FORM 51-101F3

REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

Management of Tower Energy Ltd. (the "Company") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which consist of the following:

(a) (i) proved and proved plus probable oil and gas reserves estimated as at October 31, 2006 using forecast prices and costs; and

(ii) the related estimated future net revenue; and

(b) (i) proved oil and gas reserves estimated at October 31, 2006 using constant prices and costs; and

(ii) the related estimated future net revenue.

An independent qualified reserves evaluator has evaluated the Company's reserves data. The report of the independent qualified reserves evaluator is presented below.

The Reserves Committee of the board of directors of the Company has

(a) reviewed the Company's procedures for providing information to the independent qualified reserves evaluator;

(b) held discussions with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and

(c) reviewed the reserves data with management and the independent qualified reserves evaluator.

The Reserves Committee of the board of directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has approved

(a) the content and filing with securities regulatory authorities of the reserves data and other oil and gas information;

(b) the filing of the report of the independent qualified reserves evaluator of the reserves data; and

(c) the content and filing of this report.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

Dated as of this 28th day of February, 2007

(signed) "John MacPherson"
John MacPherson
Director

(signed) "Charles Ross"
Charles Ross
CFO and Director

Chapman Petroleum Engineering Ltd.

445, 708 - 11th Avenue S.W., Calgary, Alberta T2R 0E4 • Phone: (403) 266-4141 • Fax: (403) 266-4259

February 28, 2007

Tower Energy Ltd.
Suite 2110, 1177 W. Hastings Street
Vancouver, BC
V6E 2K3

Attention: Board of Directors

Re: Report on Reserves Data
by Chapman Petroleum Engineering Ltd. ("Chapman")
Qualified Reserves Evaluators

To the board of directors of Tower Energy Ltd. (the "Company"):

1. We have evaluated the Company's reserves data as at July 31, 2006. The reserves data consist of the following:

(a) (i) proved and proved plus probable oil and gas reserves estimated as at July 31, 2006 using forecast prices and costs; and
(ii) the related estimated future net revenue; and

(b) (i) proved oil and gas reserves estimated as at July 31, 2006 using constant prices and costs; and
(ii) the related estimated future net revenue.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook') prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

4. The following tables set forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount of 10 percent, included in the reserves data of the Company evaluated by us for the year ended July 31, 2006, and identifies the respective portions thereof that we have evaluated and reported on to the Company's management and board of directors:

Independent Qualified Reserves Evaluator	Description & Preparation Date of Evaluation Report	Location of Reserves	Net Present Value of Future Revenue (before income taxes, 10% discount rate) - M$			
			Audited	Evaluated	Reviewed	Total
Chapman	Sarcee Property as at July 31, 2006[(1)]	Canada	-	3,106	-	3,106
Totals			-	3,106	-	3,106

Note: (1) There are no material changes to this property between July 31, 2006 and October 31, 2006

5. In our opinion, the reserves data evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook.

6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

7. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

[Original Signed By:]

Chapman, Calgary AB, February 28, 2007

C.W. Chapman
C. W. Chapman, P. Eng.

cwc/slz/4339

TOWER ENERGY LTD.

STATEMENT OF RESERVE DATA AND OTHER OIL AND GAS INFORMATION

EFFECTIVE OCTOBER 31, 2006

PREPARED FEBRUARY 28, 2007

NI 51-101F1

TOWER ENERGY LTD.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION (Form NI 51-101F1)

This statement of reserves data and other oil and gas information has been prepared as at October 31, 2006.

Reserves and Future Net Revenue

The following is a summary of the oil and natural gas reserves and the value of future net revenue of Tower Energy Ltd.. ("Tower" or the "Company") as evaluated by Chapman Petroleum Engineering Ltd. as at July 31, 2006 (the " Chapman Report"). In the opinion of the Company's management, as at October 31, 2006 there are no material changes in these values. The pricing used in the forecast and constant price evaluations is set forth in the notes to the tables.

