



**Management's Discussion and Analysis**  
**Twelve Month Period Ended**  
**November 30, 2007**

FORM 51-102F1

March 28, 2008

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 was created by amalgamation on June 1, 1993 in the province of British Columbia. In February 2003, the Company changed its name from "Kinetic Energy Inc." to "Torque Energy Inc."

The Company's business is the acquisition, exploration, development and operation of oil and gas properties. In 2007 it conducted its activities in the provinces of Ontario and Alberta, Canada.

### CAUTIONS

This Management's Discussion and Analysis for the year ended November 30, 2007 should be read in conjunction with the audited consolidated financial statements for the years ended November 30, 2007 and 2006, together with the notes related thereto.

This Management's Discussion and Analysis 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.

All data is presented in Canada dollars. Barrels of oil equivalent ("BOE") have been calculated using an industry accepted conversion rate of six thousand cubic feet of natural gas to one barrel of oil. Analysis includes events that have occurred up to the date of this MD&A, March 28, 2008. Financial data has been prepared in accordance with Canadian general accepted accounting principles (GAAP).

### NON-GAAP MEASURES

Included in the MD&A are references to the term "field level cash flow". This term is not defined by Generally Accepted Accounting Principles ("GAAP") in Canada and consequently is referred to as a non-GAAP measure.

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. Reported amounts may not be comparable to similarly titled measures reported by other companies.

The financial data presented herein has been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). The Company has also used certain measures of financial reporting that are commonly used as benchmarks within the oil and natural gas production industry in The Management Discussion and Analysis. The measures discussed 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. Most notably, these measures include operating netback and funds flow from operations. Operating netback is a benchmark used in the crude oil and natural gas industry to measure the contribution of oil and natural gas sales subsequent to the deduction of royalties, operating and transportation costs. Funds flow from operations is before changes in non-cash working capital and is used to analyze operations, performance and liquidity. These measures are not defined under GAAP and should not be considered in isolation or as an alternative to conventional GAAP measures. These measures and their underlying calculations are not necessarily comparable to a similarly titled measure of another entity. When these measures are used, they are defined as "non GAAP" and should be given careful consideration by the reader.

## DISCUSSION OF OPERATIONS AND FINANCIAL CONDITION

The Company's working capital deficiency decreased to \$3,980,641 at November 30, 2007 from \$4,648,830 at November 30, 2006. This decrease is attributed to utilizing cash flow from operations to retire a portion of bank debt during the period. In the short term, the Company is able to meet its liabilities as they come due and has working capital requirements of approximately \$70,000 to \$80,000 per month. Additional financing may be required to rectify the working capital deficiency.

In April 2003, the Company issued two \$2,000,000 6% debentures maturing April 1, 2005 and secured by a second fixed and floating charge. Effective March 15, 2005, the terms of the debentures were amended to extend the maturity date to April 1, 2006. Effective March 31, 2006 Torque entered into a new credit facility and repaid the notes and the lenders surrendered the debenture to Torque for cancellation. Interest on the debentures was payable semi-annually. Interest was paid to March 31, 2006. One of the debentures was payable to a company related by virtue of a common director.

The loan facility provided the Company with a revolving reducing demand loan bearing interest payable monthly at prime plus 1.50%. At the date of the approval, the bank's prime rate was 5.50%. The new loan was collateralized by a General Assignment of Book Debts together with a fixed and floating \$20,000,000 debenture over all Torque's assets. In accordance with the terms and conditions, Torque had been reducing the facility by \$75,000 per month since April 30, 2006. At November 30, 2006 the credit facility was \$6,400,000 and the available credit was \$2,125,000.

On April 10, 2007 the Company renewed its credit facility in the amount of \$6,100,000 to be used for general corporate purposes including capital expenditures.

The loan facility provides Torque with a revolving demand loan bearing interest payable monthly at the bank's prime lending rate plus 1.00%. The bank's prime lending rate in effect at the date of approval was 6.00%. At year end, the bank's prime lending rate was 6.25%. 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, 2007, \$4,050,000 of funds had been drawn against the facility as follows:

	<u>2007</u>	<u>2006</u>
Opening balance	\$4,275,000	
Funds drawn to repay former bank loan	-	\$1,890,000
Funds drawn to repay debentures	-	4,000,000
Repaid to November 30	(225,000)	(1,615,000)
Ending balance	<u>\$4,050,000</u>	<u>\$4,275,000</u>

The bank has not waived its right to demand repayment of the outstanding principal balance prior to November 30, 2007 and consequently the entire balance has been shown as a current liability. In accordance with the terms and conditions of the renewed credit facility, Torque is not required to reduce the facility with monthly instalments. At November 30, 2007, the credit facility is \$6,100,000 and, the available credit is \$2,050,000 (2006 - \$2,125,000).

