



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 exploration, development and acquisition of opportunities related to the operation and production of oil and natural gas properties. It presently conducts its activities in the provinces of Ontario and Alberta, Canada.

The following Management's Discussion and Analysis (M.D. & A.) should be read in conjunction with the audited financial statements for the years ended November 30, 2009 and 2008 together with the notes thereto and the M.D. & A. for the year ended November 30, 2008. This M.D. & A. is based on information to March 29, 2010. 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

FORWARD LOOKING STATEMENTS

This M.D. & 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 Generally Accepted Accounting Principles ("GAAP"). In conformity with Canadian Securities Administrators National Instrument 51-101, *Standards of Disclosure for Oil and Gas Activities*, natural gas volumes have been converted to barrels ("bbls") of oil equivalent ("BOE" and, if per day, "BOE/d") using a conversion ratio of six Mcf (one thousand cubic feet = one Mcf and, if per day, "Mcf/d") to one BOE. Readers are cautioned that BOE may be misleading, particularly if used in isolation.

NON-GAAP MEASURES

The Company uses certain measures of financial reporting in the M.D. & 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 GAAP in Canada and consequently are referred to as non-GAAP measures. These measures may not be



comparable to a similarly titled measure used by another entity. When these measures are used, they should be given careful consideration by the reader.

Included in the M.D.& A. are references to the following non-GAAP terms:

Funds flow from operations is determined before changes in non-cash working capital items, and 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 expenses used to calculate net income. Field level cash flow contributes to the funding of the Company's working capital and capital expenditure requirements as well as providing for the reduction to overall bank indebtedness.

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 and operating expenses.

Overall Performance

For the year ended November 30, 2009, the Company realized net income of \$333,315 (\$0.02 per share) compared to net income of \$1,683,415 (\$0.12 per share) for the same period in 2008.

The decrease in net income is due to a 41% reduction in oil and gas revenues. The decrease in total revenues is attributed to the economic factors affecting the global price for crude oil and the North American price for natural gas. Offsetting the decline in prices was a modest increase in overall sales volume of 2% as a result of having a full 12 months of production from the Mikwan property in Alberta.

Favourable variances resulted in several expense categories to help offset the unfavourable impact from crude oil and natural gas revenues. Royalty expenses declined due to their variable relationship with sales while operating expenses declined due to lower than anticipated costs at the Mikwan operation.

General administrative costs increased marginally due in part to costs related to severance and other employee-related expenses while interest costs decreased from the prior year due to a continued reduction in bank indebtedness together with lower interest rates throughout the year.

The Company generated funds flow from operations of \$957,893 for 2009 compared to \$2,359,945 for 2008. The reduction in cash flow is a result of the impact from lower revenues. Despite this decline, overall cash flow was sufficient to internally fund the Company's capital expenditure program and contribute towards reducing bank indebtedness.



MANAGEMENT'S DISCUSSION AND ANALYSIS

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A summary of the items affecting the variance in net income are as follows:

	Favourable/(Unfavourable)	
	Sales volume (BOE)	\$000's
Net income November 30, 2008	54,084	1,683
Oil sales	(2,390)	(1,607)
Gas sales	3,522	(335)
Expenses:		
royalties		227
operating		112
depletion, accretion and amortization		35
general and administrative		(32)
interest		111
other expenses		139
Net income November 30, 2009	55,216	333

Selected Annual Information

\$ - except Sales Volume as indicated	2009	2008	2007
Total sales	2,763,803	4,706,154	3,512,953
Net income (loss)	333,317	1,683,415	369,742
EPS - basic	0.024	0.122	0.027
EPS - diluted	0.024	0.118	0.026
Sales volume (BOE)	55,216	54,084	55,783
Total assets	11,197,365	11,159,785	11,084,878
Bank indebtedness	2,247,654	2,485,409	4,042,545
Funds flow from operations	957,893	2,359,945	1,268,751

EPS = Earnings per share

Results of Operations

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 together with the Canada/U.S. exchange rate. An increase in the value of the Canadian dollar negatively impacts price realizations. During the fiscal 2009 period the value of the Canadian dollar relative to the U.S. dollar increased from \$0.8031 to \$0.9473. By comparison, the Canadian dollar relative to the U.S. dollar decreased from \$1.00 to \$0.8031 during the fiscal 2008 period.



Sales summary

In 2009, total sales decreased by \$1,942,351 to \$2,763,803 compared to \$4,706,154 in 2008. Total sales volumes in 2009 increased to 55,216 BOE (151.3 BOE/d) compared to 54,084 (147.8 BOE/d) in 2008. The increase in overall sales volume is a result of having a full year of production from the Mikwan project in Alberta.

The Company received an average price of \$50.05 per BOE in 2009 compared to an average price of \$87.02 per BOE in 2008. The decrease of 42.5% is a result of both the impact from a stronger Canadian dollar relative to the U.S. dollar and the impact from economic factors that influence the global price for crude oil and the North American price for natural gas.

The following table details the oil and gas sales volumes and values for the year ending November 30th.

