

**FORM 51-101F1 STATEMENT OF RESERVES DATA
AND OTHER OIL AND GAS INFORMATION OF
PAINTED PONY PETROLEUM LTD.**

Part 1 Relevant Dates

Item 1.1 Date of Statement and Statement Information

This Statement of Reserves Data and Other Oil and Gas Information of Painted Pony Petroleum Ltd. ("**Painted Pony**" or the "**Corporation**") is dated April 28, 2010. The effective date of the information provided in this Statement is December 31, 2009 unless otherwise indicated. The information was prepared between December 31, 2009 and April 28, 2010.

Part 2 Disclosure of Reserves Data

Sproule Associates Limited ("**Sproule**") has prepared a report dated March 11, 2010 (the "**Sproule Report**"), in which it has evaluated as at December 31, 2009 the oil, natural gas and natural gas liquids reserves attributable to the principal properties of the Corporation.

The Sproule Report also presents the estimated net value of future revenue of Painted Pony's properties before and after taxes, at various discount rates. Assumptions and qualifications relating to costs and prices for future production and other matters are summarized in the notes to the following tables.

The extent and nature of all information supplied by Painted Pony and/or the operator of its properties, which may have included ownership data, well information, geological information, reservoir studies, timing and future production, gas sales contract information, current product prices, operating cost data, capital budget forecasts and future operating plans, have been relied upon by Sproule in preparing the Sproule Report and were accepted as represented without independent verification. In the absence of such information, Sproule relied, with the approval of Painted Pony, upon its opinion of reasonable practice in the industry. All information provided to Sproule was as at December 31, 2009 and, accordingly, certain of such information may not be representative of current conditions.

The definitions of the various categories of reserves and expenditures are those set out in National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* ("**NI 51-101**").

BOEs may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf to 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.

It should not be assumed that the present worth of estimated future net revenue represents the fair market value of the reserves. There is no assurance that the escalating price and cost assumptions contained in the Sproule Report will be attained and variances could be material. The reserve and revenue estimates set forth below are estimates only and the actual reserves and realized revenue may be greater or less than those calculated.

Item 2.1 Reserves Data - Forecast Prices and Costs

The following table discloses, in the aggregate, the Corporation's gross and net proved reserves and proved and probable reserves, estimated using forecast prices and costs, by product type. "Forecast prices and costs" means future prices and costs used by Sproule in the Sproule Report that are generally accepted as being a reasonable outlook of the future, or fixed or currently determinable future prices or costs to which the Corporation is bound.

Table 2.1.1
SUMMARY OF RESERVES AS OF DECEMBER 31, 2009
(Forecast Prices & Costs)⁽⁴⁾

Reserves Category	Light and Medium Oil		Heavy Oil		Natural Gas ⁽¹⁾		Natural Gas Liquids	
	Gross ⁽²⁾	Net ⁽³⁾	Gross ⁽²⁾	Net ⁽³⁾	Gross ⁽²⁾	Net ⁽³⁾	Gross ⁽²⁾	Net ⁽³⁾
	(Mbbbl)	(Mbbbl)	(Mbbbl)	(Mbbbl)	(MMcf)	(MMcf)	(Mbbbl)	(Mbbbl)
PROVED								
Developed Producing	1,435.4	1,253.5	-	-	6,695	5,159	161.6	133.7
Developed Non-Producing	3.2	2.7	-	-	348	281	2.8	2.3
Undeveloped	971.2	846.9	-	-	771	606	67.5	56.2
Total Proved	2,409.9	2,103.1	-	-	7,814	6,046	231.8	192.2
PROBABLE	1,478.0	1,290.1	-	-	5,524	4,225	148.3	122.6
TOTAL PROVED PLUS PROBABLE	3,887.9	3,393.2	-	-	13,338	10,271	380.1	314.8

Notes:

- (1) Estimates of Reserves of natural gas include associated gas and non-associated gas.
- (2) "Gross Reserves" are the Corporation's working interest share of the remaining reserves, before deduction of any royalties.
- (3) "Net Reserves" are the Corporation's working interest share of remaining reserves less all Crown, freehold, and overriding royalties and interests owned by others, plus royalty interest reserves.
- (4) May not add due to rounding.

The following table discloses, in the aggregate, the net present value of the Corporation's future net revenue attributable to the reserves categories in the previous table, estimated using forecast prices and costs, before and after deducting future income tax expenses, and calculated without discount and using discount rates of 5%, 10%, 15% and 20%. All properties are located onshore within Canada.

