Western ENERGY SERVICES CORP.

2017 Q3

Third Quarter 2017 Interim Report — Date: October 25, 2017

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, 2016 and 2015, the Company's management discussion and analysis ("MD&A") for the year ended December 31, 2016, as well as the condensed consolidated financial statements and notes as at and for the three and nine months ended September 30, 2017 and 2016. This Management Discussion and Analysis ("MD&A") is dated October 25, 2017. 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)	**2017**	**2016**	**Change**	**2017**	**2016**	**Change**
Revenue	54,131	32,485	67%	171,660	79,312	116%
Operating Revenue(1)	51,111	30,665	67%	159,733	75,258	112%
Gross Margin(1)	12,299	5,685	116%	42,424	17,255	146%
Gross Margin as a percentage of Operating Revenue	24%	19%	26%	27%	23%	17%
Adjusted EBITDA(1)	6,882	896	668%	25,628	2,269	1,029%
Adjusted EBITDA as a percentage of Operating Revenue	13%	3%	333%	16%	3%	433%
Cash flow from operating activities	1,609	909	77%	25,441	17,958	42%
Capital expenditures	6,349	651	875%	12,220	1,995	513%
Net loss	(11,478)	(16,973)	(32%)	(32,471)	(47,464)	(32%)
-basic net loss per share	(0.16)	(0.23)	(30%)	(0.44)	(0.64)	(31%)
-diluted net loss per share	(0.16)	(0.23)	(30%)	(0.44)	(0.64)	(31%)
Weighted average number of shares						
-basic	73,877,203	73,722,144	-	73,823,970	73,672,389	-
-diluted	73,877,203	73,722,144	-	73,823,970	73,672,389	-
Outstanding common shares as at period end	73,974,594	73,795,266	-	73,974,594	73,795,266	-
Operating Highlights(1)						
Contract Drilling						
Canadian Operations						
Average active rig count	20.2	11.4	77%	20.3	8.0	154%
Operating Revenue per Billable Day	16,825	15,256	10%	17,109 (3)	17,206 (4)	(1%)
Operating Revenue per Operating Day	18,604	17,017	9%	18,862 (3)	19,224 (4)	(2%)
Drilling rig utilization - Billable Days	40%	22%	82%	40%	15%	167%
Drilling rig utilization - Operating Days	36%	20%	80%	36%	14%	157%
CAODC industry average utilization(2)	29%	17%	71%	29%	15%	93%
United States Operations						
Average active rig count	3.3	1.8	83%	2.8	1.3	115%
Operating Revenue per Billable Day (US$)	19,801	18,967	4%	19,763	22,515	(12%)
Operating Revenue per Operating Day (US$)	21,832	22,246	(2%)	22,850	25,923	(12%)
Drilling rig utilization - Billable Days	65%	37%	76%	56%	26%	115%
Drilling rig utilization - Operating Days	59%	32%	84%	48%	22%	118%
Production Services						
Average active rig count	17.7	15.6	13%	17.3	11.4	52%
Service rig Operating Revenue per Service Hour	629	603	4%	661	646	2%
Service rig utilization	27%	24%	13%	26%	17%	53%

(1) See "Non-IFRS measures" on page 19 of this MD&A.

(2) Source: The Canadian Association of Oilwell Drilling Contractors ("CAODC"). The CAODC industry average is based on Operating Days divided by total available days.

(3) Excludes shortfall commitment revenue from take or pay contracts of $6.4 million for the nine months ended September 30, 2017.

(4) Excludes shortfall commitment revenue from take or pay contracts of $1.8 million for the nine months ended September 30, 2016.

Financial Position at (stated in thousands)	September 30, 2017	December 31, 2016	September 30, 2016
Working capital	46,184	51,118	55,259
Property and equipment	663,542	708,567	720,554
Total assets	737,385	793,525	794,170
Long term debt	264,958	264,070	264,118

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 ("US"). Western provides well servicing and oilfield rental equipment services in Canada through its wholly owned subsidiary Western Production Services Corp. ("Western Production Services"). Western Production Services' division, Eagle Well Servicing ("Eagle") provides well servicing operations, while its division, Aero Rental Services ("Aero") provides oilfield rental equipment services. Financial and operating results for Horizon and Stoneham are included in Western's contract drilling segment, while financial and operating results for Eagle and Aero are included in Western's production services segment. Non-International Financial Reporting Standards ("Non-IFRS") measures are defined on page 19 of this MD&A. Abbreviations for standard industry terms are included on page 21 of this MD&A.

Western has a drilling rig fleet of 56 rigs specifically suited for drilling horizontal wells of increased complexity. Western is currently the fifth largest drilling contractor in Canada, based on the Canadian Association of Oilwell Drilling Contractors ("CAODC") registered rigs, with a fleet of 51 rigs operating through Horizon. Of the Canadian fleet, 24 are classified as Cardium class rigs, 19 as Montney class rigs and eight as Duvernay class rigs. As compared to the Cardium class rigs, the Montney class rigs have a larger hookload, while the Duvernay class rigs have the largest hookload allowing the rig to support more drill pipe downhole. Additionally, Western has five Duvernay class triple drilling rigs deployed in the United States operating through Stoneham. Western is also the sixth largest well servicing company in Canada with a fleet of 66 rigs operating through Eagle. Western's oilfield rental equipment division, which operates through Aero, provides oilfield rental equipment for hydraulic fracturing services, well completions and production work, coil tubing and drilling services.

Crude oil and natural gas prices impact the cash flow of Western's customers, which in turn impacts the demand for Western's services. West Texas Intermediate ("WTI") on average was relatively constant in the third quarter of 2017 as compared to the second quarter of 2017, however was 7% higher compared to the same period in the prior year. For Western's Canadian customers, the impact of foreign exchange rates when translating WTI into the Canadian equivalent, resulted in only a 3% increase for the three months ended September 30, 2017, as compared to the same period in the prior year. Additionally, in the third quarter of 2017, Western Canadian Select ("WCS") on average declined by 1% as compared to the second quarter of 2017, however improved by 18% as compared to the same period of the prior year. For the nine months ended September 30, 2017, WTI was 19% higher than the same period of the prior year. Similarly, WCS also improved for the nine months ended September 30, 2017, increasing by 34% as compared to the nine months ended September 30, 2016. Canadian natural gas prices, such as AECO, declined quarter over quarter, decreasing on average by 41% from the second quarter of 2017 to the third quarter of 2017. Further, AECO decreased in the third quarter of 2017 as compared to the same period of the prior year, decreasing by 31%, however for the nine month period ending September 30, 2017 AECO improved by 29% as compared to the same period in the prior year. The following table summarizes average crude oil and natural gas prices, as well as average foreign exchange rates for the three and nine months ended September 30, 2017 and 2016.

	Three months ended Sept 30			Nine months ended Sept 30		
	2017	2016	Change	2017	2016	Change
Average crude oil and natural gas prices(1)(2)						
Crude Oil						
West Texas Intermediate (US$/bbl)	48.16	44.88	7%	49.32	41.44	19%
Western Canadian Select (CDN$/bbl)	47.27	40.00	18%	49.62	37.09	34%
Natural Gas						
30 day Spot AECO (CDN$/mcf)	1.65	2.38	(31%)	2.40	1.86	29%
Average foreign exchange rates(2)						
US dollar to Canadian dollar	1.25	1.30	(4%)	1.31	1.32	(1%)

(1) See "Abbreviations" on page 21 of this MD&A.

(2) Source: Bloomberg

Improved commodity prices in 2017 has led to a corresponding increase in the demand for oilfield services in both Canada and the United States. The CAODC reported that for drilling in Canada, the total number of Operating Days in the Western Canadian Sedimentary Basin ("WCSB") increased approximately 41% and 72% for the three and nine months ended September 30, 2017 respectively, as compared to the same periods in the prior year. Similarly, as reported by Baker Hughes, a GE Company, the number of active drilling rigs in the United States increased approximately 97% and 77% for the three and nine months ended September 30, 2017 respectively, as compared to the same periods in the prior year.