	<u>2007</u>	<u>2006</u>
Authorized	\$6,100,000	\$7,000,000
Monthly reductions to credit facility		(600,000)
Bank loan at November 30	4,050,000	4,275,000
Available credit at November 30	<u>\$2,050,000</u>	<u>\$2,125,000</u>

The Company realized a profit of \$369,742 (\$0.03 per share) for the 12 months ended November 2007 compared to a loss of \$55,328 (\$0.00 per share) for the same period in 2006. Oil and gas revenues less royalties increased to \$3,060,387 in 2007 versus \$2,940,662 in 2006. The principal reason for the increase is related to increases in oil price combined with stable production volumes.

General and administrative costs increased to \$714,902 in 2007 from \$673,984 over the same period in 2006. This increase is attributable to an increase in audit fees together with an increase in consulting services, salaries and benefits, bank charges, capital and other taxes. Operating costs for the 12 months ended November 30, 2007 decreased to \$747,992 compared to \$804,179 for the same period in 2006. The decrease was a result of reduced maintenance costs related to the non-operated facilities and capitalization of lease costs that were formerly included in surface lease rentals.

The Company averaged 153 BOE (barrels of oil equivalent) sold per day for the period compared to 152 BOE per day for the same period in 2006. The existing daily production volumes increased by 1 boepd as a result of increased production at Petrolia East (11%) due to maintenance results and operating efficiencies at the smaller operated properties (8%).

The Company averaged \$54.86 of revenue (net of royalties) per BOE sold in the year ending November 30, 2007 compared to \$52.94 per BOE in the previous year.

## **OUTLOOK**

The Company is pursuing a number of exploration and development opportunities in Ontario and Alberta. Discussions are underway to consider the possibility of future business ventures and acquisitions.

### **Exploration and Development**

#### **Ontario**

In the Dunwich project area, the Company has completed the shooting of 10.5 kilometres of two-dimensional seismic and this data has been processed and interpreted. An exploratory drilling location was drilled and abandoned in 2007, but additional seismic will be shot on the prospect in 2008 to identify another exploration drilling location.

In the Sombra project area, the Company participated in the drilling of an exploratory test well under the terms of a Farmout Agreement with Liberty Oil and Gas Ltd. by paying forty percent of the cost to drill, complete and equip the well. Torque earned a twenty-five percent interest in the test well. The location was defined by a three-dimensional seismic program. Drilling was completed in January 2007 and the well was dry and has been abandoned.

#### **Alberta**

In the Mikwan area of Alberta, the Company participated in the completion of a well which was originally drilled in 2003. Under the terms of the Farmout agreement, Torque pays 35% of the costs to earn a 25% working interest in the well drilled in 2003. The well was completed in July as a potential coalbed methane gas well. In February of 2008, Torque elected to participate in the drilling of two additional wells in this area at 25% working interest (after earned interest); both wells have been drilled and completed as potential coalbed methane gas wells. It is anticipated that all three wells will be tied in and producing by August 2008.

All activities will be funded with existing cash flow and the Company continues to develop exploratory plays and prospects in Ontario.

#### **Operations**

The Company will continue its replacement of older equipment in the Petrolia East Field (100% w.i.) by replacing the bottom hole pumps in the Ram #38 and CanEnerco #3 wells. At the Corey East field (94.46% w.i.) the Company will be replacing the pumpjack on the Ram #61 well.

At the Ram #84 gas well, the motor has been replaced with a new unit and the compressor will require a rebuild. It is anticipated that the work will enhance production.

## ANNUAL INFORMATION

Year ending November 30,	2007	2006	2005
Total Oil and Gas Revenues less royalties	\$3,060,387	\$2,940,662	\$ 3,109,993
Other Income	\$83,948	76,941	48,473
<b>Total Revenue</b>	<b>\$3,144,335</b>	<b>3,017,603</b>	<b>3,158,466</b>
Income (loss) before discontinued operations <sup>(1)</sup> and extraordinary items <sup>(2)</sup>	\$369,742	\$(55,328)	\$ 329,761
Basic income (loss) per share	0.03	0.00	0.02
Net income (loss) on a diluted per share basis	0.03	0.00	0.02
<b>Total assets</b>	<b>\$11,084,878</b>	<b>\$11,321,107</b>	<b>\$12,898,517</b>
<b>Total liabilities</b>	<b>\$5,093,660</b>	<b>\$5,699,631</b>	<b>\$ 7,326,954</b>
Cash dividends declared per share for each common share	0	0	0

(1) The Company has not had any discontinued operations in the last three fiscal years.

(2) The Company has not had any extraordinary items in the last three fiscal years.

The main factor that has resulted in the increase in oil and gas sales in 2007 is the maintenance of daily volumes produced as a result of field facility upgrades, combined with an increase in oil price. "Other Income" consists mainly of overhead recoveries and is directly related to the ongoing exploration and operating activities of the Company.

