Western ENERGY SERVICES CORP.

2017 Q4

2017 Management Discussion & Analysis — Date: February 21, 2018

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, 2017 and 2016. This Management Discussion and Analysis ("MD&A") is dated February 21, 2018. All amounts are denominated in Canadian dollars (CDN$) unless otherwise identified.

Financial Highlights	**Three months ended December 31**			**Year ended December 31**			
(stated in thousands, except share and per share amounts)	**2017**	**2016**	**Change**	**2017**	**2016**	**Change**	**2015**
Revenue	66,515	45,126	47%	238,175	124,438	91%	227,524
Operating Revenue[1]	59,255	41,649	42%	218,988	116,907	87%	216,485
Gross Margin[1]	15,886	8,507	87%	58,310	25,762	126%	85,951
Gross Margin as a percentage of Operating Revenue	27%	20%	35%	27%	22%	23%	40%
Adjusted EBITDA[1]	10,067	3,506	187%	35,695	5,775	518%	60,545
Adjusted EBITDA as a percentage of Operating Revenue	17%	8%	113%	16%	5%	220%	28%
Cash flow from operating activities	(800)	(1,327)	(40%)	24,641	16,631	48%	90,955
Capital expenditures	5,912	2,724	117%	18,132	4,719	284%	33,562
Net loss	(4,974)	(14,509)	(66%)	(37,445)	(61,973)	(40%)	(129,139)
-basic net loss per share	(0.06)	(0.20)	(70%)	(0.48)	(0.84)	(43%)	(1.74)
-diluted net loss per share	(0.06)	(0.20)	(70%)	(0.48)	(0.84)	(43%)	(1.74)
Weighted average number of shares							
-basic	88,812,216	73,795,896	20%	77,601,827	73,703,437	5%	74,238,320
-diluted	88,812,216	73,795,896	20%	77,601,827	73,703,437	5%	74,238,320
Outstanding common shares as at period end	92,175,598	73,795,944	25%	92,175,598	73,795,944	25%	73,646,292
Dividends declared	-	-	-	-	-	-	20,392
Dividends declared per common share	-	-	-	-	-	-	0.275
Operating Highlights[1]							
Contract Drilling							
Canadian Operations							
Average active rig count	21.6	16.2	33%	20.6	10.0	106%	14.3
Operating Revenue per Billable Day	18,807	16,657	13%	17,558 [3]	16,984 [4]	3%	23,458
Operating Revenue per Operating Day	21,100	18,811	12%	19,446 [3]	19,058 [4]	2%	25,821
Drilling rig utilization - Billable Days	43%	32%	34%	41%	20%	105%	29%
Drilling rig utilization - Operating Days	38%	28%	36%	37%	17%	118%	26%
CAODC industry average utilization[2]	28%	25%	12%	29%	17%	71%	23%
United States Operations							
Average active rig count	4.0	1.7	135%	3.1	1.4	121%	1.6
Operating Revenue per Billable Day (US$)	18,038	20,197	(11%)	19,198	21,805	(12%)	29,483 [5]
Operating Revenue per Operating Day (US$)	21,265	23,440	(9%)	22,338	25,166	(11%)	33,166 [5]
Drilling rig utilization - Billable Days	75%	34%	121%	61%	28%	118%	32%
Drilling rig utilization - Operating Days	63%	29%	117%	52%	24%	117%	29%
Production Services							
Average active rig count	17.0	17.6	(3%)	17.2	12.9	33%	19.5
Service rig Operating Revenue per Service Hour	708	638	11%	673	643	5%	779
Service rig utilization	26%	27%	(4%)	26%	20%	30%	30%

(1) See "Non-IFRS measures" on page 21 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 year ended December 31, 2017.

(4) Excludes shortfall commitment revenue from take or pay contracts of $1.8 million for the year ended December 31, 2016.

(5) Excludes shortfall commitment and standby revenue from take or pay contracts of US$4.5 million for the year ended December 31, 2015.

Financial Position at (stated in thousands)	December 31, 2017	December 31, 2016	December 31, 2015
Working capital	62,866	51,118	70,679
Property and equipment	652,828	708,567	773,647
Total assets	760,504	793,525	876,608
Long term debt	265,219	264,070	264,155

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 21 of this MD&A. Abbreviations for standard industry terms are included on page 23 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 50 rigs operating through Horizon. Of the Canadian fleet, 23 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 six drilling rigs operating through Stoneham, including five Duvernay class triple drilling rigs. Western is also the fifth 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. The following table summarizes average crude oil and natural gas prices, as well as average foreign exchange rates for the three months ended December 31, 2017 and 2016 and for the years ended December 31, 2017 and 2016.

	Three months ended December 31			Year ended December 31		
	2017	2016	Change	2017	2016	Change
Average crude oil and natural gas prices(1)(2)						
Crude Oil						
West Texas Intermediate (US$/bbl)	55.28	49.16	12%	50.81	43.37	17%
Western Canadian Select (CDN$/bbl)	49.10	45.84	7%	49.49	39.27	26%
Natural Gas						
30 day Spot AECO (CDN$/mcf)	1.67	3.11	(46%)	2.23	2.18	2%
Average foreign exchange rates(2)						
US dollar to Canadian dollar	1.27	1.33	(5%)	1.30	1.32	(2%)

(1) See "Abbreviations" on page 23 of this MD&A.

(2) Source: Bloomberg

West Texas Intermediate ("WTI") on average improved in the fourth quarter of 2017 as compared to the third quarter of 2017, increasing by 15%, and was 12% higher compared to the same period in the prior year. For Western's Canadian customers, the impact of the weaker US dollar when translating WTI into Canadian dollars, resulted in only a 7% increase for the three months ended December 31, 2017, as compared to the same period in the prior year. Canadian heavy crude pricing improved in the fourth quarter of 2017, as Western Canadian Select ("WCS") on average increased by 4% as compared to the third quarter of 2017, and by 7% as compared to the same period of the prior year. The prices for condensate and natural gas liquids ("NGL") in Canada also improved in the fourth quarter of 2017, as compared to the same period in the prior year. For the year ended December 31, 2017, WTI was 17% higher than the prior year, WCS on average increased by 26% in 2017 as compared to 2016, and the price for condensate and NGLs in Canada also improved year over year. When translating WTI into the Canadian dollar equivalent for the year ended December 31, 2017, the weaker US dollar resulted in a 15% increase as compared to the year ended December 31, 2016. Canadian natural gas prices, such as AECO, declined quarter over quarter, decreasing on average by 1% from the third quarter of 2017 to the fourth quarter of 2017 and decreasing by 46% compared to the fourth quarter of 2016. Additionally, for the year ending December 31, 2017, AECO increased by 2% as compared to 2016.

