

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Dated 29 September 2005

In accordance with National Instrument 51-101 Statement of Reserves Data and Other Oil and Gas Information ("NI 51-101"), Gilbert Laustsen Jung Associates Ltd. ("GLJ") and Paul R. Clevenger P.E. ("Clevenger") (both entities hereafter referred to as "the Evaluators") prepared the Report on Reserves Data of Emerald Bay Energy Inc. ("Emerald") (the "Emerald Report") on February 4, 2005, evaluating the proved and probable crude oil, natural gas and natural gas liquids reserves attributable to Emerald's interest in its properties and net present value of estimated future cash flow from such reserves, based on both forecasted and constant price and cost assumptions ("Emerald Properties"). The Emerald Report evaluated, effective as at December 31, 2004, the Emerald Properties' oil, natural gas and natural gas reserves. The tables below are a summary of the estimated share of Emerald's crude oil, natural gas liquids and natural gas reserves in its properties and the net present value of estimated future net revenue for these reserves, using constant and forecast prices and costs as indicated. The information set forth below is prepared in accordance with standards contained in the COGE Handbook and the reserves definitions contained in NI 51-101 and the COGE Handbook. The tables summarize the data contained in the Emerald Report and as a result may contain slightly different numbers than such report due to rounding. Also due to rounding, certain columns may not add exactly. The net present value of future net revenue attributable to the Emerald Properties reserves is stated without provision for interest costs and general and administrative costs, but after providing for estimated royalties, production costs, development costs, other income, future capital expenditures, and well abandonment costs for only those wells assigned reserves by the Evaluators. It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to the Emerald Properties' reserves estimated by the Evaluators represent the fair market value of those reserves. Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized herein. The recovery and reserve estimates of the Emerald Properties' oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates provided herein.

Emerald is not taxable; therefore no future income taxes have been forecast. Emerald is not bound by any forward selling contracts that will preclude it from fully realizing future market prices of oil and gas. The Evaluators did not identify any undeveloped reserves.

Summary of Oil and Gas Reserves using Constant Prices and CostsCanadian Assets

	Light/Medium Oil		Natural Gas		NGL's		Oil Equivalent	
	Gross ⁽¹⁾ (Mbbbl)	Net ⁽²⁾ (Mbbbl)	Gross ⁽¹⁾ (MMcf)	Net ⁽²⁾ (MMcf)	Gross ⁽¹⁾ (Mbbbl)	Net ⁽²⁾ (Mbbbl)	Gross ⁽¹⁾ (Mbbbl)	Net ⁽²⁾ (Mbbbl)
Proved Developed Producing	3	3	880	769	31	20	181	151
Proved Developed Non-Producing	0	0	322	246	0	0	54	41
Proved Undeveloped	0	0	0	0	0	0	0	0
Total Proved	3	3	1202	1015	31	20	235	192

US Assets

	Light/Medium Oil		Natural Gas		NGL's		Oil Equivalent	
	Gross ⁽¹⁾ (Mbbbl)	Net ⁽²⁾ (Mbbbl)	Gross ⁽¹⁾ (MMcf)	Net ⁽²⁾ (MMcf)	Gross ⁽¹⁾ (Mbbbl)	Net ⁽²⁾ (Mbbbl)	Gross ⁽¹⁾ (Mbbbl)	Net ⁽²⁾ (Mbbbl)
Proved Developed Producing	15	11	0	0	0	0	15	11
Proved Developed Non-Producing	0	0	0	0	0	0	0	0
Proved Undeveloped	0	0	0	0	0	0	0	0
Total Proved	15	11	0	0	0	0	15	11

in Aggregate

	Light/Medium Oil		Natural Gas		NGL's		Oil Equivalent	
	Gross ⁽¹⁾ (Mbbbl)	Net ⁽²⁾ (Mbbbl)	Gross ⁽¹⁾ (MMcf)	Net ⁽²⁾ (MMcf)	Gross ⁽¹⁾ (Mbbbl)	Net ⁽²⁾ (Mbbbl)	Gross ⁽¹⁾ (Mbbbl)	Net ⁽²⁾ (Mbbbl)
Proved Developed Producing	18	14	880	769	31	20	196	162
Proved Developed Non-Producing	0	0	322	246	0	0	54	41
Proved Undeveloped	0	0	0	0	0	0	0	0
Total Proved	18	14	1202	1015	31	20	250	203