	November 30		
	2009	2008	2007
Oil volumes - bbl	35,509	37,899	40,991
Gross oil sales \$	2,148,279	3,755,510	2,778,841
Crude oil price - \$/bbl	60.50	99.09	67.79
Natural gas volumes - Mcf	118,239	97,099	88,748
Gross natural gas sales \$	615,524	950,644	734,112
Natural gas price - \$/Mcf	5.21	9.79	8.27

Crude Oil Sales:

Crude oil sales decreased 42.8% in 2009 to \$2,148,279 compared to \$3,755,510 in 2008. This decrease is a result of a modest and normal decline in sales volume of 6.3% together with a much larger impact from the decline in the world price for crude oil.

In 2009, sales volume decreased to 35,509 bbl (97.3 bbl/d) from 37,899 bbl (103.6 bbl/d) in 2008. The decrease in volume is considered to be within the normal decline of the Company's oil reserves and there were no unexpected or material interruptions in production.

The Company received an average price of \$60.50/bbl in 2009 compared to an average price of \$99.09/bbl in 2008. While the average price per barrel of oil declined by 38.9% in 2009, the spot price received in November 2009 was \$77.62 compared to \$60.00 in November 2008. The Company continues to be exposed to the volatility of commodity prices and foreign exchange. The impact on revenue from its crude oil production is approximately \$35,000 for each \$1.00 change in the Company's realized price for crude oil.



Natural Gas Sales:

Natural gas sales decreased 35.3% in 2009 to \$615,524 compared to \$950,644 in 2008. This decrease is a result of a 46.8% decline in the average price per Mcf for natural gas. In 2009, the Company received an average price of \$5.21 per Mcf compared to an average price of \$9.79 in 2008.

The overall decrease in natural gas sales was softened by the impact of having a full twelve months of production revenue from its working interest in the Mikwan project located in Alberta. In 2009, sales volume increased to 118,239 Mcf (323.9 Mcf/d) from 97,099 Mcf (265.3 Mcf/d). The increase in volume was 21.8% higher than 2008. The impact on revenue from its natural gas production is approximately \$118,000 for each \$1.00 change in the Company's realized price for natural gas.

Expenses:

Overall expenses decreased in 2009 to \$2,118,726 from \$2,483,625 in 2008.

The most significant decrease was realized in royalty expenses which decreased \$226,830 to \$388,339 in 2009 from \$615,169 in 2008. This decrease is a result of the variable relationship that royalties have with sales of crude oil and natural gas.

Royalty burdens are comprised of freehold and overriding royalties, along with Crown royalties that are specifically related to the Mikwan Alberta assets. Natural gas royalty rates increased due to overriding royalties from the Mikwan area following the execution of a novation agreement with the operator. Oil royalties decreased moderately as a result of the Warwick well being shut-in (which carries a 10% overriding royalty) for approximately six months.



Royalty expenses expressed per BOE will show greater fluctuation due to the greater change in royalty expenses relative to production levels which historically show less volatility.

\$ - except as indicated	Year ended November 30		
	2009	2008	2007
OIL			
Royalties - \$	275,088	499,314	364,015
Royalties - % of revenue	12.81	13.30	13.10
Royalties - \$ per BOE	7.75	13.19	8.88
GAS			
Royalties - \$	113,251	115,855	88,551
Royalties - % of revenue	18.40	12.19	12.06
Royalties - \$ per BOE	5.75	7.16	5.99
TOTAL			
Royalties - \$	388,339	615,169	452,566
Royalties - % of revenue	14.05	13.07	12.88
Royalties - \$ per BOE	7.03	11.38	8.11

Operating expenses decreased to \$616,002 in 2009 compared to \$728,014 in 2008. This decrease was due to a minimal number of equipment breakdowns, minor workovers and more significantly, lower than anticipated operating costs related to the Mikwan property.

General and administrative expenses increased by \$31,955 to \$717,698 in 2009 from \$685,743 in 2008. The increase in 2009 was due largely to the recognition of a severance and its related expenses together with some moderate increases to other personnel related costs.

Interest expense decreased to \$93,117 in 2009 compared to \$203,752 in 2008 due to lower interest rates throughout the year and a reduction to the overall bank indebtedness.

Other expenses represent the impact of periodic settlement costs relating to well abandonments. The corresponding decrease of approximately \$140,000 in 2009 represents the absence of these types of expenses during 2009.

Funds flow from operations

Despite the dramatic fluctuation of global prices of crude oil and the reduction in North American natural gas prices, the Company continues to generate positive funds flow from operations which have been used to reduce bank indebtedness, fund the Company's working capital requirements and internally fund the Company's



current capital expenditure projects. Funds flow from operations decreased in 2009 to \$957,893 from \$2,359,945 in 2008. The decrease is a result of lower commodity prices and their influence on net income together with modest changes in working capital components. Funds flow from operations is calculated as follows:

\$, except as indicated	2009	2008	2007
Cash provided by operating activities	861,414	2,490,531	1,119,645
Impact of non-cash working capital items	96,479	(130,586)	149,106
Funds flow from operations	957,893	2,359,945	1,268,751

Field level cash flow

In 2009, field level cash flow decreased 47.7% to \$1,759,462 from \$3,362,971 in 2008. The decrease is attributed to lower revenues net of royalty expense that occurred from lower commodity prices. The impact from lower commodity prices was tempered by a decrease in operating expenses due to lower than anticipated operating costs at the Mikwan properties. The calculation of field level cash flow is summarized as follows:

\$, except as indicated	Year ended November 30		
	2009	2008	2007
Oil and natural gas sales	2,763,803	4,706,154	3,512,953
Royalty expense	(388,339)	(615,169)	(452,566)
Net sales	2,375,464	4,090,985	3,060,387
Operating expenses	(616,002)	(728,014)	(747,992)
Field level cash flow	1,759,462	3,362,971	2,312,395
Per share - basic	0.127	0.243	0.167
Per share - diluted	0.126	0.235	0.163

Operating netbacks

Operating netbacks provide the unit revenue and unit costs on a BOE basis for items related to field level cash flow. In 2009 operating netbacks decreased 48.8% to \$31.86/BOE compared to \$62.19/BOE in 2008. The reasons for the decrease in operating expenses/BOE are noted above. In 2009, the operating costs per BOE for wells operated by the Company averaged \$9.31 compared to operating costs of \$13.87 per BOE for non-operated wells. In 2008, the operating costs per BOE for wells operated by the Company averaged \$9.40 compared to \$18.10 per BOE for non-operated wells. The decrease in operating costs for non-operated wells is also a result of lower than anticipated operating costs related to the Mikwan properties.



\$/BOE	Year ended November 30		
	2009	2008	2007
Oil sales	60.50	99.09	67.79
Natural gas sales	31.23	58.74	49.63
Total sales	50.05	87.02	62.98
Royalty expense	(7.03)	(11.37)	(8.11)
Operating expenses	(11.16)	(13.46)	(13.41)
Netback	31.86	62.19	41.46

Depletion, amortization & accretion expenses

Depletion, amortization and accretion decreased to \$691,109 in 2009 compared to \$725,760 in 2008. The calculation of depletion is based upon the units of production method which is dependent upon certain assumptions involving the estimated gross proved reserves as determined by independent petroleum engineers and other economic factors. The recorded decreases in depletion and accretion are a result of these changing assumptions and estimates.

Asset retirement obligation (ARO)

The fair value 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. There are no asset retirement liabilities set up for those assets which have an indeterminate useful life.

The undiscounted amount of expected cash flows required to settle the asset retirement obligation is estimated at \$1,927,693 (2008 - \$1,544,668). The liability for the expected cash flows, as reflected in the financial statements, has been discounted at 9% and includes a 2.0% inflation factor (1.0% - 2008).

The continuity of the Company's liability is as follows:

\$, except as indicated	Year ended November 30		
	2009	2008	2007
Asset retirement obligation, beginning of the period	427,843	574,469	665,852
Change in estimate	(64,653)	(116,636)	(93,099)
Liabilities settled - other expenses	800	140,356	32,953
Asset retirement costs incurred	(2,678)	(189,587)	(87,997)
Accretion	72,372	19,241	56,760
Asset retirement obligation, end of period	433,684	427,843	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 mainly from the Company's cash provided by operating activities. Over the next five years, approximately 14% of the costs will be incurred and the remainder from 2015 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.

In respect of future abandonment commitments, the Company is required by statute to establish a bond with a Trustee relating to a Trust Agreement with the Ontario Ministry of Natural Resources as the beneficiary. As at November 30, 2009, the balance of this bond was \$70,000.

Income taxes

The Company uses the liability method to account for income taxes. Under this method, future tax assets and liabilities are determined based upon differences between the financial reporting and tax bases of assets and liabilities, and measured using the substantively enacted tax rates and laws that will be in effect when the differences are expected to reverse. The Company has approximately \$8.5 million in tax pools together with approximately \$4.8 million in successor tax pools available to recognize against potential taxable income. The potential income tax benefits associated with unutilized tax pools have been recognized to the extent of reducing future tax liabilities and thus no tax provision has been made.

Selected Quarterly Information

Last eight quarters \$000s, except as indicated	2009				2008			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Total sales	724.0	736.2	690.9	612.7	1,102.3	1,399.7	1,253.7	950.4
Net income (loss)	254.9	98.7	30.8	(51.1)	180.9	659.1	549.1	294.3
EPS - basic (\$)	0.019	0.007	0.002	(0.004)	0.013	0.048	0.040	0.021
EPS - diluted (\$)	0.019	0.007	0.002	(0.004)	0.013	0.046	0.039	0.021
Sales volume (BOE)	12,818	13,718	14,161	14,519	16,061	12,667	13,046	12,261
Total assets	11,197	11,138	11,171	11,174	11,160	11,449	11,224	10,964
Bank indebtedness	2,248	2,319	2,438	2,504	2,485	2,885	3,238	3,663
Funds flow from operations	473.8	260.9	187.0	36.2	343.1	820.5	733.4	462.9

EPS = Earnings per share

Liquidity

Liquidity is a measure of whether the Company will be in a position to meet its financial obligations as they come due.



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The Company's working capital deficit decreased by \$357,475 to \$2,234,653 in 2009 from \$2,592,128 in 2008. This decrease is a result of utilizing cash flow from operations to retire a portion of the bank debt after funding working capital and capital expenditure requirements.

On April 29, 2009 the Company established a revised credit facility in the amount of \$6,100,000. The credit facility provides the Company with a revolving demand loan bearing interest payable monthly at the bank's prime lending rate plus 1.50%. As at November 30, 2009, the bank's prime lending rate was 2.25%. The loan is collateralized by a General Assignment of Book Debts together with a fixed and floating \$20,000,000 debenture over all the Company's assets. The bank has not waived its right to demand repayment of the outstanding principal balance and consequently the entire balance has been shown as a current liability.

