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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, 2008

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, 2008.

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, 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.

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PART 1 - DATE OF STATEMENT

The effective date for this Statement is November 30, 2008 and the information contained in the Statement has been prepared as of March 20, 2009.

PART 2 - DISCLOSURE OF RESERVES DATA

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

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

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

Provision for abandonment and site reclamation costs has been included in the cash flow analysis, as well as the offsetting salvage value of tangible equipment after the well abandonment, based on data provided by the company. However, no provision has been made for facility abandonment, reclamation and salvage value. In addition to the abandonment and reclamation liability for 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, 2008 were 830 MBOE (November 30, 2007 were 727 MBOE). The increase of 14% is due to positive revisions of 158 MBOE based on well performance taken into account during the decline curve analysis, and the addition of 4 wells that came on production during the year. Company gross probable additional reserves of 99 MBOE were also assigned to these producing properties, for a Proved plus Probable (2P) total of 929 MBOE.

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, 2008, using forecast prices and costs.

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

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

Mstb = Thousand stock tank barrels

	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	44.908	24.954	17.399	13.545	11.199	35.509	21.316	15.579	12.496	10.543
PDNP *	0.084	0.062	0.045	0.030	0.019	(0.088)	(0.062)	(0.048)	(0.039)	(0.035)
PUD										
Proved	44.992	25.016	17.444	13.575	11.218	35.421	21.254	15.531	12.457	10.508
Probable	8.220	2.515	1.156	0.689	0.477	5.625	1.739	0.816	0.499	0.356
Total Proved Plus Probable	**53.212**	**27.531**	**18.600**	**14.264**	**11.695**	**41.046**	**22.993**	**16.347**	**12.956**	**10.864**

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

PP = Proved Producing
PDNP = Proved Developed Non-Producing
PUD = Proved Undeveloped

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

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

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

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

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

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, 2008, using constant prices and costs.

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

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

	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	24.647	15.095	11.093	8.914	7.532	21.899	14.296	10.803	8.793	7.477
PDNP *	0.021	0.012	0.003	(0.005)	(0.011)	(0.127)	(0.067)	(0.040)	(0.029)	(0.026)
PUD										
Proved	24.668	15.107	11.096	8.909	7.521	21.772	14.229	10.763	8.764	7.451
Probable	4.409	1.469	0.725	0.454	0.326	3.020	1.051	0.555	0.372	0.282
Total Proved Plus Probable	**29.077**	**16.576**	**11.821**	**9.363**	**7.847**	**24.792**	**15.280**	**11.318**	**9.136**	**7.733**

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

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

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

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

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

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

PART 3 - PRICING ASSUMPTIONS

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

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

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

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

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

(1) In the escalated pricing determination, operating and capital costs are assumed to increase at 1.0% per year.

(2) Under the constant price scenario, prices and costs are held constant for the life of the reserves. The Crude Oil at Edmonton price was held constant at Cdn.$63.89/bbl and the Natural Gas Henry Hub price was held constant at U.S.$6.47/Mcf for the Ontario properties, and the Natural Gas AECO price was held constant at Cdn.$6.92/Mcf for the Alberta properties.

(3) The $U.S./$Cdn. Exchange rate is assumed to be 0.82 in Nov-08, 0.80 in 2008-09, 0.85 in 2010-11, and 0.95 in 2012 and thereafter.

(4) In the course of the November 30, 2008 evaluation, Torque provided VON personnel with basic information which included land data, well information, geological information, contract information, operating cost data, financial data and discussions of future operating plans. Other engineering, geological or economic data required in order to conduct the evaluation and upon which the VON Report are based, was obtained from public records, other operators, and from VON non-confidential files. The extent and character of ownership and accuracy of all factual data supplied for the independent evaluation, from all sources, has been accepted as represented. The accuracy of any reserves and production estimate is a function of the quality and quantity of available data, engineering interpretation and judgement. While reserves and production estimates presented herein were considered reasonable at the time they were prepared, the estimates should be accepted with the understanding that reservoir performance subsequent to the date of the estimate may justify revision, either upward or downward. Revenue projections presented in the VON Report are based in part on forecasts of market prices, currency exchange rates, inflation, market demand and government policy which are subject to many uncertainties and may, in future, differ materially from the forecasts utilized in the VON Report. Present values of revenues documented in the VON Report do not necessarily represent the fair market value of the reserves evaluated therein.

(5) Columns may not add due to rounding.

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, 2006 reserves determination to the November 30, 2008 reserves determination:

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

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, 2008.

	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	3	0.75	0	0.00	0	0.00	3	0.75
Ontario	7	2.78	12	5.54	18	12.53	0	0.00	37	20.84
Non-Producing Wells										
Alberta	0	0.00	4	1.27	0	0.00	0	0.00	4	1.27
Ontario	3	2.24	2	2.00	0	0.00	2	1.00	7	5.24
Total Wells										
Alberta	0	0.00	7	2.02	0	0.00	0	0.00	7	2.02
Ontario	10	5.02	14	7.54	18	12.53	2	1.00	44	26.09
Total	**10**	**5.02**	**21**	**9.56**	**18**	**12.53**	**2**	**1.00**	**51**	**28.10**

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

Major Properties – F2008				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, 2008.

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

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, 2008. However, no provision was made for facility abandonment, reclamation and salvage value. Abandonment costs were allocated at $30,000 per well, site reclamation costs at $10,000 per well and salvage values were depreciated to the forecast economic life (max 50 years).

Abandonment, Salvage & Site Restoration Summary (Constant Dollars)

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

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

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

Abandonment, Salvage & Site Restoration Summary (Escalated Dollars)

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

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

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

6.5 - Tax Horizon

Based on the price and expense projections in the VON Evaluation of Reserves as at November 30, 2008, 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 7 years.

6.6 - Costs Incurred

The following table summarizes the Company's capital expenditures for the year ended November 30, 2008.

Capital Expenditure	M$
Property Acquisition Costs – Proved Properties	316
Property Acquisition Costs – Unproved Properties	187
Exploration Costs	467
Development Costs	-

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, 2008.

	Exploratory Wells		Development Wells	
	Gross	Net	Gross	Net
Oil Wells	-	-	-	-
Gas Wells	-	-	2	0.50
Dry Holes	-	-	-	-
Total Wells	-	-	2	0.50

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.

Operations

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

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

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

Ontario

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

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

Alberta

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

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, 2008.

Production Estimates for the First Year (F2009) 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	11.5		11.5	20%
Petrolia East	Ontario	16.9		16.9	30%
Dover East	Ontario	4.5	40.0	11.1	20%
Other	Ontario	2.3	42.8	9.5	17%
Other	Alberta		47.4	7.9	14%
Total	**Ontario & Alberta**	**35.2**	**130.2**	**56.9**	**100%**

6.9 - Production History

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

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

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

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

Major Properties - F2008 Production

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