Notes:

- (1) Gross Reserves means Emerald's working interest (operating and non-operating) share before deduction of royalties and income taxes.
- (2) Net Reserves means Emerald's working interest (operating and non-operating) share after deduction of royalties but before deduction of income taxes.

Summary of Net Present Value of Future Net Reserves using Constant Prices and Costs (in CDN\$ thousands)

Canadian Assets

	Before Tax Discounted At						
	0%	5%	8%	10%	12%	15%	20%
Proved Developed Producing	4,593	3,415	2,966	2,730	2,532	2,288	1,981
Proved Developed Non-Producing	1,004	893	836	802	770	726	662
Proved Undeveloped	0	0	0	0	0	0	0
Total Proved	5,597	4,308	3,802	3,532	3,302	3,014	2,643

US Assets

	Before Tax Discounted At						
	0%	5%	8%	10%	12%	15%	20%
Proved Developed Producing	288	250	230	220	209	195	177
Proved Developed Non-Producing	0	0	0	0	0	0	0
Proved Undeveloped	0	0	0	0	0	0	0
Total Proved	288	250	230	220	209	195	177

In Aggregate

	Before Tax Discounted At						
	0%	5%	8%	10%	12%	15%	20%
Proved Developed Producing	4,881	3,665	3,196	2,950	2,741	2,483	2,158
Proved Developed Non-Producing	1,004	893	836	802	770	726	662
Proved Undeveloped	0	0	0	0	0	0	0
Total Proved	5,885	4,558	4,032	3,752	3,511	3,209	2,820

Elements of Future Net Revenues using Constant Prices (in CDN\$ thousands)Canadian Assets

Year	Revenue	Royalty	Operation Costs	Development Costs	Abandonment Costs	Future net Revenue before tax
2005	1,588	323	266	325	0	690
2006	1,367	248	246	0	0	827
2007	1,041	165	214	0	0	592
2008	829	121	191	0	0	436
2009	666	92	165	0	0	334
2010	542	76	134	0	15	250
2011	454	67	107	0	0	224
2012	411	60	102	0	0	194
2013	369	54	97	0	13	152
2014	305	47	67	0	4	157
2015	276	42	64	0	0	141
2016	228	35	51	0	14	104

US Assets

Year	Revenue	Royalty	Operation Costs	Development Costs	Abandonment Costs	Future net Revenue before tax
2005	84	6	24	0	0	54
2006	72	5	23	0	0	44
2007	63	5	23	0	0	35
2008	51	4	19	0	0	28
2009	43	3	18	0	0	22
2010	37	3	18	0	0	17
2011	28	2	13	0	0	12
2012	24	2	13	0	0	9
2013	20	1	12	0	0	7
2014	15	1	9	0	0	5
2015	13	1	9	0	0	3
2016	12	1	9	0	0	2

In Aggregate

Year	Revenue	Royalty	Operation Costs	Development Costs	Abandonment Costs	Future net Revenue before tax
2005	1,672	329	290	325	0	744
2006	1,439	253	269	0	0	871
2007	1,104	170	237	0	0	627
2008	880	125	210	0	0	464
2009	709	95	183	0	0	356
2010	579	79	152	0	15	267
2011	482	69	120	0	0	236
2012	435	62	115	0	0	203
2013	389	55	109	0	13	159
2014	320	48	76	0	4	162
2015	289	43	73	0	0	144
2016	240	36	60	0	14	106

Net Present Value at a discount rate of 10% of future net revenues using forecast pricing (in CDN\$ thousands):

Natural Gas	3,901
Light/Medium Oil	163

Using constant pricing:

Natural Gas	3,532
Light/Medium Oil	220

Summary of Oil and Gas Reserves using Forecast Prices and CostsCanadian Assets

	Light/Medium Oil		Natural Gas		NGL's		Oil Equivalent	
	Gross ⁽¹⁾	Net ⁽²⁾	Gross ⁽¹⁾	Net ⁽²⁾	Gross ⁽¹⁾	Net ⁽²⁾	Gross ⁽¹⁾	Net ⁽²⁾
	(Mbbbl)	(Mbbbl)	(MMcf)	(MMcf)	(Mbbbl)	(Mbbbl)	(Mbbbl)	(Mbbbl)
Proved Developed Producing	3	3	879	768	31	20	180	151
Proved Developed Non-Producing	0	0	322	246	0	0	54	41
Proved Undeveloped	0	0	0	0	0	0	0	0
Total Proved	3	3	1201	1014	31	20	234	192
Probable	0.5	0.5	591	465	7	4	106	82
Proved plus Probable	3.5	3.5	1792	1479	38	24	340	274

US Assets

	Light/Medium Oil		Natural Gas		NGL's		Oil Equivalent	
	Gross ⁽¹⁾	Net ⁽²⁾	Gross ⁽¹⁾	Net ⁽²⁾	Gross ⁽¹⁾	Net ⁽²⁾	Gross ⁽¹⁾	Net ⁽²⁾
	(Mbbbl)	(Mbbbl)	(MMcf)	(MMcf)	(Mbbbl)	(Mbbbl)	(Mbbbl)	(Mbbbl)
Proved Developed Producing	15	11	0	0	0	0	15	11
Proved Developed Non-Producing	0	0	0	0	0	0	0	0
Proved Undeveloped	0	0	0	0	0	0	0	0
Total Proved	15	11	0	0	0	0	15	11

In Aggregate

	Light/Medium Oil		Natural Gas		NGL's		Oil Equivalent	
	Gross ⁽¹⁾	Net ⁽²⁾	Gross ⁽¹⁾	Net ⁽²⁾	Gross ⁽¹⁾	Net ⁽²⁾	Gross ⁽¹⁾	Net ⁽²⁾
	(Mbbbl)	(Mbbbl)	(MMcf)	(MMcf)	(Mbbbl)	(Mbbbl)	(Mbbbl)	(Mbbbl)
Proved Developed Producing	18	14	879	768	31	20	195	162
Proved Developed Non-Producing	0	0	322	246	0	0	54	41
Proved Undeveloped	0	0	0	0	0	0	0	0
Total Proved	18	14	1201	1014	31	20	249	203
Probable	0.5	0.5	591	465	7	4	106	82
Proved plus Probable	18.5	14.5	1792	1479	38	24	355	285

Summary of Net Present Value of Future Net Reserves using Forecast Prices and Costs (in CDN\$ thousands)

Canadian Assets

	Before Tax Discounted At						
	<u>0%</u>	<u>5%</u>	<u>8%</u>	<u>10%</u>	<u>12%</u>	<u>15%</u>	<u>20%</u>
Proved Developed Producing	4,092	3,031	2,637	2,432	2,260	2,050	1,786
Proved Developed Non-Producing	838	753	709	682	656	621	569
Proved Undeveloped	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>
Total Proved	<u>4,930</u>	<u>3,784</u>	<u>3,346</u>	<u>3,114</u>	<u>2,916</u>	<u>2,671</u>	<u>2,355</u>
Probable	<u>1,575</u>	<u>1,065</u>	<u>881</u>	<u>787</u>	<u>708</u>	<u>614</u>	<u>497</u>
Proved plus Probable	<u>6,505</u>	<u>4,849</u>	<u>4,227</u>	<u>3,901</u>	<u>3,624</u>	<u>3,285</u>	<u>2,852</u>

US Assets

	Before Tax Discounted At						
	<u>0%</u>	<u>5%</u>	<u>8%</u>	<u>10%</u>	<u>12%</u>	<u>15%</u>	<u>20%</u>
Proved Developed Producing	212	184	171	163	156	147	134
Proved Developed Non-Producing	0	0	0	0	0	0	0
Proved Undeveloped	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>
Total Proved	<u>212</u>	<u>184</u>	<u>171</u>	<u>163</u>	<u>156</u>	<u>147</u>	<u>134</u>

