Management Discussion & Analysis 2012 — Dated: February 27, 2013

The following discussion of the financial condition, changes in financial condition and results of operations of Western Energy Services Corp. (the "Company" or "Western") should be read in conjunction with the audited consolidated financial statements and accompanying notes of the Company for the years ended December 31, 2012 and 2011. This Management Discussion & Analysis ("MD&A") is dated February 27, 2013. All amounts are denominated in Canadian dollars (CDN$) unless otherwise identified.

Financial Highlights	**Three months ended December 31**		**Year ended December 31**		
(stated in thousands, except share and per share amounts)	**2012**	**2011**	**2012**	**2011**	**2010**
Revenue	83,338	101,300	308,617	262,519	56,009
Gross Margin[1]	37,360	47,170	131,063	114,837	22,902
Gross Margin as a percentage of revenue	45%	47%	42%	44%	41%
EBITDA[1]	31,381	41,473	108,931	99,324	16,504
EBITDA as a percentage of revenue	38%	41%	35%	38%	29%
Cash flow from operating activities	11,021	25,337	104,916	59,368	10,953
Capital expenditures	20,328	34,336	127,231	88,869	21,282
Net income from continuing operations	13,092	24,923	45,178	53,882	23,339
-basic net income per share	0.22	0.43	0.77	1.04 [2]	1.03 [2]
-diluted net income per share	0.22	0.41	0.74	1.00 [2]	0.96 [2]
Net income	13,092	24,314	45,178	64,746	26,590
-basic net income per share	0.22	0.42	0.77	1.25 [2]	1.17 [2]
-diluted net income per share	0.22	0.40	0.74	1.21 [2]	1.09 [2]
Weighted average number of shares					
-basic	59,485,594	58,533,287	58,784,692	51,595,078 [2]	22,724,270 [2]
-diluted	60,800,390	60,549,515	60,860,359	53,640,617 [2]	24,385,704 [2]
Outstanding common shares as at period end	59,582,143	58,533,287	59,582,143	58,533,287	37,680,944 [2]
Dividends declared	4,469	-	8,924	-	-
Dividends declared per common share	0.075	-	0.15	-	-
Operating Highlights					
Contract Drilling					
Canadian Operations					
Average contract drilling rig fleet	44	37	41	32	13
Drilling revenue per operating day (CDN$)	31,904 [3]	33,199	32,212 [3]	29,885	25,349
Drilling rig utilization rate per revenue day[4]	62%	88%	60%	77%	64%
Drilling rig utilization rate per operating day[5]	55%	79%	54%	70%	58%
CAODC industry average utilization rate[5]	40%	61%	42%	52%	37%
United States Operations					
Average contract drilling rig fleet	5	5	5	4 [6]	-
Drilling revenue per operating day (US$)	33,017	30,705	33,315	33,038	-
Drilling rig utilization rate per revenue day[4]	79%	93%	85%	89% [6]	-
Drilling rig utilization rate per operating day[5]	62%	79%	68%	70% [6]	-
Well Servicing					
Average well servicing rig fleet	7	-	5	-	-
Revenue per service hour (CDN$)	614	-	596	-	-
Service rig utilization rate[7]	45%	-	36%	-	-

(1) See Financial Measures Reconciliations on page 2.
(2) Adjusted to reflect the 20:1 share consolidation completed on June 22, 2011.
(3) Excludes $2.2 million of standby revenue from take or pay contracts.
(4) Drilling rig utilization rate per revenue day is calculated based on operating and move days.
(5) Drilling rig utilization rate per operating day is calculated on operating days only (i.e. spud to rig release basis).
(6) Calculated from the date of acquisition of the United States operations (June 10, 2011).
(7) Service rig utilization rate calculated based on full utilization of 10 hours per day, 365 days per year.

Financial Position at (stated in thousands)	December 31, 2012	December 31, 2011	December 31, 2010
Working capital	77,628	39,874	13,156
Property and equipment	568,157	473,930	188,355
Total assets	749,448	619,645	264,108
Long term debt	186,948	108,039	46,054

Financial Measures Reconciliations

Western uses certain measures in this MD&A which do not have any standardized meaning as prescribed by International Financial Reporting Standards ("IFRS"). These measures which are derived from information reported in the consolidated statements of operations and comprehensive income may not be comparable to similar measures presented by other reporting issuers. These measures have been described and presented in this MD&A in order to provide shareholders and potential investors with additional information regarding the Company.

Gross Margin

Management believes that in addition to net income, Gross Margin is a useful supplemental measure as it provides an indication of the results generated by Western's principal operating activities prior to considering administrative expenses, depreciation and amortization, how those activities are financed, the impact of foreign exchange, how the results are taxed, how funds are invested, and how non-cash items and one-time gains and losses affect results.

EBITDA

Management believes that in addition to net income, earnings from continuing operations before interest and finance costs, taxes, depreciation and amortization, other non-cash items and one-time gains and losses ("EBITDA") is a useful supplemental measure as it provides an indication of the results generated by the Company's principal operating segments similar to Gross Margin but also factors in the cash administrative expenses incurred in the period.

Operating Earnings

Management believes that in addition to net income, Operating Earnings is a useful supplemental measure as it provides an indication of the results generated by the Company's principal operating segments similar to EBITDA but also factors in the depreciation expense charged in the period.

The following table provides a reconciliation of net income under IFRS as disclosed in the consolidated statements of operations and comprehensive income to Gross Margin, EBITDA and Operating Earnings:

	Three months ended December 31		Year ended December 31	
(stated in thousands)	**2012**	**2011**	**2012**	**2011**
Gross Margin	37,360	47,170	131,063	114,837
Add (subtract):				
Administrative expenses	(6,572)	(6,260)	(24,409)	(16,987)
Depreciation - administrative	365	165	971	446
Stock based compensation - administrative	228	398	1,306	1,028
EBITDA	31,381	41,473	108,931	99,324
Depreciation - operating	(9,067)	(9,012)	(31,890)	(24,541)
Depreciation - administrative	(365)	(165)	(971)	(446)
Operating Earnings	21,949	32,296	76,070	74,337
Stock based compensation - operating	(153)	(125)	(537)	(307)
Stock based compensation - administrative	(228)	(398)	(1,306)	(1,028)
Finance costs	(3,237)	(1,246)	(12,437)	(3,650)
Other items	(583)	1,472	(756)	(677)
Income taxes	(4,656)	(7,076)	(15,856)	(14,793)
Income from discontinued operations	-	(609)	-	10,864
Net income	13,092	24,314	45,178	64,746

Overall Performance and Results of Operations

Western is an oilfield service company providing contract drilling services through its wholly owned subsidiaries Horizon Drilling Inc. ("Horizon") in Canada and Stoneham Drilling Corporation ("Stoneham") in the United States, which was acquired on June 10, 2011. In addition, during the first quarter of 2012, Western commenced well servicing operations through its wholly owned subsidiary Matrix Well Servicing Inc. ("Matrix"). On September 13, 2011, Western sold all of the shares owned and debt owing from its wholly owned subsidiary StimSol Canada Inc. ("StimSol"), and, as such, prior period results relating to StimSol have been reclassified as discontinued operations. On January 1, 2013, Western amalgamated with Horizon and Matrix to form one legal entity. Horizon and Matrix now operate as divisions of Western.