Operational results for the three months ended September 30, 2017 include:

- Operating Revenue in the third quarter of 2017 benefited from improved crude oil prices and resulted in higher customer spending and a corresponding increase in demand for Western's services. Third quarter Operating Revenue increased by $20.4 million (or 67%) to $51.1 million in 2017 as compared to $30.7 million in 2016. In the contract drilling segment, Operating Revenue totalled $38.7 million in the third quarter of 2017 as compared to $20.2 million in the third quarter of 2016, an increase of $18.5 million (or 92%); while in the production services segment, Operating Revenue totalled $12.4 million for the three months ended September 30, 2017 as compared to $10.5 million in the third quarter of 2016, an increase of $1.9 million (or 19%). Higher utilization in the third quarter of 2017, and improved pricing in all divisions, positively impacted Operating Revenue in the contract drilling and production services segments as described below:
    - Drilling rig utilization – Operating Days ("Drilling Rig Utilization") in Canada averaged 36% in the third quarter of 2017 compared to an average of 20% in the third quarter of 2016, reflecting a 1,600 basis points ("bps") increase. Third quarter 2017 Drilling Rig Utilization represented a premium of 700 bps to the CAODC industry average of 29%, whereas in the third quarter of 2016, Drilling Rig Utilization of 20% represented a 300 bps premium to the industry average. The increase in the Company's utilization premium to the industry average in the third quarter of 2017 is attributable to:
        - the quality of Western's drilling rig fleet;
        - the ability of the Company's rig crews;
        - the efforts by the Company's marketing group to reposition rigs for existing and new customers; and
        - a number of Western's customers increasing their capital budgets for 2017, as compared to 2016 when customer spending was limited.

      These factors, combined with improved commodity prices, resulted in higher demand for the Company's drilling rigs. Operating Revenue per Billable Day in the third quarter of 2017 improved by 10% as compared to the same period in the prior year, as market conditions continued to improve;
    - In the United States, four of the Company's five drilling rigs operated during the quarter, two of which were working on long term contracts, resulting in Drilling Rig Utilization of 59% in the third quarter of 2017, as compared to 32% in the same period of the prior year. Further, increased activity has led to improved pricing, as Operating Revenue per Billable Day in the United States improved by 4% in the third quarter of 2017 as compared to the third quarter of 2016; and
    - Well servicing utilization of 27% in the third quarter of 2017 compared to 24% in the same period of the prior year. Improved market conditions resulted in a 4% increase in hourly rates during the third quarter of 2017, as compared to the same period in the prior year. Improved utilization and pricing, led to a $1.6 million (or 19%) increase in well servicing Operating Revenue in the period.
- Third quarter Adjusted EBITDA improved by $6.0 million to $6.9 million in 2017 as compared to $0.9 million in the third quarter of 2016. The year over year change in Adjusted EBITDA is due to higher activity and improved pricing across all divisions in 2017.
- Administrative expenses, excluding depreciation and stock based compensation, decreased by 2% in the third quarter of 2017 as compared to the second quarter of 2017 due to lower employee costs. Third quarter 2017 administrative expenses increased by $0.6 million (or 12%) to $5.4 million, as compared to $4.8 million in the third quarter of 2016 mainly due to higher employee related costs, coupled with one time professional fees incurred in the period.
- The Company incurred a net loss of $11.5 million in the third quarter of 2017 ($0.16 per basic common share) as compared to a net loss of $17.0 million in the same period in 2016 ($0.23 per basic common share). The change can be attributed to the following:
    - A $6.0 million increase in Adjusted EBITDA due to higher utilization and pricing in both the contract drilling and production services segments;

- A $0.7 million decrease in stock based compensation expense due to a greater portion of the Company's outstanding stock options and restricted share units being fully vested in the quarter; and
- A $0.6 million decrease in depreciation expense due to lower capital spending and certain equipment being fully depreciated over the last four quarters.

Offsetting the above mentioned items is a $1.9 million decrease in income tax recovery due to improved earnings before taxes.

- Third quarter 2017 capital expenditures of $6.3 million included $4.0 million of expansion capital and $2.3 million of maintenance capital. In total, capital spending in the third quarter of 2017 increased by $5.6 million from the $0.7 million incurred in the third quarter of 2016. The Company incurred expansion capital mainly related to drilling rig upgrades in the third quarter of 2017, as well as necessary maintenance capital related to the higher activity in the period.
- Subsequent to September 30, 2017, on October 17, 2017 the Company closed the following financing transactions:
  - A lending agreement with Alberta Investment Management Corporation ("AIMCo") providing for a $215.0 million second lien secured term loan facility (the "Second Lien Facility"). The Second Lien Facility is available in a single draw which will be used to repay a portion of the Company's outstanding 7⅞% senior unsecured notes (the "Senior Notes"). Interest will be payable semi-annually, at a rate of 7.25% per annum, on January 1 and July 1 each year. Amortization payments equal to 1% of the principal amount will be payable annually in quarterly installments beginning on July 1, 2018, with the balance due on maturity, five years from the draw date. In conjunction with the Second Lien Facility, Western has issued to AIMCo approximately 7.1 million warrants to purchase common shares of Western, at an exercise price of $1.77 per common share, which have a three year life and expire on October 17, 2020;
  - A private placement with AIMCo (the "Private Placement") of 9.1 million common shares of Western at a price of $1.25 per common share, for aggregate gross proceeds of $11.4 million;
  - A bought deal offering of common shares of Western with a syndicate of underwriters (the "Bought Deal") where the underwriters purchased 9.1 million common shares of Western at a price of $1.25 per common share, for aggregate gross proceeds of $11.4 million; and
  - Completed a number of amendments to its Credit Facilities, including the following:
    - Extended the maturity of its syndicated revolving credit facility (the "Revolving Facility") and its committed operating facility (the "Operating Facility" and together the "Credit Facilities") to December 17, 2020;
    - Increased the limit of the Revolving Facility from $50.0 million to $70.0 million, while the $10.0 million Operating Facility limit remains unchanged;
    - The interest coverage and current ratio covenants have been permanently removed;
    - A debt service coverage ratio has been added, which is calculated based on EBITDA, as defined in the Credit Facilities agreement, divided by the sum of interest expense and scheduled long term debt principal repayments. This covenant will only be tested when the outstanding principal under the Credit Facilities exceeds $40.0 million or net book value of property and equipment is less than $500.0 million. If applicable, the debt service coverage ratio must meet or exceed 1.0 as at and prior to March 31, 2018, 1.25 as at June 30, 2018, 1.5 as at September 30, 2018 and December 31, 2018, and 2.0 thereafter; and
    - The Revolving Facility will continue to include an accordion feature, whereby an incremental $50.0 million of borrowing would be available, subject to the approval of the lenders.

  Western expects that the net proceeds of the Second Lien Facility, Private Placement and the Bought Deal, along with cash on hand and funds available under the Credit Facilities will be used to repay the Company's Senior Notes in the first quarter of 2018 when the Senior Notes will be redeemable at par.

Operational results for the nine months ended September 30, 2017 include:

- Operating Revenue for the nine month period ended September 30, 2017 benefited from improved commodity prices and higher customer spending which resulted in a corresponding increase in demand for Western's services. For the nine months ended September 30, 2017, Operating Revenue increased by $84.4 million (or 112%) to $159.7 million as compared to $75.3 million for the nine months ended September 30, 2016. In the contract drilling segment, Operating Revenue totalled $120.8 million for the nine months ended September 30, 2017, an increase of $70.9 million (or 142%), as compared to $49.9 million in the same period of the prior year, and included $6.4 million in shortfall commitment revenue in 2017, as compared to $1.8 million in 2016; while in the production services segment, Operating Revenue totalled $39.1 million, an increase of $13.7 million (or 54%) as compared to $25.4 million in the same period of the prior year. Higher utilization for the nine months ended September 30, 2017, as compared to the same period of the prior year, offset by lower pricing in the contract drilling segment, impacted Operating Revenue in the contract drilling and production services segments as described below:

- o Drilling Rig Utilization in Canada of 36% for the nine month period ended September 30, 2017, compared to 14% for the nine month period ended September 30, 2016, reflecting a 2,200 bps increase. Drilling Rig Utilization of 36% in 2017 represents a 700 bps premium to the CAODC industry average, whereas in the nine months ended September 30, 2016, Drilling Rig Utilization of 14% represented a 100 bps discount to the CAODC industry average. The increase in the Company's utilization premium in 2017 is attributable to:
  - the quality of Western's drilling rig fleet;
  - the ability of the Company's rig crews;
  - the efforts by the Company's marketing group to reposition rigs for existing and new customers; and
  - a number of Western's customers increasing their capital budgets for 2017, as compared to 2016 when customer spending was limited.