In Aggregate

	Before Tax Discounted At						
	<u>0%</u>	<u>5%</u>	<u>8%</u>	<u>10%</u>	<u>12%</u>	<u>15%</u>	<u>20%</u>
Proved Developed Producing	4,304	3,215	2,808	2,595	2,416	2,197	1,920
Proved Developed Non-Producing	838	753	709	682	656	621	569
Proved Undeveloped	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>
Total Proved	<u>5,142</u>	<u>3,968</u>	<u>3,517</u>	<u>3,277</u>	<u>3,072</u>	<u>2,818</u>	<u>2,489</u>
Probable	<u>1,575</u>	<u>1,065</u>	<u>881</u>	<u>787</u>	<u>708</u>	<u>614</u>	<u>497</u>
Proved plus Probable	<u>6,717</u>	<u>5,033</u>	<u>4,398</u>	<u>4,064</u>	<u>3,780</u>	<u>3,432</u>	<u>2,986</u>

Elements of Future Net Revenue using Forecast Prices Total Proved (in CDN\$ thousands)Canadian Assets

Year	Revenue	Royalty	Operation Costs	Development Costs	Abandonment Costs	Future net Revenue before tax
2005	1,560	316	266	325	0	690
2006	1,288	232	251	0	0	827
2007	954	147	223	0	0	592
2008	738	103	202	0	0	436
2009	380	75	172	0	0	334
2010	475	62	148	0	17	250
2011	398	55	120	0	0	224
2012	360	49	117	0	0	194
2013	329	45	113	0	20	152
2014	277	40	80	0	0	157
2015	255	36	78	0	0	141
2016	216	31	63	0	18	104

US Assets

Year	Revenue	Taxes	Operation Costs	Development Costs	Abandonment Costs	Future net Revenue before tax
2005	86	6	24	0	0	54
2006	68	5	23	0	0	44
2007	59	4	23	0	0	35
2008	43	3	18	0	0	28
2009	37	3	18	0	0	22
2010	34	3	18	0	0	17
2011	26	2	13	0	0	12
2012	22	2	13	0	0	9
2013	18	1	11	0	0	7
2014	14	1	9	0	0	5
2015	12	1	9	0	0	3
2016	11	1	9	0	0	2

In Aggregate

Year	Revenue	Royalty or Tax	Operation Costs	Development Costs	Abandonment Costs	Future net Revenue before tax
2005	1,646	322	290	325	0	744
2006	1,356	237	274	0	0	871
2007	1,013	151	246	0	0	627
2008	781	106	220	0	0	464
2009	417	78	190	0	0	356
2010	509	65	166	0	17	267
2011	424	57	133	0	0	236
2012	382	51	130	0	0	203
2013	347	46	124	0	20	159
2014	291	41	89	0	0	162
2015	267	37	87	0	0	144
2016	227	32	72	0	18	106

Elements of Future Net Revenue using Forecast Prices Total Proved Plus Probable (in CDN\$ thousands)

Canadian Assets

Year	Revenue	Royalty	Operation Costs	Development Costs	Abandonment Costs	Future net Revenue before tax
2005	1,806	390	310	475	0	679
2006	1,608	319	318	0	0	1,007
2007	1,213	209	287	0	0	734
2008	949	147	271	0	0	540
2009	775	110	251	0	16	403
2010	937	180	249	193	0	332
2011	755	139	209	0	17	401
2012	635	112	189	0	0	342
2013	560	93	185	0	0	289
2014	500	78	181	0	5	240
2015	439	67	170	0	0	205
2016	402	59	168	0	19	158

