Western Plains Petroleum Ltd.

MANAGEMENT'S DISCUSSION & ANALYSIS
Year ended December 31, 2010

OVERVIEW OF THE CORPORATION

Western Plains Petroleum Ltd. (the "Corporation" or "Western Plains" or "WPP") is a **heavy oil producer based in Lloydminster, Alberta.** The Corporation was incorporated under the Business Corporations Act (Alberta) on November 19, 2004 and has traded on the TSX Venture Exchange ("TSXV") since August 2006. Following various name changes and trading symbols the Corporation began trading under the symbol "WPP" on the TSXV on August 25, 2009.

The Corporation focuses on the following strategies:

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

GENERAL

This management discussion and analysis ("MD&A") of Western Plains for the year ended December 31, 2010 contains financial highlights but does not contain the complete financial statements of the Corporation. It should be read in conjunction with the Corporation's audited financial statements for the years ended December 31, 2010 and 2009. Additional information is available on SEDAR at www.sedar.com. The financial information presented herein has been prepared on the basis of Canadian generally accepted accounting principles ("GAAP"). All references to dollar amounts are in Canadian dollars.

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

NON-GAAP MEASURES

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

HIGHLIGHTS

Over the last two years Western Plains executed a strategy to eliminate $2.6 million of debt that was outstanding at December 31, 2008. Assets were sold to pay down the debt and subsequently replaced with high potential properties financed without debt. In executing this strategy, the Corporation has developed a concentrated asset base in close proximity to its operational and corporate offices in Lloydminster, Alberta. Key properties are Maidstone, Saskatchewan, Landrose, Saskatchewan and Lloydminster, Alberta. Development activity on the new properties restored the Corporation to the Q4 08 production levels. This high potential property base, strong management and governance team, and sufficient capital resources position Western Plains well to execute its 2011 development program and to continue production growth into 2011.

June 2010 Acquisition

Western Plains acquired 100% working interests in petroleum and natural gas rights located approximately 16 kilometers east of Lloydminster, in the Landrose area of Saskatchewan. At the date of acquisition the property included 920 acres, 1 producing well and 13 shut-in wells. Consideration consisted of 10,000,000 common shares and the assumption of the related asset retirement obligations.

August 2010 Disposition and Acquisition

Western Plains acquired a net 33 1/3% working interest in certain heavy oil assets located in the Lloydminster, Alberta area, comprised of 1,040 acres (347 net), including 9 shut-in heavy oil wells (previously producing) and 5 standing cased wells (previously drilled but not completed). Consideration was a combination of cash, the issuance of common shares of the Corporation, the assumption of certain trade payables of the Vendor and the assumption of the related asset retirement obligations.

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

These transactions significantly strengthened the balance sheet and positioned Western Plains for significant growth on a more diversified property base.

Production and Revenue

Production, revenue and cash flow for this heavy oil producer increased rapidly in Q4 10 to average 135 bbls for the quarter. This is a significant increase over the average production for Q3 10 of 37 bbls per day and reflects the active development program in Q4 10. The average production for the year ended December 31, 2010 was 72 bbls per day compared to 108 bbls per day for the year ended December 31, 2009. The lower average production for 2010 compared to 2009, was primarily a result of the disposition in August 2010 and the limited period of production from the wells drilled and completed since August 2010.

Western Plains, as operator, drilled 6 (net 2.75) successful oil wells in 2010 on the Landrose, Saskatchewan property. The Corporation is holding production to levels conducive to long term optimization of the resource.

The increased production had a positive impact on costs per bbl, e.g. general and administrative expense per bbl for Q4 10 was $18.66 per bbl compared to the average for the year ended December 31, 2010 of $23.41 per bbl. This expense per bbl would reduce to under $12.00 per bbl if the one-time bonus costs of $85,000 awarded in Q4 10 were eliminated. Similarly production and transportation costs for Q4 10 were $20.18 per bbl compared to the average for the year ended December 31, 2010 of $26.37 per bbl, again demonstrating the economies of scale from higher production.

Revenue in 2010 benefited from higher oil prices than 2009 as shown in the "Financial and Operating Summaries" on page 5. The realized prices per bbl for Q4 10 and Q4 09 were approximately the same. For the year ended December 31, 2010, Western Plains' realized price per bbl averaged $61.80 compared to $47.04 for the year ended December 31, 2009. The latter is a result of the very low oil prices in the first half of 2009 and as reflected in the benchmark prices shown in "Financial and Operational Summaries" on Page 5.

Strengthening of Management and Governance

In October 2010, the Corporation announced that Steven J. Glover, FCA was appointed as Vice-President, Finance and Chief Financial Officer of the Corporation. Mr. Glover is a valuable addition to the management of the Corporation, adding considerable industry experience, including CFO roles with other listed entities.

In June 2010, the Corporation announced that William D. B. Koenig was appointed Director of the Corporation. Mr. Koenig brings many years of experience in corporate finance and governance, with a focus on the oil and natural gas industry.

