Third Quarter Interim Report

Dated: October 30, 2014

The following management discussion and analysis ("MD&A") 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, 2013 and 2012, the Company's MD&A for the year ended December 31, 2013, as well as the condensed consolidated financial statements and notes as at and for the three and nine months ended September 30, 2014 and 2013. This MD&A is dated October 30, 2014. All amounts are denominated in Canadian dollars (CDN$) unless otherwise identified.

Financial Highlights	**Three months ended Sept 30**			**Nine months ended Sept 30**		
(stated in thousands, except share and per share amounts)	**2014**	**2013**	**Change**	**2014**	**2013**	**Change**
Revenue	125,225	101,389	24%	368,622	250,230	47%
Operating Revenue(1)	117,960	95,597	23%	344,939	233,293	48%
Gross Margin(1)	50,570	37,547	35%	149,405	94,579	58%
Gross Margin as a percentage of Operating Revenue	43%	39%	10%	43%	41%	5%
Adjusted EBITDA(1)	42,782	30,297	41%	126,358	73,880	71%
Adjusted EBITDA as a percentage of Operating Revenue	36%	32%	13%	37%	32%	16%
Cash flow from operating activities	22,975	6,667	245%	133,521	77,492	72%
Capital expenditures	31,144	31,002	-	77,533	67,705	15%
Net income	14,718	7,927	86%	44,614	19,449	129%
-basic net income per share	0.20	0.11	82%	0.60	0.29	107%
-diluted net income per share	0.19	0.11	73%	0.59	0.28	111%
Weighted average number of shares						
-basic	74,849,483	73,351,805	2%	74,232,921	67,569,459	10%
-diluted	75,742,044	73,793,367	3%	75,641,911	68,587,001	10%
Outstanding common shares as at period end	74,883,428	73,366,253	2%	74,883,428	73,366,253	2%
Dividends declared	5,615	5,502	2%	16,762	15,478	8%
Dividends declared per common share	0.075	0.075	-	0.225	0.225	-

Operating Highlights						
Contract Drilling						
Canadian Operations						
Average contract drilling rig fleet	49	45	9%	49	45	9%
Operating Revenue per revenue day(2)	24,887	23,055	8%	25,852	24,294	6%
Operating Revenue per operating day(3)	27,350	25,385	8%	28,343	26,918	5%
Drilling rig utilization rate per revenue day(4)	66%	62%	6%	64%	57%	12%
Drilling rig utilization rate per operating day(5)	60%	56%	7%	58%	52%	12%
CAODC industry average utilization rate(5)	46%	40%	15%	44%	39%	13%
United States Operations						
Average contract drilling rig fleet	5	5	-	5	5	-
Operating Revenue per revenue day (US$)(2)	26,239	21,777	20%	25,385	22,080	15%
Operating Revenue per operating day (US$)(3)	29,348	24,410	20%	28,905	27,128	7%
Drilling rig utilization rate per revenue day(4)	100%	98%	2%	94%	74%	27%
Drilling rig utilization rate per operating day(5)	89%	88%	1%	82%	60%	37%
Production Services						
Average well servicing rig fleet	65	65	-	65	46	41%
Operating Revenue per service hour(3)	804	743	8%	810	740	9%
Service rig utilization rate(6)	55%	51%	8%	53%	40%	33%

(1) See "Financial Measures Reconciliations" on page 2 of this MD&A.
(2) Operating Revenue per revenue day is calculated using Operating Revenue divided by operating days and mobilization days.
(3) Operating Revenue per operating day and per service hour are calculated using Operating Revenue divided by operating days and service hours, respectively.
(4) Drilling rig utilization rate per revenue day is calculated based on operating and mobilization days divided by total available days.
(5) Drilling rig utilization rate per operating day is calculated on operating days only (i.e. spud to rig release basis) divided by total available days.
(6) Service rig utilization rate is calculated based on actual well servicing hours divided by available hours, being 10 hours per day per well servicing rig, 365 days per year.

Financial Position at (stated in thousands)	September 30, 2014	September 30, 2013	December 31, 2013
Working capital	71,912	45,862	50,616
Property and equipment	816,825	770,770	783,225
Total assets	1,040,973	947,836	986,792
Long term debt	263,624	263,050	262,877

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 condensed 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.

Operating Revenue

Management believes that in addition to revenue, Operating Revenue is a useful supplemental measure as it provides an indication of the revenue generated by Western's principal operating activities, excluding flow through third party charges.

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.

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

	Three months ended September 30		Nine months ended September 30	
(stated in thousands)	**2014**	**2013**	**2014**	**2013**
Operating Revenue				
Drilling	86,735	69,499	255,228	193,715
Production services	31,463	26,127	90,957	39,607
Less: inter-company eliminations	(238)	(29)	(1,246)	(29)
	117,960	**95,597**	**344,939**	**233,293**
Third party charges	7,265	5,792	23,683	16,937
Revenue	**125,225**	**101,389**	**368,622**	**250,230**
Less: operating expenses	(90,891)	(77,375)	(265,079)	(188,079)
Add:				
Depreciation - operating	16,042	13,262	45,251	31,785
Stock based compensation - operating	194	271	611	643
Gross Margin	**50,570**	**37,547**	**149,405**	**94,579**

Adjusted EBITDA

Management believes that in addition to net income, earnings before interest and finance costs, taxes, depreciation and amortization, other non-cash items and one-time gains and losses ("Adjusted EBITDA") is a useful supplemental measure as it provides an indication of the results generated by the Company's principal operating activities 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 activities similar to Adjusted 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 condensed consolidated statements of operations and comprehensive income, to EBITDA, Adjusted EBITDA and Operating Earnings:

	Three months ended September 30		Nine months ended September 30	
(stated in thousands)	**2014**	**2013**	**2014**	**2013**
Net income	14,718	7,927	44,614	19,449
Add:				
Finance costs	5,155	4,149	15,885	11,903
Income taxes	5,525	3,647	16,527	7,698
Depreciation - operating	16,042	13,262	45,251	31,785
Depreciation - administrative	448	347	1,332	1,086
EBITDA	41,888	29,332	123,609	71,921
Add:				
Stock based compensation - operating	194	271	611	643
Stock based compensation - administrative	918	519	1,754	1,183
Other items	(218)	175	384	133
Adjusted EBITDA	42,782	30,297	126,358	73,880
Subtract:				
Depreciation - operating	(16,042)	(13,262)	(45,251)	(31,785)
Depreciation - administrative	(448)	(347)	(1,332)	(1,086)
Operating Earnings	26,292	16,688	79,775	41,009