US Assets

Year	Revenue	Taxes	Operation Costs	Development Costs	Abandonment Costs	Future net Revenue before tax
2005	86	6	24	0	0	56
2006	68	5	23	0	0	41
2007	59	4	23	0	0	32
2008	43	3	18	0	0	22
2009	37	3	18	0	0	17
2010	34	3	18	0	0	14
2011	26	2	13	0	0	10
2012	22	2	13	0	0	7
2013	18	1	11	0	0	5
2014	14	1	9	0	0	4
2015	12	1	9	0	0	2
2016	11	1	9	0	0	1

In Aggregate

Year	Revenue	Royalty or Tax	Operation Costs	Development Costs	Abandonment Costs	Future net Revenue before tax
2005	1,892	396	334	475	0	735
2006	1,676	324	341	0	0	1,048
2007	1,272	213	310	0	0	766
2008	992	150	289	0	0	562
2009	812	113	269	0	16	420
2010	971	183	267	193	0	346
2011	781	141	222	0	17	411
2012	657	114	202	0	0	349
2013	578	94	196	0	0	294
2014	514	79	190	0	5	244
2015	451	68	179	0	0	207
2016	413	60	177	0	19	159

Summary of Pricing Assumptions for Oil and Gas Reserves

The Evaluators employed the following price and exchange rate and inflation rate assumptions as of December 31, 2004 in estimating Emerald's reserves data using constant prices and costs.

Constant Prices and Costs Used in Estimates

Inflation Rate Percent	0.00
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Crude Oil \$CND/BBL

Light Sweet Crude @ Edmonton	46.54
Medium Hardisty	25.92
LLB @ Hardisty	24.33
Medium @ Cromer	32.12
WTI @ Cushing, Oklahoma (\$US/BBL)	43.45
Somerset Oil @ Somerset (\$US/BBL)	42.31

NGLs \$CDN/BBL at Edmonton

Propane	29.79
Butane	34.44
Condensate	48.97

NGLs \$CND/MMBTU

AECO Spot	6.79
Alberta Spot Plant-gate	6.54
Alberta Government Reference Plant-gate	6.49
Alberta Aggregator Plant-gate	6.39
Saskatchewan Spot Plant-gate	6.69
B.C. Spot Plant-gate	6.49
Canwest Plant-gate	5.44

Exchange Rate

\$US/\$CND	0.820
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Forecast Prices and Costs Used in Estimates

The Evaluators employed the following price and exchange rate and inflation rate assumptions as of December 31, 2004 in estimating Emerald's reserves data using forecast prices and costs.

Year	Inflation (%)	Bank of Canada Average Noon Exchange Rate	West Texas Intermediate Crude Oil at Cushing Oklahoma				Sommerset Texas Oil		Brent Blend Crude Oil FOB North Sea		Light Sweet Crude Oil (40 API, 0.3% S) at Edmonton	
			Constant 2005 \$	Then Current	Then Current	Constant 2005 \$	Then Current	Constant 2005 \$	Then Current	Constant 2005 \$	Then Current	
			\$US/bbl	\$US/bbl	\$US/bbl	\$US/bbl	\$US/bbl	\$US/bbl	\$US/bbl	\$US/bbl	\$US/bbl	\$US/bbl
2005	2.0	0.820	42.00	42.00	43.34	40.50	40.50	50.25	50.25			
2006	2.0	0.820	39.25	40.00	40.34	37.75	38.50	46.75	47.75			
2007	2.0	0.820	36.50	38.00	40.03	35.00	36.50	43.75	45.50			
2008	2.0	0.820	34.00	36.00	36.65	32.50	34.50	40.75	43.25			
2009	2.0	0.820	31.50	34.00	36.65	30.00	32.50	37.75	40.75			
2010	2.0	0.820	30.00	33.00	39.02	28.50	31.50	35.75	39.50			
2011	2.0	0.820	29.25	33.00	39.02	28.00	31.50	35.00	39.50			
2012	2.0	0.820	28.75	33.00	39.02	27.50	31.50	34.50	39.50			
2013	2.0	0.820	28.50	33.50	39.02	27.25	32.00	34.25	40.00			
2014	2.0	0.820	28.50	34.00	39.02	27.25	32.50	34.00	40.75			
2015	2.0	0.820	28.25	34.50	39.02	27.00	33.00	33.75	41.25			
2016	2.0	0.820	28.25	2%/yr	39.02	27.00	2%/yr	33.75	2%/yr			

