Western Plains Petroleum Ltd.

MANAGEMENT'S DISCUSSION & ANALYSIS
Three and six months ended June 30, 2011

OVERVIEW OF THE COMPANY

Western Plains Petroleum Ltd. (the "Company" or "Western Plains" or "WPP") is a **heavy oil producer based in Lloydminster, Alberta.** The Company 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 Company began trading under the symbol "WPP" on the TSXV in 2009.

The Company 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's discussion and analysis ("MD&A") of Western Plains for the three and six months ended June 30, 2011 contains financial highlights but does not contain the complete financial statements of the Company. It should be read in conjunction with the Company's unaudited interim financial statements for the three and six months ended June 30, 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 International Financial Reporting Standards ("IFRS"). All references to dollar amounts are in Canadian dollars.

This MD&A includes events up to August 29, 2011.

NON-GAAP MEASURES

The Company's management uses and reports certain measures not prescribed by International Financial Reporting Standards (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 IFRS and therefore may not be comparable with the calculation of a similar measure for other companies. The Company 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 Company 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.

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 for $40,000.

In March 2011, the Company acquired, from an arm's length party, a 100% working interest in petroleum and natural gas rights (320 acres) located immediately adjacent to the Company's existing property in the Maidstone area of west-central Saskatchewan for a purchase price of $750,000. The acquired property included several shut in heavy oil wells which have subsequently been reactivated.

2010 Acquisitions

Western Plains acquired petroleum and natural gas rights (920 acres, 1 producing well and several shut in wells) in the Landrose area of Saskatchewan. 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 Company, the assumption of certain trade payables of the vendor and the assumption of the related asset retirement obligations. Two (1.33 net) successful oil wells were drilled on this property in 2011.

To fund the acquisition, the Company 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 Lloydminster assets described in the previous paragraph.

Production and Revenue

The Company drilled one (0.33 net) successful oil well 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 Q2 11 with production averaging 122 bbls per day and 120 bbls per day net to WPP, per day respectively. Revenue for Q1 11 was $648,000 compared to $787,000 for Q2 11 with the increase driven by higher oil prices. Q2 10 averaged 49 bbls per day and revenue of $262,000. The large increase in revenue for Q2 11 over Q2 10 was a function of higher volume (Q2 11 – 120 bbls per day: Q1 10 – 49 bbls per day) and higher realized revenue per bbl (Q2 11 - $71.79 per bbl: Q1 10 - $58.31 per bbl).

Four (3.0 net) other wells were drilled in Q2 11 but were not brought on production until late in the quarter or subsequent to June 30, 2011.

Historically WPP had a strategy of acquiring and reactivating shut-in or standing heavy oil wells. Like many older heavy oil wells, these wells experience lost production time due to sand build up in the well bore. These wells are otherwise capable of economic production levels but do not produce at these rates consistently. Workovers and lost production are a normal part of the production cycle. As a result, WPP production has been difficult to predict and is not consistent. This fact also drives average production costs up and consumes operations time. WPP has changed its strategic focus to drilling new wells to mitigate this problem and provide a more consistent and steadily increasing production profile. This strategy commenced in 2010 with 6 (2.75 net) wells drilled and continued in 2010 with 7 (4.0 net) wells drilled to date. The six (2.75 net) 2010 wells (of a total of 36 wells that produced at least one month to date in 2011) accounted for 52% of the production in the first half of 2011.

OUTLOOK

Western Plains estimates September 2011 production to be in the range of 275 to 300 bbls per day as all 7 (4.00 net) wells drilled in 2011 are expected to be production early in that month. In total WPP has drilled 13 (6.75 net) wells since July of 2010. The Company expects to maintain a more consistent production profile given its strategic shift from a reactivation focus to drilling new wells. The new wells account for approximately 75% of the estimated production for September 2011. The Company is not planning to drill additional wells until late 2011.

Western Plains has identified other potential drilling locations for late 2011 and beyond. Several locations are in the process of being licensed. Capital costs are budgeted to be approximately $400,000 to $425,000 gross for each well, including drilling, completion and equipping. The Company will continue to expand its land holdings in its core areas close to Lloydminster, Alberta.

LIQUIDITY AND CAPITAL RESOURCES

In October 2010 the Company 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 Company has drawn on the revolving facility intermittently throughout 2011 but no amount was drawn at June 30, 2011. The Company has requested that the bank increase the facility limits in light of the production growth and increased cash flows from October of 2010. The Company has also requested that the bank waive the breach of the working capital covenant at June 30, 2011. The Company's working capital ratio, determined in accordance with the bank's formula was 0.68:1, breaching the covenant requiring that the ratio be no less than 1:1. The bank commenced its annual review of the Company's facilities subsequent to the period end but has not yet concluded its review.

