Western
ENERGY SERVICES CORP.

ANNUAL REPORT 2017

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Western Energy Services Corp. is an oilfield service company focused on providing superior service to its customers, and sustainable growth for shareholders.

CONTRACT DRILLING SERVICES

Horizon Drilling is Western's Canadian contract drilling division and currently operates a fleet of 50 drilling rigs, making it the fifth largest drilling rig contractor in Canada. Horizon's fleet is one of the newest drilling fleets in the Western Canadian Sedimentary Basin, which allows the company to provide customers with reliability, mobility and advanced technical capabilities.

Stoneham Drilling Corporation is Western's U.S. contract drilling division and currently operates a fleet of six drilling rigs in the Williston Basin in the United States. Similar in design to many of the Canadian based rigs, the U.S. fleet is suited for the current U.S. market which predominantly consists of drilling horizontal wells that are deeper and more technically challenging.

WELL SERVICING

Eagle Well Servicing is Western's well servicing division, which currently operates a fleet of 66 well servicing rigs. Eagle operates from five bases located in Alberta and Saskatchewan, allowing Eagle to service wells in all key Western Canadian Sedimentary Basin oil and natural gas resource plays. With an industry leading team, Eagle excels when it comes to safe, efficient and functional well servicing.

OILFIELD RENTAL EQUIPMENT SERVICES

Aero Rental Services is Western's oilfield rental equipment division that operates from facilities in Red Deer and Grande Prairie, Alberta, and Fort St. John, British Columbia. Aero supplies oil and natural gas exploration and production companies, as well as other oilfield service companies, with specialized high pressure rental equipment utilized in drilling and completions activities. Aero has followed an organic growth model, allowing it to evolve and adapt its rental equipment mix to the changing needs of its customers.

ANNUAL MEETING
The Annual Meeting of the Shareholders of Western Energy Services Corp. will be held on Thursday, April 26, 2018 at 3:00 pm (MDT).

Location:
The Calgary Petroleum Club, Viking Room
319 - 5th Avenue S.W. Calgary, Alberta T2P 0L5

CEO Report to Shareholders

2017 was a year of recovery for the oilfield services industry in Canada following the multi-year lows of 2016. We witnessed marked improvements in both activity and pricing, each moving the industry towards sustainability. Western benefitted from these same dynamics that impacted the rest of the industry, though we remained focused on improving our business. Merely rising with the macro tides is not what we as a management team set out to accomplish.

With this in mind, we embarked on a number of key initiatives to strengthen Western's competitive position. 1) We expanded our customer list in Canada, building upon relationships with some of the most active liquids focused exploration and production companies. Horizon, our Canadian contract drilling business, returned to premium utilization. In 2017, we worked 10% of the industry's drilling days in Canada, despite having only 8% of the Canadian Association of Oilwell Drilling Contractors ("CAODC") registered drilling rigs. This was achieved while still increasing our pricing, a testament to the quality of our people and equipment. 2) We increased activity in North Dakota having been awarded work on both spot and long-term contracts. Stoneham Drilling worked for customers across the spectrum, with activity ranging from drilling disposal wells to drilling two-mile laterals from multi-well surface pads. In our US business, we have the appropriate people and equipment to meet wide-ranging customer requirements. As in Canada, we generate higher market share by drilling days than our North Dakota rig count would entail. 3) We continued to strike a balance between pricing and utilization in our Production Services segment, ensuring that our equipment is appropriately maintained and our fleet is ready to ramp-up when industry fundamentals improve. The higher pricing achieved by the business is encouraging in a challenging market. 4) We completed a comprehensive refinancing of our outstanding debt. As a result of this refinancing, we reduced the quantum of debt, lowered our annual interest costs by over $5 million and extended the maturity date of our remaining debt. Our current capital structure provides incremental flexibility as we focus on operational excellence and on generating superior returns for our shareholders.

Looking now at 2018, the industry remains in a stage of recovery. Pricing and utilization are better than in 2016, while activity remains broadly in line with 2017. Improved sentiment, and a willingness by our exploration and production customers to deploy incremental capital as a result of higher benchmark crude oil prices, has been tempered somewhat by the continued challenges facing the Canadian natural gas market and by wider differentials impacting realized prices for Canadian heavy oil. Overall, industry capital spending in Western Canada appears to be little changed versus 2017, with spending shifting towards oil and liquids focused producers versus those that focus predominantly on natural gas. We continue to support our customers, providing best-in-class service and safety. This in turn should allow for recent efficiency gains to be sustained, and reinforce the strong returns being realized by our customers when they elect to deploy capital for their exploration and development activities.

Amidst this industry backdrop, our attention remains on fine-tuning our business for the near-term while remaining positioned to respond to a more significant recovery in Canadian industry activity. Though we are proud of our accomplishments in 2017, we strive to continuously improve. As such, we continue to watch costs closely, hone operating practices and procedures, deepen our valued customer base, sensibly deploy capital and continue to position our assets to most effectively generate cash flow. While our emphasis is to advance our business within our core geographies, we continuously explore new markets to ensure our capital allocation is optimally suited to the environment today. Our focus on strengthening our business and maximizing returns for our shareholders will not waver.

I would like to thank our customers and stakeholders for their continued support. We look forward to working together with each of you as this recovery continues. Lastly, I would like to thank our employees for their continued contributions. Though it has been a difficult few years in the oilfield services business, your contributions have not gone unnoticed.

Respectfully,

Alex R.N. MacAusland
President and CEO
Western Energy Services Corp.

March 26, 2018

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

- o 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**

Defined Terms:

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

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

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

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

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

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

Service Hours: Defined as well servicing hours completed.

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

Contract Drilling Rig Classifications:

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

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

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

Abbreviations:

- Barrel ("bbl");
- Basis point ("bps"): A 1% change equals 100 basis points and a 0.01% change is equal to one basis point;
- Canadian Association of Oilwell Drilling Contractors ("CAODC");
- DecaNewton ("daN");
- International Financial Reporting Standards ("IFRS");
- 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.

Western Energy Services Corp.

Consolidated Financial Statements

December 31, 2017 and 2016

To the Shareholders of Western Energy Services Corp.:

The accompanying consolidated financial statements have been prepared by management and approved by the Board of Directors of Western Energy Services Corp. The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board and, where appropriate, reflect management's best estimates and judgments. Management is responsible for the accuracy, integrity and objectivity of the consolidated financial statements within reasonable limits of materiality.

In discharging its responsibilities for the integrity and fairness of the consolidated financial statements, management designs and maintains the necessary accounting systems and related internal controls to provide reasonable assurance that transactions are authorized, assets are safeguarded and financial records are properly maintained to provide reliable information for the preparation of financial statements.

The Audit Committee is appointed by the Board of Directors, with all of its members being independent directors. The Audit Committee meets with management, as well as with the external auditors, to satisfy itself that management is properly discharging its financial reporting responsibilities and to review the consolidated financial statements and the auditor's report. The Audit Committee reports its findings to the Board of Directors for consideration in approving the consolidated financial statements for presentation to the shareholders. The external auditors have direct access to the Audit Committee of the Board of Directors.

The consolidated financial statements have been audited independently by Deloitte LLP on behalf of Western Energy Services Corp. in accordance with Canadian generally accepted auditing standards. Their report outlines the nature of their audit and expresses their opinion on the consolidated financial statements.

"Signed"
Alex R.N. MacAusland
President &
Chief Executive Officer

"Signed"
Jeffrey K. Bowers
Senior Vice President, Finance &
Chief Financial Officer

February 21, 2018

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Calgary, AB T2P 0R8
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INDEPENDENT AUDITOR'S REPORT

To the Shareholders of Western Energy Services Corp.

We have audited the accompanying consolidated financial statements of Western Energy Services Corp., which comprise the consolidated balance sheets as at December 31, 2017 and 2016, and the consolidated statements of operations and comprehensive income (loss), consolidated statements of changes in shareholders' equity, and the consolidated statements of cash flows for the years then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Western Energy Services Corp. as at December 31, 2017 and 2016, and its financial performance and its cash flows for the years then ended in accordance with International Financial Reporting Standards.

Deloitte LLP

Chartered Professional Accountants
February 21, 2018
Calgary, Alberta

Western Energy Services Corp.

Consolidated Balance Sheets
(thousands of Canadian dollars)

	Note	December 31, 2017	December 31, 2016
Assets			
Current assets			
Cash and cash equivalents		$ 48,825	$ 44,597
Trade and other receivables	6	48,117	34,998
Other current assets	7	6,429	5,253
		103,371	84,848
Non current assets			
Property and equipment	8	652,828	708,567
Other non current assets	7	4,305	110
		$ 760,504	$ 793,525
Liabilities			
Current liabilities			
Trade payables and other current liabilities	9	$ 39,891	$ 32,906
Current portion of provisions	10	139	140
Current portion of long term debt	11	475	684
		40,505	33,730
Non current liabilities			
Provisions	10	1,415	1,534
Long term debt	11	265,219	264,070
Deferred taxes	17	67,211	86,984
		374,350	386,318
Shareholders' equity			
Share capital	12	441,019	418,509
Contributed surplus		14,631	12,666
Retained earnings (deficit)		(95,834)	(58,308)
Accumulated other comprehensive income		24,217	32,258
Non controlling interest		2,121	2,082
		386,154	407,207
		$ 760,504	$ 793,525

The accompanying notes are an integral part of these consolidated financial statements.

Approved on behalf of the Board of Directors:

"Signed"
Ronald P. Mathison
Director, Chairman of the Board

"Signed"
Lorne A. Gartner
Director, Chairman of the Audit Committee

Western Energy Services Corp.

