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F51-101F1

STATEMENT OF OIL AND GAS RESERVES DATA

AND OTHER OIL AND GAS INFORMATION

FOR THE YEAR ENDED NOVEMBER 30, 2007

TORQUE ENERGY INC.

FORM 51-101F1

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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, 2007.

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.

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PART 1 - DATE OF STATEMENT

The effective date for this Statement is November 30, 2007 and the information contained in the Statement has been prepared as of March 18, 2008.

PART 2 - DISCLOSURE OF RESERVES DATA

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.

2.1 - 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, 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	
	(Mstb)		*(MMcf)*			
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Proved Producing	551	477	1056	924	727	631
Proved Developed Non-Producing					0	0
Proved Undeveloped					0	0
Total Proved	**551**	**477**	**1056**	**924**	**727**	**631**
Probable	101	87	193	169	133	115
Total Proved plus Probable	**652**	**564**	**1249**	**1093**	**860**	**746**

Mstb = Thousand stock tank barrels

	Net Present Values of Future Net Revenue									
	Before Income Taxes Discount at (%/year)					After Income Taxes Discounted at (%/year)				
Reserve Category	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
Total Proved Plus Probable	**38.487**	**19.404**	**13.152**	**10.234**	**8.539**	**30.919**	**17.302**	**12.376**	**9.892**	**8.370**

**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*

2.2 - Supplemental Disclosure of 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, 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	
	(Mstb)		*(MMcf)*			
	Gross	Net	Gross	Net	Gross	Net
Proved Producing	558	483	1011	885	727	631
Proved Developed Non-Producing					0	0
Proved Undeveloped					0	0
Total Proved	**558**	**483**	**1011**	**885**	**727**	**631**
Probable	101	87	187	163	132	114
Total Proved Plus Probable	**659**	**570**	**1198**	**1048**	**859**	**745**

	Net Present Values of Future Net Revenue									
	Before Income Taxes Discount at (%/year)					After Income Taxes Discounted at (%/year)				
Reserve Category	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
Total Proved Plus Probable	**42.477**	**23.324**	**16.239**	**12.663**	**10.497**	**34.167**	**20.366**	**14.781**	**11.859**	**10.013**

**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*

PART 3 - PRICING ASSUMPTIONS

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.

PART 4 - RECONCILIATION OF CHANGES IN RESERVES

4.1 - Reserves Reconciliation

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 (Mstb)			Natural Gas (MMcf)			Barrels Oil Equivalent (MBOE)		
	Proved	Probable	Total	Proved	Probable	Total	Proved	Probable	Total
Opening, December 1, 2005	**493**		**493**	**1015**		**1015**	**662**		**662**
Extensions & Improved Recovery			-			-			-
Technical Revisions	**7**		**7**	**110**		**110**	**25**		**25**
Discoveries			-			-			-
Acquisitions			-			-			-
Dispositions			-			-			-
Economic Factors			-			-			-
Production	**41**		**41**	**89**		**89**	**56**		**56**
December 1, 2006	**459**		**459**	**1036**		**1036**	**632**		**632**
Extensions & Improved Recovery			-			-			-
Technical Revisions	**133**	**101**	**234**	**109**	**193**	**302**	**151**	**133**	**284**
Discoveries			-			-			-
Acquisitions			-			-			-
Dispositions			-			-			-
Economic Factors			-			-			-
Production	**41**		**41**	**89**		**89**	**56**		**56**
December 1, 2007	**551**	**101**	**652**	**1056**	**193**	**1249**	**727**	**133**	**860**

PART 5 - 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.

PART 6 - OTHER OIL AND GAS INFORMATION

6.1 - 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
Producing Wells										
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
Non-Producing Wells										
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
Total Wells										
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
Total	10	5.02	19	9.66	20	13.03	0	0.00	49	27.70

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

Major Properties – F2007				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

6.2 - Properties With No Attributed Reserves

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

6.3 - 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.

6.4 - Additional Information Concerning 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, 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)

Constant Dollars	0% Discount	10% Discount
50 Wells	M$	M$
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)

Constant Dollars	0% Discount	10% Discount
20 Wells	M$	M$
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)

Escalated Dollars	0% Discount	10% Discount
50 Wells	M$	M$
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)

Escalated Dollars	0% Discount	10% Discount
20 Wells	M$	M$
Abandonment Cost	336	255
Site Restoration Cost	122	95
Total Liability	458	350
Salvage Value	119	90
Net Liability	339	260

6.5 - Tax Horizon

Based on the price and expense projections in the VON Evaluation of Reserves as at November 30, 2007, 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 10 years.

6.6 - Costs Incurred

The following table summarizes the Company's capital expenditures for the year ended November 30, 2007.

Capital Expenditure	M$
Property Acquisition Costs – Proved Properties	-
Property Acquisition Costs – Unproved Properties	242
Exploration Costs	239
Development Costs	107

6.7 - Exploration and Development Activities

The following table summarizes the exploratory and development wells that the Company participated in during the year ended November 30, 2007.

	Exploratory Wells		Development Wells	
	Gross	Net	Gross	Net
Oil Wells	-	-	-	-
Gas Wells	-	-	1	0.25
Dry Holes	2	0.73	-	-
Total Wells	2	0.73	1	0.25

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.

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% w.i. (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.

6.8 - 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, 2007.

Production Estimates for the First Year (F2008) 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	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%

6.9 - 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	/Unit	Q2	/Unit	Q3	/Unit	Q4	/Unit	Total F2007	/Unit
VOLUME										
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
REVENUES	**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
TOTAL OPERATING EXPENSES	235	18.68	195	12.67	156	10.83	162	12.07	748	13.41
NET FIELD LEVEL INCOME	400	31.78	639	41.51	650	45.25	623	46.38	2,312	41.45
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.*

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

Major Properties - F2007 Production

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%