Table 2.1.2
SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2009
(Forecast Prices & Costs) (M\$)

Net Present Values (NPV) of Future Net Revenue (FNR) ⁽¹⁾⁽³⁾											
Reserves Category	Before Income Taxes Discounted at (%/year) ⁽²⁾					After Income Taxes Discounted at (%/year) ⁽²⁾					BT Future Value ⁽⁴⁾
	0	5	10	15	20	0	5	10	15	20	10%/yr (\$/boe)
PROVED											
Developed Producing	101,965	85,257	73,733	65,374	59,056	101,781	85,147	73,666	65,332	59,029	32.81
Developed Non-producing	315	268	227	192	161	274	242	211	181	154	4.39
Undeveloped	38,659	29,750	23,465	18,837	15,311	29,305	21,880	16,643	12,788	9,853	23.37
Total Proved	140,939	115,276	97,426	84,403	74,528	131,360	107,270	90,519	78,301	69,036	29.50
PROBABLE	99,542	66,086	47,269	35,611	27,827	73,173	47,507	33,207	24,398	18,537	22.33
TOTAL PROVED PLUS PROBABLE	240,481	181,361	144,695	120,014	102,356	204,533	154,777	123,727	102,698	87,574	26.70

Notes:

- (1) NPV of FNR includes all resource income: sale of oil, gas, by-product reserves; processing of third party reserves; other income.
- (2) Income Taxes includes all resource income, appropriate income tax calculations and prior tax pools.
- (3) May not add due to rounding.
- (4) BT = Before Taxes

The following two tables provide additional information regarding the future net revenue attributable to total proved reserves and total proved and probable reserves outlined in the previous table.

This table discloses, in the aggregate, certain elements of the Corporation's future net revenue attributable to its proved reserves and its proved plus probable reserves, estimated using forecast prices and costs, and calculated without discount. All properties are located in Canada.

Table 2.1.3
TOTAL FUTURE NET REVENUE (Undiscounted)
AS OF DECEMBER 31, 2009
(Forecast Prices & Costs) (M\$)⁽⁴⁾

RESERVES CATEGORY	Sales Revenue ⁽²⁾	Royalties ⁽³⁾	Operating Costs	Total Develop. Costs	Well Aband. Costs	BT Future Net Revenue ⁽¹⁾	Income Taxes	AT Future Net Revenue ⁽¹⁾
PROVED	303,293	41,770	85,323	28,153	7,108	140,939	9,578	131,360
PROVED PLUS PROBABLE	520,003	72,243	149,506	46,728	11,045	240,481	35,948	204,533

Notes:

- (1) BT = Before Taxes and AT = After Taxes.
- (2) Sales Revenue includes all non-producing income.
- (3) Royalties includes any net profits interests paid, as well as the Saskatchewan Corporation Capital Tax Surcharge.
- (4) May not add due to rounding.

This table discloses, by production group, the net present value of the Corporation's future net revenue attributable to its proved reserves and its proved plus probable reserves, before deducting future income tax expenses, estimated using forecast prices and costs, and calculated using a 10% discount rate.

Table 2.1.4
NET PRESENT VALUE OF FUTURE NET REVENUE BY PRODUCTION GROUP
AS OF DECEMBER 31, 2009
(Forecast Prices & Costs)

RESERVES CATEGORY	PRODUCTION GROUP	Future Net Revenue BT Discounted (10%/ Yr) (M\$) ⁽¹⁾	Unit Value BT Discounted (10%/ Yr) \$/boe ⁽¹⁾⁽²⁾
PROVED	Light & medium crude oil ⁽³⁾	86,962	36.25
	Heavy oil ⁽³⁾	-	-
	Natural gas ⁽⁴⁾	10,464	11.57
PROVED PLUS PROBABLE	Light & medium crude oil ⁽³⁾	128,141	33.12
	Heavy oil ⁽³⁾	-	-
	Natural gas ⁽⁴⁾	16,554	10.68

Notes:

- (1) BT = Before Taxes.
- (2) Calculated as the Net Present Value before income taxes discounted at 10% per year divided by the net reserves volume.
- (3) Including solution gas and associated by-products.
- (4) Including associated by-products.

Part 3 Pricing Assumptions

Item 3.1 Forecast Prices Used in Estimates

The forecast reference prices used by Sproule in preparing the Corporation's reserves data are provided in the below table.