While commodity price environments for crude oil and natural gas in Canada have softened in 2012 as compared to 2011, prices for crude oil have remained above the five year average. The demand for oil, along with an emphasis on liquids rich natural gas, has primarily resulted in the drilling of horizontal wells in both conventional and unconventional resource plays. Horizontal wells in the western Canadian sedimentary basin ("WCSB") as a percentage of all wells drilled increased by 20% in 2012 to 66% compared to 55% in 2011. This has resulted in continued demand for drilling rigs in the WCSB, with the industry utilization rate averaging 42% during 2012, which is higher than the five year average of 40%, but lower than the prior year when industry utilization of 52% was at a five year high. The number of wells drilled on a rig release basis in Canada decreased by 14% in 2012, which resulted in the industry's operating days in Canada decreasing by 14%. However, the industry average drilling days per well improved slightly to 12.1 days, a 6% increase, reflecting the increased depth and complexity of the wells being drilled by the industry. During 2012, Western's entire drilling rig fleet has been focused on drilling horizontal wells. In Canada, Western averaged 17.5 operating days per well drilled in 2012 as compared to 14.1 operating days per well in the prior year reflecting the 29% increase in meters drilled per well which averaged 3,336 meters in 2012 as compared to 2,596 meters in 2011. In the United States, Western averaged 26.3 operating days per well drilled in 2012 as compared to 33.7 operating days per well in the prior year, a 22% decrease. However, the average meters drilled per well totalled 5,897 meters in 2012 in the United States, compared to 5,564 meters in 2011, a 6% increase. Days per well decreased while meters per well increased in the United States as improved drilling practices led to greater hole penetration per day. The average time it takes to drill a well has a direct relationship to the complexity and depth of the well.

Key operational results for the fourth quarter of 2012 include:

- During the quarter, the Company's contract drilling rig fleet increased due to the commissioning of one new telescopic Efficient Long Reach ("ELR") double drilling rig. As such, the Company exited the period with 44 drilling rigs in Canada along with 5 drilling rigs in the United States for a total contract drilling rig fleet of 49. Western currently has a drilling rig fleet of 50 rigs, with an additional telescopic ELR double drilling rig under construction which will be the Company's first convertible pad rig. Additionally, during the quarter the Company's well servicing fleet increased due to the commissioning of three new service rigs. As such, the Company exited 2012 with a fleet of eight well servicing rigs . Subsequent to December 31, 2012, the Company commissioned 2 more well servicing rigs, resulting in the Company's total well servicing rig fleet increasing to 10.
- Fourth quarter revenues decreased by $18.0 million (or 18%) to $83.3 million in 2012 as compared to $101.3 million in 2011. In Canada, revenues in the contract drilling segment were $19.6 million lower mainly due to a 19% decrease in operating days coupled with a 4% decrease in revenue per operating day. In the United States, operating days were 22% lower than in the fourth quarter of 2011 partially offset by revenue per operating day increasing by 8%. The slowdown in oilfield service activity was due in part to uncertain economic conditions, increased pricing differentials on Canadian crude oil and lower natural gas prices, which resulted in reduced producer spending on capital programs as capital markets tightened. Lower revenue in the contract drilling segment was partially offset by $1.6 million in well servicing revenue.
- Fourth quarter EBITDA decreased by $10.1 million (or 24%) to $31.4 million in 2012 (38% of revenue), as compared to $41.5 million in 2011 (41% of revenue). Similar to revenue, the decrease in EBITDA is mainly due to decreased utilization in the contract drilling segment coupled with higher administrative expenses. Cash flow from operating activities decreased by $14.3 million (or 57%) to $11.0 million in 2012 mainly due to the $10.1 million decline in EBITDA as well as a $5.2 million decrease in the change in non-cash working capital.
- Administrative expenses, excluding depreciation and stock based compensation, in the fourth quarter of 2012 remained relatively consistent increasing by $0.3 million to $6.0 million (7% of revenue) as compared to $5.7 million in 2011 (6% of revenue).
- Net income decreased by $11.2 million to $13.1 million in the fourth quarter of 2012 ($0.22 per basic common share) as compared to $24.3 million in the same period in the prior year ($0.42 per basic common share). The decrease is mainly attributed to the $10.1 million decrease in EBITDA, higher finance costs of $2.0 million due to the $175.0 million issuance in senior notes in the first quarter of 2012 offset by a $0.9 million decrease in other expenses.

- The total capital expenditures in the fourth quarter of $20.3 million include $13.2 million of expansion capital, $2.7 million of maintenance capital, and $4.4 million for critical spares. The majority of the fourth quarter 2012 capital expenditures relate to the contract drilling segment, which incurred $16.4 million in capital expenditures. These expenditures mainly relate to Western's drilling rig build program, which totalled $10.1 million in the fourth quarter. The remaining capital spending in the contract drilling segment related to ancillary drilling equipment. Additionally, $3.2 million was incurred in the well servicing segment mainly relating to Western's well servicing rig build program.

Key operational results for the year ended December 31, 2012 include:

- Revenues for 2012 increased by $46.1 million (or 18%) to $308.6 million as compared to $262.5 million in the same period of the prior year. The increase reflects Western's increased rig fleet in the contract drilling segment following the acquisition of Stoneham Drilling Trust in June of 2011 and the Company's capital program, which resulted in the Company's average fleet increasing to 46 rigs, a 28% increase over the prior year. In Canada, revenue per operating day increased to $32,212 in 2012 compared to $29,885 in 2011, however utilization per operating day decreased to 54% in 2012, as compared to 70% in 2011. In the United States, utilization and day rates remained relatively consistent with utilization per operating day of 68% in 2012 compared to 70% in 2011 and average revenue per operating day of US$33,315 in 2012 compared to US$33,038 in 2011. While utilization and day rates were relatively consistent in 2012 as compared to 2011, revenue in the United States increased by $20.0 million mainly due to a full year of operations as compared to a partial year in 2011 following the acquisition of Stoneham Drilling Trust.
- EBITDA increased by $9.6 million (or 10%) to $108.9 million (35% of revenue) in 2012 as compared to $99.3 million (38% of revenue) in 2011 due to improved drilling day rates in Canada and an increased drilling rig fleet resulting from the Company's growth. EBITDA did not increase at the same rate as revenue due to lower drilling rig utilization and increased administrative expenses. Cash flow from operating activities increased by $45.5 million (or 77%) to $104.9 million in 2012, due to the year over year increase in the change in non-cash working capital of $33.3 million, coupled with the $9.6 million increase in EBITDA in the period.
- Administrative expenses, excluding depreciation and stock based compensation, increased by $6.6 million to $22.1 million in 2012 (7% of revenue) as compared to $15.5 million in 2011 (6% of revenue). The increase is due to a strengthened management team and higher staffing levels required to support the Company's previous growth in the United States and Canada and to position the Company for future expansion.
- For 2012, net income decreased by $19.6 million to $45.2 million ($0.77 per basic common share) as compared to $64.7 million in the same period of the prior year ($1.25 per basic common share). The decrease in large part is due to the $10.1 million gain recognized on the sale of StimSol in the third quarter of the prior year. After normalizing for this transaction, net income decreased by $9.5 million. The normalized decrease is mainly attributable to increased finance costs of $8.8 million subsequent to the January 2012 senior notes issuance, increased depreciation expense of $7.9 million due to increased operating days and a larger rig fleet in 2012, offset by the $9.6 million increase in EBITDA.
- Total capital expenditures of $127.2 million in 2012 include $72.9 million in expansion capital, $31.8 million in maintenance capital and $22.5 million in critical spares. The majority of the 2012 capital expenditures related to the contract drilling segment, which incurred $110.3 million, or 87% of the capital program. These expenditures mainly relate to Western's drilling rig build program, which incurred $58.7 million in the period. The remaining capital spending in the contract drilling segment related to ancillary drilling equipment. Additionally, $12.4 million was incurred in the well servicing segment mainly related to Western's service rig build program.
- On January 30, 2012, Western completed a private offering of $175.0 million aggregate principal amount of 7⅞% senior unsecured notes due January 30, 2019 (the "Senior Notes"). The Senior Notes were issued at par. Western used the net proceeds from the offering to repay all of its outstanding indebtedness under its secured credit facilities and for general corporate purposes. As a result of the issuance of the Senior Notes, Western voluntarily reduced its revolving credit facility from $150.0 million to $125.0 million. Western's operating facility of $10.0 million remains unchanged.
- During the second quarter, the Company extended the maturity on its $125.0 million revolving credit facility by one year to June 7, 2015.