Improved market conditions in 2017, particularly the improved crude oil and condensate prices, 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 54% in 2017 as compared to 2016. Similarly, as reported by Baker Hughes, a GE Company, the average number of active drilling rigs in the United States increased approximately 71% in 2017 as compared to 2016.

Operational results for the three months ended December 31, 2017 include:

- Operating Revenue in the fourth quarter of 2017 benefited from the improved economic conditions and resulted in higher customer spending and a corresponding increase in demand for Western's services. Fourth quarter Operating Revenue increased by $17.7 million (or 42%) to $59.3 million in 2017 as compared to $41.6 million in the same period of the prior year. In the contract drilling segment, Operating Revenue totalled $45.9 million in the fourth quarter of 2017 as compared to $29.0 million in the fourth quarter of 2016, an increase of $16.9 million (or 58%); while in the production services segment, Operating Revenue totalled $13.4 million for the three months ended December 31, 2017 as compared to $12.7 million in the same period of the prior year, an increase of $0.7 million (or 5%). Higher utilization in the contract drilling segment in the fourth quarter of 2017, and improved pricing in Canada, 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 38% in the fourth quarter of 2017 compared to an average of 28% in the fourth quarter of 2016, reflecting a 1,000 basis points ("bps") increase. Fourth quarter 2017 Drilling Rig Utilization represented a premium of 1,000 bps to the CAODC industry average of 28%, whereas in the fourth quarter of 2016, Drilling Rig Utilization of 28% represented a 300 bps premium to the industry average. The increase in the Company's utilization premium to the industry average in the fourth quarter of 2017 is attributable to:
        - the quality of Western's drilling rig fleet, which meets current customer demands;
        - 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 in 2017, as compared to 2016 when customer spending was limited.

      These factors, combined with improved market conditions, resulted in higher demand for the Company's drilling rigs and a 13% improvement in Operating Revenue per Billable Day in the fourth quarter of 2017, as compared to the same period in the prior year;
    - In the United States, five of the Company's six drilling rigs operated during the quarter, two of which were working on long term contracts, resulting in Drilling Rig Utilization of 63% in the fourth quarter of 2017, as compared to 29% in the same period of the prior year. In the fourth quarter of 2017, Operating Revenue per Billable Day in the United States decreased by 11% as compared to the fourth quarter of 2016 mainly 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 for much of the quarter at a favorable day rate; and
    - Well servicing utilization of 26% in the fourth quarter of 2017 compared to 27% in the same period of the prior year. Improved market conditions resulted in an 11% increase in hourly rates during the fourth quarter of 2017, as compared to the same period in the prior year, mainly due to increased demand for fully crewed rigs, which resulted in higher hourly rates in 2017. Lower utilization was offset by improved pricing, which led to a $0.8 million (or 8%) increase in well servicing Operating Revenue in the period.
- Fourth quarter Adjusted EBITDA improved by $6.6 million (or 187%) to $10.1 million in 2017 as compared to $3.5 million in the fourth quarter of 2016. The year over year change in Adjusted EBITDA is due to increased activity in the contract drilling segment and improved pricing in Canada, which was partially offset by lower pricing in the United States and decreased well servicing activity.
- Administrative expenses, excluding depreciation and stock based compensation, increased by $0.8 million (or 16%) to $5.8 million, as compared to $5.0 million in the fourth quarter of 2016, mainly due to higher employee related costs.

- The Company incurred a net loss of $5.0 million in the fourth quarter of 2017 ($0.06 per basic common share) as compared to a net loss of $14.5 million in the same period in 2016 ($0.20 per basic common share). The change can be attributed to the following:
  - A $6.6 million increase in Adjusted EBITDA due to higher utilization in the contract drilling segment and improved pricing for contract drilling and well servicing in Canada, partially offset by lower contract drilling pricing in the United States and decreased well servicing activity;
  - A $1.6 million increase in income tax recoveries mainly due to the decrease in the federal corporate tax rates in the United States from 35.0% to 21.0%, which was signed into law in December 2017;
  - A $0.6 million increased gain in other items, which mainly consist of gains and losses on foreign exchange and asset sales;
  - A $0.4 million decrease in depreciation expense mainly due to certain equipment being fully depreciated over the last four quarters; and
  - A $0.2 million decrease in stock based compensation expense as fewer unvested stock options and restricted share units were outstanding in the quarter.
- Fourth quarter 2017 capital expenditures of $5.9 million included $3.0 million of expansion capital and $2.9 million of maintenance capital. In total, capital spending in the fourth quarter of 2017 increased by $3.2 million from the $2.7 million incurred in the fourth quarter of 2016. The Company incurred expansion capital mainly related to drilling rig upgrades and the purchase of oilfield rental equipment in the fourth quarter of 2017, as well as necessary maintenance capital related to the higher activity in the period.

Operational results for the year ended December 31, 2017 include:

- Operating Revenue in 2017 benefited from improved market conditions and higher customer spending which resulted in a corresponding increase in demand for Western's services. In 2017, Operating Revenue increased by $102.1 million (or 87%) to $219.0 million as compared to $116.9 million in 2016. In the contract drilling segment, Operating Revenue totalled $166.7 million in 2017, an increase of $87.8 million (or 111%), as compared to $78.9 million in 2016, and included $6.4 million in shortfall commitment revenue in 2017, as compared to $1.8 million in shortfall commitment revenue in 2016; while in the production services segment, Operating Revenue totalled $52.5 million, an increase of $14.4 million (or 38%) as compared to $38.1 million in 2016. Higher utilization in all divisions and higher pricing in Canada in 2017 as compared to 2016, impacted Operating Revenue in the contract drilling and production services segments as described below:
  - Drilling Rig Utilization in Canada of 37% for the year ended December 31, 2017, compared to 17% for the prior year, reflects a 2,000 bps increase. Drilling Rig Utilization of 37% in 2017 represents an 800 bps premium to the CAODC industry average, whereas in 2016, Drilling Rig Utilization of 17% was on par with the CAODC industry average of 17%. The increase in the Company's utilization premium in 2017 is attributable to:
    - the quality of Western's drilling rig fleet which meets current customer demands;
    - 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 in 2017, as compared to 2016 when customer spending was limited.

    These factors, combined with improved market conditions, resulted in higher demand for the Company's drilling rigs in 2017. Additionally, Western continued to increase its market share in 2017. Western's 50 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. The factors noted above led to improved Operating Revenue per Billable Day in 2017 particularly in the latter part of the year, resulting in a 3% year over year improvement as compared to 2016.
  - In the United States, five of the Company's six drilling rigs operated during the period, two of which were working on long term contracts, resulting in Drilling Rig Utilization of 52% for the year ended December 31, 2017, as compared to 24% in the prior year. Operating Revenue per Billable Day in the United States decreased by 12% for the year ended December 31, 2017, due to changes in the mix of rigs working on spot rates versus long term contracts, as compared to the prior year when the Company had one rig working on a long term legacy contract for much of the year at a favorable day rate; and
  - Well servicing utilization of 26% for the year ended December 31, 2017 compared to 20% in the prior year. Continued improvements in the economic environment helped increase activity year over year. Additionally, well

servicing hourly rates increased by 5% in 2017, as compared to 2016, as activity continued to improve throughout 2017. Improved utilization and pricing led to a $12.0 million (or 39%) year over year increase in well servicing Operating Revenue.

