Western Plains Petroleum Ltd.

MANAGEMENT'S DISCUSSION & ANALYSIS
Three months ended March 31, 2011

OVERVIEW OF THE CORPORATION

Western Plains Petroleum Ltd. (the "Corporation" or "Western Plains" or "WPP") is a **heavy oil producer based in Lloydminster, Alberta.** The Corporation was incorporated under the Business Corporations Act (Alberta) on November 19, 2004 and has traded on the TSX Venture Exchange ("TSXV") since August 2006. Following various name changes and trading symbols the Corporation began trading under the symbol "WPP" on the TSXV in 2009.

The Corporation focuses on the following strategies:

1. **production of conventional heavy oil,** building on the core competency of its people;
2. acquisitions, exploration and development in the Lloydminster area (Lloydminster is a border city 250 km east of Edmonton, Alberta and 275 km west of Saskatoon, Saskatchewan); and
3. careful control of development and production costs.

GENERAL

This management discussion and analysis ("MD&A") of Western Plains for the three months ended March 31, 2011 contains financial highlights but does not contain the complete financial statements of the Corporation. It should be read in conjunction with the Corporation's unaudited interim financial statements for the three months ended March 31, 2011 and the audited financial statements for the year ended December 31, 2010. Additional information is available on SEDAR at www.sedar.com. The financial information presented herein has been prepared on the basis of Canadian generally accepted accounting principles ("GAAP"). All references to dollar amounts are in Canadian dollars.

This MD&A includes events up to June 27, 2011.

NON-GAAP MEASURES

The Corporation's management uses and reports certain measures not prescribed by generally accepted accounting principles (referred to as "non-GAAP measures") in the evaluation of operating and financial performance. Operating netback, which is calculated as average unit sales prices less unit royalties and operating expenses, and corporate netback, which further deducts unit administrative and interest expense, represent net cash margin calculations for every barrel of oil equivalent sold. Net debt, which is current assets less current and other financial liabilities, is used to assess efficiency and financial strength. Operating netback, corporate netback and net debt do not have any standardized meanings prescribed by GAAP and therefore may not be comparable with the calculation of a similar measure for other companies. The Corporation uses these terms as an indicator of financial performance because such terms are often utilized by investors to evaluate junior producers in the oil and natural gas sector.

HIGHLIGHTS

The Corporation has developed a concentrated asset base in close proximity to its operational and corporate offices in Lloydminster, Alberta. Key properties are Maidstone, Saskatchewan, Landrose, Saskatchewan and Lloydminster, Alberta. This high potential property base, strong management and governance team, and sufficient capital resources position Western Plains well to execute its 2011 development program and to continue production growth.

2011 Acquisitions

In February 2011 Western Plains completed an arms-length farm out agreement for two LSDs on 2 different sections in the Standard Hill and Buzzard areas of Saskatchewan. Upon the payment of $40,000 to the farmor, the Corporation earned 50% of the farmor's interests in the land and is required to pay 100% of the costs to drill and complete (or cap and abandon) one test well on each the 2 LSDs. Upon drilling, Western Plains may opt to earn the remaining 50% of the farmor's interests in these lands. The farmor earns a 6% gross overriding royalty on any resulting production. One of the locations has been drilled in May 2011 and is producing 50 (50 net) bbls per day.

On March 30, 2011, the Corporation acquired, from an arm's length party, a 100% working interest in petroleum and natural gas rights (320 acres) located immediately adjacent to the Corporation's existing property in the Maidstone area of west-central Saskatchewan for a purchase price of $750,000. The acquisition was effective December 1, 2010. The Corporation assumed approximately $148,600 of trade accounts payable from the vendor and paid cash for the balance of the consideration. Asset retirement obligations were also assumed.

The acquired property included 10 heavy oil wells (9 vertical and 1 horizontal) of which 1 was producing 15 bbls per day at the date of acquisition. The property also has 1 horizontal water injection well. The Corporation has reactivated 5 (5 net) of the shut-in wells increasing production to 85 bbls per day. Western Plains intends to re-activate the remaining shut-in wells to further increase production.