Subsequent Events

- Subsequent to year end on February 21, 2013, the Company entered into an Arrangement Agreement whereby, subject to certain conditions, the Company will acquire all of the issued and outstanding shares of IROC Energy Services Corp. ("IROC") in exchange for a combination of cash and common shares of Western. The total transaction value is approximately $193.7 million, including the assumption of approximately $36.6 million in debt and IROC transaction costs. A portion of the consideration will be paid for in shares of the Company at an ascribed value of $7.63 per Western share. In accordance with IFRS 3, Business Combinations, the actual consideration will be determined based on the closing price of Western's shares immediately before the acquisition. The transaction is expected to be completed by way of a Plan of Arrangement under the Business Corporations Act of Alberta and is subject to normal stock exchange, court and regulatory approvals and the approval by at least 66 2/3 percent of the outstanding shares of IROC and any applicable minority shareholder approval requirements voted on at a special meeting of the shareholders of IROC, which is expected to be held prior to the end of April 2013.
- During the third quarter, Western's Board of Directors announced the implementation of a dividend policy that provides for an annual cash dividend of $0.30 per share. As such, the Board of Directors declared the following dividends during the year:
    - $0.075 per share, which was paid on October 12, 2012 to shareholders of record at the close of business on September 28, 2012;
    - $0.075 per share, which was paid on January 11, 2013, to shareholders of record at the close of business on December 31, 2012.

  Subsequent to year end, on February 27, 2013, the Board of Directors of Western declared a quarterly dividend of $0.075 per share, payable on April 12, 2013 to shareholders of record at the close of business on March 28, 2013. On a prospective basis, the declaration of dividends will be determined on a quarter-by-quarter basis by the Board of Directors.

Outlook

Western currently has a drilling rig fleet of 50 rigs, with an additional telescopic ELR double drilling rig under construction which will be the Company's first convertible pad rig. Western is the sixth largest drilling contractor in Canada with a fleet of 45 rigs. Currently, Western has five drilling rigs deployed in the United States. Additionally, Western has 10 well servicing rigs operating in Canada in the Lloydminster area.

Western's drilling rig fleet is specifically suited for the current market which is focused on drilling horizontal wells of increased complexity. In total, 96% of Western's fleet are ELR rigs with depth ratings greater than 3,000 meters and all of Western's rigs are capable of drilling resource based horizontal wells. Approximately one quarter of Western's fleet is currently under long term take-or-pay contracts with an average remaining contract life of approximately 14 months, which provide a base level of revenue. These contracts typically generate 250 operating days per year in Canada, as the annual spring breakup restricts activity during the second quarter, while in the United States these contracts typically range from 330 to 365 revenue generating days per year.

Western expects capital spending in 2013 to total $80 million including $20 million of carry forward capital from 2012 and $60 million relating to Western's 2013 capital budget. Western's 2013 capital budget includes approximately $28 million in expansion capital, $20 million in maintenance capital and $12 million in critical spare equipment. Expansion capital in the contract drilling segment aggregates to approximately $19 million and mainly relates to increasing our drilling rig fleet's pumping capacity in Canada and adding rig moving systems to certain drilling rigs in the United States, as well as additional drill pipe and other drilling equipment. Maintenance capital in 2013 of $20 million includes $10 million in drilling equipment, $6 million in drill pipe and $4 million relating to equipment recertifications.

Approximately $20 million remaining from Western's 2012 capital program is expected to be spent in 2013 mainly relating to the completion of two telescopic ELR double drilling rigs, one of which has already been commissioned. Western will finance its 2013 capital expenditure budget substantially from operating cash flows while maintaining our conservative balance sheet going into 2013 and positioning the Company for future opportunities.

In 2012, the price for natural gas has remained soft, with the AECO 30-day spot rate on average decreasing by approximately 35% as compared to the prior year. While the year over year average WTI crude oil price has remained relatively constant, increased pricing differentials in Canada, as a result of pipeline infrastructure constraints and refining capacity limitations, have resulted in a 9% year over year decrease in the average Edmonton Par price. The lower commodity price environment for crude oil and natural gas, coupled with the uncertain economic environment, due in part to the European debt crisis, is expected to result in similar levels of drilling activity in 2013 as compared to 2012. As such, the Company expects similar utilization in 2013 as compared to the prior year. Notwithstanding the softening commodity price environment, Western continues to believe that additional rig build opportunities in the contract drilling segment will be available as liquefied natural gas projects gain approval, drilling activity increases in the Duvernay and Montney resource plays in Alberta and northwest British Columbia, coupled with increased foreign investment in Canada. Currently, the largest challenges facing the drilling industry are producer spending constraints, pricing differentials on Canadian crude oil, low natural gas prices, a strong Canadian dollar and the challenge to attract and retain skilled labour. The Company believes Western's modern drilling rig fleet, which has an average age of approximately six years, and corporate culture will provide a distinct advantage in retaining and attracting qualified individuals. Western is of the view, that its modern ELR rig fleet, strong customer base and solid reputation provides a competitive advantage which will enable the Company to continue its growth strategy and higher than industry utilization through a period of lower commodity prices and drilling activity.

Segmented Information

Western operates in the contract drilling segment in both Canada and the United States as well as the well servicing segment in Canada. Contract drilling includes drilling rigs along with related equipment. Well servicing includes service rigs along with related equipment for production and work over services in addition to well completions. Certain comparative figures in the segmented information discussion have been reclassified to be consistent with the current year presentation. Please refer to page 12 for an analysis of the fourth quarter 2012 results.

Contract Drilling

	Three months ended December 31		Year ended December 31	
(stated in thousands)	**2012**	**2011**	**2012**	**2011**
Revenue	81,723	101,300	305,217	262,519
Expenses				
Operating				
Cash operating expenses	44,665	53,951	174,220	147,503
Depreciation	8,886	9,011	31,477	24,540
Stock based compensation	135	124	501	306
Total operating expenses	53,686	63,086	206,198	172,349
Administrative				
Cash administrative expenses	4,425	1,994	15,886	6,644
Depreciation	87	81	375	206
Stock based compensation	(39)	82	217	211
Total administrative expenses	4,473	2,157	16,478	7,061
Gross Margin(1)	37,058	47,349	130,997	115,016
Gross Margin as a percentage of revenue	45%	47%	43%	44%
EBITDA(1)	32,633	45,355	115,111	108,372
EBITDA as a percentage of revenue	40%	45%	38%	41%
Operating Earnings(1)	23,660	36,263	83,259	83,626
Capital expenditures	16,463	31,461	110,293	82,954
Canadian Operations				
Contract drilling rig fleet:				
Average	44	37	41	32
End of period	44	38	44	38
Drilling revenue per operating day (CDN$)	31,904 (2)	33,199	32,212 (2)	29,885
Drilling rig operating days(3)	2,198	2,706	8,127	8,074
Number of meters drilled	357,439	451,987	1,546,841	1,485,195
Number of wells drilled	112	167	464	572
Average operating days per well	19.6	16.2	17.5	14.1
Drilling rig utilization rate per revenue day(4)	62%	88%	60%	77%
Drilling rig utilization rate per operating day(3)	55%	79%	54%	70%
CAODC industry average utilization rate(3)	40%	61%	42%	52%
United States Operations				
Contract drilling rig fleet:				
Average	5	5	5	4 (5)
End of period	5	5	5	5
Drilling revenue per operating day (US$)	33,017	30,705	33,315	33,038
Drilling rig operating days(3)	286	365	1,238	640
Number of meters drilled	68,947	42,509	277,180	105,725
Number of wells drilled	12	9	47	19
Average operating days per well	23.8	40.6	26.3	33.7
Drilling rig utilization rate per revenue day(4)	79%	93%	85%	89% (5)
Drilling rig utilization rate per operating day(3)	62%	79%	68%	70% (5)

(1) See Financial Measures Reconciliations on page 2.
(2) Excludes $2.2 million of standby revenue from take or pay contracts.
(3) Utilization rate per operating day and drilling rig operating days are calculated on operating days only (i.e. spud to rig release basis).
(4) Utilization rate per revenue day is calculated based on operating and move days.
(5) Calculated from the date of acquisition of the United States operations (June 10, 2011).

