DRAKE PACIFIC ENTERPRISES LTD.

2008 - Report 51 – 101 F1

Statement of Reserves Data and Other Oil and Gas Information

The effective date of the reserves information is December 31 2008.

DISCLOSURE OF RESERVES DATA

Sproule Associates Limited ("SPROULE"), an independent third party engineering firm, was engaged to evaluate and review all the company's reserves **except** at Carmangay, Hoosier and Jenner. No valuation of possible reserves was undertaken. The pricing used in the forecast price evaluation, together with other assumptions and qualification applicable to the evaluation and contained in the SPROULE Report are set forth in "Pricing Assumptions". The SPROULE Report has been prepared in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities and the Canadian Oil & Gas Evaluation Handbook ("COGE Handbook").

Martin & Brusset Associates Limited ("MARTIN & BRUSSET"), an independent third party engineering firm, was engaged to evaluate and review the company's reserves at Carmangay. No valuation of possible reserves was undertaken. The pricing used in the forecast price evaluation, together with other assumptions and qualification applicable to the evaluation and contained in the MARTIN & BRUSSET Report are set forth in "Pricing Assumptions". The MARTIN & BRUSSET Report has been prepared in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities and the Canadian Oil & Gas Evaluation Handbook ("COGE Handbook").

AJM Petroleum Consultants ("AJM"), an independent third party engineering firm, was engaged to evaluate and review the company's reserves at Jenner and Hoosier. No valuation of possible reserves was undertaken. The pricing used in the forecast price evaluation, together with other assumptions and qualification applicable to the evaluation and contained in the AJM Report are set forth in "Pricing Assumptions". The AJM Report has been prepared in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities and the Canadian Oil & Gas Evaluation Handbook ("COGE Handbook").

All evaluations of future net production revenues set forth in the tables are stated without provision for income taxes or abandonment costs on wells and facilities where reserves are not assigned or associated general and administrative costs.

The present value of all future cash flows at December 31, 2008 was based upon crude oil and natural gas pricing assumptions prepared by SPROULE, MARTIN & BRUSSET and AJM.

All production reported by the company is in Canada, primarily in the province of Alberta with one small property in Saskatchewan.

ABBREVIATIONS:

bbl	barrel	Mcf	thousands of cubic feet
boe	barrels of oil equivalent	MM	million
btu	British thermal unit	NGL	natural gas liquids
M	thousand		

Reserves Data – Forecast Prices and Costs

The following table sets out Drake's gross volumes by production type and reserve category under a forecast price scenario. Under different price scenarios, these reserves could vary as a change in price can affect the economic limit and reserves associated with a property.

2008 Reserve Summary – Gross volumes (forecast prices)

	RESERVE VOLUMES (FORECAST PRICE & COSTS)							
	Oil		Natural Gas		NGLs		Total boes	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
RESERVE CATEGORY	(Mbbl)	(Mbbl)	(MMcf)	(MMcf)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)
PROVED								
Developed Producing	105	92	1,560	1,318	13	10	378	322
Developed Non-Producing	11	11	219	165	2	1	49	39
Undeveloped	19	16	306	235	0	0	70	55
TOTAL PROVED	135	118	2,084	1,718	15	12	497	416
PROBABLE	90	78	912	752	5	4	247	207
TOTAL PROVED PLUS PROBABLE	225	197	2,996	2,470	19	15	744	623

Net Present Value of Future Production Revenue – Forecast Prices and Costs

The following table shows the net present value of future net reserves from the company's reserves using the forecast prices shown. The estimated future net revenues disclosed do not represent the fair market value of the company's reserves.

NET PRESENT VALUES OF FUTURE NET REVENUE - FORECAST PRICES AND COSTS						UNIT VALUE BEFORE INCOME TAXES
	BEFORE INCOME TAX (%/YR)					
Discount Rate	0%	5%	10%	15%	20%	DISCOUNTED AT 10%
	($000s)	($000s)	($000s)	($000s)	($000s)	($/boe)
RESERVE CATEGORY						
PROVED						
Developed Producing	13,331	10,008	8,113	6,881	6,010	21.48
Developed Non-Producing	1,408	1,186	1,027	908	817	20.79
Undeveloped	1,877	1,547	1,295	1,096	939	18.39
TOTAL PROVED	16,616	12,741	10,435	8,885	7,766	20.98
PROBABLE	9,863	6,430	4,641	3,551	2,824	18.82
TOTAL PROVED PLUS PROBABLE	26,479	19,170	15,076	12,436	10,590	20.26

NET PRESENT VALUES OF FUTURE NET REVENUE - FORECAST PRICES AND COSTS

	AFTER INCOME TAX (%/YR)				
Discount Rate	0%	5%	10%	15%	20%
	($000s)	($000s)	($000s)	($000s)	($000s)
RESERVE CATEGORY					
PROVED					
Developed Producing	11,247	8,516	6,929	5,886	5,145
Developed Non-Producing	1,056	949	862	791	732
Undeveloped	1,362	1,117	928	781	664
TOTAL PROVED	13,665	10,582	8,719	7,459	6,541
PROBABLE	7,340	4,775	3,439	2,626	2,085
TOTAL PROVED PLUS PROBABLE	21,006	15,357	12,158	10,085	8,626

Total Future Net Revenue (Undiscounted) at December 31, 2008 – Forecast Prices

The following table shows future net revenue (undiscounted) after income taxes at Forecast Prices and Costs as of December 31, 2008

TOTAL FUTURE NET REVENUE - BREAKDOWN BY CATEGORY - UNDISCOUNTED

RESERVE CATEGORY	Revenue ($000s)	Royalties ($000s)	Operating costs ($000s)	Development Costs ($000s)	Well Abandonment Costs ($000s)	Future Net Revenue ($000s)	Income Tax ($000s)	Future net Revenue After Tax ($000s)
TOTAL PROVED	31,130	5,128	8,336	527	523	16,616	2,950	13,665
TOTAL PROVED PLUS PROBABLE	49,271	8,166	12,943	1,095	589	26,479	5,473	21,006

Future Net Revenue by Production Group – Forecast Prices and Costs

Net Present Value by Production Group as of December 31 2008 - Forecast Prices and Costs					
Reserve Category	Production Group	Future Net Revenue Before Income Tax (10%)	Unit Value Before Income Taxes (10%)		
		(M$)	($/bbl)	($/mcf)	($/boe)
Proved	Light and Medium Crude Oil (including solution gas and associated by-products)	4,177	27.83		27.83
	Natural Gas (including associated by-products)	6,258		3.00	18.02
Proved + Probable	Light and Medium Crude Oil (including solution gas and associated by-products)	6,178	25.26		25.26
	Natural Gas (including associated by-products)	8,897		2.97	17.82

Definitions and Other Notes to Reserves Data and Tables:

1. **"Gross"** means:

   a) in relation to the Company's interest in production and reserves, the Company's interest (operating and non-operating) before deduction of royalties and without including any of the Company's royalty interests;

   b) in relation to wells, the total number of wells in which we have an interest; and

   c) in relation to properties, the total area of properties in which we have an interest.

2. **"Net"** means:

   a) in relation to the Company's interest in production and reserves, the Company's interest (operating and non-operating) after deduction of royalty obligations, plus the Company's royalty interest in production or reserves;

   b) in relation to wells, the number of wells obtained by aggregating the Company's working interest in each of the Company's gross wells; and

   c) in relation to the Company's interest in a property, the total area in which we have an interest multiplied by the working interest we own.

3. **"Development well"** means a well drilled inside the established limits of an oil or gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.

4. "**Development costs**" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

   a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines and power lines, to the extent necessary in developing the reserves;

   b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and wellhead assembly;

   c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and

   d) provide improved recovery systems.

5. **"Exploratory well"** means a well that is not a development well, a service well or a stratigraphic test well.

6. "**Exploration costs**" means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as "prospecting costs") and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

   a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies (collectively sometimes referred to as "geological and geophysical costs");

   b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence, and the maintenance of land and lease records;

c) dry hole contributions and bottom hole contributions;

d) costs of drilling and equipping exploratory wells; and

e) costs of drilling exploratory type stratigraphic test wells.

7. "**Service well**" means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation or injection for combustion.

8. The crude oil, natural gas liquids and natural gas reserve estimates presented in the SPROULE, MARTIN & BRUSSET and AJM Reports are based on the definitions and guidelines contained in the COGE Handbook. A summary of those definitions are set forth below:

Reserve Categories

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on

- analysis of drilling, geological, geophysical and engineering data;
- the use of established technology; and
- specified economic conditions, specifically the forecast prices and costs and constant prices and costs.

Reserves are classified according to the degree of certainty associated with the estimates.

a) **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.

b) **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.

Criteria that must also be met for the categorization of reserves are provided in the COGE Handbook.

Each of the reserve categories (proved and probable) may be divided into developed and undeveloped categories:

a) **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 (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

i. **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.

ii. **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.

b) **Undeveloped reserves** are those reserves expected to be recovered from known 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) to which they are assigned.

In multi-well pools it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions above are applicable to individual reserve entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserves are presented).

Reported reserves should target the following levels of certainty under a specific set of economic conditions:

(a) at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and

(b) at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves.

A qualitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

9. **Forecast prices and costs**

Forecast prices and costs are those:

(a) generally acceptable as being a reasonable outlook of the future; and

(b) if and only to the extent that, there are fixed or presently determinable future prices or costs to which we are legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

10. **Abandonment and reclamation costs**

Estimated future abandonment and reclamation costs related to a property have been taken into account by SPROULE, MARTIN & BRUSSET and AJM in determining reserves that should be attributed to a property and in determining the aggregate future net revenue there from, there was deducted the reasonable estimated future well abandonment costs. No allowance was made, however, for reclamation of well sites or the abandonment and reclamation of any facilities or wells with no attributed reserves.

11. **Future income tax expenses**

Future income tax expenses are estimated (generally, year-by-year):

(a) by making appropriate allocations of estimated unclaimed costs and losses carried forward for tax purposes;

(b) without deducting estimated future costs (for example, Crown royalties) that are not deductible in computing taxable income;

(c) taking into account estimated tax credits and allowances; and

(d) applying to the future pre-tax net cash flows relating to the Company’s oil and gas activities the appropriate year-end statutory rates, taking into account future tax rates already legislated.

(e) Future net revenue is the estimated net amount to be received with respect to the development and production of reserves estimated using forecasted prices and costs. This net amount is computed by deducting from estimated future revenues: estimated amounts of future royalty obligations, costs related to the development and production of reserves, well abandonment costs and future income tax expenses.

(f) Forecast price and cost assumptions assume the continuance of current laws and regulations.

(g) The extent and character of all factual data supplied to SPROULE, MARTIN & BRUSSET and AJM were accepted by SPROULE, MARTIN & BRUSSET and AJM as represented. No field inspection was conducted.

(h) Columns may not add due to rounding.

PRICING ASSUMPTIONS

SPROULE December 31, 2008 – Forecast Price and Cost Assumptions

Year	WTI Cushing Oklahoma $US/bbl	Edmonton Par Price 40 API $Cdn/bbl	Natural gas Aeco Prices $Cdn/MMbtu	Inflation rate %/Yr	Exchange rate $US/$Cdn
2009	53.73	65.35	6.82	2.00	0.80
2010	63.41	72.78	7.56	2.00	0.85
2011	69.53	79.95	7.84	2.00	0.85
2012	79.59	86.57	8.38	2.00	0.90
2013	92.01	94.97	9.20	2.00	0.95
thereafter				various escalation rates	

MARTIN & BRUSSET December 31, 2008 – Forecast Price and Cost Assumptions

Year	WTI Cushing Oklahoma $US/bbl	Edmonton Par Price 40 API $Cdn/bbl	Natural gas Aeco Prices $Cdn/MMbtu	Inflation rate %/Yr	Exchange rate $US/$Cdn
2009	57.00	66.50	7.40	-	0.83
2010	70.00	80.00	8.00	2.00	0.85
2011	80.00	88.00	8.50	2.00	0.89
2012	87.00	93.00	8.75	2.00	0.92
2013	94.00	97.00	9.00	2.00	0.95
thereafter					+ 2% / year

AJM December 31, 2008 – Forecast Price and Cost Assumptions

Year	WTI Cushing Oklahoma $US/bbl	Edmonton Par Price 40 API $Cdn/bbl	Natural gas Aeco Prices $Cdn/mcf	Inflation rate %/Yr	Exchange rate $US/$Cdn
2009	55.00	65.40	7.00	2.00	0.82
2010	76.50	87.20	8.05	2.00	0.86
2011	88.45	96.50	8.20	2.00	0.90
2012	100.80	104.30	9.00	2.00	0.95
2013	108.25	112.05	9.75	2.00	0.95
thereafter			+ 2% / year		

RECONCILIATION OF CHANGES IN RESERVES

The following tables reconcile the reported volumes of gross reserves from December 31, 2007 to December 31, 2008 and highlight which production type and reserves categories contributed to the change.

Proved + Probable Reserves – Gross Volumes (forecast prices)

	Light and Medium oil Mbbl	**Natural gas liquids Mbbl**	**Natural gas MMcf**	**Total Mboe**
Proved Reserves at December 31 2007	80	11	981	255
Discoveries	30	1	153	57
Extensions	-	-	-	-
Improved recovery	-	-	-	-
Technical revisions	39	2	412	110
Acquisitions	16	3	860	163
Dispositions	-	-	-	-
Economic factors	-	-	-	-
Production	(30)	(2)	(323)	(86)
Proved Reserves at December 31 2008	136	15	2,083	498

	Light and Medium oil Mbbl	Natural gas liquids Mbbl	Natural gas MMcf	Total Mboe
Probable Reserves at December 31 2007	70	4	330	129
Discoveries	18	0	42	25
Extensions	-	-	-	-
Improved recovery	-	-	-	-
Technical revisions	(6)	(1)	64	4
Acquisitions	8	2	474	88
Dispositions	-	-	-	-
Economic factors	-	-	-	-
Production	-	-	-	-
Probable Reserves at December 31 2008	90	4	910	246

	Light and Medium oil Mbbl	Natural gas liquids Mbbl	Natural gas MMcf	Total Mboe
Proved plus Probable Reserves at December 31 2007	150	15	1,311	383
Discoveries	48	1	195	82
Extensions	-	-	-	-
Improved recovery	-	-	-	-
Technical revisions	33	1	476	113
Acquisitions	24	5	1,335	251
Dispositions	-	-	-	-
Economic factors	-	-	-	-
Production	(30)	(2)	(323)	(86)
Proved plus Probable Reserves at December 31 2008	226	20	2,993	744

ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Undeveloped Reserves

Proved and probable undeveloped oil reserves at Carmangay have decreased as the 2008 waterflood project has allowed the undeveloped reserves to move into developed category.

The waterflood project has also moved additional gas into the proved and probable undeveloped categories from the probable category.

Proved Undeveloped Reserves

	Oil		NGLs		Natural Gas		boes	
Proved Undeveloped	1st Attributed Mbbl	Booked Mbbl	1st Attributed Mbbl	Booked Mbbl	1st Attributed MMcf	Booked MMcf	1st Attributed Mbbl	Booked Mbbl
Prior to 2006	-	-	-	-	-	-	-	-
2006	-	-	-	-	-	-	-	-
2007	17	17	-	-	157	157	43	43
2008	-	12	-	-	4	161	1	39

Probable Undeveloped Reserves

	Oil		NGLs		Natural Gas		boes	
Probable Undeveloped	1st Attributed Mbbl	Booked Mbbl	1st Attributed Mbbl	Booked Mbbl	1st Attributed MMcf	Booked MMcf	1st Attributed Mbbl	Booked Mbbl
Prior to 2006	-	-	-	-	-	-	-	-
2006	-	-	-	-	-	-	-	-
2007	70	70	-	-	-	-	70	70
2008	-	58	-	-	41	41	7	65

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 forecasts, prices and economic conditions. All of the company's reserves are evaluated by the independent engineering firms, SPROULE, MARTIN & BRUSSET and AJM.

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

Future Development Costs

The table below sets out the development costs deducted in the estimation of future net revenue attributable to the reserve categories noted.

	FORECAST PRICES AND COSTS	
Year	Proved Reserves ($000s)	Proved plus Probable Reserves ($000s)
2009	511	511
2010	-	567
2011	-	-
2012	-	-
Remaining	16	16
	527	1,094

Sources and Costs of Funding

The Company has three sources of funding to finance its capital expenditure programs: internally generated cash flow from operations, debt financing when appropriate and new equity issues, if available on favorable terms. The Company will rely primarily on cash flow in 2009, pending improvements in product pricing and the equity markets.

Economics

The company is not aware at this time of any costs of funding that will adversely affect projections for exploration and development of prospects slated for 2009.

OTHER OIL AND GAS INFORMATION

Oil and Natural Gas Properties

The company's reserves are in the provinces of Alberta and Saskatchewan, Canada. They have been designated into 4 areas and the details are shown in the table below. The injection wells associated with Carmangay have been included in the oil well category since they are an integral part of the development of the property.

	Gross		Net		Net Oil Wells		Net Gas Wells	
	Producing	Non-Producing	Producing	Non-Producing	Producing	Non-Producing	Producing	Non-Producing
Southern Alberta	17.0	3.0	4.0	2.3	1.9	-	2.1	2.3
Central Alberta	3.0	-	1.6	-	-	-	1.6	-
Northern Alberta	5.0	14.0	3.0	8.4	-	-	3.0	8.4
Saskatchewan	3.0	-	1.7	-	0.3	-	1.4	-
Total Wells	23.0	17.0	10.2	10.6	2.2	-	8.0	10.6

Southern Alberta

Drake was active in Southern Alberta throughout the year with the drilling of new wells at Carmangay and Retlaw, and several optimization and asset rationalization projects. 2009 will see continued drilling and optimization.

Central Alberta

The company's first oil well at Swan Hills was drilled and on production early in the year adding significant initial production. Additional locations have been identified and are being graded for possible 2009 drilling and waterflood.

Northern Alberta

The company's Sousa wells were reactivated in Q2 but the area was shut in in early Q3 for additional infrastructure work to increase production and reduce costs. Early in 2009 the area was again reactivated with excellent oil and gas production rates. One successful well was drilled in Q1 2009 and there are an additional 3 drilling and re-entry locations planned for the 2009 - 2010 winter drilling season.

Saskatchewan

Drake acquired production in Saskatchewan in Q2. It consisted of a small oil well as part of the purchase of a private oil and gas company.

Properties with No Attributed Reserves

The following table summarizes the gross and net acres of unproved properties in which the company has an interest.

Area			**2009 Acreage Expiries**	
	Gross Acres	**Net Acres**	**Gross Acres**	**Net Acres**
Carmangay	318	209	-	-
Provost	633	563	-	-
Rainbow	4,744	3,305	-	-
Sousa	15,345	5,906	10,240	4,108
Suffield	633	633	-	-
Swan Hills	320	224	-	-
Total	**21,993**	**10,840**	**10,240**	**4,108**

Forward Contracts

The company may, from time to time, enter into oil and natural gas agreements to provide exposure to a variety of pricing options. As at December 31, 2008 no such arrangements were in place.

Abandonment and Reclamation Costs

The company estimates well abandonment costs on an area by area and sometimes a well by well basis. These costs are included in the SPROULE Report, MARTIN & BRUSSET Report and AJM Report ("the Reports") as a deduction in arriving at future net revenue. Well abandonment and disconnect costs were estimated and included in the Report at the individual entity level for all wells that were assigned reserves. No allowance for surface lease reclamation and salvage value was included. No abandonment costs have been estimated for suspended wells, gathering systems, batteries, and plants or processing facilities. The estimated total abandonment costs included in the audited financial statements at December 31, 2008 are $720,270 over one to seven years. The total estimated well abandonment costs to be incurred over the next five years are anticipated to be less than $600,000.

Tax Horizon

The company was not required to pay income taxes during the year ended December 31, 2008. Based on a strategy of reinvesting all internally generated cash flow in an exploration and development program, planned borrowing and on the commodity prices used in the SPROULE, MARTIN & BRUSSET and AJM Reports, the company estimates that it will not be required to pay income taxes until after 2009.

COSTS INCURRED

The following table summarizes the company's drilling results for the year ended December 31, 2008.

Location	Number of Wells	W.I.%	Gas Net to Company	Oil Net to Company	Injector well Net to company	Dry Net to Company
Carmangay	1	31	-	-	.3	-
Swan Hills	1	70	-	.7	-	-
Retlaw	1	30	.3	-	-	-

Planned exploration and development in 2009 has not been finalized as the low commodity prices and depressed equity markets make fund raising problematic. As a result, the company will continue to monitor the capital markets and determine its expenditures as and when the capital markets and/or commodity prices improve.

Production Estimates

The following table discloses, for each product type, the total volume of production estimated by SPROULE, MARTIN & BRUSSET and AJM for 2009 in the estimates of future net revenue from proved reserves disclosed above under the heading "Oil and Natural Gas Reserves and Net Present Value of Future Net Revenue.

	Oil and Ngls bbls/day	Natural gas Mcf/day	boe/day
Proved			
Sousa	8	193	40
Carmangay	44	15	46
Retlaw	-	175	29
Forestburg	-	114	19
Swan Hills	8	-	8
Other	6	537	95
	65	1,033	238
Probable			
Sousa	1	30	6
Carmangay	-	-	-
Retlaw	-	7	1
Forestburg	-	2	-
Swan Hills	-	-	-
Other	-	44	7
	1	83	15
Total proved plus probable	67	1,116	253

Production History

The following tables summarize certain information in respect of production, product prices received, royalties, operating costs and netbacks for the periods indicated below. As the company does not track operating costs by product, it and the netbacks are shown on a boe basis only.

	Quarter ended 2008				Year ended Dec 31 2008
	Mar 31	**Jun 30**	**Sep 30**	**Dec 31**	
Average daily production					
Oil and liquids bbl/day	26	54	55	63	50
Natural gas Mcf/day	391	712	785	756	662
combined boe/day	91	172	186	189	160
Average prices received					
Oil and liquids $/bbl	88.40	118.75	102.98	57.45	90.84
Natural gas $/Mcf	7.99	10.53	7.22	6.76	8.16
combined $/boe	59.55	80.49	61.03	47.21	61.94
Royalties paid					
Oil and liquids $/bbl	13.00	13.70	6.45	11.94	11.01
Natural gas $/Mcf	0.01	1.58	1.74	1.45	1.36
combined $/boe	3.79	10.80	9.27	9.79	9.05
Operating expense					
combined $/boe	21.25	23.11	21.55	21.22	21.83
Transportation					
Oil and liquids $/bbl	0.08	0.29	0.13	0.17	0.18
Natural gas $/Mcf	0.38	0.21	0.14	0.17	0.20
combined $/boe	1.66	0.96	0.63	0.74	0.90
Netbacks					
combined $/boe	32.84	45.61	29.59	15.47	30.16

2008 - Report 51 – 101 F2

Report on Reserves Data
by Independent Qualified Reserves Evaluator or Auditor

Report on Reserves Data

To the Board of Directors of Drake Pacific Enterprises Ltd. (the "Company"):

1. We have evaluated the Company's Reserves Data as at December 31, 2008. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2008, estimated using forecast prices and costs.

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 table sets forth the estimated future net revenue attributed to proved plus probable reserves, estimated using forecast prices and costs on a before tax basis and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us as of December 31, 2008, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's management and Board of Directors:

Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of Evaluation Report	Location of Reserves (Country)	Net Present Value of Future Net Revenue Before Income Taxes (10% Discount Rate)			
			Audited (M$)	Evaluated (M$)	Reviewed (M$)	Total (M$)
Sproule	Evaluation of the P&NG Reserves of Drake Pacific Enterprises Ltd., As of December 31, 2008, prepared February to April 2009	Canada				
Total			**Nil**	**7,242**	**Nil**	**7,242**

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

6. We have no responsibility to update the report referred to in paragraph 4 for events and circumstances occurring after its preparation date.

7. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

Executed as to our report referred to above:

Sproule Associates Limited
Calgary, Alberta
April _02_, 2009

Original signed by P.B. Jung
Paul B. Jung, P.Eng.
Project Leader,
Associate

Original signed by M.W. Maughan
Michael W. Maughan, C.P.G., P.Geol.
Vice-President, Geoscience

Original signed by H.J. Helwerda
Harry J. Helwerda, P.Eng.
Executive Vice-President

FORM 51-101F2
REPORT ON RESERVES DATA

To the board of directors of Drake Pacific Enterprises Ltd. (the "Company):

1 We have evaluated the Company's reserves data as at December 31, 2008. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2008, estimated using forecast prices and costs.

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 "COGI Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy and 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 table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2008 and identifies the portions thereof that we have evaluated and reported on to the Company's management and board of directors.

Independent Qualified Reserves Evaluator	Description & Prep. Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate) x 1000			
			Audited	Evaluated	Reviewed	Total
Martin & Brusset Assoc.	Dec 31/08	Canada	$0	$4,354	$0	$4,354

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. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

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 judgments regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

Executed as to our report referred to above:

Martin & Brusset Associates
Calgary, Alberta, Canada

April 13, 2009

" Neil Sedgwick "

S. Neil Sedgwick, B.Sc., P.Eng.

REPORT ON RESERVES DATA
BY
INDEPENDENT QUALIFIED RESERVES
EVALUATOR OR AUDITOR

To the Board of Directors of Drake Pacific Enterprises Ltd. (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2008. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2008, estimated using forecast prices and costs.

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 table sets 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 rate of 10 percent, included in the reserves data of the Company evaluated by us for the year end December 31, 2008 and identifies the respective portions thereof that we have evaluated and reported on to the Company's management/Board of Directors:

Independent Qualified Reserves Evaluator or Auditor	Drake Pacific Enterprises Ltd. Reserve Estimation and Economic Evaluation	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue ($M, before income taxes, 10% discount rate)			
			Audited	Evaluated	Reviewed	Total
AJM Petroleum Consultants	April 6, 2009	Canada	-	3,477.9	-	3,477.9

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

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 judgments regarding future events, actual events will vary and the variations may be material. However, any variation should be consistent with the fact that reserves are categorized according to the probability of their recovery.

Executed as to our report referred to above:

AJM Petroleum Consultants
Fifth Avenue Place, East Tower
6th Floor, 425 – 1st Street S.W.
Calgary, Alberta
T2P 3P8

Robin G. Bertram, P. Eng.
Vice President Engineering

Execution date: April 6, 2009

2008 - Report 51 – 101 F3

Report of Management and Directors
On Reserves Data and Other Information

Management of Drake Pacific Enterprises Ltd. (the "Company") is 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) proved and proved plus probable oil and gas reserves estimates as at December 31, 2008 using forecast prices and costs; and
b) the related estimated future net revenue.

Independent qualified reserves evaluators have evaluated the Company's reserves data. The reports of the independent qualified reserves evaluators will be filed with the securities regulatory authorities concurrently with this report.

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 evaluators;
b) met with the independent qualified reserves evaluators to determine whether any restrictions affected the ability of the independent qualified reserves evaluators to report without reservation; and
c) reviewed the reserves data with management and the independent qualified reserves evaluators.

The Reserve 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 the information with management. The Board of Directors has, on the recommendation of the Reserves Committee, approved:

a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information;
b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluators on 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.

(signed) *"Roger Penner"* Roger J. Penner President and CEO and Director	(signed) *"Sandra Towpich"* Sandra Towpich VP & Corporate Secretary and Director	(signed) *"Chris Bradley"* Chris Bradley CFO & Director
(signed) *"Dallas O. Hawkins"* Dallas O. Hawkins Director	(signed)"*Kevin Dretzka"* Kevin Dretzka Director	(signed)" *Neil Orr"* Neil Orr VP Business Development and Director