OUTLOOK

Western Plains expects Q1 11 production to be approximately equal to the Q4 10 average production of 135 bbls per day. The Q1 11 production is lower than earlier projections due to three factors:

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

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

Western Plains has identified 25 (12.7 net) potential drilling locations for 2011 and beyond. The Corporation is the operator for all these locations. One well was drilled in Q1 11 and a second location is licensed and will be drilled right after break up. Several other locations are in the process of being licensed with 3 gross wells expected to be drilled in Q2 2011, subject to rig availability.

The 2011 capital budget is $2.7 million and includes drilling 12 wells (5.67 net) and the continued acquisition of properties and mineral rights. Capital costs are budgeted to be approximately $400,000 to $425,000 gross for each well, including drilling, completion and equipping. Although oil wells in this area can achieve production rates up to 100 bbls per day, the Corporation holds production to 30-50 bbls per day in order to optimize long term production and reserves. Even at these curtailed production levels, the Corporation is adding production at approximately $13,000 to $15,000 per flowing bbl.

This increased production leads to economies of scale on both production and transportation costs per bbl and general and administrative costs per bbl. The Corporation expects that costs per bbl achieved in Q4 10 of approximately $24.00 per bbl for production and transportation costs and approximately $11.00 per bbl for general and administrative costs (after adjusting for the one-time bonus costs recorded in Q4 10) will be further reduced.

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

On February 18, 2011 Western Plains announced an arms-length farm out agreement for two LSDs on 2 different sections in the Standard Hill and Buzzard areas of Saskatchewan. Upon the payment of $40,000 to the farmor, the Corporation earned 50% of the farmor's interests in the land and is required to pay 100% of the costs to drill and complete (or cap and abandon) one test well on each the 2 LSDs. Upon drilling, Western Plains may opt to earn the remaining 50% of the farmor's interests in these lands. The farmor earns a 6% gross overriding royalty on any resulting production. One of the locations has been licensed and will be drilled immediately after break up.

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

The acquired property includes 10 heavy oil wells (9 vertical and 1 horizontal) of which 1 is producing at an average rate of 15 bbls per day. The property also has 1 horizontal water injection well. Western Plains intends to re-activate the 9 shut-in wells and complete a workover on the producing well to optimize production.

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

LIQUIDITY AND CAPITAL RESOURCES

As at December 31, 2010, the Corporation had net working capital of $300,000 ($200,000 working capital deficiency at December 31, 2009). In October 2010 the Corporation finalized a credit facility agreement with a Canadian chartered bank, consisting of two facilities:

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

Neither facility had been drawn as at or for the period ending December 31, 2010. Currently the Corporation has drawn $400,000 on the revolving facility. Given continued production growth and increased cash flows, the Corporation expects to increase the credit facility limits upon its next review in 2011.

In 2010 Western Plains issued common shares as follows:

- January private placement - 1,877,500 common shares at $0.08 per share for gross proceeds of $150,200,
- June property acquisition – 10,000,000 common shares were issued at a deemed price of $0.15 per share, as the sole consideration to acquire oil and gas interests,
- August private placement – 266,667 common shares at $0.15 per share for gross proceeds of $40,000,
- August property acquisition – 3,328,363 common shares were issued at a deemed price of $0.15 per share, as partial consideration to acquire oil and gas interests,
- November private placement - "flow-through" common share were issued at $0.22 per share for gross proceeds of $941,800. Eligible capital expenditures of $273,000 were incurred in 2010 with a commitment that the balance be incurred by December 31, 2012 under the look back rules of the Income Tax Act (Canada).
- December exercise of warrants – 3,352,941 shares were issued at the exercise price of $0.15 for gross proceeds of $502,941, and
- December private placement – 1,735,000 units were issued at $0.18 per unit for gross proceeds of $312,300. Each unit consisted of one common share and one-half of one common share warrant, with each whole warrant exercisable into one common share at an exercise price of $0.25 per share for a period of one year from the date of issuance. The fair value of the outstanding warrants was estimated to be $54,000.

As at December 31, 2010, the Corporation had 55,101,153 (30,259,774 at December 31, 2009) common shares outstanding, 867,500 warrants outstanding (3,352,940 at December 31, 2009, all of which were exercised in 2010 at $0.15 per share) and 4,152,000 stock options outstanding (1,452,000 at December 31, 2009) under its stock option plan.

The Corporation is well positioned to finance continued growth.

FINANCIAL AND OPERATING SUMMARIES

TABLE A - OPERATIONS BY QUARTER (Last 8 Quarters)

All production is conventional heavy oil

$000's except for Production and per share	Q4 2010	Q3 2010	Q2 2010	Q1 2010	Q4 2009	Q3 2009	Q2 2009	Q1 2009
Sales volume - total barrels	12,446	3,410	4,498	6,091	6,294	4,624	7,824	20,529
Sales volume - bbls/ day	**135**	**37**	**49**	**68**	**68**	**50**	**86**	**228**
Heavy oil revenue	756	222	288	394	389	277	411	770
Royalties	(146)	(31)	(30)	(73)	(49)	(50)	(94)	(172)
Production & transportation	(296)	(104)	(175)	(193)	(161)	(148)	(111)	(258)
Operating net back	313	87	83	128	179	79	206	340
General and administrative	(219)	(136)	(149)	(101)	(51)	(135)	(102)	(155)
Interest & financing	-	-	-	-	-	-	(58)	(54)
Corporate net back (loss)	94	(49)	(66)	27	128	(56)	46	131
Depletion & accretion	(350)	(59)	(145)	(112)	(116)	(111)	(101)	(701)
Other (expenses) revenue	(123)	-	(144)	-	-	85**	423*	-
Income (loss) for the period	**(379)**	**(108)**	**(355)**	**(85)**	**12**	**(82)**	**368**	**(570)**
Basic and diluted income (loss) per share	**(.008)**	**(0.002)**	**(0.011)**	**(0.003)**	**0.000**	**(0.003)**	**0.017**	**(0.027)**
*gain on disposition of oil properties								
**gain on settlement of debt								
Royalties as % of petroleum revenue	**19**	**14**	**11**	**19**	**13**	**18**	**23**	**22**