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 not 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.

Chapman Report – Sarcee Areas, Alberta Canada

Reserves and Revenue Information – Constant Prices and Costs

SUMMARY OF OIL AND GAS RESERVES BASED ON CONSTANT PRICES AND COSTS (8)

August 1, 2006 (as of July 31, 2006)

	Company Reserves							
	Light and Medium Oil		Heavy Oil		Natural Gas[1]		Natural Gas Liquids	
Reserves Category	Gross MSTB	Net MSTB	Gross MSTB	Net MSTB	Gross MMscf	Net MMscf	Gross Mbbl	Net Mbbl
PROVED								
Developed Producing	0	0	0	0	0	0	0	0
Developed Non-Producing	0	0	0	0	0	0	0	0
Undeveloped	0	0	0	0	0	0	0	0
TOTAL PROVED	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
PROBABLE	0	0	0	0	1,208	820	35	22
TOTAL PROVED PLUS PROBABLE(	**0**	**0**	**0**	**0**	**1,208**	**820**	**35**	**22**

Reference: Item 2.2 (1) Form 51-101F1
Columns may not add precisely due to accumulative rounding of values throughout the report.
Notes: [1] Includes associated, non-associated and solution gas where applicable.
All of the Company's reserves are in Canada.

SUMMARY OF NET PRESENT VALUES BASED ON CONSTANT PRICES AND COSTS (8)

August 1, 2006 (as of July 31, 2006)

	Net Present Values of Future Net Revenue [1]					
	Before Income Tax			After Income Tax		
	Undiscounted	Discounted @ 10%/yr.	Discounted @ 15%/yr.	Undiscounted	Discounted @ 10%/yr.	Discounted @ 15%/yr.
Reserve Category	M$	M$	M$	M$	M$	M$
Proved						
Developed Producing	0	0	0	0	0	0
Developed Non-Producing	0	0	0	0	0	0
Undeveloped	0	0	0	0	0	0
Total Proved	0	0	0	0	0	0
Probable	6,234	3,102	2,422	4,403	2,162	1,676
Total Proved Plus Probable	**6,234**	**3,102**	**2,422**	**4,403**	**2,162**	**1,676**

Reference: Item 2.2 (2) Form 51-101F1
Columns may not add precisely due to accumulative rounding of values throughout the report.
Notes: [1] This property does not qualify for ARTC.

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
BASED ON CONSTANT PRICES AND COSTS(8)

August 1, 2006
(as of July 31, 2006)

	Revenue	Royalties	Operating Costs	Developments Costs	Well Abandonment Costs	Future Net Revenues BIT[1]	Income Taxes	Future Net Revenues AIT[1]
Reserve Category	M$	M$	M$	M$	M$	M$	M$	M$
Total Proved	0	0	0	0	0	0	0	0
Proved Plus Probable	11,346	3,617	827	360	8	6,234	1,831	4,403

Reference: Item 2.2 (3)(b) NI 51-101F1
Notes: [1] This property does not qualify for ARTC.

FUTURE NET REVENUE
BY PRODUCTION GROUP
BASED ON CONSTANT PRICES AND COSTS (8)

August 1, 2006
(as of July 31, 2006)

				Future Net Revenue
				Before Income Taxes[1]
				Discounted at 10%/Yr.
Reserve Category				M$
Total Proved		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
Proved Plus Probable		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)		3,102

Reference: Item 2.2 (3)(c) NI 51-101F1
Notes: [1] Does not include ARTC

Reserves and Revenue Information – Forecast Prices and Costs

SUMMARY OF OIL AND GAS RESERVES
BASED ON FORECAST PRICES AND COSTS (8)
August 1, 2006 (as of July 31, 2006)

