REVISED

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Disclosure of Reserves Data

In accordance with National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101"), Sproule Unconventional Limited ("Sproule") prepared a report (the "Sproule Report") dated March 19, 2009 and effective December 31, 2008. The Sproule Report evaluated the oil, natural gas liquids ("NGL") and natural gas reserves of Richards Oil & Gas Limited (the "Company") as at December 31, 2008. The preparation date of the information regarding the reserves in the Sproule Report is January to March 2008.

The tables below are a summary of the oil, NGL and natural gas reserves of the Company and the net present value of future net revenue attributable to such reserves as evaluated in the Sproule Report based on forecast price and cost assumptions. The tables summarize the data contained in the Sproule 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 Company's 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 Sproule. It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to the Company's reserves estimated by Sproule 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 Company's oil, NGL 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.

The values shown for income taxes and future net revenue after income taxes were calculated on a stand-alone basis in the Sproule Report. The values shown may not be representative of future income tax obligations, applicable tax horizon or after tax valuation.

The Sproule Report is based on certain factual data supplied by the Company and Sproule's opinion of reasonable practice in the industry. The extent and character of ownership and all factual data pertaining to the Company's petroleum and natural gas properties and contracts (except for certain information residing in the public domain) were supplied by the Company to Sproule and accepted without any further investigation. Sproule accepted this data as presented and neither title searches nor field inspections were conducted.

All of the reserves held by the Company are located in Canada, and specifically, in the provinces of Alberta and Saskatchewan.

RESERVES DATA – FORECAST PRICES AND COSTS

Summary of Oil and Gas Reserves - Forecast Prices and Costs

Reserve Category	Light & Medium Oil		Heavy Oil		Conventional Natural Gas		Coalbed Methane		Natural Gas Liquids	
	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)
Proved										
Developed Producing	-	-	6	6	452	366	1,145	974	1	1
Developed Non-Producing	-	-	-	-	-	-	605	538	-	-
Undeveloped	-	-	-	-	-	-	5,728	4,869	-	-
Total Proved	-	-	6	6	452	366	7,478	6,381	1	1
Probable	-	-	3	3	549	430	5,272	4,365	0.3	0.2
Total Proved + Probable	**-**	**-**	**9**	**9**	**1,001**	**796**	**12,750**	**10,746**	**1**	**1**

Summary of Net Present Values of Future Net Revenue - Forecast Prices and Costs

Reserve Category	Before Income Taxes Discounted at (%/year) 5 (M$)	10 (M$)	15 (M$)	20 (M$)	Unit Value Before Income Tax Discounted at 10% $/BOE
Proved					
Developed Producing	4,995	4,476	4,060	3,722	19.47
Developed Non-Producing	2,039	1,716	1,470	1,278	19.15
Undeveloped	6,711	4,083	2,217	868	5.03
Total Proved	**13,745**	**10,275**	**7,747**	**5,868**	**9.09**
Probable	10,349	6,869	4,571	3,007	8.57
Total Proved + Probable	**25,094**	**17,144**	**12,318**	**8,875**	**8.87**

Reserve Category	After Income Taxes Discounted at (%/year) 5 (M$)	10 (M$)	15 (M$)	20 (M$)
Proved				
Developed Producing	4,995	4,476	4,060	3,722
Developed Non-Producing	2,039	1,716	1,470	1,278
Undeveloped	6,711	4,083	2,217	868
Total Proved	**13,745**	**10,275**	**7,747**	**5,868**
Probable	9,955	6,640	4,434	2,923
Total Proved + Probable	**23,700**	**16,915**	**12,181**	**8,791**

Total Future Net Revenues, Undiscounted - Forecast Prices and Costs

Reserve Category	Revenue (M$)	Royalties (M$)	Operating Costs (M$)	Development Costs (M$)	Well Abandonment/ Other Costs (M$)	Future Net Revenue Before Income Taxes (M$)	Income Taxes (M$)	Future Net Revenue After Income Taxes (M$)
Proved	67,968	9,823	25,524	12,622	1,352	18,647	nil	18,647
Proved + Probable	122,397	19,304	46,389	20,219	1,982	34,503	695	33,808

Net Present Value of Future Net Revenues - by Production Group
Forecast Prices and Costs

