Western Plains Petroleum Ltd.

MANAGEMENT'S DISCUSSION & ANALYSIS
Year ended December 31, 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; and
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).

The Company announced in February 2012 that the Board of Directors had appointed a special committee of independent Board members with a mandate to undertake a process to evaluate the various strategic alternatives available to Western Plains with the goal of maximizing shareholder value. These alternatives may include, but are not limited to, the spinout of certain properties of Western Plains or other business combinations. In April 2012 the Company announced it had engaged an exclusive financial advisor and agent to assist in identifying and evaluating possible liquidity events. No decision on any particular alternative has been reached at this time.

GENERAL

This management's discussion and analysis ("MD&A") of Western Plains for the year ended December 31, 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 audited financial statements for the years ended December 31, 2011 and 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 April 27, 2012.

NON-IFRS MEASURES

The Company's management uses and reports certain measures not prescribed by International Financial Reporting Standards (referred to as "non-IFRS 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 International Financial Reporting Standards ("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 and Dispositions

In March 2011, the Company acquired, from an arm's length party, a 100% working interest and operatorship in oil and natural gas assets located near Maidstone, Saskatchewan. The purchase price was $754,000, subject to normal industry adjustments to the effective date of December 1, 2010. Consideration consisted of cash, assumption of certain trade payables of the vendor and the assumption of the related decommissioning obligations. A 36% working interest in this property was later sold for cash proceeds of $450,000 and effective December 31, 2011. Western Plains continues as the operator of the property.

In February 2011 Western Plains entered into 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. The Company drilled a 100% WI well at Standard Hill in 2011 and is currently in discussions with the farmor regarding the Buzzard commitment.

In November 2011 the joint interest partner on one well drilled in 2011 in the Edam, Saskatchewan area, purchased the Company's 50% working interest for $400,000. This was a related party transaction considered by and approved by an independent committee of the Board based on an independent reserve evaluation.

2010 Acquisitions and Dispositions

Western Plains acquired 100% working interest and operatorship of oil and natural gas assets in the Landrose area of Saskatchewan. Consideration consisted of 10,000,000 common shares and the assumption of the related decommissioning obligations.

Western Plains also acquired a 33 1/3% working interest and operatorship in oil and natural gas assets near Lloydminster, Alberta. 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 decommissioning obligations.

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 decommissioning obligations. The same acquirer also purchased a 33 1/3% working interest in the Lloydminster assets described in the previous paragraph.

Production and Revenue

Revenue for 2011 was $3,631,564 compared to $1,634,373 for 2010 with the increase driven primarily by higher sales volumes of heavy oil. Sales volumes of heavy oil in 2011 averaged 151 bbls per day compared to 72 bbls per day for 2010. Q4 11 averaged 178 bbls per day and revenue of $1,195,894 compared to 135 bbls per day and $755,859 of oil revenue for Q4 10. Average realized oil prices per bbl. were comparable year over year as shown in Tables A and B. The 2011 average realized price per bbl. for Western Plains' heavy oil was $65.70 compared to $61.80 for 2010. The, boosted by the higher benchmark prices in Q4 2011. The increased production in Q3 11 (184 bbls per day), which was approximately the same as Q4 11 (177 bbls per day), was a result of the drilling activity in 2011 resulting in 7 (4.33 net) producing oil wells. One (0.5 net) of the 2011 drilled wells was sold effective November 1, 2011.

OUTLOOK

The Company's 2011 production averaged 151 bbls per day of heavy oil. Western Plains has maintained this production profile in 2012 to March 31, 2012. One (0.5 net) well was drilled in March 2012 and was placed on production late that month. This well had initial flush production in excess of 100 (50 net) bbls per day which is expected to increase the overall Company production going forward.

The Company announced in February 2012 that the Board of Directors had appointed a special committee of independent Board members with a mandate to undertake a process to evaluate the various strategic alternatives available to Western Plains with the goal of maximizing shareholder value. These alternatives may include, but are not limited to, the spinout of certain properties of Western Plains or other business combinations. In April 2012, the Company announced it had engaged an exclusive financial advisor and agent to assist in identifying and evaluating possible liquidity events. No decision on any particular alternative has been reached at this time.