	Company Reserves							
	Light and Medium Oil		Heavy Oil		Natural Gas [1]		Natural Gas Liquids	
Reserves Category	Gross MSTB	Net MSTB	Gross MSTB	Net MSTB	Gross MMscf	Net MMscf	Gross Mbbl	Net Mbbl
PROVED								
Developed Producing	0	0	0	0	0	0	0	0
Developed Non-Producing	0	0	0	0	0	0	0	0
Undeveloped	0	0	0	0	0	0	0	0
TOTAL PROVED	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
PROBABLE	0	0	0	0	1,208	824	35	22
TOTAL PROVED PLUS PROBABLE(	**0**	**0**	**0**	**0**	**1,208**	**824**	**35**	**22**

Reference: Item 2.2 (1) Form 51-101F1
Columns may not add precisely due to accumulative rounding of values throughout the report.
Notes: [1] Includes associated, non-associated and solution gas where applicable.
All of the Company's reserves are in Canada.

SUMMARY OF NET PRESENT VALUES
BASED ON FORECAST PRICES AND COSTS (8)
August 1, 2006 (as of July 31, 2006)

Before Income Tax

	Net Present Values of Future Net Revenue [1]				
	Discounted at				
Reserve Category	0%/Yr. M$	5%/Yr. M$	10%/Yr. M$	15%/Yr. M$	20%/Yr. M$
Proved					
Developed Producing	0	0	0	0	0
Developed Non-Producing	0	0	0	0	0
Undeveloped	0	0	0	0	0
Total Proved	0	0	0	0	0
Probable	6,275	4,215	3,106	2,429	1,977
Total Proved Plus Probable	**6,275**	**4,215**	**3,106**	**2,429**	**1,977**

After Income Tax

	Net Present Values of Future Net Revenue[1]				
	Discounted at				
Reserve Category	0%/Yr. M$	5%/Yr. M$	10%/Yr. M$	15%/Yr. M$	20%/Yr. M$
Proved					
Developed Producing	0	0	0	0	0
Developed Non-Producing	0	0	0	0	0
Undeveloped	0	0	0	0	0
Total Proved	0	0	0	0	0
Probable	4,429	2,957	2,164	1,678	1,354
Total Proved Plus Probable	**4,429**	**2,957**	**2,164**	**1,678**	**1,354**

Reference: Item 2.2 (2) Form 51-101F1
Columns may not add precisely due to accumulative rounding of values throughout the report.
Notes: [1] This property does not qualify for ARTC.
All of the Company's reserves are in Canada.

TOTAL FUTURE NET REVENUE (UNDISCOUNTED) BASED ON FORECAST PRICES AND COSTS (8)

August 1, 2006
(as of July 31, 2006)

	Revenue	Royalties	Operating Costs	Developments Costs	Well Abandonment Costs	Future Net Revenues BIT [1]	Income Taxes	Future Net Revenues AIT[1]
Reserve Category	M$	M$	M$	M$	M$	M$	M$	M$
Total Proved	0	0	0	0	0	30	0	0
Proved Plus Probable	11,672	3,650	1,372	365	10	6,275	1,846	4,429

Reference: Item 2.2 (3)(b) NI 51-101F1
Notes: [1] This property does not qualify for ARTC.

FUTURE NET REVENUE BY PRODUCTION GROUP BASED ON FORECAST PRICES AND COSTS (8)

August 1, 2006

(as of July 31, 2006)

		Future Net Revenue Before Income Taxes[1] Discounted at 10%/Yr.
Reserve Category		M$
Total Proved	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
Proved Plus Probable	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)	3,106

Reference: Item 2.2 (3)(c) NI 51-101F1
Notes: [1] Does not include ARTC

Pricing Assumption

The following tables detail the benchmark reference prices for the regions in which the Corporation operated as at July 31, 2006 reflected in the reserves data disclosed herein. The pricing assumptions for both the constant prices and costs and forecast prices and costs were provided and included in the Chapman Report.