At November 30, 2009, bank indebtedness was \$ 2,247,654 as follows:

	2009 (\$)	2008 (\$)
Overdraft/(Cash)	(2,346)	160,409
Demand Loan	2,250,000	2,325,000
Ending balance	2,247,654	2,485,409

The Company's accounts receivable will come due within approximately 30 days of the balance sheet date while the Company's accounts payable and accrued liabilities will come due within 60 days of the balance sheet date.

At November 30, 2009, \$2,250,000 of funds had been drawn against the credit facility of \$6,100,000, leaving an available credit of \$3,850,000. In the short term, the Company is expected to meet its liabilities as they come due and comply with all banking covenants although additional financing may be required to rectify the working capital deficit.

Capital Resources

Presently, the Company's production mix is weighted at approximately 65% in respect of crude oil production and approximately 35% in respect of natural gas. In 2009, despite lower average prices for crude oil, the Company was successful in funding working capital requirements, funding its capital expenditure program and reducing overall bank indebtedness. In the short term, the world wide price for crude oil has increased approximately \$15-\$20 per barrel from the 2009 average. Based upon these existing conditions, the Company believes that sufficient cash will be generated to successfully fund its working capital requirements, capital expenditure programs and reduce bank indebtedness. The Company will continue to be exposed to the risk associated with any further changes in the world wide price for crude oil and the North American price for



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natural gas and foreign exchange. For this and other forward looking statements, please refer to the section titled *Forward Looking Statements* on page 1.

At November 30, 2009, the available credit is \$3,850,000 (2008 - \$3,775,000) as follows:

	2009 (\$)	2008 (\$)
Authorized	6,100,000	6,100,000
Demand loan at November 30	2,250,000	2,325,000
Available credit at November 30	3,850,000	3,775,000

Presently, the Company is in the process of renewing the credit facility and expects to have this completed consistent with the current arrangement. For this and other forward looking statements, please refer to the section titled *Forward Looking Statements* on page 1.

The Company is not under any existing contractual commitments relating to its capital expenditure program for 2010 although the Company does anticipate capital spending amounts to reach similar levels as tabled below:

(\$000)	Fiscal year		
	2009	2008	2007
Balance December 1	18,134	17,282	16,787
Canadian expenditures:			
Lease and land acquisitions	282	187	242
Geological & geophysical	111	205	59
Drilling, completion and workovers	146	251	194
Equipping and facilities	3	208	(14)
Capitalized administration and other	116	118	107
Subtotal	658	969	588
Asset retirement obligation adjustment	(65)	(117)	(93)
Disposition of oil and gas properties	0	0	0
Net Canadian Expenditures	593	852	495
Balance November 30	18,727	18,134	17,282

The Company's capital expenditures in 2009 were primarily related to the Company's investment in the S.W. Ontario basin.

In 2009, the Company funded its capital expenditure program from internal sources. The Company expects to fund its 2010 expenditures from unencumbered cash flow and may also utilize the available bank credit facility.



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

Year	\$
2010	49,186
2011	16,585
2012	5,707
2013	5,707
2014	-

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 2010 fiscal year any off-balance sheet arrangements.

Transactions with related parties

During the year ended November 30, 2009, \$30,000 (2008 - \$30,000) was paid for office facilities and administrative services to a company (Ionic Management Corp.) related by virtue of a common director (Brian E. Bayley).

Fourth Quarter

During the fourth quarter, net revenue remained relatively consistent with the prior two quarters as the Company continued to benefit from rising prices for its crude oil production. In the quarter, the Company received an average of \$75.26/bbl for its oil production and an average of \$4.03/Mcf for its natural gas production. There was a small work-over project completed in the Corey East field that did cause a minor interruption in oil production. At the same, the project to repair the production casing leak at Warwick 6-17-IV was completed and production commenced at the beginning of October 2009. As a result, fourth quarter production was the lowest production quarter for the fiscal year. The Company was able to record some modest recoveries in



operating costs together with overall lower general and administrative costs. Operating cost reductions were a result of adjustments to reflect the actual costs versus anticipated costs related to the Mikwan project while general and administrative expenses in the quarter were lower due to lower personnel related costs.

Critical Accounting Estimates

The preparation of the financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the amounts reported in the 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 barrel 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 expected 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 and probable 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.

New Accounting Standards

The Accounting Standards Board, Canadian Institute of Chartered Accountants ("CICA") has announced that Canadian publicly accountable enterprises must adopt International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board effective for fiscal years beginning on or after January 1, 2011. Reporting in IFRS by the Company will commence in the first quarter of the Company's 2012 fiscal year with comparative figures. The Company will follow a four key phase approach to ensure successful conversion to International Financial Reporting Standards as follows:

- IFRS diagnostic impact assessment
- Design and Planning
- Solution development
- Implementation

1. IFRS diagnostic impact assessment

Perform a review to identify the differences between GAAP as used by the Company, and IFRS.

Status: This phase is in progress. Initial findings suggest that there may be several areas that may require a significant amount of effort to quantify the impact on the opening balance sheet and to put in place procedures and controls to efficiently and effectively address the particular IFRS difference on an ongoing basis.

2. Design and Planning

Results determined from the diagnostic assessment will be used to design and plan the conversion project.

Status: Not started. This phase is expected to commence during the second and third quarters of the fiscal 2010 year.