As at June 30, 2011, the Company 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	**Q2 2011**	**Q1 2011**	**Q4 2010**	**Q3 2010**	**Q2 2010**	**Q1 2010**	**Q4 2009**	**Q3 2009**
Sales volume - total barrels	10,959	11,003	12,446	3,410	4,498	6,091	6,294	4,624
Sales volume - bbls/ day	**120**	**122**	**135**	**37**	**49**	**68**	**68**	**50**
Heavy oil revenue	787	648	756	222	262	394	389	277
Royalties	(148)	(106)	(146)	(31)	(30)	(73)	(49)	(50)
Production & transportation	(441)	(285)	(296)	(104)	(149)	(194)	(161)	(148)
Operating net back	198	257	314	87	83	127	179	79
General, administrative & transaction	(137)	(156)	(219)	(241)	(209)	(101)	*	*
Interest & financing	-	(10)	(5)	(31)	(36)	(7)	*	*
Corporate net back (loss)	61	91	90	(185)	(162)	19	*	*
Depletion	(196)	(151)	(176)	(32)	(36)	(38)	*	*
Other (expenses) revenue	(66)	61	(263)	(39)	(143)	78	*	*
Income (loss) for the period	**(201)**	**1**	**(351)**	**(256)**	**(341)**	**59**	*	*
Basic and diluted income (loss) per share	**.00**	**.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	**19**	**16**	**19**	**14**	**11**	**19**	**13**	**18**
Per bbl. analysis	**Per bbl.**	**Per bbl.**	**Per bbl.**	**Per bbl.**	**Per bbl.**	**Per bbl.**	**Per bbl.**	**Per bbl.**
Heavy oil revenue	71.79	58.89	60.73	65.20	58.31	64.67	61.82	59.88
Royalties	(13.47)	(9.63)	(11.76)	(9.07)	(6.57)	(11.98)	(7.75)	(10.79)
Production and transportation	(40.27)	(25.90)	(23.86)	(30.39)	(33.17)	(31.75)	(25.53)	(32.02)
Operating net back	**18.05**	**23.36**	**25.11**	**25.74**	**18.56**	**20.94**	**28.54**	**17.07**
General and administrative	(12.47)	(14.18)	(17.62)	(70.98)	(46.46)	(16.59)	(8.11)	(29.31)
Interest and financing	-	(0.91)	(0.40)	(9.09)	(8.00)	(1.18)	*	*
Corporate netback (loss)	5.57	8.27	7.09	(54.33)	(35.90)	3.27	*	*
Depletion and accretion	(17.88)	(13.72)	(14.14)	(9.39)	(8.00)	(6.24)	*	*
***not comparable to IFRS**								
WPP revenue prices	**71.79**	**58.89**	**60.73**	**65.20**	**58.31**	**64.67**	**61.82**	**59.88**
Benchmark prices								
Edmonton light 40 API	102.63	88.51	80.71	76.02	75.46	80.31	76.75	71.70
Hardisty heavy 12 API	73.21	62.36	62.30	60.57	59.67	68.79	64.03	60.90
Heavy oil differential	29.41	26.15	18.41	15.45	15.79	11.52	12.72	10.80

FINANCIAL AND OPERATING SUMMARIES

TABLE B – BALANCE SHEET

$000's								
***not comparable to IFRS**	**Q2 2011**	**Q1 2011**	**Q4 2010**	**Q3 2010**	**Q2 2010**	**Q1 2010**	**Q4 2009**	**Q3 2009**
Net working capital (deficiency)	(1,868)	(593)	204	(141)	(395)	(164)	(347)	*
Total assets	8,814	7,521	7,305	5,020	4,439	2,393	2,453	*
Total liabilities	4,145	2,651	2,436	1,742	1,443	693	958	*
Shareholders' equity	4,669	4,870	4,869	3,278	2,996	1,700	1,494	*
SHARES 000's								
Basic outstanding	55,101	55,101	55,101	45,732	42,137	32,137	30,260	26,907
Weighted average	55,101	55,101	48,749	43,544	33,456	31,929	28,000	26,907

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 2010 – acquired the Landrose, Saskatchewan property, with common shares as consideration.
- 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 after payout in April 2011) 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 Company 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.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 4 (2.67 net) successful oil wells, including the earning well on the farm in property acquired in Q1 11.
- Q3 11 – drilled 2 (1.0 net) successful oil wells, including the second earning well on the farm in property acquired in Q1 11.