Per bbl analysis	**Per bbl**	**Per bbl**	**Per bbl**	**Per bbl**	**Per bbl**	**Per bbl**	**Per bbl**	**Per bbl**
Heavy oil revenue	60.73	65.20	58.31	64.67	61.82	59.88	52.53	37.53
Royalties	(11.76)	(9.07)	(6.57)	(11.98)	(7.75)	(10.79)	(12.06)	(8.40)
Production and transportation	(23.79)	(30.39)	(33.17)	(31.75)	(25.53)	(32.02)	(14.17)	(12.56)
Operating net back	**25.18**	**25.74**	**18.57**	**20.94**	**28.54**	**17.07**	**26.30**	**16.57**
General and administrative	(17.62)	(39.99)	(33.21)	(16.59)	(8.11)	(29.31)	(13.10)	(7.55)
Interest and financing	-	-	-	-	-	-	(7.36)	(2.63)
Corporate netback (loss)	7.56	(14.25)	(14.64)	4.35	20.43	(12.24)	5.83	6.39
Depletion & accretion	(28.12)	(17.37)	(32.21)	(18.34)	(18.47)	(23.95)	(12.91)	(34.15)
Other (expenses) revenue	(9.87)	-	(32.06)	-	-	18.42	54.05	-
Income (loss) for the period	(30.43)	(31.62)	(78.92)	(13.99)	1.96	(17.77)	46.98	(27.76)
WPP revenue prices	**60.73**	**65.20**	**58.31**	**64.67**	**61.82**	**59.88**	**52.53**	**37.53**
Benchmark prices								
Edmonton light 40 API	80.71	76.02	75.46	80.31	76.75	71.70	66.19	50.15
Hardisty heavy 12 API	62.30	60.57	59.67	68.79	64.03	60.90	58.07	39.38
Heavy oil differential	18.41	15.45	15.79	11.52	12.72	10.80	8.12	10.77
Funds (invested in) recovered from petroleum properties	**(1,427)**	**263**	**(157)**	**(69)**	**(212)**	**(778)**	**2,703**	**(50)**

FINANCIAL AND OPERATING SUMMARIES
TABLE B -OPERATIONS FOR THE YEARS ENDED DECEMBER 31, 2010, 2009 and 2008

All production is conventional heavy oil

$000's except for Production and per share	**2010**	**2009**	**2008**
Production - total barrels	26,444	39,271	44,382
Production - bbls/ day	**72**	**108**	**121**
Heavy oil revenue	1,634	1,847	3,134
Royalties	(280)	(365)	(761)
Production & transportation	(742)	(677)	(761)
Operating net back	612	805	1,612
General and administrative	(606)	(463)	(896)
Interest & financing	-	(92)	(171)
Corporate net back (loss)	6	250	545
Depletion & accretion	(666)	(1,029)	(1,280)
Other (expenses) revenue	(267)	508*	(77)
Income (loss) for the period	**(927)**	**(272)**	**(812)**
Basic and diluted income (loss) per share	**(0.023)**	**(0.011)**	**(0.055)**
*gain on disposition of oil properties + gain on settlement of debt			
Royalties as % of petroleum revenue	**17**	**20**	**24**

Per bbl analysis	**Per bbl**	**Per bbl**	**Per bbl**
Heavy oil revenue	61.80	47.04	70.62
Royalties	(10.58)	(9.31)	(17.14)
Production and transportation	(28.07)	(17.25)	(17.14)
Operating net back	**23.15**	**20.48**	**36.34**
General and administrative	(22.92)	(11.80)	(20.08)
Interest and financing	-	(2.35)	(3.85)
Corporate netback (loss)	0.23	6.33	12.41
Depletion & accretion	(25.18)	(26.21)	(28.86)
Other (expenses) revenue	(10.10)	10.77	(1.84)
Income (loss) for the period	(35.05)	(9.10)	(18.29)

FINANCIAL AND OPERATING SUMMARIES
TABLE C – BALANCE SHEET

$000's	**Q4 2010**	**Q3 2010**	**Q2 2010**	**Q1 2010**	**Q4 2009**	**Q3 2009**	**Q2 2009**	**Q1 2009**
Net working capital (deficiency)	265	(80)	(322)	(103)	(208)	(377)	174	(2,575)
Total assets	7,070	5,026	4,242	2,323	2,453	2,297	2,034	4,288
Total liabilities	2,095	1,473	1,120	483	674	783	637	3,258
Shareholders equity	4,975	3,553	3,122	1,840	1,779	1,514	1,397	1,030
SHARES 000's								
Basic outstanding	55,101	45,732	42,137	32,137	30,260	26,907	21,227	21,227
Weighted average	48,749	43,544	33,456	31,929	28,000	26,907	21,227	21,227

OPERATING RESULTS

Production volumes and revenues (refer to Financial and Operating Summaries on pages 5 & 6)

Q4 10 average production was 135 bbls per day compared to Q4 09 average production of 68 bbls per day. Production for the year ended December 31, 2010 averaged 72 bbls per day compared to production for the year ended December 31, 2009 which averaged 108 bbls per day.