2010 Acquisitions

Western Plains acquired 100% working interests in petroleum and natural gas rights in the Landrose area of Saskatchewan. At the date of acquisition the property included 920 acres, 1 producing well and 13 shut-in wells. Consideration consisted of 10,000,000 common shares and the assumption of the related asset retirement obligations. Six (2.75 net) successful oil wells were drilled on this property in 2010.

In a second transaction Western Plains acquired a net 33 1/3% working interest in petroleum and natural gas rights in the Lloydminster, Alberta area, comprised of 1,040 acres (347 net), including 9 shut-in heavy oil wells and 5 standing cased wells (previously drilled but not completed). Consideration was a combination of cash, the issuance of common shares of the Corporation, the assumption of certain trade payables of the vendor and the assumption of the related asset retirement obligations. Subsequent development has included the reactivation and testing of the shut-in wells, completion and equipping of the 5 (1.67 net) standing cased wells and the drilling of 2 (.83 net) wells.

To fund the acquisition, the Corporation divested a 50% undivided interest in all of its oil and gas assets. Consideration was a combination of cash proceeds and the settlement of the related asset retirement obligations. The same acquirer also purchased a 33 1/3% working interest in the assets described in the previous paragraph.

Production and Revenue

One (0.33 net) successful oil well was drilled in Q1 11 which commenced production in early April 2011. This followed the drilling of five wells (2.5 net) in Q4 10. Production was consistent between Q1 11 and Q4 10 with production averaging 122 bbls per day and 135 bbls net to WPP, per day respectively. This is a significant increase over the average production for Q1 10 of 68 bbls per day and Q3 10 average production of 37 bbls per day. The increase reflects the active development program in Q4 10. Revenue for Q1 11 was $648,000 compared to $394,000 for Q1 10 with the increase driven by the volume increase.

The Q1 11 production is lower than earlier projections due to three factors:

- Curtailment of production by a total of approximately 100 bbls per day for the six new wells drilled in the second half of 2010. Curtailed production over the first year or two optimizes long term production.
- The harsh winter led to lost production and down wells amounting to approximately 40 bbls per day. Spring break up does not allow the Corporation to move service rigs to restore the down wells.
- Limited availability of drilling rigs in the Lloydminster area has delayed new drilling in Q1 2011. Winter is the peak drilling season in the north.

The new wells drilled in Q4 initially produced at rates up to 100 bbls per day (gross). After analyzing analogous wells in the area, Western Plains reached the conclusion that long term production is optimized by curtailing production for the first 15,000 to 20,000 bbls. Wells produced at these lower levels then produce cumulative production levels three to four times greater than wells initially produced at high levels.

OUTLOOK

Western Plains estimates current production to be 290 bbls per day as 3 (1.83 net) wells have been drilled in 2011 with 1 (0.33 net) well on production in early April, 1 (1 net) well on production in early June and 1 (0.50 net) well expected to be on production by the end of June. Several wells were off production for a portion of the harsh winter and were repaired or otherwise reactivated following break up. Unusually wet weather and seasonal maintenance at sales delivery points during the month of June may impact on sales volumes of the Company in the short term.

Western Plains has identified 25 (12.7 net) potential drilling locations for 2011 and beyond. The Corporation is the operator for all these locations. Several locations are licensed and others in the process of being licensed. The 2011 capital budget is $2.7 million and includes drilling 12 (5.67 net) wells and the continued acquisition of properties and mineral rights. Capital costs are budgeted to be approximately $400,000 to $425,000 gross for each well, including drilling, completion and equipping.

Increased production leads to economies of scale on both production and transportation costs per bbl and general and administrative costs per bbl.

The Corporation continues to expand its land holdings through acquisitions of properties in close proximity to existing land holdings and its corporate and operations centre in the City of Lloydminster, Alberta.

The Corporation is able to finance growth from its working capital, cash flows, the well-financed and motivated working interest partners and remaining credit facilities with a Canadian chartered bank (for more details refer to “Liquidity and Capital Resources”).

LIQUIDITY AND CAPITAL RESOURCES

In October 2010 the Corporation finalized a credit facility agreement with a Canadian chartered bank, consisting of two facilities:

- a revolving operating facility with a limit of $800,000 and an interest rate of bank prime plus 1.5%, and
- a development facility with a limit of $300,000 and an interest rate of bank prime plus 2.0%.