Table 3.1
SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
AS OF DECEMBER 31, 2009

Forecast Year	OIL		GAS		NGL	Inflation Rate ⁽²⁾ (%/Yr)	Exchange Rate ⁽³⁾ (\$US/\$Cdn)
	WTI Cushing Oklahoma (\$US/bbl)	Edmonton Par Price 40° API Light Crude Oil (\$Cdn/bbl)	AECO Gas ⁽¹⁾ Price (\$Cdn/MMBtu)	Pentanes Plus FOB Field Gate (\$Cdn/bbl)			
2010	79.17	84.25	5.36	86.28		2.0	0.92
2011	84.46	89.99	6.21	92.16		2.0	0.92
2012	86.89	92.61	6.44	94.84		2.0	0.92
2013	90.20	96.19	7.23	98.51		2.0	0.92
2014	92.01	98.13	7.98	100.50		2.0	0.92
Thereafter ⁽⁵⁾							

Notes:

- (1) Summary table identifies benchmark reference pricing schedules that might apply to a reporting issuer.
- (2) Inflation rates for forecasting prices and costs.
- (3) Exchange rates used to generate the benchmark reference prices in this table.
- (4) Product sales prices will reflect those reference prices with further adjustments for quality and transportation to point of sale.
- (5) Escalation rate of 2%

This price forecast is Sproule's standard price forecast effective December 31, 2009. Sproule is a qualified reserves evaluator under the definitions of NI 51-101 and is independent of the Corporation.

In 2009, the Corporation received a weighted average price of \$69.15 per barrel (before transportation, marketing fees, royalties and hedging) for its crude oil, \$4.20 per mcf for its natural gas, \$58.84 per barrel for condensate and \$24.22 per barrel for NGLs.

Part 4 Reconciliation of Changes In Reserves

Item 4.1 Reserves Reconciliation

The following table provides a reconciliation of the Corporation's gross reserves based on forecast prices and costs.

Table 4.1
RECONCILIATION OF CORPORATION GROSS RESERVES BY PRINCIPLE PRODUCT TYPE
(Forecast Prices & Costs)⁽¹⁾⁽²⁾⁽³⁾

Factors	Light and Medium Oil			Associated and Non-Associated Gas			Natural Gas Solution			Natural Gas Liquids		
	Proved (Mbbbl)	Probable (Mbbbl)	Proved Plus Probable (Mbbbl)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)	Proved (Mbbbl)	Probable (Mbbbl)	Proved Plus Probable (Mbbbl)
December 31, 2008	1,202.8	793.8	1,996.6	7,821	3,600	11,422	527	552	1,079	153.3	126.8	280.2
Extensions	562.2	(14.7)	547.5	282	1,428	1,710	386	150	536	63.0	33.2	96.2
Improved Recovery	-	-	-	-	-	-	-	-	-	-	-	-
Technical Revisions	470.4	207.1	677.5	(81)	(177)	(258)	(33)	(228)	(261)	(8.1)	(45.1)	(53.2)
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Acquisitions	500.4	491.8	992.2	49	14	63	218	184	402	38.4	33.4	71.8
Dispositions	-	-	-	-	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-	-	-	-	-	-	-
Production	(325.9)	-	(325.9)	(1,334)	-	(1,334)	(21)	-	(21)	(14.8)	-	(14.8)
December 31, 2009	2,409.9	1,478.0	3,887.9	6,737	4,866	11,603	1,077	658	1,735	231.8	148.3	380.1

Notes:

- (1) May not add due to rounding.
- (2) Using price forecasts as indicated in Item 3.2 of this report.
- (3) Gross reserves means the Corporation's working interest share of the remaining reserves, before deduction of any royalties.

Part 5 Additional Information Relating To Reserves Data

Item 5.1 Undeveloped Reserves

The following table discloses the Corporation's gross proved undeveloped reserves, all of which are attributable to properties in which the Corporation has a working interest position. All proved undeveloped reserves are attributable to acreage that offsets existing production and are determined as per NI 51-101 guidelines. The Corporation has plans for developing the proved undeveloped and the probable undeveloped reserves within the next two years.