Overall Performance and Results of Operations

Western is an oilfield service company focused on three core business lines: contract drilling, well servicing and oilfield rental equipment services. Western provides contract drilling services through its division, Horizon Drilling (“Horizon”) in Canada, and its wholly owned subsidiary, Stoneham Drilling Corporation (“Stoneham”), in the United States. Subsequent to the acquisition of IROC Energy Services Corp. (“IROC”) on April 22, 2013, Western provides well servicing operations in Canada through Western Energy Services Partnership’s (the “Partnership”) division, Eagle Well Servicing (“Eagle”). Previously, well servicing operations were conducted through Western’s division, Matrix Well Servicing (“Matrix”). Western also provides oilfield rental equipment services in Canada through the Partnership’s division, Aero Rental Services (“Aero”). Financial and operating results for Eagle and Aero from the date of the acquisition, as well as Matrix, are included in Western’s production services segment.

Western currently has a drilling rig fleet of 55 rigs, with an average age of approximately seven years. Western is the sixth largest drilling contractor in Canada with a fleet of 50 rigs operating through Horizon. Additionally, Western has five Efficient Long Reach (“ELR”) triple drilling rigs deployed in the United States operating through Stoneham. Western is also the seventh largest well servicing company in Canada with a fleet of 65 rigs operating through Eagle. Western’s well servicing rig fleet is one of the newest in the Western Canadian Sedimentary Basin (“WCSB”), with an average age of approximately five years. Western’s oilfield equipment rental division, which operates through Aero, provides oilfield rental equipment for frac services, well completions and production work, coil tubing services and drilling.

Crude oil prices weakened in the third quarter of 2014. The price for light oil, such as West Texas Intermediate (“WTI”), decreased by 8% for the three months ended September 30, 2014, as compared to the same period in the prior year and by 6% as compared to the second quarter of 2014. The price for heavy oil, such as Western Canadian Select (“WCS”), decreased by 1% for the third quarter of 2014 as compared to the same period of the prior year and by 6% as compared to the second quarter of 2014. For the nine months ended September 30, 2014, WTI increased marginally by 1% and WCS increased by 17% as compared to the same period in 2013. Natural gas prices have improved significantly in the three and nine months ended September 30, 2014, with the AECO 30-day spot rate increasing on average by 66% and 60% respectively, compared to the three and nine months ended September 30, 2013, as heating demand increased in the first quarter due to a cold winter, resulting in decreased storage levels across North America. However, subsequent to September 30, 2014, the commodity price environment for crude oil and natural gas has deteriorated as compared to the third quarter 2014 average. Despite the reduction in commodity prices, the demand for oil, along with an emphasis on liquids rich natural gas, resulted in increased drilling of horizontal wells in both conventional and unconventional resource plays. Horizontal wells in the WCSB, as a percentage of all wells drilled, increased in the nine month period ended September 30, 2014 to 76% compared to 70% in the same period of 2013. This has resulted in continued demand in the WCSB for Western’s ELR drilling rigs, as industry utilization rates for the third quarter of 2014 averaged 46%, which is an increase over the five year average of 45% and an improvement over the prior year when industry utilization averaged 40%. Similarly, industry utilization rates for the first nine months of 2014 averaged 44%, which is consistent with the five year average of 43% and an improvement over the prior year when industry utilization averaged 39%. In Canada, Western's average operating days per well drilled increased by 1% to 16.4 operating days per well in the first nine months of 2014 as compared to 16.2 operating days per well in the same period of the prior year. In the United States, Western averaged 24.0 operating days per well drilled in the first nine months of 2014 as compared to 26.8 operating days per well in the same period of the prior year, a 10% decrease. The average time it takes to drill a well has a direct relationship to the Company's operating effectiveness, as well as to the complexity and depth of the well.

Key operational results for the three months ended September 30, 2014 include:

- Third quarter Operating Revenues increased by $22.4 million (or 23%) to $118.0 million in 2014 as compared to $95.6 million in 2013. The increase is due to higher utilization and improved day rates in the contract drilling segment in both Canada and the United States, coupled with a larger average drilling rig fleet in Canada, resulting in a $17.2 million increase in Operating Revenues during the period. Additionally, improved utilization and pricing resulted in a $5.6 million increase in Operating Revenues for the production services segment during the period.
- Third quarter Adjusted EBITDA totalled $42.8 million in 2014 (36% of Operating Revenue), a $12.5 million (or 41%) increase, as compared to $30.3 million in the third quarter of 2013 (32% of Operating Revenue). The year over year increase in Adjusted EBITDA is due to the increased activity in both the contract drilling and production services segments resulting in a $9.4 million and $3.2 million increase in Adjusted EBITDA respectively. For the three months ended September 30, 2014, Operating Revenue per revenue day in the contract drilling segment increased by 8% in Canada and 20% in the United States, while on a combined basis in contract drilling, operating expenses per revenue day increased marginally by 4% mainly due to higher labour costs associated with increased pad drilling activity and increased repair and maintenance costs.
- Administrative expenses, excluding depreciation and stock based compensation, in the third quarter of 2014 increased marginally by $0.5 million (or 7%) to $7.8 million (7% of Operating Revenue) as compared to $7.3 million in the third quarter of 2013 (8% of Operating Revenue). As a percentage of Operating Revenue, administrative expenses have decreased as Western has been able to effectively control costs while increasing the size and scale of the Company's operations.
- Net income increased by $6.8 million to $14.7 million in the third quarter of 2014 ($0.20 per basic common share) as compared to net income of $7.9 million in the same period in 2013 ($0.11 per basic common share), an improvement of $0.09 per basic common share. The increase is mainly attributed to the increase in Adjusted EBITDA of $12.5 million, which was partially offset by an increase in depreciation expense of $2.9 million due to increased activity, an increase of $1.9 million in income tax expense due to the increase in taxable income, and an increase of $1.1 million in finance costs due to the additional $90.0 million in senior notes issued in September 2013.
- Third quarter capital expenditures of $31.1 million included $24.6 million of expansion capital, $3.5 million of maintenance capital and $3.0 million for critical spares. The majority of the third quarter 2014 capital expenditures relate to the contract drilling segment, which incurred $26.3 million of capital expenditures. These expenditures mainly relate to Western's drilling rig build program, which totalled $18.3 million in the period relating to the construction of five drilling rigs. The remaining capital spending in the contract drilling segment related to ancillary drilling equipment. Additionally, $4.7 million was incurred in the production services segment mainly relating to the construction of one slant well servicing rig, as well as well servicing rig upgrades and the purchase of additional oilfield rental equipment.