During the year ended December 31, 2012, revenues in the contract drilling segment totalled $305.2 million, a $42.7 million (or 16%) increase over the same period in the prior year. The increase is due to a higher number of operating days in 2012 for both Canadian and United States operations compared to 2011 as a result of the Company's average fleet increasing to 46 rigs, a 28% increase over the prior year, in addition to higher day rates in Canada.

For the year ended December 31, 2012, Canadian operations performed strongly during the winter drilling season at the start of the year, but were impacted by a longer spring breakup and lower activity through the remainder of the year. As a result, utilization per operating day decreased to 54% in 2012, as compared to 70% in 2011. However, the Company's utilization remained 29% above the CAODC industry average of 42%. Despite modest pricing pressure in the latter half of 2012, strong demand for the Company's ELR drilling rigs resulted in revenue per operating day increasing by 8% to $32,212 in 2012 as compared to $29,885 in the prior year. Additionally, approximately $2.2 million in standby revenue relating to take or pay contracts, which has been excluded from the revenue per operating day, was recorded in the fourth quarter of 2012.

In the United States, operating days increased by 598 days (or 93%) in the period due to a full year of contribution from the United States operations following the acquisition of Stoneham Drilling Trust in June 2011; however, utilization decreased slightly to 68% for the year due to lower activity levels in the Williston basin of North Dakota in the second half of 2012 due to increased competition and reduced customer budgets. The drop in the Williston basin rig count is due to the natural progression of multi well pads as customers look for cost synergies in pad drilling as they switch their focus from delineation and land retention to development of their properties in the area. For the year ended December 31, 2012, revenue per operating day remained relatively consistent increasing by 1% to US$33,315.

During 2012, EBITDA in the contract drilling segment increased by $6.7 million (or 6%) to $115.1 million (38% of the segment's revenue), as compared to $108.4 million (41% of the segment's revenue) in 2011. EBITDA as a percentage of revenue has decreased in 2012 as compared to the prior year, despite improved day rates in Canada, due to lower utilization as well as an increased allocation of corporate administrative expenses required to support the Company's growth.

Total capital expenditures of $110.3 million in the contract drilling segment for the year ended December 31, 2012 include $60.7 million related to expansion capital, $27.2 million related to maintenance capital and $22.4 million related to critical spares. Of the capital expenditures incurred during the year, $58.7 million relates to the Company's rig build program with the remaining capital spending relating to ancillary drilling equipment, including additional top drives, loaders and drill pipe.

Well Servicing

(stated in thousands)	Three months ended December 31 2012	2011	Year ended December 31 2012	2011
Revenue	1,615	-	3,400	-
Expenses				
Operating				
Cash operating expenses	1,313	179	3,334	179
Depreciation	181	1	413	1
Stock based compensation	18	1	36	1
Total operating expenses	1,512	181	3,783	181
Administrative				
Cash administrative expenses	479	450	1,723	450
Depreciation	14	6	64	6
Stock based compensation	9	63	(30)	63
Total administrative expenses	502	519	1,757	519
Gross Margin(1)	302	(179)	66	(179)
EBITDA(1)	(177)	(629)	(1,657)	(629)
Operating Earnings(1)	(372)	(636)	(2,134)	(636)
Capital expenditures	3,283	2,833	12,358	5,472
Well servicing rig fleet:				
Average	7	-	5	-
End of period	8	-	8	-
Revenue per service hour (CDN$)	614	-	596	-
Total service hours	2,633	-	5,705	-
Service rig utilization rate(2)	45%	-	36%	-

(1) See Financial Measures Reconciliations on page 2.

(2) Utilization rate calculated based on full utilization of 10 hours per day, 365 days per year.

During 2012, the Company began operations in its well servicing division, Matrix, in Canada in the Lloydminster area. The Lloydminster well servicing market was targeted by Western as it is less capital intensive and the Company believes the fundamentals for heavy oil, which is the main focus in the area, will remain strong in the long term. Additionally, the well servicing market in the Lloydminster area typically remains more active during the second quarter, when spring breakup is impacting the rest of the industry in western Canada. Matrix's operations are in the start-up phase of development and have been focused on the construction and commissioning of its first 10 well servicing rigs, of which 8 were operating by December 31, 2012; establishing a presence in the Lloydminster area; and hiring management, field, and office support staff. As such, revenue of $3.4 million and EBITDA of negative $1.7 million for the year ended December 31, 2012 do not reflect a normalized period of activity. Matrix's revenue per service hour of $596 may be lower than some of our competitors operating in other geographic areas, as the Lloydminster well servicing market is mainly focused on heavy oil production work, which is highly competitive and less capital intensive, and typically results in lower hourly rates. As Matrix continues to establish their operations and obtains the necessary scale, the Company believes utilization rates and margins will continue to improve.

Capital expenditures of $12.4 million for the year ended December 31, 2012 mainly relate to expansion capital associated with the Company's well servicing rig build program which was substantially complete at year-end, with the final 2 rigs being commissioned in the first quarter of 2013.

Corporate

(stated in thousands)	Three months ended December 31 2012	2011	Year ended December 31 2012	2011
Administrative				
Cash administrative expenses	1,075	3,253	4,523	8,419
Depreciation	264	78	532	234
Stock based compensation	258	253	1,119	754
Total administrative expenses	1,597	3,584	6,174	9,407
Finance costs	3,237	1,246	12,437	3,650
Other items	583	(1,472)	756	677
Income taxes				
Current tax expense	276	1,635	5,090	585
Deferred tax expense	4,380	5,441	10,766	14,208
Total income taxes	4,656	7,076	15,856	14,793
Capital expenditures	582	42	4,580	443

For the year ended December 31, 2012, corporate administrative expenses, excluding depreciation and stock based compensation, decreased by $3.9 million or 46%, as compared to 2011. The decrease in corporate administrative expenses is due to an increased allocation of administrative expenses to Western's subsidiaries, offset by increased staffing levels required to position the Company for future growth.

For 2012, finance costs increased by $8.8 million to $12.4 million as compared to the prior year. The increase is due to the issuance of $175.0 million aggregate principal amount of 7⅞% senior unsecured notes on January 30, 2012, which resulted in an increased average debt balance outstanding for the year ended December 31, 2012 of $169.6 million as compared to an average debt balance outstanding of $77.4 million in the prior year. Additionally, the issuance of the Senior Notes increased the Company's effective interest rate to approximately 8% from approximately 5% previously.

Other items for the year ended December 31, 2012, totalled $0.8 million, unchanged from 2011. In 2012 other items mainly relate to net losses on the sale of certain non core assets. In the prior year, other items mainly consisted of acquisition costs associated with the acquisition of Stoneham of $3.3 million which were partially offset by net foreign exchange gains of $1.4 million and net gains on the sale of certain non core assets of $1.2 million.

For 2012, income taxes totalled $15.9 million reflecting an effective tax rate of approximately 26% compared to 2011 when income taxes totalled $14.8 million which represented an effective tax rate of approximately 22%. The change in effective tax rates from 2011 is mainly due to favourable adjustments relating to tax planning in 2011 associated with the acquisition of Stoneham Drilling Trust which resulted in realizing previously unrecognized tax losses leading to a lower effective tax rate.

Corporate capital expenditures of $4.6 million for the year ended December 31, 2012 relate to leasehold and system improvements.