Western Plains has identified other potential drilling locations for 2012 and beyond in its core areas of operations. Capital costs are budgeted to be approximately $425,000 gross for each well, including drilling, completion and equipping.

LIQUIDITY AND CAPITAL RESOURCES

Western Plains' primary sources of liquidity to meet operating expenses and fund its development capital program are derived from the Company's internal funds flow from operations and its revolving operating bank credit facility. Western Plains utilizes this facility to fund daily operating activities and acquisitions as needed. Because of the liquidity and capital resource alternatives available to the Company, including internal funds flow from operations, Western Plains believes that its liquidity is sufficient to fund ongoing operations.

As at December 31, 2011, the Company's credit facility agreement with a Canadian chartered bank consisted of two facilities:

- a revolving operating facility limit of $1,000,000 (increased from $800,000 in September 2011) with interest at bank prime plus 1.5%, and
- a development facility limit of $300,000 with interest at bank prime plus 2.0%.

The Company drew on the revolving operating facility intermittently throughout 2011 with a draw at December 31, 2011 of $125,000.

The Company was in breach of the bank's working capital covenant at December 31, 2011 which was subsequently waived by the bank as the bank increased the revolving operating facility to $2,200,000 in February 2012 in light of the increased production, reserves and cash flows.

The Company's bank indebtedness does not have a specific maturity date as it is a demand facility. This means that the lender has the ability to demand repayment of all outstanding indebtedness or a portion thereof at any time. If that were to occur the Company would be required to source alternate credit facilities or sell assets to repay the indebtedness. The Company reduces this risk by complying with the covenants of the credit facility agreement and maintaining a minimal balance on the facility. On an ongoing basis the Company will review its capital expenditures to ensure that cash flow and or access to credit facilities is available to fund these capital expenditures. The Company has the flexibility to adjust capital expenditures based on cash flow to manage debt levels.

As at December 31, 2011, the Company had 55,101,153 (55,101,153 at December 31, 2010) common shares outstanding, with a capitalization of $7.3 million. In addition the Company had 4,960,000 stock options outstanding (4,152,000 at December 31, 2010) under its stock option plan. The stock options have exercise prices ranging from $0.11 to $0.21 per share with a weighted average exercise price of $0.15 per share.

FINANCIAL AND OPERATING SUMMARIES
TABLE A - OPERATIONS BY QUARTER

All production is conventional heavy oil	IFRS	IFRS	IFRS	IFRS	IFRS	IFRS	IFRS	IFRS
$000's except for Production and per share	**Q4 2011**	**Q3 2011**	**Q2 2011**	**Q1 2011**	**Q4 2010**	**Q3 2010**	**Q2 2010**	**Q1 2010**
Sales volume - total barrels	16,363	16,953	10,959	11,003	12,446	3,410	4,498	6,091
Sales volume - bbls/ day	**178**	**184**	**120**	**122**	**135**	**37**	**49**	**68**
Heavy oil revenue	1,196	1,001	787	648	756	222	262	394
Royalties	(263)	(178)	(148)	(106)	(146)	(31)	(30)	(73)
Production & transportation	(554)	(300)	(441)	(285)	(296)	(104)	(149)	(194)
Operating net back	379	523	198	257	314	87	83	127
General, administrative & transaction	(232)	(280)	(137)	(156)	(219)	(242)	(208)	(101)
Bank interest & loan fees	(3)	(10)	-	(3)	-	-	-	-
Corporate net back (loss)	144	233	61	98	95	(155)	(125)	26
Depletion and depreciation	(233)	(266)	(197)	(150)	(176)	(32)	(36)	(38)
Other non-cash income (expenses)	(68)	381	(67)	54	(270)	(69)	(180)	71
Income (loss) for the quarter	**(158)**	**348**	**(203)**	**2**	**(351)**	**(256)**	**(341)**	**59**
Basic and diluted income (loss) per share	**(.00)**	**.01**	**.00**	**.00**	**(.01)**	**(0.01)**	**(0.01)**	**0.00**
Royalties as % of petroleum revenue	**22**	**18**	**19**	**16**	**19**	**14**	**11**	**19**