3. Solution development

This phase will assess the changes required to accounting and business systems in order to transition to IFRS. It will include accounting policy changes and changes to internal processes as required throughout the Company.



Status: Not started. This phase is expected to commence during the second and third quarters of the fiscal 2010 year.

4. Implementation

This final phase will implement the solutions identified in Phase 3 sufficient to produce IFRS-compliant financial reporting.

Status: Not started. This phase is expected to commence during fourth quarter of the fiscal 2010 year.

It is not practically possible at this time to quantify the impact of these differences. The Company expects to make changes to processes and systems before the 2011 fiscal year, in time to enable the Company to record transactions under IFRS for comparative purposes in the 2012 financial year reporting.

Financial Instruments and Other Instruments

Business risks

The Company's business is the acquisition, exploration, development and any other opportunities related to the operation and production of oil and natural gas properties. In addition, the Company is exposed to a number of risks. Please refer to Note 13 of the Financial Statements for the assessment of such risks.

Controls and procedures

During 2009, there were no changes to internal controls over financial reporting that have materially affected, or are reasonably likely to materially affect, the Company's internal controls over financial reporting.

Outstanding share data

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

	2009	
	Shares	Amount
Common shares outstanding	13,837,698	\$12,143,910



Stock Options:

As at November 30, 2009, options to purchase 880,000 shares were outstanding. All options are fully vested and exercisable at a weighted average price of \$0.10 per share. During the year, no new options were granted and options to purchase 300,000 shares were forfeited.

Basic and Diluted Share Amounts

	2009
Weighted average number of shares outstanding	13,837,698
Shares issuable pursuant to stock options	161,452
Weighted average number of diluted shares outstanding	13,999,150

Outlook

Management continues to evaluate the Company's asset base of producing and exploration properties in its mandate to improve shareholder value with minimal increase in debt or incurring excessive shareholder dilution. Initial results have been encouraging. For this and other forward looking statements, please refer to the section titled *Forward Looking Statements* on page 1.

Development Operations:

As a result of this review of the Company's assets, Management has initiated an assessment to determine their viability to function as commercial gas storage reservoirs. The Company has acquired 400 acres of petroleum and natural gas and storage rights at 100% working interest adjacent to one of its current producing properties. The Company reprocessed and interpreted nine lines of in-house seismic with encouraging results. To further delineate the reefal structure, an additional four line seismic program was designed and shot in mid-February 2010. These lines are currently being processed and the Company's geophysicist will then interpret and present his report in early April.

In February 2009 the Warwick 6-17-IV (50% working interest or net three BOE/day) developed a production casing leak and a bridge plug was set to shut off the flow of water into the reservoir. The Company reached an agreement with its joint venture partner to remedy this leak on July 6, 2009. The operation began September 8, 2009 and was completed successfully on September 21, 2009 and on budget. Current production is 13 bbl/d of fluid with an oil cut of 40% or 5.44bbl/d of oil compared with 6.92bbl/d of fluid with an oil cut of 100% or 6.92bbl/d of oil before the casing leak.



In the Mikwan area of Alberta, the Company participated in the drilling of a fourth gas well in February 2009, with tie-in to the Encana Lousana compressor site in March 2009. Initial production averaged 100 Mcf/d (25 Mcf/d net).

Management is continuing to perform economic and pressure evaluations at Ram #91 and Reefex #1, (both shut-in gas wells). In late August 2009 a wire line test at Ram #91 showed that the wellbore was filled with natural gas and reservoir fluid indicating a reservoir with additional recoverable gas reserves nearby. The Company performed a production test of this well in December 2009 to measure the open flow potential for natural gas. The results of this test established there are reserves associated with this well but the daily production flow does not warrant the capital costs to tie this well into the market pipeline grid. The Company is currently evaluating other opportunities for this well. The Company moved the testing equipment to the Reefex #1 well in late January 2010 and began the production test in mid-February, 2010. The production test and results for the Reefex #1 well should be completed by early to mid-April 2010.

Exploration:

In late July 2009, the Company's management initiated a review of all the historical exploration and seismic information which had been stored off site. Torque's corporate acquisitions over time have allowed it to create one of the most extensive proprietary exploration database available to anyone in the Ontario industry. A number of excellent prospects have been revealed and are currently in the acquisition process. This is proving to be a low cost, potentially high return, and internally driven enhancement of Torque assets.

One of these prospects was an over-looked pinnacle reef type play with five in-house processed lines of seismic. The Company has leased the key 800 acres. The Company's geophysicist reviewed four existing lines of in-house seismic and designed one additional 2.16 kilometre line through the center of the feature. In early February 2010 this line of seismic was shot. It is currently being processed and the Company's geophysicist will then interpret and present his report in early April 2010.

The Company continues to refine its eight oil and gas prospects and has acquired 3,002 acres of petroleum and natural gas rights at 100% working interest in the Dunwich-Southwold prospect area of Ontario. This prospect and an additional seven prospects also located in south-western Ontario were originally identified using high resolution geophysics. The Company has completed the SGH (soil gas hydrocarbon) sampling survey and has integrated these results into the geological/geophysical models to form a geological assessment report on each of these prospects. The Company is currently designing a program to infill areas on which it does not have any SGH information. Once this sampling survey and results are tabulated a seismic program will be designed. The program is planned to be shot in September 2010.