The Corporation had drawn $225,000 at March 31, 2011. Given continued production growth and increased cash flows, the Corporation expects to increase the credit facility limits upon its next review later this year.

As at March 31, 2011, the Corporation had 55,101,153 (55,101,153 at December 31, 2010) common shares outstanding, 867,500 warrants outstanding (867,500 at December 31, 2010) and 4,152,000 stock options outstanding (4,152,000 at December 31, 2010) under its stock option plan.

FINANCIAL AND OPERATING SUMMARIES

TABLE A - OPERATIONS BY QUARTER (Last 8 Quarters)

All production is conventional heavy oil	IFRS	IFRS	IFRS	IFRS	IFRS	CDN*	CDN*	CDN*
$000's except for Production and per share	**Q1 2011**	**Q4 2010**	**Q3 2010**	**Q2 2010**	**Q1 2010**	**Q4 2009**	**Q3 2009**	**Q2 2009**
Sales volume - total barrels	11,003	12,446	3,410	4,498	6,091	6,294	4,624	7,824
Sales volume - bbls/ day	**122**	**135**	**37**	**49**	**68**	**68**	**50**	**86**
Heavy oil revenue	648	756	222	262	394	389	277	411
Royalties	(106)	(146)	(31)	(30)	(73)	(49)	(50)	(94)
Production & transportation	(285)	(296)	(104)	(149)	(194)	(161)	(148)	(111)
Operating net back	257	314	87	83	127	179	79	206
General, administrative & transaction	(156)	(219)	(241)	(209)	(101)	*	*	*
Interest & financing	(10)	(5)	(31)	(36)	(7)	*	*	*
Corporate net back (loss)	91	90	(185)	(162)	19	*	*	*
Depletion	(151)	(176)	(32)	(36)	(38)	*	*	*
Other (expenses) revenue	61	(263)	(39)	(143)	78	*	*	*
Income (loss) for the period	**1**	**(351)**	**(256)**	**(341)**	**59**	*	*	*
Basic and diluted income (loss) per share	**.00**	**(.01)**	**(0.01)**	**(0.01)**	**0.00**	*	*	*
***Canadian GAAP – depletion, interest and other expenses would be materially different under IFRS, so not presented.**								
Royalties as % of petroleum revenue	**16**	**19**	**14**	**11**	**19**	**13**	**18**	**23**
Per bbl analysis	**Per bbl**	**Per bbl**	**Per bbl**	**Per bbl**	**Per bbl**	**Per bbl**	**Per bbl**	**Per bbl**
Heavy oil revenue	58.89	60.73	65.20	58.31	64.67	61.82	59.88	52.53
Royalties	(9.63)	(11.76)	(9.07)	(6.57)	(11.98)	(7.75)	(10.79)	(12.06)
Production and transportation	(25.90)	(23.86)	(30.39)	(33.17)	(31.75)	(25.53)	(32.02)	(14.17)
Operating net back	**23.36**	**25.11**	**25.74**	**18.56**	**20.94**	**28.54**	**17.07**	**26.30**
General and administrative	(14.18)	(17.62)	(70.98)	(46.46)	(16.59)	(8.11)	(29.31)	(13.10)
Interest and financing	(0.91)	(0.40)	(9.09)	(8.00)	(1.18)	*	*	*
Corporate netback (loss)	8.27	7.09	(54.33)	(35.90)	3.27	*	*	*
Depletion	(13.72)	(14.14)	(9.39)	(8.00)	(6.24)	*	*	*
***not comparable to IFRS**								
WPP revenue prices	**58.89**	**60.73**	**65.20**	**58.31**	**64.67**	**61.82**	**59.88**	**52.53**
Benchmark prices								
Edmonton light 40 API	88.45	80.71	76.02	75.46	80.31	76.75	71.70	66.19
Hardisty heavy 12 API	61.43	62.30	60.57	59.67	68.79	64.03	60.90	58.07
Heavy oil differential	27.02	18.41	15.45	15.79	11.52	12.72	10.80	8.12

