COBRA VENTURE CORPORATION

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

(COMPLYING WITH FORM 51-101F1)

EFFECTIVE DATE (as at fiscal year end): NOVEMBER 30, 2008

March 30, 2009

DEFINITIONS, NOTES AND OTHER CAUTIONARY STATEMENTS

Abbreviations, Terms and Conversions

Certain terms and abbreviations used in this statement of reserves data and other information are defined below:

"BBL"	barrel of oil or NGL;
"bcf"	billion cubic feet of natural gas;
"boe"	barrel of oil equivalent determined by converting (i) a volume of natural gas to barrels of oil using the ratio of 6 mcf to one barrel and (ii) a volume of NGLs to barrels of oil using the ratio of one barrel of NGLs to one barrel of oil; this conversion is not based on either energy content or prices;
"boepd"	barrel of oil equivalent per day;
"bpd"	barrel of oil or NGL per day;
"mbbl"	thousand barrels;
"mboe"	thousand barrels of oil equivalent;
"mmbtu"	million British Thermal Units;
"Mcf"	thousand cubic feet of natural gas;
"Mcfd"	thousand cubic feet of natural gas per day;
"MMcf"	million cubic feet of natural gas;
"MMcfd"	million cubic feet of natural gas per day;
"MSTB"	thousand stock tank barrels;
"NGL"	natural gas liquids;

In this statement of reserves data and other information, measurements are given in standard Imperial or metric units only. The following table sets forth certain standard conversions.

To Convert From	To	Multiply By
Mcf	cubic metres	28.174
cubic metres	cubic feet	35.494
BBL	cubic metres	0.159
cubic metres	BBL	6.290
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.471

Unless otherwise indicated, the following definitions and other notes are applicable.

1. ***"Gross"*** means:

   (a) in relation to Cobra Venture Corporation’s (the “Corporation” or “Company”) interest in production and reserves, its "gross revenues", which are the Corporation's interest (operating and non-operating) share before deduction of royalties and without including any royalty interest of the Corporation;

   (b) in relation to wells, the total number of wells in which the Corporation has an interest; and

   (c) in relation to properties, the total area of properties in which the Corporation has an interest.

2. ***"Net"*** means:

   (a) in relation to the Corporation's interest in production and reserves, its "net reserves", which are the Corporation's interest (operating and non-operating) share after deduction of royalty obligations, plus the Corporation's royalty interest in production of reserves;

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

(c) in relation to the Corporation's interest in a property, the total area in which the Corporation has an interest multiplied by the working interest owned by the Corporation.

3. *Definitions used for reserve categories are as follows:*

"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, which are generally accepted as being reasonable.

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.

<u>Development and Production Status</u>

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.

<u>Levels of Certainty for Reported Reserves</u>

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:

- At least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves;

- At least a 50 percent probability that the quantities 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.

4. *Forecast prices and costs*

"*Future prices and costs*" that are**:**

(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 the Corporation is 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).

5. *Future income tax expense*

"*Future income tax expenses*" are estimated**:**

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

(b) Without deducting estimated future costs 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 Corporation's oil and gas activities the appropriate year-end statutory rates, taking into account future tax rates already legislated.

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

7. "***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.

8. "***Exploration well***" means a well that is not a development well, a service well or a stratigraphic test well.

9. "***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 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;

   (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.

10. "***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.

11. Numbers may not add due to rounding.

12. The estimates of future net revenue presented do not represent fair market value.

13. Disclosure provided herein in respect of boes may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

14. Estimated future abandonment and reclamation costs related to a property have been taken into account by Reliance Engineering Group Ltd. in determining reserves that should be attributable to a property and in determining the aggregate future net revenue therefrom, there was deducted the reasonable estimated future well abandonment costs.

15. Both the constant and forecast price and cost assumptions assume the continuance of current laws and regulations.

16. The extended character of all factual data supplied to Reliance Engineering Group Ltd. were accepted by them as represented. No field inspection was conducted

Form 51-101F1

COBRA VENTURE CORPORATION. (“the Corporation” or “Company”)

STATEMENT OF RESERVE DATA AND OTHER OIL AND GAS INFORMATION

March 30, 2009

PART 1

RELEVANT DATES

The effective date of the information being provided in this statement is November 30, 2008. The preparation date of the information being provided in this statement is March 30, 2009. For a glossary of terminology and definitions relating to the information included in this report, readers are referred to National policy Instrument 51-101 “Standards for Disclosure for Oil and Gas Activities” (“NI 510101”).

RESERVES AND FUTURE NET REVENUE

The following is a summary of the oil and natural gas reserves and the net present values of future net revenue of Cobra Venture Corporation as evaluated by Reliance Engineering Group Ltd. of Calgary Alberta Report dated February 12, 2009. Reliance Engineering Group Ltd. are independent qualified reserves evaluators appointed by the Corporation pursuant to NI 51-101. Reliance Engineering Group Ltd. independently evaluated all of the Corporation’s Oil and Gas properties.

The estimated future net revenue figures contained in the following tables do not necessarily represent the fair market value of the Corporation’s reserves. There is no assurance that the forecast price and costs assumptions contained in the Reliance Engineering Group Ltd.’s report will be attained and variances could be material. Other assumptions relating to costs and other matters are included in the Reliance Engineering Group Ltd.’s report. The recovery and reserves estimates attributed to the Corporation’s properties described herein are estimates only. The actual reserves attributable to the Corporation’s properties may be greater or less than those calculated.

PART 2

DISCLOSURE OF RESERVE DATA

All of the Corporation’s properties, reserves and production are located in Canada in the provinces of Alberta and Saskatchewan.

The following tables detail the aggregate gross and net reserves of the Corporation, as at November 30, 2008, using constant prices and costs as well the aggregate net present value of future net revenue discounted at 5%, 10%, 15% and 20%:

TABLE A
SUMMARY OF RESERVES
FORECAST VALUES
NOVEMBER 30, 2008

	Economically Recoverable Remaining Reserves Gross 100% Lease				Company Gross				Company Net			
	Oil				Oil				Oil			
	Light & Medium MSTB	Heavy MSTB	Gas MMCF	NGL MSTB	Light & Medium MSTB	Heavy MSTB	Gas MMCF	NGL MSTB	Light & Medium MSTB	Heavy MSTB	Gas MMCF	NGL MSTB
Proven Producing	172.9	-	173.0	13.7	-	-	37.0	-	23.1	-	43.0	2.4
Proven Developed (Non-Producing)	-	-	-	-	-	-	-	-	-	-	-	-
Total Proven	**172.9**	**-**	**173.0**	**13.7**	**-**	**-**	**37.0**	**-**	**23.1**	**-**	**43.0**	**2.4**
Probable	131.4	-	-	-	-	-	47.0	-	19.4	-	44.0	1.3
Total Proven Plus Probable	**304.3**	**-**	**173.0**	**13.7**	**-**	**-**	**84.0**	**-**	**42.5**	**-**	**87.0**	**3.7**

TABLE B
TOTAL COMPANY INTERESTS (FORECAST VALUES)
CUMULATIVE FUTURE CASHFLOW IN THOUSANDS OF $ (CDN)
BEFORE INCOME TAX
NOVEMBER 30, 2008

						UNIT VALUE BEFORE INCOME TAX DEDUCTED AT 10% PER YEAR		
		Discounted					Oil	
	Undisc.	5%	10%	15%	20%	Gas ($/Mcf)	Light & Medium ($/bbl)	Heavy ($/bbl)
Proven Producing	1,833	1,723	1,627	1,543	1,470	3.61	65.58	-
Proven Developed (Non-Producing)	-	-	-	-	-	-	-	-
Total Proven	**1,833**	**1,723**	**1,627**	**1,543**	**1,470**	**3.61**	**65.58**	**-**
Probable	1,837	1,489	1,237	1,048	902	4.18	55.57	-
Total Proven Plus Probable	**3,670**	**3,212**	**2,864**	**2,591**	**2,372**	**3.93**	**61.01**	**-**

Note: The estimated future cash flow represents the Going Concern Value (GCV) but does not necessarily represent the Market Value.

TABLE C
TOTAL COMPANY INTERESTS (FORECAST VALUES)
CUMULATIVE FUTURE CASHFLOW IN THOUSANDS OF $ (CDN)
AFTER INCOME TAX
NOVEMBER 30, 2008

		DISCOUNTED			
	Undisc.	5%	10%	15%	20%
Proven Producing	1,313	1,236	1,169	1,111	1,060
Proven Developed (Non-Producing)	-	-	-	-	-
Total Proven	**1,313**	**1,236**	**1,169**	**1,111**	**1,060**
Probable	1,349	1,096	912	525	667
Total Proven Plus Probable	**2,662**	**2,332**	**2,081**	**1,636**	**1,727**

The following tables provide a breakdown of various elements of future net revenue attributable to proved reserves and proved plus probable (in total) of the Corporation estimated using forecast prices and costs and calculated without discount :

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
FORECAST PRICES AND COSTS
NOVEMBER 30, 2008

	Proved Reserves (M$)	Proved plus Probable Reserves (M$)
Revenue	2,015	4,017
Royalties	44	116
Operating costs	125	217
Development costs	Nil	Nil
Well Abandonment costs	13	14
Future Net Revenue Before Income Taxes	1,833	3,670

Income Taxes	520	1,008
Future Net Revenue After Income Taxes	1,313	2,662

The following table details by production group the net present value of future net revenue (before deducting future income tax expenses) estimated using forecast prices and costs and calculated using a discount rate of 10% .

FUTURE NET REVENUE
BY PRODUCTION GROUP
FORECAST PRICES AND COSTS
NOVEMBER 30, 2008

		Future Net Revenue Before Income Taxes (discounted at 10% per year)	Unit Value	
Reserve Category		(M$)	$/Mcf	$/bbl
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	1,515	--	65.58
	Heavy Oil (including solution gas and other by-products)	--	--	--
	Natural Gas (including by-products but excluding gas and by-products from oil wells)	112	3.61	--
Proven Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	2,593	--	61.01
	Heavy Oil (including solution gas and other by-products)	--	--	--
	Natural Gas (including by-products but excluding gas and by-products from oil wells)	271	3.93	--

Notes:

(1) Including solution gas and other by-products
(2) Including by-products but excluding solution gas from oil wells
(3)

PART 3

PRICING ASSUMPTIONS

The following tables detail the benchmark reference prices for the regions in which the Corporation operated as at November 30, 2008 reflected in the reserves data disclosed above under "Disclosure of Reserves Data". These pricing assumptions were provided by **Reliance Engineering Group Ltd.**, an independent qualified reserves evaluator and auditor.

PRODUCT PRICE SCHEDULE
NOVEMBER 30, 2008

YEAR	$US/BBL	CANADIAN CRUDE FOB EDMONTON $(CND)/BBL (2)	CROMER $/BBL (3)	BOW RIVER $/BBL (4)	$US/CDN EXCHANGE	SPOT GAS $/MCF (5)	NGL $/BBL
2003 (actual)	30.95	43.50	37.55	33.00	0.72	6.49	37.41
2004 (actual)	41.57	53.31	45.75	37.98	0.77	6.45	44.30
2005 (actual)	56.60	69.11	57.07	44.96	0.88	8.42	55.97
2006 (actual)	66.22	73.16	62.35	51.85	0.88	6.96	63.46
2007 (actual)	72.40	77.05	65.70	53.65	0.94	6.43	64.35
Jan-Nov 2008 (actual)	104.88	108.60	98.29	88.76	0.96	8.08	85.55
Dec 2008	76.20	78.90	68.60	59.10	0.82	7.10	62.70
2009	53.75	65.35	58.15	52.30	0.80	6.70	54.35
2010	63.10	72.80	66.25	59.70	0.85	7.30	59.05

2011	69.55	79.95	72.75	65.55	0.85	7.60	64.85
2012	79.60	86.55	79.65	72.70	0.90	8.15	70.25
2013 (6)	92.00	95.90	84.40	72.90	0.95	8.95	77.05

Note:

(1) West Texas Intermediate – Cushing, Oklahoma
(2) 40^{o} API and 0.5 percent sulphur adjusted for gravity and transportation
(3) Cromer Medium 29^{o} API and 2.0 percent sulphur adjusted for gravity and transportation.
(4) Bow River 24.3^{o} API adjusted for gravity and transportation
(5) Adjusted for heating value and aggregator contract price.
(6) Prices escalated at 1.50 percent per year thereafter.

WELLHEAD PRICE SCHEDULE
NOVEMBER 30, 2008

YEAR	OIL LIGHT & MEDIUM ($/BBL)	GAS ($/Mcf)	NGL ($/BBL)
2008	73.10	7.47	44.50
2009	62.12	7.08	36.15
2010	69.27	7.54	40.85
2011	74.95	7.71	46.65
2012	81.64	8.13	52.06
2013 (1)	86.31	8.74	61.54

NOTE (1) Prices escalated at 1.50 percent per year thereafter.

PART 4

RECONCILIATIONS OF CHANGES IN RESERVES AND FUTURE NET REVENUE

The following table outlines the reconciliation of changes in the Corporation's net remaining oil reserves estimates for the Corporation for the period November 30, 2007 to November 30, 2008 using forecast prices and costs:

RECONCILIATION OF COMPANY NET REMAINING OIL RESERVES
(AFTER ROYALTIES)
BY PRINCIPAL PRODUCT TYPE
FORECAST PRICES AND COSTS
NOVEMBER 30, 2008

	Light and Medium (MSTB)			Heavy (MSTB)			NGL (MSTB)		
	Total Proved	Probable	Total Proved Plus Probable	Total Proved	Probable	Total Proved Plus Probable	Total Proved	Probable	Total Proved Plus Probable
November 30, 2007	13.3	21.0	34.5	--	--	--	0.2	--	0.2
Improved Recovery (Performance)	--	--	--	--	--	--	--	--	--
Technical Revisions (Negative)	(6.2)	(12.1)	(18.3)	--	--	--	--	--	--

RECONCILIATION OF COMPANY NET REMAINING OIL RESERVES (continued)
(AFTER ROYALTIES)
BY PRINCIPAL PRODUCT TYPE
FORECAST PRICES AND COSTS
NOVEMBER 30, 2008

	Light and Medium (MSTB)			Heavy (MSTB)			NGL (MSTB)		
	Total Proved	Probable	Total Proved Plus Probable	Total Proved	Probable	Total Proved Plus Probable	Total Proved	Probable	Total Proved Plus Probable
Technical Revisions (Positive)	--	--	--	--	--	--	--	--	--
Discoveries	27.0	10.3	37.3	--	--	--	2.6	1.3	3.9
Acquisitions	--	--	--	--	--	--	--	--	--
Dispositions	--	--	--	--	--	--	--	--	--
Economic Factors	--	--	--	--	--	--	--	--	--
Production	(11.0)	--	(11.0)	--	--	--	(0.4)	--	(0.4)
November 30, 2008	23.1	23.1	42.5	--	--	--	2.4	1.3	3.7

The following table outlines the reconciliation of changes in the Corporation's net remaining gas reserves estimates for the Corporation for the period November 30, 2007 to November 30, 2008 using forecast prices and costs.

RECONCILIATION OF COMPANY NET REMAINING GAS RESERVES
(AFTER ROYALTIES)
BY PRINCIPAL PRODUCT TYPE
FORECAST PRICES AND COSTS
NOVEMBER 30, 2008

	ASSOCIATED AND NON-ASSOCIATED GAS (MMCF) INCLUDING SOLUTION GAS		
	Total Proved	Probable	Total Proved Plus Probable
November 30, 2007	50	--	50
Extensions	--	--	--
Improved Recovery (Performance)	--	--	--
Technical Revisions (Negative)	(2)	--	(2)
Technical Revisions (Positive)	--	38	38
Discoveries	13	6	19
Acquisitions	--	--	--
Dispositions	--	--	--
Economic Factors	--	--	--
Production (Sales)	(18)	--	(18)
November 30, 2008	43	44	87

PART 5

ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Undeveloped Reserves

The proved and probable undeveloped reserves of the Corporation have been estimated in accordance with procedures and standards contained in the COGE Handbook. In general, the Corporation's undeveloped reserves are scheduled to be developed within the next two years. See "Oil and Gas Properties" for the Corporation's general development plans for its undeveloped reserves.

Significant Factors or Uncertainties

The production rates, Oil and Gas reserves and cash flow information contained in the Reliance Engineering Group Ltd. Report are only estimates and the actual production and ultimate reserves may be greater or less than the estimates prepared by Reliance. Factors, consideration and assumptions that the independent evaluator used to develop these estimates include, but are not limited to:

: Historical production;
: Government regulation;
: Assumptions regarding commodity prices, production, development costs, taxes and capital expenditures;
: Timing of capital expenditures;
: Effectiveness of enhanced recovery schemes;
: Marketability of production;
: Operating costs and royalties;
: Initial production rates;
: Production decline rates;
: Ultimate recovery of reserves: and
: Future oil and gas prices.

Future Development Costs

The following table details the development costs deducted in the estimation of future net revenue attributable to proved reserves of the Corporation (estimated and forecast prices and costs) and proved plus probable reserves of the Corporation (estimated using forecast prices and costs and constant prices and costs):

FUTURE DEVELOPMENT AND ABANDONMENT COSTS
FORECAST PRICES AND COSTS
NOVEMBER 30, 2008

	Total Proven		Proven Plus Probable	
Year	Capital	Abandonment	Capital	Abandonment
2008	--	--	--	--
2009	--	--	--	--
2010	--	2,405	--	--
2011	--	--	--	--
2012	--	--	--	--
2013	--	--	--	--
2014	--	--	--	2,553
2015	--	--	--	--

FUTURE DEVELOPMENT AND ABANDONMENT COSTS (continued)
FORECAST PRICES AND COSTS
NOVEMBER 30, 2008

	Total Proven		Proven Plus Probable	
Year	Capital	Abandonment	Capital	Abandonment
2016	--	--	--	--
2017	--	10,805	--	--
Remainder	--	--	--	11,468
Total (Undiscounted)	--	13,210	--	14,021
10% DCF	--	6,836	--	4,955

The Corporation's source of funding for future development costs of the Corporation's reserves will be derived from a combination of cash flow, debt and new equity. Management of the Corporation does not anticipate that the costs of funding referred to above will materially affect the Corporation's disclosed reserves and future net revenues or will make the development of any of the Corporation's properties uneconomic.

The Corporation’s petroleum and natural gas investing activities have been funded to date primarily through the issuance of common shares and expects that it will continue to be able to utilize this source of financing until it develops additional cash flow from operations.

For additional information regarding the future development of the Corporation’s properties, see Part 6 – Oil and Gas Properties and Wells.

Additional Information Concerning Abandonment and Reclamation Costs

The Corporation bases its estimates for the costs of abandonment and reclamation of surface leases, wells, facilities and pipelines on previous experience of management with similar well sites and facility locations. As at November 30, 2008, management does not expect any abandonment in 2009. Within the next three (3) financial years, it is expected such costs will total approximately $2,450.

PART 6

OTHER OIL AND GAS INFORMATION

Producing Wells

The following table summarizes the Corporation's interests, as at November 30, 2008, in oil and gas wells:

NOVEMBER 30, 2008

	Oil Wells		Natural Gas		Total	
	Gross	Net	Gross	Net	Gross	Net
PRODUCING (Note 1)						
Alberta	Nil	Nil	7.0	1.6	7.0	1.6
Saskatchewan	9.0	Note 2	Nil	NIl	9.0	Note 2
British Columbia	Nil	Nil	Nil	Nil	Nil	Nil
Total Producing	9.0	Nil	7.0	1.6	16.0	1.7

Note: (1) Includes wells that are temporarily shut-in but which are capable of production.
(2) The Corporation has gross overriding royalty interests in the wells in Saskatchewan

Production Forecasts

The following table presents the oil and NGL production forecast by area:

NET OIL & NGL PRODUCTION FORECAST
FORECAST PRICES AND COSTS
NOVEMBER 30, 2008

	Company Gross - BBLS/Day				
	2008	2009	2010	2011	2012
PRODUCING					
SASKATCHEWAN					
Viewfield	57.5	36.5	16.4	7.9	3.4
Total Producing	57.5	36.5	16.4	7.9	3.4
PROBABLE					
SASKATCHEWAN					
Viewfield	--	0.4	17.1	9.7	7.4
Total Proven Plus Probable	57.5	36.9	33.5	17.6	10.8

The following presents the gas production forecast by area:

SALES GAS PRODUCTION FORECAST
FORECAST PRICES AND COSTS
NOVEMBER 30, 2008

	Company Net - MCF/Day				
	2008	2009	2010	2011	2012
PRODUCING					
ALBERTA					
Pembina	36.0	25.0	17.0	11.0	9.0
SASKATCHEWAN					
Viewfield	28.0	18.0	7.0	3.0	1.0
Total Proven Producing	64.0	43.0	24.0	14.0	1.0
PROBABLE					
ALBERTA					
Pembina	--	10.0	13.0	13.0	11.0
SASKATCHEWAN					
Viewfield	--	--	2.0	3.0	3.0
Total Probable	--	10.0	15.0	16.0	14.0
Total Proven Plus Probable	64.0	53.0	39.0	30.0	24.0

Remaining Reserves and Present Worth Values

The following table presents the remaining reserves and present worth values for forecast prices and costs, by property:

REMAINING RESERVES AND PRESENT WORTH VALUES
FORECAST PRICES AND COSTS
NOVEMBER 30, 2008

	Company Share										
	Economically Recoverable Remaining Reserves										
	Gross				Net				Present Worth Values Before Income Tax		
	Oil				Oil						
	Light and Medium MSTB	Heavy MSTB	Gas MMCF	NGL MSTB	Light and Medium MSTB	Heavy MSTB	Gas MMCF	NGL MSTB	5% M$	10% M$	15% M$
PROVEN PRODUCING											
ALBERTA											
Pembina	--	--	37.0	--	--	--	31.0	--	121.0	112.0	103.0
SASKATCHEWAN											
Viewfield	--	--	--	--	23.1	--	12.0	2.4	1,601.0	1,515.0	1,440.0
TOTAL PRODUCING	--	--	37.0	--	23.1	--	43.0	2.4	1,722.0	1,627.0	1,543.0
PROBABLE											
ALBERTA											
Pembina	--	--	47.0	--	--	--	38.0	--	197.0	159.0	133.0
SASKATCHEWAN											
Viewfield	--	--	--	--	19.4	--	6.0	1.3	1,293.0	1,078.0	915.0
TOTAL PROBABLE	--	--	47.0	--	19.4	--	44.0	1.3	1,490.0	1,237.0	1,048.0
TOTAL PROVEN PLUS PROBABLE	--	--	84.0	--	42.5	--	87.0	3.7	3,212.0	2,864.0	2,591.0

The following table sets forth the estimates of the Corporation's estimated of oil reserves and present values, by property and location, for forecast prices and costs:

ESTIMATES OF OIL RESERVES AND NET PRESENT VALUES
FORECAST PRICES AND COSTS
NOVEMBER 30, 2008

OIL RESERVES - LIGHT AND MEDIUM

Location	Ultimate Oil Reserves (MSTB)	Cumulative Production (MSTB)	Remaining Oil Reserves (MSTB)	Company Working Interest (%)	Company Gross Oil Reserves (MSTB)	Lessor Royalties & Burdens %	Company Net Oil Reserves (MSTB)	Net Present Values Before Income Taxes 5% (M$)	10% (M$)	15% (M$)	20% M$)
PROVEN PRODUCING											
SASKATCHEWAN											
Viewfield											
91/08-31-07-07W2M	81.9	67.7	14.2	16.00 (RI)	--	--	2.27	119	111	104	97
92/08-31-07-07W2M	20.2	12.2	8.0	16.00 (RI)	--	--	12.80	66	62	59	56
91/19-31-07-07W2M	78.8	69.5	9.3	5.00 (RI)	--	--	0.46	23	23	22	21
91/16-31-07-07W2M	84.3	43.1	41.2	5.00 (RI)	--	--	2.06	107	100	95	90
91/06-06-08-07W2M	4.6	2.5	2.1	8.00 (RI)	--	--	0.16	11	11	11	11
21/03-05-08-08W2M	27.4	21.8	5.6	11.52 (RI)	--	--	0.65	50	46	43	40
91/15-05-08-08W2M	40.7	33.0	7.7	11.52 (RI)	--	--	0.89	68	63	58	54
92/15-05-08-08W2M	51.7	14.3	37.4	18.00 (RI)	--	--	6.73	506	484	465	447
91/16-05-08-08W2M	57.0	9.5	47.5	18.00 (RI)	--	--	8.55	651	615	585	558
TOTAL PROVEN PRODUCING	446.6	273.6	173.0		--	--	23.05	1,601	1,515	1,442	1,374

ESTIMATES OF OIL RESERVES AND NET PRESENT VALUES (continued)
FORECAST PRICES AND COSTS
NOVEMBER 30, 2008

OIL RESERVES - LIGHT AND MEDIUM

Location	Ultimate Oil Reserves (MSTB)	Cumulative Production (MSTB)	Remaining Oil Reserves (MSTB)	Company Working Interest (%)	Company Gross Oil Reserves (MSTB)	Lessor Royalties & Burdens %	Company Net Oil Reserves (MSTB)	Net Present Values Before Income Taxes 5% (M$)	10% (M$)	15% (M$)	20% M$)
PROBABLE											
SASKATCHEWAN											
Viewfield											
91/02-31-07-07W2M Location	60.0	--	60.0	16.00 (RI)	--	--	9.20	506	447	398	358
91/09-31-07-07W2M	9.8	--	9.8	5.00 (RI)	--	--	0.49	27	23	21	19
91/16-31-07-07W2M	28.7	--	28.7	5.00 (RI)	--	--	2.70	37	30	26	22
91-03-05-08-08W2M	2.6	--	2.6	11.52 (RI)	--	--	0.30	24	19	16	13
92/15-08-08-08W2M	21.6	--	21.6	18.00 (RI)	--	--	3.89	311	254	212	179
91/16-05-08-08W2M	27.3	--	27.3	18.00 (RI)	--	--	4.91	388	303	243	199
TOTAL PROBABLE	150.0	--	150.0		--	--	21.49	1,293	1,076	916	790
TOTAL PROVEN PLUS PROBABLE	596.6	273.6	323		--	--	44.54	2,894	2,591	2,358	2,164

SOLUTION GAS RESERVES (Values included with Oil Reserves)

Location	Remaining Oil Reserves (MSTB)	GOR (Raw Gas) (Scf/bb)	Remaining Recoverable Raw Gas (MMcf)	Surface Loss (%)	Sales Gas Remaining Solution Gas Reserves (MMcf)	Company Working Interest (%)	Company Gross Solution Gas Reserves (MMcf)	Lessor Royalties Burdens (%)	Company Net Solution Gas Reserves (MMcf)
PROVEN PRODUCING									
SASKATCHEWAN									
Viewfield									
21/03-05-08-08W2M	5.6	735	4.0	10.0	3.7	11.52 (RI)	--	--	0.4
91/03-05-08-08W2M	7.7	700	5.0	10.0	4.8	11.52 (RI)	--	--	0.5
92/15-05-08-08W2M	37.4	770	29.0	10.0	25.9	18.00 (RI)	--	--	4.7
91/16-05-08-08W2M	47.5	800	38.0	10.0	34.2	18.00 (RI)	--	--	6.1
TOTAL PROVEN PRODUCING	98.2		76.0		68.6				11.7
PROBABLE									
SASKATCHEWAN									
Viewfield									
91/03-05-08-08W2M	5.6	700	2.0	10.0	1.7	11.52 (RI)	--	--	0.2
92/15-05-08-08W2M	7.7	770	17.0	10.0	15.0	18.00 (RI)	--	--	2.7
91/16-05-08-08W2M	47.5	800	22.0	10.0	19.6	18.00 (RI)	--	--	3.5
TOTAL PROBABLE	51.5		41.0		36.3				6.4
TOTAL PROVEN PLUS PROBABLE	149.7		117.0		105.00				18.1

The following table represents the Corporation's estimates of gas reserves and net present values for forecast prices and costs:

ESTIMATES OF GAS RESERVES AND NET PRESENT VALUES
FORECAST PRICES AND COSTS
NOVEMBER 30, 2008

NON-ASSOCIATED GAS RESERVES

Location	Gas Reserves (Raw Gas) (MMcf)	Cumulative Production (Raw Gas) (MMcf)	Gas Reserves (Raw Gas) (MMcf)	Surface Loss (%)	Gas Reserves (Raw Gas) (MMcf)	Company Working Interest %	Company Gross Gas Reserves (MMcf)	Lessor Royalties and Burdens (%)	Company Net Gas Reserves (MMcf)
PROVEN PRODUCING									
ALBERTA									
Pembina									
02/16-24-48-08W5M	112.0	71.0	41.0	10	37.0	6.67	2.0	Crown	2.0
02/05-30-48-08W5M	232.0	92.0	140.0	10	126.0	27.00	34.0	Crown + 11.875% GORR	28.0
TOTAL PROVEN PRODUCING	344.0	163.0	163.0		163.0		36.0		30.0

	Net Present Values Before Income Taxes 5% (M$)	10% (M$)	15% (M$)	20% M$)
PROVEN PRODUCING				
ALBERTA				
Pembina				
02/16-24-48-08W5M	119	111	104	97
02/05-30-48-08W5M	651	615	585	558
TOTAL PROVEN PRODUCING	1,601	1,515	1,442	1,374

Location	Gas Reserves (Raw Gas) (MMcf)	Cumulative Production (Raw Gas) (MMcf)	Gas Reserves (Raw Gas) (MMcf)	Surface Loss (%)	Gas Reserves (Raw Gas) (MMcf)	Company Working Interest %	Company Gross Gas Reserves (MMcf)	Lessor Royalties and Burdens (%)	Company Net Gas Reserves (MMcf)
PROBABLE									
ALBERTA									
Pembina									
02/16-24-48-08W5M	40.0	--	40.0	10	36.0	6.67	2.0	Crown	2.0
02/05-30-48-08W5M	185.0	--	185.0	10	166.0	27.00	45.0	Crown + 11.875% GORR	36.0
TOTAL PROBABLE	225.0	--	225.0		202.0		47.0		38.0

	Net Present Values Before Income Taxes 5% (M$)	10% (M$)	15% (M$)	20% M$)
PROBABLE				
ALBERTA				
Pembina				
02/16-24-48-08W5M	10	9	9	8
02/05-30-48-08W5M	186	150	124	104
TOTAL PROBABLE	196	159	133	112

	Gas Reserves (Raw Gas) (MMcf)	Cumulative Production (Raw Gas) (MMcf)	Gas Reserves (Raw Gas) (MMcf)	Surface Loss (%)	Gas Reserves (Raw Gas) (MMcf)	Company Working Interest %	Company Gross Gas Reserves (MMcf)	Lessor Royalties and Burdens (%)	Company Net Gas Reserves (MMcf)
TOTAL PROVEN PLUS PROBABLE	559.0	163.0	406.0		365.0		83.0		68.0

	Net Present Values Before Income Taxes 5% (M$)	10% (M$)	15% (M$)	20% M$)
TOTAL PROVEN PLUS PROBABLE	317	271	236	208

Production Forecasts

The following table shows the Corporation's net oil and NGL production forecast for forecast prices and costs:

NET OIL & NGL PRODUCTION FORECAST
FORECAST PRICES AND COSTS
NOVEMBER 30, 2008

	Company Gross - BBLS/Day				
	2008	2009	2010	2011	2012
PRODUCING					
SASKATCHEWAN					
Viewfield	57.5	36.5	16.4	7.9	3.4
Total Producing	57.5	36.5	16.4	7.9	3.4
PROBABLE					
SASKATCHEWAN					
Viewfield	--	0.4	17.1	9.7	7.4
Total Proven Plus Probable	57.5	36.9	33.5	17.6	10.8

The following table shows the Corporation's net sales gas production forecast for forecast prices and costs:

SALES GAS PRODUCTION FORECAST
FORECAST PRICES AND COSTS
NOVEMBER 30, 2008

	Company Net - MCF/Day				
	2008	2009	2010	2011	2012
PRODUCING					
ALBERTA					
Pembina	36.0	25.0	17.0	11.0	9.0
SASKATCHEWAN					
Viewfield	28.0	18.0	7.0	3.0	1.0
Total Proven Producing	64.0	43.0	24.0	14.0	1.0
PROBABLE					
ALBERTA					
Pembina	--	10.0	13.0	13.0	11.0
SASKATCHEWAN					
Viewfield	--	--	2.0	3.0	3.0
Total Probable	--	10.0	15.0	16.0	14.0
Total Proven Plus Probable	64.0	53.0	39.0	30.0	24.0

Oil and Gas Properties

Viewfield Area, Saskatchewan

The Corporation, through various farmouts, has gross overriding royalty interests ranging from 5.0% to 18.0% in nine (9) producing oil and gas wells in the Viewfield area of Saskatchewan. The royalty interests received from six (6) of these wells are on gross basis, and therefore there are no deductions for crown royalties, transportation or any other expenses related to the marketing of the products produced. The royalty interest received from three (3) natural gas wells are on a net basis allowing for deductions for processing and marketing which is estimated to be at $3.50 per Mcf. These wells continue to produce oil, natural gas and liquids on a monthly basis providing the Corporation with continuous monthly cash flow.

The Corporation has retained 80% of the freehold mineral rights on these lands and during the year ended November, 2008, sold 480 acres for a total purchase price of $790,000.

As the Corporation only has overriding royalty interest in the property, there are not any abandonment liabilities associated with these interests.

The following table summarizes the evaluation of the area to the Corporation:

VIEWFIELD, SASKATCHEWAN
ECONOMICALLY RECOVERABLE REMAINING OIL RESERVES
NOVEMBER 30, 2008

	Economically Recoverable Remaining Reserves Gross 100% Lease				Company Share										
					Company Interest								Present Worth Value Before Income Taxes		
					Company Gross				Company Net						
	Oil				Oil				Oil						
	Light & Medium MSTB	Heavy MSTB	Gas MMcf	NGL MSTB	Light & Medium MSTB	Heavy MSTB	Gas MMCF	NGL MSTB	Light & Medium MSTB	Heavy MSTB	Gas MMCF	NGL MSTB	5% M$	10% M$	15% M$
Proven Producing	172.9	--	69.0	13.7	--	--	--	--	23.1	--	12.0	2.4	1,601.0	1,515.0	1,440.0
Proven Developed (Non-Producing)	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Total Proven	172.9	--	69.0	13.7	--	--	--	--	23.1	--	12.0	2.4	1,601.0	1,515.0	1,440.0
Probable	131.4	--	36.0	7.3	--	--	--	--	19.4	--	6.0	1.3	1,293.0	1,078.0	915.0
Total Proven Plus Probable	304.3	--	105.0	21.0	--	--	--	--	42.5	--	18.0	3.7	2,894.0	2,593.0	2,355.0

Pembina Area, Alberta

The Corporation retains a 27% working interest in two (2) gas wells located on Section 19 and Section 30-48-08W5M and a 6.67% in one (1) other natural gas well located on Section 16-24-08W5M.

The Pembina 05-18-48-08W5M was drilled in the summer of 2006 encountered multiple natural gas zones, however as of November 30, 2008 the well was shut-in pending completion of a zone located up hole. The Pembina 05-30-48-08W5M was drilled, completed and placed on stream during the spring of 2007 and produced at a rate of approximately 34 Mcf per day net to the Corporation. The estimated gathering and processing costs is $0.85 per Mcf along with an estimated operating cost of $1,250 per month which covers contract operator, administrative overhead and general lease maintenance. This well is subject to Alberta crown royalty and gross overriding royalties totalling 11.88%.

The Pembina 16-24-48-08W5M well was drilled and completed during the spring of 2007 and placed on production during December of 2008. The well produced at rate of approximately 8.0 Mcf per day net to the Corporation for year. This well is subject to an estimated gathering and processing cost of $0.85 per Mcf.

A fourth well located at 10-24-08-48W5M was abandoned during the 2007-2008 year end.

The estimated abandonment liabilities, net of salvage, is estimated to be $35,000 per well (gross) using 2008 dollars.

The following table summarizes the evaluation of this area to the Corporation:

PEMBINA, ALBERTA
NATURAL GAS RESERVES
FORECAST PRICES AND COSTS
NOVEMBER 30, 2008

	Economically Recoverable Remaining Reserves Gross (100% Lease		Company Share: Economically Recoverable Remaining Gas Reserves				Present Worth Values Before Income Tax		
			Gross		Net				
	Gas MMCF	NGL MSTB	Gas MSTB	NGL MSTB	Gas MMCF	NGL MSTB	5% M$	10% M$	15% M$
Proven Producing	163.0	--	37.0	--	31.0	--	121.0	112.0	103.0
Proven Developed	--	--	--	--	--	--	--	--	--
Total Proven	163.0	--	37.0	--	31.0	--	121.0	112.0	103.0
Probable	203.0	--	47.0	--	38.0	--	197.0	159.0	133.0
TOTAL PROVEN PLUS PROBABLE	366.0	--	84.0	--	69.0	3.7	318.0	271.0	236.0

Operating Costs

The following table is a summary of operating costs as of November 30, 2008:

SUMMARY OF OPERATING COSTS
NOVEMBER 30, 2008

Area	Fixed	Variable	
	$/Well/Month	$/BBL	$/Mcf
ALBERTA			
Pembina			
02/16-24-48-08W5M	1,250	--	0.85
02/05-30-48-08W5M	1,250	--	0.85
SASKATCHEWAN			
Viewfield			
91/02-31-07-07W2N - Location	--	--	--
91/08-31-07-07W2M	--	--	--
92-08-31-07-07W2M	--	--	--
91/09-31-07-07W2M	--	--	--
91/16-31-07-07W2M	--	--	--
91/06-06-08-07W2M	--	--	--
21/03-05-08-08W2M	--	--	3.50
91/03-05-08-08W2M	--	--	3.50
92/15-05-08-08W2M	--	--	3.50
91/16-05-08-08W2M	--	--	3.50

Properties with no Attributed Reserves

The following table shows a summary of prospective land values to which no attributed reserves have been assigned.

SUMMARY OF PROSPECTIVE LAND VALUES
FORECAST PRICES AND COSTS
NOVEMBER 30, 2008

	TYPE OF HOLDING	EXPIRY DATE yy-mm-dd	GROSS ACRES	AREA INTEREST PERCENT	AREA INTEREST NET ACRES	GORR %	VALUE ASSIGNED PER ACRE $	VALUE ASSIGNED TOTAL $
ALBERTA								
ALDERSON								
T 13-R 9 W4M								
N/2 Section 33	PNG Below base of SWS	12-10-03	320	50.00	160	0.0	300	48,000
ISOEGUN								
T 67-R 20 W5M								
SW/4 Section 6	PNG	12-10-31	160	40.00	64	0.0	160	10,200
WILLESDEN GREEN								
T 38-R 6 W5M								
SW/4 Section 1	PNG Below base of Edmonton to Base Cardium	12-11-14	160	80.00	128	0.0	50	6,400
RICH								
T 34-R 20 W4M								
Sections 14, 24 and 25	PNG From Base Mannville to Base Precambrian	09-06-17	1,920	18.75	360	0.0	30	12,600
Section 30	PNG From Base Mannville to Base Precambrian	09-06-17	640	25.00	160	0.0	10	1,600
	TOTAL RICH		2,560		520			14,200
TOTAL ALBERTA			3,200		872			78,800
SASKATCHEWAN								
VIEWFIELD								
T07-R 08 W2M								
S/2 Section 9	PNG	HBP	320	50.00	160	0.0	75	12,000
T08-R07 W2M								
SE/4 Section 8	PNG	HBP	160	100.00	160	0.0	150	24,000
SW/4 Section 9	PNG	NBP	160	100.00	160	0.0	150	2,400
	TOTAL VIEWFIELD		640		480			60,000
TOTAL CANADA			3,840		1,352			138,000

Inga Area N.E. British Columbia

Early in the summer of 2006, having reviewed seismic data, the Corporation obtained one (1) section of land underlying a significant structure in Northeastern British Columbia. Cobra Venture Corporation's net working interest is 75%, and additional seismic structures are being reviewed with the intent to accumulate a large land position in the prospect area.

Cessford Area, Alberta

The Corporation announced that it had entered into an agreement on October 25, 2005 to acquire an interest in a Farmout and Participation Agreement to immediately commence an initial four well drilling program in the Cessford area of Alberta. The development properties are held 100% by the operating industry partner and target multiple natural gas prospective zones. The Corporation has the right to earn a 50% working interest before payout and 25% working interest after payout by paying 50% of all costs associated with the drilling program. There is a finder's fee payable on the transaction of 100,000 common shares at a price of $0.15 per share, which has been recorded in the financial statements as an obligation to issue shares.

Effective November 14, 2005, the Company did not proceed with the four development well program in the Cessford area of Alberta.

Central Alberta

In Central Alberta, the Corporation has been successful in acquiring varying interests between 25-50% in 320 acres at Alderson, 160 acres at Willesden Green, and 160 acres in the Iosegun areas of Alberta. License applications are currently underway to drill up to 2 Cardium wells at Willesden Green and a Nisku recompletion program is planned for the Iosegun lands. A 3D seismic farm-in program has been completed by a third party on the Alderson lands and is currently being evaluated. The Corporation is actively evaluating new opportunities in Alberta to increase its land position and drilling inventory of light oil targets.

Alderson Area, Alberta

In the fall of 2007, the Corporation obtained a 50% net working interest in 320 acres of land in Central Alberta for $77,215.

The proposed 3D program has been completed by a 3rd party at no cost to the Corporation. The evaluation by this 3D seismic seems to indicate the presence of a large high anomaly, which as the potential for a new oil pool. The anomaly is offset by a smaller anomaly that produced 98,000 barrels from depths of only 900 meters. The Corporation holds a 25% working interest in the existing lands and 3D seismic.

Willesden Green Area, Alberta

In the fall of 2007, the Corporation obtained a 40% net working interest in 160 acres of land in Central Alberta for $18,570.

The Corporation has applied for and has been granted a holding in the Willesden Green area which is anticipated to allow two oil well locations to be drilled immediately adjacent to the Cardium U pool. The Corporation is currently surveying the first locations. Pending the successful completion of the first well, a second location will be drilled offsetting the first well. Offset wells in the area have exhibited total production rates of 60,000 to 109,000 barrels of oil.

Iosegun Area, Alberta

In the fall of 2007, the Corporation obtained a 20% net working interest in 160 acres of land in Central Alberta for $15,543.

The Company has acquired the oil and natural gas rights to the Nisku zone and plans to re-enter an oil well that was abandoned in the 1980’s with historical production of between 20 and 30 BBLs/d of light oil.

The surface audit of the existing well site has been completed by the current owner of the wellbore. The Corporation has vetted this environmental audit and is fully satisfied that no environmental liabilities exist with the old well site and it is anticipated that the Corporation will now be proceeding with taking over the existing wellbore from the current owners. The potential re-entry is anticipated to re-establish the production of approximately 20-30 barrels of light oil per day that existed when the well was abandoned in the 1980’s. The Corporation owns a 20% working interest but may earn additional percentages by farm-in from the current owners.

Valhalla Area, Alberta

The Corporation has entered into an agreement to acquire a 20% working interest in lands in the Valhalla area. The section shows several interesting sands that have high natural gas readings on the lithology gas detector during drilling of an old abandoned well. The Corporation has identified several natural gas zones which correlate to nearby natural gas wells drilled to the Bluesky-Gething formation that produced between 1 Bcf and 2.5 Bcf in offset wells. Also of interest is the shallower Paddy-Cadotte sand package that produced over 3.8 Bcf in a nearby wellbore. This land acquisition is anticipated to close soon and once acquired, a location has been identified for winter drilling in 2009 budget. The Corporation will also have the option to earn an additional 30% interest for a total 50% working interest in the section of land. Initial production rates for the offset Bluesky well were 1.5 MMcf/d, while the Paddy production rates were over 4 MMcf/d for the first year in a well 2 miles to the south of these lands.

Forward Contracts

Not Applicable

Tax Horizon

As at November 30, 2008 the Corporation has the following exploration and development expenditures and undepreciated capital costs which may be carried forward indefinitely to reduce future Canadian taxable income.

Non-capital losses (carry-forward)	$102,000
UCC	57,060
COPGE	Nil
CDE	Nil
CEE	Nil

Exploration and Development Activities

For the year ended November 30, 2008 the Corporation completed the following exploratory and development wells:

EXPLORATION AND DEVELOPMENT ACTIVITIES
YEAR ENDED NOVEMBER 30, 2008

	Exploratory wells		Development wells	
	Gross	Net	Gross	Net
Oil	Nil	Nil	Nil	Nil
Gas	Nil	Nil	1.0	0.8
Service	Nil	Nil	Nil	Nil
Dry	Nil	Nil	Nil	Nil
Total	Nil	Nil	1.0	0.8

The Corporation's most important current and likely exploration and development activities are described under "Oil and Gas Properties".

Production History

The following tables set forth the average daily production volumes, royalties, production costs and the resulting netbacks for the periods indicated as at November 30, 2008:

ACTUAL AVERAGE DAILY PRODUCTION VOLUMES AND NETBACKS
YEAR ENDED NOVEMBER 30, 2008 BY QUARTER

CANADA	Q1 FEB 29	Q2 MAY 31	Q3 JUN 30	Q4 NOV 30
Revenue				
Light and Medium Oil and NGL				
Average Daily Production (BBL)	-	-	-	-
Average Sales Price ($/BBL)	$ 53.67	$53.83	$56.33	$64.83
Heavy Oil				
Average Daily Production (BBL)	-	-	-	-
Average Sales Price ($/BBL)	$ -	$ -	$ -	$ -
Natural Gas				
Average Daily Production (Mcf)	40.9	42.2	55.2	40.2
Average Sales Price ($/Mcf)	$ 7.30	$ 7.07	$ 8.06	$ 6.74

ACTUAL AVERAGE DAILY PRODUCTION VOLUMES AND NETBACKS (continued)
YEAR ENDED NOVEMBER 30, 2008 BY QUARTER

CANADA		Q1 FEB 29		Q2 MAY 31		Q3 JUN 30		Q4 NOV 30
Barrels of Oil Equivalent								
Average Daily Production (boe)		6.8		7.1		9.2		6.7
Average Sales Price ($/boe)	$	(43.85)	$	(69.53)	$	(48.31)	$	(40.51)
Royalties (Crown, Freehold, Overriding)								
Average Royalties Paid ($/boe)	$	8.47	$	17.68	$	12.09	$	12.64
Production Costs								
Average Production Costs ($/boe)	$	12.20	$	12.28	$	8.87	$	4.07
Netback ($/boe)	$	(23.18)	$	(39.57)	$	(27.35)	$	(23.80)

ACTUAL AVERAGE ROYALTY PRODUCTION VOLUME AND PRICES
RECEIVED FOR THE YEAR ENDED NOVEMBER 30, 2008

CANADA		
Oil and Liquid Royalty Revenue		
Average daily royalty production (BBL)		23.5
Average sales price received ($/BBL)	$	94.44
Gas Royalty Revenue		
Average daily royalty production (Mcf)		2.9
Average price received ($/Mcf)	$	6.58
Barrels of Oil Equivalent		
Average daily royalty production (BOE)		24.0
Average price received ($/BOE)	$	93.34

Petroleum and Natural Gas Interest – Summary of Costs Incurred

		British Columbia		Alberta		Saskatchewan		Total
Balance November 30, 2007	$	160,051	$	1,253,471	$	(891,530)	$	521,992
Acquisition costs		-		-		-		-
Land				75,554		-		75,554
Sale of mineral properties		-		-		(459,263)		(459,263)
Mineral leases		-		-		1,589		1,589
Deferred costs:								
Geological Fees		-		23,551		-		23,551
Engineering and consulting		-		12,135		-		12,135
Drilling costs		-		708,051		-		708,051
Completion costs				414,985				414,985
Geophysical services		-		3,006		-		3,006
Surface location costs		-		3,000		-		3,000
Cost recoveries		-		-		-		-
Asset retirement obligations		-		16,800		-		16,800
Production equipment		-		74,403		-		74,403
Balance November 30, 2008	**$**	**160,051**	**$**	**2,584,956**	**$**	**(1,349,204)**	**$**	**1,395,803**