Constant Dollars)

Constant Dollars	0% Discount	10% Discount
52 Wells	M\$	M\$
Abandonment Cost	866	285
Site Restoration Cost	311	96
Total Liability	1177	381
Salvage Value	282	108
Net Liability	895	273

**Abandonment, Salvage & Site Restoration Costs
Over Next Three Financial Years (Constant Dollars)**

Constant Dollars	0% Discount	10% Discount
13 Wells	M\$	M\$
Abandonment Cost	204	180
Site Restoration Cost	68	60
Total Liability	272	240
Salvage Value	72	64
Net Liability	200	176

Abandonment, Salvage & Site Restoration Summary (Escalated Dollars)

Escalated Dollars	0% Discount	10% Discount
52 Wells	M\$	M\$
Abandonment Cost	1102	303
Site Restoration Cost	402	102
Total Liability	1504	405
Salvage Value	342	114
Net Liability	1162	291

*Abandonment, Salvage & Site Restoration Costs
Over Next Three Financial Years (Escalated Dollars)*

Escalated Dollars	0% Discount	10% Discount
13 Wells	M\$	M\$
Abandonment Cost	207	182
Site Restoration Cost	69	61
Total Liability	276	243
Salvage Value	73	65
Net Liability	203	178

The following points need to be considered when reviewing the foregoing summary of the VON report:

Reserves

Company gross reserves as used herein means those reserves accruing to the Company after deduction of all outside working interests but before deduction of overriding and lessor royalties and before Crown royalties.

Net reserves as used herein means those reserves accruing to the Company after deduction of all outside working interests, overriding and lessor royalties and Crown royalties. The cash flow forecasts are after direct lifting costs, normal allocated overhead, future investments, and well abandonment costs net of salvage value, and lease clean-up costs, and show both before and after income tax values.

The NI 51-101 guidelines provide a higher level of confidence on reserve recovery. For example, the definition for Proved Reserves indicates that actual recoveries are likely to exceed the estimated proved reserves and there is a 90 percent probability of recovering at least that amount. The definition of Probable Reserves indicates that recovery of a higher amount of probable reserve is just as likely as recovering less than that amount.

The properties were evaluated by VON Resource Management Ltd. in accordance with the following National Instrument 51-101 definitions.

I. Proved Reserves

Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

II. Probable Reserves

Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

III. Possible Reserves

Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.

Other criteria that must also be met for the categorization of reserves are provided in Section 5.5 of Volume 1 of the COGE Handbook.

Development & Production Status

Each of the reserves categories (proved, probable, and possible) may be divided into developed or undeveloped categories.

Developed Reserves

Developed reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (e.g., when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

Developed Producing Reserves

Developed producing reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

Developed Non-Producing Reserves

Developed non-producing reserves are those reserves that either have not been on production, or have previously been on production, but are shut in, and the date of resumption of production is unknown.

Undeveloped Reserves

Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (e.g., when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned.

In multi-well pools, it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities, and completion intervals in the pool and their respective development and production status.

Levels of Certainty for Reported Reserves

The qualitative certainty levels contained in the definitions in Section I, II and III are applicable to individual reserves entities, which refers to the lowest level at which reserves estimates are made, and to reported reserves, which refers to the highest level sum of individual entity estimates for which reserve estimates are made.

Reported total reserves estimated by deterministic or probabilistic methods, whether comprised of a single reserves entity or an aggregate estimate for multiple entities should target the following level of certainty under a specific set of economic conditions:

- a. There is a 90% probability that at least the estimated proved reserves will be recovered.
- b. There is a 50% probability that at least the sum of the estimated proved reserves plus probable reserves will be recovered.
- c. There is a 10% probability that at least the sum of the estimated proved reserves plus probable reserves plus possible reserves will be recovered.

A quantitative measure of the probability associated with a reserves estimate is generated only when a probabilistic estimate is conducted. The majority of reserves estimates will be performed using deterministic methods that do not provide a quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

Additional clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in Section 5.5.3 of Volume 1 of the COGE Handbook. Whether deterministic or probabilistic methods are used, evaluators are expressing their professional judgment as to what are reasonable estimates.