Key operational results for the nine months ended September 30, 2014 include:

- Operating Revenue for the nine months ended September 30, 2014 increased by $111.6 million (or 48%) to $344.9 million as compared to $233.3 million in the same period in 2013. The increase is due to higher utilization and improved day rates, coupled with a larger average drilling rig fleet in the contract drilling segment, as well as the increased contribution from the production services segment following the acquisition of IROC in April of 2013.
- For the first nine months of 2014, Adjusted EBITDA increased by $52.5 million to $126.4 million (37% of Operating Revenue), as compared to $73.9 million (32% of Operating Revenue) in the same period of the prior year. The increase in Adjusted EBITDA reflects increased activity and improved pricing, coupled with effective cost control in all divisions, as well as the larger drilling rig fleet and the increased size and scale of Western's production services segment.
- Year to date administrative expenses, excluding depreciation and stock based compensation, increased by $2.3 million to $23.0 million (7% of Operating Revenue) in 2014, as compared to $20.7 million (9% of Operating Revenue) in the same period of the prior year. As a percentage of Operating Revenue, administrative expenses have decreased as Western has been able to effectively control costs while increasing the size and scale of the Company's operations.

- Net income increased by $25.2 million to $44.6 million in the nine months ended September 30, 2014 ($0.60 per basic common share) as compared to $19.4 million ($0.29 per basic common share) in the same period in 2013. The increase is mainly attributed to the $52.5 million increase in Adjusted EBITDA, offset by an increase of $13.7 million in depreciation expense due to increased activity, an increase of $8.8 million in income tax expense due to the increase in taxable income, an increase of $4.0 million in finance costs due to the additional $90.0 million in senior notes issued in September of 2013, and increases in stock based compensation and other items totalling $0.8 million.
- Year to date capital expenditures of $77.5 million include $61.6 million of expansion capital, $9.3 million of maintenance capital and $6.6 million for critical spares. The majority of the capital expenditures for the nine months ended September 30, 2014 relate to the contract drilling segment, which incurred $67.3 million in capital expenditures. These expenditures mainly relate to Western's drilling rig build program, which totalled $46.1 million year to date, as two drilling rigs were commissioned in the first quarter of 2014, with an additional five drilling rigs under construction, one of which has been commissioned subsequent to September 30, 2014. Additionally, two 1,500 hp AC pad conversions were completed in the United States in the second quarter of 2014. The remaining capital spending in the contract drilling segment related to ancillary drilling equipment. Additionally, $10.1 million was incurred in the production services segment mainly relating to the construction of one slant well servicing rig, as well as well servicing rig upgrades and the purchase of additional oilfield rental equipment.

Subsequent Event

On October 30, 2014, the Board of Directors of Western declared a quarterly dividend of $0.075 per share, payable on January 15, 2015 to shareholders of record at the close of business on December 31, 2014. On a prospective basis, the declaration of dividends will be determined on a quarter-by-quarter basis by the Board of Directors.

Outlook

Western's drilling rig fleet is specifically suited for drilling horizontal wells of increased complexity. In total, 95% of Western's fleet are ELR drilling rigs with depth ratings greater than 3,000 meters and all of Western's rigs are capable of drilling resource based horizontal wells. Currently, 19 of Western's 55 drilling rigs (or 35%) are operating under long term take-or-pay contracts, with 13 of these contracts expiring between 2015 and 2017, providing a base level of future revenue. These contracts typically generate 250 operating days per year in Canada, as 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's approved capital spending for 2014 remains unchanged totalling approximately $170 million comprised of $130 million in expansion capital and $40 million in maintenance capital, which includes $12 million for critical spare equipment. The majority of Western's expansion capital budget relates to the drilling rig build program, which in addition to the three telescopic double drilling rigs already commissioned in Canada during 2014, one of which was commissioned subsequent to September 30, 2014, includes two additional 5,000m telescopic ELR double drilling rigs and two 6,000m ELR AC triple pad drilling rigs. Expansion capital also includes two additional 1,500 hp AC pad conversions in the United States, which were both completed in the second quarter of 2014, the construction of a slant well servicing rig for the production services segment as well as additional oilfield rental equipment and ancillary drilling and well servicing equipment. Western believes the 2014 capital budget provides a prudent use of cash resources and ensures that it has the flexibility to execute on strategic opportunities as they arise, or alternatively adjust downward if necessary should there be a prolonged downturn in oilfield service activity. Western expects approximately $45 million of its capital spending to carry forward into 2015. With this carry forward, the Company will have flexibility over the timing and deployment of some, or all, of this capital. This budget demonstrates the Company's commitment to maintaining and increasing Western's premier drilling and well servicing rig fleet and expanding Western's strategic presence in the oilfield rental equipment market.

While commodity prices for much of 2014 have been strong, the recent pressure on crude oil and natural gas prices may negatively impact our customer's cash flows and may affect their capital spending on oilfield services into 2015. However, the impact of lower commodity prices has been partially offset by the weakening of the Canadian dollar. Western believes oilfield service activity for the fourth quarter of 2014 and the first quarter of 2015 will remain steady, with less visibility beyond spring breakup in 2015. Activity will be impacted by the development of resource plays in Alberta and northeast British Columbia including those related to liquefied natural gas projects, increased crude oil transportation capacity through rail and pipeline development and foreign investment into Canada. Currently, the largest challenges facing the oilfield service industry are producer spending constraints as a result of lower commodity prices, pricing differentials on Canadian crude oil, the challenge to attract and retain skilled labour and the potential negative impact on gas pricing caused by increased gas production from shale plays across North America. The Company believes Western's modern drilling and well servicing rig fleet, strong utilization, and corporate culture will provide a distinct advantage in retaining and attracting qualified individuals. Western's view is that its modern fleet, strong customer base and solid reputation provide a competitive advantage which will enable the Company to continue its growth strategy and higher than industry average utilization.