Per bbl. analysis	**Per bbl.**	**Per bbl.**	**Per bbl.**	**Per bbl.**	**Per bbl.**	**Per bbl.**	**Per bbl.**	**Per bbl.**
Heavy oil revenue	73.09	59.05	71.79	58.89	60.73	65.20	58.31	64.67
Royalties	(16.07)	(10.50)	(13.47)	(9.63)	(11.76)	(9.07)	(6.57)	(11.98)
Production and transportation	(33.86)	(17.70)	(40.27)	(25.90)	(23.86)	(30.39)	(33.17)	(31.75)
Operating net back	**23.16**	**30.85**	**18.05**	**23.36**	**25.11**	**25.74**	**18.56**	**20.94**
General, administrative & transaction	(14.18)	(16.52)	(12.47)	(14.18)	(17.62)	(70.98)	(46.46)	(16.59)
Bank interest and loan fees	(0.18)	(0.61)	-	(0.27)	-	-	-	-
Corporate netback (loss)	8.80	13.72	5.58	8.90	7.63	(45.45)	(27.79)	4.27
Depletion and depreciation per bbl.	(14.24)	(15.69)	(17.98)	(13.63)	(14.14)	(9.39)	(8.00)	(6.24)

WPP revenue per bbl.	**73.09**	**59.05**	**71.79**	**58.89**	**60.73**	**65.20**	**58.31**	**64.67**
Benchmark prices								
Edmonton light 40 API	97.87	92.27	102.63	88.51	80.71	76.02	75.46	80.31
Hardisty heavy 12 API	77.83	61.98	73.21	62.36	62.30	60.57	59.67	68.79
Heavy oil differential	20.04	30.29	29.41	26.15	18.41	15.45	15.79	11.52

FINANCIAL AND OPERATING SUMMARIES
TABLE B -OPERATIONS FOR THE YEARS ENDED DECEMBER 31, 2011, 2010 and 2009

All production is conventional heavy oil

$000's except for Production and per share	**IFRS 2011**	**IFRS 2010**
Sales volume - total barrels	55,278	26,444
Sales volumes - bbls/ day	**151**	**72**
Heavy oil revenue	3,632	1,634
Royalties	(696)	(280)
Production & transportation	(1,579)	(743)
Operating net back	1,357	611
General, administrative & transaction	(807)	(771)
Bank interest and loan fees	(17)	-
Corporate net back	534	(160)
Depletion & depreciation	(846)	(282)
Other non-cash income (expenses)	300	(447)
Loss for the period	**(12)**	**(889)**
Basic and diluted income (loss) per share	**(0.000)**	**(0.023)**

Royalties as % of petroleum revenue	**19**	**17**

Per bbl. analysis	**Per bbl.**	**Per bbl.**
Heavy oil revenue	65.70	61.80
Royalties	(12.59)	(10.58)
Production and transportation	(28.56)	(28.11)
Operating net back	**24.57**	**23.11**
General, administrative and transaction	(14.60)	(29.16)
Bank interest and loan fees	(0.29)	-
Corporate netback	9.68	(6.05)
Depletion and depreciation per bbl.	(15.30)	(10.66)
WPP revenue per bbl.	65.70	61.80
Benchmark prices		
Edmonton light 40 API	95.56	77.80
Hardisty heavy 12 API	69.10	62.30
Heavy oil differential	26.47	15.51

FINANCIAL AND OPERATING SUMMARIES
TABLE C – BALANCE SHEET

$000's	**Q4 2011**	**Q3 2011**	**Q2 2011**	**Q1 2011**	**Q4 2010**	**Q3 2010**	**Q2 2010**	**Q1 2010**
Net cash (debt)	(1,947)	(1,844)	(1,748)	(593)	204	(141)	(395)	(164)
Total assets	9,534	9,691	8,814	7,504	7,305	5,020	4,439	2,393
Total liabilities	4,602	4,675	4,145	2,632	2,436	1,742	1,443	693
Shareholders' equity	4,932	5,016	4,669	4,872	4,869	3,278	2,996	1,700
SHARES 000's								
Basic outstanding	55,101	55,101	55,101	55,101	55,101	45,732	42,137	32,137
Weighted average	55,101	55,101	55,101	55,101	49,115	43,544	33,456	31,929