Documented Reserves Categories

Production and revenue projections are prepared for each of the following main reserves categories:

Reserves Category

- i. Proved
- ii. Probable, and Proved Plus Probable
- iii. Proved Plus Probable Plus Possible*

Production and Development Status

- i. Developed Producing**
- ii. Developed Non-producing
- iii. Undeveloped
- iv. Total (sum of developed producing, developed non-producing and undeveloped)

**Generally, VON only evaluates possible reserves when specifically requested by a client.*

*** As producing reserves are inherently developed, VON simply refers to "developed producing reserves" as "producing".*

When evaluating reserves, the VON evaluator generally first identifies the producing situation and assigns proved, proved plus probable and proved plus probable plus possible reserves in recognition of the existing level of development and the existing depletion strategy. Incremental non-producing (developed non-producing or undeveloped) reserves are subsequently assigned recognizing future development opportunities and enhancements to the depletion mechanism. It should be recognized that future developments may result in accelerated recovery of producing reserves.

VON, in their evaluation, used the November 30, 2008 Sproule price and market forecasts as summarized below after a comprehensive review of information. Information sources include numerous government agencies, industry publications, Canadian oil refiners and natural gas marketers. The forecasts presented herein are based on an informed interpretation of currently available data. While these forecasts are considered reasonable as at the date of the evaluation, users of these forecasts should understand the inherent high uncertainty in forecasting any commodity or market. These forecasts will be revised periodically as market, economic and political conditions change.

**Summary of Pricing and Inflation Rate Assumptions as of November 30, 2008
Forecast Prices and Cost**

Year	Crude Oil Edmonton Par (\$/bbl)	Natural Gas Henry Hub US\$/Mcf	Exchange Rate US\$/Cdn\$	Natural Gas Henry Hub Cdn\$/Mcf	Natural Gas AECO Cdn\$/Mcf	*Average Company Field Price Oil Cdn\$/Bbl	*Average Company Field Price Gas Cdn\$/Mcf
Weighted Average Historical Price for F2008	106.91	9.06	0.96	9.44	8.18	97.28	9.54
November 2008	63.89	6.47	0.82	7.89	6.92	56.62	8.42
December 2008	75.41	6.72	0.80	8.40	7.35	66.55	8.11
2009	81.17	7.19	0.80	8.99	7.94	72.32	8.72
2010	85.15	7.94	0.85	9.34	8.30	76.31	9.14
2011	83.94	8.16	0.85	9.60	8.55	75.13	9.45
2012	91.59	9.37	0.95	9.86	8.81	82.81	9.79
2013	92.50	9.46	0.95	9.96	8.91	83.75	9.96
2014	93.42	9.55	0.95	10.05	9.01	84.69	10.11
2015	94.34	9.65	0.95	10.16	9.11	85.66	10.26
2016	+1.0%/year	+1.0%/year	0.95	+1.0%/year	+1.0%/year	+1.0%/year	+1.0%/year

** Average company field price is after quality and transportation adjustments.*

VON used the Sproule Associates Limited November 30, 2008 price forecast for their evaluation of the Torque properties.

- (1) In the escalated pricing determination, operating and capital costs are assumed to increase at 1.0% per year.
- (2) Under the constant price scenario, prices and costs are held constant for the life of the reserves. The Crude Oil at Edmonton price was held constant at Cdn.\$63.89/bbl and the Natural Gas Henry Hub price was held constant at U.S.\$6.47/Mcf for the Ontario properties, and the Natural Gas AECO price was held constant at Cdn.\$6.92/Mcf for the Alberta properties.
- (3) The \$U.S./\$Cdn. Exchange rate is assumed to be 0.82 in Nov-08, 0.80 in 2008-09, 0.85 in 2010-11, and 0.95 in 2012 and thereafter.
- (4) In the course of the November 30, 2008 evaluation, Torque provided VON personnel with basic information which included land data, well information, geological information, contract information, operating cost data, financial data and discussions of future operating plans. Other engineering, geological or economic data required in order to conduct the evaluation and upon which the VON Report are based, was obtained from public records, other operators, and from VON non-confidential files. The extent and character of ownership and accuracy of all factual data supplied for the independent evaluation, from all sources, has been accepted as represented. The accuracy of any reserves and production estimate is a function of the quality and quantity of available data, engineering interpretation and judgement. While reserves and production estimates presented herein were considered reasonable at the time they were prepared, the estimates should be accepted with the understanding that reservoir performance subsequent to the date of the estimate may justify revision, either upward or downward. Revenue projections presented in the VON Report are based in part on forecasts of market prices, currency exchange rates, inflation, market demand and government policy which are subject to many uncertainties and may, in future, differ materially from the forecasts utilized in the VON Report. Present values of revenues documented in the VON Report do not necessarily represent the fair market value of the reserves evaluated therein.
- (5) Columns may not add due to rounding.

