

**TOWER ENERGY LTD.
STATEMENT OF RESERVES DATA
AND OTHER OIL AND GAS INFORMATION
(Form 51-101F1)**

Part 1 – Date of Statement

This statement of reserves data and other oil and gas information is dated October 31, 2009.

The effective date is October 31, 2009.

The preparation date is February 24, 2010.

Part 2 – Disclosure of Reserves Data

The following is a summary of the oil and natural gas reserves and the value of future net revenue of Tower Energy Ltd.(the "Company") as evaluated by Chapman Petroleum Engineering Ltd. ("Chapman") as at October 31, 2009, and dated February 24, 2010 (the "Chapman Report"). Chapman is an independent qualified reserves evaluator and auditor.

All evaluations of future revenue are after the deduction of future income tax expenses, unless otherwise noted in the tables, royalties, development costs, production costs and well abandonment costs but before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses. The estimated future net revenue contained in the following tables does not necessarily represent the fair market value of the Company's reserves. There is no assurance that the forecast price and cost assumptions contained in the Chapman Report will be attained and variances could be material. Other assumptions and qualifications relating to costs and other matters are included in the Chapman Report. The recovery and reserves estimates on the Company's properties described herein are estimates only. The actual reserves on the Company's properties may be greater or less than those calculated.

SUMMARY OF OIL AND GAS RESERVES BASED ON FORECAST PRICES AND COSTS AS AT OCTOBER 31, 2009

Reserves Category	Company Reserves ⁽¹⁾							
	Light and Medium Oil		Heavy Oil		Natural Gas ⁽⁹⁾		Natural Gas Liquids	
	Gross MSTB	Net MSTB	Gross MSTB	Net MSTB	Gross MMscf	Net MMscf	Gross Mbbl	Net Mbbl
PROVED								
Developed Producing ⁽²⁾⁽⁶⁾	0	0	0	0	0	0	0	0
Developed Non-Producing ⁽²⁾⁽⁷⁾	0	0	0	0	0	0	0	0
Undeveloped ⁽²⁾⁽⁸⁾	0	0	0	0	0	0	0	0
TOTAL PROVED⁽²⁾	0	0	0	0	0	0	0	0
TOTAL PROBABLE⁽³⁾	0	0	0	0	1,208	755	35	32
TOTAL PROVED + PROBABLE⁽²⁾⁽³⁾	0	0	0	0	1,208	755	35	32

**SUMMARY OF NET PRESENT VALUES
BASED ON FORECAST PRICES AND COSTS
AS AT OCTOBER 31, 2009**

Reserves Category	Net Present Values of Future Net Revenue									
	Before Income Tax					After Income Tax				
	Discounted at					Discounted at				
	0%/yr. \$M	5%/yr. \$M	10%/yr. \$M	15%/yr. \$M	20%/yr. \$M	0%/yr. \$M	5%/yr. \$M	10%/yr. \$M	15%/yr. \$M	20%/yr. \$M
PROVED										
Developed Producing ⁽²⁾⁽⁶⁾	0	0	0	0	0	0	0	0	0	0
Developed Non-Producing ⁽²⁾⁽⁷⁾	0	0	0	0	0	0	0	0	0	0
Undeveloped ⁽²⁾⁽⁸⁾										
TOTAL PROVED⁽²⁾	0	0	0	0	0	0	0	0	0	0
TOTAL PROBABLE⁽³⁾	5,441	3,441	2,422	1,827	1,444	5,117	3,327	2,378	1,809	1,436
TOTAL PROVED + PROBABLE⁽²⁾⁽³⁾	5,441	3,441	2,422	1,827	1,444	5,117	3,327	2,378	1,809	1,436

**TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
BASED ON FORECAST PRICES AND COSTS
AS AT OCTOBER 31, 2009**

	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)
Total Proved ⁽²⁾	0	0	0	0	0	0	0	0
Total Proved Plus Probable ⁽²⁾⁽³⁾	12,453	4,648	1,898	456	10	5,441	(325)	5,117

**FUTURE NET REVENUE BY PRODUCTION GROUP
BASED ON FORECAST PRICES AND COSTS
AS AT OCTOBER 31, 2009**

Reserve Category	Production Group	Future Net Revenue Before Income Taxes (Discounted at 10%/Year) (\$M)
Total Proved ⁽²⁾	Light and Medium Oil (including solution gas and other by-products)	0
	Heavy Oil (including solution gas and other by-products)	0
	Natural Gas (including by-products but not solution gas)	0
Total Proved Plus Probable ⁽²⁾⁽³⁾	Light and Medium Oil (including solution gas and other by-products)	0
	Heavy Oil (including solution gas and other by-products)	0
	Natural Gas (including by-products but not solution gas)	2,422