Liquidity and Capital Resources

On January 30, 2012, Western completed a private offering of $175.0 million aggregate principal amount of 7⅞% senior unsecured notes due January 30, 2019. In conjunction with the closing of the Senior Notes, Western voluntarily reduced its revolving credit facility from $150.0 million to $125.0 million. Western's operating facility of $10.0 million remains unchanged. During the second quarter of 2012, Western extended the maturity date of its revolving credit facility by one year to June 7, 2015. As at December 31, 2012, Western had cash and cash equivalents of $6.6 million, resulting in a consolidated net debt balance of $186.1 million, an increase of $69.9 million as compared to December 31, 2011 due to capital expenditures of $127.2 million, the purchase of investments of $33.2 million, cash interest payments of $6.4 million and dividend payments of $4.5 million, exceeding cash flow from operating activities of $104.9 million. At December 31, 2012, Western had a working capital balance of $77.6 million, a $37.7 million increase as compared to December 31, 2011, due to Western's $6.6 million in cash and cash equivalents at the end of the year, the fair value of Western's investments of $35.1 million, partially offset by a $3.5 million decrease in trade and other receivables due to lower activity in the fourth quarter of 2012, and the dividends payable of $4.5 million. At December 31, 2012, Western had approximately $114.5 million in available credit facilities and is in compliance with all debt covenants. As such, cash from operations coupled with Western's working capital, cash balances and available credit facilities are expected to be sufficient to cover Western's financial obligations including the 2013 capital budget.

Fourth Quarter 2012

Selected Financial Information

Financial Highlights	Three months ended December 31	
(stated in thousands, except share and per share amounts)	2012	2011
Revenue	83,338	101,300
Gross Margin(1)	37,360	47,170
Gross Margin as a percentage of revenue	45%	47%
EBITDA(1)	31,381	41,473
EBITDA as a percentage of revenue	38%	41%
Cash flow from operating activities	11,021	25,337
Capital expenditures	20,328	34,336
Net income	13,092	24,314
-basic net income per share	0.22	0.42
-diluted net income per share	0.22	0.40
Weighted average number of shares		
-basic	59,485,594	58,533,287
-diluted	60,800,390	60,549,515
Outstanding common shares as at period end	59,582,143	58,533,287
Dividends declared	4,469	-
Dividends declared per common share	0.075	-
Operating Highlights		
Contract Drilling		
Canadian Operations		
Average contract drilling rig fleet	44	37
Contract drilling rig fleet - end of period	44	38
Drilling revenue per operating day (CDN$)	31,904 (2)	33,199
Drilling rig operating days(3)	2,198	2,706
Number of meters drilled	357,439	451,987
Number of wells drilled	112	167
Average operating days per well	19.6	16.2
Drilling rig utilization rate per revenue day(4)	62%	88%
Drilling rig utilization rate per operating day(3)	55%	79%
CAODC industry average utilization rate	40%	61%
United States Operations		
Average contract drilling rig fleet	5	5
Contract drilling rig fleet - end of period	5	5
Drilling revenue per operating day (US$)	33,017	30,705
Drilling rig operating days(3)	286	365
Number of meters drilled	68,947	42,509
Number of wells drilled	12	9
Average operating days per well	23.8	40.6
Drilling rig utilization rate per revenue day(4)	79%	93%
Drilling rig utilization rate per operating day(3)	62%	79%
Well Servicing		
Average well servicing rig fleet	7	-
Well servicing rig fleet - end of period	8	-
Revenue per service hour (CDN$)	614	-
Total service hours	2,633	-
Service rig utilization rate(5)	45%	-

(1) See Financial Measures Reconciliations on page 2.
(2) Excludes $2.2 million of standby revenue from take or pay contracts.
(3) Drilling rig utilization rate per operating day is calculated on operating days only (i.e. spud to rig release basis).
(4) Drilling rig utilization rate per revenue day is calculated based on operating and move days.
(5) Service rig utilization rate calculated based on full utilization of 10 hours per day, 365 days per year.

Contract Drilling

During the fourth quarter of 2012, revenues in the contract drilling segment totalled $81.7 million; a $19.6 million (or 19%) decrease over the same period in the prior year. The decrease in revenue is due to lower activity in Canada and the United States, as operating days decreased by 19% and 22% respectively. Revenue per operating day in Canada was $31,904 in the fourth quarter of 2012 compared to $33,199 for the same period in the prior year (4% decrease) due to overall lower pricing in the market as a result of decreased industry activity. Additionally, approximately $2.2 million in standby revenue relating to take or pay contracts, which has been excluded from the revenue per operating day, was recorded in the fourth quarter of 2012.

Canadian operations in the fourth quarter of 2012 were impacted by a slowdown in oilfield service activity as uncertain economic conditions and lower commodity prices resulted in reduced producer spending on capital programs. As such, utilization per operating day decreased to 55% as compared to 79% in the same period of the prior year. Despite the decrease in activity, the Company's utilization was 38% higher than the CAODC industry average of 40%.

In the United States, utilization per operating day averaged 62% in the fourth quarter of 2012 as compared to 79% in the same period of the prior year. While operating days decreased by 79 days (or 22%) in the period due to reduced activity and increased competition in the Williston basin of North Dakota, revenue per operating day increased 8% to US$33,017 from US$30,705 in 2011. The decline in activity in the Williston basin is mainly due to the natural progression of multi well pads as customers switch their focus from delineation and land retention to developing their properties in the area.

During the fourth quarter of 2012, EBITDA in the contract drilling segment decreased by $8.9 million (or 21%) to $32.6 million (40% of the segment's revenue), as compared to $41.5 million (41% of the segment's revenue) in the same period of the prior year due to lower activity levels and an increased allocation of corporate administrative expenses required to support the Company's growth.

Well Servicing

During the fourth quarter of 2012, revenues in the well servicing segment totaled $1.6 million and EBITDA totaled negative $0.2 million. During the quarter, Matrix had 2,633 service hours which represented an average utilization of 45%, which was higher than the third quarter of 2012, which had 1,799 service hours and an average utilization of 39%. Revenue per service rig hour increased from $582 in the third quarter of 2012 to $614 in the fourth quarter of 2012, a 5% increase. As Matrix continues to gain experience and improve their operations, the Company believes utilization will continue to increase.

Corporate

During the fourth quarter of 2012, corporate administrative expenses, excluding depreciation and stock based compensation, decreased $2.2 million (or 67%) to $1.1 million as compared to $3.3 million in the fourth quarter of 2011. The decrease is mainly attributed to an increased allocation of administrative expenses to Western's operating divisions, offset by higher staffing levels.

For the fourth quarter of 2012, interest expense increased by $2.0 million to $3.2 million as compared to $1.2 million in the same period of the prior year. This increase is mainly attributed to the issuance of our Senior Notes in January 2012 resulting in higher interest rates and a higher average debt balance outstanding.

For the fourth quarter of 2012 and 2011, income taxes totalled $4.6 million and $7.1 million respectively, which reflected effective tax rates of approximately 26% and 22% respectively. The increase in the effective tax rate in the fourth quarter of 2012 as compared to the same period of the prior year is due to the recognition of previously unrecognized tax losses in the prior year which lowered the effective tax rate.

Consolidated

Revenue and EBITDA decreased by $18.0 million and $10.1 million to $83.3 million and $31.4 million, respectively in the fourth quarter of 2012 as compared to $101.3 million and $41.5 million, respectively in 2011. The decrease is mainly due to lower activity in the contract drilling segment.

Net income decreased by $11.2 million to $13.1 million in the fourth quarter of 2012 as compared to $24.3 million in the same period in the prior year. The decrease is mainly attributed to the $10.1 million decrease in EBITDA, higher finance costs of $2.0 million due to the issuance our Senior Notes in the first quarter of 2012 offset by a $0.9 million decrease in other expenses.

Summary of Quarterly Results

In addition to other market factors, quarterly results of Western are markedly affected by weather patterns throughout its operating area in Canada. Historically, the first quarter of the calendar year is very active, followed by a much slower second quarter due to what is known in the Canadian oilfield service industry as spring breakup. As a result of this, the variation of Western's results on a quarterly basis, particularly in the first and second quarters, can be dramatic year over year independent of other demand factors. The following is a summary of selected financial information of the Company for the last eight completed quarters.