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 variances for the 8 quarters shown in the "Financial and Operating Summaries" on the prior two pages:

- Q2 2009 - disposed of all producing wells in the Golden Lake and Rush Lake areas of Saskatchewan reducing production by approximately 180 bbls per day.
- Q3 2009 – acquired six (6 net) non producing wells.
- Q4 2009 –activated and put on production non-producing wells acquired in prior quarter.
- Q2 2010 – acquired the Landrose, Saskatchewan property, with common shares as compensation.
- Q2 2010 – consummated Joint Operating Agreement (JOA) naming WPP as field operator, for a property targeted for acquisition. All wells were shut in.
- Q2 2010 – reactivated several of the shut in wells under the JOA, and earned operating fees which have been recorded as a reduction of production expenses.
- Q2 2010 – performed successful workovers on two (2 net) wells which were shut in for two months prior to and during the workover process.
- Q3 2010 – disposed of 50% working interest in all producing and non producing properties.
- Q3 2010 – acquired a 33 1/3% working interest in the property for which Western Plains was field operator.
- Q3 2010 –completed and put on production 2 (0.67 net) of 5 wells (drilled and cased but not previously completed) on the acquired property.
- Q3 2010 –drilled one well (0.25 net) in the Landrose area with Western Plains as operator. A farm in partner paid 100% of the costs subject to a 10% convertible gross overriding royalty (GORR) of which 5% is payable to the Corporation until payout. At payout in April 2011, Western Plains opted to take a 25% working interest in lieu of retaining the GORR.
- Q4 2010 – drilled and put on production 5 (2.5 net) wells in the Landrose, SK area.
- Q4 2010 – completed and put on production 2 (.67) additional wells (drilled and cased but not previously completed) on the property acquired in August 2010.
- Q4 2010 - performed workovers on three (2 net) wells to restore or increase production.
- Q1 2011- entered into a farm-out agreement to acquire two LSDs on two different sections of land in the Standard Hill and Buzzard areas of Saskatchewan.
- Q1 2011 – drilled and completed 1 successful oil well (0.33 net) on the Blackfoot heavy oil property in the Lloydminster, Alberta area as the first well in a proposed 3 well (1 net) program
- Q1 2011 – acquired additional petroleum and natural gas interests (100% WI in 320 acres) in the Maidstone area of west-central Saskatchewan and expects to have up to 5 wells reactivated and on production by May 2011. The acquisition included 1 producing well (approximately 15 bbls/day) and 9 shut in wells. Work will commence to reactivate the shut in wells in Q2 11.

The Corporation will continue to increase production on this more diverse property base.

Oil Pricing (refer to Financial and Operating Summaries on pages 5 & 6)

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.

Though crude oil prices increased during 2010, the price differential between heavy and light crude oil increased in the second half of 2010 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 as of the date hereof. As a result Western Plains realized an average oil price of $60.73 per bbl in Q4 10 as compared to $61.82 in Q4 09, though the differential between Hardisty heavy and Edmonton light oil increased to $18.41 in Q4 10 from $12.72 in Q4 09. For the year ended December 31, 2010, WPP realized an average price of $61.80 per bbl compared to $47.04 per bbl for the year ended December 31, 2009.

Royalties (refer to Financial and Operating Summaries on pages 5 & 6)

Q4 10 includes the higher production volumes from the newly drilled wells. The higher production volumes and strong oil prices triggers a higher royalty burden under the crown regimes. This explains the higher overall burden in Q4 10 of 19% compared to 13% in Q4 09 and 14% in Q3 10.

The production decline and lower prices in Q3 10 and Q2 10 compared to Q1 10 reduced the overall royalty burden under the declining scale method of determining Alberta and Saskatchewan crown royalties. A royalty refund was received and recorded in Q2 10. This explains the shift of royalty expense as a % of revenue of 11% in Q2 10 compared to 14% in Q3 10 and 19% in Q1 10.

Production and transportation costs (refer to Financial and Operating Summaries on pages 5 & 6)

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

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

A significant portion of production costs are fixed and therefore production expense per bbl varies significantly with volume. The increased production in Q4 10 reduced production costs per bbl for Q4 10 to $23.79 per bbl (2010 averaged $28.07 per bbl) and that level of cost per bbl or lower is expected for 2011.

General and administrative (G&A) (refer to Financial and Operating Summaries on pages 5 & 6)

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. Including the bonus expense, G&A costs in Q4 amounted to $17.62 per bbl. If the bonus expense is excluded G&A costs per bbl in Q4 10 amount to just under $11 per bbl, much lower than the 2010 annual average of $22.92 per bbl. The Corporation expects similar economies of scale as production continues to increase.