  These factors, combined with improved commodity prices, resulted in higher demand for the Company's drilling rigs. Additionally, Western continued to increase its market share in 2017. Western's 51 drilling rigs in Canada represent approximately 8% of the rigs registered with the CAODC, however Western's total operating days in 2017, represented 10% of the total industry Operating Days reported by the CAODC. Operating Revenue per Billable Day in the current period, was consistent with the same period in the prior year, decreasing by 1% as compared to the same period in the prior year.
- o In the United States, four of the Company's five drilling rigs operated during the period, two of which were working on long term contracts, resulting in Drilling Rig Utilization of 48% for the nine months ended September 30, 2017, as compared to 22% in the same period of the prior year. Operating Revenue per Billable Day in the United States decreased by 12% for the nine months ended September 30, 2017 due to changes in the mix of rigs working on spot rates versus long term contracts, as compared to the same period of the prior year when the Company had one rig working on a long term legacy contract; and
- o Well servicing utilization of 26% for the nine months ended September 30, 2017 compared to 17% in the same period of the prior year. Continued improvements in commodity prices helped improve activity year over year. Additionally, well servicing hourly rates increased by 2% for the nine months ended September 30, 2017, as compared to the nine months ended September 30, 2016. Improved utilization and pricing led to an $11.2 million (or 56%) increase in well servicing Operating Revenue in the period.

- Adjusted EBITDA for the nine months ended September 30, 2017 increased by $23.3 million to $25.6 million in 2017 as compared to $2.3 million for the nine months ended September 30, 2016. The year over year increase in Adjusted EBITDA is due to higher activity across all divisions, a $4.6 million increase in shortfall commitment revenue in 2017, and the Company's ability to safely and efficiently reactivate equipment and crews without incurring significant costs, including rigs that had been idle for an extended period of time. These factors were aided by improved pricing in the production services segment, which was partially offset by lower pricing in the contract drilling segment.
- Administrative expenses, excluding depreciation and stock based compensation, for the nine month period ended September 30, 2017 increased by $1.8 million (or 12%) to $16.8 million as compared to $15.0 million in the same period of the prior year. The increase in administrative expenses is mainly due to higher employee related costs, coupled with one time professional fees incurred in the period.
- The Company incurred a net loss of $32.5 million for the nine months ended September 30, 2017 ($0.44 per basic common share) as compared to a net loss of $47.5 million for the same period in 2016 ($0.64 per basic common share). The decrease in net loss can be attributed to the following:
  - o A $23.3 million increase in Adjusted EBITDA due to higher utilization in both the contract drilling and production services segments, and increased shortfall commitment revenue;
  - o A prior period loss on asset decommissioning of $5.2 million in the contract drilling segment;
  - o A $1.7 million decrease in stock based compensation expense, due to a greater portion of the Company's outstanding stock options and restricted share units being fully vested in the period; and
  - o A $0.7 million decrease in finance costs mainly due to the Company reducing its available Credit Facilities in 2016 from $195.0 million to $60.0 million, resulting in lower standby fees.

Offsetting the above mentioned items are the following:

- An increase of $7.4 million in depreciation expense due to the Company changing from unit of production to straight line depreciation for drilling and well servicing rigs effective April 1, 2016;
- A $3.5 million increase in other items, as the first quarter of 2016 included foreign exchange gains of $2.5 million, while the first quarter of 2017 included $1.6 million in transaction costs related to the unsuccessful acquisition of Savanna Energy Services Corp. ("Savanna"); and
- A $5.1 million decrease in income tax recovery due to improved earnings before taxes.

- Year to date capital expenditures of $12.2 million included $6.4 million of expansion capital and $5.8 million of maintenance capital. In total, capital spending for the nine months ended September 30, 2017 increased by $10.2 million from the $2.0 million incurred in the same period of 2016. The Company incurred expansion capital mainly related to drilling rig upgrades in the nine months ended September 30, 2017, which have contributed to the increase in cash flow from operating activities year to date, as well as necessary maintenance capital related to the higher activity in the period.

Outlook

Currently, 22 of Western's drilling rigs are operating. Five of Western's 56 drilling rigs (or 9%) are under long term take or pay contracts, with two expected to expire in 2018, two expected to expire in 2019 and one expected to expire in 2020. These contracts each typically generate between 250 and 350 Billable Days per year.

Western's capital budget for 2017 remains unchanged and totals approximately $20 million comprised of $8 million in expansion capital and $12 million in maintenance capital. The majority of the capital budget relates to expansion capital in the contract drilling segment related to drilling rig upgrades that offer compelling economics. Western believes the revised 2017 capital budget provides a prudent use of cash resources and will allow it to maintain its premier drilling and well servicing rig fleets, while remaining responsive to customer requirements. Western will continue to manage its operations in a disciplined manner and make any required adjustments to its capital program as customer demand changes. Approximately $2 million from the revised 2017 capital budget is expected to be carried forward into 2018.

Since hitting 10 year lows in the first quarter of 2016, commodity prices, while remaining well below previous highs, have improved. As such, North American drilling rig counts have begun to recover and the Company is expecting increased year over year activity levels throughout the remainder of 2017. However, improved pricing for the Company's services has lagged the recovery in activity and is expected to occur gradually as rates are typically increased for rigs and drilling programs on an individual basis rather than universally. Improving gross margin is a priority for the Company and, as has been demonstrated over the last two quarters, Western is working to implement higher rates with each rig that is awarded work. Prices for Western's services below historical levels will continue to impact Adjusted EBITDA and cash flow from operating activities in the near term. However, Western's variable cost structure and a prudent capital budget will aid in preserving balance sheet strength. In addition to $39.6 million in cash and cash equivalents at September 30, 2017, Western currently has $80.0 million of available credit under its undrawn amended Credit Facilities, which do not mature until December 17, 2020. Additionally, Western plans to repay the Senior Notes in the first quarter of 2018 with proceeds from the Second Lien Facility, Private Placement and the Bought Deal completed subsequent to September 30, 2017, along with cash on hand and funds available under the Credit Facilities. Completing these financing transactions will lower Western's total debt and leverage metrics, decrease Western's effective interest rates and extend the maturity on all of Western's long term debt. Additionally, Western will save approximately $5.3 million annually in cash interest expense, due to the decreased total debt level and lower interest rate on the Second Lien Facility, as compared to the existing Senior Notes.

Oilfield service activity in Canada will be impacted by the development of resource plays in Alberta and northeast British Columbia including those related to increased crude oil transportation capacity through pipeline development, increased environmental regulations including the implementation of a carbon tax in Alberta, and decreased foreign investment into Canada. Currently, the largest challenges facing the oilfield service industry are continued customer spending constraints as a result of lower commodity prices and the increasing challenge of staffing field crews, particularly in the well servicing division. Western's view is that its modern drilling and well servicing rig fleets, reputation, and disciplined cash management provide a competitive advantage which will enable the Company to manage through the current slowdown in oilfield service activity.

Segmented Information

Western operates in the contract drilling segment in both Canada and the United States as well as in 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

Financial Highlights	Three months ended Sept 30			Nine months ended Sept 30		
(stated in thousands)	2017	2016	Change	2017	2016	Change
Revenue						
Operating Revenue[1]	38,711	20,210	92%	120,754	49,922	142%
Third party charges	2,474	1,190	108%	9,686	2,405	303%
Total revenue	41,185	21,400	92%	130,440	52,327	149%
Expenses						
Operating						
Cash operating expenses	31,851	18,155	75%	98,317	39,628	148%
Depreciation	12,916	13,158	(2%)	38,914	32,211	21%
Stock based compensation	15	36	(58%)	80	204	(61%)
Total operating expenses	44,782	31,349	43%	137,311	72,043	91%
Administrative						
Cash administrative expenses	2,750	2,782	(1%)	8,415	8,478	(1%)
Depreciation	61	78	(22%)	196	247	(21%)
Stock based compensation	29	64	(55%)	134	243	(45%)
Total administrative expenses	2,840	2,924	(3%)	8,745	8,968	(2%)
Gross Margin[1]	9,334	3,245	188%	32,123	12,699	153%
Gross Margin as a percentage of Operating Revenue	24%	16%	50%	27%	25%	8%
Adjusted EBITDA[1]	6,584	463	1,322%	23,708	4,221	462%
Adjusted EBITDA as a percentage of Operating Revenue	17%	2%	750%	20%	8%	150%
Operating Earnings[1]	(6,393)	(12,773)	(50%)	(15,402)	(28,237)	(45%)
Capital expenditures	5,630	446	1,162%	10,543	996	959%