Table 5.1.1
SUMMARY OF PROVED UNDEVELOPED RESERVES
(Forecast Prices & Costs)⁽³⁾

Year	Light and Medium Oil		Heavy Oil		Natural Gas ⁽²⁾		Natural Gas Liquids	
	First Attributed (Mbbbl)	Cumulative at Year End ⁽¹⁾ (Mbbbl)	First Attributed (Mbbbl)	Cumulative at Year End ⁽¹⁾ (Mbbbl)	First Attributed (MMcf)	Cumulative at Year End ⁽¹⁾ (MMcf)	First Attributed (Mbbbl)	Cumulative at Year End ⁽¹⁾ (Mbbbl)
2009	204.6	971.2	-	-	165.2	771.0	25.2	67.5
2008	358.4	482.4	-	-	560.0	560.0	38.1	38.1
2007	124.0	124.0	-	-	-	-	-	-
2006	-	-	-	-	-	-	-	-

Notes:

- (1) Cumulative at year end is equal to the residual cumulative of previous year plus first attributed.
- (2) Includes associated gas and non-associated gas.
- (3) Gross reserves are the Corporation's working interest share of the remaining reserves, before deduction of any royalties.

Table 5.1.2
SUMMARY OF PROBABLE UNDEVELOPED RESERVES
(Forecast Prices & Costs)⁽³⁾

Year	Light and Medium Oil		Heavy Oil		Natural Gas ⁽²⁾		Natural Gas Liquids	
	First Attributed (Mbbbl)	Cumulative at Year End ⁽¹⁾ (Mbbbl)	First Attributed (Mbbbl)	Cumulative at Yr End ⁽¹⁾ (Mbbbl)	First Attributed (MMcf)	Cumulative at Year End ⁽¹⁾ (MMcf)	First Attributed (Mbbbl)	Cumulative at Year End ⁽¹⁾ (Mbbbl)
2009	229.3	823.9	-	-	1,686.9	1,901.0	54.6	70.2
2008	207.9	518.6	-	-	352.0	352.0	38.4	38.4
2007	310.7	310.7	-	-	-	-	-	-
2006	-	-	-	-	-	-	-	-

Notes:

- (1) Cumulative at year end is equal to the residual cumulative of previous year plus first attributed.
- (2) Includes associated gas and non-associated gas.
- (3) Gross reserves are the Corporation's working interest share of the remaining reserves, before deduction of any royalties.

Item 5.2 Significant Factors or Uncertainties

The main area of uncertainty is commodity price as the Corporation currently sells all production at spot market pricing and has no hedges presently in place.

The process of estimating oil and gas reserves is complex, requiring significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas processing and costs change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions and are evaluated by an independent engineering firm. As circumstances change and additional data become available, reserve estimates also change. Estimates made are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and governmental restrictions.

Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. As a result, the subjective decisions, new geological or production information and a changing environment may impact these estimates. Revisions to reserve estimates can arise from changes in period end oil and gas prices and reservoir performance. Such revisions can be either positive or negative. The reserve estimates of the Corporation's oil reserves produced in this document are estimates only. There is no assurance or guarantee that the estimated reserves will be recovered. Actual reserves may be greater or less than the estimates provided herein.

Item 5.3 Future Development Costs

The following table provides information regarding the development costs deducted in the estimation of future net revenue attributable to the Corporation's reserves.

Table 5.3
FUTURE DEVELOPMENT COSTS
Forecast Prices & Costs (M\$)⁽¹⁾⁽²⁾

Year	For Proved Reserves	For Proved Plus Probable Reserves
2010	20,771	31,987
2011	7,288	14,550
2012	94	94
2013	-	-
2014	-	-
2015	-	97
2016	-	-
Total Undiscounted	28,153	46,728
Total Discounted @ 10%/ Yr	26,327	43,428

Notes:

- (1) Future Development Costs shown are associated with booked reserves in the Sproule Report and do not necessarily represent the Corporation's full exploration and development budget.
- (2) May not add due to rounding.

The Corporation expects that the funds required for future development costs will be obtained from the combination of positive working capital, internally-generated cash flow, credit facilities and equity financing. There can be no guarantee that funds will be available or that the Corporation will allocate funding to develop all of the reserves attributed in the Sproule Report. Failure to develop those reserves would have a negative impact on future cash flow.

Interest and other costs of external funding are not included in the future development costs of the reserves or in the future net revenue estimates, and would reduce reserves and future net revenue to some degree depending upon the funding sources utilized. The Corporation does not anticipate that interest or other funding costs would make development of any property uneconomic.

Part 6 Other Oil and Gas Information

Item 6.1 Oil and Gas Properties and Wells

The following is a description of the Corporation's principal properties on production or under development. Estimates of reserves for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

Southeast Saskatchewan

The Corporation's operations in Saskatchewan are located near the towns of Weyburn and Estevan. The area is prospective for light, sweet oil from the Bakken, Midale, Frobisher and Alida formations.