As the sales volumes in the first three quarters in 2010 were in the range of 3,400 to 6,100 bbls, relatively small changes in G&A costs in a quarter had a significant impact on cost per bbl. Legal, accounting, advisory, regulatory and travel expenses were incurred in Q2 10 and Q3 10 related to the property transactions and the annual general and special shareholder meeting in June 2010. These increased costs account for the difference between Q1 10 G&A costs of $101,000 compared to Q2 10 and Q3 10 costs of $149,000 and $136,000 respectively. These increased costs combined with the lower production volumes drove G&A costs per bbl much higher in Q2 10 ($33.21 G&A costs per bbl) and Q3 10 ($39.99 G&A costs per bbl) compared to Q1 10 ($16.59 per bbl).

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

Q4 09 G&A expenses are lower than prior quarters due in part to the capitalizing of general and administrative costs and certain geological costs for the entire year in that quarter. The overhead was capitalized based on standard rates used in the industry.

Interest and financing (refer to Financial and Operating Summaries on pages 5 & 6)

There was no interest expense after Q2 09 as all bank debt and a note payable were retired by July 2009. Certain financing costs were incurred in 2010 and recorded as general and administrative expense. These costs were to establish the bank credit facilities including legal fees and commitment fees charged by the bank. No interest was incurred in 2010 as the Corporation did not draw on the facilities until 2011.

Depletion and accretion (D&A) (refer to Financial and Operating Summaries on pages 5 & 6)

D&A expense amounted to $28.12 per bbl in Q4 10, compared to $18.47 per bbl in Q4 09. For the year ended December 31, 2010 D&A expense amounted to $25.18 per bbl compared to $26.21 per bbl for the year ended December 21, 2009. Depletion expense is a function of volume produced as it is computed on a “units of production” basis using the full cost accounting policy. The depletion rate is computed based on total proved bbls as determined by the independent reserve evaluator. Significant development costs were expended in Q4 10 as 5 wells (2.5 net) were drilled. The total proved reserve bbls were conservatively determined as the wells have been on production only a few months. The high Q4 10 costs combined with conservative total proved reserve bbls led to the higher depletion per bbl in Q4 10 compared to Q3 10 and Q4 09.

Probable reserves for the Corporation’s properties are significant. Under International Financial Reporting Standards (IFRS) energy companies may choose the proved plus probable basis for the computation of depletion. As probable reserves are determined based on a probability of recovery of 50% or more, this broader depletion base under IFRS will generate a more realistic estimate of real depletion. See “New Accounting Standards” herein.

The decrease in volume following the property sale in May 2009 lowered the total expense for depletion and accretion. The sale proceeds, net of the gain, were credited against the accumulated capital costs reducing costs subject to depletion in later quarters. The impact on depletion was greater than 20% and thus a gain was recorded on this disposition as required under Canadian accounting standards for the full cost method.

INCOME TAX

The Corporation had the following tax pools:

Nature of tax pool	Annual Deduction Available-%	December 31, 2010 $000's	December 31, 2009 $000's
Canadian oil and gas property expense (COGPE)	10	2,571	1,156
Canadian development expense (CDE)	30	536	-
Canadian exploration expense (CEE)	100	334	606
Specified foreign exploration & development expense	10	472	525
Undepreciated capital cost (UCC)	25	810	16
Share issue costs	20	92	43
Non capital loss carry forward	100	1,200	493

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

The recovery of income taxes in 2010 relates to the renouncement in 2010 of certain tax expenditures to flow through share investors. The Corporation has not recorded any future tax asset or liability, nor has it recorded any tax recovery related to its operating losses in 2009 or 2010, due to the uncertainty of the Corporation's ability to fully utilize the available income tax pools against its future income.

Sufficient eligible capital expenditures were incurred in 2010 to meet all remaining commitments from "flow through" common shares issues in 2008 and 2009. Flow through common shares issued in November 2010 requires that eligible expenditures of $941,800 be incurred by December 31, 2011. Approximately $273,000 of eligible expenditures was incurred in 2010 with the balance to be incurred in 2011. The full amount was renounced in March 2010 and effective December 31, 2010 under the look back rule.

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

CRITICAL ACCOUNTING ESTIMATE

Management is often required to make judgments, assumptions and estimates in the application of generally accepted accounting principles that may have a significant impact on the financial results of the Corporation. The Corporation's significant accounting policies are described in Note 2 to the financial statements. The following is a discussion of the accounting estimates that are critical in determining the Corporation's financial results.

(a) *Property and equipment*

(i) *Oil and natural gas reserves*

The Corporation's proved oil and gas reserves at the current and prior year end were evaluated and reported on by an independent petroleum engineering consultant. 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 Corporation 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 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) *Full cost accounting and depletion*

The alternative method of accounting for oil and natural gas properties and equipment is the successful efforts method. A major difference in applying the successful efforts method is that exploratory dry holes and geological and geophysical exploration costs would be charged against net earnings in the year incurred rather than being capitalized to property and equipment.

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

(iii) *Impairment-ceiling test*

The ceiling test uses future prices determined by the independent reserve evaluator adjusted for price differentials specific to the Corporation and considered reasonable and relevant to Western Plains's products and showed no impairment. 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 Corporation to develop the resource or lose the petroleum and natural gas rights.