Operating Highlights						
Canadian Operations						
Contract drilling rig fleet:						
Average active rig count[1]	20.2	11.4	77%	20.3	8.0	154%
End of period	51	51	-	51	51	-
Operating Revenue per Billable Day[1]	16,825	15,256	10%	17,109 [3]	17,206 [4]	(1%)
Operating Revenue per Operating Day[1]	18,604	17,017	9%	18,862 [3]	19,224 [4]	(2%)
Operating Days[1]	1,681	940	79%	5,027	1,959	157%
Number of meters drilled	541,933	269,445	101%	1,478,468	473,121	212%
Number of wells drilled	160	85	88%	407	149	173%
Average Operating Days per well	10.5	11.1	(5%)	12.4	13.2	(6%)
Drilling rig utilization - Billable Days[1]	40%	22%	82%	40%	15%	167%
Drilling rig utilization - Operating Days[1]	36%	20%	80%	36%	14%	157%
CAODC industry average utilization[1][2]	29%	17%	71%	29%	15%	93%
United States Operations						
Contract drilling rig fleet:						
Average active rig count[1]	3.3	1.8	83%	2.8	1.3	115%
End of period	5	5	-	5	5	-
Operating Revenue per Billable Day (US$)[1]	19,801	18,967	4%	19,763	22,515	(12%)
Operating Revenue per Operating Day (US$)[1]	21,832	22,246	(2%)	22,850	25,923	(12%)
Operating Days[1]	272	145	88%	656	306	114%
Number of meters drilled	71,295	39,393	81%	177,376	94,776	87%
Number of wells drilled	12	8	49%	30	20	49%
Average Operating Days per well	22.9	17.7	29%	22.0	15.0	47%
Drilling rig utilization - Billable Days[1]	65%	37%	76%	56%	26%	115%
Drilling rig utilization - Operating Days[1]	59%	32%	84%	48%	22%	118%

(1) See "Non-IFRS measures" on page 19 of this MD&A.

(2) Source: The Canadian Association of Oilwell Drilling Contractors ("CAODC"). The CAODC industry average is based on Operating Days divided by total available days.

(3) Excludes shortfall commitment revenue from take or pay contracts of $6.4 million for the nine months ended September 30, 2017.

(4) Excludes shortfall commitment revenue from take or pay contracts of $1.8 million for the nine months ended September 30, 2016.

For the three months ended September 30, 2017, Operating Revenue in the contract drilling segment totalled $38.7 million, an $18.5 million increase (or 92%), as compared to the same period in the prior year. For the nine months ended September 30, 2017, Operating Revenue in the contract drilling segment totalled $120.8 million, a $70.9 million increase (or 142%), as compared to the same period in the prior year. An improved commodity price environment and a corresponding increase in demand for contract drilling services in both Canada and the United States, led to higher year over year activity for both the three and nine months ended September 30, 2017. Additionally, the Company recognized $6.4 million related to shortfall commitment revenue for the nine months ended September 30, 2017, as compared to $1.8 million in the same period of the prior year. Pricing in Canada continued to recover for the three months ended September 30, 2017, increasing by 10%, as compared to the same period of the prior year, whereas for the nine months ended September 30, 2017 day rates decreased slightly by 1% as compared to the same period of the prior year, mainly due to lower pricing experienced in the first quarter of 2017, compared to the first quarter of 2016. In the United States, Operating Revenue per Billable Day for the three months ended September 30, 2017 improved by 4% due to improving market conditions. However, Operating Revenue per Operating Day for the three months ended September 30, 2017 decreased by 2%, due to longer wells being drilled and more wells being drilled on pads, which require minimal move time, in the current period, as compared to the same period in the prior year. This resulted in a lower proportion of mobilization days in the third quarter of 2017, as compared to the same period in the prior year, and led to the decrease in Operating Revenue per Operating Day. For the nine months ended September 30, 2017, pricing was 12% lower as compared to the same periods of the prior year due to changes in the mix of rigs working on spot rates versus long term legacy contracts.

For the three and nine months ended September 30, 2017, cash operating expenses per Billable Day in the contract drilling segment, excluding third party charges, decreased by 2% and 4% to total approximately $13,605 and $14,068 respectively, mainly due to a higher proportion of fixed operating costs being allocated over more Billable Days in 2017, as compared to the same periods in the prior year.

Gross Margin per Billable Day, excluding shortfall commitment revenue, improved by 62% for the three months ended September 30, 2017, due to a combination of increased activity, pricing trending higher, and lower per day operating costs. However, Gross Margin per Billable Day declined by 5% for the nine months ended September 30, 2017 as compared to the same period of the prior year due to lower day rates in both Canada and the United States.

Contract drilling Adjusted EBITDA for the three months ended September 30, 2017 increased by $6.1 million to $6.6 million, as compared to $0.5 million in the same period of the prior year. The increase is mainly due to increased customer activity and higher Operating Revenue per Billable Day in both Canada and the United States, as prices continued to improve in the third quarter of 2017 as incremental work was awarded. For the nine months ended September 30, 2017, Adjusted EBITDA in the contract drilling segment increased by $19.5 million to $23.7 million, as compared to $4.2 million for the nine months ended September 30, 2016. The increase for the nine months ended September 30, 2017 is mainly due to increased customer activity resulting in improved Drilling Rig Utilization, a $4.6 million increase in shortfall commitment revenue, and the Company's ability to safely and efficiently reactivate equipment and crews without incurring significant costs, including rigs that had been idle for an extended period of time, partially offset by lower Operating Revenue per Billable Day in both Canada and the United States.

For the three and nine months ended September 30, 2017, cash administrative expenses, which exclude depreciation and stock based compensation, totalled $2.8 million and $8.4 million respectively, and were consistent with the same periods in the prior year.

Depreciation expense for the three months ended September 30, 2017 of $13.0 million was $0.2 million lower than the same period in the prior year, due to low capital spending and certain equipment being fully depreciated over the last four quarters. For the nine months ended September 30, 2017, depreciation expense of $39.1 million increased by $6.6 million as compared to the same period of the prior year due to the use of straight line depreciation effective April 1, 2016, as compared to the unit of production method of depreciation used previously. Due to lower than normal levels of activity in the first quarter of 2016, the change in depreciation method resulted in higher depreciation expense in the first quarter of 2017, as compared to the same period in the prior year. Additionally, in the second quarter of 2016, the Company recognized a loss on asset decommissioning of $5.2 million in the contract drilling segment.

Capital expenditures in the contract drilling segment totalled $5.6 million and $10.5 million for the three and nine months ended September 30, 2017 respectively. Capital expenditures in the third quarter of 2017 include $3.7 million of expansion capital and $1.9 million of maintenance capital, whereas capital expenditures for the nine months ended September 30, 2017 include $5.9 million of expansion capital and $4.6 million of maintenance capital. Contract drilling capital expenditures for the three and nine months ended September 30, 2017 represent increases of $5.2 million and $9.5 million respectively, from the $0.4 million and $1.0 million incurred in the corresponding periods of the prior year. The Company incurred expansion capital relating to rig upgrades in 2017, which have contributed to the increase in cash flow from operating activities year to date, as well as necessary maintenance capital related to the higher activity in the period.

Canadian Operations

During third quarter of 2017, Drilling Rig Utilization in Canada increased to an average of 36% as compared to an average of 20% in the third quarter of 2016. On a year to date basis, Drilling Rig Utilization in Canada increased to 36% in 2017 as compared to 14% in the same period of the prior year. The increase in utilization is due to higher demand as commodity prices improved in 2017, resulting in the Company's Operating Days increasing by 79% and 157% respectively for the three and nine months ended September 30, 2017, as compared to the same periods in 2016.

The Company's Drilling Rig Utilization in Canada of 36% in the third quarter of 2017 reflects an approximate 700 bps premium to the CAODC average of 29%, as compared to a 300 bps premium in the same period of the prior year. Drilling Rig Utilization in Canada of 36% for the nine months ended September 30, 2017 reflects an approximate 700 bps premium to the CAODC average of 29%, as compared to a 100 bps discount in the same period of the prior year. The increase in the Company's utilization premium in 2017 as compared to 2016 is due to:

- the quality of Western's drilling rig fleet;
- the ability of the Company's rig crews;
- the continued marketing efforts to broaden the Company's customer base; and
- improved commodity prices and a number of Western's customers increasing their capital budgets for 2017, as compared to 2016 when customer spending was limited.