Three months ended	Dec 31, 2012	Sep 30, 2012	Jun 30, 2012	Mar 31, 2012	Dec 31, 2011	Sep 30, 2011	Jun 30, 2011	Mar 31, 2011
(stated in thousands, except per share amounts)								
Revenue	83,338	69,573	44,819	110,887	101,300	80,786	30,340	50,093
Gross Margin[(1)]	37,360	29,382	14,108	50,213	47,170	35,005	11,274	21,388
EBITDA[(1)]	31,381	23,944	9,364	44,242	41,473	30,392	8,533	18,926
Cash flow from operating activities	11,021	9,248	58,930	25,717	25,337	3,391	21,026	9,614
Income from continuing operations	13,092	8,251	827	23,008	24,923	13,891	4,750	10,318
per share - basic[(2)]	0.22	0.14	0.01	0.39	0.43	0.24	0.09	0.27
per share - diluted[(2)]	0.22	0.14	0.01	0.38	0.41	0.23	0.09	0.26
Net income	13,092	8,251	827	23,008	24,314	24,893	4,193	11,344
per share - basic[(2)]	0.22	0.14	0.01	0.39	0.42	0.43	0.08	0.30
per share - diluted[(2)]	0.22	0.14	0.01	0.38	0.40	0.41	0.08	0.28
Total assets	749,448	727,113	699,356	706,061	619,645	584,823	543,117	329,114
Long term financial liabilities[(3)]	186,948	176,739	171,764	171,570	108,039	108,057	116,186	28,030
Dividends declared	4,469	4,457	-	-	-	-	-	-

(1) See Financial Measures Reconciliations on page 2.

(2) Adjusted to reflect the 20:1 share consolidation completed on June 22, 2011.

(3) Long term financial liabilities consist of long term debt.

Revenue has steadily increased over the last eight quarters due to the Company's continued growth in size through the acquisition of Stoneham Drilling Trust in the second quarter of 2011 and the Company's capital program which has added nine drilling rigs to Western's fleet over the last eight quarters. The exception to the growth in revenue occurred in the second quarters of 2012 and 2011, which were impacted by spring breakup, and the third and fourth quarters of 2012, which were impacted by lower activity levels in the oilfield services industry.

EBITDA has followed a similar trend to revenue, steadily increasing due to the acquisition of Stoneham Drilling Trust and the Company's significant capital program and impacted by the reduced activity associated with spring break up in the second quarters of 2012 and 2011 as well as lower activity in the third and fourth quarters of 2012. This trend reflects strong margins, above industry average utilization rates and economies of scale that have been achieved as a result of Western's consolidation strategy.

Net income has fluctuated throughout the last eight quarters due to the cyclical nature of the oilfield service industry, as well as the gain on the sale of StimSol in the third quarter of 2011.

Total assets of the Company have increased throughout the last eight quarters due to the growth of the Company through the acquisition of Stoneham Drilling Trust in the second quarter of 2011 and the Company's capital spending program which added assets of $88.9 million in 2011 and $127.2 million in 2012.

Goodwill

Goodwill represents the excess, at the date of acquisition, of the purchased price of the business acquired over the fair value of the net tangible and intangible assets acquired. A continuity of Western's goodwill balance as at December 31, 2012 is as follows:

(stated in thousands)	Amount
December 31, 2010	$ 29,117
Stoneham Drilling Trust acquisition	26,410
December 31, 2011 and 2012	$ 55,527

The goodwill balance at December 31, 2010 relates to the Pantera Drilling Trust acquisition completed in 2010. The goodwill acquired as part of the Stoneham acquisition in 2011 is attributable to the purchase price being approximately 113% of the replacement cost of the assets acquired.

Discontinued Operations

On September 13, 2011, the Company sold its Canadian wholly-owned subsidiary StimSol, the remainder of its production services segment, to a third party for gross proceeds equal to approximately $24.0 million. As a result of the net proceeds exceeding the carrying value of StimSol's net assets less cost to sell, the Company recognized a $10.1 million gain on the sale of StimSol. No cash taxes were owed on this transaction.

The net income from discontinued operations for the years ended December 31, 2012 and 2011 is as follows:

(stated in thousands)	Year ended December 31, 2012	Year ended December 31, 2011
Revenue from discontinued operations	$ -	$ 12,930
Operating expenses	-	10,528
Gross profit	-	2,402
Administrative expenses	-	1,300
Finance costs	-	1
Other items	-	38
Income before tax from discontinued operations	-	1,063
Income tax expense	-	310
Income from discontinued operations	-	753
Gain on sale of StimSol (net of tax)	-	10,111
Net income from discontinued operations	$ -	$ 10,864

There were no assets and liabilities from discontinued operations at December 31, 2012 or December 31, 2011.

Contractual Obligations

In the normal course of business, the Company incurs contractual obligations. The expected maturities of the Company's contractual obligations are as follows:

	Payments due by period						
(stated in thousands)	2013	2014	2015	2016	2017	Thereafter	Total
Senior Notes	$ -	$ -	$ -	$ -	$ -	$ 175,000	$ 175,000
Senior Notes interest	13,781	13,781	13,781	13,781	13,781	20,672	89,577
Trade payables	37,239	-	-	-	-	-	37,239
Operating leases	3,696	3,241	2,433	2,413	2,279	16,267	30,329
Revolving facility	-	-	15,000	-	-	-	15,000
Operating facility	5,460	-	-	-	-	-	5,460
Purchase commitments	7,602	-	-	-	-	-	7,602
Finance leases	351	191	28	-	-	-	570
Total	$ 68,129	$ 17,213	$ 31,242	$ 16,194	$ 16,060	$ 211,939	$ 360,777

Outstanding Share Data

	February 27, 2013	December 31, 2012	December 31, 2011
Common shares outstanding	59,655,921	59,582,143	58,533,287
Warrants outstanding	1,464,032	1,527,811	2,525,000
Stock options outstanding	2,685,400	2,522,733	2,101,000

Off Balance Sheet Arrangements

As at December 31, 2012, Western had no off balance sheet arrangements in place.

Transactions with Related Parties

During the year ended December 31, 2012, the Company entered into sales transactions totaling approximately $5.9 million (2011: $5.6 million) with a customer who shares a common Director with the Company. These related party transactions, which have been recorded in the Company's revenue, are in the normal course of operations, have been measured at the agreed exchange amount, which is the amount of consideration established and agreed to by the related parties, and which are similar to those negotiated with third parties. All outstanding balances are to be settled in cash, and none of the balances are secured. At December 31, 2012, approximately $0.4 million (December 31, 2011: $2.9 million) is outstanding in trade and other receivables.

Financial Instruments

Fair Values

All financial instruments are measured at fair value upon initial recognition of the transaction. Measurement in subsequent periods is dependent on whether the instrument is classified as "financial asset or financial liability at fair value through profit or loss", "available-for-sale financial assets", "held-to-maturity investments", "loans and receivables", or "other financial liabilities".

The Company derecognizes a financial asset when the contractual right to the cash flows from the asset expires, or it transfers the right to receive the contractual cash flows on the financial asset in a transaction in which substantially all the risks and rewards of ownership of the financial asset are transferred. The Company derecognizes a financial liability when its contractual obligations are discharged, cancelled or expire.

Financial assets and liabilities are offset and the net amount presented in the balance sheet when the Company has a legal right to offset the amounts and intends either to settle on a net basis or to realize the asset and settle the liability simultaneously.

The Company has the following non-derivative financial assets:

(i) Financial assets at fair value through profit or loss:

Cash and cash equivalents is held for trading within the fair value through profit or loss category. Financial assets at fair value through profit or loss are measured at fair value, and changes therein are recognized in net income.

(ii) Loans and receivables:

Loans and receivables are financial assets with fixed or determinable payments that are not quoted in an active market. Such assets are recognized initially at fair value adjusted for any directly attributable transaction costs. Subsequent to initial recognition, loans and receivables are measured at amortized cost using the effective interest method, less any impairment losses. The Company's trade and other receivables are categorized as loans and receivables.