(b) *Asset retirement obligations*

Western Plains's asset retirement obligation is based on the Corporation's net ownership in wells and facilities. Determination of the current retirement costs is based on estimated abandonment and reclamation costs for each well. To estimate future retirement costs, Western Plains applied a 2% inflation factor which it believes is reasonable over the long term and is consistent with rates used by others in the industry. The credit adjusted risk free rates of 8-10% to discount retirement costs to the current reporting date. These rates are reasonable given the environment for capital and credit and consistent with rates used by others in the industry. Expected retirement dates range from 2018 to 2029. This estimate is based on the expected productive life of the wells and regulatory requirements.

(b) *Stock-based compensation*

Western Plains used the Black Scholes option pricing model to determine the fair value of stock 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 Corporation's share price over the life of the options. These estimates may vary from the actual life and volatility.

(c) *Future income tax*

The asset and liability method of accounting for income taxes requires determination of substantially enacted income tax rates. The Corporation 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 this time. 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 future taxes determined at a point in time, and to the extent that these differences are created, they can impact the charge against earnings for future taxes. The Corporation evaluates future income tax assets to make a determination of whether the assets will be realized. A valuation allowance has been taken based on management's assessment that it is more likely than not (50% probability) that the income tax recovery will not occur. A valuation allowance for the full amount of the estimated future income tax asset was recorded at December 31, 2010 and at December 31, 2009.

NEW ACCOUNTING STANDARDS

International Financial Reporting Standards

International Financial Reporting Standards ("IFRS") are to be followed by Canadian public companies effective January 1, 2011. Comparative financial statements for 2010 will also be required to follow IFRS. The full cost accounting method now used by the Corporation is not consistent with IFRS which will require reporting more consistent with successful efforts. The Corporation has completed the following key elements of its plan for the changeover:

- Finalized IFRS accounting policies and changes to financial disclosure;
- Completed the implementation of the new IFRS compatible oil and gas accounting system w; and
- Reviewed and modified internal controls as necessary.

Accounting Policy Choices

Western Plains' significant areas of impact include property and equipment ("P&E"), assets retirement obligations ("ARO"), impairment testing, and income taxes. The following discussion provides an overview of these areas, as well as the exemptions available under IFRS 1, *First-time Adoption of International Reporting Standards*. In general, IFRS 1 requires first time adopters to retrospectively apply IFRS, although it does provide optional and mandatory exemptions to these requirements. Western Plains is eligible for certain of these exemptions and has chosen to adopt certain exemptions as described below. Western Plains will continue to update its IFRS changeover plan to reflect new and amended accounting standards issued by the International Accounting Standards Board. The nature and preliminary estimates of certain of the IFRS impacts are provided below.

Property and equipment (P&E)

Under Canadian GAAP, Western Plains follows the CICA's guidelines on full cost accounting in which all costs directly associated with the acquisition of, the exploration for, and the development of natural gas and crude oil reserves are capitalized into one cost pool as Western Plains operates only in Western Canada. Costs accumulated in this full cost pool are depleted using the unit-of-production method based on proved reserves determined using estimated future prices and costs. Upon transition to IFRS, Western Plains will be required to adopt new accounting policies for each of pre-exploration costs, exploration and evaluation costs and development costs.

Western Plains will adopt the IFRS 1 exemption, which allows the Corporation to deem its January 1, 2010 IFRS P&E costs to be equal to its Canadian GAAP historical net book value. On January 1, 2010, the IFRS exploration and evaluation costs will be equal to the Canadian GAAP unproved properties balance ($nil for Western Plains) and the IFRS development costs will be equal to the full cost pool balance. Western Plains expects to allocate this full cost pool to the area level cost pools based on the economic valuation (present values based on a 10% discount rate) as determined by the independent reserve evaluator at December 31, 2009.

Pre-exploration costs are those expenditures incurred prior to obtaining legal right to explore and must be expensed as incurred under IFRS. Currently, Western Plains capitalizes and depletes pre-exploration costs within the full cost pool.

> IFRS Impact on the Financial Statements of Western Plains Petroleum Ltd.
> Historically pre-exploration costs were not material to Western Plains and are not material for 2010.

Exploration and evaluation costs (e.g. costs incurred to acquire petroleum and natural gas rights or the costs of drilling exploration wells) are those expenditures for an area or project for which technical feasibility and commercial viability have not yet been determined. Under IFRS, Western Plains will initially capitalize these costs as Exploration and Evaluation assets on the balance sheet. When the area or project is determined to be technically feasible and commercially viable, the costs will be transferred to property and equipment (P&E). Unrecoverable exploration and evaluation costs associated with an area or project will be expensed.

IFRS Impact on the Financial Statements of Western Plains Petroleum Ltd.
Western Plains had not allocated any costs to undeveloped property at January 1, 2010. It did not drill any exploration wells in 2009 or 2010. The Corporation will not assign any of its petroleum and natural gas properties held on January 1, 2010 to exploration and evaluation assets.

Development costs include those expenditures for an area or projects where technical feasibility and commercial viability (i.e. producing and other proved reserves have been assigned by the independent reserve evaluator) have been determined. All costs at January 1, 2010 will be allocated to this category and be subject to depletion as was done under Canadian generally accepted accounting principles. Under IFRS, Western Plains will continue to capitalize these costs within P&E on the balance sheet. However, the costs will be depleted on a unit-of-production basis over an area level (unit of account) instead of the full cost pool currently utilized under Canadian GAAP.

IFRS Impact on the Financial Statements of Western Plains Petroleum Ltd.
Western Plains will establish two development areas being Saskatchewan heavy oil properties and Alberta heavy oil properties. The Saskatchewan and Alberta assets are similar in terms of geological, engineering, operational, marketing and pricing factors and are in close geographic proximity to the Corporation's corporate and operational centre in the City of Lloydminster, Alberta. However the different provincial royalty, environment and other regulatory regimes could result in materially different reserve and economic valuations of reserves in the future. Depletion on the unit-of-production method and impairment will be applied on these two areas separately rather than as a single cost centre as is now the case under Canadian GAAP. This change to area level computation of depletion expense is not expected to have a material impact on the depletion expense to be reported under IFRS for 2010.

IFRS allows the Corporation to choose proved plus probable reserves over which capital costs are to be recorded as depletion expense under the units of production method of computing depletion expense, whereas Canadian GAAP prescribes only proved reserves as the reserve base over which capital costs are to be recorded as depletion expense. Upon conversion to IFRS, the Corporation will adopt proved plus probable reserves as the reserve base for the computation of depletion expense on the units of production method.

IFRS Impact on the Financial Statements of Western Plains Petroleum Ltd.
This change will materially reduce depletion expense. To illustrate the potential impact, the Corporation had total proved reserves at December 31, 2009 of 121,000 bbls compared to proved plus probable reserves of 490,000 bbls as determined by an independent reserve evaluator. Although other IFRS changes in accounting policies (e.g. lower discount rates will increase asset retirement costs capitalized as property and equipment) will also impact the computation of depletion expense, this four fold increase in the depletable reserves would reduce depletion expense by approximately the same factor.

Under IFRS, divestures of petroleum and natural gas properties will generally result in a gain or loss recognized in net earnings. Under Canadian GAAP, proceeds of divestitures are normally deducted from the full cost pool without recognition of a gain or loss unless the deduction would result in a change to the depletion rate of 20 percent or greater, in which case a gain or loss is recorded.

IFRS Impact on the Financial Statements of Western Plains Petroleum Ltd.
The disposition by Western Plains in Q3 10 did not result in the recording of a gain or loss under Canadian GAAP. However under IFRS the Corporation expects to record a loss on disposal in the financial statements. This immediate recognition of a loss reduces the costs subject to future depletion and consequently future depletion expense will be lower.

Impairment

Under Canadian GAAP, Western Plains is required to recognize an upstream impairment loss if the carrying amount exceeds the undiscounted cash flows from proved reserves for the full cost pool. If an impairment loss is to be recognized, it is then measured at the amount the carrying value exceeds the sum of the fair value (discounted, future, estimated cash flows) of the proved and probable reserves and the costs of unproved properties.

Under IFRS, Western Plains is required to recognize and measure an impairment loss if the carrying value exceeds the recoverable amount for a cash-generating unit (operating assets generating independent cash flows). Under IFRS, the recoverable amount is the higher of fair value less cost to sell and value in use. Impairment losses, other than goodwill, are reversed under IFRS when there is an increase in the recoverable amount.

IFRS Impact on the Financial Statements of Western Plains Petroleum Ltd.
Western Plains will group its P&E assets into two cash-generating units based on the independence of cash inflows from other assets or other groups of assets. The Corporation has identified Saskatchewan heavy oil assets and Alberta heavy oil assets as its two development areas and each will be considered as a cash generating unit. As provincial government policy can be a significant determinant of cash flows this provincial distinction will determine cash generating units although in every other respect the properties are similar. These two cash generating units were each tested for impairment at January 1, 2010. No impairment was observed which was the same result when the impairment test was applied on the single cost centre basis under Canadian GAAP.

Asset Retirement Obligation (ARO)

Under Canadian GAAP, ARO is measured as the estimated fair value of the retirement and decommission expenditures expected to be incurred and discounted using credit adjusted risk free discount rates. Existing liabilities are not re-measured at each period end using current discount rates. Under IFRS, ARO is measured as the estimate of the expenditures to be incurred and allows the use of current risk free discount rates at each re-measurement date. Western Plains intends to utilize risk free rates rather than credit adjusted risk free rates. The impact of the change in discount rates is recorded as a part of the accretion expense (categorized as a financing expense under IFRS) for the period. As a result of Western Plain's intended use of the IFRS 1 assets exemption, the Corporation is required to revalue its January 1, 2010 ARO balance and, recognize the adjustment if any, in retained earnings.