- Adjusted EBITDA increased by $29.9 million (or 518%) to $35.7 million in 2017 as compared to $5.8 million in 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 Canada, which was partially offset by lower pricing in the United States.
- Administrative expenses in 2017, excluding depreciation and stock based compensation, increased by $2.6 million (or 13%) to $22.6 million as compared to $20.0 million in 2016. 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 $37.4 million for the year ended December 31, 2017 ($0.48 per basic common share) as compared to a net loss of $62.0 million for the year ended December 31, 2016 ($0.84 per basic common share). The decrease in net loss can be attributed to the following:
  - A $29.9 million increase in Adjusted EBITDA due to higher utilization in both the contract drilling and production services segments, improved contract drilling and well servicing pricing in Canada, and increased shortfall commitment revenue;
  - A prior period loss on asset decommissioning of $5.2 million in the contract drilling segment;
  - A $1.8 million decrease in stock based compensation expense as fewer of the Company's unvested stock options and restricted share units were outstanding in the period; and
  - A $0.6 million decrease in finance costs mainly due to the Company reducing its available Credit Facilities in 2016, resulting in lower standby fees.

  Offsetting the above mentioned items are the following:
  - An increase of $7.0 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 $2.9 million increase in other items which totaled a loss of $1.4 million in 2017, as compared to a gain of $1.5 million in 2016, and include $1.6 million in transaction costs related to the unsuccessful acquisition of Savanna Energy Services Corp. ("Savanna") in 2017, as well as gains and losses on foreign exchange and asset sales; and
  - A $3.4 million decrease in income tax recovery due to improved earnings before taxes, offset by the decrease in the United States federal corporate tax rates from 35.0% to 21.0%, which was signed into law in December 2017.
- Capital expenditures of $18.1 million for the year ended December 31, 2017 included $9.4 million of expansion capital and $8.7 million of maintenance capital. In total, capital spending for 2017 increased by $13.4 million from the $4.7 million incurred in 2016. The Company incurred expansion capital mainly related to drilling rig upgrades in 2017, which have contributed to the increase in cash flow from operating activities in the year, as well as necessary maintenance capital related to the higher activity in the period.
- 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 was available in a single draw which was made subsequent to December 31, 2017, and was used to repay a portion of the Company's outstanding 7⅞% senior unsecured notes (the "Senior Notes"). Interest is 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 are payable annually in quarterly installments beginning on July 1, 2018, with the balance due on January 31, 2023. In conjunction with the Second Lien Facility, Western 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 expire on October 17, 2020;
  - A private placement with AIMCo 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 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 remained unchanged;
  - The interest coverage and current ratio covenants were permanently removed;
  - A debt service coverage ratio was 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 the net book value of property and equipment is less than $400.0 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 continues to include an accordion feature, whereby an incremental $50.0 million of borrowing would be available, subject to the approval of the lenders.
- Subsequent to December 31, 2017, on January 31, 2018 the Company completed the one time draw of $215.0 million on its Second Lien Facility. The proceeds from the Second Lien Facility draw, along with cash on hand and funds available under the Credit Facilities were used to redeem the Senior Notes at their par value of $265.0 million on February 1, 2018.

Outlook

Currently, 37 of Western's drilling rigs are operating. Four of Western's 56 drilling rigs (or 7%) are under long term take or pay contracts, with one 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 2018 remains unchanged and is expected to total $20 million, including capital spending carry forward for 2017 of approximately $2 million, with $8 million allocated for expansion capital and $12 million for maintenance capital. Western believes the 2018 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.

Since hitting 10 year lows in the first quarter of 2016, crude oil prices, while remaining well below previous highs, have improved. As such, North American drilling rig counts recovered in 2017 and the Company is expecting stable year over year activity levels in 2018. Improving gross margin continues to be a priority for the Company and, as has been demonstrated over the last three quarters, Western is working to implement higher rates with each rig that is awarded work. Prices for Western's services remain below historical levels and 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. As at December 31, 2017, in addition to $48.8 million in cash and cash equivalents, Western had $80.0 million of available credit under its Credit Facilities, which do not mature until December 17, 2020. Western repaid the $265.0 million in outstanding Senior Notes at par in the first quarter of 2018 with proceeds from the $215.0 million Second Lien Facility, along with cash on hand and funds available under the Credit Facilities. Completing these financing transactions has lowered Western's total debt and leverage metrics, decreased Western's effective interest rates and extended 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 Senior Notes.

Oilfield service activity in Canada will be affected by the development of resource plays in Alberta and northeast British Columbia which will be impacted by pipeline construction, 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 December 31**			**Year ended December 31**		
(stated in thousands)	**2017**	**2016**	**Change**	**2017**	**2016**	**Change**
Revenue						
Operating Revenue[1]	45,906	28,965	58%	166,660	78,887	111%
Third party charges	6,596	2,762	139%	16,282	5,167	215%
Total revenue	52,502	31,727	65%	182,942	84,054	118%
Expenses						
Operating						
Cash operating expenses	39,677	26,382	50%	137,994	66,010	109%
Depreciation	12,991	13,113	(1%)	51,905	45,324	15%
Stock based compensation	49	83	(41%)	129	287	(55%)
Total operating expenses	52,717	39,578	33%	190,028	111,621	70%
Administrative						
Cash administrative expenses	2,830	2,819	-	11,245	11,297	-
Depreciation	55	75	(27%)	251	322	(22%)
Stock based compensation	54	102	(47%)	188	345	(46%)
Total administrative expenses	2,939	2,996	(2%)	11,684	11,964	(2%)
Gross Margin[1]	12,825	5,345	140%	44,948	18,044	149%
Gross Margin as a percentage of Operating Revenue	28%	18%	56%	27%	23%	17%
Adjusted EBITDA[1]	9,995	2,526	296%	33,703	6,747	400%
Adjusted EBITDA as a percentage of Operating Revenue	22%	9%	144%	20%	9%	122%
Operating Loss[1]	(3,051)	(10,662)	(71%)	(18,453)	(38,899)	(53%)
Capital expenditures	4,416	2,158	105%	14,959	3,154	374%