The Company's income increased from a loss of \$55,328 in 2006 to a profit of \$369,742 in 2007.

The Company has not made any significant acquisitions or dispositions throughout this period or significant increases in reserves.

### Oil & Gas Sales

#### Years ended November 30

(000's)	2007 (\$000s)	2006 (\$000s)	2005 (\$000s)	2006-2007 % Change
Gross oil and natural gas liquid sales	2,779	2,598	2,542	7%
Gross natural gas sales	734	780	1,028	(6%)
Royalties	453	437	460	4%
<b>Oil &amp; Gas Sales, Net of Royalties</b>	<b>3,060</b>	<b>2,941</b>	<b>3,110</b>	<b>4%</b>

Oil and gas sales, net of royalties, increased 4% in 2007 to \$3.1 million. Production volumes on a barrel of oil equivalent basis (BOE) (calculated on the basis of 6:1 gas to oil) increased from 152 BOE per day (BOE/d) in 2006 to 153 BOE/d in 2007. The production increases experienced by the Company were due to increases at Petrolia East (11%) and the minor operated properties (8%) that offset the normal declines in production for the remaining properties. Increased oil prices and increased oil price differentials in 2007 also contributed to the \$119,000 in increased revenues compared to 2006. This increase was partially offset by a decrease in gas price.

### Years ended November 30

	2007	2006	2005	2006-2007 % change
Oil and natural gas liquids volumes - Mbbl	41	41	44	0%
Oil and natural gas liquids price - \$/bbl	67.79	63.69	57.67	6%
Gross oil and natural gas liquids sales - (\$000s)	2,779	2,598	2,542	7%
Natural gas volumes - MMcf	89	89	96	0%
Natural gas price - \$/Mcf	8.27	8.80	10.74	(6%)
Gross natural gas sales - (\$000s)	734	780	1,028	(6%)

bbl = one barrel (of oil)  
M = one thousand

cf = cubic feet (of natural gas)  
MM = one million

Oil and natural gas volumes increased in 2007 from 2006 due to increased production at Petrolia East and the company operated minor properties that offset the normal declines in production for the period. These increases were the result of facility upgrades and production maintenance efforts. The 6% increase in oil price offset the 6% decrease in natural gas price.

Total royalties paid by the Company on oil and gas production increased from \$436,741 in 2006 to \$452,566 in 2007, an increase of 4%. The increase in royalties is due to increased revenue as a result of maintained production rates combined with higher oil prices.

### General & Administrative Expenses

Net general and administrative expenses increased 6% to \$714,902 in 2007. During 2007, the Company capitalized \$ 107,360 (2006 - \$ 114,000) of general and administration expenses related to geology and the development of oil and gas properties.

	2007	2006	2005	2006-2007 % Change
<b>Gross General &amp; Administrative Expenses</b>	\$822,262	\$787,984	\$636,058	4%
Recoveries	-	-	-	-
Capitalized amounts	107,360	114,000	118,757	(6%)
<b>Net General &amp; Administrative Expenses</b>	<b>\$714,902</b>	<b>\$673,984</b>	<b>\$517,301</b>	<b>6%</b>

Net general and administrative expenses on a BOE basis increased to \$12.82 in 2007.

(/BOE)	2007	2006	2005	2006-2007 % Change
<b>Gross General &amp; Administrative Expenses</b>	\$14.74	\$14.19	\$10.60	4%
Recoveries	-	-	-	-
Capitalized amounts	\$1.92	\$2.05	\$1.98	(6%)
<b>Net General &amp; Administrative Expenses</b>	<b>\$12.82</b>	<b>\$12.13</b>	<b>\$8.62</b>	<b>6%</b>

### Operating Expenses

Operating expenses for 2007 decreased to \$747,992 compared to \$804,179 for the same period in 2006. On a BOE basis, 2007 operating costs were \$13.41/BOE compared to \$14.48/BOE in 2006, a 7% decrease. The decrease on a BOE basis resulted from increased production at Petrolia East and the Company operated minor properties, and the reduction in major field maintenance at Dover East.

## Depletion, Amortization & Accretion Expenses

	2007	2007	2006	2006	2005	2005	2006-2007 % Change	2006- 2007 % Change
	\$000's	\$/BOE	\$000's	\$/BOE	\$000's	\$/BOE	\$000's	\$/BOE
Depletion and amortization	897	\$16.09	916	16.48	932	15.53	(2%)	(2%)
Accretion - ARO	57	1.02	65	1.17	73	1.22	(12%)	(13%)
<b>Total</b>	<b>\$954</b>	<b>\$17.11</b>	<b>\$981</b>	<b>\$17.65</b>	<b>\$1,005</b>	<b>\$16.75</b>	<b>(3%)</b>	<b>(3%)</b>

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 \$0.95 Million in 2007. On a BOE basis, depletion, amortization and accretion decreased 3% from \$17.65 to \$17.11.