FINANCIAL AND OPERATING SUMMARIES

TABLE B – BALANCE SHEET

$000's								
***not comparable to IFRS**	**Q1 2011**	**Q4 2010**	**Q3 2010**	**Q2 2010**	**Q1 2010**	**Q4 2009**	**Q3 2009**	**Q2 2009**
Net working capital (deficiency)	(593)	204	(141)	(395)	(164)	(347)	*	*
Total assets	7,521	7,305	5,020	4,439	2,393	2,453	*	*
Total liabilities	2,651	2,436	1,742	1,443	693	958	*	*
Shareholders equity	4,870	4,869	3,278	2,996	1,700	1,494	*	*
SHARES 000's								
Basic outstanding	55,101	55,101	45,732	42,137	32,137	30,260	26,907	21,227
Weighted average	55,101	48,749	43,544	33,456	31,929	28,000	26,907	21,227

OPERATING RESULTS

Development and Acquisition Activity

The following property transactions and development activities (all heavy oil properties near Lloydminster, Alberta) affected average production levels and explain most of the quarter over quarter production and revenue variances for the 8 quarters shown in the "Financial and Operating Summaries" on the prior two page:

- Q2 2009 - disposed of all producing wells in the Golden Lake and Rush Lake areas of Saskatchewan reducing production by approximately 180 bbls per day.
- Q3 2009 – acquired six (6 net) non producing wells.
- Q4 2009 –activated and put on production non-producing wells acquired in prior quarter.
- Q2 2010 – acquired the Landrose, Saskatchewan property, with common shares as compensation.
- Q2 2010 – consummated Joint Operating Agreement (JOA) naming WPP as field operator, for a property targeted for acquisition. All wells were shut in.
- Q2 2010 – reactivated several of the shut in wells under the JOA, and earned operating fees which have been recorded as a reduction of production expenses.
- Q2 2010 – performed successful workovers on two (2 net) wells which were shut in for two months prior to and during the workover process.
- Q3 2010 – disposed of 50% working interest in all producing and non producing properties.
- Q3 2010 – acquired a 33 1/3% working interest in the property for which Western Plains was field operator.
- Q3 2010 –completed and put on production 2 (0.67 net) of 5 wells (drilled and cased but not previously completed) on the acquired property.
- Q3 2010 –drilled one well (0.25 net) in the Landrose area with Western Plains as operator. A farm in partner paid 100% of the costs subject to a 10% convertible gross overriding royalty (GORR) of which 5% is payable to the Corporation until payout. At payout in April 2011, Western Plains opted to take a 25% working interest in lieu of retaining the GORR.
- Q4 2010 – drilled and put on production 5 (2.5 net) wells in the Landrose, SK area.
- Q4 2010 – completed and put on production 2 (.67 net) additional wells (drilled and cased but not previously completed) on the property acquired in August 2010.
- Q4 2010 - performed workovers on three (2 net) wells to restore or increase production.
- Q1 2011- entered into a farm-out agreement to acquire two LSDs on two different sections of land in the Standard Hill and Buzzard areas of Saskatchewan.
- Q1 2011 – drilled 1 successful oil well (0.33 net) on the Blackfoot heavy oil property in the Lloydminster, Alberta.
- Q1 2011 – acquired additional petroleum and natural gas interests (100% WI in 320 acres) in the Maidstone area Saskatchewan.
- Q2 11 - reactivated 5 (5 net) wells on the acquired Maidstone property
- Q2 11 – drilled 2 (1.50 net) successful oil wells, 1 on the Blackfoot property in the Lloydminster, Alberta area and 1 on the farm in property acquired in Q1 11.

Production volumes and revenues (refer to Financial and Operating Summaries on page 4)

Q1 11 average production was 122 bbls per day compared to Q1 10 average production of 68 bbls per day. The development activity in the fall of 2010 included drilling 5 (2.5 net) wells and accounts for the significant improvement.

Oil Pricing

All of Western Plains' crude oil consists of heavy oil produced in Saskatchewan and Alberta that is marketed based on refiners' posted prices for Western Canadian Select heavy oil, adjusted for the quality (primarily density) of the crude oil on a well by well basis. The majority of Western Plains' heavy oil ranges in density from approximately 13.6° API to 15.9° API. The refiners' posted prices are influenced by the US$ WTI reference price, transportation costs, US$/C$ exchange rates and the supply/demand situation of particular crude oil quality streams during the year. The prices realized by Western Plains on heavy oil sales are net of treating fees, blending costs, required for its heavy grades of oil to meet pipeline stream specifications, and pipeline tariffs.