Operating Highlights						
Canadian Operations						
Contract drilling rig fleet:						
Average active rig count[1]	21.6	16.2	33%	20.6	10.0	106%
End of period	50	51	(2%)	50	51	(2%)
Operating Revenue per Billable Day[1]	18,807	16,657	13%	17,558 [3]	16,984 [4]	3%
Operating Revenue per Operating Day[1]	21,100	18,811	12%	19,446 [3]	19,058 [4]	2%
Operating Days[1]	1,774	1,317	35%	6,801	3,276	108%
Number of meters drilled	508,552	349,172	46%	1,987,020	822,293	142%
Number of wells drilled	137	106	30%	544	255	113%
Average Operating Days per well	12.9	12.5	3%	12.5	12.9	(3%)
Drilling rig utilization - Billable Days[1]	43%	32%	34%	41%	20%	105%
Drilling rig utilization - Operating Days[1]	38%	28%	36%	37%	17%	118%
CAODC industry average utilization[1][2]	28%	25%	12%	29%	17%	71%
United States Operations						
Contract drilling rig fleet:						
Average active rig count[1]	4.0	1.7	135%	3.1	1.4	121%
End of period	6	5	20%	6	5	20%
Operating Revenue per Billable Day (US$)[1]	18,038	20,197	(11%)	19,198	21,805	(12%)
Operating Revenue per Operating Day (US$)[1]	21,265	23,440	(9%)	22,338	25,166	(11%)
Operating Days[1]	313	134	134%	969	440	120%
Number of meters drilled	82,542	32,915	151%	259,918	127,691	104%
Number of wells drilled	16	7	126%	46	27	69%
Average Operating Days per well	19.8	20.6	(4%)	21.3	16.4	30%
Drilling rig utilization - Billable Days[1]	75%	34%	121%	61%	28%	118%
Drilling rig utilization - Operating Days[1]	63%	29%	117%	52%	24%	117%

(1) See "Non-IFRS measures" on page 21 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 year ended December 31, 2017.

(4) Excludes shortfall commitment revenue from take or pay contracts of $1.8 million for the year ended December 31, 2016.

For the year ended December 31, 2017, Operating Revenue in the contract drilling segment totalled $166.7 million, an $87.8 million increase (or 111%), as compared to the prior year. Improved market conditions and a corresponding increase in demand for contract drilling services in both Canada and the United States, led to higher year over year activity in 2017. Additionally, the Company recognized $6.4 million related to shortfall commitment revenue in 2017, as compared to $1.8 million in the prior year. For the year ended December 31, 2017, day rates in Canada improved by 3% as compared to the year ended December 31, 2016, mainly due to increased demand for the Company's services. In 2017, pricing in the United States was 12% lower as compared to the 2016 due to changes in rig mix and a greater portion of rigs working on spot rate contracts versus long term legacy contracts, which had higher day rates.

Third party charges per Billable Day in the contract drilling segment increased to approximately $1,900 in 2017 as compared to approximately $1,100 in 2016. The increase is mainly due to increased fuel purchases and trucking costs, which are recharged to the customer, as more customers elected to purchase these services through the Company rather than directly from a third party provider in 2017.

For the year ended December 31, 2017, cash operating expenses per Billable Day in the contract drilling segment, excluding third party charges, decreased by 3% to total approximately $14,054, mainly due to fixed operating costs being allocated over more Billable Days in 2017, as compared to the prior year.

Gross Margin per Billable Day, excluding shortfall commitment revenue, improved by 14% for the year ended December 31, 2017, as compared to the prior year, mainly due to increased activity, as fixed operating costs were allocated over more Billable Days, and higher day rates in Canada, offset partially by lower pricing in the United States.

Adjusted EBITDA in 2017 in the contract drilling segment increased by $27.0 million to $33.7 million, as compared to $6.7 million in 2016. The increase for 2017 is mainly due to increased customer activity resulting in improved Drilling Rig Utilization, a $4.6 million increase in shortfall commitment revenue, higher Operating Revenue per Billable Day in Canada 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 the United States.

Cash administrative expenses for 2017, which exclude depreciation and stock based compensation, totalled $11.2 million and were consistent with the prior year.

Depreciation expense in 2017 of $52.2 million increased by $6.6 million as compared to 2016 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. 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 $14.9 million in 2017, and include $8.2 million of expansion capital and $6.7 million of maintenance capital. Contract drilling capital expenditures for the year ended December 31, 2017 represent an increase of $11.7 million from the $3.2 million incurred in 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, as well as necessary maintenance capital related to the higher activity in the period.

Canadian Operations

For the year ended December 31, 2017, Drilling Rig Utilization in Canada increased to 37% as compared to 17% in the prior year. The increase in utilization is due to higher demand as market conditions improved in 2017, resulting in the Company's Operating Days in Canada increasing by 108% in 2017, as compared to 2016.

Drilling Rig Utilization in Canada of 37% in 2017 reflects an approximate 800 bps premium to the CAODC average of 29%, as compared to being equal to the CAODC average of 17% in 2016. 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 which meets current customer demands;
- the ability of the Company's rig crews;
- the continued marketing efforts to broaden the Company's customer base; and
- improved crude oil and condensate prices and a number of Western's customers increasing their capital budgets in 2017, as compared to 2016 when customer spending was limited.

For the year ended December 31, 2017, Operating Revenue per Billable Day in Canada improved by 3% and totalled $17,558, compared to $16,984 in 2016.

United States Operations

In the Williston basin in North Dakota, where the Company operates, active drilling rigs increased by 42% to 47 at December 31, 2017, as compared to 33 at December 31, 2016. Improved activity, as well as the transfer of a Cardium class drilling rig from the Canadian fleet to the United States fleet in late 2017, resulted in Western's Operating Days in the United States increasing by 529 days (or 120%). Drilling Rig Utilization was 52% for the year ended December 31, 2017 compared to 24% in the prior year. Operating Revenue per Billable Day in 2017 decreased by 12% to US$19,198, as compared to US$21,805 in 2016, due to changes in rig mix and a greater portion of rigs working on spot market contracts versus long term legacy contracts, which had higher day rates.

Production Services

Financial Highlights	**Three months ended December 31**			**Year ended December 31**		
(stated in thousands)	**2017**	**2016**	**Change**	**2017**	**2016**	**Change**
Revenue						
Operating Revenue[1]	13,362	12,710	5%	52,456	38,064	38%
Third party charges	664	715	(7%)	2,905	2,364	23%
Total revenue	14,026	13,425	4%	55,361	40,428	37%
Expenses						
Operating						
Cash operating expenses	10,964	10,264	7%	41,998	32,710	28%
Depreciation	3,248	3,438	(6%)	13,323	12,579	6%
Stock based compensation	17	54	(69%)	131	345	(62%)
Total operating expenses	14,229	13,756	3%	55,452	45,634	22%
Administrative						
Cash administrative expenses	1,561	1,546	1%	6,130	6,014	2%
Depreciation	72	84	(14%)	309	398	(22%)
Stock based compensation	30	8	275%	109	253	(57%)
Total administrative expenses	1,663	1,638	2%	6,548	6,665	(2%)
Gross Margin[1]	3,062	3,161	(3%)	13,363	7,718	73%
Gross margin as a percentage of Operating Revenue	23%	25%	(8%)	25%	20%	25%
Adjusted EBITDA[1]	1,501	1,615	(7%)	7,233	1,704	324%
Adjusted EBITDA as a percentage of Operating Revenue	11%	13%	(15%)	14%	4%	250%
Operating Loss[1]	(1,819)	(1,907)	(5%)	(6,399)	(11,273)	(43%)
Capital expenditures	1,338	566	136%	3,013	1,564	93%