### Asset retirement obligation (ARO)

The undiscounted amount of expected cash flows required to settle the asset retirement obligation is estimated at \$1,920,279 (2006 - \$1,675,190). The liability for the expected cash flows, as reflected in the consolidated financial statements, has been discounted at 9% and includes a 2.0% inflation factor (2.0% - 2006).

The schedule below is a reconciliation of Torque's asset retirement obligation for the period ended November 30, 2007:

Asset retirement obligation, beginning of year	\$665,852
Change in estimate	(93,099)
Liabilities settled	32,953
Asset retirement costs incurred	(87,997)
Accretion	56,760
Asset retirement obligation, end of year	\$574,469

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 29% of the costs will be incurred and the remainder from 2013 to 2056. 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, 2007, the Company had approximately \$9.4 Million of tax pools available for deduction against future earnings (2006 - \$10.2 Million). A breakdown of the tax pool balances is as follows:

Tax Pools	2007 (000's)	2006 (000's)	2005 (000's)	Maximum Annual Rate of Deduction
Canadian Development Expenses	\$657	\$ 496	\$ 412	30%
Canadian Oil & Gas Property Expenses	5,938	6,346	6,926	10%
Undepreciated Capital Cost Allowances	1,467	1,949	1,876	20 - 45%
Canadian Exploration Expense	1,278	1,219	1,010	100%
Share Issue Costs	0	0	26	5 year straight line
Non-capital Losses	0	17	0	100%
Loan financing fees	108	154	240	5 year straight line
<b>TOTAL</b>	<b>9,448</b>	<b>10,181</b>	<b>\$ 10,490</b>	

In addition, the Company has various successor pools in the amount of \$6,492,412 (2006 - \$6,492,412) 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:

	2007	2006	2005
Combined tax rate	36%	38%	36.12%
Expected income tax recovery at statutory rate	\$ 143,919	\$ (21,036)	\$ 119,600
Recognition of benefit of oil and gas property pools	(143,919)	-	-
Accreted interest	-	-	24,400
Resource related adjustments	-	(51,523)	(112,600)
Stock based compensation	-	39,992	-
Unrecognized future tax assets/Other	-	32,567	(31,400)
Actual income tax provision	\$ -	\$ -	\$ -

## Capital Expenditures

Net capital expenditures totalled \$495,000 in 2007 compared to \$484,000 in 2006. The change in oil and gas properties for the period 2005 through 2007 is summarized below:

(\$000')	2007	2006	2005	2006 - 2007 % Change
<b>Balance, November 30</b>	\$16,787	\$16,303	\$16,066	<b>1%</b>
Canadian expenditures:				
Lease and land acquisitions	242	234	152	
Geological & geophysical	59	114	24	
Drilling, completion and workovers	194	81	91	
Equipping and facilities	(14)	39	27	
Capitalized amounts and other	107	-	-	
<b>Subtotal</b>	<b>\$588</b>	<b>\$468</b>	<b>\$294</b>	<b>59%</b>
Asset retirement obligation adjustment	(93)	16	(57)	
Disposition of oil and gas properties	0	0	0	
<b>Net Canadian Expenditures</b>	<b>495</b>	<b>484</b>	<b>237</b>	<b>104%</b>
<b>Total</b>	<b>\$17,282</b>	<b>\$16,787</b>	<b>\$16,303</b>	<b>3%</b>

The Company's capital expenditures were related to upgrades in existing facilities and the drilling of an exploratory well on the Dunwich prospect in S.W. Ontario. Additionally, the Company acquired a total of 13.3 kilometres of two dimensional seismic on the Dunwich and Aldborough prospects.

## Fourth Quarter

Net revenues decreased in the fourth quarter compared to the preceding quarter due to lower sales volumes combined with lower gas prices. Production volumes were down due to various wells being shut-in for maintenance. Operating costs increased during the fourth quarter due to maintenance work on non-operated properties. There were no extraordinary items or unusual year end adjustments during the period.

## Summary of Quarterly Results

	2007				2006			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Revenues (net)	\$649,247	\$849,688	\$840,998	\$804,402	\$760,054	\$751,659	\$805,837	\$700,053
Net income (loss) in total	\$(50,587)	\$117,220	\$175,614	\$127,495	\$(8,607)	\$37,232	\$83,516	\$(167,469)
Per share basis	\$0.00	\$0.01	\$0.01	\$0.01	\$0.00	\$0.00	\$0.01	\$(0.01)
Diluted per share basis	\$0.00	\$0.01	\$0.01	\$0.01	\$0.00	\$0.00	\$0.01	\$(0.01)

In the eight quarters shown above, there were no discontinued operations or extraordinary items.