The price differential between heavy and light crude oil increased in Q4 10 ($18.41) and Q1 11 ($27.02) over prior quarters (Q3 10 - $15.45: Q1 10 - $11.52) primarily due to a transportation disruption resulting from the nine week maintenance shut-down of a pipeline that carries Canadian crude oil to refineries in the U.S. Midwest. Further short term maintenance shut-downs of this pipeline followed in January and February 2011, with product delivery rates having been largely restored by late April. As a result Western Plains realized an average oil price of $58.89 per bbl in Q1 11 as compared to $64.67 in Q1 11. Current revenue per bbl is approximately $75.00 per bbl.

Royalties (refer to Financial and Operating Summaries on page 4)

Q1 11 overall royalty burden averaged 16% compared to 19% in Q4 10. Q4 10 includes the higher production volumes from the newly drilled wells. The higher production volumes and strong oil prices triggers a higher royalty burden under the crown regimes. This explains the higher overall burden in Q4 10 of 19% compared to 13% in Q4 09 and 14% in Q3 10. The Corporation incurs a mix of crown, freehold and overriding royalties. The volumes and mix of oil wells producing in a quarter impact the overall average burden. Since Q1 10 there has been a significant change in the mix which explains the variation between Q1 11 of 16% and Q1 10 of 19%.

Production and transportation costs (refer to Financial and Operating Summaries on page 4)

Major repairs or a workover in a quarter significantly increase costs per bbl given the small production volumes of the Corporation. This was significant in Q2 10 as the service rig costs for the two workovers mentioned above totaled approximately $47,000 ($10.45 per bbl). Service rig costs in Q4 2010 amounted to $24,000 ($1.93 per bbl)

Winter operating costs are higher than other seasons as certain costs (e.g. snowplowing) are incurred only in cold weather. Heavy oil production costs tend to be higher than light oil production costs. WPP transportation costs are low and comprise only the trucking of clean oil short distances to the sales terminal.

A significant portion of production costs are fixed and therefore production expense per bbl varies significantly with volume. The increased production in Q1 11 and Q4 10 reduced production costs per bbl from prior quarters. The Corporation expects this trend to continue given higher production volumes in Q2 2011 and continued drilling of new wells through the rest of 2011.

General and administrative (G&A) (refer to Financial and Operating Summaries on page 4)

As production increases as a result of development work and further acquisitions, G&A costs per bbl will reduce significantly as these costs tend to be fixed. Q4 10 costs include year- end bonuses totaling $85,000, a significant portion of the total Q4 10 costs of $219,000. Q1 11 G&A expenses averaged $14.18 per bbl down considerably from the 2010 annual average of $22.92 per bbl. The Corporation expects similar economies of scale as production continues to increase.

The Corporation contracts all G&A services and has no employees. This includes the President and CEO position for which consulting fees are paid to a corporation with an officer and director in common with Western Plains.

Interest and financing (refer to Financial and Operating Summaries on page 4)

The Corporation drew on its bank credit facilities for the first time in 2011 giving rise to bank interest costs for the first time since Q2 09. There has been no bank or other debt since July 2009. Under IFRS accretion on the asset retirement obligations (decommissioning costs) is recorded as a finance expense and not part of depletion and accretion.

Depletion and accretion (D&A) (refer to Financial and Operating Summaries on page 4)

Depletion expense is a function of volume produced as it is computed on a “units of production” basis using proved plus probable reserves as the depletion base under IFRS. Canadian GAAP allowed only total proved reserves as the depletion base. Probable reserves for the Corporation’s properties are significant and consequently depletion per bbl is much lower under IFRS.

INCOME TAX

The Corporation had the following tax pools:

Nature of tax pool	Annual Deduction Available-%	December 31, 2010 $000’s
Canadian oil and gas property expense (COGPE)	10	2,571
Canadian development expense (CDE)	30	536
Canadian exploration expense (CEE)	100	334
Specified foreign exploration & development expense	10	472
Undepreciated capital cost (UCC)	25	810
Share issue costs	20	92
Non capital loss carry forward	100	1,200

The non capital loss carry forward expires in 2025 to 2030.