(iii) Available for sale:

From time to time, the Company may have certain equity investments in publicly traded entities. Investments that have a quoted price in an active market are measured at fair value with changes in fair value recognized in other comprehensive income. When the investment is ultimately sold, any gains or losses are recognized in net income and any unrealized gains or losses previously recognized in other comprehensive income are reversed.

The Company has the following non-derivative financial liabilities:

(i) Other financial liabilities:

Trade and other payables, finance lease obligations, the Senior Notes and credit facilities are classified as "other financial liabilities". Other financial liabilities are recognized initially at fair value net of any directly attributable transaction costs. Other financial liabilities, including the Senior Notes, are subsequently measured at amortized cost using the effective interest method. Transaction costs incurred with respect to the credit facilities are deferred and amortized using the straight-line method over the term of the facility. The asset is recognized in other assets on the balance sheet while the amortization is included in finance costs within net income.

(ii) Equity instruments:

Common shares are classified as equity. Incremental costs directly attributable to the issue of common shares are recognized as a deduction from equity, net of any tax effects.

(iii) Embedded derivatives:

Derivatives embedded in other instruments or host contracts are separated from the host contract and accounted for separately when their economic characteristics and risks are not closely related to the host contract. Embedded derivatives are recorded on the balance sheet at estimated fair value and changes in the fair value are recorded through net income.

Credit Risk

The Company's accounts receivable are with customers in the oil and gas industry and are subject to normal industry credit risk. The Company's practice is to manage credit risk by performing a detailed analysis of the credit worthiness of new customers before the Company's standard payment terms are offered. Additionally, the Company constantly reviews individual customer trade receivables, taking into consideration payment history and the aging of the receivable to monitor collectability.

Interest Rate Risk

The Company is exposed to interest rate risk on debt subject to floating interest rates, such as the Company's credit facilities.

Foreign Exchange Risk

The Company is exposed to foreign exchange fluctuations in relation to its US dollar capital expenditures and US operations. The Company ensures that its net exposure is kept to an acceptable level by buying or selling foreign currencies at spot rates when necessary to address short term imbalances. From time-to-time the Company may use forward foreign currency contracts to hedge against these fluctuations.

Liquidity Risk

Liquidity risk is the exposure of the Company to the risk of not being able to meet its financial obligations as they become due. To manage liquidity risk, the Company forecasts operational results and capital spending on a regular basis. Variances between actual results and forecast are continually monitored to assess the Company's ability to meet its financial obligations.

Recent Pronouncements and Amendments

A number of new standards, amendments to standards and interpretations are not yet effective for the period ended December 31, 2012, and have not been applied in preparing Western's financial statements for the year ended December 31, 2012.

A summary of new standards that have not been adopted which may impact the Company in the future are as follows:

- IFRS 9, Financial Instruments was issued in November 2009. The standard is effective for annual periods beginning on or after January 1, 2013, with earlier application permitted. Requirements for financial liabilities were added to IFRS 9 in October 2010. Most of the requirements for financial liabilities were carried forward unchanged from IAS 39, Financial Instruments: Recognition and Measurement. However, some changes were made to the fair value option for financial liabilities to address the issue of an entity's own credit risk. The Company is assessing the effect of IFRS 9 on its financial results and financial position; however, any changes are not expected to be material.
- IFRS 10, Consolidated Financial Statements, establishes principles for the presentation and preparation of consolidated financial statements when an entity controls one or more other entities. IFRS 10 supersedes IAS 27, Consolidated and Separate Financial Statements, and SIC-12, Consolidation—Special Purpose Entities, and is effective for annual periods beginning on or after January 1, 2013. Earlier application is permitted. The Company is assessing the effect of the changes to IFRS 10 on its financial results and financial position; however, any changes are not expected to be material.
- IFRS 12, Disclosure of Interests in Other Entities, applies to entities that have an interest in a subsidiary, a joint arrangement, an associate or an unconsolidated structured entity. IFRS 12 is effective for annual periods beginning on or after January 1, 2013. Earlier application is permitted. The Company is assessing the effect of the changes to IFRS 12 on its financial statement disclosures but does not anticipate any material changes.
- IFRS 13, Fair Value Measurement, defines fair value, sets out in a single IFRS framework for measuring fair value and requires disclosures about fair value measurements. IFRS 13 applies to IFRSs that require or permit fair value measurements or disclosures about fair value measurements (and measurements, such as fair value less costs to sell, based on fair value or disclosures about those measurements), except in specified circumstances. IFRS 13 is to be applied for annual periods beginning on or after January 1, 2013. Earlier application is permitted. The Company is assessing the effect of the changes to IFRS 13 on its financial results and financial position and anticipates the application of the new standard may affect certain amounts in the financial statements resulting in more extensive disclosures.

Disclosure Controls and Procedures and Internal Controls Over Financial Reporting

The Chief Executive Officer ("CEO") and Vice President, Finance & Chief Financial Officer ("CFO") of Western are responsible for establishing and maintaining disclosure controls and procedures ("DC&P") and internal control over financial reporting ("ICFR") for the Company.

DC&P is designed to provide reasonable assurance that material information relating to the Company is made known to the CEO and CFO by others, particularly in the period in which the annual filings are being prepared, and that information required to be disclosed in documents filed with securities regulatory authorities is recorded, processed, summarized and reported within the time periods specified in securities legislation, and includes controls and procedures designed to ensure that such information is accumulated and communicated to the Company's management, including the CEO and CFO, as appropriate, to allow timely decisions regarding required disclosure. ICFR is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS.

In accordance with the requirements of National Instrument 52-109 "Certification of Disclosure in Issuers' Annual and Interim Filings", an evaluation of the effectiveness of DC&P and ICFR was carried out under the supervision of the CEO and CFO at December 31, 2012. Based on this evaluation, the CEO and CFO have concluded that, subject to the inherent limitations noted below, the Company's DC&P and ICFR are effectively designed and operating as intended.

The Company's management, including the CEO and CFO, does not expect that the Company's DC&P and ICFR will prevent or detect all misstatements or instances of fraud. The inherent limitations in all control systems are such that they can provide only reasonable, not absolute, assurance that all control issues, misstatements or instances of fraud, if any, within the Company have been detected.

There was no change to the Company's ICFR that occurred during the most recent interim period that has materially affected, or is reasonably likely to materially affect, the Company's ICFR.

Critical Accounting Estimates

This Management's Discussion and Analysis of the Company's financial condition and results of operations is based on its consolidated financial statements which were prepared in accordance with IFRS. The presentation of these financial statements in conformity with IFRS requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of provisions at the date of the financial statements and the reported amounts of revenue and expenses during the reporting period. These estimates and judgements are based on historical experience and on various assumptions that are believed to be reasonable under the circumstances. Anticipating future events cannot be done with certainty, therefore these estimates may change as new events occur, more experience is acquired and as the Company's operating environment changes. The Company's key accounting estimates relate to business combinations, impairment, depreciation, current and deferred taxes and the determination of the fair value of stock options.

The accounting estimates believed to be the most difficult, subjective or have complex judgements and which are the most critical to the reporting of results of operations and financial positions are as follows:

Business Combinations

The Company assesses the fair values of the net assets acquired based on management's best estimate of market value, which takes into consideration the condition of the assets acquired, current industry conditions and the discounted future cash flows expected to be received from the assets as well as the amount it is expected to cost to settle the outstanding liabilities.

Impairment

The Company assesses impairment at each reporting date by evaluating conditions specific to the organization that may lead to impairment of assets. Where an impairment indicator exists, or annually in the case of goodwill, the recoverable amount of the asset or cash generating unit is determined. Value-in-use and fair value less cost to sell calculations performed in assessing the recoverable amounts incorporate a number of key estimates. As at December 31, 2012, the Company completed its assessments and did not identify indicators of impairment for the long-lived assets of the Company.

Depreciation

The Company's property and equipment is depreciated based upon estimates of useful lives and salvage values. These estimates are based on industry practice and the Company's own experience and may change as more experience is gained, market conditions shift or new technological advancements are made.