## RESERVES

VON Resource Management Ltd. (VON) of Calgary, Alberta, independent petroleum consultants prepared a report dated March 10, 2008 in which VON evaluated, effective November 30, 2007, 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 Proven Producing wells, the abandonment and reclamation costs and offsetting salvage value was included in the Total Proven 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, 2007 were 727 MBOE (November 30, 2006 were 632 MBOE). The increase of 15% is due to positive revisions of 151 MBOE based on well performance taken into account during the decline curve analysis as well as a significant reduction in the gas shrinkage factor at Dover East, after the installation of a new Sales Meter by Union Gas. Company gross probable additional reserves of 133 MBOE were also assigned to these producing properties, for a Proved plus Probable (2P) total of 860 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, 2007, 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, 2007***

	Oil		Gas		MBOE	
	<i>(Mstb)</i>		<i>(MMcf)</i>			
	Gross	Net	Gross	Net	Gross	Net
Proved Producing	551	477	1056	924	727	631
Proved Developed Non-Producing					0	0
Proved Undeveloped					0	0
<b>Total Proved</b>	<b>551</b>	<b>477</b>	<b>1056</b>	<b>924</b>	<b>727</b>	<b>631</b>
Probable	101	87	193	169	133	115
<b>Total Proved plus Probable</b>	<b>652</b>	<b>564</b>	<b>1249</b>	<b>1093</b>	<b>860</b>	<b>746</b>

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	30.073	17.175	12.297	9.816	8.303	25.393	15.855	11.819	9.614	8.209
PDNP *	(0.216)	(0.199)	(0.185)	(0.173)	(0.162)	(0.302)	(0.248)	(0.212)	(0.189)	(0.172)
PUD										
Proved	29.857	16.976	12.112	9.643	8.141	25.091	15.607	11.607	9.425	8.037
Probable	8.630	2.428	1.040	0.591	0.398	5.828	1.695	0.769	0.467	0.333
<b>Total Proved Plus Probable</b>	<b>38.487</b>	<b>19.404</b>	<b>13.152</b>	<b>10.234</b>	<b>8.539</b>	<b>30.919</b>	<b>17.302</b>	<b>12.376</b>	<b>9.892</b>	<b>8.370</b>

\*Abandonment and Surface Reclamation Liability net of Salvage Value for non-producing wells

PP = Proved Producing

PDNP = Proved Developed Non Producing

PUD = Proved Undeveloped

**Total Future Net Revenue (Undiscounted) effective as of November 30, 2007  
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	52,682	7,028	14,381	30	1386	29,857	4,766	25,091
Proved Plus Probable Reserves	64,779	8,645	16,193	30	1424	38,487	7,568	30,919

**Future Net Revenue by Production Group effective as of November 30, 2007  
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)*	10,741	21
	Natural Gas (including by-products but excluding solution gas from oil wells)	1,371	12
	Total	12,112	19
Proved Plus Probable Reserves	Light and medium crude oil (including solution gas and other by-products)*	11,630	19
	Natural Gas (including by-products but excluding solution gas from oil wells)	1,522	12
	Total	13,152	18

\*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, 2007, 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, 2007***

	Oil		Gas		MBOE	
	<i>(Mstb)</i>		<i>(MMcf)</i>		Gross	Net
	Gross	Net	Gross	Net		
Proved Producing	558	483	1011	885	727	631
Proved Developed Non-Producing					0	0
Proved Undeveloped					0	0
<b>Total Proved</b>	<b>558</b>	<b>483</b>	<b>1011</b>	<b>885</b>	<b>727</b>	<b>631</b>
Probable	101	87	187	163	132	114
<b>Total Proved Plus Probable</b>	<b>659</b>	<b>570</b>	<b>1198</b>	<b>1048</b>	<b>859</b>	<b>745</b>

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	35.353	21.140	15.296	12.161	10.196	29.470	18.873	14.203	11.563	9.841
PDNP *	(0.212)	(0.196)	(0.182)	(0.170)	(0.159)	(0.299)	(0.256)	(0.225)	(0.201)	(0.182)
PUD										
Proved	35.141	20.944	15.114	11.991	10.037	29.171	18.617	13.978	11.362	9.659
Probable	7.336	2.380	1.125	0.672	0.460	4.996	1.749	0.803	0.497	0.354
<b>Total Proved Plus Probable</b>	<b>42.477</b>	<b>23.324</b>	<b>16.239</b>	<b>12.663</b>	<b>10.497</b>	<b>34.167</b>	<b>20.366</b>	<b>14.781</b>	<b>11.859</b>	<b>10.013</b>

*\*Abandonment and Surface Reclamation Liability net of Salvage Value for non-producing wells*

**Total Future Net Revenue (Undiscounted) effective as of November 30, 2007**  
**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	53,244	7,117	10,104	30	852	35,141	5,970	29,171
Proved Plus Probable Reserves	62,957	8,421	11,177	30	852	42,477	8,310	34,167