The recovery of income taxes in 2010 and 2011 relate to the renouncement of certain tax expenditures to flow through share investors. The Corporation has not recorded any future tax asset or liability, nor has it recorded any tax recovery related to its operating losses in, due to the uncertainty of the Corporation’s ability to fully utilize the available income tax pools against its future income.

Flow through common shares issued in November 2010 require that eligible expenditures of $941,800 be incurred by December 31, 2011. Approximately $350,000 of eligible expenditures has been incurred to date with the balance to be incurred by December 31, 2011. The full amount was renounced in March 2010 and effective December 31, 2010 under the look back rule.

The Corporation is eligible to substitute up to $1 million development expenditures for exploration expenditures because its taxable capital is under the limit of $15 million as prescribed in the Income Tax Act (Canada).

CRITICAL ACCOUNTING ESTIMATE

Management is often required to make judgments, assumptions and estimates in the application of generally accepted accounting principles that may have a significant impact on the financial results of the Corporation. The Corporation’s significant accounting policies are described in notes in the financial statements at March 31, 2011 and are discussed in the MD&A for December 31, 2010.

NEW ACCOUNTING STANDARDS

International Financial Reporting Standards

International Financial Reporting Standards (“IFRS”) are followed by Canadian public companies effective January 1, 2011, including Western Plains. Comparative financial statements for 2010 have been restated to follow IFRS.

Implications for Western Plains

(a) IFRS 1 election for full cost oil and gas entities
The Corporation elected an IFRS 1 exemption whereby the Canadian GAAP full cost pool was measured upon transition to IFRS as follows:

(i) The Corporation had no exploration and evaluation assets at the transition date under Canadian GAAP and thus no part of the Property and Equipment at that date were reclassified from the full cost pool to intangible exploration assets; and
(ii) the entire full cost pool was allocated to the producing/development assets and components pro rata using reserve values.

(b) Decommissioning provision:
Under Canadian GAAP asset retirement obligations were discounted at a credit adjusted risk fee rate of 8 percent. Under IFRS the estimated cash flow to abandon and remediate the wells and facilities has been discounted at a risk free rate of 4% percent. Upon transition to IFRS this resulted in an $145,447 increase in the decommissioning obligations with a corresponding increase in the deficit. Also under IFRS the obligation is discounted at each period end at the current risk free discount rate.

(c) Share-based payments:
Under Canadian GAAP, the Corporation recognized an expense related to their share-based payments on a straight-line basis through the date of full vesting and did not incorporate a forfeiture multiple. Under IFRS, the Corporation is required to recognize the expense over the individual vesting periods for the graded vesting awards and estimate a forfeiture rate. Because all of the Corporation's options have all vested immediately upon granting, this change in accounting policy had no impact on the statement of financial position at the transition date or on the 2010 financial statements.

(d) Depletion policy:
Upon transition to IFRS, the Corporation adopted a policy of depleting oil and natural gas interests on a unit of production basis over proved plus probable reserves. The depletion policy under Canadian GAAP was based on units of production over proved reserves. In addition depletion was done on the Canadian cost center under Canadian GAAP. IFRS requires depletion and depreciation to be calculated based on individual areas (fields or combinations thereof). The Corporation has chosen two areas (which are also the cash generating units) being Alberta heavy oil assets and Saskatchewan heavy oil assets.

(e) Transaction costs incurred for business combinations:
Under Canadian GAAP transaction costs were capitalized as a component of the cost of the acquisition. Under IFRS transaction costs are expensed.

(g) Flow through shares
Under Canadian GAAP the entire proceeds from issuing flow through shares is recorded as equity at the time of receipt. This form of investment allows the investor to claim income tax deductions for the flow through of certain resource deductions renounced to the investor by the Corporation. Under Canadian GAAP the cost of forgone income tax deductions is recorded as a reduction of equity by the Corporation at the time it files the renouncement with the income tax authorities and the impact on deferred tax assets or liabilities is also recorded at that time as income tax recovery on the statement of income. Under IFRS, at the time of the issue, the proceeds are classified in part as equity based on the fair value of the share price at the date of issue of the flow through shares and in part as a liability based on the excess of the issue price over the fair value of the share price, if any, at the issue date. The resulting liability is reduced at the time the renouncement is filed with the income tax authorities and the impact on deferred tax assets or liabilities is also recorded at that time as income tax recovery on the statement of income.