Reserves

VON Resource Management Ltd. (VON) of Calgary, Alberta, independent petroleum consultants prepared a report dated March 24, 2010 in which VON evaluated, effective November 30, 2009, the quantity and estimated future cash flow of the Company's total estimated proved and probable Canadian reserves.

Reserve estimates of the properties were determined in accordance with the reserve classification, definitions and procedures outlined under the National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* of the Canadian Securities Administrators 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, 2009 were 759 thousand BOE, "MBOE", (November 30, 2008 was 830 MBOE). Company gross probable additional reserves of 90 MBOE were also assigned to these producing properties, for a Proved plus Probable (2P) total of 849 MBOE (November 30, 2008 was 929 MBOE). For this and other forward looking statements, please refer to the section titled *Forward Looking Statements* on page 1.



Reserves Data (Forecast Prices and Costs)

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, 2009, using forecast prices and costs.

Oil, Natural Gas and Natural Gas Liquids Reserves and Present Value of Estimated Future Cash Flows Based on Forecast Price and Cost Assumptions Effective as of November 30, 2009

	Oil		Gas		MBOE	
	<i>(Mstb)</i>		<i>(MMcf)</i>			
	Gross	Net	Gross	Net	Gross	Net
Proved Producing	553	477	1,238	1,080	759	657
Proved Developed Non-Producing	0	0	0	0	0	0
Proved Undeveloped	0	0	0	0	0	0
Total Proved	553	477	1,238	1,080	759	657
Probable	62	55	166	136	90	77
Total Proved plus Probable	615	532	1,404	1,216	849	734

Mstb = Thousand stock tank barrels MMcf = Million cubic feet

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	50.808	25.951	17.396	13.280	10.857	42.648	23.006	15.980	12.482	10.365
PDNP *	-0.201	-0.169	-0.147	-0.132	-0.119	-0.248	-0.202	-0.170	-0.149	-0.132
PUD	0	0	0	0	0	0	0	0	0	0
Proved	50.607	25.782	17.249	13.148	10.738	42.400	22.804	15.810	12.333	10.233
Probable	9.607	2.873	1.258	0.713	0.472	7.552	2.272	1.004	0.577	0.388
Total Proved Plus Probable	60.214	28.655	18.507	13.861	11.210	49.952	25.076	16.814	12.910	10.621

* Includes 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, 2009
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	78,985	10,747	16,189	0	1442	50,607	8,207	42,400
Proved Plus Probable Reserves	90,039	12,156	16,205	0	1464	60,214	10,262	49,952

**Future Net Revenue by Production Group effective as of November 30, 2009
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-products)*	15,578	30
	Natural Gas (including by-products but excluding solution gas from oil wells)	1,671	12
	Total	17,249	26
Proved Plus Probable Reserves	Light and medium crude oil (including solution gas and other by-products)*	16,508	29
	Natural Gas (including by-products but excluding solution gas from oil wells)	1,999	12
	Total	18,507	25

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

Reserves Data (Constant Prices and Costs)

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, 2009, using constant prices and costs.



Oil, Natural Gas and Natural Gas Liquids Reserves and Present Value of Estimated Future Cash Flows Based on Constant Price and Cost Assumptions Effective as of November 30, 2009

	Oil		Gas		MBOE	
	<i>(Mstb)</i>		<i>(MMcf)</i>		Gross	Net
	Gross	Net	Gross	Net		
Proved Producing	550	475	821	710	687	593
Proved Developed Non-Producing	0	0	0	0	0	0
Proved Undeveloped	0	0	0	0	0	0
Total Proved	550	475	821	710	687	593
Probable	63	54	164	138	90	78
Total Proved Plus Probable	613	529	985	848	777	671

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	29.858	17.400	12.470	9.877	8.267	26.607	16.274	11.977	9.629	8.131
PDNP *	-0.188	-0.160	-0.140	-0.126	-0.115	-0.232	-0.187	-0.158	-0.138	-0.122
PUD	0	0	0	0	0	0	0	0	0	0
Proved	29.670	17.240	12.330	9.751	8.152	26.375	16.087	11.819	9.491	8.009
Probable	4.653	1.541	0.722	0.424	0.286	3.659	1.227	0.588	0.355	0.245
Total Proved Plus Probable	34.323	18.781	13.052	10.175	8.438	30.034	17.314	12.407	9.846	8.254

* Includes Abandonment and Surface Reclamation Liability net of Salvage Value for all non-producing wells.

**Total Future Net Revenue (Undiscounted) effective as of November 30, 2009
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	45,554	6,195	8,824	0	866	29,670	3,295	26,375
Proved Plus Probable Reserves	50,980	6,878	8,913	0	866	34,323	4,289	30,034



**Future Net Revenue by Production Group effective as of November 30, 2009
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)*	11,707	23
	Natural Gas (including by-products by excluding solution gas from oil wells)	623	7
	Total	12,330	21
Proved Plus Probable Reserves	Light and medium crude oil (including solution gas and other by-products)*	12,296	22
	Natural Gas (including by-products but excluding solution gas from oil wells)	756	7
	Total	13,052	19