**Future Net Revenue by Production Group effective as of November 30, 2007**  
**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)*	14,193	27
	Natural Gas (including by-products by excluding solution gas from oil wells)	921	9
	Total	15,114	24
Proved Plus Probable Reserves	Light and medium crude oil (including solution gas and other by-products)*	15,210	24
	Natural Gas (including by-products but excluding solution gas from oil wells)	1,029	8
	Total	16,239	22

*\*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, 2007. 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)*

<b>Constant Dollars</b>	<b>0% Discount</b>	<b>10% Discount</b>
50 Wells	<b>M\$</b>	<b>M\$</b>
Abandonment Cost	906	368
Site Restoration Cost	325	133
Total Liability	1231	501
Salvage Value	287	117
Net Liability	944	384

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

<b>Constant Dollars</b>	<b>0% Discount</b>	<b>10% Discount</b>
20 Wells	<b>M\$</b>	<b>M\$</b>
Abandonment Cost	327	247
Site Restoration Cost	119	92
Total Liability	446	339
Salvage Value	111	84
Net Liability	335	255

### *Abandonment, Salvage & Site Restoration Summary (Escalated Dollars)*

<b>Escalated Dollars</b>	<b>0% Discount</b>	<b>10% Discount</b>
50 Wells	<b>M\$</b>	<b>M\$</b>
Abandonment Cost	1408	403
Site Restoration Cost	512	145
Total Liability	1920	548
Salvage Value	393	112
Net Liability	1527	436

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

<b>Escalated Dollars</b>	<b>0% Discount</b>	<b>10% Discount</b>
20 Wells	<b>M\$</b>	<b>M\$</b>
Abandonment Cost	336	255
Site Restoration Cost	122	95
Total Liability	458	350
Salvage Value	119	90

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

Proved  
 Probable, and Proved Plus Probable  
 Proved Plus Probable Plus Possible\*

### Production and Development Status

Developed Producing \*\*  
 Developed Non-producing  
 Undeveloped  
 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, VON evaluators generally first identify the producing situation and assign 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 November 30, 2007 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 at this time, 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, 2007 Forecast Prices and Cost*

Year	Crude Oil Edmonton Par (\$/bbl)	Natural Gas Henry Hub US\$/Mcf	Exchange Rate US\$/Cdn\$	*Avg. Company Field Price Oil Cdn\$/Bbl	*Avg. Company Field Price Gas Cdn\$/Mcf
Weighted Average Historical Price for F2007	75.25	6.95	0.92	66.05	7.98
November 2007	89.96	7.27	1.00	82.41	7.00
December 2007	91.72	7.89	1.00	82.64	8.30
2008	86.58	8.18	1.00	77.53	8.59
2009	79.58	8.38	1.00	70.53	8.80
2010	64.31	7.80	1.00	55.25	8.22
2011	63.44	7.96	1.00	54.40	8.37
2012	64.71	8.08	1.00	55.65	8.50
2013	66.01	8.20	1.00	56.96	8.63
2014	67.34	8.32	1.00	58.25	8.76
2015	+2.0%/year	+2.0%/year	1.00	+2.0%/year	+2.0%/year

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

VON used the Sproule Associates Limited November 30, 2007 price forecast for their evaluation of the Torque properties.

- (1) In the escalated pricing determination, operating and capital costs are assumed to increase at 2.0% 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 \$89.96/bbl and the Natural Gas Henry Hub price was held constant at US \$7.27/Mcf.
- (3) The \$U.S./\$CDN Exchange rate is assumed to be 1.0 in 2007 and thereafter.
- (4) In the course of the November 30, 2007 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, 2005 reserve determination to the November 30, 2007 reserve determination:

	Crude Oil and Liquids			Natural Gas			Barrels Oil Equivalent		
	(Mstb)			(MMcf)			(MBOE)		
	Proved	Probable	Total	Proved	Probable	Total	Proved	Probable	Total
<b>Opening, December 1, 2005</b>	<b>493</b>		<b>493</b>	<b>1015</b>		<b>1015</b>	<b>662</b>		<b>662</b>
Extensions & Improved Recovery			-			-			-
Technical Revisions	7		7	110		110	25		25
Discoveries			-			-			-
Acquisitions			-			-			-
Dispositions			-			-			-
Economic Factors			-			-			-
Production	41		41	89		89	56		56
<b>December 1, 2006</b>	<b>459</b>		<b>459</b>	<b>1036</b>		<b>1036</b>	<b>632</b>		<b>632</b>
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
<b>December 1, 2007</b>	<b>551</b>	<b>101</b>	<b>652</b>	<b>1056</b>	<b>193</b>	<b>1249</b>	<b>727</b>	<b>133</b>	<b>860</b>