Operating Revenue per Billable Day improved by 10% to total $16,825 for the three months ended September 30, 2017 compared to $15,256 in the same period of the prior year. The increase in day rates year over year can be attributed to increased industry activity as a result of improved commodity prices, with prices trending higher as incremental work is awarded. For the nine months ended September 30, 2017, Operating Revenue per Billable Day in Canada decreased by 1% as compared to the same period of the prior year and totalled $17,109, compared to $17,206 in 2016. Third party charges per Billable Day of $1,300 for the three months ended September 30, 2017 remained relatively consistent as compared to $1,200 for the same period in the prior year, whereas for the nine months ended September 30, 2017 third party charges per Billable Day totalled $1,400 and were higher as compared to $1,200 in the same period of the prior year. The increase for the three ended September 30, 2017 is mainly due to increased drill pipe inspections, partially offset by lower fuel charges, whereas for the nine months ended September 30, 2017, the increase is mainly due to increased fuel purchases, which are recharged to the customer.

United States Operations

Activity in the United States has improved and in the Williston basin in North Dakota, where the Company operates, drilling rig counts increased by 67% to 50 active drilling rigs at September 30, 2017, as compared to 30 active drilling rigs at September 30, 2016. Improved activity resulted in Western's Operating Days in the United States increasing by 127 days (or 88%) resulting in Drilling Rig Utilization of 59% for the three months ended September 30, 2017 compared to 32% in same period of the prior year. Similarly, for the nine months ended September 30, 2017, Western's Operating Days in the United States increased by 350 days (or 114%), resulting in Drilling Rig Utilization of 48% compared to 22% for the same period of the prior year. Additionally, third quarter Operating Revenue per Billable Day in the United States improved by 4% to US$19,801, as compared to the same period of the prior year, as increased activity has led to improved pricing. However, for the nine months ended September 30, 2017, Operating Revenue per Billable Day decreased by 12% to US$19,763, due to changes in the mix of rigs working on spot rates versus long term contracts, as the Company had one rig working on a long term legacy contract in 2016.

Production Services

Financial Highlights	**Three months ended Sept 30**			**Nine months ended Sept 30**		
(stated in thousands)	**2017**	**2016**	**Change**	**2017**	**2016**	**Change**
Revenue						
Operating Revenue(1)	12,411	10,460	19%	39,094	25,354	54%
Third party charges	546	630	(13%)	2,241	1,649	36%
Total revenue	12,957	11,090	17%	41,335	27,003	53%
Expenses						
Operating						
Cash operating expenses	9,992	8,650	16%	31,034	22,446	38%
Depreciation	3,280	3,554	(8%)	10,075	9,141	10%
Stock based compensation	6	53	(89%)	114	291	(61%)
Total operating expenses	13,278	12,257	8%	41,223	31,878	29%
Administrative						
Cash administrative expenses	1,478	1,461	1%	4,569	4,468	2%
Depreciation	76	92	(17%)	237	314	(25%)
Stock based compensation	18	55	(67%)	79	245	(68%)
Total administrative expenses	1,572	1,608	(2%)	4,885	5,027	(3%)
Gross Margin(1)	2,965	2,440	22%	10,301	4,557	126%
Gross margin as a percentage of Operating Revenue	24%	23%	100%	26%	18%	44%
Adjusted EBITDA(1)	1,487	979	52%	5,732	89	6,340%
Adjusted EBITDA as a percentage of Operating Revenue	12%	9%	33%	15%	-	100%
Operating Earnings(1)	(1,869)	(2,667)	(30%)	(4,580)	(9,366)	(51%)
Capital expenditures	719	205	251%	1,675	998	68%

Operating Highlights						
Well servicing rig fleet:						
Average active rig count(1)	17.7	15.6	13%	17.3	11.4	52%
End of period	66	66	-	66	66	-
Service rig Operating Revenue per Service Hour(1)	629	603	4%	661	646	2%
Service Hours(1)	16,328	14,335	14%	47,296	31,123	52%
Service rig utilization (1)	27%	24%	13%	26%	17%	53%

(1) See "Non-IFRS measures" on page 19 of this MD&A.

The Company's production services segment includes Eagle's well servicing fleet, which totals 66 rigs, as well as Aero's oilfield rental equipment. Operating Revenue for the quarter ended September 30, 2017 increased by $1.9 million (or 19%) to $12.4 million, compared to $10.5 million in same period of the prior year. In the third quarter of 2017, Eagle's contribution to Operating Revenue in the production services segment of $10.3 million compared to $8.7 million in the same period of the prior year, whereas Aero's contribution to Operating Revenue in the production services segment of $2.1 million in the third quarter of 2017 compared to $1.8 million in the same period of the prior year. Operating Revenue for the nine months ended September 30, 2017 increased by $13.7 million (or 54%) to $39.1 million, compared to $25.4 million in the same period of the prior year. For the nine months ended September 30, 2017, Eagle's contribution to Operating Revenue in the production services segment of $31.3 million compared to $20.1 million in the prior year, whereas Aero's contribution to Operating Revenue in the production services segment of $7.8 million compared to $5.3 million in the prior year. The increase in Operating Revenue for both Eagle and Aero for the three and nine months ended September 30, 2017, as compared to the same periods in the prior year, is due to higher industry activity and increased customer spending resulting from the improved commodity price environment.

Eagle's Service Hours increased by 14% in the third quarter of 2017 to 16,328 (27% utilization) as compared to 14,335 (24% utilization) in the same period of the prior year. Service Hours for the nine months ended September 30, 2017 improved by 52% to 47,296 (26% utilization) as compared to 31,123 (17% utilization) in the same period of the prior year. The increase in Service Hours for both the three and nine months ended September 30, 2017 is due to higher demand as a result of improved commodity prices. Operating Revenue per Service Hour increased by 4% for the three months ended September 30, 2017 to $629, as compared to $603 in the prior year. For the nine months ended September 30, 2017 Operating Revenue per Service Hour increased by 2% to $661 as compared to $646 in the prior year. Hourly rates have increased as market conditions continued to improve throughout 2017.

Adjusted EBITDA increased in the third quarter of 2017, as compared to the same period in the prior year, by $0.5 million (or 52%) to $1.5 million. For the nine months ended September 30, 2017, Adjusted EBITDA increased by $5.6 million (or 6,340%) to $5.7 million, compared to $0.1 million in the prior year. The higher Adjusted EBITDA for both the three and nine months ended September 30, 2017 was due to the improved commodity price environment, which increased the demand for the Company's services and resulted in prices beginning to recover.

During the three and nine months ended September 30, 2017, cash administrative expenses, which exclude depreciation and stock based compensation, totalled $1.5 million and $4.6 million respectively, and were consistent with the same periods of the prior year increasing 1% and 2% in each of the respective periods.

Depreciation expense in the third quarter of 2017 decreased by 5% to $3.4 million, as compared to $3.6 million in third quarter of 2016 due to low capital spending and certain equipment being fully depreciated over the last four quarters. For the nine months ended September 30, 2017, depreciation expense increased by 8% to $10.3 million, as compared to $9.5 million in the same period of the prior year due to the use of straight line depreciation effective April 1, 2016, as compared to the unit of production method of depreciation used previously. Due to lower than normal levels of activity in the first quarter of 2016, the change in depreciation methodology resulted in higher depreciation expense in the first quarter of 2017, as compared to the same period in the prior year.

During the three months ended September 30, 2017, capital expenditures in the production services segment totalled $0.7 million, as compared to $0.2 million for the three months ended September 30, 2016, and consisted of $0.4 million of expansion capital and $0.3 million of maintenance capital. During the nine months ended September 30, 2017, capital expenditures in the production services segment totalled $1.7 million, as compared to $1.0 million for the nine months ended September 30, 2016, and included expansion capital of $0.5 million and maintenance capital of $1.2 million.