OFF BALANCE SHEET ARRANGEMENTS

The Corporation has not engaged in any off-balance sheet arrangements such as obligations under guarantee contracts, a retained or contingent interest in assets transferred to an unconsolidated entity, any obligation under derivative instruments (except as disclosed) or any obligation under a material variable interest in an unconsolidated entity that provides financing, liquidity, market risk or credit risk support to the Corporation or engages in leasing or hedging services with the Corporation.

INDUSTRY CONDITIONS AND RISKS

The business of exploration, development and acquisition of oil and gas reserves involves a number of business risks inherent in the oil and gas industry which may impact The Corporation's results and several of which are beyond control of the Corporation. These business risks are operational, financial or regulatory in nature. These risks and the Corporation's approach to managing these issues are the same as disclosed in the Management Discussion and Analysis for the year ended December 31, 2010. The Corporation does not currently use derivative instruments as a means to manage risk.

RELATED PARTY TRANSACTIONS

The Corporation entered into the following related party transactions, all of which were in the normal course of operations and have been valued at the exchange amount that is the amount of consideration established and agreed to by the related parties:

- Legal services provided by a law firm in which an officer and director is employed:
  - $62,901 was incurred in the three months ended March 31, 2011 ($238,876 in the year ended December 31, 2010);
- Various oil field services and products provided by or sold to corporations in which David Forrest, an officer and director of the Corporation, is an officer and a director:
  - $nil was incurred for oil field services and products in the three months ended March 31, 2011 ($190,633 in the year ended December 31, 2010);
  - $nil of oil was sold by Western Plains in the three months ended March 31, 2011 ($36,808 in the year ended December 31, 2010)
- No oil and natural gas interests ($698,187 during the year ended December 31, 2010) were acquired the three months ended March 31, 2011 from a corporation in which David Forrest, an officer and a director of the Corporation, is an officer and director.
- Executive services provided by a corporation in which David Forrest, an officer and a director of the Corporation, is an officer and director:
  - $43,740 was incurred and paid in the three months ended March 31, 2011 ($140,000 in the year ended December 31, 2010).

Forward-Looking Statements

The matters discussed in this MD&A include certain forward-looking statements. Forward-looking statements include, without limitation, any statement that may predict, forecast, indicate or imply future results, performance or achievements. Forward-looking statements may be identified, without limitation, by the use of such words as "anticipates", "estimates", "expects", "intends", "plans", "predicts", "projects", "believes", or words or phrases of similar meaning. In addition, any statement that may be made concerning future performance, strategies or prospects and possible future corporate action, is also a forward-looking statement. Forward-looking statements are based on current expectations and projections about future general economic, political and relevant market factors, such as interest rates, foreign exchange rates, equity and capital markets, and the general business environment, in each case assuming no changes to applicable tax or other laws or government regulation. Expectations and projections about future events are inherently subject to, among other things, risks and uncertainties, some of which may be unforeseeable. Accordingly, assumptions concerning future economic and other factors may prove to be incorrect at a future date. Forward-looking statements are not guarantees of future performance, and actual events could differ materially from those expressed or implied in any forward-looking statements made by the Corporation. Any number of important factors could contribute to these digressions, including, but not limited to, general economic, political and market factors in North America and internationally, interest and foreign exchange rates, global equity and capital markets, business competition, technological change, changes in government relations, unexpected judicial or regulatory proceedings and catastrophic events. We stress that the above mentioned list of important factors is not exhaustive. We encourage you to consider these and other factors carefully before making any investment decisions and we urge you to avoid placing undue reliance on forward-looking statements. The Corporation disclaims any intention or obligation to update or revise these forward-looking statements as a result of new information, future events or otherwise, except as required under applicable securities laws.

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Three months ended March 31, 2011

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