Consolidated Statements of Operations and Comprehensive Income (Loss)
(thousands of Canadian dollars except share and per share amounts)

	Note	Year ended December 31, 2017	Year ended December 31, 2016
Revenue		$ 238,175	$ 124,438
Operating expenses		245,352	157,212
Gross profit (loss)		(7,177)	(32,774)
Administrative expenses		25,517	24,691
Finance costs	15	21,950	22,522
Other items	16	1,356	(1,549)
Loss on asset decommissioning	8	-	5,490
Loss before income taxes		(56,000)	(83,928)
Income tax recovery	17	(18,555)	(21,955)
Net loss		(37,445)	(61,973)
Other comprehensive loss (1)			
Loss on translation of foreign operations		3,977	1,964
Unrealized foreign exchange loss on net investment in subsidiary		4,064	3,572
Comprehensive loss		$ (45,486)	$ (67,509)
Net income (loss) attributable to:			
Shareholders of the Company		$ (37,526)	$ (62,042)
Non controlling interest		81	69
Comprehensive income (loss) attributable to:			
Shareholders of the Company		$ (45,567)	$ (67,578)
Non controlling interest		81	69
Net loss per share:			
Basic		$ (0.48)	$ (0.84)
Diluted		(0.48)	(0.84)
Weighted average number of shares:			
Basic	14	77,601,827	73,703,437
Diluted	14	77,601,827	73,703,437

(1) Other comprehensive loss includes items that may be subsequently reclassified into profit and loss.

The accompanying notes are an integral part of these consolidated financial statements.

Western Energy Services Corp.

Consolidated Statements of Changes in Shareholders' Equity
(thousands of Canadian dollars)

	Share capital	Contributed surplus (1)	Retained earnings (deficit)	Accumulated other comprehensive income(2)	Non controlling interest	Total shareholders' equity
Balance at December 31, 2015	$ 417,622	$ 10,148	$ 3,734	$ 37,794	$ 2,398	$ 471,696
Common shares:						
Issued on vesting of restricted share units	887	(887)	-	-	-	-
Stock based compensation	-	3,405	-	-	-	3,405
Distributions to non controlling interest	-	-	-	-	(385)	(385)
Comprehensive income (loss)	-	-	(62,042)	(5,536)	69	(67,509)
Balance at December 31, 2016	418,509	12,666	(58,308)	32,258	2,082	407,207
Common shares:						
Issue of common shares (net of issue costs)	21,614	-	-	-	-	21,614
Issued on vesting of restricted share units	896	(896)	-	-	-	-
Stock based compensation	-	1,781	-	-	-	1,781
Issue of warrants	-	1,080	-	-	-	1,080
Distributions to non controlling interest	-	-	-	-	(42)	(42)
Comprehensive income (loss)	-	-	(37,526)	(8,041)	81	(45,486)
Balance at December 31, 2017	$ 441,019	$ 14,631	$ (95,834)	$ 24,217	$ 2,121	$ 386,154

(1) Contributed surplus relates to stock based compensation described in Note 13.

(2) At December 31, 2017, the accumulated other comprehensive income balance consists of the translation of foreign operations and unrealized foreign exchange on net investment in subsidiary.

The accompanying notes are an integral part of these consolidated financial statements.

Western Energy Services Corp.

Consolidated Statements of Cash Flows
(thousands of Canadian dollars)

	Note	Year ended December 31, 2017	Year ended December 31, 2016
Operating activities			
Net loss		$ (37,445)	$ (61,973)
Adjustments for:			
Depreciation included in operating expenses	8	65,227	57,903
Depreciation included in administrative expenses	8	1,213	1,569
Non cash stock based compensation included in operating expenses	13	215	466
Non cash stock based compensation included in administrative expenses	13	1,566	2,939
Finance costs	15	21,950	22,522
Loss on asset decommissioning	8	-	5,490
Income tax recovery	17	(18,555)	(21,955)
Other		507	985
Income taxes received		1,633	8,278
Change in non cash working capital		(11,670)	407
Cash flow from operating activities		24,641	16,631
Investing activities			
Additions to property and equipment	8	(18,132)	(4,719)
Proceeds on sale of property and equipment		943	549
Change in non cash working capital		2,585	20
Cash flow used in investing activities		(14,604)	(4,150)
Financing activities			
Issue of common shares	12	22,750	-
Share issue costs	12	(1,549)	-
Repayment of long term debt		(680)	(709)
Second lien debt issue costs		(4,323)	-
Finance costs paid		(22,124)	(21,553)
Dividends paid		-	(3,682)
Distributions to non controlling interest		(42)	(385)
Change in non cash working capital		159	-
Cash flow used in financing activities		(5,809)	(26,329)
Increase (decrease) in cash and cash equivalents		4,228	(13,848)
Cash and cash equivalents, beginning of year		44,597	58,445
Cash and cash equivalents, end of year [1]		$ 48,825	$ 44,597

[1] At December 31, 2017 and 2016, the Company's cash and cash equivalents consisted of bank accounts and high interest savings accounts with banks within the Company's existing credit facilities syndicate.

The accompanying notes are an integral part of these consolidated financial statements.

1. Reporting entity:

Western Energy Services Corp. ("Western") is a company domiciled in Canada. The address of the registered office is 1700, 215 - 9th Avenue SW, Calgary, Alberta. Western is a publicly traded company that is listed on the Toronto Stock Exchange ("TSX") under the symbol "WRG". These consolidated financial statements as at and for the years ended December 31, 2017 and 2016 (the "Financial Statements") are comprised of Western, its divisions and its wholly owned subsidiaries (together referred to as the "Company"). The Company is an oilfield service company providing contract drilling services through its division, Horizon Drilling ("Horizon") in Canada, and its wholly owned subsidiary, Stoneham Drilling Corporation ("Stoneham") in the United States. 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.

2. Basis of preparation and significant accounting policies:

(a) Statement of compliance:

These Financial Statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board.

Preparation of these Financial Statements in accordance with IFRS requires the use of certain critical accounting estimates. It also requires management to exercise judgment in applying the Company's accounting policies. The areas involving a higher degree of judgment or complexity and areas where assumptions and estimates are significant to these Financial Statements are disclosed in Note 4.

These Financial Statements were approved for issuance by Western's Board of Directors on February 21, 2018.

(b) Basis of measurement:

The consolidated financial statements have been prepared using the historical cost basis except as detailed in the Company's accounting policies in Note 3.

(c) Functional and presentation currency:

These Financial Statements are presented in Canadian dollars, which is Western's functional currency.

3. Significant accounting policies:

The significant accounting policies set out below have been applied consistently to all periods presented in these Financial Statements, unless otherwise indicated.

(a) Basis of consolidation:

These Financial Statements include the accounts of Western and its subsidiaries, which are entities over which Western has control. Control exists when Western has the power, directly or indirectly, to direct the relevant activities of an entity so as to obtain benefit from its activities. The financial results of Western's subsidiaries are included in the Financial Statements from the date that control commences until the date that control ceases. The accounting policies of Western's subsidiaries have been aligned with the policies adopted by Western. When Western ceases to control a subsidiary, the financial statements of that subsidiary are de-consolidated.

Inter-company balances and transactions, and any income and expenses arising from inter-company transactions, have been eliminated in these Financial Statements.

A portion of the Company's operations are conducted through arrangements where the Company and a third party each have a 50% interest. Based on the criteria outlined in IFRS 10, Consolidated Financial Statements, the Company determined that, for financial reporting purposes, the Company has control of these arrangements. As a result, the Company fully consolidates the arrangements and has recorded a non controlling interest in equity and net income.

3. Significant accounting policies (continued):

(b) Foreign currency transactions and operations:

The Canadian dollar is Western's functional and presentation currency. Each of the Company's subsidiaries' functional currency is determined individually and items included in the financial statements of each subsidiary are measured using that functional currency. Transactions in foreign currencies are translated to the respective functional currencies of Western and its subsidiaries at exchange rates in effect on the date of the transactions. Monetary assets and liabilities denominated in foreign currencies at the balance sheet date are translated to the functional currency at the exchange rate in effect on the balance sheet date with any resulting foreign exchange gain or loss recognized in net income. Non-monetary items measured in terms of historical cost in a foreign currency are translated using the exchange rate in effect on the date of the transaction. Foreign currency gains and losses on transactions are reported on a net basis and recognized in other items within net income.

The Company's foreign operations are conducted through Stoneham, which has a US dollar functional currency. For the purposes of presenting the Financial Statements, the assets and liabilities of this foreign operation are translated to Canadian dollars using exchange rates in effect on the balance sheet date. Income and expenses are translated at the average exchange rate for the period. Exchange differences arising from this translation are recognized in other comprehensive income.

(c) Business combinations:

The Company uses the acquisition method to account for business combinations. The Company measures goodwill as the fair value of the consideration transferred, less the net recognized amount (generally fair value) of the identifiable assets acquired and liabilities assumed, all measured as of the acquisition date. When the excess is negative, a gain on acquisition is recognized immediately in net income.

Goodwill is allocated as of the date of the business combination to the Company's operating segments that are expected to benefit from the business combination and represents the lowest level within the entity at which the goodwill is monitored for internal management purposes, which can be no higher than the operating segment level. Goodwill is not amortized and is tested for impairment annually. Additionally, goodwill is reviewed at each reporting date to determine if events or changes in circumstances indicate that the asset might be impaired, in which case an impairment test is performed. Goodwill is measured at cost less accumulated impairment losses.

Transaction costs, other than those associated with the issue of debt or equity securities, that the Company incurs in connection with a business combination are expensed as incurred and recognized in other items within net income.

(d) Financial instruments:

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

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

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

The Company has the following non-derivative financial assets:

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

Cash and cash equivalents are 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.

3. Significant accounting policies (continued):

(d) Financial instruments (continued):

(ii) Loans and receivables:

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

(iii) Available for sale:

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

The Company has the following non-derivative financial liabilities:

(i) Other financial liabilities:

Trade payables and other current liabilities, finance lease obligations, senior unsecured notes (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. Please refer to Note 24 for additional information on the Company's term loan.

(ii) Equity instruments:

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

(e) Cash and cash equivalents:
Cash and cash equivalents are comprised of cash balances and short term investments with original maturities of three months or less.