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

Q2 11 average production was 120 bbls per day compared to Q2 10 average production of 49 bbls per day. The 5 (2.5 net) wells drilled in Q4 2010 accounts for the significant improvement. One (0.33 net) well drilled in March 2011 produced throughout Q2 11 and offset normal production declines. The 4 (3.0 net) wells drilled in Q2 commenced production after Q2 2011 as well as two wells drilled in Q3 2011.

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 again in Q2 11 to an average of $29.41 per bbl compared to $15.79 per bbl in Q2 10. This differential has increased each quarter since Q2 10 to $15.45 per bbl in Q3 10, $18.41 per bbl in Q4 10 and $26.15 per bbl in Q1 11. The differential in Q3 10 was 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 per bbl in Q1 10. Q2 11 revenue averaged $72.00 per bbl consistent with the high benchmark prices for the same period.

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

The Company 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. Q2 11 overall royalty burden averaged 19% compared to 11% in Q2 10. Q2 11 includes the higher production volumes from the recently drilled wells. The higher production volumes and strong oil prices triggers a higher royalty burden under the crown regimes.

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 Company. 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). Abandonment costs of $37,000 were expensed in Q2 11 and account for $3.38 per bbl. Certain annual costs including surface rents were expensed in the quarter and contributed to the high costs per bbl. Certain low producing but high maintenance wells have been shut in. The wet spring and summer also contributed to high operating costs. 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.

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. Q2 11 G&A expenses averaged $12.47 per bbl down considerably from the 2010 annual average of $22.92 per bbl and $46.46 per bbl in Q2 10.

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

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

The Company drew on its bank credit facilities for the first time in Q1 2011 giving rise to bank interest costs for the first time since Q2 09. Under IFRS accretion on the asset retirement obligations (decommissioning costs) is recorded as a finance expense but was grouped as a non-cash item, depletion and accretion for the analysis on page 4.

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 Company’s properties are significant and consequently depletion per bbl. is much lower under IFRS. Accretion of the decommissioning liability includes the impact of the change in discount rate. IFRS requires the decommissioning liability to be discounted at the current risk free rate at each period end. The decrease in the discount rate from 4% at March 31, 2011 to 3.55% at June 30, 2011 contributed $62,000 to total accretion expense for Q2 11 of $66,000.

INCOME TAX

The Company 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 Company 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 Company's ability to fully utilize the available income tax pools against its future income.

Flow through common shares issued in November 2010 required that eligible expenditures of $941,800 be incurred and that commitment was fully met by June 30, 2011. The full amount was renounced in March 2010, effective December 31, 2010 under the look back rule.

The Company 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 Company. The Company's significant accounting policies are described in notes in the financial statements at March 31, 2011 and are discussed in the MD&A for March 31, 2011.

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 Company elected an IFRS 1 exemption whereby the Canadian GAAP full cost pool was measured upon transition to IFRS as follows:

(i) The Company 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 3.55% percent at June 30, 2011. The transition to IFRS resulted in a $145,447 increase in the decommissioning obligations with a corresponding increase in the deficit. The obligation is discounted at each period end at the current risk free discount rate.

(c) Share-based payments:
Under Canadian GAAP, the Company 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 Company 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 Company'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 Company 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 Company 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 Company. Under Canadian GAAP the cost of forgone income tax deductions is recorded as a reduction of equity by the Company 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 Company 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 Company or engages in leasing or hedging services with the Company.

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 Company's results and several of which are beyond control of the Company. These business risks are operational, financial or regulatory in nature. These risks and the Company's approach to managing these issues are the same as disclosed in the Management's Discussion and Analysis for the year ended December 31, 2010. The Company does not currently use derivative instruments as a means to manage risk.

RELATED PARTY TRANSACTIONS

The Company 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:
  - $108,602 was incurred in 2011 year to date ($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 Company, is an officer and a director:
  - $nil was incurred for oil field services and products in 2011 year to date ($190,633 in the year ended December 31, 2010);
  - $nil of oil was sold by Western Plains in 2011 year to date ($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 2011 year to date from a corporation in which David Forrest, an officer and a director of the Company is an officer and director.
- Consulting services amounting to $4,000 ($nil in the year ended December 31, 2011) were provided in 2011 by a corporation in which Menno Wiebe, a director of the Company is an officer and director.
- Executive services provided by a corporation in which David Forrest, an officer and a director of the Company, is an officer and director:
  - $87,480 was incurred and paid in 2011 year to date ($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 Company. 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 Company 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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