## 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, 2007.

	Oil Wells		Gas Wells		Oil & Gas Wells		Other Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
<b>Producing Wells</b>										
Alberta	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
Ontario	7	2.78	10	5.04	19	12.53	0	0.00	36	20.34
<b>Non-Producing Wells</b>										
Alberta	0	0.00	5	1.62	0	0.00	0	0.00	5	1.62
Ontario	3	2.24	4	3.00	1	0.50	0	0.00	8	5.74
<b>Total Wells</b>										
Alberta	0	0.00	5	1.62	0	0.00	0	0.00	5	1.62
Ontario	10	5.02	14	8.04	20	13.03	0	0.00	44	26.09
<b>Total</b>	<b>10</b>	<b>5.02</b>	<b>19</b>	<b>9.66</b>	<b>20</b>	<b>13.03</b>	<b>0</b>	<b>0.00</b>	<b>49</b>	<b>27.70</b>

## PRODUCTION HISTORY

The following table summarizes, for the year ended November 30, 2007, the Company's production volumes, revenue, prices received, operating expenses, royalties, and resulting netback in total and per unit of volume.

Fiscal 2007	Q1		Q2		Q3		Q4		Total F2007	
	/Unit		/Unit		/Unit		/Unit		/Unit	
<b>VOLUME</b>										
Oil Production - Mstb & bbl/d	9	99	12	128	10	114	10	108	41	112
Gas Production - MMcf & Mcf/d	22	244	21	233	23	255	22	241	89	243
MBOE (6:1) & BOE/d	13	140	15	167	14	157	13	148	56	153
<b>REVENUES</b>										
	M\$	\$/Unit	M\$	\$/Unit	M\$	\$/Unit	M\$	\$/Unit	M\$	\$/Unit
Oil Revenue	534	59.84	755	63.85	741	70.76	750	76.63	2,779	67.79
Oil Royalties	(70)	(7.84)	(98)	(8.32)	(98)	(9.35)	(98)	(10.01)	(364)	(8.88)
Net Oil Revenue	464	52.00	656	55.53	643	61.41	652	66.61	2,415	58.91
Gas Revenue	194	8.86	202	9.43	186	7.92	152	6.92	734	8.27
Gas Royalties	(23)	(1.07)	(24)	(1.14)	(22)	(0.96)	(18)	(0.83)	(89)	(1.00)
Net Gas Revenue	171	7.79	178	8.29	163	6.97	133	6.09	646	7.27
Operating Expenses (excl. trans.)	214	17.00	187	12.16	129	8.98	153	11.42	722	12.95
Transportation	21	1.68	8	0.51	27	1.86	9	0.66	26	0.46
<b>TOTAL OPERATING EXPENSES</b>	<b>235</b>	<b>18.68</b>	<b>195</b>	<b>12.67</b>	<b>156</b>	<b>10.83</b>	<b>162</b>	<b>12.07</b>	<b>748</b>	<b>13.41</b>
<b>NET FIELD LEVEL INCOME</b>	<b>400</b>	<b>31.78</b>	<b>639</b>	<b>41.51</b>	<b>650</b>	<b>45.25</b>	<b>623</b>	<b>46.38</b>	<b>2,312</b>	<b>41.45</b>
REVENUE \$/BOE	57.89		62.16		64.45		67.09		62.98	
ROYALTIES \$/BOE	7.42		7.97		8.36		8.65		8.11	
OPERATING COSTS \$/BOE	18.68		12.67		10.83		12.07		13.41	
NETBACK \$/BOE	31.78		41.51		45.25		46.38		41.45	

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

## Major Properties - F2007 Production

The following table lists, for each major field, and in total, the Company's production volumes for the year ended November 30, 2007.

PROPERTY	PROVINCE	W.I. OIL Mstb	W.I. GAS MMcf	W.I. MBOE	% of Total MBOE
Corey East	Ontario	12.7		12.7	23%
Petrolia East	Ontario	20.1		20.1	36%
Dover East	Ontario	5.4	45.3	13.0	23%
Other	Ontario	2.9	43.7	10.2	18%
TOTAL	Ontario	41.1	89.0	56.0	100%

## Major Properties - F2007 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, 2007.

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	640	224.0	Drill two wells
Botha	Alberta	Onshore	640	177.6	None
Ontario	Ontario	Onshore	18,915	13,168	Drill one well

## Major Properties - Projected F2008 Production Estimates for the First Year (2008) 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, 2007.

Property	Province	W.I. OIL Mstb	W.I. GAS MMcf	W.I. MBOE	% of Total MBOE
Corey East	Ontario	11.2		11.2	22%
Petrolia East	Ontario	17.9		17.9	36%
Dover East	Ontario	4.4	43.6	11.7	23%
Other	Ontario	2.6	38.4	9.0	19%
Total	Ontario	36.1	82.0	49.8	100%

## LIQUIDITY AND CAPITAL RESOURCES

In 2007, 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.