Year	Bow River Crude Oil Stream Quality at Hardisty		Heavy Crude Oil Proxy (12 API) at Hardisty		Medium Crude Oil (29 API, 2.0%S) at Cromer		Alberta Natural Gas Liquids (Then Current Dollars)			
	Constant 2005 \$	Then Current	Constant 2005 \$	Then Current	Constant 2005 \$	Then Current	Spec Ethane	Edmonton Propane	Edmonton Butane	Edmonton Pentanes Plus
	\$US/bbl	\$US/bbl	\$US/bbl	\$US/bbl	\$US/bbl	\$US/bbl	\$CDN/bbl	\$CDN/bbl	\$CDN/bbl	\$CDN/bbl
2005	35.00	35.00	27.50	27.50	43.75	43.75	22.00	32.25	37.25	50.75
2006	34.50	35.25	28.00	28.50	40.75	41.50	21.25	30.50	35.25	48.25
2007	33.75	35.00	27.75	28.75	38.00	39.50	20.50	29.00	33.75	46.00
2008	31.25	33.25	25.75	27.25	35.50	37.75	20.00	27.75	32.00	43.75
2009	29.00	31.50	23.50	25.50	32.75	35.50	20.00	26.00	30.25	41.25
2010	27.50	30.50	22.50	24.75	31.00	34.25	20.00	25.25	29.25	40.00
2011	27.00	30.50	22.00	24.75	30.50	34.25	20.00	25.25	29.25	40.00
2012	26.50	30.50	21.50	24.75	29.75	34.25	20.00	25.25	29.25	40.00
2013	26.25	30.75	21.00	24.75	29.75	34.75	20.25	25.50	29.50	40.50
2014	26.25	31.50	21.25	25.50	29.75	35.50	20.75	26.00	30.25	41.25
2015	26.00	31.75	21.00	25.75	29.50	36.00	21.00	26.50	30.50	41.75
2016	26.00	2%/yr	21.00	2%/yr	29.50	2%/yr	2%/yr	2%/yr	2%/yr	2%/yr

Reserves Reconciliation

Canadian Assets

Factors	Light/Medium Oil			Conventional Natural Gas			NGL's			Oil Equivalent		
	Net Proved (Mbbbl)	Net Probable (Mbbbl)	Net Proved Plus Probable (Mbbbl)	Net Proved (MMcfc)	Net Probable (MMcfc)	Net Proved Plus Probable (MMcfc)	Net Proved (Mbbbl)	Net Probable (Mbbbl)	Net Proved Plus Probable (Mbbbl)	Net Proved (MBoe)	Net Probable (MBoe)	Net Proved Plus Probable (MBoe)
January 1, 2004	4	1	5	671	159	830	25	6	31	141	34	175
Extensions	0	0	0	152	71	223	0	0	0	25	12	37
Improved Recovery	0	0	0	0	0	0	0	0	0	0	0	0
Technical Revisions	1	-1	0	183	-44	139	-3	-2	-5	29	-10	19
Discoveries	0	0	0	118	278	396	0	0	0	20	47	67
Acquisitions	0	0	0	0	0	0	0	0	0	0	0	0
Dispositions	0	0	0	0	0	0	0	0	0	0	0	0
Economic Factors	0	0	0	0	0	0	0	0	0	0	0	0
Production	-2		-2	-110		-110	-2		-2	-22		-22
January 1, 2005	3	0	3	1,014	464	1,478	20	4	24	193	83	276

US Assets

Light/ Medium Oil	
Factors	Net Proved (Mbbbl)
January 1, 2004	15
Technical Revisions	-2
Production	-2
January 1, 2005	11