In 2009 in Southeast Saskatchewan, the Corporation drilled 19 (16.5 net) wells at a net success rate of 98%, and closed four acquisitions at a cost of \$13.6 million. Operations are grouped into five main areas, based primarily on geographic proximity; Kisbey, Midale, Weyburn, Wapella and Other.

a) Kisbey

The Kisbey area is located approximately 30 miles northeast of the town of Estevan, Saskatchewan. The Corporation's assets in the area are primarily focused on Bakken exploitation, which is generally accomplished using horizontal wellbores and multi-stage fracture stimulations. The Kisbey property is operated by partners. In 2009, the Corporation participated in the drilling of 2 (0.45 net) wells in the Kisbey area and 2 (0.6 net) wells are planned for in 2010. Painted Pony's developed and undeveloped land at December 31, 2009 was 1,573 net acres, of which 86% is undeveloped. During the first quarter of 2009, a number of wells within the Kisbey area were tied in to a partner operated gas plant, enabling the sale of solution gas and associated liquids. Sales in 2009 from the Kisbey area averaged 174 boe/d, weighted 95% oil and liquids.

b) Midale/Huntoon

The Midale area is located approximately 20 miles southeast of the town of Weyburn, Saskatchewan. The Corporation's assets in the area are, like Kisbey, focused on Bakken exploitation, though Bakken exploration is ongoing on undeveloped lands. Midale/Huntoon comprises the Corporation's largest producing area.

As at December 31, 2009, Painted Pony had 10,061 net acres of developed and undeveloped land in the Midale/Huntoon area, of which 88% is undeveloped.

During 2009, Painted Pony drilled 16 (15.7 net) wells in the Midale/Huntoon area. In 2010, the Corporation currently anticipates drilling 27 (24.3 net) wells on these lands. For 2009, the combination of the drilling program and acquisitions increased sales to an average of 644 boe/d, with production during the fourth quarter averaging 1,211 boe/d. By comparison, production in 2008 was 171 bbls/d.

Late in 2009, construction of a multi-well oil battery, water disposal and gathering system in the Midale/Huntoon area commenced. By January 2010, the facility was completed and area Bakken wells began to be tied into the battery and gathering system. Solution gas and liquids conservation activities are also underway in this area, and are targeted to be completed by mid-year 2010.

c) Weyburn

The Weyburn area is located west of the Corporation's Midale area. As of December 31, 2009, the Corporation had aggregated 18,084 net acres of developed and undeveloped land, 99% undeveloped, through land sales, farm-in wells and freehold leasing. With this large undeveloped land base, the Corporation considers this property as a Bakken exploration asset, with exploration drilling planned for 2010. In 2009, Painted Pony drilled 1 (0.3 net) well in the area. Sales in 2009 from the Weyburn area averaged 78 boe/d, weighted 99% oil and liquids.

d) Wapella

The Wapella area is located northeast of the Corporation's Kisbey area. As of December 31, 2009, the Corporation had aggregated 25,402 net acres of undeveloped land. Like Weyburn, the Corporation considers this property as a Bakken exploration asset, with exploration drilling planned for 2010.

e) Other

Painted Pony has 5,025 net acres of lands in other areas of south-east Saskatchewan. In the first quarter of 2010, the Corporation drilled one successful well (100% working interest) in the Alameda area targeting the Frobisher zone.

Northeast British Columbia

The Corporation's operations in Northeast British Columbia are located north of Fort St. John near the Alaska Highway. The area is prospective for gas from multiple zones, including the Montney, Halfway, Gething, Bluesky, Cadomin and Buckinghorse formations.

The Corporation holds a significant land base in the area, totalling 104,066 net acres (effective December 31, 2009). These assets have been sparsely drilled to date, but since 2009 industry activity has accelerated, with successful results in both conventional and unconventional plays. Reservoirs in the area could be characterized as stacked, gas charged and over-pressured. Gas in the area is produced through gathering systems that are owned in part by the Corporation, and processed and transported through facilities owned by third-party midstream companies.