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 operating periods shown in the "Financial and Operating Summaries" in Tables A and B:

- Q2 2010 – acquired 100% working interest and operatorship in the Landrose, Saskatchewan property, with common shares as consideration.
- Q3 2010 – disposed of 50% working interest in all producing and non-producing properties while retaining operatorship of all the oil and natural gas assets.
- Q3 2010 – acquired a 33 1/3% working interest and operatorship of the Blackfoot, Alberta oil and gas assets.
- Q3 2010 – completed and placed on production 2 (0.67 net) 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) at Landrose, Saskatchewan.
- Q4 2010 – drilled and placed on production 5 (2.5 net) wells at Landrose, Saskatchewan.
- Q4 2010 – completed and placed on production 2 (.67 net) additional wells (drilled and cased but not previously completed) on the property acquired in Q3 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, Alberta heavy oil property.
- Q1 2011 – acquired additional oil and natural gas assets at Maidstone, Saskatchewan.
- Q2 11 – reactivated 5 (5 net) wells on the acquired Maidstone property.
- Q2 11 – drilled 4 (2.67 net) successful oil wells.
- Q3 11 – drilled 2 (1.0 net) successful oil wells.
- Q4 11 – disposed of a 36% working interest (cash proceeds of $450,000) of the oil and natural gas assets at Maidstone, Saskatchewan which were acquired in Q1 11.
- Q4 11 – drilled 1 (0.15 net before payout and 0.35 after payout) successful oil well. There was no cash cost to Western Plains as it contributed equipment from a shut in well to equip this new well.
- Q1 12 – drilled 1 (0.5 net) successful oil well at Landrose, Saskatchewan with very promising initial flush production.

OPERATING RESULTS

Production volumes and revenues (refer to Tables A and B)
The Company's average production for 2011 was 151 bbls per day of heavy oil compared to 72 bbls per day for 2010. Q4 11 production averaged 177 bbls per day compared to the Q4 10 average production of 135 bbls per day. The 5 (2.5 net) wells drilled in Q4 2010 account for the significant improvement to production and revenue in Q4 2010 over the prior quarters in 2010. The 4 (2.67 net) wells drilled in Q2 11 commenced production after Q2 2011 as well as 1 (0.5 net) well drilled in Q3 2011. This accounts for the increase in Q3 and Q4 of 2011 compared to Q1 and Q2 of 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 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 average price differential between light oil and the Company's heavy oil was $26.47 per bbl. for 2011 compared to $15.51 per bbl. for 2010. The price differential was unfavorable in Q4 11 averaging $20.04 per bbl. compared to $18.41 per bbl. in Q4 10. This differential between the light oil benchmark price and the heavy oil benchmark price increased each quarter between Q2 10 and Q3 11 as demonstrated in Table A. The decline to a more favorable differential in Q4 11 to $20.04 per bbl. was a welcome change from $30.29 per bbl. in Q3 2011.

Royalties (refer to Tables A and B)

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 royalty burden. Q4 11 overall royalty burden averaged 22% compared to 19% in Q4 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. This accounts for the increase from the 2010 overall royalty burden of 17% compared to the 2011 overall royalty burden of 19%.

Production and transportation costs (refer to Tables A and B)

Production and transportation costs in 2011 averaged $28.56 per bbl. compared to $28.11 per bbl. for 2010. The wet spring and summer in 2011 contributed to higher 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.

Some quarters include abandonment or workover costs for certain wells and those costs contribute to higher per bbl. operating costs in those quarters. The Maidstone oil and gas assets acquired in 2011 required significant reactivation costs as well as repairs and other costs giving rise to significant production costs in 2011. The property should benefit from this investment with more consistent production in 2012. A 36% working interest of this property was sold effective December 31, 2011.