(f) Embedded derivatives:
Derivatives embedded in other instruments or host contracts are separated from the host contract and accounted for separately when their economic characteristics and risks are not closely related to the host contract. Embedded derivatives are recorded on the balance sheet at 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 changes in the value of the embedded derivatives are included in other items within net income.

(g) Property and equipment:
Items of property and equipment are measured at cost less accumulated depreciation and accumulated impairment losses.

Cost includes expenditures that are directly attributable to the acquisition of the asset and bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management.

The cost of self-constructed assets includes the cost of materials and direct labour as well as any other costs directly attributable to bringing the assets to a working condition for their intended use.

(tabular amounts are in thousands of Canadian dollars, except common share and per common share amounts)

3. Significant accounting policies (continued):

(g) Property and equipment (continued):

Borrowing costs directly attributable to the acquisition, construction or production of qualifying assets, which are assets that necessarily take a substantial period of time to get ready for their intended use or sale, are included in the cost of those assets, until such time as the assets are substantially available for their intended use. All other borrowing costs are recognized in net income in the period incurred.

The cost of replacing a part of an item of property and equipment is recognized in the carrying amount of the item if it is probable that the future economic benefits embodied within the part will flow to the Company, and its cost can be measured reliably. Costs associated with certifications and overhauls of drilling and well servicing rigs are capitalized and depreciated over the anticipated period between certifications, while the carrying amount of a replaced part, previous certification or overhaul is derecognized and recorded as a loss in net income as incurred. The costs of day-to-day servicing of property and equipment (i.e. repairs and maintenance) are recognized in net income as incurred.

Effective April 1, 2016, Western changed the method for depreciating its drilling and well servicing rigs and related equipment from unit of production to straight line and changed certain estimates relating to useful lives and salvage values. The change in depreciation methodology reflects the technological developments within the industry and the Company believes that straight line depreciation better reflects the future economic benefit related to these assets. Additionally, the change results in idle or underutilized assets being depreciated more quickly in periods of low activity. A summary of depreciation methodologies for the Company's property and equipment as at December 31, 2017 and 2016 is as follows:

	Expected Life	**Residual values**	**Depreciation method**
Buildings	25 years	-	Straight line
Drilling rigs and related equipment:			
Drilling rigs	8 to 25 years	10%	Straight line
Drill pipe	5 to 8 years	-	Straight line
Major inspections and overhauls	3 to 5 years	-	Straight line
Well servicing rigs and related equipment	12 to 25 years	10%	Straight line
Ancillary drilling and well servicing equipment	5 to 15 years	-	Straight line
Rental equipment	1 to 30 years	-	Straight line
Shop and office equipment	1 to 10 years	-	Straight line
Vehicles	3 years	20%	Straight line

A summary of depreciation methodologies for the Company's property and equipment prior to April 1, 2016 is as follows:

	Expected Life	**Residual values**	**Depreciation method**
Buildings	25 years	-	Straight line
Drilling rigs and related equipment:			
Drilling rigs	1,600 to 5,000 operating days	10-20%	Unit of production
Drill pipe	1,000 to 1,700 operating days	10%	Unit of production
Major inspections and overhauls	1,000 operating days	-	Unit of production
Well servicing rigs and related equipment	22,000 to 44,000 service hours	10-20%	Unit of production
Ancillary drilling and well servicing equipment	5 to 15 years	-	Straight line
Rental equipment	1 to 30 years	-	Straight line
Shop and office equipment	1 to 10 years	-	Straight line
Vehicles	3 years	20%	Straight line

3. Significant accounting policies (continued):

(g) Property and equipment (continued):

Depreciation is calculated based on the cost of the asset, less its estimated residual value. Depreciation is recognized in net income on a straight line basis over the estimated useful lives of each class of asset. Leased assets are depreciated over the shorter of the lease term and their estimated useful lives unless it is reasonably certain that the Company will obtain ownership at the end of the lease term, in which case, the estimated useful life of the asset is used. Land is not depreciated. Depreciation methods, useful lives and residual values are reviewed at least annually and adjusted if appropriate.

An item of property and equipment is derecognized when it is either disposed of or when it is determined that no further economic benefit is expected from the item's future use or disposal and as such is decommissioned. Losses realized on decommissioned assets are recognized in net income upon derecognition. Gains and losses on disposal of an item of property and equipment are determined by comparing the proceeds from disposal, less associated costs of disposal, with the carrying amount of property and equipment, and are recognized in other items within net income.

(h) Inventory:

Inventory is primarily comprised of operating supplies and is measured at the lower of cost and net realizable value. Inventory is charged to operating expenses as items are consumed using the weighted average cost method.

(i) Impairment:

(i) Financial assets:

Financial assets are assessed at each reporting date to determine whether there is objective evidence that they are impaired. A financial asset is impaired if objective evidence indicates a loss event has occurred after the initial recognition of the asset, and the loss event had a negative effect on the estimated future cash flows of the asset that can be estimated reliably.

(ii) Non-financial assets:

The carrying amounts of the Company's non-financial assets are reviewed at each reporting date to determine whether there is an indication of impairment. If an indication exists, then the asset's carrying amount is assessed for impairment. For goodwill the recoverable amount is estimated each year at the same time, unless there is an indication of impairment.

For the purpose of impairment testing, assets that cannot be tested individually are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets (the "cash-generating unit" or "CGU"). For the purposes of goodwill impairment testing, goodwill acquired in a business combination is allocated to the CGUs that are expected to benefit from the business combination.

An impairment loss is recognized in net income if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses recognized in respect of CGUs are allocated first to reduce the carrying amount of any goodwill allocated to the CGU, and then to reduce the carrying amounts of the other assets in the CGU on a pro rata basis.

The recoverable amount of an asset or cash-generating unit is the greater of its value in use and its fair value less costs to sell. 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 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.

3. Significant accounting policies (continued):

(i) Impairment (continued):

(ii) Non-financial assets (continued):

An impairment loss in respect of goodwill is not reversed. In respect of assets other than goodwill, impairment losses recognized in prior periods are assessed at each reporting date for indications that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimates used to determine the recoverable amount and the decrease in impairment loss can be objectively related to an event occurring after the impairment was recognized. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depreciation or amortization, if no impairment loss had been recognized. Such reversal is recognized in net income.

(j) Employee benefits:

(i) Short-term employee benefits:

Short-term employee benefit obligations are measured on an undiscounted basis and are expensed as the related service is provided. A liability is recognized for the amount expected to be paid under short-term cash bonus plans if the Company has a present legal or constructive obligation to pay this amount as a result of past service provided by the employee, and the obligation can be estimated reliably.

(ii) Stock based compensation awards:

Stock based compensation expense relates to stock options as well as cash and equity settled restricted share units ("RSUs"). The grant date fair values of stock option and equity settled RSUs granted are recognized as an expense, with a corresponding increase in contributed surplus in equity, over the vesting period. The amount recognized as an expense is based on the estimate of the number of awards expected to vest, which is revised if subsequent information indicates that actual forfeitures are likely to differ from the estimate. Upon exercise of stock options, the consideration paid by the holder is included in share capital and the related contributed surplus associated with the stock options exercised is reclassed into share capital. Upon vesting of equity settled RSUs, the related contributed surplus associated with the RSU is reclassified into share capital.

For cash settled RSUs, the fair value of the RSUs is recognized as stock based compensation expense, with a corresponding increase in accrued liabilities over the vesting period. The amount recognized as an expense is based on the estimate of the number of RSUs expected to vest. Cash settled RSUs are measured at their fair value at each reporting period on a mark-to-market basis. Upon vesting of the cash settled RSUs, the liability is reduced by the cash payout.

(k) Provisions:

A provision is recognized if, as a result of a past event, the Company has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability. The unwinding of the discount is recognized as a finance cost within net income. Also, a provision is recognized if an inducement or incentive is associated with a lease, such as a free rent period on an office lease or cash payments received for leasehold improvements. Lease inducements received are recognized as a reduction to the total lease expense, over the term of the lease.

(l) Revenue:

The Company's services are sold based upon purchase orders or contracts with customers that include fixed or determinable prices based upon daily or hourly rates and recoverable costs. Revenue is recognized when there is persuasive evidence that an arrangement exists, the service has been provided, the rate is fixed or determinable, and collection of the amounts billed to the customer is reasonably assured. The Company considers persuasive evidence to exist when a formal contract is signed or customer acceptance is obtained. Contract terms do not include a provision for significant post-service delivery obligations. Revenue from contracts of long or medium terms are recorded using the percentage-of-completion method, as services are provided, and collection is reasonably assured.

3. Significant accounting policies (continued):

(m) Leased assets and payments:

At inception of an arrangement, the Company determines whether such an arrangement is or contains a lease. Leases which result in the Company assuming substantially all the risks and rewards of ownership are classified as finance leases. Upon initial recognition of a finance lease, the leased asset and corresponding liability are measured at an amount equal to the lower of its fair value and the present value of the minimum lease payments under the lease agreement. Subsequent to initial recognition, the asset is accounted for in accordance with the accounting policy applicable to that asset.

Payments made under finance leases are apportioned between finance expense and the reduction of the outstanding liability. Finance expense is allocated to each period during the lease term using the effective interest rate method.

Leases that are not classified as finance leases are considered operating leases. Payments made under operating leases are recognized in net income on a straight line basis over the term of the lease.

(n) Finance income and finance costs:

Finance income comprises interest income on cash and cash equivalent balances. Interest income is recognized as it accrues in net income.

Finance costs comprise interest expense on borrowings, costs associated with securing debt instruments, and unwinding of the discount on provisions. Borrowing costs that are not directly attributable to the acquisition or construction of a qualifying asset are recognized in net income when incurred.

Warrants issued in conjunction with long term debt financings are included in deferred charges at their grant date fair value and amortized over the life of the warrant as a finance cost.