CRUDE OIL
HISTORICAL, CONSTANT, CURRENT AND FUTURE PRICES
July 1, 2006

Date	WTI [1] $US/STB	Alberta Par Price [2] $CDN/STB	Alberta Heavy [3] $CDN/STB	Sask. Light [4] $CDN/STB	Sask. Heavy [5] $CDN/STB	B.C. Light [6] $CDN/STB	ART Credits [7] Rate %	ART Credits [7] Max M$
HISTORICAL PRICES								
1994	17.16	22.27	18.19	20.76	19.16	21.12	70.08	n/a
1995	18.41	25.11	19.76	22.77	20.57	23.85	73.75	n/a
1996	21.98	29.39	25.09	28.41	26.07	27.99	72.82	n/a
1997	20.59	27.90	21.15	26.52	23.73	26.32	61.35	n/a
1998	14.46	20.39	14.68	19.31	17.01	19.38	69.32	n/a
1999	19.21	27.88	23.71	27.23	25.65	27.42	68.88	n/a
2000	30.39	44.90	34.51	43.37	40.12	n/a	25.85	n/a
2001	25.98	39.66	25.41	35.57	31.84	n/a	25.00	n/a
2002	26.09	40.63	32.20	37.67	34.57	n/a	25.00	n/a
2003	30.84	43.57	32.65	40.13	37.64	n/a	25.00	500
2004	41.48	52.89	37.52	48.96	45.74	n/a	25.00	500
2005	56.62	69.16	43.25	62.04	56.53	n/a	25.00	500
2006 (6 months)	66.65	73.86	49.99	66.92	60.52	n/a	25.00	500
CONSTANT PRICES								
July 31, 2006	74.40	84.22	63.04	77.42	73.61	82.11	25.00	500
CURRENT YEAR FORECAST								
2006 (6 months)	68.00	77.90	49.08	70.50	64.69	75.96	25.00	500
FUTURE FORECAST								
2007	65.00	75.36	47.48	68.20	62.58	73.48	25.00	500
2008	60.00	69.68	43.90	63.06	57.86	67.94	25.00	500
2009	56.00	65.14	41.04	58.95	54.09	63.51	25.00	500
2010	55.00	64.00	40.32	57.92	53.14	62.40	25.00	500
2011	55.00	64.00	40.32	57.92	53.14	62.40	25.00	500
2012	56.10	65.25	41.11	59.05	54.18	63.62	25.00	500
2013	57.22	66.53	41.91	60.21	55.24	64.86	25.00	500
2014	58.37	67.83	42.73	61.38	56.32	66.13	25.00	500
2015	59.53	69.15	43.57	62.58	57.42	67.42	25.00	500
2016	60.72	70.51	44.42	63.81	58.54	68.74	25.00	500
2017	61.94	71.89	45.29	65.06	59.69	70.09	25.00	500
2018	63.18	73.29	46.17	66.33	60.86	71.46	25.00	500
2019	64.44	74.73	47.08	67.63	62.05	72.86	25.00	500
2020	65.73	76.19	48.00	68.95	63.27	74.29	25.00	500
2021	67.04	77.69	48.94	70.31	64.51	75.74	25.00	500
Constant thereafter								

Notes:

[1] West Texas Intermediate quality (D2/S2) crude landed in Cushing, Oklahoma.

[2] Equivalent price for Light Sweet Crude (D2/S2) landed in Edmonton, Alberta after exchange of 0.89$US/$CDN for 2006 and 0.88$US/$CDN thereafter, and transportation differential of $1.50 CDN/STB.

[3] Bow River at Hardisty, Alberta (905 kg/m3, 2.1% sulphur).

[4] Light Sour Blend at Cromer, Saskatchewan (850 kg/m3, 1.2% sulphur).

[5] Midale at Cromer, Saskatchewan (880 kg/m3, 2.0% sulphur).

[6] B.C. Light at Taylor, British Columbia (825 kg/m3, 0.5% sulphur).

[7] ARTC rates are from www.revenue.gov.ab.ca/publications/tax_rebates/rates_surveys_tnotes/rtc.html.

[8] Capital expenditures and operating costs are escalated at 2.0% per year until 2021.