Reconciliation of Reserves

The following table provides a continuity of company gross reserves from the November 30, 2006 reserves determination to the November 30, 2008 reserves determination:

	Crude Oil and Liquids			Natural Gas			Barrels Oil Equivalent		
	(Mstb)			(MMcf)			(MBOE)		
	Proved	Probable	Total	Proved	Probable	Total	Proved	Probable	Total
December 1, 2006	459		459	1036		1036	632		632
Extensions & Improved Recovery			-			-			-
Technical Revisions	133	101	234	109	193	302	151	133	284
Discoveries			-			-			-
Acquisitions			-			-			-
Dispositions			-			-			-
Economic Factors			-			-			-
Production	41		41	89		89	56		56
December 1, 2007	551	101	652	1056	193	1249	727	133	860
Extensions & Improved Recovery			-			-			-
Technical Revisions	70	(26)	44	216	(94)	122	106	(42)	64
Discoveries			-	313	45	358	52	8	60
Acquisitions			-			-			-
Dispositions			-			-			-
Economic Factors			-			-			-
Production	39		39	98		98	55		55
December 1, 2008	582	75	657	1487	144	1631	830	99	929

Oil and Gas Properties and Wells

The following table summarizes the Company's interests in oil, gas and other wells, by location at November 30, 2008.

	Oil Wells		Gas Wells		Oil & Gas Wells		Other Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
<i>Producing Wells</i>										
Alberta	0	0.00	3	0.75	0	0.00	0	0.00	3	0.75
Ontario	7	2.78	12	5.54	18	12.53	0	0.00	37	20.84
<i>Non-Producing Wells</i>										
Alberta	0	0.00	4	1.27	0	0.00	0	0.00	4	1.27
Ontario	3	2.24	2	2.00	0	0.00	2	1.00	7	5.24
<i>Total Wells</i>										
Alberta	0	0.00	7	2.02	0	0.00	0	0.00	7	2.02
Ontario	10	5.02	14	7.54	18	12.53	2	1.00	44	26.09
Total	10	5.02	21	9.56	18	12.53	2	1.00	51	28.10

PRODUCTION HISTORY

The following table summarizes, for the year ended November 30, 2008, the Company's production volumes, revenue, prices received, operating expenses, royalties, and resulting netback in total and per unit of volume.

Fiscal 2008	Q1	/Day	Q2	/Day	Q3	/Day	Q4	/Day	Total F2008	/Day
VOLUME										
Oil Production - Mstb & bbl/d	9	102	9	102	9	101	10	109	38	103
Gas Production - MMcf & Mcf/d	18	195	22	237	20	222	37	408	97	265
MBOE (6:1) & BOE/d	12	135	13	142	12	138	16	177	54	148
REVENUES										
	M\$	\$/Unit	M\$	\$/Unit	M\$	\$/Unit	M\$	\$/Unit	M\$	\$/Unit
Oil Revenue	799	85.88	1,014	107.82	1,144	123.53	798	80.79	3,756	99.22
Less: Oil Royalties	106	11.34	134	14.29	155	16.68	105	10.62	499	13.19
Net Oil Revenue	694	74.54	880	93.54	990	106.84	693	70.17	3,256	86.03
Gas Revenue	151	8.53	239	10.97	255	12.51	305	8.21	951	9.79
Less: Gas Royalties	18	1.03	29	1.34	31	1.53	37	1.00	116	1.19
Net Gas Revenue	133	7.50	210	9.63	224	10.97	268	7.21	835	8.60
TOTAL NET REVENUE	827	67.42	1,090	83.56	1,214	95.83	961	59.80	4,091	75.71
Operating Expenses (excl. trans.)	113	9.19	142	10.86	152	12.05	224	13.92	630	11.66
Transportation	22	1.83	24	1.87	26	2.01	25	1.57	98	1.81
TOTAL OPERATING EXPENSES	135	11.02	166	12.73	178	14.06	249	15.49	728	13.47
FIELD LEVEL CASH FLOW	692	56.40	924	70.83	1,036	81.77	712	44.31	3,363	62.24
REVENUE \$/BOE	77.52		96.10		110.50		68.63		87.09	
ROYALTIES \$/BOE	10.10		12.54		14.67		8.83		11.38	
OPERATING COSTS \$/BOE	11.02		12.73		14.06		15.49		13.47	
NETBACK \$/BOE	56.40		70.83		81.77		44.31		62.24	

* Operating expenses include Overhead Recovery Costs on Operated Properties of approximately M\$15 per quarter.