General and administrative, including transaction costs (G&A) (refer to Tables A and B)

The 2010 G&A costs include bonuses totaling $85,000 and transaction costs of $164,881, a significant portion of the total 2010 costs of $770,926. The Company did not pay bonuses for 2011. The higher level of capital and operating activity in 2011 explains the increase in G&A costs from $770,926 in 2010 to $806,733 in 2011.

As production increases as a result of development work and further acquisitions, G&A costs per bbl. decline as these costs tend to be fixed. G&A expenses for 2011 averaged $14.60 per bbl., down considerably from the 2010 annual average of $29.16 per bbl. The Q4 11 average of $14.18 per bbl. is comparable to the Q4 10 average of $17.62 per bbl. due to similar volumes shipped in those quarters. The volume increase from 72 bbls per day in 2010 to 151 bbls per day in 2011 explains this significant decrease in G&A costs per bbl.

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.

Bank interest and loan fees (refer to Tables A and B)

The Company drew on its bank credit facilities for the first time in Q1 2011 giving rise to bank interest and loan fees for the first time in that quarter. Accretion on the decommissioning provisions is a component of finance expense on the statement of operations in the financial statements but is shown as other non-cash expense in the analysis in Tables A and B.

Depletion and depreciation (refer to Tables A and B)

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. The significant increase in the expense in Q3 and Q4 2011relates to the higher volume of production. Similarly depletion expense increased in Q4 2010 due to the production increase. Capital expenditures were significant in Q2 and Q3 2011. These capital expenditures added to the costs subject to depletion and contribute to the higher costs of depletion per in 2011 of $15.30 per bbl. compared to $10.66 per bbl. in 2010.

INCOME TAX

The Company had the following tax pools:

Nature of tax pool	Annual Deduction Available-%	December 31, 2011 $000's	December 31, 2010 $000's
Canadian oil and gas property expense (COGPE)	10	2,320	2,571
Canadian development expense (CDE)	30	643	141
Canadian exploration expense (CEE)	100	660	606
Specified foreign exploration & development expense	10	425	472
Undepreciated capital cost (UCC)	25	1,462	810
Share issue costs	20	67	92
Non capital loss carry forward	100	1,406	1,030

The non-capital loss carry forward expires in 2025 to 2031.

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 ESTIMATES

Management is often required to make judgments, assumptions and estimates in the application of International Financial Reporting Standards that may have a significant impact on the financial results of the Company. The Company's significant accounting policies are described in Note 3 to the audited financial statements for the years ended December 31, 2011 and 2010. The following is a discussion of the accounting estimates that are critical in determining the Company's financial results:

(a) Property and equipment

(i) Oil and natural gas reserves

The Company's proved and probable oil and gas reserves at the current and prior year end were evaluated and reported on by an independent reserves evaluator. The estimation of reserves is a subjective process. Forecasts are based on engineering data, projected future rates of production, estimated commodity price forecasts and the timing of future expenditures, all of which are subject to a number of uncertainties and various interpretations. The Company expects that over time its reserve estimates will be revised upward or downward based on updated information such as the results of future drilling, testing and production levels. Proved and probable reserve estimates can have a significant impact on net earnings, as they are a key component in the calculation of depletion on a unit of production basis. Downward revisions to reserve estimates could also result in an impairment of oil and natural gas property and equipment.

(ii) Depletion

The unit-of-production method of depletion is based on estimated proven and probable reserves. Changes in estimated proved and probable reserves or future development costs have a direct impact on depletion expense.

(iii) Impairment

The impairment test uses future prices determined by the independent reserve evaluator adjusted for price differentials specific to the Company and considered reasonable and relevant to Western Plain's products. The value of undeveloped land was included, with the value taking into account the remaining lease period for the mineral rights. Mineral leases require the Company to develop the resource or lose the oil and natural gas assets.

(b) Decommissioning provision

The decommissioning provision is based on the Company's net ownership in wells and facilities. Determination of the current decommissioning provisions is based on estimated abandonment and reclamation costs for each well. To estimate future retirement costs, Western Plains applied a 1.5% (2.0% at December 31, 2010) inflation factor which it believes is reasonable over the long term and is consistent with rates used by others in the industry. The risk free rate is used to discount decommissioning provisions to the current reporting date. Expected retirement dates range from 2019 to 2031. This estimate is based on the expected productive life of the wells and regulatory requirements.