Operating Highlights						
Well servicing rig fleet:						
Average active rig count[1]	17.0	17.6	(3%)	17.2	12.9	33%
End of period	66	66	-	66	66	-
Service rig Operating Revenue per Service Hour[1]	708	638	11%	673	643	5%
Service Hours[1]	15,650	16,182	(3%)	62,946	47,305	33%
Service rig utilization [1]	26%	27%	(4%)	26%	20%	30%

(1) See "Non-IFRS measures" on page 21 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 year ended December 31, 2017 increased by $14.4 million (or 38%) to $52.5 million, compared to $38.1 million in the prior year. In 2017, Eagle's contribution to Operating Revenue in the production services segment increased by 39% to $42.4 million compared to $30.4 million in the prior year, whereas Aero's contribution to Operating Revenue in the production services segment increased by 31% to $10.1 million in 2017 compared to $7.7 million in the prior year. The increase in Operating Revenue for both Eagle and Aero in 2017, as compared to 2016, is due to higher industry activity and increased customer spending resulting from the improved market conditions.

Eagle's Service Hours improved by 33% to 62,946 (26% utilization) in 2017, as compared to 47,305 (20% utilization) in 2016. The increase in Service Hours in 2017 is due to higher demand as a result of the improved economic environment, specifically improved crude oil and condensate prices. Operating Revenue per Service Hour increased by 5% to $673 in 2017, as compared to $643 in the prior year. Hourly rates have increased as activity continued to improve throughout 2017.

Adjusted EBITDA increased by $5.5 million (or 324%) to $7.2 million in 2017, compared to $1.7 million in 2016. The higher Adjusted EBITDA in 2017 was due to the improved market conditions, which increased the demand for the Company's services and resulted in prices beginning to recover.

During the year ended December 31, 2017, cash administrative expenses, which exclude depreciation and stock based compensation, totalled $6.1 million, increasing by 2% over the prior year.

Depreciation expense for 2017 increased by 5% to $13.6 million, as compared to $13.0 million in 2016, 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 year ended December 31, 2017, capital expenditures in the production services segment totalled $3.0 million, as compared to $1.6 million in the prior year, and included expansion capital of $1.2 million, mainly related to additional oilfield rental equipment, and maintenance capital of $1.8 million.

Corporate

	Three months ended December 31			Year ended December 31		
(stated in thousands)	**2017**	**2016**	**Change**	**2017**	**2016**	**Change**
Administrative						
Cash administrative expenses	1,428	635	125%	5,240	2,676	96%
Depreciation	157	206	(24%)	653	849	(23%)
Stock based compensation	313	375	(17%)	1,392	2,537	(45%)
Total administrative expenses	1,898	1,216	56%	7,285	6,062	20%
Finance costs	5,598	5,478	2%	21,950	22,522	(3%)
Other items	(700)	(83)	743%	1,356	(1,549)	(188%)
Income taxes						
Current tax recovery	42	(511)	(108%)	75	(1,708)	(104%)
Deferred tax recovery	(6,884)	(4,672)	47%	(18,630)	(20,247)	(8%)
Total income taxes	(6,842)	(5,183)	32%	(18,555)	(21,955)	(15%)
Operating Loss(1)	(1,585)	(841)	88%	(5,893)	(3,525)	67%
Capital expenditures	159	-	100%	160	1	15,900%

(1) See "Non-IFRS measures" on page 21 of this MD&A.

Corporate cash administrative expenses, which exclude depreciation and stock based compensation, increased by $2.5 million in 2017, as compared to the prior year, due to higher employee related costs coupled with one time professional fees incurred in the year.

Finance costs in 2017 on a consolidated basis decreased by $0.5 million, as compared to the prior year. The majority of the decrease is due to the Company reducing its available Credit Facilities in 2016, resulting in lower standby fees. The Company had an effective interest rate on its borrowings of 8.3% throughout 2017 and 8.5% throughout 2016.

Other items, which total a loss of $1.4 million, as compared to a $1.5 million gain in the prior year, 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 year ended December 31, 2017, income taxes on a consolidated basis totalled a recovery of $18.6 million, representing an effective tax rate of 33.1%, as compared to an effective tax rate of 26.2% in 2016. The Company's effective tax rate in 2017 was impacted by a decrease in the federal corporate tax rates in the United States from 35.0% to 21.0%. Normalizing for the impact of the United States tax reform, the Company's effective tax rate would be 26.9%.

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 December 31, 2017, Western had working capital of $62.9 million, an increase of $11.8 million from December 31, 2016. Included in working capital is cash and cash equivalents of $48.8 million, the majority of which was invested in liquid high interest savings accounts with banks within the Company's existing Credit Facilities syndicate. Western's consolidated Net Debt balance at December 31, 2017 was $216.9 million.

During the year ended December 31, 2017, Western had the following changes to its cash balances, which resulted in a $4.2 million increase in cash and cash equivalents in the year:

(stated in $000s)	
Opening balance, at December 31, 2016	44,597
Add:	
Adjusted EBITDA	35,695
Issue of common shares, net of share issue costs	21,201
Income taxes received	1,633
Proceeds on sale of property and equipment	943
Deduct:	
Finance costs paid	(22,124)
Additions to property and equipment	(18,132)
Second Lien Facility issue costs	(4,323)
Savanna transaction costs	(1,597)
Change in non cash working capital	(8,926)
Other items	(142)
Ending balance, at December 31, 2017	**48,825**

Subsequent to December 31, 2017, the $265.0 million Senior Notes were repaid at par on February 1, 2018 by a combination of a single draw on the Company's $215.0 million Second Lien Facility, as well as through cash on hand and the funds available under the Company's Credit Facilities. Western's Credit Facilities, which have a limit of $80.0 million, mature on December 17, 2020. Western's cash from operations and available Credit Facilities are expected to be sufficient to cover Western's financial obligations.

Advances under the Credit Facilities are 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 $400.0 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 21 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 December 31, 2017, the Revolving Facility and the Operating Facility were undrawn. A summary of the Company's financial covenants as at December 31, 2017 is as follows:

December 31, 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 11 of the December 31, 2017 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 $400.0 million. When applicable 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 December 31, 2017, Western is in compliance with all debt covenants under its Credit Facilities.