Segmented Information

Western operates in the contract drilling segment in both Canada and the United States as well as the production services segment in Canada. Contract drilling includes drilling rigs along with related equipment. Production services includes well servicing rigs and related equipment as well as oilfield rental equipment.

Contract Drilling

	Three months ended Sept 30			Nine months ended Sept 30		
(stated in thousands)	**2014**	**2013**	**Change**	**2014**	**2013**	**Change**
Revenue						
Operating Revenue(1)	86,735	69,499	25%	255,228	193,715	32%
Third party charges	5,514	4,847	14%	18,604	15,580	19%
Total revenue	92,249	74,346	24%	273,832	209,295	31%
Expenses						
Operating						
Cash operating expenses	53,984	46,217	17%	158,034	127,213	24%
Depreciation	12,178	9,883	23%	33,967	26,245	29%
Stock based compensation	129	193	(33%)	384	514	(25%)
Total operating expenses	66,291	56,293	18%	192,385	153,972	25%
Administrative						
Cash administrative expenses	4,348	3,621	20%	13,418	12,486	7%
Depreciation	58	74	(22%)	180	263	(32%)
Stock based compensation	150	126	19%	277	170	63%
Total administrative expenses	4,556	3,821	19%	13,875	12,919	7%
Gross Margin(1)	38,265	28,129	36%	115,798	82,082	41%
Gross Margin as a percentage of Operating Revenue	44%	40%	10%	45%	42%	7%
Adjusted EBITDA(1)	33,917	24,508	38%	102,380	69,596	47%
Adjusted EBITDA as a percentage of Operating Revenue	39%	35%	11%	40%	36%	11%
Operating Earnings(1)	21,681	14,551	49%	68,233	43,088	58%
Capital expenditures	26,251	28,096	(7%)	67,281	62,073	8%
Canadian Operations						
Contract drilling rig fleet:						
Average	49	45	9%	49	45	9%
End of period	49	46	7%	49	46	7%
Operating Revenue per revenue day(2)	24,887	23,055	8%	25,852	24,294	6%
Operating Revenue per operating day(3)	27,350	25,385	8%	28,343	26,918	5%
Drilling rig operating days(4)	2,692	2,335	15%	7,754	6,345	22%
Number of meters drilled	530,183	450,729	18%	1,538,653	1,337,149	15%
Number of wells drilled	158	133	19%	473	393	20%
Average operating days per well	17.0	17.6	(3%)	16.4	16.2	1%
Drilling rig utilization rate per revenue day(5)	66%	62%	6%	64%	57%	12%
Drilling rig utilization rate per operating day(6)	60%	56%	7%	58%	52%	12%
CAODC industry average utilization rate(6)	46%	40%	15%	44%	39%	13%
United States Operations						
Contract drilling rig fleet:						
Average	5	5	-	5	5	-
End of period	5	5	-	5	5	-
Operating Revenue per revenue day (US$)(2)	26,239	21,777	20%	25,385	22,080	15%
Operating Revenue per operating day (US$)(3)	29,348	24,410	20%	28,905	27,128	7%
Drilling rig operating days(4)	410	403	2%	1,121	825	36%
Number of meters drilled	99,524	84,682	18%	257,815	174,180	48%
Number of wells drilled	18	14	29%	47	31	51%
Average operating days per well	22.8	28.8	(21%)	24.0	26.8	(10%)
Drilling rig utilization rate per revenue day(5)	100%	98%	2%	94%	74%	27%
Drilling rig utilization rate per operating day(6)	89%	88%	1%	82%	60%	37%

(1) See "Financial Measures Reconciliations" on page 2 of this MD&A.
(2) Operating Revenue per revenue day is calculated using Operating Revenue divided by operating days and mobilization days.
(3) Operating Revenue per operating day is calculated using Operating Revenue divided by operating days.
(4) Drilling rig operating days are calculated on a spud to rig release basis.
(5) Utilization rate per revenue day is calculated based on operating and mobilization days divided by total available days.
(6) Utilization rate per operating day is calculated on operating days only (i.e. spud to rig release basis) divided by total available days.

During the third quarter of 2014, Operating Revenues in the contract drilling segment totalled $86.7 million, a $17.2 million (or 25%) increase as compared to the third quarter of 2013, due to an increased average drilling rig fleet in Canada, as well as improved utilization and higher day rates in both Canada and the United States. For the nine months ended September 30, 2014, Operating Revenues in the contract drilling segment totalled $255.2 million, a $61.5 million (or 32%) increase, as compared to the first nine months of 2013. An increased average drilling rig fleet in Canada of 49 rigs for the nine month period ended September 30, 2014, compared to 45 in the same period of the prior year, and increased demand for the Company's contract drilling services in both Canada and the United States, coupled with improved pricing, resulted in increased Operating Revenue in the nine month period ended September 30, 2014, as compared to the same period of 2013.

During the third quarter of 2014, the Company's utilization per operating day in Canada increased to 60%, as compared to 56% in the third quarter of 2013, which coupled with the 9% increase in the Company's average drilling rig fleet, resulted in operating days increasing by 15% to 2,692 in the third quarter of 2014 as compared to 2,335 in the third quarter of 2013. During the nine months ended September 30, 2014, utilization per operating day in Canada increased to 58% from 52% in the first nine months of 2013. The larger fleet and improved utilization resulted in an increase of approximately 22% in the Company's operating days to 7,754 days in the first nine months of 2014, compared to 6,345 days in the same period of 2013. The Company's utilization per operating day in Canada of 60% for the three months ended September 30, 2014 reflects an approximate 1,400 bps premium to the Canadian Association of Oilwell Drilling Contractors ("CAODC") industry average of 46%, as compared to the 1,600 bps premium realized in the same period of the prior year. The Company's utilization per operating day in Canada of 58% for the nine months ended September 30, 2014 reflects an approximate 1,400 bps premium to the CAODC industry average of 44%, an increase from the 1,300 bps premium realized in the same period of the prior year. The Company's utilization premium, as compared to the CAODC industry average, is attributed to the Company's customer base which includes a high proportion of large independent and major exploration and production companies that are more likely to drill through cycles and have a long term focus, coupled with Western's continued investment in its ELR fleet, which enhances the marketability of its rigs.