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

Pricing Assumptions

VON, in its evaluation, used the November 30, 2009 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, 2009
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 F2009	63.46	4.21	0.87	4.85	4.31	58.70	5.00
November 2009	78.48	4.29	0.94	4.54	4.95	75.53	5.08
December 2009	85.79	4.61	0.90	5.12	4.07	82.11	4.72
2010	89.60	5.40	0.90	6.00	4.95	85.91	5.46
2011	90.91	6.36	0.93	6.88	5.83	87.21	6.32
2012	93.05	6.72	0.93	7.26	6.21	89.24	6.72
2013	94.97	8.12	0.95	8.55	7.50	91.26	7.98
2014	96.89	8.28	0.95	8.72	7.67	93.15	8.24
2015	98.85	8.45	0.95	8.89	7.84	95.10	8.50
2016	100.84	8.62	0.95	9.07	8.02	97.07	8.71
2017	+2.0%/year	+2.0%/year	0.95	+2.0%/year	+2.0%/year	+2.0%/year	+2.0%/year

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

VON used the Sproule Associates Limited November 30, 2009 price forecast for its evaluation of the Torque properties.

- (1) In the escalated pricing determination, operating & capital costs were increased 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.\$78.48/bbl and the Natural Gas Henry Hub price was held constant at U.S.\$4.29/Mcf for the Ontario properties, and the Natural Gas AECO price was held constant at Cdn.\$4.95/Mcf for the Alberta properties, with corresponding Company differentials applied.
- (3) The \$U.S./\$Cdn. Exchange rate is assumed to be 0.94 in Nov-09, 0.90 in 2009-10, 0.93 in 2011-12, and 0.95 in 2013 and thereafter.
- (4) In the course of the November 30, 2009 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 complete 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.

Reserves Reconciliation

The following table provides a continuity of Company gross reserves from the November 30, 2007 reserves determination to the November 30, 2009 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, 2007	551	101	652	1,056	193	1,249	727	133	860
Extensions & Improved Recovery	0	0	0	0	0	0	0	0	0
Technical Revisions	70	-26	44	216	-94	122	106	-42	64
Discoveries	0	0	0	313	45	358	52	8	60
Acquisitions	0	0	0	0	0	0	0	0	0
Dispositions	0	0	0	0	0	0	0	0	0
Economic Factors	0	0	0	0	0	0	0	0	0
Production	39	0	39	98	0	98	55	0	55
December 1, 2008	582	75	657	1,487	144	1,631	830	99	929
Extensions & Improved Recovery	0	0	0	0	0	0	0	0	0
Technical Revisions	6	-13	-7	-127	22	-105	-15	-9	-24
Discoveries	0	0	0	0	0	0	0	0	0
Acquisitions	0	0	0	0	0	0	0	0	0
Dispositions	0	0	0	0	0	0	0	0	0
Economic Factors	0	0	0	0	0	0	0	0	0
Production	35	0	35	122	0	122	56	0	56
December 1, 2009	553	62	615	1,238	166	1,404	759	90	849

There was some variability in the performance of the wells but by far the most significant factor in any technical changes to the reserves was the change in price forecasts from last year. Oil is stronger and gas is weaker, which has led to higher values in the oil properties and lower reserves and values in the gas properties.



Additional Information Relating to Reserves 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 Statement 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 Statement.

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, 2009.

	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	4	1.00	0	0.00	0	0.00	4	1.00
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	0	0.00	0	0.00	0	0.00	0	0.00
Ontario	3	2.24	2	2.00	0	0.00	2	1.00	7	5.24
<i>Total Wells</i>										
Alberta	0	0.00	4	1.00	0	0.00	0	0.00	4	1.00
Ontario	10	5.02	14	7.54	18	12.53	2	1.00	44	26.09
Total	10	5.02	18	8.54	18	12.53	2	1.00	48	27.09



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

Major Properties – F2009				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	0	0	0	0	3.0	2.8	1.0	0.9	4.0	3.8
Petrolia East	Ontario	Onshore	Battery	0	0	0	0	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

Properties With No Attributed Reserves

The following table lists the Company's undeveloped land position effective November 30, 2009.

Property	Province	Location	Gross Acres	Net Acres	Work Commitments
Mikwan	Alberta	Onshore	320	80	None
Ontario	Ontario	Onshore	18,063	13,229	Seismic

Forward Contracts

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.

Abandonment and Reclamation Costs

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, 2009. 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). Included in the values below are additional site restoration costs for the abandonment of 4 facilities totalling \$80,000.



Abandonment, Salvage & Site Restoration Summary (Constant Dollars)

Constant Dollars	0% Discount	10% Discount
48 Wells	M\$	M\$
Abandonment Cost	828	261
Site Restoration Cost	323	88
Total Liability	1,151	349
Salvage Value	270	103
Net Liability	881	246

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

Constant Dollars	0% Discount	10% Discount
9 Wells	M\$	M\$
Abandonment Cost	174	148
Site Restoration Cost	58	49
Total Liability	232	197
Salvage Value	64	55
Net Liability	168	142

Abandonment, Salvage & Site Restoration Summary (Escalated Dollars)

Escalated Dollars	0% Discount	10% Discount
48 Wells	M\$	M\$
Abandonment Cost	1,372	299
Site Restoration Cost	579	102
Total Liability	1,951	401
Salvage Value	404	117
Net Liability	1,547	284

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

Escalated Dollars	0% Discount	10% Discount
9 Wells	M\$	M\$
Abandonment Cost	179	153
Site Restoration Cost	60	51
Total Liability	239	204
Salvage Value	66	57
Net Liability	173	147



Reserves Categories and Levels Of Uncertainty For Reported Reserves

The following points need to be considered when reviewing the reserves information generated from the VON Resource Management Ltd. Evaluation of Certain Oil and Gas Properties of Torque Energy Inc. as of November 30, 2009.