(b) Share-based compensation

Western Plains uses the Black Scholes option pricing model to determine the fair value of share based compensation at the grant date which requires that management estimate the risk free interest rate, the expected life of the of the securities, the expected forfeiture rate and the expected volatility of the Company's share price over the life of the options. These estimates may vary from the actual life and volatility.

(c) Deferred tax

Accounting for deferred taxes requires determination of substantially enacted income tax rates applicable to the future years. The Company estimates the accounting and tax values during the period over which temporary difference are likely to reverse and tax rates expected to be effective when the temporary differences reverse. The estimated future tax provisions are subject to revisions, both upwards and downwards, that are not known at the time the initial estimates of deferred taxes are computed. In addition to these revisions, future capital activities can impact the timing of the reversal of any temporary differences. These differences can have an impact on the amount of deferred taxes determined at a point in time, and to the extent that these differences are created, they can impact the charge against earnings for deferred taxes. The Company evaluates deferred income tax assets to make a determination of whether the assets are likely to be realized. Based on management's assessment that it is not likely that a future income tax recovery will occur, the deferred tax assets were not recognized as at December 31, 2011 and 2010.

NEW ACCOUNTING STANDARDS

IFRS 9, Financial Instruments, was issued by the IASB on November 12, 2009 and is the first step to replace IAS 39, "Financial Instruments: Recognition and Measurement". IFRS 9 uses a single approach to determine whether a financial asset is measured at amortized cost or fair value, replacing the multiple rules in IAS 39. The approach in IFRS 9 is based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. The new standard also requires a single impairment method to be used, replacing the multiple impairment methods in IAS 39. IFRS 9 is effective for annual periods beginning on or after January 1, 2013. The Company is currently evaluating the impact of IFRS 9 on its financial statements.

IFRS 11, Joint Arrangements, was issued by the IASB on May 12, 2011 as part of its new suite of consolidation and related standards. Under IFRS 11, classification of the joint arrangements depends on whether parties have rights to and obligations for underlying assets and liabilities and joint ventures are no longer allowed to use proportionate consolidation and must use equity accounting. The new requirements are effective in annual periods beginning on or after January 1, 2013. The Company is currently evaluating the impact of IFRS 9 and believes the standard will not impact its financial statements.

Fair Value Measurements

The IASB issued IFRS 13, "Fair Value Measurement" which provides a consistent and less complex definition of fair value, establishes a single source of guidance for determining fair value and introduces consistent requirements for disclosures related to fair value measurement. Prospective application of this standard is effective for fiscal periods beginning on or after January 1, 2013, with early adoption permitted. The Company is currently assessing the impact of this standard.

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 Western Plains' results and several of which are beyond control of the Company. These business risks are operational, financial or regulatory in nature.

Operational risks include exploration and development of economic oil and gas reserves, unsuccessful exploration and development drilling activity, competition from other producers, reservoir performance, safety and environmental concerns, access to and ability to retain cost effective contract services, escalating industry costs for contracted services and equipment, product marketing and hiring and retaining qualified personnel. The Company attempts to control operating risks by:

- Maintaining a disciplined approach to implementation of the exploration and development program.
- Striving for ownership levels and operator status which allows Western Plains to manage costs, timing and sales of production.
- Maintaining insurance commensurate with its level and scope of operations to protect against loss from destruction of assets, pollution, blowouts or other losses.

The Company's revenues, profitability and future growth and the carrying value of its properties are substantially dependent on prevailing prices of oil and gas. The Company's ability to borrow and to obtain additional capital on attractive terms is also substantially dependent upon oil and gas prices. Prices for oil and gas are subject to large fluctuations in response to changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond the control of the Company.

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Company to incur costs to remedy such discharge. Although the Company believes that it is in material compliance with current applicable environmental regulations, no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise adversely affect the Company's financial condition, results of operations or prospects.