For the third quarter of 2014, Operating Revenue per revenue day in Canada increased approximately 8% to $24,887 in the third quarter of 2014 as compared to $23,005 in the third quarter of 2013. This increase is attributable to higher day rates on the drilling rigs Western has commissioned in the past 12 months, as well as improved day rates on both long term contracts and rigs operating on short term contracts at current market rates. Third party charges per revenue day in Canada for the third quarter of 2014 remained constant at approximately $1,800 as compared to the third quarter of 2013.

For the nine months ended September 30, 2014, Operating Revenue per revenue day in Canada totalled $25,852 compared to $24,294 in the same period of the prior year, a 6% increase attributable to the same market increases described above. Third party charges per revenue day in the first nine months of 2014 remained constant at approximately $2,100 compared to the same period in the prior year.

In the United States, utilization per operating day for the three months ended September 30, 2014 was 89%, compared to 88% in the third quarter of 2013. During both of the third quarters of 2014 and 2013, the Company's drilling rig fleet was fully utilized on a revenue day basis. For the nine months ended September 30, 2014, operating days increased by 296 days (or 36%). Similarly, utilization per operating day for the nine months ended September 30, 2014 increased to 82% compared to 60% in the same period in the prior year, mainly due to fewer down days. With the exception of downtime on two rigs for the completion of 1,500 hp AC pad conversions in the first half of 2014, the fleet in the United States was fully utilized in the nine month period ended September 30, 2014 resulting in the increase in utilization.

In the United States, Operating Revenues per revenue day for the three and nine months ended September 30, 2014 increased by 20% and 15% respectively, to US$26,239 and US$25,385, as day rates on Western's upgraded rig fleet have improved and as mobilization days as a percentage of total revenue days have decreased as the Company transitions to walking pad rigs.

During the third quarter of 2014, Adjusted EBITDA in the contract drilling segment increased by $9.4 million (or 38%) to $33.9 million (39% of the segment's Operating Revenue), as compared to $24.5 million (35% of the segment's Operating Revenue) in the third quarter of 2013. The increase in Adjusted EBITDA and Adjusted EBITDA as a percentage of Operating Revenue is attributed to the increase in operating days and improved day rates in Canada and the United States. Partially offsetting the increase in Operating Revenue, is a 4% increase in operating expenses per revenue day, mainly due to the Company's increased pad drilling which is more intense and continuous in nature and requires larger crew configurations, as well as increased repair and maintenance costs incurred during the period. The additional crew costs associated with pad drilling are recovered through Operating Revenue. Additionally, gross cash administrative expenses per revenue day have increased in the third quarter of 2014 by 6% as compared to the same period in the prior year, due to increased employee related costs. For the nine months ended September 30, 2014, Adjusted EBITDA in the contract drilling segment increased by $32.8 million (or 47%) to $102.4 million (40% of the segment's Operating Revenue), as compared to $69.6 million (36% of the segment's Operating Revenue) in the same period of the prior year, due to the increase in operating days in both Canada and the United States in the nine month period ended September 30, 2014, relative to the same period in the prior year, and improved day rates, coupled with effective cost control as operating costs per revenue day have increased by 3% for the same reasons as previously noted in this MD&A.

For the three and nine months ended September 30, 2014, cash administrative expenses, excluding depreciation and stock based compensation, increased to $4.3 million and $13.4 million respectively, compared to $3.6 million and $12.5 million respectively, in the same three and nine month periods in the prior year, mainly due to higher employee related expenses.

Depreciation expense in the contract drilling segment for the three months ended September 30, 2014 increased by $2.3 million to $12.2 million, while for the nine months ended September 30, 2014 depreciation expense increased by $7.6 million to $34.1 million. The increase for both the three and nine months ended September 30, 2014 is due to increased operating days and an increase in ancillary equipment which is depreciated on a straight-line basis.

Total capital expenditures of $26.3 million in the contract drilling segment for the third quarter of 2014 includes $21.2 million related to expansion capital, $2.4 million related to maintenance capital and $2.7 million related to critical spares. Of the expansion capital incurred during the third quarter of 2014, $18.3 million relates to the Company's rig build program incurred on the construction of five drilling rigs with the remaining capital spending relating to ancillary drilling equipment. Total capital expenditures of $67.3 million in the contract drilling segment for the nine months ended September 30, 3014 includes $54.9 million related to expansion capital, $6.1 million related to maintenance capital and $6.3 million related to critical spares. Of the expansion capital incurred during the first nine months of 2014, $46.1 million relates to the Company's rig build program, which in addition to the five drilling rigs under construction in the third quarter, commissioned an additional two drilling rigs in Canada in the first quarter of 2014 and completed two 1,500 hp AC pad conversions in the United States in the second quarter of 2014.

Production Services

	Three months ended Sept 30			Nine months ended Sept 30		
(stated in thousands)	**2014**	**2013**	**Change**	**2014**	**2013**	**Change**
Revenue						
Operating Revenue(1)	31,463	25,823	22%	90,957	39,303	131%
Third party charges	1,751	1,249	40%	5,079	1,661	206%
Total revenue	33,214	27,072	23%	96,036	40,964	134%
Expenses						
Operating						
Cash operating expenses	20,909	17,654	18%	62,429	28,467	119%
Depreciation	3,864	3,379	14%	11,284	5,540	104%
Stock based compensation	65	78	(17%)	227	129	76%
Total operating expenses	24,838	21,111	18%	73,940	34,136	117%
Administrative						
Cash administrative expenses	2,034	2,316	(12%)	5,871	3,999	47%
Depreciation	105	-	100%	311	-	100%
Stock based compensation	145	56	159%	294	56	425%
Total administrative expenses	2,284	2,372	(4%)	6,476	4,055	60%
Gross Margin(1)	12,305	9,418	31%	33,607	12,497	169%
Gross margin as a percentage of Operating Revenue	39%	36%	8%	37%	32%	16%
Adjusted EBITDA(1)	10,271	7,102	45%	27,736	8,498	226%
Adjusted EBITDA as a percentage of Operating Revenue	33%	28%	18%	30%	22%	36%
Operating Earnings(1)	6,302	3,723	69%	16,141	2,958	446%
Capital expenditures	4,734	2,736	73%	10,091	5,252	92%
Well servicing rig fleet:						
Average	65	65	-	65	46	41%
End of period	65	65	-	65	65	-
Operating Revenue per service hour(2)	804	743	8%	810	740	9%
Total service hours	33,071	30,328	9%	93,313	46,476	101%
Service rig utilization rate(3)	55%	51%	8%	53%	40%	33%