Date	GRP [1] $/MMBTU	GRP [1] $/GJ	AECO Spot Gas [NIT] $/MMBTU	Sask. Gas [2] $/MMBTU	B.C. Gas [3] $/MMBTU	Propane [4] $/BBL	Butane [4] $/BBL	Pentanes Plus [4] $/BBL	NGL Mix [5] $/BBL
HISTORICAL PRICES									
1994	1.82	1.73	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	1.55	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	5.78	5.48	5.44	5.48	6.12	31.27	30.27	44.98	35.08
2002	3.86	3.66	4.13	4.17	3.85	19.14	25.11	40.72	27.41
2003	6.45	6.11	7.03	6.47	6.45	28.85	32.15	44.23	34.46
2004	6.25	5.92	6.60	6.50	6.25	31.95	38.40	54.06	40.52
2005	8.13	7.71	8.82	8.38	8.13	38.03	46.31	69.32	49.90
2006 (6 mo. Est.)	7.10	6.73	6.76	7.35	7.10	39.21	52.70	78.89	55.16
CONSTANT PRICES									
July 31, 2006	7.32	6.94	7.07	7.57	7.32	43.88	55.64	84.18	59.50
CURRENT YEAR FORECAST									
2006 (6 months)	7.80	7.39	8.05	8.05	7.80	42.07	51.42	78.68	55.86
FUTURE FORECAST									
2007	8.51	8.07	8.86	8.76	8.51	40.70	49.74	76.12	54.04
2008	8.00	7.58	8.35	8.25	8.00	37.63	45.99	70.38	49.96
2009	7.50	7.11	7.85	7.75	7.50	35.17	42.99	65.79	46.70
2010	7.25	6.87	7.60	7.50	7.25	34.56	42.24	64.64	45.89
2011	7.00	6.64	7.35	7.25	7.00	34.56	42.24	64.64	45.89
2012	7.14	6.77	7.49	7.39	7.14	35.24	43.07	65.90	46.78
2013	7.28	6.90	7.63	7.53	7.28	35.92	43.91	67.19	47.70
2014	7.43	7.04	7.78	7.68	7.43	36.63	44.76	68.50	48.63
2015	7.58	7.18	7.93	7.83	7.58	37.34	45.64	69.84	49.58
2016	7.73	7.33	8.08	7.98	7.73	38.07	46.53	71.21	50.55
2017	7.88	7.47	8.23	8.13	7.88	38.82	47.44	72.60	51.54
2018	8.04	7.62	8.39	8.29	8.04	39.58	48.37	74.03	52.55
2019	8.20	7.77	8.55	8.45	8.20	40.35	49.32	75.48	53.58
2020	8.37	7.93	8.72	8.62	8.37	41.14	50.29	76.96	54.63
2021	8.53	8.09	8.88	8.78	8.53	41.95	51.27	78.46	55.70

Constant thereafter

Notes:

[1] 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] Capital expenditures and operating costs are escalated at 1.5% per year until 2021.

Notes:

1. "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.
2. "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.
3. "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.
4. "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.
5. "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.
6. "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.
7. "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.
8. The pricing assumptions used in the Chapman Report with respect to net values of future net revenue (forecast) as well as the inflation rates used for operating and capital costs are set forth below along with the product prices used in the constant price and cost evaluations. Chapman Petroleum Engineering Ltd. is an independent qualified reserves evaluator appointed pursuant to NI 51-101.
9. Includes ARTC.
10. Does not include ARTC.
11. Includes associated, non-associated and solution gas where applicable.
12. Includes Water Disposal Income.