Reserve Category	Production Group	Future Net Revenue Before Income Taxes Discounted at 10%/ Year (M$)	Unit Value Before Income Taxes Discounted at 10%/ Year $/BOE
Proved			
	Light and Medium Crude Oil (including solution gas and associated by-products)	-	-
	Heavy Oil (including solution gas and associated by-products)	165	28.45
	Coalbed Methane (including associated by-products)	8,585	8.07
	Natural Gas (including associated by-products)	1,213	19.66
	Other Revenue	312	
Total		**10,275**	
Proved plus Probable	Light and Medium Crude Oil (including solution gas and associated by-products)	-	-
	Heavy Oil (including solution gas and associated by-products)	248	29.87
	Coalbed Methane (including associated by-products)	13,420	7.49
	Natural Gas (including associated by-products)	3,081	23.08
	Other Revenue	395	
Total		**17,144**	

Pricing Assumptions

Sproule employed the following pricing, exchange rate and inflation rate assumptions as at December 31, 2008 in estimating the Company's reserves data using forecast prices and costs:

Summary of Pricing and Inflation Rate Assumptions - Forecast Prices and Costs

	Oil			Natural Gas & Natural Gas Liquids				
Year	WTI Cushing Oklahoma ($US/bbl)	Edmonton Par Price 40° API ($Cdn/bbl)	Cromer Medium 29° API ($Cnd/bbl)	AECO Gas Prices ($Cdn/MmBtu)	Pentanes Plus FOB Field Gate ($Cdn/bbl)	Butanes FOB Field Gate ($Cdn/bbl)	Inflation Rate (%/Yr)	Exchange Rate ($US/$Cdn)
2009	53.73	65.35	58.16	6.82	66.93	51.15	2.0	.800
2010	63.41	72.78	66.23	7.56	74.54	54.25	2.0	.850
2011	69.53	79.95	72.76	7.84	81.88	59.59	2.0	.850
2012	79.59	86.57	79.65	8.38	88.66	64.53	2.0	.900
2013	92.01	94.97	87.38	9.20	97.27	70.79	2.0	.950
Thereafter				Various Escalation Rates				

The weighted average realized sales prices for Richards Oil & Gas Limited for the year ended December 31, 2008 were $8.07 per Mcf for natural gas and $76.40 per bbl for heavy oil.

Reconciliation of Company Gross Reserves[1] - By Principal Product Type
As at December 31, 2008 - Forecast Prices and Costs

	Heavy Oil (Mbbls)			Conventional Natural Gas (MMcf)		
	Gross Proved	Gross Probable	Gross Proved Plus Probable	Gross Proved	Gross Probable	Gross Proved Plus Probable
December 31, 2007	7	3	10	138	38	176
Extensions and improved recovery	-	-	-	257	515	772
Transfer	-	-	-	-	-	-
Technical revisions	2	-	2	44	(13)	31
Economic factors	-	-	-	64	9	73
Production	(3)	0	(3)	(51)	-	(51)
December 31, 2008	6	3	9	452	549	1,001

	Coalbed Methane (MMcf)			Total Company BOE		
	Gross Proved	Gross Probable	Gross Proved Plus Probable	Gross Proved	Gross Probable	Gross Proved Plus Probable
December 31, 2007	6,785	3,807	10,592	1,161	644	1,805
Extensions and improved recovery	166	2,099	2,265	71	436	507
Transfer				-	-	-
Technical revisions	759	(629)	130	136	(108)	28
Economic factors	155	(5)	150	37	1	38
Production	(387)	0	(387)	(76)	-	(76)
December 31, 2008	7,478	5,272	12,750	1,329	973	2,302

Note: (1) "Gross" means the Company's working interest reserves before calculation of royalties and before consideration of the Company's royalty interests.

Undeveloped Reserves

Product Type	Units	Company Gross Reserves First Attributed By Year				
		Prior	2006	2007	2008	Total
Proved Undeveloped						
Heavy Oil	Mbbl	-	-	-	-	-
Conventional Natural Gas	Mmcf	-	-	-	-	-
Coalbed Methane	Mmcf	843.0	2,922.0	788.3	1,175.0	5,728.3
Total: Oil Equivalent	**Mboe**	**140.5**	**487.0**	**131.4**	**195.8**	**954.7**
Probable Undeveloped						
Heavy Oil	Mbbl	11.0	(11.0)	-	-	-
Conventional Natural Gas	Mmcf	-	-	-	549.0	549.0
Coalbed Methane	Mmcf	765.0	2,533.0	509.2	1,465.0	5,272.2
Total: Oil Equivalent	**Mboe**	**138.5**	**411.2**	**84.8**	**335.7**	**910.2**

The Company has a development program underway in all its Coalbed Methane reserves areas. All undeveloped Coalbed Methane reserves have resulted from discoveries in the period 2005 though to 2008. The remaining undeveloped reserves are downspacing locations primarily at the Company's Lacombe and Thorsby properties. These wells are in the budget to be drilled and tied-in over the next three years and are economic under current assumptions in the Sproule Report.

Significant Factors or Uncertainties Affecting Reserves Data

The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering, and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions. The Company's reserves are evaluated by Sproule, an independent engineering firm.

As circumstances change and additional data becomes available, reserve estimates also change. Estimates made are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and governmental restrictions.

Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. As a result, the subjective decisions, new geological or production information and a changing environment may impact these estimates. Revisions to reserve estimates can arise from changes in year-end oil and gas prices, and reservoir performance. Such revisions can be either positive or negative.

Other than the various risks and uncertainties that participants in the oil and gas industry are exposed to generally, the Company is unable to identify any important economic factors or significant uncertainties that will affect any particular components of the reserves data disclosed herein.

Future Development Costs

FUTURE DEVELOPMENT COSTS BY RESERVES CATEGORIES
FORECAST PRICES AND COSTS

Reserve Category	Total (undiscounted)	Total (NPV 10%)	2009	2010	2011	2012 and 2013
Proved Reserves (Forecast Prices and Costs)	12,622	11,182	4,755	7,867	-	-
Proved Plus Probable Reserves (Forecast Prices and Costs)	20,200	17,700	5,500	13,700	1,000	-

The Company expects to finance the identified development costs from a combination of cash flow, available working capital, debt and equity. The Company does not expect that the costs of funding the development costs will make the development of the properties uneconomic.

Principal Properties

Morningside/Lacombe Area, Alberta

The Morningside property is located between the cities of Red Deer and Edmonton and is approximately 10 kilometers northwest of the town of Lacombe. The Company holds four sections of land (1,280 net acres) in this property. During 2005 through to the end of 2007 the Company drilled and completed 15 wells on the Morningside lands. At the end of December 2008, all 15 wells that have been drilled and completed to date have been tied into a sales pipeline. Current average per well production from the 15 wells are at rates of 100 Mcf per day from the Horseshoe Canyon coals and the comingled Belly River and Edmonton sands. In the first half of 2009 the Company intends to eliminate the remaining distributed compression used on the southern sections of this property and in doing so reduce go forward operating costs, and improve the well productivity. Company interest production in the Morningside Area for the period ended December 31, 2008 averaged 672 Mcf/d.

The Lacombe property was acquired effective July 1, 2005 from Drumlin Energy Corp. This non-operated property sits adjacent to the Company's Morningside lands. The assets acquired comprise an average 36% Working Interest in 19 sections of land, and a 42% Working Interest in a gas gathering pipeline and approximately 120 Mcf per day (net) of conventional gas production. Since the acquisition of the assets, the operator has drilled an additional seven (gross) Horseshoe Canyon CBM wells in early 2006, an additional six (gross) Horseshoe Canyon CBM wells in mid 2007 and one (gross) additional well in 2008. These additional wells have added approximately 280 mcf per day (net) of CBM production from these new wells. The Company is in discussion with the operator regarding the additional development drilling and production enhancement opportunities on this property. Company interest production in the Lacombe Area for the period ended December 31, 2008 averaged 351 Mcf/d.

Thorsby, Alberta

The Thorsby Horseshoe Canyon CBM properties were purchased from Mazzerado Resources Ltd. effective July 1, 2005. The Company purchased a 30% working interest in seven sections of land plus a 30% working interest in the gas gathering pipeline in the area. One Horseshoe Canyon coalbed methane well was drilled in February 2007 and was brought on production in September 2007. The performance of this well was encouraging enough that the Company acquired two sections of adjacent Crown land in November 2007 at 100% working interest. In late 2007 the Company also increased its working interest in its original seven sections of land from 30% to 45%. In January 2008, the Company further increased its opportunity to expand in Thorsby when it entered into a farmin agreement representing a five well drilling commitment to earn a 100% working interest on five sections that are adjacent with the Company’s current landholdings. Under the terms of the agreement, the Company has the option to earn up to 9.75 additional surrounding sections with the drilling of additional wells. In 2008 the Company drilled the five commitment wells and drilled an additional six option wells under the terms of the farmin aggreement. Company interest production in the Thorsby Area for the period ended December 31, 2008 averaged 18 Mcf/d with all of this production in the last two weeks of the year.

Crossfield, Alberta

The Crossfield property consists of five sections of land purchased at a Crown land sale in March 2006. The Company holds a 60% working interest in all rights in the five sections. The Crossfield property is primarily a Horseshoe Canyon CBM play with additional upside from the conventional Edmonton, Belly River, Elkton, Viking, Elkton and Crossfield formations. The Company shot and owns a proprietary 3D seismic over the entire five section block. Two wells have been drilled to date. In the first well the Viking formation was initially tested and abandoned. Testing in this well now is currently focused on the Edmonton sand and Horseshoe Canyon CBM potential. The second well was drilled in 2007 and the drill focused specifically on Horseshoe Canyon CBM. Both of these wells show strong potential from the current zones of interest. The Company is at present reviewing options for getting the natural gas to market and evaluating additional land opportunities. Up to 18 additional wells could be drilled in this area.

Gadsby, Alberta

The Corporation entered into a deal with one of its partners to drill to earn Mannville conventional and CBM rights in their lands in the Gadsby area, which is located approximately 15 kilometres south of the town of Stettler. To date, four sections of land have been earned through the drilling of three wells.

Two wells were drilled in December 2005 in which the Glauconite zone was subsequently completed and tied in, and a third well was drilled in June 2006 in which the Viking zone was completed and tied in. Preliminary testing of the Mannville coals was done while drilling these wells. During 2007 conventional gas production declined from the Glauconite wells significantly due to natural reservoir depletion and water production issues. Currently the Company is only producing from two of the three original wells at Gadsby. Company interest production in the Gadsby Area for the period ended December 31, 2008 averaged 104 Mcf/d. These wells also provided base line information on the Mannville CBM resource potential.

Saskatchewan Heavy Oil Properties

The Company has 260 net acres of property in the province of Saskatchewan. Company interest production in the Saskatchewan Area for the period ended December 31, 2008 averaged 8 bbl/d.

Greater Berland Area, Alberta

The Company holds approximately 18 gross sections of land (6,935 net acres) in the Greater Berland area, 10 earned sections at Marsh and eight earned sections at Lambert. The Company has assembled a significant land position in this area and is currently evaluating the Ardley coal zone. The Ardley is largest CBM opportunity in Alberta that to date has not produced commercial levels of CBM.

Banshee (Ansell and Shaw) / Coal Valley, Alberta

The Banshee / Coal Valley property comprises some 11 gross section (4,374 net acres), eight earned sections at Ansell and three at Coal Valley (all of which are earned). Similar to the Company’s efforts in the Greater Berland Area, the Company has also assembled a significant land position in this area and is also currently evaluating the Ardley coal zone.

Oil and Gas Wells

The following table sets forth the number and status of wells in which the Company has a working interest as at December 31, 2008.

Property	Number of Producing Wells (1) (Gross)	Number of Producing Wells (1) (Net)	Number of Non-Producing Wells (1) (Gross)	Number of Non-Producing Wells (1) (Net)
Morningside	15	8.7	-	-
Lacombe	17	6.6	6	2.3
Thorsby	3	2.6	15	12.0
Gadsby	2	2.0	1	1.0
Lone Rock & Marsden	4	0.6	-	-
Manitou Lake	-	-	1	0.2

(1) The above well description and well count data refers only to wells which reserves are reported, exploratory test wells drilled to investigate resource assets are not included.

The following table sets forth the status of the producing wells in which the Company has a working interest as at December 31, 2008.

Property	Location	Status	Facilities
Morningside	Alberta	Producing CBM	On Pipe
Thorsby	Alberta	Producing CBM and Natural Gas	On Pipe
Lacombe	Alberta	Producing CBM and Natural Gas	On Pipe
Gadsby	Alberta	Producing Natural Gas	On Pipe
Lone Rock, Marsden and Manitou Lake	Saskatchewan	Producing Heavy Oil	Trucked to sales

Properties With No Attributed Reserves (interest of the Company in terms of net area)

Canadian Property	Unproven Acreage (Gross)	Unproven Acreage (Net)	Wells Drilled(1) (Gross)
Banshee / Coal Valley	7,040	4,374	4
Greater Berland	11,520	6,935	8
Crossfield	3,200	1,920	2

Notes:
(1) Exploratory test wells drilled to investigate resource assets.

Forward Contracts

As at December 31, 2008, the Company is not bound by any agreements (including a transportation agreement), directly or through an aggregator, under which it may be precluded from fully realizing, or may be protected from the full effect of, future market prices for oil or gas.

Additional Information Concerning Abandonment and Reclamation Costs

In deriving estimates for abandonment and restoration costs, the Company considered the geographic location of the wells and facilities in place, the nature of the facilities and actual field experience. Using this methodology, the Company's total undiscounted, un-escalated abandonment and restoration costs, net of estimated salvage value, is estimated at $1,618,252 ($741,874 discounted at 10%). It is estimated that these costs are expected to be incurred for approximately 45.1 net wells in Canada, along with similar costs for the Company's facilities and pipelines interests. All of the estimated abandonment and restoration costs were deducted in computing future net revenue. The portion of the Company's undiscounted total abandonment and reclamation costs expected to be paid in the next three financial years is estimated to be $303,364.

Tax Horizon

The Company is currently not required to pay taxes in Canada for its most recently completed financial year. Based on after tax economic forecasts (constant price case), income taxes are payable by the Company beginning in 2020.

Costs Incurred

The following table summarizes in Canadian dollars certain expenditures of the Company during the financial year ended December 31, 2008:

	Property Acquisition Costs ($)		Exploration Costs	Development Costs	Total
Country	**Unproved Properties**	**Proved Properties**	**($)**	**($)**	**($)**
Canada	26,201	18,955	578,819	6,455,577	7,079,552

(1) The definitions of the various categories of properties and expenses are those set out in NI 51-101.

Drilling Activity

The following table sets forth the gross and net exploratory and development wells in which the Company participated during the year ended December 31, 2008.

	Exploration Wells		Development Wells	
	(Gross)	**(Net)**	**(Gross)**	**(Net)**
Oil	-	-	-	-
Gas	-	-	13	12
D&A	-	-	-	-
Total	-	-	13	12

The Company plans to continue with development of its Horseshoe Canyon CBM properties in the Lacombe and Thorsby areas, to expand it land base and explore options for getting its natural gas to market in the Crossfield area.

The Company spent $7,079,552 on capital expenditures relating to its oil and gas properties during the year 2008, excluding any purchases acquired for non-cash consideration. The following table summarized the Company's investment activities by types:

	Amount $
Land and carrying costs	45,156
Geological and geophysical	64,732
Drilling and completion	3,754,694
Well equipment and facilities	3,214,970
Acquisition of oil and gas properties	-
	7,079,552

Production Estimates for 2009

The following table discloses, by product type, the total volume of production estimated by Sproule for 2009 in the estimates of future net revenue from proved and probable reserves disclosed under “Petroleum and Natural Gas Reserves”:

	Heavy Oil (Bbls/d)	Natural Gas [(1)] (Mcf/d)	NGLs (Bbls/d)	BOE (BOE/d)	%
Morningside	-	619	-	103	34
Thorsby	-	796	-	133	43
Lacombe	-	305	1	52	17
Gadsby	-	63	-	11	4
Lone Rock, Marsden and Manitou Lake	7	-	-	7	2
Estimated Total Production	7	1,430	1	306	100

(1) Natural Gas production includes Conventional Natural Gas production and production of Coalbed Methane including associated by-products

Production and Netback History

	2008				
	First Quarter	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Year Ended December 31, 2008**
Total Sales Volumes					
Natural Gas (Mcf/d)	1,232	1,174	1,023	1,149	1,144
Oil (Bbls/d)	9	7	10	8	8
NGLs (Bbls/d)	3	1	1	2	2
Combined (Bopd)	217	204	182	201	201
Average price received					
Natural Gas ($/Mcf)	7.90	10.03	7.65	6.64	8.07
Oil ($/Bbl)	60.17	100.38	100.37	42.10	76.40
NGLs ($/Bbl)	72.97	79.26	74.96	38.96	65.37
Combined ($/Bopd)	48.18	61.68	49.15	39.90	49.73
Royalties paid					
Natural Gas ($/Mcf)	1.26	0.94	1.07	1.05	1.08
Oil ($/Bbl)	6.62	13.74	15.10	3.62	9.96
NGLs ($/Bbl)	11.35	91.91	21.12	(28.46)	27.32
Combined ($/Bopd)	7.58	6.35	7.47	5.85	6.81
Operating expenses (1)					
Natural Gas ($/Mcf)	2.92	3.01	3.78	3.63	3.34
Oil ($/Bbl)	17.36	18.07	23.21	22.06	20.39
NGLs ($/Bbl)	18.26	17.92	22.97	21.69	20.02
Combined ($/Bopd)	17.99	18.08	22.70	21.79	20.04
Netback					
Natural Gas ($/Mcf)	3.72	6.08	2.80	1.96	3.65
Oil ($/Bbl)	36.19	68.57	62.06	16.42	46.05
NGLs ($/Bbl)	43.36	(30.57)	30.87	45.73	18.03
Combined ($/Bopd)	22.61	37.25	18.98	12.26	22.88

Note:

(1) Operating expenses includes costs of field contractors, compression, transportation, chemicals and treating supplies, operating overhead and minor well workovers.