Western Plains Petroleum Ltd.

MANAGEMENT'S DISCUSSION & ANALYSIS
Three and nine months ended September 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 nine months ended September 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 nine months ended September 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 November 25, 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 and Dispositions

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, subject to normal industry adjustments. The acquired property included several shut in heavy oil wells which have subsequently been reactivated. A working interest in this property (50% working interest) was exchanged in a property swap late in 2011, as described below.

Western Plains Petroleum Ltd. entered into an asset exchange agreement with an arms-length party, pursuant to which the Company exchanged a 50% net interest in 320 acres of petroleum and natural gas rights 6 (6.0 net) wells in west-central Saskatchewan for:

- 50% interest in 40 acres of petroleum and natural gas interests located in the same area,
- 50% net interest in 640 acres of undeveloped petroleum and natural gas rights located in east-central Alberta, and
- cash proceeds of $375,000, subject to industry standard closing adjustments, which included reactivation costs incurred by WPP since April 1, 2011.

The exchange had an effective date of April 1, 2011. The payment of $375,000 was received in installments with the last payment in October 2011. The industry closing adjustments netted to approximately $223,000 in favor of WPP due to capital costs incurred between April 1, 2011 and September 30, 2011. The Company continues as the operator of the property, and is confident the full amount will be recovered from the joint interest partner.

2010 Acquisitions and Dispositions

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

Revenue for Q3 11 was $1,001,000 compared to $787,000 for Q2 11 with the increase driven by higher volumes. Q3 10 averaged 37 bbls per day and revenue of $222,000. The large increase in revenue for Q3 11 over Q3 10 was a function of higher volume (Q3 11 – 184 bbls per day: Q3 10 – 37 bbls per day) notwithstanding lower realized revenue per bbl. (Q3 11 - $59.05 per bbl.: Q3 10 - $65.20 per bbl.).

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.

Four (3.0 net) wells were drilled in Q2 11 but were not brought on production until late in the quarter or subsequent to June 30, 2011. Two (1 net) wells were drilled in Q3 11 of which one (0.5 net) was on production by September 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. 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 2011 with 7 (4.0 net) wells drilled to date.

OUTLOOK

September 2011 production averaged 206 bbls per day as 6 (3.4 net) wells drilled in 2011 were on production 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 Company is planning to drill one (0.15 net before payout and 0.325 net after payout) additional well in 2011 for which the Company will not incur any cash costs. Its share of capital costs consists of equipment moved from a non-producing well.

Western Plains has identified other potential drilling locations for 2012 and beyond. Several locations are in the process of being licensed. Capital costs are budgeted to be approximately $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

As at September 30, 2011, the Company's credit facility agreement with a Canadian chartered bank consists 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 has drawn on the revolving operating facility intermittently throughout 2011 with a draw at September 30, 2011 of $225,000. The Company was in breach of the bank's working capital covenant at September 30, 2011 and has since initiated the following remedial action:

- deferred all capital spending except for limited activities directly resulting in maintaining or increasing production,
- applied all cash in-flow from operating activities to debt reduction (estimated to have reduced the working capital deficiency by approximately $250,000 by the current date),
- applied cash in-flow from divesture of the Company's working interest in one well to reduce the working capital deficiency by $400,000,
- engaged a reserve evaluator to prepare a reserve report with an effective date of September 30, 2011. The report is in progress and will be presented to the bank upon completion, and
- commenced a scheduled interim review of the revolver facility limit to take into account the increased production and reserves from the 7 (4.0 net) wells drilled in 2011. The review is not yet complete but is expected to result in an increase to the revolving operating facility limit.

The combination of the above initiatives is expected to resolve the working capital deficiency before December 31, 2011.