a) Conventional

The primary conventional targets in the area are the Cretaceous Bluesky, Gething and Cadomin zones. At Blair and Gundy, the Corporation has had consistent success developing the Bluesky interval using vertical wells and three-dimensional seismic to reduce risk. Several deeper Triassic, Permian and Mississippian plays have been pursued in the area by predecessors, targeting thrust sheets with enhanced natural fracturing which enhances productivity. At Cypress, which is in this deep structural setting, operating costs are higher and as a result the Corporation elected to temporarily shut in production in mid-2009 until gas prices strengthen. In 2009, 1 (0.5 net) gas well was drilled and in 2010 to-date 2 (1.0 net) gas wells have been drilled.

b) Montney

The Montney formation is a thick, dolomitic siltstone in the Corporation's area of focus. Industry activity in the area has shown this formation to hold significant reserves which can be recovered by applying advanced horizontal multi-stage fracture stimulations. The Corporation has accumulated a large land base in the area and has begun developing the resource on three blocks.

On the Cameron and Cypress blocks, two farm-out agreements have been made with a senior oil and gas producer. The initial conditions of both farm-out agreements have been satisfied with the drilling of four wells, primarily in 2009. Both agreements contained rolling option provisions whereby additional lands could be earned by conducting additional operations. On the Cameron block, the rolling option continues and further delineation of the resource is planned by the farmee through 2010. Three horizontal wells have been drilled to-date and are awaiting completion after spring break-up. The Corporation will retain a 20% working interest in wells drilled under the Cameron farm-out, after paying 20% of the equipping and tie-in costs.

At Blair, the Company has drilled 3 (2.3 net) wells to delineate the resource on this high working-interest block. Through 2010, this program will continue in order to quantify the resource in place, in preparation for this area to be brought to commercial development.

c) Buckinghorse

The Buckinghorse shale is a gas-charged, organically rich shale deposit that is pervasive across Painted Pony lands in British Columbia. The zone is over-pressured, with an approximate thickness of 800 meters. The Corporation participated in the experimental recompletion and tie-in of two vertical Buckinghorse wells in the Blair area as part of a pilot program. In 2010, the Corporation plans to participate in drilling 2 (1.0 net) wells targeting the Buckinghorse shale formation.

The following table sets forth information respecting the Corporation's wells and lands as at December 31, 2009.

Table 6.1
WELLS AND LAND HOLDINGS
INCLUDING PROPERTIES WITH NO ATTRIBUTED RESERVES⁽¹⁾

	Producing		Non-Producing		Developed Land		Undeveloped Land	
	Gross Wells	Net Wells	Gross Wells	Net Wells	Gross Acres	Net Acres	Gross Acres	Net Acres
Saskatchewan ⁽²⁾								
Wapella	-	-	-	-	160	160	25,242	25,242
Weyburn	7	4.4	1	0.5	241	161	18,326	17,923
Midale	31	29.3	4	4.0	1,365	1,247	11,188	8,814
Kisbey	23	5.5	2	0.3	924	216	5,595	1,357
Other	4	1.3	5	2.3	200	101	6,432	4,924
	65	40.5	12	7.1	2,890	1,885	66,783	58,260
British Columbia ⁽³⁾								
Blair/Town	18	9.4	25	14.7	27,929	13,549	49,803	33,051
Cameron	6	2.9	-	-	4,433	2,190	61,595	31,428
Cypress	5	1.9	7	3.8	8,867	3,438	33,117	8,827
Other	1	0.04	4	0.6	5,444	2,019	12,516	9,564
	29	14.0	36	19.1	46,673	21,196	157,031	82,870
Total	94	54.5	48	26.2	49,563	23,081	223,814	141,130

Note:

- (1) May not add due to rounding.
- (2) All of the Corporations' wells in Saskatchewan are oil wells.
- (3) All of the Corporations' wells in British Columbia are gas wells.

Item 6.2 Properties with No Attributed Reserves

The following table sets forth information respecting the Corporation's undeveloped lands as at December 31, 2009.

Table 6.2
PROPERTIES WITH NO ATTRIBUTED RESERVES⁽¹⁾⁽³⁾

LOCATION	Unproved Properties		2010 Expiring
	Gross Acres	Net Acres	Net Acres
Saskatchewan	66,783	58,260	314
British Columbia ⁽²⁾	157,031	82,870	39,768
Total	223,814	141,130	40,082

Notes:

- (1) Unproved Properties have no attributed reserves as of December 31, 2009. Undeveloped acreage within properties where reserves have been booked as of December 31, 2009 has not been included.
- (2) Of the 39,768 net acres:
 - a) 16,968 acres are held in expiring drilling licences. The Corporation will continue to hold an interest in these lands by virtue of payment of additional rental fees for one year.
 - b) 10,573 acres held in expiring leases are currently being continued on the basis of a program of work. The Corporation expects the majority of these lands to be continued indefinitely.
- (3) May not add due to rounding.