The componentization of the Company's property and equipment, specifically drilling rig equipment and well servicing rig equipment, is based on management's judgment as to which components constitute a significant cost in relation to the entire item. The componentization process also requires management's judgement in assessing whether individual components have similar consumption patterns and useful lives.

Income taxes

Preparation of the consolidated financial statements involves determining an estimate of, or provision for, income taxes in each of the jurisdictions in which the Company operates. The process also involves making an estimate of taxes currently payable and taxes expected to be payable or recoverable in future periods, referred to as deferred taxes. Deferred taxes result from the effects of temporary differences due to items that are treated differently for tax and accounting purposes. The tax effects of these differences are reflected in the consolidated balance sheet as deferred tax assets and liabilities. An assessment must also be made to determine the likelihood that the Company's future taxable income will be sufficient to permit the recovery of deferred tax assets. To the extent that such recovery is not probable, recognized deferred tax assets must be reduced to the recoverable amount. Judgement is required in determining the provision for income taxes and recognition of deferred tax assets and liabilities. Management must also exercise judgement in its assessment of continually changing tax interpretations, regulations and legislation, to ensure deferred tax assets and liabilities are complete and fairly presented. The effects of differing assessments and applications could be material.

Share-based payments

Stock based compensation expense associated with stock options granted is based on various assumptions, using the Black-Scholes option-pricing model to calculate an estimate of fair value. The inputs into the model include interest rates, expected life, expected volatility, expected forfeitures and share prices and these inputs affect the estimated fair value calculated. Determining the estimated expected life, volatility and forfeitures requires judgement.

Business Risks

For a comprehensive listing of the Company's business risks please see the most recent Annual Information Form as filed on SEDAR at www.sedar.com. The Company's primary business risks are as follows:

- The Company's business relies on the oil and gas exploration and production industry which is subject to a number of risks including general economic conditions, fluctuations in demand and supply of production components, fluctuations in commodity prices, competition and increases in operating costs. In addition, changes may occur in government regulations, including regulations relating to foreign acquisitions, prices, taxes, royalties, land tenure, allowable production, importing and exporting of oil and natural gas and environmental protection for the oil and gas industry as a whole. Risks affecting the oil and gas exploration and production industry may also affect the Company's business. The exact effect of these risks cannot be accurately predicted.
- In addition to global economic events and uncertainty, the capacity within North America to ship commodities to market introduces uncertainties in levels of activity and pricing for oil and natural gas production.
- The Company is vulnerable to market prices. Fixed costs, including costs associated with operations, leases, labour costs and depreciation account for a significant portion of the Company's expenses. As a result, reduced productivity resulting from reduced demand, equipment failure, or other factors could significantly affect its revenues and financial results.
- Competition among related service companies is significant. Some competitors are larger and have greater revenues than the Company and overall greater financial resources. The Company's ability to generate revenues depends on its ability to attract and win contracts and to perform services.
- Currently, the Company is focused on providing services in the western Canadian sedimentary basin as well as certain geographic areas in the United States, which may expose the Company to more extreme market fluctuations relating to items such as weather and general economic conditions which may be more extreme than the broader industry conditions.
- The success of the Company is dependent upon the efforts and abilities of its management team. The loss of any member of the management team could have a material adverse effect upon the business and prospects of the Company.
- The Company's business is subject to the operating risks inherent to the oilfield service industry. On occasion, substantial liabilities to third parties may be incurred. The Company will have the benefit of insurance maintained by it and industry standard contracts, however, it may become liable for damages against which it cannot adequately insure or against which it may elect not to insure because of high costs or other reasons.

- The oilfield service industry has experienced a high degree of invention and innovation. It is possible that new technology will be developed which will compete with the Company's products and services.
- A portion of the operations of the Company are in the United States which subject the Company to currency fluctuations and different tax and regulatory laws.

Forward-Looking Statements and Information

This MD&A contains certain statements or disclosures relating to Western that are based on the expectations of Western as well as assumptions made by and information currently available to Western which may constitute forward-looking information under applicable securities laws. All such statements and disclosures, other than those of historical fact, which address activities, events, outcomes, results or developments that Western anticipates or expects may, or will occur in the future (in whole or part) should be considered forward-looking information. In some cases, forward-looking information can be identified by terms such as "forecast", "future," "may", "will", "expect", "anticipate,", "believe", "potential", "enable", "plan", "continue", "contemplate", "pro-forma", or other comparable terminology.

In particular, forward-looking information in this MD&A include, under the heading "Outlook" the statements: "Western expects capital spending in 2013 to total $80 million including $20 million of carry forward capital from 2012 and $60 million relating to Western's 2013 capital budget, Western's 2013 capital budget includes approximately $28 million in expansion capital, $20 million in maintenance capital and $12 million in critical spare equipment" and "Western will finance its 2013 capital expenditure budget substantially from operating cash flows while maintaining our conservative balance sheet going into 2013 and positioning the Company for future opportunities." and, "The lower commodity price environment for crude oil and natural gas, coupled with the uncertain economic environment, due in part to the European debt crisis, is expected to result in similar levels of drilling activity in 2013 as compared to 2012. As such, the Company expects similar utilization in 2013 as compared to the prior year." and, "Western is of the view, that its modern ELR rig fleet, strong customer base and solid reputation provides a competitive advantage which will enable the Company to continue its growth strategy and higher than industry utilization through a period of lower commodity prices and drilling activity."

These forward-looking statements and information are based on certain key expectations and assumptions made by Western, including the assumption that its cash flow during 2013 will be sufficient to cover its budgeted expansion and maintenance capital expenditures, that its rig utilization rates will not materially decrease from 2012 levels and that its modern rig fleet will allow it to continue its growth strategy and maintain a higher utilization than industry averages.

In addition, the MD&A contains the following statements which are set forth in the paragraph immediately preceding the section headed "Outlook". "Subsequent to year end on February 21, 2013, the Company entered into an Arrangement Agreement whereby, subject to certain conditions, the Company will acquire all of the issued and outstanding shares of IROC Energy Services Corp. ("IROC") in exchange for a combination of cash and common shares of Western." and, "The transaction is expected to be completed by way of a Plan of Arrangement under the Business Corporations Act (Alberta) and is subject to normal stock exchange, court and regulatory approvals and the approval by at least 66 2/3 percent of the outstanding shares of IROC and any applicable minority shareholder approval requirements voted on at a special meeting of the shareholders of IROC, which is expected to be held prior to the end of April 2013."

Readers are cautioned that there are a number of conditions that must be met, including the approval of the shareholders of IROC before the above-described transaction can be completed.

The forward-looking information assumes the completion of the above-described transaction and there is no assurance that all of the conditions to the above-described transaction will be met and therefore there is a risk that the above-described transaction will not be completed and if completed the expected benefits may not materialize.

As such, many factors could cause the performance or achievement of Western or IROC to be materially different from any future results, performance or achievements that may be expressed or implied by such forward-looking statements. Because of the risks, uncertainties and assumptions contained herein, readers should not place undue reliance on these forward-looking statements.

Although Western believes that the expectations and assumptions on which such forward-looking statements and information are based are reasonable, undue reliance should not be placed on the forward-looking statements and information as Western cannot give any assurance that they will prove to be correct. Since forward-looking statements and information address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results could differ materially from those currently anticipated due to a number of factors and risks. These include, but are not limited to, general economic, market and business conditions. Readers are cautioned that the foregoing list of risks and uncertainties is not exhaustive. Additional information on these and other risk factors that could affect Western's operations and financial results are included in Western's annual information form and the other disclosure documents filed by Western with securities regulatory authorities which may be accessed through the SEDAR website at www.sedar.com. The forward-looking statements and information contained in this MD&A are made as of the date hereof and Western does not undertake any obligation to update publicly or revise and forward-looking statements and information, whether as a result of new information, future events or otherwise, unless so required by applicable securities laws.

Additional data

Additional information relating to the Company is filed on SEDAR at www.sedar.com.