**OIL AND GAS RESERVES AND NET PRESENT VALUES BY PRODUCTION GROUP
BASED ON FORECAST PRICES AND COSTS
AS AT OCTOBER 31, 2009**

Reserve Group by Category	Reserves						Net Present Value (BIT)	Unit Values @ 10%/yr
	Oil		Gas ⁽⁹⁾		NGL			
	Gross MSTB	Net MSTB	Gross MMscf	Net MMscf	Gross Mbbbl	Net Mbbbl		
							10% M\$	
Assoc & Non-Assoc Gas								
Proved								
Developed Producing	0	0	0	0	0	0	0	N/A
Developed Non-Producing	0	0	0	0	0	0	0	N/A
Undeveloped	0	0	0	0	0	0	0	N/A
Total Proved	0	0	0	0	0	0	0	N/A
Probable	0	0	1,208	755	35	22	2,422	3.21
Proved Plus Probable	0	0	1,208	755	35	22	2,422	3.21

Notes:

- "Gross Reserves" are the Company's working interest (operating or non-operating) share before deducting of royalties and without including any royalty interests of the Company. "Net Reserves" are the Company's working interest (operating or non-operating) share after deduction of royalty obligations, plus the Company's royalty interests in 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.
- "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.
- "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.
- "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.
- "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 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 are those reserves expected to be recovered from know accumulations where a significant expenditure (for example, 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.
- Includes associated, non-associated and solution gas where applicable.

Part 3 - Pricing Assumptions

The following table detail the benchmark reference prices for the regions in which the Company operated, as at October 31, 2009, reflected in the reserves data disclosed above under “Part 2 – Disclosure of Reserves Data”. The forecast price assumptions assume the continuance of current laws and regulations and take into account inflation with respect to future operating and capital costs. There will be adjustments to field prices from the benchmarks below

NATURAL GAS & BY-PRODUCTS HISTORICAL, CONSTANT, CURRENT AND FUTURE PRICES November 1, 2009									
Date	GRP [1]		AECO Spot Gas	Sask. Gas [2]	B.C. Gas [3]	Propane [4]	Butane [4]	Pentanes Plus [4]	NGL Mix [5]
	\$/MMBTU	\$/GJ	\$/MMBTU	\$/MMBTU	\$/MMBTU	\$/BBL	\$/BBL	\$/BBL	\$/BBL
HISTORICAL PRICES	GRP								
1994	1.82	1.72	1.78	1.88	1.81	12.72	13.44	21.67	15.62
1995	1.31	1.24	1.08	1.35	1.29	14.38	13.97	24.11	17.18
1996	1.63	1.54	1.33	1.52	1.50	22.95	17.19	30.05	23.35
1997	1.97	1.87	1.67	1.84	1.80	17.73	19.07	30.90	22.08
1998	1.94	1.84	1.94	2.05	1.94	11.13	12.06	21.86	14.63
1999	2.48	2.35	2.82	2.83	2.51	15.93	18.01	27.73	20.09
2000	4.50	4.27	5.56	4.85	4.00	31.38	35.01	46.35	36.96
2001	5.41	5.12	5.44	5.48	6.12	31.27	30.27	44.98	35.08
2002	3.89	3.68	4.13	4.17	3.85	19.14	25.11	40.72	27.41
2003	6.14	5.81	7.03	6.47	6.45	28.85	32.15	44.23	34.46
2004	6.31	5.98	6.60	6.56	6.25	31.95	38.40	54.06	40.52
2005	8.31	7.87	8.82	8.56	8.31	38.03	46.31	69.32	49.90
2006	6.57	6.22	6.55	6.82	6.57	38.97	50.42	76.08	53.54
2007	6.21	5.88	6.47	6.46	6.21	40.47	49.76	75.96	53.90
2008	7.89	7.47	8.17	8.14	7.89	44.69	54.08	104.75	65.53
2009(10mos)	3.75	3.55	3.86	4.00	3.75	16.62	19.65	65.76	32.27
CONSTANT PRICES									
October 30, 2009 [6]	4.33	4.10	4.46	4.58	5.16	31.17	34.19	82.21	47.39
CURRENT YEAR FORECAST									
2009(2 mos)	3.88	3.68	4.00	4.13	3.88	40.03	45.73	78.28	53.21
FUTURE FORECAST									
2010	5.82	5.52	6.00	6.07	5.82	39.83	45.46	77.82	52.91
2011	6.31	5.98	6.50	6.56	6.31	41.46	47.69	81.64	55.38
2012	6.79	6.44	7.00	7.04	6.79	41.84	48.21	82.53	55.96
2013	7.28	6.90	7.50	7.53	7.28	46.36	54.42	93.16	62.82
2014	7.47	7.08	7.70	7.72	7.47	48.63	57.53	98.48	66.25
2015	7.67	7.27	7.90	7.92	7.67	49.98	59.39	101.66	68.31
2016	7.76	7.36	8.00	8.01	7.76	50.89	60.63	103.79	69.68
2017	7.96	7.54	8.20	8.21	7.96	51.79	61.87	105.92	71.05
2018	8.15	7.73	8.40	8.40	8.15	52.70	63.11	108.04	72.43
2019	8.35	7.91	8.60	8.60	8.35	53.60	64.36	110.17	73.80
2020	8.54	8.10	8.80	8.79	8.54	54.51	65.60	112.30	75.17
2021	8.74	8.28	9.00	8.99	8.74	55.41	66.84	114.42	76.54
2022	8.93	8.46	9.20	9.18	8.93	56.32	68.08	116.55	77.92
2023	9.12	8.65	9.40	9.37	9.12	57.23	69.33	118.68	79.29
2024	9.32	8.83	9.60	9.57	9.32	58.13	70.57	120.80	80.66