(o) Income tax:

Income tax expense is comprised of current and deferred income taxes. Income tax is recognized in net income and other comprehensive income except to the extent that it relates to items recognized in equity on the consolidated balance sheet.

Current income tax is calculated using tax rates which are enacted or substantively enacted at the end of the reporting period. Management periodically evaluates positions taken in tax returns with respect to situations in which applicable tax regulations are subject to interpretation. It establishes provisions on the basis of amounts expected to be paid to taxation authorities.

Deferred income taxes are recognized, using the liability method, on temporary differences arising between the tax basis of assets and liabilities and their carrying amounts in the respective entity's financial statements.

Deferred income taxes are determined using tax rates which are enacted or substantively enacted at the end of the reporting period and are expected to apply when the related deferred income tax asset is realized or the deferred income tax liability is settled.

Deferred tax liabilities are recognized for all taxable temporary differences, except for temporary differences that arise from goodwill which are not deductible for tax purposes.

Deferred tax assets are recognized to the extent it is probable that taxable profits will be available against which the deductible balances can be utilized. All deferred tax assets are analyzed at each reporting period and reduced to the extent that it is no longer probable that the asset will be recovered.

3. Significant accounting policies (continued):

(p) Earnings per share:

The Company presents basic and diluted earnings per share ("EPS") data for its common shares. Basic EPS is calculated by dividing the Company's net income or loss by the weighted average number of common shares outstanding during the reporting period. Diluted EPS is determined by adjusting the Company's net income or loss and the weighted average number of common shares outstanding for the effects of all potentially dilutive common shares, which comprise equity settled RSUs, in-the-money stock options and outstanding warrants. Diluted EPS is calculated using the treasury stock method where the deemed proceeds from the exercise of stock options or warrants and the associated unrecognized stock based compensation expense are considered to be used to reacquire common shares at the average common share price for the reporting period. The average market value of Western's common shares for purposes of calculating the dilutive effect of stock options is based on quoted market prices for the period during which the options were outstanding in the reporting period.

(q) Operating segment reporting:

An operating segment is a component of the Company that engages in business activities from which it may earn revenues and incur expenses, including revenues and expenses that relate to transactions with any of the Company's other operating segments. All operating segments' results are reviewed regularly by the Company's President & Chief Executive Officer and Senior Vice President, Finance & Chief Financial Officer ("Executive Management"), to make decisions about resources to be allocated to the operating segment and assess its performance.

Operating segment results that are reported to Executive Management include items directly attributable to an operating segment as well as those that can be allocated on a reasonable basis. The Company's operating segments are defined in Note 5.

(r) Standards adopted in the year:

The Company did not adopt any new or revised accounting standards for the years ended December 31, 2017 and 2016.

(s) New standards and interpretations not yet adopted:

A number of new standards, amendments to standards and interpretations are not yet effective for the year ended December 31, 2017, and have not been applied in preparing these Financial Statements. The following new standards have not been adopted which may impact the Company in the future:

- IFRS 15, Revenue from Contracts with Customers, was issued in May 2014 and replaces the previous guidance on revenue recognition. The standard is effective for annual periods beginning on or after January 1, 2018, with earlier application permitted. The standard provides a single principles based five step model to be applied to all contracts with customers. The Company has completed its preliminary assessments of IFRS 15 and its impact on the Financial Statements. Under IFRS 15, Western anticipates that its contracts with customers in the contract drilling segment will be impacted by the new standard. The Company expects that these contracts will be classified either as short term contracts, such as spot market contracts with expiries of less than a year, or long term committed contracts, with expiries greater than one year. It is anticipated that short term contracts will be accounted for under IFRS 15, based on specific performance obligations contained within the contracts, whereas long term contracts will be accounted for as operating leases by the lessor under IFRS 16, Leases. The company expects to apply the practical expedient per IFRS 15, paragraph B16, which enables the Company to recognize revenue as the related revenue is invoiced. As Western currently invoices on a per day basis, Western anticipates no significant impact on revenue recognition by applying the practical expedient.

  The Company does not expect any significant changes to its Financial Statements, other than more detailed revenue disclosures including, but not limited to, the different categories of revenue by contract classification, as well as additional disclosures on the determination of contract classification and contract balances outstanding. It is not expected that IFRS 15 will have a significant impact on the production services segment.

(tabular amounts are in thousands of Canadian dollars, except common share and per common share amounts)

3. Significant accounting policies (continued):

(s) New standards and interpretations not yet adopted (continued):

- IFRS 9, Financial Instruments, was amended in July 2014 with respect to its classification and measurement of financial assets and introduces a new expected loss impairment model. This standard is effective for annual periods beginning on or after January 1, 2018, with early adoption permitted and shall be applied retrospectively. The standard now includes three categories for financial assets, as compared to five categories under IAS 39, including amortized cost, fair value through profit or loss, and fair value through other comprehensive income. IFRS 9 removes the loans and receivables and held for trading categories previously included under IAS 39. For financial liabilities, most of the requirements from IAS 39 were included in IFRS 9 and are not expected to impact the Company's financial liabilities. Additionally, IFRS 9 also includes a greater emphasis on the Company's credit risk and how the Company's credit losses are determined.

  Western has completed its assessments of IFRS 9 and does not expect significant changes to its current methodologies for accounting for its financial instruments, however does expect additional financial statement disclosures under the new standard, including the changes in financial instrument classifications as well as expanded disclosure on the Company's credit risk. The following table summarizes the expected changes to the Company's financial asset and liability classifications:

	IAS 39		IFRS 9	
Financial Asset / Liability	**Classification**	**Measurement**	**Classification**	**Measurement**
Cash and cash equivalents	Held for trading	Fair value	Amortized cost	Amortized cost
Trade and other receivables	Loans and receivables	Amortized cost	Amortized cost	Amortized cost
Trade payables and other current liabilities	Other financial liabilities	Amortized cost	Amortized cost	Amortized cost
Finance lease obligations	Other financial liabilities	Amortized cost	Amortized cost	Amortized cost
Senior Notes	Other financial liabilities	Amortized cost	Amortized cost	Amortized cost
Credit Facilities	Other financial liabilities	Amortized cost	Amortized cost	Amortized cost

- IFRS 2, Share Based Payments, was amended in June 2016, clarifying how to account for certain types of share based payment transactions, including the accounting for the effects of vesting and non vesting conditions on the measurement of cash settled share based payments, accounting for share based payment transactions with a net settlement feature for withholding tax obligations, and accounting for modifications to the terms and conditions of a share based payment that changes the classification of the share based payment transaction from cash settled to equity settled. The IFRS 2 amendments are effective for annual periods beginning on or after January 1, 2018. The Company has evaluated the change in the standard and there is no material impact from the amendment.

- IFRS 16, Leases, was issued in January 2016 and replaces the previous guidance on leases. This standard provides a single recognition and measurement model to be applied to leases, with required recognition of assets and liabilities for most leases. This standard is effective for annual periods beginning on or after January 1, 2019, with early adoption permitted if the Company is also applying IFRS 15, Revenue from Contracts with Customers. The Company has completed its preliminary assessments of IFRS 16 and does not anticipate early adopting IFRS 16. The adoption of IFRS 16 is expected to have an impact on the Financial Statements, as the Company currently has a long term office lease that is classified as an operating lease, with monthly rent payments recorded through administrative expenses. Under IFRS 16, Western's office lease will become a finance lease, with the present value of the future lease payments used to estimate the value of the right of use asset and lease obligation. Western currently estimates the value of the right of use asset to be approximately $6.2 million with a corresponding net liability of approximately $7.1 million as at January 1, 2019. IFRS 16 will result in additional disclosure in Western's notes to the Financial Statements, relating to the right of use asset and the lease obligation. Additionally, Western will be required to disclose the depreciation relating to the right of use asset and interest relating to the lease obligation separately in the notes to the Financial Statements. Western expects that IFRS 16 will not have a significant impact on Western's other short term operating leases, such as office equipment.

3. Significant accounting policies (continued):

(s) New standards and interpretations not yet adopted (continued):

Additionally, Western anticipates that its long term drilling contracts will be classified as operating leases under IFRS 16. The Company does not expect any significant changes to its Financial Statements as the current treatment for its long term drilling contracts is consistent with IFRS 16 guidance. However, the Company does anticipate more detailed note disclosures in its Financial Statements relating to its long term drilling contracts.

4. Critical accounting estimates:

The preparation of the Financial Statements in conformity with IFRS requires management to make estimates, judgments and assumptions that affect the application of accounting policies (described in Note 3) 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.

A number of the Company's accounting policies and disclosures require key assumptions concerning the future and other estimates that have a significant risk of causing a material adjustment to the carrying amounts of assets and liabilities or disclosures within the next fiscal year. Where applicable, further information about the assumptions made is disclosed in the notes specific to that asset or liability. The critical accounting estimates and judgments set out below have been applied consistently to all periods presented in these Financial Statements.

(a) 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 is an indicator 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 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 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.

4. Critical accounting estimates (continued):

(b) 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). 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.

(c) Income taxes:

Preparation of the 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.

(d) Stock based compensation:

The fair value of stock options, equity settled 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.

The 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.

(e) Non-derivative financial liabilities:

As detailed in Note 3 (d), 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.

(f) 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. Note 19 details further information on the Company's allowance for doubtful accounts.

(tabular amounts are in thousands of Canadian dollars, except common share and per common share amounts)

5. Operating segments:

The Company operates in the oilfield service industry through its contract drilling segment in Canada and the United States, and through its production services segment in Canada. Contract drilling includes drilling rigs along with related ancillary equipment and provides services to crude oil and natural gas exploration and production companies. Production services includes well servicing rigs and related equipment, as well as oilfield rental equipment and provides services to crude oil and natural gas exploration and production companies and in the case of oilfield rental equipment, to other oilfield service companies.

The Company's Executive Management review internal management reports for these operating segments on at least a monthly basis.