Future Net Revenue Reconciliation

Canadian Assets

Factors	Before Tax (\$000 CDN)
January 1, 2004	2,371
Extensions	0
Improved Recovery	463
Technical Revisions	774
Discoveries	371
Acquisitions	0
Dispositions	0
Economic Factors	325
Production	-772
January 1, 2005	3,532

US Assets

Factors	Before Tax (\$000 CDN)
January 1, 2004	154
Technical Revisions	-56
Production	24
Net change in sales price	145
January 1, 2005	219

Significant Factors and Uncertainties

Oil and natural gas exploration involves a high degree of risk and there is no assurance that expenditures made on future exploration by the Corporation will result in new discoveries of oil or natural gas in commercial quantities. It is difficult to project the costs of implementing an exploratory drilling program due to the inherent uncertainties of drilling in unknown formations, the costs associated with encountering various drilling conditions such as over pressured zones and tools lost in the hole, and changes in drilling plans and locations as a result of prior exploratory wells or additional seismic data and interpretations thereof.

The Corporation currently has a limited number of specific identified exploration or development prospects. Management will continue to evaluate prospects on an ongoing basis in a manner consistent with industry standards and their past practices. The long-term commercial success of the Corporation depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. No assurance can be given that the Corporation will be able to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, the Corporation may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic.

Future oil and gas exploration may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While close well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

In addition, oil and gas operations are subject to the risks of exploration, development and production of oil and natural gas properties, including encountering unexpected formations or pressures, premature declines of reservoirs, blow-outs, cratering, sour gas releases, fires and spills. Losses resulting from the occurrence of any of these risks could have a materially adverse effect on future results of operations, liquidity and financial condition.

Future Development Costs (in CDN\$ thousands)

Canadian Assets

Entity Description	2005	2006	2007	2008	2009
Proved Producing	0	0	0	0	0
Total Proved	325	0	0	0	0
Probable	150	0	0	0	0
Total Proved Plus Probable	475	0	0	0	0

All Future development costs discounted at 10%: \$567,000. The Corporation intends to fund these future development costs from cash flow.

No Future Capital is required for US Assets.

Oil and Gas Properties and Wells

The Corporation has high working interest in many wells in Alberta and Texas.

The Corporation's Canadian assets are all located onshore in Alberta. The Corporation's US assets are all located onshore in Sommerset County, Texas. The Corporation's processing assets include single well oil and gas batteries.

	Gross	Net
Producing Wells	68	47.1
Non-Producing Wells	6	3.8

Wells in the Clive and Twining fields of Alberta are the only wells to which reserves have been assigned but are not currently producing. These wells were drilled in 2004 and are awaiting tie-in. They are all within one mile of natural gas gathering systems.

The Corporation owns 1400 hectares in the Clive and Lottie Lake, Alberta areas to which no proved reserves have been assigned. A well has already been drilled by the Company in Clive. No land expiries are expected.

Abandonment costs

The Emerald Report details future abandonment and reclamation costs for the oil and gas properties. The Evaluators estimate abandonment and reclamation costs based on similar costs experienced in the area and reduce the amount by expected salvage value of facilities. The Corporation is not responsible for abandonment costs for wells that it owns net profits interests. In total, the Corporation expects to be responsible for abandonment and reclamation costs for 46 net wells. Total abandonment costs are expected to be \$57 thousand before discounting or \$27 thousand discounted at 10%. The Corporation expects to pay none of these in the next three fiscal years. All these costs are in Canadian dollars and are included in the future net revenues in this report.

Tax Horizon

Based on the Corporation's current levels of investment in R&D and exploration, the company does not expect to become cash taxable within the next seven years. Should the company stop investing in R&D and the exploration for PNG, the company would expect to be cash taxable in 2008.

Costs Incurred in 2004

The following table shows gross capital expenditures for the Corporation in the categories and for the periods indicated:

	Year Ended December 31, 2004	Year Ended December 31, 2003
Land & Acquisition	\$1,117,000	\$293,000
Geological & Geophysical	461,000	(7,000)
Drilling & Exploration	21,000	2,000
Office	5,000	10,000
Total	<u>\$1,604,000</u>	<u>\$298,000</u>

Exploration and Development Drilling Activity

Clive – The key for development in Clive relies on the success of the CBM production after tie-in. When the Corporation begins producing economic volumes of Coalbed Methane in the 2 wells in section 14 – it opens-up numerous opportunities such as:

From 3 to 6 additional locations on section 14.