Constant thereafter

- Notes:
- [1] Alberta Gas Reference Price (GRP) represents the average of all system and direct (spot and firm) sales.
 - [2] Price paid at field delivery point.
 - [3] Price paid by CanWest net of raw gas gathering and processing charges but before deduction of field gathering and compression charges.
 - [4] Reference point is FOB Edmonton for fractionated product.
 - [5] Natural Gas Liquids blended mix price assuming typical liquid composition of 40% propane, 30% butane and 30% pentanes plus.
 - [6] October 30, 2009 is the last trading day of October 2009.

The Company's weighted average prices received this fiscal year are: \$4.35/Mscf table for natural gas

Part 4 – Reconciliation of Changes in Reserves

The following table sets forth a reconciliation of the changes in the Company's gross reserves as at October 31, 2009 against such reserves as at October 31, 2009 based on the forecast price and cost assumptions:

RECONCILIATION OF COMPANY GROSS RESERVES BY PRINCIPAL PRODUCT TYPE BASED ON FORECAST PRICES AND COSTS AS AT OCTOBER 31, 2009

	Light and Medium Oil			Heavy Oil			Associated and Non-Associated Gas		
	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (MMscf)	Probable (MMscf)	Proved Plus Probable (MMscf)
At Oct. 31, 2008							4	1,230	1,234
Production(Sales)	0	0	0	0	0	0	0	0	0
Dispositions	-	-	-	-	-	-	0	0	0
Acquisitions	-	-	-	-	-	-	0	0	0
Discoveries	-	-	-	-	-	-	0	0	0
Extensions	-	-	-	-	-	-	0	0	0
Revisions to Previous Estimates									
Economic Factors	-	-	-	-	-	-	0	0	0
Technical	-	-	-	-	-	-	(4)	(22)	(26)
Extensions & Improved Recovery	-	-	-	-	-	-	-	-	-
At Oct. 31, 2009							0	1,208	1,208

Part 5 – Additional Information Relating to Reserves Data

Undeveloped Reserves

The Company had no proved undeveloped reserve as at October 31, 2009 or in prior years.

The following table sets forth the volumes of probable undeveloped net reserves that were attributed for each of the Company's product types for the most recent three financial years and in the aggregate before that time:

	Light and Medium Oil (Mbbl)	Heavy Oil (Mbbl)	Natural Gas (MMscf)	Natural Gas Liquids (Mbbl)
Aggregate prior to 2007	-	-	520	15
2007	-	-	520	15
2008	-	-	520	15
2009	-	-	520	15

The following discussion generally describes the basis on which the Company attributes probable and possible undeveloped reserves and its plans for developing those undeveloped reserves.