IFRS Impact on the Financial Statements of Western Plains Petroleum Ltd.
Risk free discount rates are lower than the Corporation's credit adjusted risk free rates and therefore the asset retirement obligation under IFRS will be greater than under Canadian GAAP. Since the initial recording of that provision is recorded as an addition to P&E, that carrying value and depletion expense will be greater under IFRS than under Canadian GAAP.
The asset retirement obligation for Western Plains at December 31, 2009 is estimated to be approximately $338,000 under IFRS compared to $192,000 under Canadian GAAP. The difference of approximately $146,000 will be recorded as an adjustment to retained earnings at January 1, 2010, upon conversion to IFRS. Accretion expense is not material to Western Plains as the total expense in 2010 is estimated to be approximately $15,000 under Canadian GAAP. IFRS accretion expense will not be materially different.

Income Taxes

In transitioning to IFRS, the Corporation's future tax liability will be impacted by the tax effects resulting from the IFRS changes discussed above. Western Plains continues to assess the impact that the IFRS income tax principles may have on the Corporation.

Other IFRS Considerations

Business combinations and joint ventures entered into prior to January 1, 2010 will not be retrospectively restated using IFRS principles. One of the significant differences is that transaction costs are expensed rather than recorded as a component of the purchase equation.

IFRS Impact on the Financial Statements of Western Plains Petroleum Ltd.
Transaction costs of approximately $136,000 were incurred on property acquisitions in 2010 and were recorded as property and equipment in 2010 and then depleted as part of the full cost base under Canadian GAAP. These costs will be expensed immediately under IFRS. Similarly transaction costs totaling approximately $44,000 were deducted from the proceeds of the Q3 10 disposition (credited to the full cost pool) and under IFRS the Corporation will record those costs as expense.

Business Combinations

CICA Handbook Section 1582, "Business Combinations" establishes revised principles and requirements for the acquisition method for business combinations and related disclosures. This standard will be adopted for business combinations included in the 2010 comparative financial information in the 2011 financial statements under IFRS.

Consolidated Financial Statements

CICA Handbook Section 1601 "Consolidated Financial Statements", together with Section 1602 below, establishes revised principles and requirements for the preparation of consolidated financial statements. This standard will be adopted effective January 1, 2011.

Non-controlling Interests

CICA Handbook Section 1602 "Non-controlling Interests" establishes revised principles and requirements for the accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. The standard requires a non-controlling interest in a subsidiary to be classified as a separate component of equity. In addition, net earnings and components of other comprehensive income are attributed to both the parent and non-controlling interests. This standard will be adopted effective January 1, 2011.

OFF BALANCE SHEET ARRANGEMENTS

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

INDUSTRY CONDITIONS AND RISKS

The business of exploration, development and acquisition of oil and gas reserves involves a number of business risks inherent in the oil and gas industry which may impact Western Plains's results and several of which are beyond control of the Corporation. 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 employees. The Corporation 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 Corporation's revenues, profitability and future growth and the carrying value of its properties are substantially dependent on prevailing prices of oil and gas. The Corporation'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 relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond the control of the Corporation.

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 Corporation to incur costs to remedy such discharge. Although the Corporation 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 Corporation's financial condition, results of operations or prospects.

The Corporation'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 Contact and others. In accordance with customary industry practice, Contact 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. Environmental regulation is becoming increasingly stringent and costs and expenses of regulatory compliance are increasing. Contact expects it will be able to fully comply with all regulatory requirements in this regard.

The Corporation 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 Corporation manages its working capital and debt positions so as not to overextend the Corporation. Capital expenditures are limited to funds available for cash from operating activities, available lines of credit and proceeds from issuing shares when the Corporation 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 Corporation’s operations, financial results and real or perceived risk to investors or creditors. These matters are largely beyond the Corporation’s control but are monitored to the extent possible.

RELATED PARTY TRANSACTIONS

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

- Legal services provided by a law firm in which an officer and director is employed:
  - $232,876 was incurred in the year ended December 31, 2010 ($104,479 in the year ended December 31, 2009);
- Various oil field services and products provided by or sold to corporations in which David Forrest, an officer and director of the Corporation, is an officer and a director:
  - $190,633 was incurred for oil field services and products in the year ended December 31, 2010 ($278,358 in the year ended December 31, 2009); and
  - $36,808 of oil was sold by Western Plains in the year ended December 31, 2010 ($nil in the year ended December 31, 2009)
- Oil and natural gas interests ($nil during the year ended December 31, 2009) were acquired in two transactions in the year ended December 31, 2010 from a corporation in which David Forrest, an officer and a director of the Corporation, is an officer and director. One transaction was for undeveloped land for cash consideration of $30,000 and the second was for oil and natural gas interests for consideration consisting of 4,441,250 common shares valued at $0.15 per share for a total of $750,000. The latter transaction received shareholder and TSXV approvals;
- Executive services provided by a corporation in which David Forrest, an officer and a director of the Corporation, is an officer and director:
  - $140,000 was incurred and paid in the year ended December 31, 2010 ($120,000 in the year ended December 31, 2009)

The 2010 financial statements include the following related party transactions in the 2009 comparative amounts, with no balances remaining outstanding at December 31, 2009 or the end of the current period:

- Interest of $80,436 paid to a corporation controlled by David Forrest, an officer and director of the Corporation; and
- $53,609 paid to entities controlled by former officers for accounting services.

Forward-Looking Statements

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

Western Plains Petroleum Ltd.
MANAGEMENT'S DISCUSSION & ANALYSIS
Year ended December 31, 2010

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