The Company's operations are subject to the risks normally incident to the operation and development of oil and natural gas properties and the drilling of oil and natural gas wells, including encountering unexpected formations or pressures, blowouts and fires, all of which could result in personal injuries, loss of life and damage to property of Western Plains and others. In accordance with customary industry practice, Western Plains is not fully insured against all of these risks, nor are all such risks insurable, however management is of the opinion that adequate insurance has been obtained, where available.

The Company is also exposed to financial risks in the form of commodity prices, interest rates, the Canadian to U.S. dollar exchange rate and inflation. Western Plains manages commodity price risks by focusing its capital program on areas that will generate attractive rates of return even at substantially lower commodity prices than the industry is currently receiving. WPP may use financial instruments to manage its exposure to unusual swings in commodity prices. The Company manages its working capital and debt positions so as not to overextend the Company. Capital expenditures are limited to funds available for cash from operating activities, available lines of credit and proceeds from issuing shares when the Company believes that is prudent.

WPP is subject to a variety of regulatory risks that it does not control. Safety and environmental matters are monitored to ensure compliance and to ensure employees, contractors and the public is protected. Changes in government or regulatory policies for matters such as royalties, income taxes, surface rights, mineral rights, operational requirements or processes for regulatory approvals, may impact the Company’s operations, financial results and real or perceived risk to investors or creditors. These matters are largely beyond the Company’s control but are monitored to the extent possible.

RELATED PARTY TRANSACTIONS

The financial statements of Company include balances and transactions with directors and officers of the Company, or with companies related to directors or officers of the Company. These 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, are summarized as follows:

- Legal services were provided by a law firm in which Leigh Stewart, Corporate Secretary and Director of Western Plains, is an employee at a cost of approximately $157,000 in 2011.

- Various transactions occurred with corporations in which David Forrest, President, CEO and Director of the Company, is an officer and a director:
    - Approximately $304,000 was incurred for various oil field services in 2011, primarily related to contacting a service rig to perform work on Western Plain's wells;
    - $175,000 was incurred in 2011 as fees for the services of Mr. Forrest as President and CEO of the Company and a further $3,000 was incurred to reimburse travel costs; and
    - In 2010 oil and natural gas properties were acquired from a company controlled by Mr. Forrest for approximately $696,000 with common shares as the consideration.

- Certain oil and natural gas properties are held as joint arrangements (working interest partner) with an entity with which David Forrest, Steven Glover, Vice President and Chief Financial Officer and Stephen Johnston, Director are or were involved in management roles:
    - Two (1.0 net) wells were drilled in 2011 as 50/50 partners pursuant to farm in agreements;
    - The Company sold its 50% working interest in one of these wells to this related party in November 2011 for cash proceeds of $400,000 ; and
    - Normal joint interest partner transactions were conducted throughout the year in accordance with normal industry practices in relation to the two jointed owned oil wells.

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.

Corporate Address

Western Plains Petroleum Ltd.
#202, 5004 18th Street,
Lloydminster, Alberta, T9V 1V4
www.westernplainspetroleum.com
Telephone (780) 871-0725
Fax (780) 875-0725

Directors
David Forrest [1]
Stephen H. Johnston [1]
Leigh D. Stewart [1]
Menno Wiebe
William Koenig [1]
[1] *Member of the Audit Committee*

Officers
David Forrest, President and CEO
Steven Glover, VP Finance and CFO
Leigh Stewart, Corporate Secretary

Auditors
MNP LLP
900, 700 – 6th Ave. SW
Calgary, Alberta, T2P 0T8

Transfer Agent
Olympia Trust Company
2300, 125 – 9th Ave. SE
Calgary, Alberta, T2G 0P6

Bankers
Canadian Western Bank
606-4th St. SW,
Calgary, Alberta, T2P 1T1

Legal Counsel
Davis LLP
1000, 250-2nd St. SW
Calgary, Alberta T2P 0C1

Reserve Evaluator
Deloitte & Touche LLP (formerly AJM Petroleum Consultants Ltd.)
6th Floor, 425 1st ST SW
Calgary, AB T2P 3L8