RECONCILIATION OF COMPANY NET RESERVES BY PRINCIPAL PRODUCT TYPE BASED ON FORECAST PRICES AND COSTS [8]

The following table sets forth a reconciliation of the changes in the Company's reserves as at October 31, 2006 against such reserves as at October 31, 2005 based on the forecast price and cost assumptions set forth in note 8:

	Light and Medium Oil			Heavy Oil			Associated and Non-Associated Gas		
	Net Proved (Mbbl)	Net Probable (Mbbl)	Net Proved Plus Probable (Mbbl)	Net Proved (Mbbl)	Net Probable (Mbbl)	Net Proved Plus Probable (Mbbl)	Net Proved (MMscf)	Net Probable (MMscf)	Net Proved Plus Probable (MMscf)
At October 31, 2005	-	-	-	-	-	-	-	-	-
Production(Sales)	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	824	824
Dispositions	-	-	-	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-
Extensions	-	-	-	-	-	-	-	-	-
Revisions to Previous Estimates	-	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-	-	-	-
Technical	-	-	-	-	-	-	-	-	-
Improved Recovery	-	-	-	-	-	-	-	-	-
At October 1, 2006	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**824**	**824**

The following table sets forth changes between future net revenue estimates attributable to net proved reserves as at October 31, 2006 against such reserves as at October 31, 2005.

RECONCILIATION OF CHANGES IN NET PRESENT VALUES OF FUTURE NET REVENUE OF NET PROVED RESERVES DISCOUNTED AT 10% BASED ON CONSTANT PRICES AND COSTS [8]

	2006 ($M)
Future Revenue Prediction at October 31, 2005	-
Net Value of Sales.	
Net change in production costs for future production.	-
Net change in sales prices for future production.	-
Net change in royalties for future production.	-
Change in development costs Incurred.	-
Change in future development costs.	-
Change from extension & improved recovery.	-
Discoveries.	-
Acquisition	-
Disposition.	
Revisions in quantity estimates.	-
Accretion of discount (10% of discounted future net revenue at the beginning for the financial year.)	-
Net change in income taxes.	-
Other Factors.	-
Future Net Revenue at October 31, 2006	-

Additional Information Relating to Reserves Data

Undeveloped Reserves

The following discussion generally describes the basis on which the Company attributes Proved and Probable Undeveloped reserves and its plans for developing those Undeveloped Reserves.

Proved Undeveloped Reserves

Proved Undeveloped reserves are generally those reserves related to wells that have been tested and not yet tied-in for production or wells drilled near the end of the fiscal year. In addition, such reserves may relate to planned infill drilling locations. The Company has no reserves attributed to this category.

Probable Undeveloped Reserves

Probable Undeveloped reserves are generally those reserves have been tested or indicated by analogy to be productive, infill drilling locations and land contiguous to production. The Company has plans to drill and tie- one location in Sarcee, Alberta in January 2008.

The following table sets forth the future development costs that have been estimated and included in the Chapman Report.

FUTURE DEVELOPMENT COSTS

Summary of Company Anticipated Capital Expenditures
Development Costs
August 1, 2006
(as of July 31, 2006)

Forecast Prices and Costs

	Future Development Costs – M$ [1]			
	Total Proved		**Total Proved Plus Probable**	
	Discounted at:			
Year	**Undisc.**	**10%/year**	**Undisc.**	**10%/year**
2006	0	0	93	91
2007	0	0	273	250
2008	0	0	0	0
2009	0	0	0	0
2010	0	0	0	0
Sub Total (2006-2010)	**0**	**0**	**365**	**341**
Remainder	0	0	0	0
Total	**0**	**0**	**365**	**341**

Reference: item 5.3 (b) (i) & (ii) NI 51-101F1
Notes: [1] Costs apply only to properties evaluated.

The Company expects to fund the future development costs by Private Placement and Flow Through funding.

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 Corporation's estimates are based on current production forecast, prices and economic conditions. All of the Corporation's reserves are evaluated by an independent engineering firm, Chapman Petroleum Engineering Ltd., an independent engineering firm.

As circumstances change and additional date become 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 Tower Energy Ltd. to ensure that reserves estimate are accurate, revisions arise as new information becomes available. As new geological, production and economic is incorporated into the process of estimating reserves the accuracy of the reserve estimate improves.