For the year ended December 31, 2017 the Company had no significant customers comprising 10.0% or more of the Company's total revenue. For the year ended December 31, 2016, the Company had one significant customer comprising 10.0% of the Company's total revenue. The Company's significant customers may change from period to period.

Review of Fourth Quarter 2017 Results

Selected Financial Information

Financial Highlights	**Three months ended December 31**		
(stated in thousands, except share and per share amounts)	**2017**	**2016**	**Change**
Total Revenue	66,515	45,126	47%
Operating Revenue	59,255	41,649	42%
Gross Margin[(1)]	15,886	8,507	87%
Gross Margin as a percentage of Operating Revenue	27%	20%	35%
Adjusted EBITDA[(1)]	10,067	3,506	187%
Adjusted EBITDA as a percentage of Operating Revenue	17%	8%	113%
Cash flow from operating activities	(800)	(1,327)	(40%)
Capital expenditures	5,912	2,724	117%
Net loss	(4,974)	(14,509)	(66%)
-basic net loss per share	(0.06)	(0.20)	(70%)
-diluted net loss per share	(0.06)	(0.20)	(70%)
Weighted average number of shares			
-basic	88,812,216	73,795,896	20%
-diluted	88,812,216	73,795,896	20%
Outstanding common shares as at period end	92,175,598	73,795,944	25%

Operating Highlights			
Contract Drilling			
Canadian Operations			
Contract drilling rig fleet:			
Average active rig count[(1)]	21.6	16.2	33%
End of period	50	51	(2%)
Operating Revenue per Billable Day[(1)]	18,807	16,657	13%
Operating Revenue per Operating Day[(1)]	21,100	18,811	12%
Operating Days[(1)]	1,774	1,317	35%
Number of meters drilled	508,552	349,172	46%
Number of wells drilled	137	106	30%
Average Operating Days per well	12.9	12.5	3%
Drilling rig utilization - Billable Days[(1)]	43%	32%	34%
Drilling rig utilization - Operating Days[(1)]	38%	28%	36%
CAODC industry average utilization rate[(2)]	28%	25%	12%
United States Operations			
Contract drilling rig fleet:			
Average active rig count[(1)]	4.0	1.7	135%
End of period	6	5	20%
Operating Revenue per Billable Day[(1)]	18,038	20,197	(11%)
Operating Revenue per Operating Day (US$)[(1)]	21,265	23,440	(9%)
Operating Days[(1)]	313	134	134%
Number of meters drilled	82,542	32,915	151%
Number of wells drilled	16	7	126%
Average Operating Days per well	19.8	20.6	(4%)
Drilling rig utilization - Billable Days[(1)]	75%	34%	121%
Drilling rig utilization - Operating Days[(1)]	63%	29%	117%
Production Services			
Well servicing rig fleet:			
Average active rig count[(1)]	17.0	17.6	(3%)
End of period	66	66	-
Service rig Operating Revenue per Service Hour[(1)]	708	638	11%
Service Hours[(1)]	15,650	16,182	(3%)
Service rig utilization[(1)]	26%	27%	(4%)

(1) See "Non-IFRS measures" on page 21 of this MD&A.

(2) Source: CAODC. The CAODC industry average is based on Operating Days divided by total available days.

Review of Fourth Quarter 2017 Results

Consolidated

Fourth quarter Operating Revenue increased by $17.6 million (or 42%) to $59.3 million in 2017 as compared to $41.7 million in the same period of the prior year. In the contract drilling segment, Operating Revenue increased by $16.9 million (or 58%) to $45.9 million in the fourth quarter of 2017 as compared to $29.0 million in the fourth quarter of 2016; while in the production services segment, Operating Revenue increased by $0.7 million (or 5%) during the three months ended December 31, 2017 to $13.4 million as compared to $12.7 million in the same period of the prior year. Adjusted EBITDA increased by $6.6 million (or 187%) to $10.1 million in the fourth quarter of 2017, as compared to $3.5 million in the fourth quarter of 2016. The increase in consolidated Operating Revenue and Adjusted EBITDA is a result of higher utilization in the contract drilling segment and improved pricing in Canada, which was partially offset by lower pricing the United States and decreased well servicing activity.

Contract Drilling

During the fourth quarter of 2017, Operating Revenue in the contract drilling segment totalled $45.9 million, a $16.9 million increase (or 58%), as compared to the same period in the prior year. Improved market conditions 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 the three months ended December 31, 2017. Pricing in Canada continued to recover for the three months ended December 31, 2017, increasing by 13%, however pricing in the United States decreased by 11% as compared to the same period of the prior year due to changes in the active rig mix and a greater portion of rigs working on spot market contracts versus long term legacy contracts, which had higher day rates.

Third party charges per Billable Day of $2,700 for the three months ended December 31, 2017 compared to $1,600 for the same period in the prior year. The increase is mainly due to increased fuel purchases and trucking costs in the fourth quarter of 2017, compared to the same period in the prior year, as more customers elected to purchase these services through the Company rather than directly from a third party provider.

For the three months ended December 31, 2017, cash operating expenses per Billable Day in the contract drilling segment, excluding third party charges, averaged approximately $14,018, consistent with the prior year. Gross Margin per Billable Day, excluding shortfall commitment revenue, improved by 67% for the three months ended December 31, 2017, due to a combination of increased activity, pricing trending higher, and effective cost management.

Contract drilling Adjusted EBITDA for the three months ended December 31, 2017 increased by $7.5 million to $10.0 million, as compared to $2.5 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 Canada, as prices continued to improve in the fourth quarter of 2017 as incremental work was awarded.

For the three months ended December 31, 2017, cash administrative expenses, which exclude depreciation and stock based compensation, totalled $2.8 million and were consistent with the same period in the prior year.

Depreciation expense for the quarter ended December 31, 2017, totalled $13.0 million, a decrease of $0.2 million as compared to the same period in the prior year mainly due to certain equipment being fully depreciated over the last four quarters.

Capital expenditures in the contract drilling segment totalled $4.4 million in the fourth quarter of 2017 and include $2.2 million related to expansion capital, and $2.2 million related to maintenance capital. Contract drilling capital expenditures represent a 105% increase from the $2.2 million incurred in the three months ended December 31, 2016. During the fourth quarter of 2017, expansion capital mainly related to rig upgrades.

Canadian Operations

During fourth quarter of 2017, Drilling Rig Utilization in Canada increased to an average of 38% as compared to an average of 28% in the fourth quarter of 2016. The increase in utilization is due to increased customer spending as market conditions improved in 2017, resulting in the Company's Operating Days increasing by 35% in the fourth quarter of 2017, as compared to the same period in 2016. The Company's Drilling Rig Utilization in Canada of 38% in the fourth quarter of 2017 reflects an approximate 1,000 bps premium to the CAODC average of 28%, as compared to a 300 bps premium in the same period of the prior year.