Probable Undeveloped Reserves

The Company's Probable Undeveloped reserves are on a structure which has been defined by seismic surveys. Non-producing wells on the structure have tested gas. Log analysis and structural mapping indicates that the well and drilling location will be productive of gas. The Company intends to develop these reserves during 2010 and 2011.

Significant Factors or Uncertainties

The estimation of reserves requires significant judgment and decisions based on available geological, geophysical, engineering and economic data. These estimates can change substantially as additional information from ongoing development activities and production performance becomes available and as economic and political conditions impact oil and gas prices and costs change. The Company's estimates are based on current production forecast, prices and economic conditions. All of the Company's reserves are evaluated by Chapman Petroleum Engineering Ltd., an independent engineering firm.

As circumstances change and additional data becomes available, reserve estimates also change. Based on new information, reserves estimates are reviewed and revised, either upward or downward, as warranted. Although every reasonable effort has been made by the Company to ensure that reserves estimate are accurate, revisions may arise as new information becomes available. As new geological, production and economic data is incorporated into the process of estimating reserves the accuracy of the reserve estimate improves.

Certain information regarding the Company set forth in this report, including management's assessment of the Company's future plans and operations contain forward-looking statements that involve substantial known and unknown risks and uncertainties. These risks include, but are not limited to: the risks associated with the oil and gas industry, commodity prices and exchange rates; industry related risks could include, but are not limited to, operational risks in exploration, development and production, delays or changes in plans, risks associated with the uncertainty of reserve estimates, health and safety risks and the uncertainty of estimates and projections of production, costs and expenses. Competition from other producers, the lack of available qualified personnel or management, stock market volatility and ability to access sufficient capital from internal and external sources are additional risks the Company faces in this market. The Company's actual results, performance or achievements could differ materially from those expressed in, or implied by, these forward looking statements and accordingly, no assurance can be given that any events anticipated by the forward looking statements will transpire or occur, if any of them do, what benefits the Company can derive from. The reader is cautioned not to place undue reliance on this forward looking information.

Future Development Costs

The following table shows the development costs anticipated in the next five years, which have been deducted in the estimation of the future net revenues of the proved and probable reserves.

	Total Proved Estimated Using Forecast Prices and Costs (Undiscounted) (\$M)	Total Proved Plus Probable Estimated Using Forecast Prices and Costs (Undiscounted) (\$M)
2009	0	0
2010	0	92
2011	0	364
2012	0	0
2013	0	0
Total for five years	0	456
Remainder	0	0
Total for all years	0	456

The Company has been successful in raising its required capital through equity financings and plans to continue to do so for the development costs specified above. The effect of the costs of the expected funding would have no impact on the revenues or reserves currently being reported.

Part 6 – Other Oil and Gas Information

Oil and Gas Properties and Wells

The following table sets forth the number of wells in which the Company held a working interest as at October 31, 2009:

	Oil		Natural Gas	
	Gross⁽¹⁾	Net⁽¹⁾	Gross⁽¹⁾	Net⁽¹⁾
Sarcee, AB Area	0	0	0	0
Producing	0	0	0	0
Non-producing	0	0	1	0.05

All of the Company's wells are located onshore in western Alberta, Canada in active oil and gas producing areas.

The following descriptions are applicable to the Company properties as at October 31, 2009.

Sarcee, Alberta

The Company owns a five percent working interest in 2,560 acres of land in this area. These lands contain one non-producing gas well and one identified development drilling location. Production will be subject to Indian Royalties which are equivalent to Alberta Crown Royalties plus a 6.5 percent gross overriding royalty. The unit of interest is the Mississippian (Visean) age Turner Valley Formation of the Rundle Group.

Properties with No Attributed Reserves

The Company has no properties with any attributed reserves.

Forward Contracts

Currently, the Company has no forward contracts.

Additional Information Concerning Abandonment and Reclamation Costs

The estimated abandonment and restoration costs used by Chapman are based on the AEUB Directive 11, which details the typical costs of abandonment and reclamation by well type in each specific geographic region. The Company expects to have costs relating to 0.1 net wells, including the location to be drilled. All costs have been included in the Chapman report.