Information regarding the results of the operating segments is included below. Performance is measured based on operating earnings, as included in internal management reports. Operating earnings is used to measure performance as management believes that such information is the most relevant in evaluating the results of certain operating segments relative to other entities that operate within these industries. Operating earnings is calculated as revenue less operating expenses (excluding stock based compensation), administrative expenses (excluding stock based compensation) and depreciation expense.

The following is a summary of the Company's results by operating segment for the years ended December 31, 2017 and 2016:

Year ended December 31, 2017	Contract Drilling	Production Services	Corporate	Inter-segment Elimination	Total
Revenue	$ 182,942	$ 55,361	$ -	$ (128)	$ 238,175
Operating loss	(18,453)	(6,399)	(5,893)	-	(30,745)
Finance costs	-	-	21,950	-	21,950
Depreciation	52,156	13,631	653	-	66,440
Additions to property and equipment (1)	15,512	3,565	160	-	19,237

(1) Additions include the purchase of property and equipment and finance lease additions.

Year ended December 31, 2016	Contract Drilling	Production Services	Corporate	Inter-segment Elimination	Total
Revenue	$ 84,054	$ 40,428	$ -	$ (44)	$ 124,438
Operating loss	(38,899)	(11,273)	(3,525)	-	(53,697)
Finance costs	-	-	22,522	-	22,522
Loss on asset decommissioning	5,225	265	-	-	5,490
Depreciation	45,646	12,977	849	-	59,472
Additions to property and equipment (1)	3,154	1,564	1	-	4,719

(1) Additions include the purchase of property and equipment and finance lease additions.

Total assets and liabilities by operating segment are as follows:

As at December 31, 2017	Contract Drilling	Production Services	Corporate	Total
Total assets	$ 568,218	$ 136,100	$ 56,186	$ 760,504
Total liabilities	95,182	27,613	251,555	374,350

As at December 31, 2016	Contract Drilling	Production Services	Corporate	Total
Total assets	$ 605,121	$ 147,891	$ 40,513	$ 793,525
Total liabilities	99,873	28,324	258,121	386,318

(tabular amounts are in thousands of Canadian dollars, except common share and per common share amounts)

5. Operating segments (continued):

A reconciliation of operating loss to loss before income taxes by operating segment is as follows:

Year ended December 31, 2017	Contract Drilling	Production Services	Corporate	Total
Operating loss	$ (18,453)	$ (6,399)	$ (5,893)	$ (30,745)
Deduct:				
Stock based compensation	(318)	(239)	(1,392)	(1,949)
Finance costs	-	-	(21,950)	(21,950)
Other items	-	-	(1,356)	(1,356)
Loss before income taxes	$ (18,771)	$ (6,638)	$ (30,591)	$ (56,000)

Year ended December 31, 2016	Contract Drilling	Production Services	Corporate	Total
Operating loss	$ (38,899)	$ (11,273)	$ (3,525)	$ (53,697)
Add (deduct):				
Stock based compensation	(633)	(598)	(2,537)	(3,768)
Finance costs	-	-	(22,522)	(22,522)
Other items	-	-	1,549	1,549
Loss on asset decommissioning	(5,225)	(265)	-	(5,490)
Loss before income taxes	$ (44,757)	$ (12,136)	$ (27,035)	$ (83,928)

Segmented information by geographic area is as follows:

As at December 31, 2017	Canada	United States	Total
Property and equipment	$ 554,006	$ 98,822	$ 652,828
Total assets	652,935	107,569	760,504

As at December 31, 2016	Canada	United States	Total
Property and equipment	$ 599,511	$ 109,056	$ 708,567
Total assets	673,113	120,412	793,525

	Canada	United States	Total
Revenue - year ended December 31, 2017	$ 207,230	$ 30,945	$ 238,175
Revenue - year ended December 31, 2016	109,588	14,850	124,438

Significant Customers:

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.

6. Trade and other receivables:

The Company’s trade and other receivables as at December 31, 2017 and 2016 are as follows:

	December 31, 2017	December 31, 2016
Trade receivables	$ 39,055	$ 23,508
Accrued trade receivables	8,870	9,375
Income tax receivable	-	1,685
Other receivables	219	453
Allowance for doubtful accounts	(27)	(23)
Total	$ 48,117	$ 34,998

The Company’s exposure to credit risk related to trade and other receivables is disclosed in Note 19.

(tabular amounts are in thousands of Canadian dollars, except common share and per common share amounts)

7. Other Assets:

The Company's other assets as at December 31, 2017 and 2016 are as follows:

	December 31, 2017	December 31, 2016
Current:		
Prepaid expenses	$ 1,925	$ 1,899
Inventory	2,712	2,770
Deposits	492	475
Deferred charges	1,300	109
Total current portion of other assets	6,429	5,253
Non current:		
Deferred charges	4,305	110
Total non current portion of other assets	4,305	110
Total other assets	$ 10,734	$ 5,363

8. Property and Equipment:

The following table summarizes the Company's property and equipment as at December 31, 2017 and 2016:

	Land	Buildings	Contract drilling equipment	Production services equipment	Office and shop equipment	Vehicles under finance leases	Total
Cost:							
Balance at December 31, 2015	$ 5,089	$ 4,205	$ 790,681	$ 202,218	$ 12,604	$ 3,631	$ 1,018,428
Additions	-	-	3,132	1,304	283	-	4,719
Loss on asset decommissioning	-	-	(6,507)	(300)	(351)	-	(7,158)
Disposals	-	-	(617)	(1,741)	(28)	(323)	(2,709)
Foreign exchange adjustment	-	-	(7,040)	-	(20)	(148)	(7,208)
Balance at December 31, 2016	$ 5,089	$ 4,205	$ 779,649	$ 201,481	$ 12,488	$ 3,160	$ 1,006,072
Additions	-	191	14,746	2,916	279	-	18,132
Finance lease additions	-	-	-	-	-	1,105	1,105
Disposals	-	-	(3,576)	(1,527)	-	(789)	(5,892)
Foreign exchange adjustment	-	-	(9,983)	-	(43)	(19)	(10,045)
Balance at December 31, 2017	$ 5,089	$ 4,396	$ 780,836	$ 202,870	$ 12,724	$ 3,457	$ 1,009,372
Accumulated depreciation:							
Balance at December 31, 2015	$ -	$ 826	$ 178,793	$ 56,668	$ 6,992	$ 1,502	$ 244,781
Depreciation for the year	-	195	45,018	12,210	1,470	579	59,472
Loss on asset decommissioning	-	-	(1,282)	(71)	(315)	-	(1,668)
Disposals	-	-	(359)	(1,007)	(23)	(191)	(1,580)
Foreign exchange adjustment	-	-	(3,389)	-	(14)	(97)	(3,500)
Balance at December 31, 2016	$ -	$ 1,021	$ 218,781	$ 67,800	$ 8,110	$ 1,793	$ 297,505
Depreciation for the year	-	197	51,730	13,080	1,030	403	66,440
Disposals	-	-	(2,553)	(1,209)	-	(584)	(4,346)
Foreign exchange adjustment	-	-	(2,998)	-	(42)	(15)	(3,055)
Balance at December 31, 2017	$ -	$ 1,218	$ 264,960	$ 79,671	$ 9,098	$ 1,597	$ 356,544
Carrying amounts:							
At December 31, 2016	$ 5,089	$ 3,184	$ 560,868	$ 133,681	$ 4,378	$ 1,367	$ 708,567
At December 31, 2017	$ 5,089	$ 3,178	$ 515,876	$ 123,199	$ 3,626	$ 1,860	$ 652,828

Assets under construction:

Included in property and equipment at December 31, 2017 are assets under construction of $2.0 million (December 31, 2016: $2.3 million) which includes ancillary drilling and well servicing equipment.

(tabular amounts are in thousands of Canadian dollars, except common share and per common share amounts)

8. Property and Equipment (continued):

Impairment:

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 amount of its net assets, and as such performed an impairment analysis on each of its CGUs. These CGUs are based on contract drilling rigs, well servicing rigs and oilfield rental equipment within the Company's contract drilling and production services segments.

As at December 31, 2017, the recoverable amounts allocated to these CGUs were determined based on a value in use cash flow projection based on historical results, recent industry conditions and the Company's most recent 2018 forecast. Cash flow projections for 2019 to 2022 have assumed a gradual increase in activity to historical levels. Cash flow projections thereafter are determined based on a terminal value calculated using a 2% per annum growth rate. For the purposes of completing the impairment analysis on the contract drilling CGU, assumptions were made relating to average contract drilling utilization, which range from approximately 40% to 50% per year. For the purposes of completing the impairment analysis on the well servicing CGU, assumptions were made relating to average well servicing utilization, which range from approximately 30% to 35% per year.

The forecasted cash flows are based on management's best estimates of asset utilization, pricing for available equipment, costs to maintain that equipment and an after tax discount rate of 12.0% per annum. The results of the tests indicated no impairment of property and equipment at December 31, 2017.

The most sensitive inputs to the model are the discount rate and the growth rate. The impairment test's sensitivity to these inputs is as follows: All else being equal, a 0.5% increase in the discount rate would not have changed the results of the impairment tests. All else being equal, a 5% decrease in cash flows would not have changed the results of the impairment tests.

As at December 31, 2016, the Company identified impairment indicators related to the prolonged commodity price downturn and as such performed an impairment analysis on each of its CGUs. The recoverable amounts allocated to these CGUs as at December 31, 2016 were determined based on a discounted cash flow calculation which used cash flow projections based on historical results and incorporated the Company's most recent 2017 forecast. For the purposes of completing the impairment analysis on the contract drilling CGU, assumptions were made relating to average contract drilling utilization. These rates ranged from 30% to 55% per year. For the purposes of completing the impairment analysis on the well servicing CGU, assumptions were made relating to average well servicing utilization. These rates ranged from 30% to 50% per year. The forecasted cash flows were based on management's best estimates of asset utilization, pricing for available equipment, costs to maintain that equipment and an after tax discount rate of 12.5% per annum. The results of the tests indicated no impairment of property and equipment at December 31, 2016.