As at September 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 4,110,000 stock options outstanding (4,152,000 at December 31, 2010) under its stock option plan. In October 2011 the Company granted an aggregate of 1,000,000 stock options, exercisable into common shares at $0.11 per share, to directors, officers and certain consultants (all personnel work on a consulting basis) 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	IFRS	CDN*	CDN*
$000's except for Production and per share	**Q3 2011**	**Q2 2011**	**Q1 2011**	**Q4 2010**	**Q3 2010**	**Q2 2010**	**Q1 2010**	**Q4 2009**
Sales volume - total barrels	16,953	10,959	11,003	12,446	3,410	4,498	6,091	6,294
Sales volume - bbls/ day	**184**	**120**	**122**	**135**	**37**	**49**	**68**	**68**
Heavy oil revenue	1,001	787	648	756	222	262	394	389
Royalties	(178)	(148)	(106)	(146)	(31)	(30)	(73)	(49)
Production & transportation	(448)	(441)	(285)	(296)	(104)	(149)	(194)	(161)
Operating net back	375	198	257	314	87	83	127	179
General, administrative & transaction	(132)	(137)	(156)	(219)	(241)	(209)	(101)	*
Interest & financing (excludes accretion)	36	-	(10)	(5)	(31)	(36)	(7)	*
Corporate net back (loss)	279	61	91	90	(185)	(162)	19	*
Depletion	(267)	(196)	(151)	(176)	(32)	(36)	(38)	*
Other non-cash income (expenses)	334	(66)	61	(263)	(39)	(143)	78	*
Income (loss) for the period	**346**	**(201)**	**1**	**(351)**	**(256)**	**(341)**	**59**	*
Basic and diluted income (loss) per share	**.01**	**.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	**18**	**19**	**16**	**19**	**14**	**11**	**19**	**13**

Per bbl. analysis	**Per bbl.**	**Per bbl.**	**Per bbl.**	**Per bbl.**	**Per bbl.**	**Per bbl.**	**Per bbl.**	**Per bbl.**
Heavy oil revenue	59.05	71.79	58.89	60.73	65.20	58.31	64.67	61.82
Royalties	(10.50)	(13.47)	(9.63)	(11.76)	(9.07)	(6.57)	(11.98)	(7.75)
Production and transportation	(26.43)	(40.27)	(25.90)	(23.86)	(30.39)	(33.17)	(31.75)	(25.53)
Operating net back	**22.12**	**18.05**	**23.36**	**25.11**	**25.74**	**18.56**	**20.94**	**28.54**
General and administrative	(7.79)	(12.47)	(14.18)	(17.62)	(70.98)	(46.46)	(16.59)	(8.11)
Interest and financing	2.12	-	(0.91)	(0.40)	(9.09)	(8.00)	(1.18)	*
Corporate netback (loss)	16.46	5.57	8.27	7.09	(54.33)	(35.90)	3.27	*
Depletion	(15.75)	17.88)	(13.72)	(14.14)	(9.39)	(8.00)	(6.24)	*

***not comparable to IFRS**								
WPP revenue prices	**59.05**	**71.79**	**58.89**	**60.73**	**65.20**	**58.31**	**64.67**	**61.82**
Benchmark prices								
Edmonton light 40 API	92.27	102.63	88.51	80.71	76.02	75.46	80.31	76.75
Hardisty heavy 12 API	61.98	73.21	62.36	62.30	60.57	59.67	68.79	64.03
Heavy oil differential	30.29	29.41	26.15	18.41	15.45	15.79	11.52	12.72

FINANCIAL AND OPERATING SUMMARIES

TABLE B – BALANCE SHEET

$000's								
***not comparable to IFRS**	**Q3 2011**	**Q2 2011**	**Q1 2011**	**Q4 2010**	**Q3 2010**	**Q2 2010**	**Q1 2010**	**Q4 2009**
Net cash (debt)	(1,844)	(1,868)	(593)	204	(141)	(395)	(164)	(347)
Total assets	9,690	8,814	7,521	7,305	5,020	4,439	2,393	2,453
Total liabilities	4,675	4,145	2,651	2,436	1,742	1,443	693	958
Shareholders' equity	5,015	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	55,101	45,732	42,137	32,137	30,260
Weighted average	55,101	55,101	55,101	48,749	43,544	33,456	31,929	28,000

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, Saskatchewan 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, Saskatchewan 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.
- Q3 11 – disposed of a 50% working interest (cash proceeds of $375,000 plus 50% of the reactivation costs incurred by WPP plus undeveloped land valued at $100,000) in in the Maidstone property acquired in Q1 11.

OPERATING RESULTS

Production volumes and revenues (refer to Financial and Operating Summaries on page 5)

Q3 11 production averaged 184 bbls per day compared to Q3 10 average production of 37 bbls per day. The 5 (2.5 net) wells drilled in Q4 2010 accounts for the significant improvement to production and revenue in Q4 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. One (0.5 net) well drilled in Q2 2011 did not commence production until October 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 was unfavorable again in Q3 11 averaging $30.29 per bbl. compared to $15.45 per bbl. in Q3 10. This differential between the light oil benchmark price and the heavy oil benchmark price has increased each quarter since Q2 10 to $15.45 per bbl in Q3 10, $18.41 per bbl. in Q4 10, $26.15 in Q1 11, $29.41 in Q2 11 and $30.29 in Q3 2011.

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.

Royalties (refer to Financial and Operating Summaries on page 5)

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. Q3 11 overall royalty burden averaged 18% compared to 14% in Q3 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 5)

No significant repair or workover costs were incurred in Q3 2011 leading to lower production costs per bbl than previous quarters. 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 5)

As production increases as a result of development work and further acquisitions, G&A costs per bbl. will continue to decline 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. Q3 11 G&A expenses averaged $7.79 per bbl., down considerably from the 2010 annual average of $22.92 per bbl and $70.98 per bbl. in Q3 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 5**)**

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. The accretion is shown as other non-cash expense in the analysis on page 5.

Depletion (refer to Financial and Operating Summaries on page 5)

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.

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 ESTIMATES

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

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 Corporation is currently evaluating the impact of IFRS 9 on its financial statements.

IAS 12, Income Taxes, was amended on December 20, 2010 to remove subjectivity in determining on which basis an entity measures the deferred tax relating to an asset. The amendment introduces a presumption that an entity will assess whether the carrying value of an asset will be recovered through the sale of an asset. The amendment to IAS 12 is effective for reporting periods beginning on or after January 1, 2012. The Corporation is currently evaluating the impact of this amendment to IAS 12 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 Corporation is currently evaluating the impact of IFRS 9 and believes the standard will not be applicable to the preparation of its financial instruments.

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 industry practices and have been valued at the exchange amount that is the amount of consideration established and agreed to by the related parties:

- Legal services provide by a law firm in which an officer and director (Leigh Stewart) is an associate:
  - $174,506 was incurred to the date of these financial statements (2010 - $232,876) of which $15,554 (2010 - $40,272) was in accounts payable and accrued liabilities at the period end:
  - Costs were recorded as general and administrative expense, share issue costs or as a transaction expense depending on the activity for which legal services were provided;

- Various oil field services and products provided by or sold to corporations in which an officer and director of the Company (David Forrest) is an officer and a director:
  - $103,793 was incurred to the date of these financial statements (2010 - $190,633) of which $99,963 (2010 - $nil) was in accounts payable and accrued liabilities at the period end;
  - $7,652 of services or goods were sold to a related entity of which $4,442 ($nil at December 31, 2010) was in accounts receivable at the period ended September 30, 2011;
  - Costs were recorded as either production expense or capital expenditures depending on the nature of the expenditure;

- Oil sold to a corporation in which an officer and director of the Company (David Forrest) is an officer and a director:
  - $nil was earned in 2011 (2010 - $36,808) of which $nil (2010 - $nil) was in accounts receivable at the period end;
  - Proceeds were recorded as petroleum revenue.

- Executive services provided by a corporation in which an officer and a director of the Company (David Forrest) is an officer and director:
  - $131,220 was incurred to the date of these financial statements (2010 - $140,000) of which $nil (2010 - $nil) was in accounts payable and accrued liabilities at the period end;
  - Costs were recorded as general and administrative expense.

- Consulting services related to prospective oil and natural gas prospects in Colombia provided by a corporation in which a director of the Company (Menno Wiebe) is an officer and director amounting to $4,000 (2010 - $nil) which was paid prior to June 30, 2011 and recorded as general and administrative expense;

- Certain oil and natural gas properties are held as joint arrangements (working interest partner) with an entity which is related by way of common management (Stephen Johnston and David Forrest):
    - Capital costs of $274,362 ($nil in 2010) were incurred and billed to the working interest partner;
    - Net revenue of $29,062 ($nil in 2010) was earned on behalf of the working interest partner;
    - Cash calls totaling $400,000 ($nil in 2010) were paid by the working interest partner of which $156,680 is in accounts payable and accrued liabilities at the period ended September 30, 2011 ($nil at December 31, 2010).

- In 2010 $696,187 of oil and natural gas properties were acquired from a corporation in which an officer and director of the Company is an officer and a director. No oil properties were acquired from a related party in 2011.

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

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