(1) See "Financial Measures Reconciliations" on page 2 of this MD&A.

(2) Operating Revenue per service hour is calculated using Operating Revenue divided by service hours.

(3) Utilization rate is calculated based on actual well servicing hours divided by available hours, being 10 hours per day per well servicing rig, 365 days per year.

Subsequent to the acquisition of IROC on April 22, 2013, the Company's well servicing fleet increased significantly to 65 rigs as at September 30, 2014, as compared to 10 rigs immediately prior to the acquisition. Previously, Western's well servicing rigs operated through Matrix. Subsequent to the acquisition of IROC, the Company's well servicing rigs, including the Matrix well servicing rigs, operate through Eagle. Additionally, with the acquisition of IROC, Western acquired approximately $35 million in oilfield rental equipment, which is operated through Aero. During the third quarter of 2014, Operating Revenue totalled $31.5 million as compared to $25.8 million in the third quarter of 2013, reflecting improved utilization and hourly rates. Operating Revenue increased significantly for the nine months ended September 30, 2014 to $91.0 million, compared to $39.3 million in the same period of the prior year due to a full period's contribution from the assets acquired in the acquisition of IROC in April 2013, coupled with improved utilization and hourly rates. For the three and nine months ended September 30, 2014, Aero's contribution to Operating Revenue in the production services segment totalled $4.9 million and $15.4 million respectively, compared to $3.7 million and $5.4 million respectively, in the same periods in the 2013 due to improved demand, continued investment in oilfield rental equipment and in the case of the nine months ended September 30, 2014, a full period's contribution from Aero's assets following the acquisition of IROC in April 2013.

During the third quarter of 2014, well servicing hours increased to 33,071 as compared to 30,328 in the third quarter of 2013, mainly due to increased utilization which improved to 55% from 51% in the same period of the prior year. The improved utilization is partially attributed to Eagle's increased focus on steam assisted gravity drainage ("SAGD") work in the oil sands in Northern Alberta. During the third quarter of 2014, Eagle had 4 well servicing rigs working in this area which realized utilization of 96%, as compared to the same period of the prior year when Eagle had one rig working in this area. Additionally, activity in most of Eagle's operating areas improved year over year, with the exception of Estevan, Saskatchewan and Red Deer, Alberta due to unfavourable weather conditions in the third quarter of 2014. For the three months ended September 30, 2014, Operating Revenue per service hour also increased by 8% to $804 compared to $743 in the same period in the prior year.

As a result of the increased well servicing rig fleet subsequent to the acquisition of IROC in April of 2013, well servicing hours increased to 93,313 in the nine month period ended September 30, 2014 compared to 46,476 in the first nine months of 2013, a 101% increase. Utilization also improved year to date in 2014 to 53% compared to 40% in the same period in the prior year. In the nine months ended September 30, 2014, Operating Revenue per service hour increased 9% to $810. The increase in Operating Revenue per service hour is attributed to the increased size of the Company's well servicing operations as Eagle operates in a number of different geographic locations, whereas prior to the IROC acquisition, the Company operated solely in the Lloydminster area which is highly competitive, less capital intensive and typically results in lower hourly rates.

Adjusted EBITDA increased in the third quarter of 2014 to $10.3 million (33% of the segment's Operating Revenue), which is an improvement from $7.1 million (28% of the segment's Operating Revenue) in the third quarter of 2013 mainly due to improved utilization and hourly rates. For the nine months ended September 30, 2014, Adjusted EBITDA increased to $27.7 million (30% of the segment's Operating Revenue) from $8.5 million (22% of the segment's Operating Revenue) in the same period in 2013. The increase in Adjusted EBITDA for the nine months ended September 30, 2014 is attributed to improved utilization and hourly rates, coupled with a full period of operations for Eagle in 2014, compared to a partial period subsequent to the IROC acquisition in April 2013. Partially offsetting the increase in Operating Revenue, is a 5% and 4% increase in operating expenses per operating hour for the three and nine months ended September 30, 2014 respectively, as compared to the same periods in the prior year, mainly due to increased labour costs.

Cash administrative expenses, excluding depreciation and stock based compensation, decreased 12% for the third quarter of 2014 to $2.0 million from $2.3 million in the third quarter of 2013. For the nine months ended September 30, 2014, cash administrative expenses, excluding depreciation and stock based compensation increased 47% to $5.9 million mainly due to the increased size and scale of Western's production services segment following the acquisition of IROC in April of 2013.

Depreciation expense in the production services segment for the three months ended September 30, 2014 increased by 17% to $4.0 million mainly due to increased activity during the period. Year to date in 2014, depreciation expense increased significantly by 109% to $11.6 million mainly due to higher utilization and a full period of operations from the assets acquired in the IROC acquisition, compared to the partial period in 2013.

During the three and nine months ended September 30, 2014, capital expenditures in the production services segment totalled $4.7 million and $10.1 million respectively, and mainly relate to expansion capital associated with the construction of one slant well servicing rig, as well as well servicing rig upgrades and the purchase of additional oilfield rental equipment.