Major Properties - F2008 Production

The following table lists, for each major field, and in total, the Company's production volumes for the year ended November 30, 2008.

PROPERTY	PROVINCE	W.I. OIL Mstb	W.I. GAS MMcf	W.I. MBOE	% of Total MBOE
Corey East	Ontario	13.0		13.0	24%
Petrolia East	Ontario	17.7		17.7	33%
Dover East	Ontario	4.8	42.6	11.9	22%
Other	Ontario	2.7	38.0	9.0	17%
Other	Alberta		16.8	2.8	5%
TOTAL	Ontario & Alberta	38.2	97.4	54.4	100%

Major Properties - F2008 Wells

The Company's major properties are summarized in the table below:

Major Properties				Producing Wells						Non-Producing		Total	
				Oil Wells		Gas Wells		Oil & Gas Wells		Other Wells		All Wells	
Property	Province	Location	Facilities	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Corey East	Ontario	Onshore	Battery					3.0	2.8	1.0	0.9	4.0	3.8
Petrolia East	Ontario	Onshore	Battery					4.0	4.0	1.0	1.0	5.0	5.0
Dover East	Ontario	Onshore	Gas Plant & Battery	2.0	1.0	8.0	3.5	7.0	3.5	2.0	1.0	19.0	9.0

Unproved Properties

The following table lists the Company's undeveloped land position effective November 30, 2008.

Property	Province	Location	Gross Acres	Net Acres	Work Commitments
Cranberry	Alberta	Onshore	1,280	422.4	None
Fort Assiniboine	Alberta	Onshore	640	211.2	Drill one well
Mikwan	Alberta	Onshore	320	80.0	Drill one well
Botha	Alberta	Onshore	640	177.6	None
Ontario	Ontario	Onshore	18,321	12,943.0	None

Major Properties - Projected F2009

Production Estimates for the First Year (2009) reflected in the Estimates of Future Net Revenues

The following table summarizes the production volumes from the Company's significant fields, and a total of its production for the first year reflected in the estimates of net revenues forecast as at November 30, 2008.

Property	Province	W.I. OIL Mstb	W.I. GAS MMcf	W.I. MBOE	% of Total MBOE
Corey East	Ontario	11.5		11.5	20%
Petrolia East	Ontario	16.9		16.9	30%
Dover East	Ontario	4.5	40.0	11.1	20%
Other	Ontario	2.3	42.8	9.5	17%
Other	Alberta		47.4	7.9	14%
Total	Ontario & Alberta	35.2	130.2	56.9	100%

OUTLOOK

The Company continues to evaluate existing properties for production and asset value optimization.

Development and Exploration

Operations

The Company completed Ram/BP #4 (50% working interest) which had been shut-in since 1998 and tied it into the Ram/BP #5 Union Gas meter site. Net production to the Company is 40 Mcf per day.

At Ram #84 (100% working interest) a major overhaul of the compressor system was completed resulting in consistent daily gas production.

At Ram #91 and Reefex #1 (both 100% working interest) the Company is currently performing an economic evaluation of the two shut-in gas wells with results expected by mid summer.

Alberta

In the Mikwan area of Alberta, the Company participated in the tie-in of the fourth well to the Encana Lousana compressor site in March 2009. The first three wells went on production July 18, 2008. At November 30, 2008 the combined production rate was 555 Mcf per day (93 boe/day), with net production of 139 Mcf per day (23 boe/day) to the Company. The fourth well is projected to be on production in mid April 2009.

Ontario

During the year the Company completed shooting of an additional 8 kilometres of two-dimensional seismic. This data has been processed and interpreted. An exploratory drilling location in this Dunwich project area has been defined, but spudding the well has been delayed as the Company looks for a partner to participate in the drilling of this well.

The Company has acquired 3,002 acres of petroleum and natural gas rights at 100% working interest in the Dunwich-Southwold prospect area. This prospect and an additional seven prospects also located in southwestern Ontario were originally identified using high resolution magnetics. The Company has completed the SGH (soil gas hydrocarbon) sampling survey and is currently integrating these results into the geological/geophysical models to form a geological assessment report on each of these prospects. The Company will be looking for partners to participate in the continuing development of these prospects.

Proposed Transactions

The Company does not have any proposed transactions at this point in time.