FUTURE ABANDONMENT AND RESTORATION COSTS

	Total Proved Estimated Using Forecast Prices and Costs (Undiscounted) (\$M)	Total Proved Estimated Using Forecast Prices and Costs (10% Discounted) (\$M)	Total Proved Plus Probable Estimated Using Forecast Prices and Costs (Undiscounted) (\$M)	Total Proved Plus Probable Estimated Using Forecast Prices and Costs (10% Discounted) (\$M)
2009	0	0	0	0
2010	0	0	0	0
2011	0	0	0	0
Total for three years	0	0	0	0
Remainder	0	0	10	0
Total for all years	0	0	10	0

Tax Horizon

In the proved plus probable case, the Company is forecast to become taxable in 2025 and thereafter.

Costs Incurred

The following table summarizes the capital expenditures made by the Company on oil and natural gas properties for the year ended October 31, 2009. table

Property Acquisition Costs (\$M)		Exploration Costs (\$M)	Development Costs (\$M)
Proved Properties	Unproved Properties		
-	-	-	\$2961

Exploration and Development Activities

The following table sets forth the number of exploratory and development wells which the Company completed during its 2009 financial year:

	Exploratory Wells		Development Wells	
	Gross ⁽¹⁾	Net ⁽¹⁾	Gross ⁽¹⁾	Net ⁽¹⁾
Oil Wells	-	-	-	-
Gas Wells	-	-	-	-
Service Wells	-	-	-	-
Dry Holes	-	-	-	-
Total Completed Wells	-	-	-	-

The Company did not drill or develop any additional reserves in the fiscal year.

Production Estimates

The following table sets forth the volume of production estimated by Chapman for 2010 (14 mo.):

TOTAL PROVED RESERVES				
AREA	Light and Medium Oil (Mbbl)	Heavy Oil (Mbbl)	Natural Gas (MMscf)	Natural Gas Liquids (Mbbl)
Sarcee, Alberta	0	0	0	0
	0	0	0	0
Total for all areas	0	0	0	0

TOTAL PROVED PLUS PROBABLE RESERVES				
AREA	Light and Medium Oil (Mbbl)	Heavy Oil (Mbbl)	Natural Gas (MMscf)	Natural Gas Liquids (Mbbl)
Sarcee, Alberta	0	0	57	2
	0	0	57	2
Total for all areas	0	0	57	2

These values are gross to Company's working interest before the deduction of royalties payable to others.

Production History

The following table sets forth certain information in respect of production, product prices received, royalties, production costs and netbacks received by the Company for each quarter of its most recently completed financial year:

	Three Months Ended January 31, 2009	Three Months Ended April 30, 2009	Three Months Ended July 31, 2009	Three Months Ended October 31, 2009
Average Daily Production				
Light and Medium Oil (Bbl/d)	-	-	-	-
Natural Gas (Mscf/d)	0.41	0.63	0.34	0.29
Average Net Prices Received				
Light and Medium Oil (\$/Bbl)	-	-	-	-
Natural Gas (\$/Mscf)	6.03	4.23	3.35	2.72
Royalties				
Light and Medium Oil (\$/Bbl)	-	-	-	-
Natural Gas (\$/Mscf)	0.68	0.25	0.18	0.15
Production Costs				
Light and Medium Oil (\$/Bbl)	-	-	-	-
Natural Gas (\$/Mscf)	5.22	4.21	4.77	7.74
Netback Received				
Light and Medium Oil (\$/Bbl)	-	-	-	-
Natural Gas (\$/Mscf)	(0.31)	0.11	1.43	5.06

ABBREVIATIONS AND CONVERSION

In this document, the abbreviations set forth below have the following meanings:

Oil and Natural Gas Liquids		Natural Gas	
Bbl	barrel	Mscf	thousand standard cubic feet
Bbls	barrels	MMscf	million standard cubic feet
Mbbls	thousand barrels	Mscf/d	thousand standard cubic feet per day
MMbbls	million barrels	MMscf/d	million standard cubic feet per day
MSTB	1,000 stock tank barrels	MMBTU	million British Thermal Units
Bbls/d	barrels per day	Bscf	billion standard cubic feet
NGLs	natural gas liquids	GJ	gigajoule
STB	stock tank barrels of oil		
STB/d	stock tank barrels of oil per day		
Other			
AECO	Niska Gas Storage's natural gas storage facility located at Suffield, Alberta.		
BIT	Before Income Tax		
AIT	After Income Tax		
BOE	barrel of oil equivalent on the basis of 1 BOE to 6 Mscf of natural gas. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 1 BOE for 6 Mscf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.		
BOE/d	barrel of oil equivalent per day		
m ³	cubic metres		
\$M	thousands of dollars		
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade		