NATIONAL INSTRUMENT 51-101

Standards of Disclosure for Oil and Gas Activities

Reporting Issuer

Mooncor Oil & Gas Corp.

2010 Oil and Gas Activities and Reserves Data

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Standards of Disclosure for Oil and Gas Activities

April 29, 2011

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The statement of reserves data and other oil and gas information set forth below (the "Statement") is dated April 29, 2011. The effective date of the Statement is December 31, 2010. The preparation date of the Statement is April 29, 2011.

Disclosure of Reserves and Resources Data

All of the Corporation's reserves are in Canada, specifically, in the provinces of Alberta, Saskatchewan and Ontario. The reserves data set forth below (the "Reserves Data") is based on an evaluation by DeGolyer and MacNaughton Canada Limited ("DeGolyer MacNaughton") of Calgary with an effective December 31, 2010. The Reserves Data summarizes the crude oil, natural gas liquids and natural gas reserves of the Corporation and the net present values of future net revenue for these reserves using constant prices and costs and forecast prices and costs. The independent report was prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101. Additional information not required by NI 51-101 has been presented to provide continuity and additional information which we believe is important to the readers of this information. The Company engaged DeGolyer MacNaughton to provide an independent evaluation of the P&NG rights held by the Company.

The net present value of future net revenue attributable to the Corporation'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 downhole well abandonment costs for only those wells assigned reserves by DeGolyer MacNaughton. It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to the Corporation's reserves estimated by DeGolyer MacNaughton represent the fair market value of those reserves. There is no assurance that the forecast prices and associated costs assumptions will be attained. Variances could be material. The recovery and volume estimates of the Corporation's crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquid reserves may be greater than, or less than, the estimates provided herein.

FORM 51-101F1

Statement of Reserves Data and Other Oil and Gas Information

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Part 1: Date of Statement and Definitions

1.1 Certain Definitions

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 (see the discussion of "Economic Assumptions" below).

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

i. **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.

ii. **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 lee than the sum of the estimated proved plus probable reserves.

iii. **Possible reserves** are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved + probable + possible reserves.

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:

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

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

vi. at least a 10% probability that the quantities actually recovered will equal or exceed the sum of the estimated proved + probable + possible 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.

Forecast Prices and Costs

Forecast prices and costs are those:

vii. generally acceptable as being a reasonable outlook of the future; and

viii. 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).

Additional clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in the COGE Handbook.

In this Annual Information Form, the following words and phrases have the following meanings, unless the context otherwise requires:

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum;

"**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:

ix. 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, pumping equipment and wellhead assembly;

x. 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;

xi. 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

xii. provide improved recovery systems.

"**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:

xiii. 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;

xiv. 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;

xv. dry hole contributions and bottom hole contributions;

xvi. costs of drilling and equipping exploratory wells; and

xvii. costs of drilling exploratory type stratigraphic test wells.

"**Gross**" means:

in relation to the Corporation's interest in production and reserves, its "Corporation gross reserves", which are the Corporation's interest (operating and non-operating) share before deduction of royalties and without including any royalty interest of the Corporation;

xviii. in relation to wells, the total number of wells in which the Corporation has an interest; and

xix. in relation to properties, the total area of properties in which the Corporation has an interest.

"**Net**" means:

in relation to the Corporation's interest in production and reserves, the Corporation's interest (operating and non-operating) share after deduction of royalties obligations, plus the Corporation's royalty interest in production or reserves.

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

xxi. 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.

"**NI 51-101**" means National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities;

"**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.

Reserves Data (Forecast Prices and Costs)

1.2 Relevant Dates

2. The date of this statement is April 29, 2011.
3. The effective date of the information provided is December 31, 2010.
4. The preparation date of the information being provided is April 29, 2011.

Part 2: Disclosure of Reserves Data

SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
as of December 31, 2010

FORECAST PRICES AND COSTS

RESERVES

	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS non-associated & associated		NATURAL GAS solution		NATURAL GAS LIQUIDS	
RESERVE CATEGORY	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)
PROVED										
Developed Producing										
Developed Non-Producing			43	36						
Undeveloped										
Total Proved			**44**	**36**						
Probable			49	34						
Total Proved + Probable			**92**	**70**						
Possible			29	22						
Total Proved + Prob + Poss			**121**	**92**						

NET PRESENT VALUES

	BEFORE INCOME TAXES DISCOUNTED AT (%/year)					AFTER INCOME TAXES DISCOUNTED AT (%/year)				
RESERVE CATEGORY	0 (M$)	5 (M$)	10 (M$)	15 (M$)	20 (M$)	0 (M$)	5 (M$)	10 (M$)	15 (M$)	20 (M$)
Proved Developed Producing										
Proved Developed Non-Producing	1,294	1,149	1,026	922	834	1,294	1,149	1,026	922	834
Proved Undeveloped										
Total Proved	**1,294**	**1,149**	**1,026**	**922**	**834**	**1,294**	**1,149**	**1,026**	**922**	**834**
Probable	1,597	1,297	1,074	905	775	1,597	1,297	1,074	905	775
Total Proved + Probable	**2,891**	**2,446**	**2,100**	**1,827**	**1,609**	**2,891**	**2,446**	**2,100**	**1,827**	**1,609**
Possible	1,013	684	476	342	252	1,013	684	476	342	252
Total Proved + Prob + Poss	**3,904**	**3,130**	**2,576**	**2,169**	**1,861**	**3,904**	**3,130**	**2,576**	**2,169**	**1,861**

TOTAL FUTURE NET REVENUE (UNDISCOUNTED) as of December 31, 2010

FORECAST PRICES AND COSTS

RESERVES CATEGORY	REVENUE (M$)	ROYALTIES (M$)	OPERATING COSTS (M$)	DEVELOPMENT COSTS (M$)	WELL ABANDONMENT COSTS (M$)	FUTURE NET REVENUE BTAX (M$)	INCOME TAXES (M$)	FUTURE NET REVENUE ATAX (M$)
Proved Developed Producing								
Proved Developed	2,996	444	1,113	104	42	1,294		1,294
Total Proved	2,996	444	1,113	104	42	1,294		1,294
Total Proved + Probable	6,527	1,525	1,961	104	45	2,891		2,891
Total Proved + Prob + Poss	8,812	2,063	2,691	104	49	3,904		3,904

FUTURE NET REVENUE BY PRODUCTION GROUP as of December 31, 2010

FORECAST PRICES AND COSTS

		FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year)	**Unit Value**
RESERVES CATEGORY	PRODUCTION GROUP	(M$)	($/BOE)
PROVED	Light & Medium Crude Oil (including solution gas) Heavy Oil Natural Gas (including by-products but excluding solution gas from oil wells)	1,026	28.17
PROVED + PROBABLE	Light & Medium Crude Oil (including solution gas) Heavy Oil Natural Gas (including associated by-products but excluding solution gas from oil wells)	2,100	30.04

Part 3: Pricing Assumptions

Forecast Prices Used in Estimates

The forecast reference prices used in preparing the Company's reserves data are provided in the following table. This price forecast is the independent reserve evaluator's standard price forecast effective at December 31, 2010.

Summary of Pricing and Inflation Rate Assumptions

Year	WTI Crude Oil Cushing ($US/bbl)	Edmonton Light Crude ($Cdn/bbl)	Heavy Oil 12 API Hardisty ($Cdn/bbl)	Alberta Spot Sales Plantgate ($Cdn/Mcf)	Edmonton Pentanes Plus ($Cdn/bbl)	Edmonton Butane ($Cdn/bbl)	Inflation Rate (%/Yr)	Exchange Rate ($US/$CDN)
Forecast								
2011	88.00	89.30	71.44	3.98	91.09	66.98	0	0.98
2012	90.78	92.13	71.86	4.69	93.97	69.10	2.0	0.98
2013	93.64	95.04	72.23	5.38	96.94	71.28	2.0	0.98
2014	96.57	98.02	73.51	6.02	99.98	73.51	2.0	0.98
2015	99.58	101.08	75.81	6.31	103.11	75.81	2.0	0.98
2016	101.58	103.11	77.33	6.44	105.17	77.33	2.0	0.98
2017	103.61	105.17	78.88	6.58	107.27	78.88	2.0	0.98
2018	105.68	107.27	80.45	6.72	109.42	80.45	2.0	0.98
2019	107.79	109.42	82.06	6.87	111.60	82.06	2.0	0.98
2020	109.95	111.60	83.70	7.01	113.84	83.70	2.0	0.98
2021	112.15	113.84	85.38	7.16	116.11	85.38	2.0	0.98
2022	114.39	116.11	87.09	7.31	118.44	87.09	2.0	0.98
Thereafter	+2.0%/Year							

Part 4: Reconciliation of Changes in Reserves

RESERVES RECONCILIATION - FORECAST PRICE CASE

COMPANY SHARE GROSS

Effective Date: December 31, 2010

	Total Oil (BBL)	Light/Med Oil (BBL)	Heavy Oil (BBL)	Sales Gas (MMCF)	NGL (BBL)	BOE (BBL)
TOTAL PROVED PRODUCING						
Opening Balance (Dec. 31, 2009)	-	-	-	-	-	-
Extensions	-	-	-	-	-	-
Improved Recovery	-	-	-	-	-	-
Technical Revisions*	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-
Acquisitions**	-	-	-	-	-	-
Dispositions**	-	-	-	-	-	-
Economic Factors ***	-	-	-	-	-	-
Production	-	-	-	-	-	-
						-
Closing Balance (Dec. 31, 2010)	-	-	-	-	-	-
						-
TOTAL PROVED DEVELOPED						-
Opening Balance (Dec. 31, 2009)	**43,552**	-	**43,552**	-	-	**43,552**
						-
Extensions	-	-	-	-	-	-
Improved Recovery	-	-	-	-	-	-
Technical Revisions*	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-
Acquisitions**	-	-	-	-	-	-
Dispositions**	-	-	-	-	-	-
Economic Factors ***	**(164)**	-	**(164)**		-	**(164)**
Production	**(492)**	-	**(492)**	-	-	**(492)**
						-
Closing Balance (Dec. 31, 2010)	**42,896**	-	**42,896**	-	-	**42,896**
						-
TOTAL PROVED						-
Opening Balance (Dec. 31, 2009)	**43,552**	-	**43,552**	-	-	**43,552**
						-
Extensions	-	-	-	-	-	-
Improved Recovery	-	-	-	-	-	-
Technical Revisions*	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-
Acquisitions**	-	-	-	-	-	-
Dispositions**	-	-	-	-	-	-
Economic Factors ***	**(164)**	-	**(164)**	-	-	**(164)**
Production	**(492)**	-	**(492)**	-	-	**(492)**
						-
Closing Balance (Dec. 31, 2010)	**42,896**	-	**42,896**	-	-	**42,896**

-

TOTAL PROVED + PROBABLE

Opening Balance (Dec. 31, 2009)	**92,113**	**-**	**95,130**	**-**	**-**	**95,130**
Extensions	**-**	**-**	**-**	**-**	**-**	**-**
Improved Recovery	**-**	**-**	**-**	**-**	**-**	**-**
Technical Revisions*	**-**	**-**	**-**	**-**	**-**	**-**
Discoveries	**-**	**-**	**-**	**-**	**-**	**-**
Acquisitions**	**-**	**-**	**-**	**-**	**-**	**-**
Dispositions**	**-**	**-**	**-**	**-**	**-**	**-**
Economic Factors ***	**238**	**-**	**238**	**-**	**-**	**238**
Production	**(492)**	**-**	**(492)**	**-**	**-**	**(492)**
Closing Balance (Dec. 31, 2010)	**91,859**	**-**	**91,859**	**-**	**-**	**91,859**

TOTAL PROVED + PROBABLE + POSSIBLE

Opening Balance (Dec. 31, 2009)	**121,155**	**-**	**121,155**	**-**	**-**	**121,155**
Extensions	**-**	**-**	**-**	**-**	**-**	**-**
Improved Recovery	**-**	**-**	**-**	**-**	**-**	**-**
Technical Revisions*	**-**	**-**	**-**	**-**	**-**	**-**
Discoveries	**-**	**-**	**-**	**-**	**-**	**-**
Acquisitions**	**-**	**-**	**-**	**-**	**-**	**-**
Dispositions**	**-**	**-**	**-**	**-**	**-**	**-**
Economic Factors ***	**360**	**-**	**360**	**-**	**-**	**360**
Production	**(492)**	**-**	**(492)**	**-**	**-**	**(492)**
Closing Balance (Dec. 31, 2010)	**121,023**	**-**	**121,023**	**-**	**-**	**121,023**

The numbers in this table may not exactly add due to rounding.

* Includes technical revisions due to reservoir performance, geological and engineering changes; economic revisions due to changes in economic limits; and working interest changes resulting from the timing of interest reversions.

** Includes production attributable to any acquired interests from the acquisition date to effective date of the report and production realized from disposed interests from the opening balance date to the effective date of disposition.

*** includes economic revisions related to price, operating cost and royalty factor changes

Part 5: Additional Information Relating to Reserves Data
The following table summarizes capital development costs related to the recovery of the Company's reserves and future abandonment costs.

Future Development Costs

	Forecast Prices and Costs (Undiscounted)	
Year	Proved Reserves M$	Proved plus Probable Reserves M$
2011	104	104
2012		
2013		
2014		
2015		
Remaining		
Total	104	104
Total Undiscounted	104	104
Total Discounted @10%	99	99

Part 6: Other Oil and Gas Information

6.1 Oil and Gas Properties and Wells

6.1.1 Lloydminster Property

Mooncor acquired two suspended heavy oil wells and the P&NG rights to 80 gross acres (64 net acres) of land from an arms length industry partner in February 2008. The two wells acquired are 02/04-28-049-02W4 (100% BPO – 60% APO) and 02/03-28-049-02W4 (60% W.I.%). The wells are currently completed in the upper Sparky zone and are designated as the Sparky AAA pool.

Well 02/04-28-049-02W4 was drilled August 2006. The 02/03-28-049-02W6 was drilled in September 2006. The wells were equipped to pump by the previous operator but were shut-in soon after being put on production.

6.2 Properties with No Attributed Reserves

6.2.1 Lonestar Property

Lonestar is located in Northern Alberta approximately 200 kilometers north of Grande Prairie and approximately 50 kilometers north-west of the town of Peace River. The well and leases are within the Peace River Oilsands area. Mooncor drilled and cased a 2100 meter well in February 2007 to test a Gilwood anomaly identified by 2D seismic. The well has not been completed. Mooncor acquired 2 sections (1280 acres) of P&NG rights in September 2007 and the designated Oilsands rights in March 2008. The leases have a primary 5 year term for P&NG and a 15 year term for Oilsands rights.

The area is relatively isolated and the nearest tie-in point for a successful well is approximately 15 kilometers to the north-east. The area is winter access only and Mooncor is required to submit a Caribou Management Plan for approval prior to conducting active operations. Mooncor has no marketing agreement for production and plans to sell its pro-rata share of sales volumes into the spot market at AECO spot pricing less deductions and adjustments.

6.2.2 White Hill Lakes Property

Mooncor is investigating shallower unconventional reservoirs associated primarily with siltstones and shales. The Cretaceous strata, from the Lea Park down to the top of the Mannville, are predominantly marine shales. Studies of organic carbon content within this section suggest that total organic carbon ("TOC") ranges from less than 3 percent to as much as 12 percent of marine Type II kerogens. Hydrogen indices range up to 450.

The sediments are immature, generating only biogenic gas, as they have not reached sufficient depths and temperatures to generate thermogenic gas. The Second White Speckled Shale and the Fish Scales Zone appear to be the major source rocks having high TOC. Other shaly sections are also considered to be effective source rocks having TOC's ranging from 2 to 3 percent.

Wells that commercially produce from the Second White Specks formation of the Upper Cretaceous are approximately 120 kilometers west of the White Hill Lakes property.

The White Hill Lakes area is located approximately 40 kilometers east of the town of North Battleford in west central Saskatchewan. The area is predominantly a heavy oil producing region of the province.

Mooncor has earned 11.25 sections (7200 acres) that it has converted to lease.

6.2.3 South West Ontario

Mooncor exited the year with 15,664 gross and net acres of freehold mineral right lands in South West Ontario. The lands acquired are prospective in the Cambrian, Ordovician, Silurian (stratigraphic, reef and structural traps) and Devonian formations.

The Oil & Gas Industry is well established in SW Ontario and offers a premium commodity pricing environment in addition to a low royalty rate of 12.5%. This is a proven oil and gas exploration basin that is domain to primarily small undercapitalized industry. The basin has year round drilling access and substantial existing infrastructure.

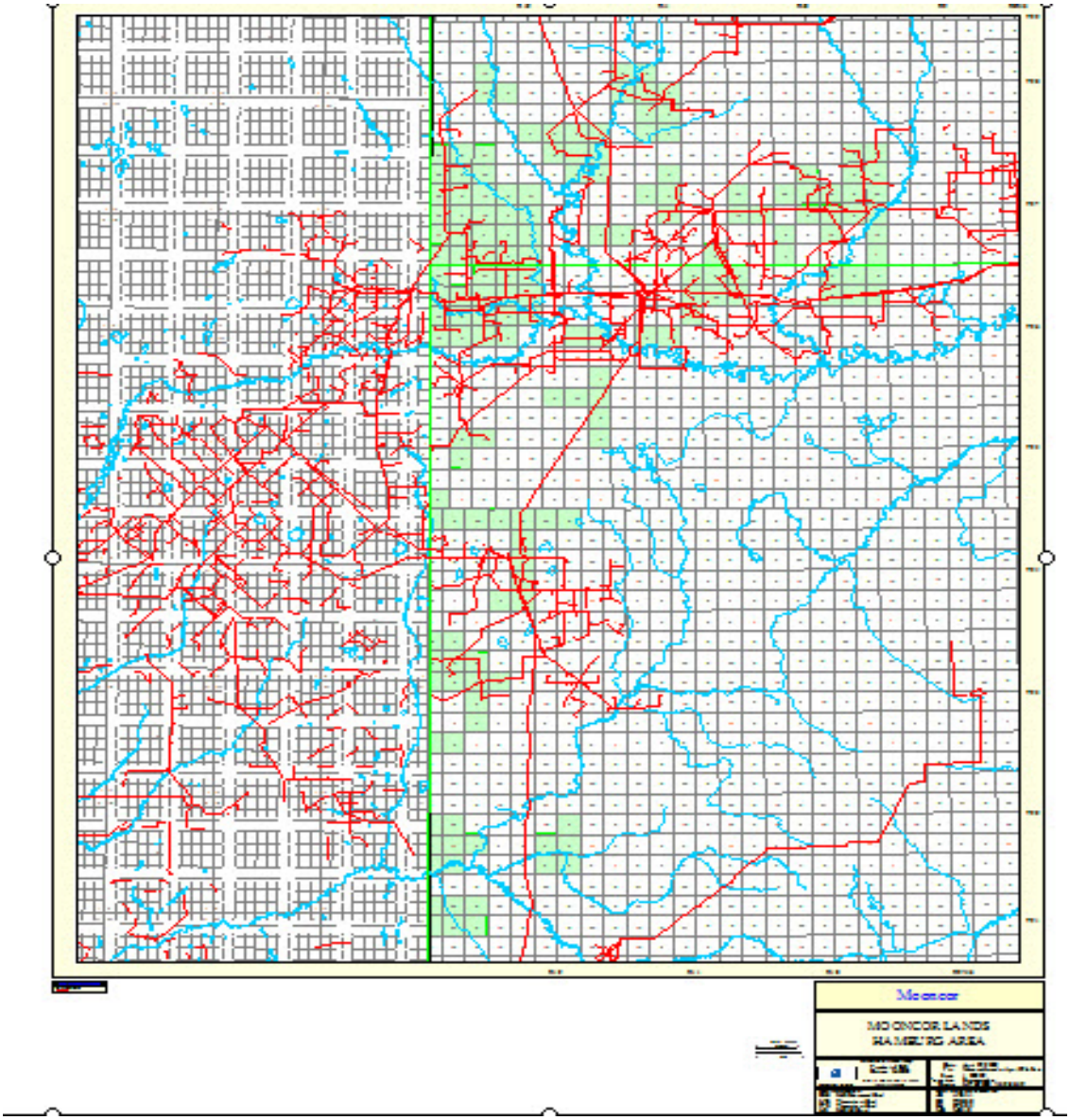
6.2.4 Hamburg – Chinchaga Property

Mooncor exited the year with 103,680 gross and net acres (162 Sections) of lands acquired at crown land sales. The lands acquired are largely contiguous and are situated in Alberta proximal to the British Columbia border.

The Hamburg Chinchaga lands are located in an area of the Western Canada Sedimentary basin that lays along the north side of the Precambrian Peace River Arch. More than 500 wells have been drilled in the area from 1983 to present to test the Slave Point and deeper Gilwood sands. The area has also been favourable for Triassic (Montney, Doig and Halfway) and Cretaceous (Bluesky, Gething and Spirit River) zones.

The area has a well-developed infrastructure system in place including gas gathering systems, processing plants and an extensive road network.

Mooncor has acquired the lands primarily based on the prospectivity for Devonian shales. The main Devonian shales that exist within the area are in the Fort Simpson and Muskwa Formations.



Mooncor has mapped a large shale gas opportunity in northern Alberta. We are able to confirm the southeastward extension of the massive Horn River Muskwa (a.k.a. Duvernay) shale gas discovery from northern British Columbia through to northwestern Alberta, based on detailed geologic mapping, gas detection review, petrographic analysis and, most importantly, the actual occurrence of gas and pressure in the shale system.

6.3 Forward Contracts

Not applicable.

6.4 Additional Information Concerning Abandonment and Reclamation Costs

The Company estimates abandonment and reclamation costs on a producing region basis. At present, the Company has made provision to abandon 1.7 net wells over the total life of these fields and has deducted the estimated abandonment costs from the future cash flow projections.

ABANDONMENT & RECLAMATION COSTS (Forecast Prices & Costs)

	Total Abandonment and Reclamation Costs Including Well Abandonment and Disconnect Costs (M$)
Total Proved Reserves (Yr)	
2011	-
2012	-
2013	-
2014	-
2015	-
Remaining	42
Total	42
Proved + Probable Reserves (Yr)	
2011	-
2012	-
2013	-
2014	-
2015	-
Remaining	45
Total	45

Note: The numbers in this table may not add exactly due to rounding.

The Company does not expect to incur any costs over the next three years.

6.5 Tax Horizon

The Company is not required to pay income taxes for the most recent financial year as it did not realize any profit from operations.

6.6 Costs Incurred in 2010

The Company's property acquisition costs were $**100,000.00**. This amount was incurred in acquiring P&NG rights in the Kent and Lambton counties of South West Ontario. Development expenses incurred for the latest financial year were $**562,601** related to the Corporations work on the Lloydminster and Hamburg properties in Alberta.

6.7 Exploration and Development Activities

During the last financial year, the Company participated in drilling the following wells:

	Oil		Gas		Service		D & A		Total	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Exploratory	0	0	0	0	0	0	0	0	0	0
Development	0	0	0	0	0	0	0	0	0	0
Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

All the wells are located in Canada.

6.8 Production Estimates

SUMMARY OF PRODUCTION ESTIMATES BY PRODUCTION GROUP
TOTAL PROVED RESERVES FOR YEAR 2011 (Forecast Prices & Costs)

RESERVES CATEGORY	**Forecast Prices & Costs** **Gross Daily Production (2)**
Light & Medium Oil (bbls/d)	-
Heavy Oil (bbls/d)	27
Associated and Non-Associated Gas (Mcf/d)	-
Natural Gas Liquids (bbls/d)	-
TOTAL (1) (boe/d)	**27**

(1) Barrels of Oil Equivalent (boe) have been reported based on natural gas conversion of 6 Mcf/1 bbl.

(2) Gross production is Company interest before all royalty deductions.

Note: The numbers in this table may not add exactly due to rounding.

SUMMARY OF COMPANY SHARE GROSS PRODUCTION ESTIMATES (1) BY FIELD
TOTAL PROVED RESERVES FOR YEAR 2010 (Forecast Prices & Costs)

	Light & Medium Oil (bbl/d)	Heavy Oil (bbl/d)	Natural Gas (2) (Mcf/d)	Natural Gas Liquids (bbl/d)
FIELD				
Lloydminster	-	27	-	-
TOTAL	**-**	**27**	**-**	**-**

(1) Daily production is taken from the Reserves Report as of December 31, 2010

(2) Natural Gas includes Associated and Non-Associated sales gas volumes.

Note: The totals shown above may not match the corporate totals due to rounding.