Corporate

(stated in thousands)	Three months ended Sept 30 2014	2013	Change	Nine months ended Sept 30 2014	2013	Change
Administrative						
Cash administrative expenses	1,406	1,313	7%	3,758	4,214	(11%)
Depreciation	285	273	4%	841	823	2%
Stock based compensation	623	337	85%	1,183	957	24%
Total administrative expenses	2,314	1,923	20%	5,782	5,994	(4%)
Finance costs	5,155	4,149	24%	15,885	11,903	33%
Other items	(218)	175	(225%)	384	133	189%
Income taxes						
Current tax expense	1,986	289	587%	5,787	289	1,902%
Deferred tax expense	3,538	3,358	5%	10,739	7,409	45%
Total income taxes	5,524	3,647	51%	16,526	7,698	115%
Capital expenditures	159	170	(6%)	161	380	(58%)

Corporate administrative expenses, for the three and nine months ended September 30, 2014 increased by $0.1 million and decreased by $0.4 million respectively, to $1.4 million and $3.8 million respectively, mainly due to effective cost management during the period.

For the three and nine month periods ended September 30, 2014, finance costs, on a consolidated basis, increased by $1.0 million and $4.0 million respectively, as compared to the same period in the prior year. The increase is mainly due to the higher debt levels following the acquisition of IROC on April 22, 2013 and the resulting issuance of the $90.0 million in principal amount of senior notes on September 18, 2013.

Other items for the three months ending September 30, 2014 relate to foreign exchange and asset sale gains and losses, whereas for the nine month period ending September 30, 2014, other items consist of foreign exchange, asset sale and derivative gains and losses.

For the three months ended September 30, 2014, income taxes, on a consolidated basis, totalled $5.5 million representing an effective tax rate of 27.3%. For the nine months ended September 30, 2014, income tax expense totalled $16.5 million and represented an effective tax rate of approximately 27.0%. Western's effective tax rate in 2014 is expected to average between 27.0% to 27.5%.

Liquidity and Capital Resources

The Company's liquidity needs in the short term and long term can be sourced in several ways including: funds from operations, borrowing against existing credit facilities, new debt instruments, equity issuances and proceeds from the sale of assets. As at September 30, 2014, Western had cash and cash equivalents of $41.1 million, an increase of $23.7 million from December 31, 2013. As a result, Western's consolidated net debt balance at September 30, 2014 was $223.6 million, a decrease of $22.8 million as compared to December 31, 2013. During the nine months ending September 30, 2014, Western incurred capital expenditures of $77.5 million, paid dividends of $16.7 million, made cash interest payments of $19.2 million, and paid income taxes of $0.5 million. These cash outflows were offset by Adjusted EBITDA of $126.4 million and $9.5 million raised on the exercise of stock options and warrants.

As at September 30, 2014, Western had a working capital balance of $71.9 million, a $21.3 million increase as compared to December 31, 2013, mainly due to increased activity. As at September 30, 2014, the Company has $265.0 million in senior notes outstanding, $135.0 million in available credit facilities and is in compliance with all debt covenants. Currently, Western's net debt to trailing 12 month Adjusted EBITDA is 1.3 with no scheduled long term debt repayments until January 2019. 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 2014 capital budget.

For the three and nine months ended September 30, 2014, the Company had one significant customer comprising 12.8% and 13.5% respectively, of the Company's total revenue. The trade receivable balance relating to this customer as at September 30, 2014 represented 10.7% of the Company's total trade and other receivables. This customer is a publicly traded company with a market capitalization in excess of $45 billion as at September 30, 2014. For the three months ended September 30, 2013, the Company had two significant customers comprising 11.5% and 10.6% of the Company's total revenue. For the nine months ended September 30, 2013, the Company had one significant customer comprising 11.2% of the Company's total revenue. The Company's significant customers may change quarter to quarter.

Summary of Quarterly Results

In addition to other market factors, quarterly results of Western are markedly affected by weather patterns throughout its operating areas. 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 significant quarter over quarter 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	Sep 30, 2014	Jun 30, 2014	Mar 31, 2014	Dec 31, 2013	Sep 30, 2013	Jun 30, 2013	Mar 31, 2013	Dec 31, 2012
(stated in thousands, except per share amounts)								
Revenue	125,225	81,981	161,416	129,713	101,389	50,835	98,006	83,338
Operating Revenue(1)	117,960	77,352	149,627	119,831	96,473	48,010	88,810	76,458
Gross Margin(1)	50,570	31,206	67,629	52,980	37,547	16,087	40,945	37,360
Adjusted EBITDA(1)	42,782	24,028	59,548	43,543	30,297	9,199	34,384	31,381
Cash flow from operating activities	22,975	71,912	38,634	36,866	6,667	48,381	22,444	11,021
Net income (loss)	14,718	4,396	25,500	15,797	7,927	(3,381)	14,903	13,092
per share - basic	0.20	0.06	0.35	0.22	0.11	(0.05)	0.25	0.22
per share - diluted	0.19	0.06	0.34	0.21	0.11	(0.05)	0.24	0.22
Total assets	1,040,973	1,016,112	1,019,192	986,792	947,836	903,882	748,112	749,448
Long term financial liabilities(2)	263,624	263,293	263,119	262,877	263,050	232,529	182,068	186,948
Dividends declared	5,615	5,609	5,538	5,504	5,502	5,501	4,474	4,469

(1) See "Financial Measures Reconciliations" on page 2 of this MD&A.

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

With the exception of lower activity in the second quarters of 2013 and 2014, due to the cyclical nature of the oilfield service industry, revenues have increased significantly due to the acquisition of IROC in April of 2013 and increased activity in both the contract drilling and production services segments.

Adjusted EBITDA has followed a similar trend to revenue, steadily increasing after spring breakup in the second quarters through the third and fourth quarters and into the first quarter. Adjusted EBITDA is generally highest in the first quarter when activity is the highest. Adjusted EBITDA has shown continuous improvement from the third quarter of 2013 through to the first quarter of 2014, with Adjusted EBITDA impacted by spring breakup in Canada in the second quarter of 2014. However, Adjusted EBITDA was impacted by spring breakup to a much lesser extent in the second quarter of 2014 than in past second quarters, due to increased pad drilling, improved commodity prices, and a weaker Canadian dollar leading to more customers drilling through spring breakup.

Net income has fluctuated throughout the last eight quarters due to the cyclical nature of the oilfield service industry and has been impacted by higher depreciation rates and increased finance costs.