Farm-in on section 29 (directly north of 14) with Devon.

Provides a good business model for a small-cap company like the Corporation that would focus on smaller blocks of CBM farm-in land in the Horseshoe Canyon field.

Holding for down-spacing has been acquired in section 14 and 23.

Belly River down-spacing could provide at least 2 additional locations in sections 14 and 16.

Lottie Lake – The Corporation currently owns from Base of Mannville to Basement on 4 ½ sections of land in 58-11 W4M which was purchased as part of a play developed in-house. The Corporation felt that this area has Cooking Lake potential at about 1000 meters. Our near-term strategy is as follows:

Review the analysis and develop geophysical program to have additional data.

Farm-in on Viking rights.

With good seismic and the Viking rights - it then provides us a good basis for a Cooking Lake test well in Q3 of 2005.

Chauvin – The Corporation is currently negotiating a farm-in in the Chauvin area to drill a Devonian test well. The test well has good well control and seismic purchased. Sparky oil and Viking gas are potential bail-outs. Our strategy is as follows:

Negotiate reasonable farm-in terms.

Drilling priority based on Lottie Lake and Clive plans.

8 potential locations (16 BOEPD/well – risked)

Somerset-Von Ormy – Exploration in the U.S. and Western Canada can most often be "counter-cyclical" in terms of exploration opportunities. Currently in Western Canada small-cap companies like the Corporation are competing at land sales with larger companies with large land budgets. This leaves the smaller companies aggressively competing for farm-in opportunities. In certain areas of South Texas leases and drilling locations can still be acquired by smaller companies. Justification points for exploration in South Texas include:

Management has been active in the region since 1980 – drilling over 200 wells.

The Corporation already has operations in the region.

Minimal barriers to entry.

Land owners are typically the mineral owners – making it much easier to negotiate surface issues.

Drilling and completion costs are comparable to Western Canada – when considering exchange rate.

More production dollars make it to the bottom line. For example; if the Corporation farms-in and drills a 10 BOEPD well in Western Canada – the Corporation nets about 6.5 BOEPD before pay-out – after a GORR and Crown Royalty. After payout that number drops to about 3 BOEPD after the GORR converts to a 50% WI and Crown Royalty. That same well drilled in South Texas nets us about 8 BOEPD before AND after payout. This makes for very compelling economics.

Currently the Corporation has identified 27 drilling locations with 80 to 84% net revenue interests – ready for drilling. An additional 50+ locations are currently under review.

Edson – The Corporation has varied interests in a few sections in the Edson area as a result of our major transaction. The Corporation plan to study the up-hole potential in each of its working interest partners in Q3. The Corporation will adjust its drilling plans should research indicate something worthwhile.

Production Estimates for 2005

Canadian Assets

	Light/ Medium Oil	Residue Gas	NGL
	bbl/d	mcf/d	bbl/d
Proved	1	579	10
Proved Plus Probable	1	679	11

US Assets

	Light/ Medium Oil
	bbl/d
Proved	5

In Aggregate

	Light/ Medium Oil	Residue Gas	NGL
	bbl/d	mcf/d	bbl/d
Proved	6	579	10
Proved Plus Probable	1	679	11

Production History for 2004

<u>Production</u>	2004 Q1	2004 Q2	2004 Q3	2004 Q4
Crude (bbl/d)	6	7.4	5	7
Gas (mcf/d)	381	367	370	385
NGL (bbl/d)	10	8.8	10	9
BOE (boe/d)	79	78	77	80

Elements of Historic Cash Flow (\$/boe)

Revenue	39.25	43.79	41.85	44.43
Royalty	8.04	2.84	8.67	8.84
Production Costs	5.68	13.62	14.43	0.06
Net back	25.53	27.33	18.75	35.53