The Company had no drilling commitments at December 31, 2009.

Item 6.3 Forward Contracts

As of December 31, 2009, the Corporation had not entered into financial or physical hedges in respect of commodity prices or foreign exchange contracts or any other similar forward sale contracts.

Item 6.4 Additional Information Concerning Abandonment and Restoration Costs

Table 6.4.1
ABANDONMENT & RECLAMATION COSTS⁽¹⁾
(Forecast Prices & Costs) (M\$)

	Total Proved		Total Proved Plus Probable	
	Undiscounted	Discounted at 10%	Undiscounted	Discounted at 10%
Portion deducted in estimating future net revenue	2,838	723	3,822	594

For purposes of the consolidated financial statements, as at December 31, 2009 the Corporation estimated the total future asset retirement obligation to be \$8.5 million. The total future asset retirement obligation (“ARO”) was estimated based on the Corporation’s net ownership interest in all wells, the estimated costs to abandon and reclaim the wells, the estimated rate of inflation, and the estimated timing of the costs to be incurred in future periods.

Well abandonment estimates are based upon individual well characteristics and location, and lease reclamation estimates are based on geographic location.

Table 6.4.2
ASSET RETIREMENT OBLIGATIONS (“ARO”)

	ARO Undiscounted (M\$)	ARO discounted at 10% (M\$)	Estimated net ARO expected to be paid in the next 3 years (M\$)	Estimated number of net wells for which costs are expected to be incurred
Total estimated in the financial statements	8,498	2,439	88.0	79.1

Item 6.5 Tax Horizon

The Corporation was not required to pay any cash income taxes for the year ended December 31, 2009. Tax payable beyond 2009 will become a function of commodity prices, production volumes and capital expenditures. The Corporation does not expect to pay cash income taxes, based on the reserves disclosed herein, and projected capital expenditures and active tax planning until 2011 or later.

Item 6.6 Costs Incurred

The following table summarizes certain expenditures for the Corporation for the year ending December 31, 2009.

Table 6.6
PROPERTY ACQUISITION/DISPOSITION COSTS AND CAPITAL EXPENDITURES⁽¹⁾
FOR THE YEAR ENDED DECEMBER 31, 2009

	Amount (M\$)
Property Acquisition	
Proved	13,588
Unproved	-
Capital Expenditures	
Land Purchases	6,349
Exploration Costs	1,327
Development Costs	34,175
TOTAL	55,439

Note:

- (1) Capital expenditures in this table exclude expenditures such as furniture and office equipment (\$56M) and asset retirement costs (\$508M).

Item 6.7 Exploration and Development Activities

The following table sets forth the number of gross and net wells drilled by the Corporation during the year ended December 31, 2009.

Table 6.7
OIL AND GAS WELL ACTIVITY IN YEAR 2009⁽¹⁾

Wells	Well Activity	
	Gross ⁽²⁾	Net ⁽³⁾
Development		
Gas	1	0.5
Oil	18	16.2
Service	-	-
Dry	1	0.3
Total	20	17.0
Exploratory		
Gas	-	-
Oil	-	-
Service	-	-
Dry	-	-
Total	-	-
TOTAL	20	17.0

Notes:

- (1) Results of Development and Exploratory activities during the financial year ended December 31, 2009.
(2) "Gross" wells means the number of wells in which the Corporation has a working interest or a royalty interest that may be converted to a working interest.
(3) "Net" wells means the aggregate number of wells obtained by multiplying each gross well by the Corporation's revenue percentage working interest therein.

See Item 6.1 "Oil and Gas Properties and Wells" for a description of the Corporations' exploration and development plans.

Item 6.8 Production Estimates

The following table summarizes the Corporation's estimated future average daily production volumes for 2010 for each product type:

**Table 6.8.1
SUMMARY OF PRODUCTION ESTIMATES BY PRODUCTION GROUP
GROSS PROVED AND GROSS PROBABLE RESERVES FOR 2010**

RESERVES CATEGORY	Forecast Prices & Costs Net Daily Production ⁽²⁾	
	Gross Proved	Gross Probable
Light & medium oil (bbls/d)	1,487	246
Associated & non-associated gas (Mcf/d)	3,691	406
Natural gas liquids (bbls/d)	138	19
TOTAL⁽¹⁾ (boe/d)	2,240	333

Notes:

- (1) Barrels of oil equivalent (boe) have been reported based on natural gas conversion of 6 Mcf:1 bbl.
- (2) Net production is the Corporation's working interest before all royalty deductions.