Total assets of the Company have increased throughout the last eight quarters due to the Company's capital spending program. During the second quarter of 2013, the significant increase in the Company's total assets was due to the acquisition of IROC.

Contractual Obligations

In the normal course of business the Company incurs contractual obligations. The expected maturities of the Company's contractual obligations as at September 30, 2014 are as follows:

(stated in thousands)	2014	2015	2016	2017	2018	Thereafter	Total
Senior Notes	$ -	$ -	$ -	$ -	$ -	$ 265,000	$ 265,000
Senior Notes interest	-	20,869	20,869	20,869	20,869	10,434	93,910
Trade payables and other current liabilities	54,527	-	-	-	-	-	54,527
Dividends payable	5,615	-	-	-	-	-	5,615
Operating leases	1,096	4,324	3,276	2,444	2,374	14,168	27,682
Purchase commitments	30,730	4,733	-	-	-	-	35,463
Other long term debt	404	934	567	215	-	-	2,120
Total	$ 92,372	$ 30,860	$ 24,712	$ 23,528	$ 23,243	$ 289,602	$ 484,317

There have been no material changes in the contractual obligations detailed above, other than in the normal course of business, during the current interim period.

Outstanding Share Data

	October 30, 2014	September 30, 2014	December 31, 2013
Common shares outstanding	74,883,428	74,883,428	73,386,191
Warrants outstanding	-	-	108,261
Restricted share units outstanding	274,028	274,572	-
Stock options outstanding	5,154,038	5,089,745	4,425,598

Off Balance Sheet Arrangements

As at September 30, 2014, Western had no off balance sheet arrangements in place.

Transactions with Related Parties

During the quarter ended September 30, 2014, the Company had no transactions with related parties.

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 a "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 expired.

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.

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 their estimated fair value and changes in the fair value are recorded through net income. The asset is recognized in other assets on the balance sheet while a change in the value of the embedded derivative is included in other items within net income.

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.

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.

Disclosure Controls and Procedures and Internal Controls Over Financial Reporting

As Western's common shares trade on the Toronto Stock Exchange, per National Instrument 52-109, CERTIFICATION OF DISCLOSURE IN ISSUERS' ANNUAL AND INTERIM FILINGS, the Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") of the Company have certified as at September 30, 2014 that they have designed or caused to be designed under their supervision, disclosure controls and procedures ("DC&P") to provide reasonable assurance that: (i) material information relating to the Company, including its consolidated subsidiaries, is made known to the CEO and the CFO by others within those entities, particularly during the periods in which the interim filings of the Company are being prepared; and (ii) information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation.

The CEO and CFO do not expect that the DC&P will prevent or detect all errors, misstatements and fraud but are designed to provide reasonable assurance of achieving their objectives. A control system, no matter how well designed or operated, can only provide reasonable, but not absolute, assurance that the objectives of the control system are met. In addition to DC&P, the CEO and CFO have designed internal controls over financial reporting, or caused them to be designed under their supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS.

During the three months ended September 30, 2014, there were no changes in internal control over financial reporting that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Critical Accounting Estimates

This MD&A of the Company's financial condition and results of operations is based on the condensed consolidated financial statements for the three and nine months ended September 30, 2014, 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 occur with absolute 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 share based payments.

The accounting estimates believed to be the most difficult, subjective or require complex judgements and which are the most critical to the reporting of results of operations and financial positions of the Company 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 September 30, 2014, 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 and equity settled restricted share units 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, expected dividends and share prices and these inputs affect the estimated fair value calculated. Determining the estimated expected life, volatility, forfeitures and expected dividends requires judgement.

Business Risks

For a comprehensive listing of the Company's business risks please see the most recent Annual Information Form for the year ended December 31, 2013 as filed on SEDAR at www.sedar.com. The Company's primary business risks as at September 30, 2014 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 impacting the oil and gas exploration and production industry, including the ability of oil and gas companies to accumulate capital or variations in their exploration and development budgets, may also affect the Company's business. The exact impact 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, and labour costs 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 WCSB 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 includes, but is not limited to, statements relating to future declaration of dividends; the future demand for the Company's services and equipment; the terms of existing and future drilling contracts in Canada and the US and the revenues resulting therefrom; the Company's expansion and maintenance capital plans for 2014, including the ability of current capital resources to cover Western's financial obligations and the 2014 capital budget; the Company's expected sources of funding to support such capital plans; expectations as to the increase in crude oil transportation capacity through rail and pipeline development; expectations as to the necessary approvals for liquefied natural gas projects being obtained; the expectation of continued foreign investment into the Canadian oilfield industry; the expectation of increase in oilfield services activities in general, and drilling activity in various resource plays in particular, including the type of drilling; the Company's expected utilization for its drilling and well servicing divisions; strong oilfield activity levels and pricing; increased commodity pricing; the improving economic conditions in North America; the Company's ability to achieve its desired return on investment through existing or future rig build opportunities; the continued and enhanced marketability of the Company's drilling and servicing rigs; the Company's expected tax rate in 2014; and forward-looking statements under the heading "Critical Accounting Estimates".

The material assumptions in making the forward-looking statements in this MD&A include, but are not limited to, assumptions relating to, demand levels and pricing for oilfield services; fluctuations in the price and demand for oil and natural gas; commodity pricing; the continued business relationship between the Company and its one significant customer; general economic and financial market conditions; the development of liquefied natural gas projects, crude oil transport and pipeline approval and development; the Company's ability to finance its operations; the effects of seasonal and weather conditions on operations and facilities; the competitive environment to which the various business segments are, or may be, exposed in all aspects of their business; the ability of the Company's various business segments to access equipment (including spare parts and new technologies); changes in laws or regulations; currency exchange fluctuations; the ability of the Company to attract and retain skilled labour and qualified management; the ability to retain and attract significant customers; and other unforeseen conditions which could impact the use of services supplied by Western including Western's ability to respond to such conditions.

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, the risk that the demand for oilfield services will not continue to improve for the remainder of 2014, and other general industry, economic, market and business conditions. Readers are cautioned that the foregoing list of risks, uncertainties and assumptions are 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 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 any 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

The Annual Information Form containing additional information relating to the Company is filed on SEDAR at www.sedar.com.