Operating Revenue per Billable Day improved by 13% to total $18,807 for the three months ended December 31, 2017 compared to $16,657 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 economic conditions, with prices trending higher as incremental work is awarded.

United States Operations

Improved crude oil prices led to increased customer spending, resulting in Western's Operating Days in the United States increasing by 179 days (or 134%), representing Drilling Rig Utilization of 63% for the three months ended December 31, 2017 compared to 29% in same period of the prior year. However, fourth quarter Operating Revenue per Billable Day in the United States decreased by 11% to US$18,038, as compared to the same period of the prior year, due to changes in the active rig mix in 2017 and a greater portion of rigs working on spot market contracts versus long term legacy contracts, which had higher day rates.

Production Services

During the fourth quarter of 2017, Operating Revenue increased by $0.7 million (or 6%) to $13.4 million, compared to $12.7 million in the fourth quarter of 2016. In the fourth quarter of 2017, Eagle's contribution to Operating Revenue in the production services segment of $11.1 million compared to $10.3 million in the same period of the prior year, whereas Aero's contribution to Operating Revenue in the production services segment of $2.3 million in the fourth quarter of 2017 compared to $2.4 million in the fourth quarter of 2016.

Eagle's Service Hours decreased by 3% in the fourth quarter of 2017 to 15,650 (26% utilization) as compared to 16,182 (27% utilization) in the same period of the prior year. The decrease in Service Hours for the three months ended December 31, 2017 is due to lower spot market activity and challenges attracting and retaining field crews. However, Operating Revenue per Service Hour increased by 11% for the three months ended December 31, 2017 to $708, as compared to $638 in the prior year, mainly due to increased demand for fully crewed rigs which resulted in higher hourly rates in 2017.

Adjusted EBITDA decreased in the fourth quarter of 2017, as compared to the fourth quarter of 2016, by $0.1 million (or 7%) to $1.5 million. The lower Adjusted EBITDA for the quarter ended December 31, 2017 was due to lower well servicing utilization and decreased Operating Revenue in Aero, offset partially by improvements in hourly well servicing rates.

Cash administrative expenses, which exclude depreciation and stock based compensation, totalled $1.6 million in the fourth quarter of 2017, an increase of 1% mainly due to higher employee related costs.

Depreciation expense in the fourth quarter of 2017 decreased by 6% to $3.3 million, as compared to $3.5 million in fourth quarter of 2016, due to low capital spending and certain equipment being fully depreciated over the last four quarters.

During the three months ended December 31, 2017, capital expenditures in the production services segment totalled $1.3 million, as compared to $0.6 million for the three months ended December 31, 2016, and consisted of $0.7 million of expansion capital and $0.6 million of maintenance capital. Expansion capital was mainly related to additional oilfield rental equipment added in Aero.

Corporate

Corporate cash administrative expenses, which exclude depreciation and stock based compensation, for the three month period ended December 31, 2017 increased by $0.8 million to $1.4 million, mainly due to higher employee related costs.

For the three month period ended December 31, 2017, finance costs on a consolidated basis remained relatively consistent at $5.6 million, as compared to $5.5 million in the same period of the prior year. The Company had an effective interest rate on its borrowings of 8.4% during the fourth quarter of 2017, as compared to 8.2% in the same period of the prior year.

Other items which total a gain of $0.7 million for the three months ended December 31, 2017 consist of net gains and losses on foreign exchange and asset sales.

For the three months ended December 31, 2017, income taxes on a consolidated basis totalled a recovery of $6.8 million and represent an effective tax rate of 57.9%, as compared to an effective tax rate of 26.3% during the three months ended December 31, 2016. The effective tax rate in the fourth quarter of 2017 was mainly impacted by the decrease in the federal corporate tax rate in the United States from 35.0% to 21.0%. Normalizing for the United States tax reform, the Company's effective tax rate would have been 26.0%.

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)	Dec 31, 2017	Sep 30, 2017	Jun 30, 2017	Mar 31, 2017	Dec 31, 2016	Sept 30, 2016	Jun 30, 2016	Mar 31, 2016
Revenue	66,515	54,131	33,307	84,222	45,126	32,485	12,890	33,937
Operating Revenue[1]	59,255	51,111	30,469	78,153	41,649	30,665	12,393	32,200
Gross Margin[1]	15,886	12,299	5,667	24,458	8,507	5,685	2,703	8,867
Adjusted EBITDA[1]	10,067	6,882	121	18,625	3,506	896	(1,990)	3,364
Cash flow from operating activities	(800)	1,609	20,659	3,173	(1,327)	909	8,444	8,604
Net loss	(4,974)	(11,478)	(16,628)	(4,365)	(14,509)	(16,973)	(24,172)	(6,319)
per share - basic	(0.06)	(0.16)	(0.23)	(0.06)	(0.20)	(0.23)	(0.33)	(0.09)
per share - diluted	(0.06)	(0.16)	(0.23)	(0.06)	(0.20)	(0.23)	(0.33)	(0.09)
Total assets	760,504	737,385	758,278	785,040	793,525	794,170	814,757	842,492
Long term debt	265,219	264,958	264,702	264,150	264,070	264,118	264,145	264,118

(1) See "Non-IFRS measures" on page 21 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. In 2017, Revenue and Adjusted EBITDA in each quarter increased, as compared to the same quarter in the prior year, due to improving market conditions throughout 2017.

Net loss is impacted by the seasonal nature of the oilfield service industry in Canada. While net loss has been negative throughout the last eight quarters, due to the prolonged decline in crude oil and natural gas prices, every quarter in 2017 has improved as compared to the same quarter in 2016. 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 change in depreciation methodology, resulting in higher depreciation expense starting in the second quarter of 2016, coupled with low capital spending during the downturn in crude oil and natural gas prices.

Contractual Obligations

In the normal course of business the Company incurs contractual obligations. The expected maturities of the Company's contractual obligations as at December 31, 2017 are as follows:

(stated in thousands)	2018	2019	2020	2021	2022	Thereafter	Total
Senior Notes	-	265,000	-	-	-	-	265,000
Senior Notes interest	20,869	10,520	-	-	-	-	31,389
Trade payables and other current liabilities [1]	31,029	-	-	-	-	-	31,029
Operating leases	3,691	3,461	3,261	2,435	2,151	4,482	19,481
Purchase commitments	2,873	-	-	-	-	-	2,873
Other long term debt	484	308	499	-	-	-	1,291
Total	58,946	279,289	3,760	2,435	2,151	4,482	351,063

(1) Trade payables and other current liabilities exclude the Company's interest accrued as at December 31, 2017 on the Senior Notes.

Other than the $215.0 million Second Lien Facility, which was drawn on January 31, 2018 and is described previously, and the repayment of the $265.0 million Senior Notes on February 1, 2018, there have been no material changes in the contractual obligations detailed above, other than in the normal course of business, subsequent to December 31, 2017.

Outstanding Share Data

	February 21, 2018	December 31, 2017	December 31, 2016
Common shares outstanding	92,177,098	92,175,598	79,795,944
Restricted share units outstanding - equity settled	189,920	191,420	410,311
Stock options outstanding	6,284,516	6,475,613	6,153,886

Off Balance Sheet Arrangements

As at December 31, 2017, Western had no off balance sheet arrangements in place.

Transactions with Related Parties

During the years ended December 31, 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 payables and other current liabilities, 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. Transaction costs related to undrawn term loans are recognized in deferred charges until the term loan is drawn. Subsequent to drawing on the term loan, transaction costs are netted against the term loan and amortized using the effective interest method.

(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. 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

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

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

In accordance with the requirements of National Instrument 52-109 "Certification of Disclosure in Issuers' Annual and Interim Filings", an evaluation of the effectiveness of DC&P and ICFR was carried out under the supervision of the CEO and CFO at December 31, 2017. This evaluation was based on the framework established in the Internal Control – Integrated Framework (2013) issued in May 2013 by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). Based on this evaluation, the CEO and CFO have concluded that the Company's DC&P and ICFR are effectively designed and operating as intended.

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

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

Critical Accounting Estimates

This MD&A of the Company's financial condition and results of operations is based on the consolidated financial statements for the year ended December 31, 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. In assessing fair value less costs to sell, the Company must estimate the price that would be received to sell the asset or CGU less any incremental costs directly attributable to the disposal. In assessing value in use, 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 and discount rates.

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 December 31, 2017, the Company identified impairment indicators related to the prolonged commodity price downturn and the Company's market capitalization being less than the carrying amounts of its net assets, and as such performed an impairment analysis on each of its CGUs. The results of the impairment test indicated no impairment of property and equipment existed at December

31, 2017. Additionally, there were no reversals of previous property and equipment impairment losses during the year ended December 31, 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, 2017 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 consolidated financial statements involves determining an estimate of, or provision for, income taxes in each of the jurisdictions in which the Company operates. The process also involves making an estimate of taxes currently payable and taxes expected to be payable or recoverable in future periods, referred to as deferred taxes. Deferred taxes result from the effects of temporary differences due to items that are treated differently for tax and accounting purposes. The tax effects of these differences are reflected in the consolidated balance sheet as deferred tax assets and liabilities.

An assessment must also be made to determine the likelihood that the Company's future taxable income will be sufficient to permit the recovery of deferred 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 stock options, equity settled restricted share units ("RSUs"), and warrants 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, 2017 as filed on SEDAR at www.sedar.com. The Company's primary business risks as at December 31, 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.

- 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, 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 may find it necessary in the future to obtain additional debt or equity to support ongoing operations, to re-finance debt, to undertake capital expenditures or to undertake acquisitions or other business combination transactions. There can be no assurance that additional financing will be available when needed or on terms acceptable to the Company.
- 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. Effective January 1, 2018 the Alberta government increased the price on carbon emissions to $30 per tonne, from $20 per tonne in 2017. 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, interest, 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.
- The Company's operations are subject to many hazards inherent in the oilfield service industry, such as blowouts, explosions, damaged or lost drilling, well servicing and oilfield rental equipment or damage or loss from inclement weather, which could result in business interruption, casualty losses, damage or destruction of equipment, suspension of operations, environmental damage or damage to property.
- During the prolonged downturn many oilfield service workers have left the industry and, therefore, as 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, Senior Notes and the Second Lien Facility.
- 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's business is subject to credit risk primarily from credit exposure to customers, with a concentration of credit risk with customers in the crude oil and natural gas industry.
- 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 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 consolidated statements of operations and comprehensive income, to Operating Revenue and Gross Margin:

	Three months ended December 31		**Year ended December 31**	
(stated in thousands)	**2017**	**2016**	**2017**	**2016**
Operating Revenue				
Drilling	45,906	28,965	166,660	78,887
Production services	13,362	12,710	52,456	38,064
Less: inter-company eliminations	(13)	(26)	(128)	(44)
	59,255	**41,649**	**218,988**	**116,907**
Third party charges	7,260	3,477	19,187	7,531
Revenue	**66,515**	**45,126**	**238,175**	**124,438**
Less: operating expenses	(66,933)	(53,308)	(245,352)	(157,212)
Add:				
Depreciation - operating	16,238	16,551	65,227	57,903
Stock based compensation - operating	66	138	260	633
Gross Margin	**15,886**	**8,507**	**58,310**	**25,762**

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 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 December 31		**Year ended December 31**	
(stated in thousands)	**2017**	**2016**	**2017**	**2016**
Net loss	**(4,974)**	**(14,509)**	**(37,445)**	**(61,973)**
Add:				
Finance costs	5,598	5,478	21,950	22,522
Income tax recovery	(6,842)	(5,183)	(18,555)	(21,955)
Depreciation - operating	16,238	16,551	65,227	57,903
Depreciation - administrative	284	365	1,213	1,569
EBITDA	**10,304**	**2,702**	**32,390**	**(1,934)**
Add:				
Stock based compensation - operating	66	138	260	633
Stock based compensation - administrative	397	484	1,689	3,135
Loss on asset decommissioning	-	265	-	5,490
Other items	(700)	(83)	1,356	(1,549)
Adjusted EBITDA	**10,067**	**3,506**	**35,695**	**5,775**
Subtract:				
Depreciation - operating	(16,238)	(16,551)	(65,227)	(57,903)
Depreciation - administrative	(284)	(365)	(1,213)	(1,569)
Operating Loss	**(6,455)**	**(13,410)**	**(30,745)**	**(53,697)**

Net Debt

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

(stated in thousands)	**December 31, 2017**	**December 31, 2016**
Long term debt	265,219	264,070
Current portion of long term debt	475	684
Less: cash and cash equivalents	(48,825)	(44,597)
Net Debt	**216,869**	**220,157**

<u>Defined Terms:</u>

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");
- Natural Gas Liquids ("NGL");
- 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 information and statements contained herein that are not clearly historical in nature constitute forward-looking information, and the words "may", "will", "should", "could", "expect", "intend", "anticipate", "believe", "estimate", "propose", "plan", "predict", "potential", "continue", or the negative of these terms or other comparable terminology are generally intended to identify forward-looking information. Such information represents the Corporation's internal projections, estimates or beliefs concerning, among other things, an outlook on the estimated amounts and timing of capital expenditures, anticipated future debt levels and revenues or other expectations, beliefs, plans, objectives, assumptions, intentions or statements about future events or performance. This information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information.

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 2018; the Company's liquidity needs including the ability of current capital resources to cover Western's financial obligations and the 2018 capital budget; 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; demand for crude oil and natural gas and the price and volatility of crude oil and natural gas; pressures on commodity pricing; the continued business relationships between the Company and its significant customers; 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 general business, economic and market 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 2018 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.