The Company's working capital deficiency decreased to \$3,980,641 at November 30, 2007 from \$4,648,830 at November 30, 2006. This decrease is attributed to utilizing cash flow from operations to retire a portion of bank debt and debenture obligations during the period. In the short term, the Company is able to meet its liabilities as they come due and has working capital requirements of approximately \$70,000 to \$80,000 per month. The Company will be reliant on capital markets to grow the asset base in the future.

At November 30, 2007, the Company's market value of common shares was \$2,075,655 based on the closing price of \$0.15 per share and 13,837,698 shares outstanding. The number of common shares outstanding at March 28, 2008 remains at 13,837,698.

The Company is currently generating cash flows on a monthly basis in excess of its obligations to its creditors and is in compliance with all the covenants of its debt holder. Provided the commodity prices remain consistent through the year December 1, 2007 to November 30, 2008, the Company will be able to finance its operations and proposed capital expenditures and exploration activities in 2008 and continue to remedy its working capital deficiency with its cash flow and existing cash on hand while maintaining a reserve for any downward trend in commodity prices.

The Company may see a slight increase in operating costs in fiscal 2008 as existing wells and production facilities continue a program of upgrades to enhance production volumes and cash flows.

General and administrative expenses are expected to remain flat during the period December 1, 2007 to November 30, 2008.

The Company is committed to leased office premises and office equipment with future lease payments as outlined in Note 13 of the financial statements:

2008	\$44,829
2009	\$44,829
2010	\$44,829
2011	\$12,142

The Company continues to be proactive in seeking industry partners and mergers to increase its reserve base which will enable the Company to enhance its exploration and development activities beyond the current cash flow capabilities of the Company.

## COMMITMENTS AND CONTRACTUAL OBLIGATIONS

Subsequent to year end 2007, the Company has the following commitments and contractual obligations:

In Alberta, the Company has an outstanding working commitment to drill one well with respect to the Fort Assiniboine project in Alberta. The cost to Torque would be approximately \$125,000. Additionally, the Company has committed to the drilling and completion of two development wells in the Mikwan area at a total cost to the Company of \$122,300.

The Company is committed to leased office premises and office equipment with future lease payments, plus common costs and the commitment to drill two development wells in the Mikwan area and one well in the Fort Assiniboine area, both in Alberta as follows:

2008	\$301,053
2009	\$ 47,262
2010	\$ 44,829
2011	\$ 12,142

## Other Indemnifications

In the ordinary course of business, the Company and its subsidiaries enter into contracts which contain indemnification provisions, such as loan 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 2008 fiscal year any off-balance sheet arrangements.

## **RELATED PARTY TRANSACTIONS**

During the year ended November 30, 2007, \$31,878 (2006 - \$32,142) was paid for office facilities and administrative services to a company related by virtue of a common director.

During the year ended November 30, 2007, \$133,750 (2006 - \$130,200) was paid to an officer of the Company for management fees. Of this amount, \$107,360 (2006 - \$103,360) is included in petroleum and natural gas properties and equipment. At November 30, 2007, \$18,479 (2006 - \$15,156) was included in accounts receivable and prepaid expenses related to these transactions. The transactions are in the normal course of business and have been recognized at the agreed to exchange amounts.

## **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** - Future revenues depend on benchmark prices for crude oil and natural gas, which fluctuate from time to time. Adverse fluctuations can have a significant negative effect on the Company's revenues. The Company has not entered into a commodity hedge program to protect its reinvestment potential. This strategy allows the Company to benefit in a high commodity price environment.

**Explorations 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 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.

**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 cash is on deposit with one financial institution. As such, the Company is exposed to credit risk associated with this concentration of funds.

## 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 significantly 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>2007</u>		<u>2006</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:

	Effective Date	Common Shares	Option Price	Weighted Average Exercise Price	Expiry Date
<b>Options outstanding, November 30, 2005</b>		271,875	\$0.80	\$0.80	10-Jan-07
Options granted during the year	27-Jan-07	1,100,000	\$0.10	\$0.10	26-Jan-11
Options forfeited during the year	10-Sep-06	(60,000)	\$0.10	\$0.10	26-Jan-11
Options forfeited during the year	10-Sep-06	(6,250)	\$0.80	\$0.80	10-Jan-07
Options forfeited during the year	19-Sep-06	(265,625)	\$0.80	\$0.80	10-Jan-07
Options granted during the year	20-Oct-06	140,000	\$0.13	\$0.13	19-Oct-11
<b>Options outstanding, November 30, 2006</b>		1,180,000	\$0.10	\$0.10	
<b>Options outstanding, November 30, 2007</b>		1,180,000	\$0.10	\$0.10	

In 2007, there were no new stock purchase options granted, exercised or forfeited.

## ADDITIONAL INFORMATION

Additional information relating to Torque is on SEDAR at [www.sedar.com](http://www.sedar.com) and [www.torqueenergy.com](http://www.torqueenergy.com).