Corporate

	Three months ended Sept 30			Nine months ended Sept 30		
(stated in thousands)	**2017**	**2016**	**Change**	**2017**	**2016**	**Change**
Administrative						
Cash administrative expenses	1,189	546	118%	3,812	2,041	87%
Depreciation	163	208	(22%)	496	643	(23%)
Stock based compensation	111	634	(82%)	1,079	2,162	(50%)
Total administrative expenses	1,463	1,388	5%	5,387	4,846	11%
Finance costs	5,521	5,708	(3%)	16,352	17,044	(4%)
Other items	235	266	(12%)	2,056	(1,466)	(240%)
Income taxes						
Current tax recovery	33	(370)	(109%)	33	(1,197)	(103%)
Deferred tax recovery	(4,104)	(5,673)	(28%)	(11,746)	(15,575)	(25%)
Total income taxes	(4,071)	(6,043)	(33%)	(11,713)	(16,772)	(30%)
Operating earnings(1)	(1,352)	(754)	79%	(4,308)	(2,684)	61%
Capital expenditures	-	-	-	1	1	-

(1) See "Non-IFRS measures" on page 19 of this MD&A.

Corporate cash administrative expenses, which exclude depreciation and stock based compensation, decreased by 4% in the third quarter of 2017, as compared to the second quarter of 2017 due to lower employee related costs. However, cash administrative expenses increased by $0.7 million and $1.8 million for the three and nine months ended September 30, 2017 respectively, due to higher employee related costs, coupled with one time professional fees incurred in the period.

For the three and nine month periods ended September 30, 2017, finance costs on a consolidated basis decreased by $0.2 million and $0.6 million respectively, as compared to the same periods in the prior year. The majority of the decrease is due to the Company reducing its available Credit Facilities in 2016 from $195.0 million to $60.0 million, resulting in lower standby fees. The Company had an effective interest rate on its borrowings of 8.3% throughout the nine month ending September 30, 2017 as compared to 8.6% throughout 2016.

Other items for the three months ended September 30, 2017 total $0.2 million, as compared to $0.3 million in the same period of the prior year, and consist of gains and losses on foreign exchange and asset sales. For the nine months ended September 30, 2017, other items total a loss of $2.1 million, as compared to a $1.5 million gain in the same period of the prior year, and include $1.6 million of transaction costs related to the unsuccessful acquisition of Savanna, as well as gains and losses on foreign exchange and asset sales.

For the three month period ended September 30, 2017, income taxes on a consolidated basis totalled a recovery of $4.1 million, representing an effective tax rate of 26.2%, as compared to an effective tax rate of 26.3% in the same period of 2016. For the nine month period ended September 30, 2017, income taxes on a consolidated basis totalled a recovery of $11.7 million, representing an effective tax rate of 26.5%, as compared to an effective tax rate of 26.1% in the same period of 2016.

Liquidity and Capital Resources

The Company's liquidity needs in the short and long term can be sourced in several ways including: available cash balances, funds from operations, borrowing against the Credit Facilities, new debt instruments, equity issuances and proceeds from the sale of assets. As at September 30, 2017, Western had working capital of $46.2 million, a decrease of $4.9 million from December 31, 2016. Included in working capital is cash and cash equivalents of $39.6 million, the majority of which is invested in liquid high interest savings accounts with banks within the Company's existing Credit Facilities syndicate. Western's consolidated Net Debt balance at September 30, 2017 was $225.8 million. During the nine months ended September 30, 2017, Western had Adjusted EBITDA of $25.6 million, a positive change in non-cash working capital of $3.0 million and received income tax refunds of $1.7 million, offset by cash interest payments of $21.1 million, capital expenditures of $12.2 million, and transaction costs of $1.6 million which resulted in a $5.0 million decrease in cash and cash equivalents in the period.

Currently, the Company has $265.0 million in Senior Notes outstanding which mature on January 30, 2019, with repayment planned for the first quarter of 2018. It is expected that the Senior Notes will be repaid by a combination of a single draw on the Company's $215.0 million Second Lien Facility in the first quarter of 2018, proceeds from the Private Placement and Bought Deal completed in October 2017, as well as through cash on hand and the funds available under the Company's amended Credit Facilities. Western has $80.0 million of available credit under the amended Credit Facilities described previously which mature on December 17, 2020. As such, cash from operations coupled with Western's working capital, including cash balances, and the previously mentioned financings completed in October 2017 are expected to be sufficient to cover Western's financial obligations.

Additionally, advances under the Credit Facilities will be limited by the Company's borrowing base. The borrowing base is applicable when the Debt Service Coverage ratio is less than 2.0 and either (i) more than $40.0 million is drawn on the Credit Facilities or (ii) the net book value of Western's property and equipment is less than $500.0 million. The borrowing base is determined as follows:

- 85% of eligible investment grade accounts receivable; plus
- 75% of eligible non-investment grade accounts receivable; plus
- 25% of the net book value of property and equipment to a maximum of $50.0 million.

Amounts borrowed under the Credit Facilities bear interest at the bank's Canadian prime rate, US base rate, LIBOR or the banker's acceptance rate plus an applicable margin depending, in each case, on the ratio of Consolidated Debt to Consolidated EBITDA as defined by the Credit Facilities agreement. Adjusted EBITDA, as defined by the Credit Facilities agreement, differs from Adjusted EBITDA as defined under Non-IFRS measures on page 19 of this MD&A, by including certain items such as realized foreign exchange gains or losses.

The Credit Facilities are secured by the assets of Western and its subsidiaries. As at September 30, 2017, the Revolving Facility and the Operating Facility were undrawn. A summary of the Company's amended financial covenants as at September 30, 2017 is as follows:

September 30, 2017	**Covenants**
Maximum Consolidated Senior Debt to Consolidated EBITDA Ratio (1)	3.0:1.0 or less
Maximum Consolidated Debt to Consolidated Capitalization Ratio (1)	0.6:1.0 or less
Minimum Debt Service Coverage Ratio (1)(2)	Not applicable

(1) See covenant definitions in Note 6 of the September 30, 2017 condensed consolidated financial statements.

(2) Consolidated Debt Service Coverage Ratio is only applicable when $40.0 million or more is drawn on the Credit Facilities or the net book value of Western's property and equipment is less than $500.0 million. The ratio must meet or exceed 1.0 as at and prior to March 31, 2018, 1.25 as at June 30, 2018, 1.5 as at September 30, 2018 and December 31, 2018 and 2.0 thereafter.

At September 30, 2017, Western is in compliance with all debt covenants under its amended Credit Facilities.

For the three months ended September 30, 2017 the Company had one significant customer comprising 10.5% of the Company's total revenue. The trade receivable balance outstanding related to this customer was 3.5% of the Company's total trade and other receivables as at September 30, 2017. For the nine months ended September 30, 2017, the Company had no customers comprising 10.0% or more of the Company's total revenue. For the three months ended September 30, 2016, the Company had one significant customer comprising 11.4% of the Company's total revenue. For the nine months ending September 30, 2016, the Company also had one significant customer comprising 11.8% of the Company's total revenue. The Company's significant customers may change from period to period.

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", where due to the spring thaw, provincial and county road bans restrict movement of heavy equipment. 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 (stated in thousands, except per share amounts)	**Sep 30, 2017**	**Jun 30, 2017**	**Mar 31, 2017**	**Dec 31, 2016**	**Sept 30, 2016**	**Jun 30, 2016**	**Mar 31, 2016**	**Dec 31, 2015**
Revenue	54,131	33,307	84,222	45,126	32,485	12,890	33,937	42,678
Operating Revenue(1)	51,111	30,469	78,153	41,649	30,665	12,393	32,200	40,458
Gross Margin(1)	12,299	5,667	24,458	8,507	5,685	2,703	8,867	13,372
Adjusted EBITDA(1)	6,882	121	18,625	3,506	896	(1,990)	3,364	7,573
Cash flow from operating activities	1,609	20,659	3,173	(1,327)	909	8,444	8,604	11,139
Net loss	(11,478)	(16,628)	(4,365)	(14,509)	(16,973)	(24,172)	(6,319)	(55,010)
per share - basic	(0.16)	(0.23)	(0.06)	(0.20)	(0.23)	(0.33)	(0.09)	(0.75)
per share - diluted	(0.16)	(0.23)	(0.06)	(0.20)	(0.23)	(0.33)	(0.09)	(0.75)
Total assets	737,385	758,278	785,040	793,525	794,170	814,757	842,492	876,608
Long term debt	264,958	264,702	264,150	264,070	264,118	264,145	264,118	264,155
Dividends declared	-	-	-	-	-	-	-	3,682

(1) See "Non-IFRS measures" on page 19 of this MD&A.

Revenue and Adjusted EBITDA were impacted by lower commodity prices throughout the last eight quarters with the most significant declines occurring during 2016, with Revenue and Adjusted EBITDA beginning to recover throughout 2017.