During the year ended December 31, 2017, the Company evaluated its property and equipment and decommissioned $nil (December 31, 2016 - $5.5 million) of equipment for which it was determined that no further economic benefit would be realized.

9. Trade payable and other current liabilities:

Trade payables and current liabilities as at December 31, 2017 and 2016 are as follows:

	December 31, 2017	December 31, 2016
Trade payables	$ 21,304	$ 13,976
Accrued trade payables and expenses	18,587	18,930
Total	$ 39,891	$ 32,906

The Company's exposure to foreign exchange and liquidity risk related to trade payables and other current liabilities is disclosed in Note 19.

(tabular amounts are in thousands of Canadian dollars, except common share and per common share amounts)

10. Provisions:

As at December 31, 2017 and 2016, the Company has recognized a provision for the deferral of office lease inducements received, which are amortized on a straight-line basis over the life of the contract. The following table summarizes Western's lease inducements:

	Lease inducements
Balance at December 31, 2015	$ 1,819
Provisions used during the year	(145)
Balance at December 31, 2016	1,674
Provisions used during the year	(120)
Balance at December 31, 2017	$ 1,554

The following table summarizes the balance sheet classification of the Company's provisions as at December 31, 2017 and 2016:

	December 31, 2017	December 31, 2016
Current	$ 139	$ 140
Non current	1,415	1,534
	$ 1,554	$ 1,674

11. Long term debt:

This note provides information about the contractual terms of the Company's long term debt instruments.

	December 31, 2017	December 31, 2016
Current:		
Other long term debt – current portion [1]	$ 475	$ 684
Total current portion of long term debt	475	684
Non current:		
Senior Notes	265,000	265,000
Less: net unamortized premium and issue costs on Senior Notes	(569)	(1,088)
Other long term debt – non current portion [1]	788	158
Total non current portion of long term debt	265,219	264,070
Total long term debt	$ 265,694	$ 264,754

(1) Other long term debt relates to finance lease obligations.

Credit facilities:

On October 17, 2017, the Company amended the terms, extended the maturity of the Credit Facilities to December 17, 2020 and increased the amount available under the Revolving Facility from $50.0 million to $70.0 million. At December 31, 2017, Western's credit facilities consisted of a $70.0 million syndicated revolving credit facility (the "Revolving Facility") and a $10.0 million committed operating facility (the "Operating Facility" and together the "Credit Facilities"). The $10.0 million Operating Facility remains unchanged. In addition to the $80.0 million of available credit under the revised Credit Facilities, Western has access to an accordion feature whereby an incremental $50.0 million of borrowing would become available, subject to the approval of the lenders.

Advances under the Credit Facilities will be limited by the Company's borrowing base. The borrowing base is applicable when the Debt Service Coverage ratio is less than 2.0 and either (i) more than $40.0 million is drawn under 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 investment grade accounts receivable; plus
- 75% of 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.

(tabular amounts are in thousands of Canadian dollars, except common share and per common share amounts)

11. Long term debt (continued):

Credit facilities (continued):

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.

The Company's Credit Facilities are subject to the following financial covenants:

	Covenant	Dec 31, 2017
Maximum Consolidated Senior Debt to Consolidated EBITDA Ratio (1)(2)	3.0:1.0 or less	0.0:1.0
Maximum Consolidated Debt to Consolidated Capitalization Ratio (3)(4)	0.6:1.0 or less	0.36:1.0
Minimum Debt Service Coverage Ratio (5)	1.0:1.0 or more	Not applicable

(1) Consolidated Senior Debt in the Credit Facilities is defined as indebtedness under the Revolving Facility, Operating Facility and finance leases; reduced by all cash and cash equivalents.

(2) Consolidated EBITDA in the Credit Facilities is defined on a trailing twelve month basis as consolidated net income (loss), plus interest, income taxes, depreciation and amortization and any other non-cash items or extraordinary or non-recurring losses, less gains on sale of property and equipment and any other non-cash items or extraordinary or non-recurring gains that are included in the calculation of consolidated net income.

(3) Consolidated Debt in the Credit Facilities is defined as Consolidated Senior Debt plus the outstanding principal on both the second lien secured term loan and unsecured debt, including the Senior Notes.

(4) Consolidated Capitalization in the Credit Facilities is defined as the aggregate of Consolidated Debt and total shareholders` equity as reported on the consolidated balance sheet.

(5) Debt Service Coverage Ratio is defined as the ratio of Consolidated EBITDA, as previously defined, divided by the sum of interest expense on a twelve month trailing basis, including capitalized interest, and scheduled long term debt principal repayments for the next twelve months. The 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. 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.

As at December 31, 2017 and 2016, the Company was in compliance with all covenants related to its Credit Facilities.

Senior Notes:

As at December 31, 2017 the Company had $265.0 million 7⅞% senior unsecured notes (the "Senior Notes") outstanding which are due on January 30, 2019. The Senior Notes contain certain early redemption options under which the Company has the option to redeem all or a portion of the Senior Notes at various redemption prices, which include the principal amount plus accrued and unpaid interest, if any, to the applicable redemption date. Interest is payable semi-annually on January 30 and July 30. The Senior Notes are unsecured, ranking equal in right of payment to all existing and future unsecured indebtedness, and have been guaranteed by the Company's current and future subsidiaries. The Senior Notes indenture contains certain restrictions relating to items such as making restricted payments and incurring additional debt. The Senior Notes were repaid subsequent to December 31, 2017. Please refer to Note 24 for additional details.

At December 31, 2017, the fair value of the Senior Notes was approximately $267.8 million (December 31, 2016: $249.4 million).

Second Lien Facility:

On October 17, 2017 the Company completed 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 and was used to repay a portion of the Company's outstanding Senior Notes subsequent to December 31, 2017. 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.

Please refer to Note 24 for additional information on long term debt changes subsequent to December 31, 2017.

(tabular amounts are in thousands of Canadian dollars, except common share and per common share amounts)

12. Share capital:

The Company is authorized to issue an unlimited number of common shares. The following table summarizes Western's common shares:

	Issued and outstanding shares		Amount
Balance at December 31, 2015	73,646,292	$	417,622
Issued on vesting of restricted share units	149,652		887
Balance at December 31, 2016	73,795,944		418,509
Issued on vesting of restricted share units	179,654		896
Issued for cash - October 17, 2017	18,200,000		22,750
Issuance costs, net of deferred tax	-		(1,136)
Balance at December 31, 2017	92,175,598	$	441,019

During the years ended December 31, 2017 and 2016, no dividends were declared. The Company had no dividends payable as at December 31, 2017 and 2016.

On October 17, 2017, the Company closed a private placement of 9.1 million common shares at a price of $1.25 per common share, for aggregate gross proceeds of $11.4 million, as well as a bought deal offering of 9.1 million common shares at a price of $1.25 per common share, for aggregate gross proceeds of $11.4 million.

13. Stock based compensation:

Stock options:

The Company's stock option plan provides for stock options to be issued to directors, officers, employees and consultants of the Company so that they may participate in the growth and development of Western. Subject to the specific provisions of the stock option plan, eligibility, vesting period, terms of the options and the number of options granted are to be determined by the Board of Directors at the time of grant. The stock option plan allows the Board of Directors to issue up to 10% of the Company's outstanding common shares as stock options.

The following table summarizes the movements in Western's outstanding stock options:

	Stock options outstanding		Weighted average exercise price
Balance at December 31, 2015	6,058,906	$	7.10
Granted	1,453,362		3.26
Forfeited	(1,067,283)		6.69
Expired	(291,099)		7.92
Balance at December 31, 2016	6,153,886		6.23
Granted	1,422,111		1.40
Forfeited	(705,981)		5.67
Expired	(394,403)		7.22
Balance at December 31, 2017	6,475,613	$	5.17

For the years ended December 31, 2017 and 2016, no stock options were cancelled. The average fair value of the stock options granted in 2017 was $0.38 per stock option (2016: $0.82 per stock option).

(tabular amounts are in thousands of Canadian dollars, except common share and per common share amounts)

13. Stock based compensation (continued):

Stock Options (continued):

The following table summarizes the details of Western's outstanding stock options:

As at December 31, 2017 Exercise Price ($/share)	Number of options outstanding	Weighted average contractual life remaining (years)	Number of options exercisable
1.20-2.50	1,310,178	4.62	15,984
2.51-4.50	1,210,514	3.64	389,179
4.51-6.50	1,714,592	2.61	1,166,507
6.51-8.50	1,218,868	0.80	1,196,535
8.51-11.14	1,021,461	1.61	1,021,461
	6,475,613	2.71	3,789,666

As at December 31, 2017, Western had 3,789,666 (December 31, 2016: 2,951,043) exercisable stock options outstanding at a weighted average exercise price equal to $6.92 (December 31, 2016: $7.49) per stock option.

The accounting fair value of the stock options as at the date of grant is calculated in accordance with a Black Scholes option pricing model using the following average inputs:

	Year ended December 31, 2017	Year ended December 31, 2016
Risk-free interest rate	1%	1%
Average forfeiture rate	16%	15%
Average expected life	2.0 years	2.0 years
Maximum life	5.0 years	5.0 years
Average vesting period	2.0 years	2.0 years
Expected dividend	0%	0%
Expected share price volatility	49%	46%

Restricted share unit plan:

The Company's restricted share unit ("RSU") plan provides RSUs to be issued to directors, officers, employees and consultants of the Company so that they may participate in the growth and development of Western. Subject to the specific provisions of the RSU plan, eligibility, vesting period, terms of the RSUs and the number of RSUs granted are to be determined by the Board of Directors at the time of the grant. The RSU plan allows the Board of Directors to issue up to 5% of the Company's outstanding common shares as equity settled RSUs, provided that, when combined, the maximum number of common shares reserved for issuance under all stock based compensation arrangements of the Company does not exceed 10% of the Company's outstanding common shares.

The following table summarizes the movements in Western's outstanding RSUs:

	Equity settled	Cash settled	Total
Balance at December 31, 2015	410,269	349,235	759,504
Granted	182,554	187,437	369,991
Issued as a result of dividends	6,540	5,556	12,096
Vested	(149,652)	(108,478)	(258,130)
Forfeited	(39,400)	(115,485)	(154,885)
Balance at December 31, 2016	410,311	318,265	728,576
Granted	6,200	1,122,807	1,129,007
Vested	(179,654)	(127,598)	(307,252)
Forfeited	(45,437)	(91,581)	(137,018)
Balance at December 31, 2017	191,420	1,221,893	1,413,313

(tabular amounts are in thousands of Canadian dollars, except common share and per common share amounts)

13. Stock based compensation (continued):

Restricted share unit plan (continued):

The estimated fair value of the equity settled RSUs granted during the year ended December 31, 2017 was less than $0.1 million (December 31, 2016: $0.5 million) and will be recognized as an expense over the vesting period of the RSUs.

The accounting fair value of the equity settled RSUs as at the grant date is calculated in accordance with a Black Scholes option pricing model using the following average inputs:

	Year ended December 31, 2017	Year ended December 31, 2016
Risk-free interest rate	1%	1%
Average forfeiture rate	10%	7%
Average expected life	2.0 years	2.0 years
Maximum life	3.0 years	3.0 years
Average vesting period	2.0 years	2.0 years
Expected dividend	0%	0%
Expected share price volatility	47%	46%

Stock based compensation expense recognized in the consolidated statements of operations and comprehensive income (loss) is comprised of the following:

	Year ended December 31, 2017	Year ended December 31, 2016
Stock options	$ 1,267	$ 2,429
Restricted share units – equity settled grants	514	976
Total equity settled stock based compensation expense	1,781	3,405
Restricted share units – cash settled grants	168	363
Total stock based compensation expense	$ 1,949	$ 3,768

The outstanding liability related to cash settled RSUs at December 31, 2017 was $0.4 million (December 31, 2016: $0.4 million).

Warrants:

On October 17, 2017, in conjunction with the closing of the Second Lien Facility, Western issued 7,099,546 warrants to AIMCo. Each warrant will entitle AIMCo to acquire one common share at an exercise price of $1.77 per common share at any time prior to October 17, 2020, after which they expire.

The accounting fair value of the warrants as at the grant date is calculated in accordance with a Black Scholes option pricing model using a risk free rate of 1.5%, a forfeiture rate of nil, an average expected life of 1.5 years, an expected dividend of nil, and an expected share price volatility of 50%. The fair value of the Company's warrants at grant date was approximately $1.1 million.

14. Earnings per share:

The weighted average number of common shares is calculated as follows:

	Year ended December 31, 2017	Year ended December 31, 2016
Issued common shares, beginning of period	73,795,944	73,646,292
Weighted average number of common shares issued	3,805,883	57,145
Weighted average number of common shares (basic)	77,601,827	73,703,437
Dilutive effect of equity securities	-	-
Weighted average number of common shares (diluted)	77,601,827	73,703,437

For the year ended December 31, 2017, 6,475,613 stock options (December 31, 2016: 6,153,886 stock options), 191,420 equity settled RSUs (December 31, 2016: 410,311 equity settled RSUs) and 7,099,546 warrants (December 31, 2016: nil) were excluded from the diluted weighted average number of common shares calculation as their effect would have been anti-dilutive.

(tabular amounts are in thousands of Canadian dollars, except common share and per common share amounts)

15. Finance costs:

Finance costs recognized in the consolidated statements of operations and comprehensive income (loss) are comprised of the following:

	Year ended December 31, 2017	Year ended December 31, 2016
Interest expense on long term debt	$ 21,506	$ 21,679
Amortization of debt financing fees and provisions	794	984
Interest income	(350)	(141)
Total finance costs	$ 21,950	$ 22,522

The Company had an effective interest rate of 8.3% on its borrowings for the year ended December 31, 2017 (December 31, 2016: 8.5%).

16. Other items:

Other items recognized in the consolidated statements of operations and comprehensive income (loss) are comprised of the following:

	Year ended December 31, 2017	Year ended December 31, 2016
Transaction costs	$ 1,597	$ -
Loss on sale of fixed assets	603	580
Mark-to-market loss on fair value of derivatives	-	552
Realized foreign exchange gain	(868)	(2,678)
Unrealized foreign exchange loss (gain)	24	(3)
Total other items	$ 1,356	$ (1,549)

17. Income taxes:

Income taxes recognized in the consolidated statements of operations and comprehensive income (loss) are comprised of the following:

	Year ended December 31, 2017	Year ended December 31, 2016
Current tax expense (recovery)	$ 75	$ (1,708)
Deferred tax recovery	(18,630)	(20,247)
Total income tax recovery	$ (18,555)	$ (21,955)

The following table summarizes the income taxes recognized directly into equity, related to the share issuance in 2017:

	Year ended December 31, 2017	Year ended December 31, 2016
Share issue costs	$ 413	$ -

(tabular amounts are in thousands of Canadian dollars, except common share and per common share amounts)

17. Income taxes (continued):

The following provides a reconciliation of loss before income taxes to total income taxes recognized in the consolidated statements of operations and comprehensive income (loss):

	Year ended December 31, 2017		Year ended December 31, 2016	
Loss before income taxes		$ (56,000)		$ (83,928)
Federal and provincial statutory rates	27.0%	(15,120)	26.7%	(22,438)
Income (loss) taxed at higher rates		86		(408)
Stock based compensation		902		893
Non controlling interest		(22)		(19)
Non-deductible expenses		(563)		258
Change in effective tax rate on temporary differences		(3,319)		(165)
Change in estimate		67		-
Return to provision adjustment		(613)		(37)
Other		27		(39)
Total income taxes		$ (18,555)		$ (21,955)

The following table details the nature of the Company's temporary differences:

	December 31, 2017	December 31, 2016
Property and equipment	$ (125,427)	$ (141,226)
Deferred charges and accruals	(423)	65
Provisions	414	446
Long term debt	(39)	(210)
Share issue costs	379	-
Other tax pools	1,245	1,159
Tax loss carry-forwards	56,640	52,782
Net deferred tax liabilities	$ (67,211)	$ (86,984)

Movements of the Company's temporary differences for the year ended December 31, 2017 are as follows:

	Balance Dec 31, 2016	Recognized in equity	Recognized in net income (loss)	Impact of foreign exchange	Balance Dec 31, 2017
Property and equipment	$ (141,226)	$ -	$ 13,568	$ 2,231	$ (125,427)
Deferred charges and accruals	65	-	(486)	(2)	(423)
Provisions	446	-	(32)	-	414
Long term debt	(210)	-	171	-	(39)
Share issue costs	-	413	(34)	-	379
Other tax pools	1,159	-	94	(8)	1,245
Tax loss carry-forwards	52,782	-	5,349	(1,491)	56,640
Net deferred tax liabilities	$ (86,984)	$ 413	$ 18,630	$ 730	$ (67,211)

(tabular amounts are in thousands of Canadian dollars, except common share and per common share amounts)

17. Income taxes (continued):

Movements of the Company's temporary differences for the year ended December 31, 2016 are as follows:

	Balance Dec 31, 2015	Recognized in equity	Recognized in net income (loss)	Impact of foreign exchange	Balance Dec 31, 2016
Property and equipment	$ (139,075)	$ -	$ (3,428)	$ 1,277	$ (141,226)
Other assets	(148)	-	148	-	-
Deferred charges and accruals	(20)	-	86	(1)	65
Provisions	483	-	(37)	-	446
Long term debt	59	-	(269)	-	(210)
Other tax pools	1,114	-	67	(22)	1,159
Tax loss carry-forwards	29,885	-	23,680	(783)	52,782
Net deferred tax liabilities	$ (107,702)	$ -	$ 20,247	$ 471	$ (86,984)

As at December 31, 2017, the Company has gross loss carry-forwards equal to approximately $147.6 million in Canada, which will expire between 2035 and 2037. In the United States, the Company has approximately US$49.2 million gross loss carry forwards which expire between 2028 and 2036.

18. Costs by nature:

The Company presents certain expenses in the consolidated statements of operations and comprehensive income (loss) by function. The following table presents significant expenses by nature:

	Year ended December 31, 2017	Year ended December 31, 2016
Depreciation of property and equipment (Note 8)	$ 66,440	$ 59,472
Employee benefits: salaries and benefits	128,252	76,087
Employee benefits: stock based compensation (Note 13)	1,949	3,768
Repairs and maintenance	19,166	8,707
Third party charges	19,187	7,531

19. Financial risk management and financial instruments:

The Company's financial instruments include cash and cash equivalents, trade and other receivables, trade payables and other current liabilities and long term debt instruments such as the Credit Facilities and the Senior Notes. Cash and cash equivalents are carried at fair value. The carrying amounts of trade and other receivables, trade payables, and other current liabilities approximate their fair values due to their short term nature. The Credit Facilities bear interest at rates that approximate market rates and therefore their carrying values approximate fair values. The Senior Notes are recorded at their amortized cost. Fair value disclosure of the Senior Notes is based on their trading price on December 31, 2017.

Interest rate risk:

The Company is exposed to interest rate risk on certain debt instruments, such as the Operating Facility and Revolving Facility, to the extent the prime interest rate changes and/or the Company's interest rate margin changes. For the Credit Facilities, a one percent change in interest rates would have had a $nil impact on interest expense for the years ended December 31, 2017 and 2016 as there was no balance outstanding on the Credit Facilities during the years ended December 31, 2017 and 2016. 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.