Reserves Definitions

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 reserves 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.

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 judgement 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, 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.

Tax Horizon

Based on the price and expense projections in the VON Evaluation of Reserves as at November 30, 2009, the Company does not expect to pay income tax in the current fiscal year. With the tax pools available to the Company, and cash flows as projected, income taxes are not expected to become payable for the next 6 years. For this and other forward looking statements, please refer to the section titled *Forward Looking Statements* on page 1.

Costs Incurred

The following table summarizes the Company's capital expenditures for the year ended November 30, 2009.

Capital Expenditure	M\$
Property Acquisition Costs – Proved Properties	133
Property Acquisition Costs – Unproved Properties	149
Exploration Costs	111
Development Costs	146
Other Costs – (CCA, ARO)	54



Exploration and Development Activities

The following table summarizes the exploratory and development wells that the Company participated in during the year ended November 30, 2009.

	Exploratory Wells		Development Wells	
	Gross	Net	Gross	Net
Oil Wells	-	-	-	-
Gas Wells	-	-	1	0.25
Dry Holes	-	-	-	-
Total Wells	-	-	1	0.25

In the Mikwan area of Alberta, the Company participated in the drilling of a fourth gas well in February 2009, with tie-in to the Encana Lousana compressor site in March 2009. Initial production averaged 100 Mcf/d (25 Mcf/d net). The Mikwan field sales averaged a net 99 Mcf/d (16.5 BOE/d) to the Company for 2009.

Production Estimates

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 future net revenues forecast as at November 30, 2009.

Production Estimates for the First Year (F2010) reflected in the Estimates of Future Net Revenues – Major Properties and Company Total

Property	Province	W.I. OIL Mstb	W.I. GAS MMcf	W.I. MBOE	% of Total MBOE
Corey East	Ontario	10.2		10.2	21%
Petrolia East	Ontario	15.5		15.5	31%
Dover East	Ontario	4.3	33.1	9.8	20%
Other	Ontario	2.5	37.5	8.7	18%
Other	Alberta		32.3	5.4	11%
Total	Ontario & Alberta	32.5	102.9	49.6	100%



MANAGEMENT'S DISCUSSION AND ANALYSIS

March 29, 2010

Production History

The following table summarizes, for the year ended November 30, 2009, the Company's production volumes, revenue, prices received, operating expenses, royalties, and resulting netback in total and per unit of volume.

Fiscal 2009	Q1	/Day	Q2	/Day	Q3	/Day	Q4	/Day	Total F2009	/Day
VOLUME										
Oil Production – Mstb & bbl/d	9	103	9	98	9	99	8	89	36	97
Gas Production – MMcf & Mcf/d	31	350	31	335	28	300	28	311	118	324
MBOE (6:1) & BOE/d	14	161	14	154	14	149	13	141	55	151
REVENUES	M\$	\$/Unit	M\$	\$/Unit	M\$	\$/Unit	M\$	\$/Unit	M\$	\$/Unit
Oil Revenue	376	40.60	529	58.61	633	69.48	610	75.26	2,148	60.50
Less: Oil Royalties	48	5.21	65	7.16	81	8.88	81	10.03	275	7.75
Net Oil Revenue	328	35.39	464	51.45	552	60.59	529	65.24	1,873	52.75
Gas Revenue	236	7.50	162	5.26	103	3.72	114	4.03	616	5.21
Less: Gas Royalties	36	1.14	25	0.82	36	1.31	16	0.56	113	0.96
Net Gas Revenue	200	6.36	137	4.44	67	2.42	98	3.47	502	4.25
TOTAL NET REVENUE	528	36.39	601	42.44	619	45.13	627	48.91	2,375	43.02
Operating Expenses (excl. trans.)	190	13.05	181	12.81	100	7.23	57	4.45	527	9.55
Transportation	23	1.61	23	1.6	22	1.64	20	1.59	89	1.61
TOTAL OPERATING EXPENSES	213	14.66	204	14.41	122	8.87	77	6.04	616	11.16
FIELD LEVEL CASH FLOW	315	21.73	397	28.03	497	36.26	550	42.87	1,759	31.87
REVENUE \$/BOE	42.20		48.79		53.67		56.48		50.05	
ROYALTIES \$/BOE	5.81		6.35		8.54		7.57		7.03	
OPERATING COSTS \$/BOE	14.66		14.41		8.87		6.04		11.16	
NETBACK \$/BOE	21.73		28.03		36.26		42.87		31.86	

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

The following table lists, for each major field, and in total, the Company's production volumes for the year ended November 30, 2009.

Major Properties - F2009 Production

PROPERTY	PROVINCE	W.I. OIL Mstb	W.I. GAS MMcf	W.I. MBOE	% of Total MBOE
Corey East	Ontario	12.2		12.2	22%
Petrolia East	Ontario	16.3		16.3	30%
Dover East	Ontario	4.3	38.2	10.7	19%
Other	Ontario	2.7	43.8	10.0	18%
Other	Alberta		36.2	6.0	11%
TOTAL	Ontario & Alberta	35.5	118.2	55.2	100%