**Table 6.8.2
SUMMARY OF PRODUCTION ESTIMATES⁽¹⁾⁽³⁾
GROSS PROVED RESERVES BY FIELD FOR 2010**

	Light & Medium Oil (bbl/d)	Heavy Oil (bbls/d)	Natural Gas ⁽²⁾ (Mcf/d)	Natural Gas Liquids (bbl/d)
Saskatchewan				
Kisbey	187	-	65	10
Midale	1,211	-	598	96
Other	89	-	27	4
British Columbia				
Blair	-	-	1,527	16
Cameron/Gundy	-	-	1,458	12
Cypress	-	-	11	-
Other	-	-	5	-
Total	1,487	-	3,691	138

Notes:

- (1) Daily production is taken from the Sproule Report.
- (2) Natural gas includes associated gas and non-associated sales gas volumes.
- (3) May not add due to rounding.

**Table 6.8.3
SUMMARY OF PRODUCTION ESTIMATES⁽¹⁾⁽³⁾
GROSS PROBABLE RESERVES BY FIELD FOR 2010**

	Light & Medium Oil (bbl/d)	Heavy Oil (bbls/d)	Natural Gas ⁽²⁾ (Mcf/d)	Natural Gas Liquids (bbl/d)
Saskatchewan				
Kisbey	34	-	4	-
Midale	207	-	102	17
Other	5	-	2	-
British Columbia				
Blair	-	-	60	1
Cameron/Gundy	-	-	238	2
Cypress	-	-	-	-
Other	-	-	-	-
Total	246	-	406	19

Notes:

- (1) Daily production is taken from the Sproule Report.
- (2) Natural gas includes associated gas and non-associated sales gas volumes.
- (3) May not add due to rounding.

Item 6.9 Production History

The following table summarizes the Corporation's average daily production volumes, before deduction of royalties, for the financial year ended December 31, 2009.

**TABLE 6.9.1
PRODUCTION HISTORY – YEAR ENDED DECEMBER 31, 2009**

Product Type Yearly Quarter	Production Volume ⁽¹⁾	Average Per Unit of Volume (\$/bbl, \$/mcf)			
		Price	Royalties ⁽²⁾	Costs ⁽³⁾	Netbacks
Light and Medium Oil (bbls/d)					
1st Quarter	583	51.51	8.15	11.25	32.10
2nd Quarter	543	66.85	9.84	14.17	42.84
3rd Quarter	1,008	71.18	9.30	10.80	51.08
4th Quarter	1,427	75.63	10.65	12.12	52.86
Natural Gas (MMcf/d)					
1st Quarter	3.6	5.30	1.33	3.25	0.72
2nd Quarter	4.4	3.58	0.05	3.20	0.33
3rd Quarter	3.6	3.20	0.18	2.22	0.80
4th Quarter	3.2	4.94	0.45	2.83	1.66
Condensate and Natural Gas Liquids (bbls/d)					
1st Quarter	37	37.94	7.99	20.26	9.69
2nd Quarter	38	45.75	13.38	17.59	14.78
3rd Quarter	44	41.96	5.67	12.48	23.81
4th Quarter	44	54.57	8.81	15.28	30.48

Notes:

- (1) Production volumes reflect the Corporation's share of average daily production volume, before deduction of royalties.
- (2) Royalties exclude prior period adjustments and credits.
- (3) Production costs include transportation costs and production operating costs.

The following table summarizes the Corporation's production volumes during the year ended December 31, 2009 for each field including those comprising in excess of 20% of production and in total by product type.

**TABLE 6.9.2
PRODUCTION HISTORY BY MAJOR FIELD – YEAR ENDED DECEMBER 31, 2009**

	Light & Medium Oil (bbl/d)	Heavy Oil (bbl/d)	Natural Gas (Mcf/d)	Condensate and Natural Gas Liquids (bbl/d)
Saskatchewan				
Kisbey	156	-	51	9
Midale	644	-	-	-
Weyburn	76	-	6	1
Other	17	-	-	-
British Columbia				
Blair	-	-	1,915	18
Cameron/Gundy	-	-	1,648	13
Cypress	-	-	92	-
TOTAL	893	-	3,712	41