Net loss is impacted by the seasonal nature of the oilfield service industry in Canada. Net loss has been negative throughout the last eight quarters due to the prolonged decline in crude oil and natural gas prices. In addition, the Company recorded $68.5 million of impairments in the fourth quarter of 2015, significantly impacting net income in that period. A decommissioning loss of $5.2 million was recorded and the Company changed its depreciation methodology from unit of production to straight line in the second quarter of 2016, which significantly impacted net income.

Total assets over the last eight quarters have been impacted by the impairments noted above and the change in depreciation methodology.

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, 2017 are as follows:

(stated in thousands)	2017	2018	2019	2020	2021	Thereafter	Total
Senior Notes	-	-	265,000	-	-	-	265,000
Senior Notes interest	-	20,869	10,520	-	-	-	31,389
Trade payables and other current liabilities (1)	23,392	-	-	-	-	-	23,392
Operating leases	1,038	3,998	3,802	3,604	2,781	7,701	22,924
Purchase commitments	2,495	-	-	-	-	-	2,495
Other long term debt	231	422	241	362	-	-	1,256
Total	27,156	25,289	279,563	3,966	2,781	7,701	346,456

(1) Trade payables and other current liabilities exclude the Company's interest accrued as at September 30, 2017 on the Senior Notes.

Other than the Second Lien Facility, which closed subsequent to September 30, 2017 and is described previously, there have been no material changes in the contractual obligations detailed above, other than in the normal course of business, during the three months ended September 30, 2017.

Outstanding Share Data

	October 25, 2017	September 30, 2017	December 31, 2016
Common shares outstanding	92,174,594	73,974,594	79,795,944
Restricted share units outstanding - equity settled	200,807	200,807	410,311
Stock options outstanding	6,827,542	6,828,042	6,153,886

Off Balance Sheet Arrangements

As at September 30, 2017, Western had no off balance sheet arrangements in place.

Transactions with Related Parties

During the three and nine months ended September 30, 2017 and 2016, 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 from 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 are classified as 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:

The Company’s trade and other receivables are classified as 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.

(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 issuance of common shares are recognized as a deduction from equity, net of any tax effects.

Credit Risk

The Company's trade receivables are with customers in the crude oil and natural 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 trade receivable to monitor collectability. The Company records an allowance for doubtful accounts if an account is determined to be uncollectible. Any provisions recorded by the Company are reviewed regularly to determine if any of the balances provided for should be written off. The allowance for doubtful accounts could materially change as a result of fluctuations in the financial position of the Company's customers.

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, which are currently undrawn. Other long term debt, such as the Senior Notes and the Company's finance leases have fixed interest rates, however they are subject to interest rate fluctuations relating to refinancing as required.

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. 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, 2017 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 International Financial Reporting Standards ("IFRS").

During the three months ended September 30, 2017, there were no changes in internal control over financial reporting that materially affected, or are reasonably likely to materially affect, Western's 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, 2017, which were prepared in accordance with IFRS. The presentation of these financial statements in conformity with IFRS requires management to make estimates, judgments and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from these estimates. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected. 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 critical accounting estimates relate to business combinations, impairment, property and equipment, income taxes, stock based compensation, non-derivative financial liabilities and the Company's allowance for doubtful accounts.

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 value 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

An evaluation of whether or not an asset is impaired involves consideration of whether indicators of impairment exist. Factors which could indicate impairment exists include: significant underperformance of an asset relative to historical or projected operating results, significant changes in the manner in which an asset is used or in the Company's overall business strategy, the carrying amount of the net assets of the entity being more than its market capitalization or significant negative industry or economic trends. In some cases, these events are clear. However, in many cases, a clearly identifiable event indicating possible impairment does not occur. Instead, a series of individually insignificant events occur over a period of time leading to an indication that an asset may be impaired. Events can occur in these situations that may not be known until a date subsequent to their occurrence. Management continually monitors the Company's operating segments, the markets, and the business environment, and makes judgments and assessments about conditions and events in order to conclude whether a possible impairment exists.

When there are indicators of impairment and at a minimum annually in the case of goodwill, the recoverable amount of the asset is estimated to determine the amount of impairment, if any. Where it is not possible to estimate the recoverable amount of an individual asset, the Company estimates the recoverable amount of the cash generating unit ("CGU") to which the asset belongs. A CGU is the smallest identifiable group of assets that generates cash inflows that are largely independent of the cash inflows from other assets or groups of assets. The determination of CGUs is based on management judgement.

The recoverable amount for property and equipment is the higher of fair value less costs to sell and value in use, whereas for goodwill the recoverable amount is based on the value in use calculation. In assessing fair value less costs to sell, the estimated future cash flows are discounted to their present value using an appropriate discount rate that reflects current market assessments of the time value of money and the risks specific to the asset or CGU. Arriving at the estimated future cash flows involves significant judgments, estimates and assumptions, including those associated with the future cash flows of the CGU, determination of the CGU, discount rates and asset useful lives.

If indicators conclude that the asset is no longer impaired, the Company will reverse impairment losses on assets. Impairment losses on goodwill are not reversed. Similar to determining if an impairment exists, judgment is required in assessing if a reversal of an impairment loss is required. 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, 2017, the Company completed its assessment of impairment and determined there was no impairment of property and equipment. Additionally, there were no reversals of previous property and equipment impairment losses during the three or nine months ended September 30, 2017.

Property and equipment

Property and equipment is depreciated over the estimated useful life of the asset while factoring in an asset's estimated residual value as determined by management. All estimates of useful lives and residual values are set out in Note 3 (g) of the December 31, 2016 annual consolidated financial statements. Assessing the reasonableness of the estimated useful life, residual value and the appropriate depreciation methodology requires judgment and is based on management's experience and knowledge of the industry. Additionally, when determining to decommission an asset, future utilization and economic conditions are considered based on management's experience and knowledge of the industry and requires management's judgement.

Income taxes

Preparation of the condensed 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 condensed 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 income tax assets. To the extent that such recovery is not probable, recognized deferred tax assets must be reduced. Judgment is required in determining the provision for income taxes and recognition of deferred tax assets and liabilities. Management must also exercise judgment 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.

Stock based compensation

The fair values of employee stock options and equity settled restricted share units ("RSUs") are measured using a Black Scholes option pricing model. Measurement inputs include the common share price on the grant date, the exercise price of the instrument, the expected common share price volatility, the weighted average expected life of the instruments, the expected dividends and the risk-free interest rate. Service and non-market performance conditions are not taken into account in determining fair value.

Stock based compensation recognized is also determined based on management's grant date estimate of the forfeitures that are expected to occur over the life of the stock options and equity settled RSUs. Cash settled RSUs outstanding are fair valued using a mark-to-market calculation based on the Company's closing common share price at the end of the period. The number of stock options and RSUs that actually vest could differ from the estimated number of awards expected to vest and any differences between the actual and estimated forfeitures are recognized prospectively as they occur.

Non-derivative financial liabilities

The Company records its financial instruments at fair value on inception with changes in fair value recorded when required by the Company's classification of such instruments.

Calculation of the fair value of the Company's financial instruments is complex and requires judgment around the selection of market inputs and is based on many variables including but not limited to credit spreads and interest rate spreads which are factors outside management's control.

The fair value of non-derivative financial liabilities for disclosure purposes is calculated based on the present value of future principal and interest payments, discounted at the market rate of interest at the reporting date. For finance leases, the market rate of interest is determined by reference to similar lease agreements.

Allowance for doubtful accounts

The Company reviews its outstanding accounts receivable balances on at least a monthly basis to determine collectability. Accounts receivable balances are also reviewed as circumstances change in the economy and/or a customer's credit worthiness changes. An allowance for doubtful accounts is recorded if an account is considered uncollectible.

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, 2016 as filed on SEDAR at www.sedar.com. The Company's primary business risks as at September 30, 2017 are as follows:

- The Company's business relies on the crude oil and natural gas exploration and production industry which is subject to a number of risks including general economic conditions, fluctuations in demand and supply of crude oil and natural gas production, 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 crude oil and natural gas and environmental protection for the crude oil and natural gas industry as a whole. Risks impacting the crude oil and natural gas exploration and production industry, including the ability of crude oil and natural 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.
- The current low commodity price environment is expected to continue throughout 2017. If a low commodity price environment persists as expected, the demand for the Company's equipment and services will remain lower than

normal and the Company's utilization rates and revenue will continue to be adversely affected during such time. In addition, lower utilization and revenue could result in the Company not being in compliance with certain covenants in its Credit Facilities and under its Senior Note indenture, which in turn could restrict the Company's ability to access its Credit Facilities, pay distributions and incur additional debt in the future.