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, 2006:

	Oil		**Natural Gas**	
	Gross(1)	**Net(1)**	**Gross(1)**	**Net(1)**
Alberta				
Producing	-	-	-	-
Non-producing	-	-	1	1

All of the Company's wells are located in Alberta, Canada.

The following descriptions are applicable to the Company properties as at October 31, 2006.

Sarcee, Alberta

The Company, under a under a farmout agreement, owns a 5% percent working interest in 2,560 acres on four sections of land in this area by paying 10% percent of the gross capital development expenditures. These lands contain one well and one identified drilling location. Production will be subject to Indian Royalties which are equivalent to Alberta New 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. The Company incurred $340,112 in development expenditures in the year ended October 31, 2006.

Costs Incurred

The Company acquired a 5% percent working interest in 2,560 acres on four sections of land in the Sarcee area by paying 10% percent of the gross capital development expenditures. The Company incurred $340,112 in development costs, on the Sarcee property during the year ended October 31, 2006. The Company incurred $340,112 in development costs, on the Sarcee property during the year ended October 31, 2006. The Company incurred $534,283 in development costs, on the Sarcee property during the year ended October 31, 2005.

Discussion

Exploration and Development Activities

In the year ended October 31, 2006 the Company participated in the drilling of one well in the Sarcee area of Alberta.

Properties with No Attributed Reserves

The Company currently does not hold any properties with no attributed reserves in Canada

Forward Contracts

Currently, the Company has no forward contracts.

Abandonment and Reclamation Costs

The abandonment and restorations costs are based on the AEUB Directive 11, which details the costs of abandonment and reclamation by well type in each specific geographic region, and included in the Chapman Report.

FUTURE ABANDONMENT AND RESTORATION COSTS

Sarcee, Alberta - Canada

Summary of Company Anticipated Abandonment
And Lease Restoration Costs
August 1, 2006
(as of July 31, 2006)

Forecast Prices and Costs

	Abandonment and Lease Restoration Costs – M$ [1]			
	Total Proved		**Total Proved Plus Probable**	
	Discounted at:			
Year	**Undisc.**	**10%/year**	**Undisc.**	**10%/year**
2006	0	0	0	0
2007	0	0	0	0
2008	0	0	0	0
Sub Total (2006-2008)	**0**	**0**	**0**	**0**
Remainder	0	0	10	0[2]
Total	**0**	**0**	**10**	**0[2]**

Reference: item 6.4 (c) & (e) NI 51-101F1
Notes: [1] Costs apply only to wells evaluated.
[2] Values shown as “0” reflect a value of less than $500.

Tax Horizon

The Company was not taxable in the year ended October 31, 2006. The Company estimates that it will not be taxable in the year ended October 31, 2007

Production Estimates

The following table sets out a summary of the forecast production volume (on gross basic) estimated for the Company's assets for the year ended October 31, 2007.

	Sarcee
Average Daily Production	
Light and Medium Oil (bbl/d)	-
Natural Gas (MMscf/d)	-

These values are net to Tower's working interest after the deduction of royalties payable to others.

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 October 31, 2006	Three Months Ended July 31, 2006	Three Months Ended April 30, 2006	Three Months Ended January 31, 2006
Average Daily Production				
Light and Medium Oil (bbl/d)	-	-	-	-
Natural Gas (MMscf/d)	-	-	-	-
Average Net Prices Received				
Light and Medium Oil ($/bbl)	-	-	-	-
Natural Gas ($/MMscf)	-	-	-	-
Royalties				
Light and Medium Oil ($/bbl)	-	-	-	-
Natural Gas ($/Mscf)	-	-	-	-
Production Costs				
Light and Medium Oil ($/bbl)	-	-	-	-
Natural Gas ($/Mscf)	-	-	-	-
Netback Received				
Light and Medium Oil ($/Mbbl)	-	-	-	-
Natural Gas ($/Mscf)	-	-	-	-