(tabular amounts are in thousands of Canadian dollars, except common share and per common share amounts)

19. Financial risk management and financial instruments (continued):

Foreign exchange risk:

The Company is exposed to foreign currency fluctuations in relation to its United States dollar capital expenditures and international operations. From time to time, the Company may use forward foreign currency contracts to hedge against these fluctuations. At December 31, 2017, portions of the Company's cash balances, trade payables and accrued liabilities were denominated in United States dollars and subject to foreign exchange fluctuations which are recorded within net income. In addition, Stoneham, Western's United States subsidiary, is subject to foreign currency translation adjustments upon consolidation, which is recorded separately within other comprehensive income. For the year ended December 31, 2017, the increase or decrease in net income and other comprehensive income for each one percent change in foreign exchange rates between the Canadian and United States dollars is estimated to be $0.2 million and $0.6 million, respectively (December 31, 2016: $0.2 million and $0.5 million, respectively).

Credit risk:

Credit risk arises from cash and cash equivalents held with banks and financial institutions, as well as credit exposure to customers in the form of outstanding trade and other receivables. The maximum exposure to credit risk is equal to the carrying value of the financial assets which reflects management's assessment of the credit risk.

At December 31, 2017, less that 1% of the Company's trade receivables were more than 90 days old. The Company believes the unimpaired amounts greater than 90 days old are still collectible based on historic payment behavior and an analysis of the underlying customers' ability to pay.

The table below provides an analysis of the Company's trade and other receivables as at December 31, 2017 and 2016:

	December 31, 2017	December 31, 2016
Trade receivables:		
Current	$ 26,248	$ 14,931
Outstanding for 31 to 60 days	9,558	6,219
Outstanding for 61 to 90 days	3,193	2,261
Outstanding for over 90 days	56	97
Accrued trade receivables	8,870	9,375
Other receivables	219	453
Income tax receivable	-	1,685
Allowance for doubtful accounts	(27)	(23)
Total	$ 48,117	$ 34,998

Impairment losses:

The allowance for doubtful accounts in respect of trade and other receivables is used to record impairment losses unless the Company is satisfied that no recovery of the amount owing is possible; at that point the amounts are considered unrecoverable and are written off against the financial asset directly. For the year ended December 31, 2017, the Company impaired less than $0.1 million in trade receivables (December 31, 2016: less than $0.1 million).

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. The Company manages liquidity risk through management of its capital structure, monitoring and reviewing actual and forecasted cash flows and the effect on bank covenants, and maintaining unused credit facilities where possible to ensure there are available cash resources to meet the Company's liquidity needs.

The Company's cash and cash equivalents, cash flow from operating activities, existing Credit Facilities, and the Second Lien Facility are expected to be greater than anticipated capital expenditures and the contractual maturities of the Company's financial liabilities. This expectation could be adversely affected by a material negative change in the oilfield service industry, which in turn could lead to covenant breaches on the Company's Credit Facilities, which if not amended or waived, could limit, in part, or in whole, the Company's access to the Credit Facilities and the Second Lien Facility.

(tabular amounts are in thousands of Canadian dollars, except common share and per common share amounts)

19. Financial risk management and financial instruments (continued):

Liquidity risk (continued):

The table below provides an analysis of the expected maturities of the Company's outstanding obligations at December 31, 2017:

	Total amount	Due prior to December 31 2018	2019	2020	2021	2022	Thereafter
Financial liabilities:							
Trade and other current liabilities	$ 39,891	$ 39,891	$ -	$ -	$ -	$ -	$ -
Senior Notes	265,000	-	265,000	-	-	-	-
Other long-term debt	1,263	475	788	-	-	-	-
Total	$ 306,154	$ 40,366	$ 265,788	$ -	$ -	$ -	$ -

Cash flows included in the maturity analysis may occur significantly earlier, or at significantly different amounts. Details of other operating commitments are disclosed in Note 20. Please refer to Note 24 for additional information regarding the repayment of the Senior Notes subsequent to December 31, 2017.

Market risk:

Market risk is the risk that changes in market prices, such as foreign exchange rates, interest rates and equity prices will affect the Company's income or the value of its financial instruments. The objective of market risk management is to manage and control market risk exposures within acceptable parameters while optimizing returns.

The Company may use derivatives and also incur financial liabilities in order to manage market risks. All such transactions are carried out within the guidelines set by the Board of Directors. The Company does not apply hedge accounting in order to manage volatility within the statements of operations and comprehensive income (loss).

Fair value:

Financial assets and liabilities recorded at fair value in the consolidated balance sheets are categorized based upon the level of judgment associated with the inputs used to measure their fair value. Hierarchical levels based on the amount of subjectivity associated with the inputs in the fair value determination of these assets and liabilities are as follows:

Level I – Inputs are unadjusted, quoted prices in active markets for identical assets or liabilities at the measurement date.

Level II – Inputs (other than quoted prices included in Level I) are either directly or indirectly observable for the asset or liability through correlation with market data at the measurement date and for the duration of the instrument's anticipated life.

Level III – Inputs reflect management's best estimate of what market participants would use in pricing the asset or liability at the measurement date. Consideration is given to the risk inherent in the valuation technique and the risk inherent in the inputs to the model.

The Company's cash and cash equivalents balance is the only financial asset measured using fair value. The Company's cash and cash equivalents are categorized as Level I as there are quoted prices in an active market for these instruments.

Capital management:

The overall capitalization of the Company at December 31, 2017 and 2016 is as follows:

	Note	December 31, 2017	December 31, 2016
Other long term debt	11	$ 1,263	$ 842
Senior Notes	11	265,000	265,000
Total debt		266,263	265,842
Shareholders' equity		386,154	407,207
Less: cash and cash equivalents		(48,825)	(44,597)
Total capitalization		$ 603,592	$ 628,452

(tabular amounts are in thousands of Canadian dollars, except common share and per common share amounts)

19. Financial risk management and financial instruments (continued):
Capital management (continued):

Management is focused on several objectives while managing the capital structure of the Company, specifically:

- Ensuring the Company has the financing capacity to continue to execute on opportunities to increase overall market share through strategic acquisitions or organic growth that add value for the Company's shareholders;
- Maintaining a strong capital base to ensure that investor, creditor and market confidence are secured;
- Maintaining balance sheet strength, ensuring the Company's strategic objectives are met, while retaining an appropriate amount of leverage; and
- Safeguarding the entity's ability to continue as a going concern, such that it continues to provide returns for shareholders and benefits for other stakeholders.

The Company manages its capital structure based on current economic conditions, the risk characteristics of the underlying assets, and planned capital requirements within guidelines approved by its Board of Directors. Total capitalization is maintained or adjusted by drawing on existing debt facilities, issuing new debt or equity securities when opportunities are identified and through the disposition of underperforming assets to reduce debt when required.

As at December 31, 2017, the Company had $80.0 million in undrawn credit under its Credit Facilities and was in compliance with all debt covenants (see Note 11). Please refer to Note 24 for changes to the Company's total debt, subsequent to December 31, 2017.

20. Commitments:

As at December 31, 2017, the Company has commitments which require payments based on the maturity terms as follows:

	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 interest accrued as at December 31, 2017 on the Senior Notes.

Senior Notes and interest:
The Company pays interest on the Senior Notes semi-annually on January 30 and July 30. The Senior Notes are due January 30, 2019.

Trade payables and other current liabilities:
The Company has recorded trade payables for amounts due to third parties which are expected to be paid within one year.

Operating leases:
The Company has offices and oilfield service equipment under operating leases. The leases typically run for a period of one to ten years, typically with an option to renew the lease after that date.

Purchase commitments:
The Company has agreements in place to purchase certain capital and other operational items with third parties.

Other long term debt:
The Company has other long term debt relating to leased vehicles.

21. Related party transactions:

During the years ended December 31, 2017 and 2016, the Company had no transactions with related parties. At December 31, 2017, there are no significant balances outstanding in trade and other receivables with related parties (December 31, 2016: $nil).

(tabular amounts are in thousands of Canadian dollars, except common share and per common share amounts)

22. Key management personnel:

The following table summarizes expenses related to key management personnel:

	Year ended December 31, 2017	Year ended December 31, 2016
Short-term employee benefits	$ 1,963	$ 1,315
Stock based compensation [(1)]	743	1,131
	$ 2,706	$ 2,446

(1) The total fair value of stock options and RSUs granted to key management personnel for the year ended December 31, 2017 was equal to $0.4 million (December 31, 2016: $0.5 million), which is being recognized in net income (loss) over the stock option's and RSU's vesting period.

23. Subsidiaries

Details of the Company's material wholly owned subsidiaries and partnerships at the end of the reporting periods are as follows:

		Ownership interest (%)	
	Country of incorporation	December 31, 2017	December 31, 2016
Stoneham Drilling Corporation	USA	100	100
Western Production Services Corp.	Canada	100	100

24. Subsequent Event:

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 Facility were used to redeem the Senior Notes at their par value of $265.0 million on February 1, 2018.

CORPORATE INFORMATION

DIRECTORS

Donald D. Copeland [1][2][3] Victoria, British Columbia

Lorne A. Gartner [1][3] Calgary, Alberta

Alex R.N. MacAusland [3] Calgary, Alberta

Ronald P. Mathison [1][2] Calgary, Alberta

John R. Rooney [2][3] Calgary, Alberta

[1] Member of the Audit Committee
[2] Member of the Corporate Governance and Compensation Committee
[3] Member of the Health, Safety and Environment Committee

OFFICERS

Ronald P. Mathison, Chairman of the Board

Alex R.N. MacAusland, President and Chief Executive Officer

Jeffrey K. Bowers, Sr. Vice President, Finance and Chief Financial Officer

Rick M. Harrison, Sr. Vice President, Operations

Darcy D. Reinboldt, Sr. Vice President, Operations

David G. Trann, Vice President, Finance

Peter J. Balkwill, Vice President, Operations Finance

Jeremy P. Matthies, Vice President, General Counsel and Corporate Secretary

AUDITOR

Deloitte LLP Calgary, Alberta

LEAD BANK

HSBC Bank Canada

STOCK EXCHANGE LISTING

Toronto Stock Exchange Symbol: WRG

TRANSFER AGENT

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