- The Company's exploration and production customers' facilities and other operations emit greenhouse gases and require them to comply with legislation in those provinces and states where they operate. On November 22, 2015, the Alberta government announced new emissions regulations, including an economy wide price on carbon emissions effective January 1, 2017 and methane emission reductions. In September 2016, the Canadian Federal government announced its intention to impose a national carbon price on the provinces, requiring provinces to adopt either a carbon price or cap-and-trade approach and to meet a federally established minimum price. The direct or indirect costs of these new greenhouse gas emission reduction regulations, as well as regulations which may be adopted in these or other jurisdictions in the future, may have a material adverse effect on the Company's business, financial condition and results of operations and cash flows, as well as impacting the Company's customers' operations.
- 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 crude 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 financial results.
- Competition among oilfield service companies offering related services is significant. Some competitors are larger and have greater revenue than the Company and overall greater financial resources. The Company's ability to generate revenue 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.
- During the prolonged downturn many oilfield service workers have left the industry and, therefore, if activity increases it may be difficult for the Company to attract and retain field crews. This could have a material adverse effect on the Company's business and financial results.
- 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 ability of the Company to make payments, dividends or enter into certain transactions will be subject to the applicable laws and contractual restrictions in the instruments governing its indebtedness, including the Credit Facilities and Senior Notes.
- 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.
- The loss of a significant customer or customers, or any decrease in services provided or prices charged to a significant customer or customers could have a material adverse effect on the Company's business and financial results.
- The Company relies on various information systems to manage its business. If these systems were compromised as a result of a successful cyber-attack, this could have a material adverse effect on the Company business and financial results.

Non-IFRS Measures

Western uses certain measures in this MD&A which do not have any standardized meaning as prescribed by IFRS. These measures, which are derived from information reported in the condensed consolidated financial statements, 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. These Non-IFRS measures are identified and defined as follows:

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 such as rig fuel, which at the customer's request may be paid for initially by Western, then recharged in its entirety to Western's customers.

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, stock based compensation, 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 Sept 30		**Nine months ended Sept 30**	
(stated in thousands)	**2017**	**2016**	**2017**	**2016**
Operating Revenue				
Drilling	38,711	20,210	120,754	49,922
Production services	12,411	10,460	39,094	25,354
Less: inter-company eliminations	(11)	(5)	(115)	(18)
	51,111	**30,665**	**159,733**	**75,258**
Third party charges	3,020	1,820	11,927	4,054
Revenue	**54,131**	**32,485**	**171,660**	**79,312**
Less: operating expenses	(58,049)	(43,601)	(178,419)	(103,904)
Add:				
Depreciation - operating	16,196	16,712	48,989	41,352
Stock based compensation - operating	21	89	194	495
Gross Margin	**12,299**	**5,685**	**42,424**	**17,255**

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 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 Adjusted EBITDA but also factors in the depreciation expense incurred in the period.

The following table provides a reconciliation of net loss under IFRS, as disclosed in the condensed consolidated statements of operations and comprehensive income, to earnings before interest and finance costs, taxes, depreciation and amortization (“EBITDA”), Adjusted EBITDA and Operating Loss:

	Three months ended Sept 30		Nine months ended Sept 30	
(stated in thousands)	**2017**	**2016**	**2017**	**2016**
Net loss	**(11,478)**	**(16,973)**	**(32,471)**	**(47,464)**
Add:				
Finance costs	5,521	5,708	16,352	17,044
Income tax recovery	(4,071)	(6,043)	(11,713)	(16,772)
Depreciation - operating	16,196	16,712	48,989	41,352
Depreciation - administrative	300	378	929	1,204
EBITDA	**6,468**	**(218)**	**22,086**	**(4,636)**
Add:				
Stock based compensation - operating	21	89	194	495
Stock based compensation - administrative	158	759	1,292	2,651
Loss on asset decommissioning	-	-	-	5,225
Other items	235	266	2,056	(1,466)
Adjusted EBITDA	**6,882**	**896**	**25,628**	**2,269**
Subtract:				
Depreciation - operating	(16,196)	(16,712)	(48,989)	(41,352)
Depreciation - administrative	(300)	(378)	(929)	(1,204)
Operating Loss	**(9,614)**	**(16,194)**	**(24,290)**	**(40,287)**

Net Debt

The following table provides a reconciliation of long term debt under IFRS, as disclosed in the condensed consolidated balance sheets to Net Debt:

(stated in thousands)	**September 30, 2017**	**December 31, 2016**
Long term debt	264,958	264,070
Current portion of long term debt	500	684
Less: cash and cash equivalents	(39,576)	(44,597)
Net Debt	**225,882**	**220,157**

Defined Terms:

Average active rig count (contract drilling): Calculated as drilling rig utilization – Billable Days multiplied by the average number of drilling rigs in the Company’s fleet for the period.

Average active rig count (production services): Calculated as service rig utilization multiplied by the average number of service rigs in the Company’s fleet for the period.

Billable Days: Defined as Operating Days plus rig mobilization days.

Drilling rig utilization – Operating Days (or “Drilling Rig Utilization”): Calculated based on Operating Days divided by total available days.

Drilling rig utilization – Billable Days: Calculated based on Billable Days divided by total available days.

Operating Days: Defined as contract drilling days, calculated on a spud to rig release basis.

Service Hours: Defined as well servicing hours completed.

Service rig utilization: Calculated based on Service Hours divided by available hours, being 10 hours per day, per well servicing rig, 365 days per year in 2017 (2016: 366 days).

Contract Drilling Rig Classifications:

Cardium class rig: Defined as any contract drilling rig which has a total hookload less than or equal to 399,999 lbs (or 177,999 daN).

Montney class rig: Defined as any contract drilling rig which has a total hookload between 400,000 lbs (or 178,000 daN) and 499,999 lbs (or 221,999 daN).

Duvernay class rig: Defined as any contract drilling rig which has a total hookload equal to or greater than 500,000 lbs (or 222,000 daN).

Abbreviations:

- Barrel (“bbl”);
- Basis point (“bps”): A 1% change equals 100 basis points and a 0.01% change is equal to one basis point;
- Canadian Association of Oilwell Drilling Contractors (“CAODC”);
- DecaNewton (“daN”);
- International Financial Reporting Standards (“IFRS”);
- Pounds (“lbs”);
- Thousand cubic feet (“mcf”);
- West Texas Intermediate (“WTI”); and
- Western Canadian Sedimentary Basin (“WCSB”).

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”, or other comparable terminology.

In particular, forward-looking information in this MD&A includes, but is not limited to, statements relating to commodity pricing; the future demand for and utilization of the Company’s services and equipment; the pricing for the Company’s services and equipment; the terms of existing and future drilling contracts in Canada and the US and the revenue resulting therefrom (including the number of Operating Days typically generated from the Company’s contracts); the Company’s expansion and maintenance capital plans for 2017; the Company’s liquidity needs including the ability of current capital resources to cover Western’s financial obligations and the 2017 capital budget; the expected use of proceeds of the Second Lien Facility, Private Placement and the Bought Deal; the Company’s expected sources of funding to support such capital plans and the Company’s ability to adjust capital spending for the remainder of 2017 if market conditions, including customer demand changes; the expected benefits from cost control measures; the use and availability of the Company’s Credit Facilities; pricing for Western’s services and impact on Adjusted EBITDA; the Company’s ability to maintain certain covenants under its Credit Facilities; the future declaration of dividends; expectations as to the increase in crude oil transportation capacity through pipeline development; the potential impact of changes to environmental laws and regulations and the implementation of a carbon tax in Alberta; the expectation of continued foreign investment into the Canadian crude oil and natural gas industry; expectations relating to producer spending, and the Company’s ability to find and maintain enough field crew members; the Company’s change to its depreciation assumptions; and forward-looking statements under the headings “Disclosure Controls and Procedures and Internal Controls Over Financial Reporting” and “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 crude oil and natural gas; the continued low levels of and pressures on commodity pricing; the continued business relationship between the Company and its significant customers; general economic and financial market conditions; 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 on 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 2017 and that commodity prices will remain low, 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.