Western Energy Services Corp.

2016 ANNUAL REPORT

THE YEAR IN REVIEW

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Western
ENERGY SERVICES CORP.

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

Annual Meeting

The Annual Meeting of the Shareholders of Western Energy Services Corp. will be held on Tuesday, May 9, 2017 at 10:00 am (MT).

Location:
The Metropolitan Conference Centre
Plaza Room
333 - 4th Avenue S.W.
Calgary, Alberta T2P 0H9

CONTRACT DRILLING SERVICES

Horizon Drilling is Western's Canadian contract drilling division and currently operates a fleet of 51 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 five 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 four 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.

CEO Report to Shareholders

Defense was the name of the game throughout 2016 for Western. Amidst multi-year lows in commodity prices, and with a corresponding decline in spending by our exploration and production customers, management focused on protecting the balance sheet, maintaining our high capacity equipment, and retaining our highly skilled workforce. As we benchmark our performance on each of these metrics, we are able to report that we did admirably, achieving each of these goals, resulting in Western exiting the year with $51 million of positive working capital, $45 million of cash, sporting a fleet of in-demand equipment, and recognizing a strong retention rate of our employees. It is through the considerable effort, dedication and loyalty of everyone at Western that we find ourselves well positioned today. Thank you to all our employees for working with us to achieve our goals through this challenging period.

As we now focus on 2017, changes in the macro environment have caused a shift in the business outlook for Western away from the defensive posture of 2016. Crude oil prices have rebounded from the lows reached in 2016, allowing our customers to take a more constructive approach to deploying capital. This directly and positively impacts the demand for our drilling, well servicing and oilfield rental equipment. While Western remains well positioned to respond to incremental demand and capture incremental market share, our always prudent approach to running the business will be maintained.

For 2017, this prudent approach means continuing to watch costs and spend within our means, as our focus on creating shareholder value has not wavered. Our 2017 capital expenditure program is $13 million, providing balance between capital preservation and maintaining our equipment to the high standard that our customers demand. Within our capital spending budget, we have allocated $2 million for expansion capital allowing Western to respond to customer specific requests. We continuously monitor activity, and will adjust spending as customer demand warrants.

Since Western was recapitalized in 2009, the Company has traditionally generated above average drilling rig utilization in Canada. This has been achieved through top-performing personnel and by assembling a fleet of the most relevant equipment in Canada. At Western, it has not been our aim to deliver one 'perfect' drilling rig; this cannot be achieved. The Western Canadian Sedimentary Basin ("WCSB") is a diverse play, spanning four provinces and one territory, with target formations across a variety of depth horizons. Each operator, targeting each zone, requires different specifications in a drilling rig, and these specifications are continually evolving. Western recognized this early on, building the fleet to the make-up as it is today. We have rigs that offer a variety of hookloads, mast types, pumping capacity, power systems, and top drives. What is universal across all our drilling rig fleet is that each rig is designed to operate safely and efficiently, with a focus on being highly mobile. Justification for our belief that we have the right equipment is provided by our recent utilization. In January 2017, Western hit the ground running, ramping-up quickly and early in the new year. We achieved peak utilization of 36 Canadian drilling rigs or 71% in Q1 2017. Our drilling rig utilization led our peer group throughout the first quarter of 2017 as our rigs were in high demand. We continue to see strong demand for our drilling rigs, with this momentum expected to continue following break-up.

In the U.S., our fleet of five drilling rigs in the Williston Basin of North Dakota continues to deliver strong results. We ran two drilling rigs through Q1 2017, and have recently added a third drilling rig, bringing our utilization up to 60%. Like our Canadian fleet, our U.S. rigs offer the specifications that are demanded in the areas that they operate, including 1,600 HP pumps, 7,500 psi circulating systems, and walking systems.

Our production services business has also seen higher activity through the early part of 2017. Our well servicing rigs, operated by Eagle Well Servicing, continues to add hours, achieving a peak rig count of 32 in the first quarter of 2017. As the upturn in customer spending continues, Eagle is optimally positioned to increase market share with its modern fleet of service rigs and high-performance rig crews. Our Aero rental business continues to be a leader in pressure control equipment, and we are encouraged by the outlook for this segment.

Finally, I would also like to take this opportunity to thank our customers and stakeholders for their continued support. We recognize that fiscal 2016 was challenging for everyone involved in the oil and gas industry, and we now look forward to working together as we embark towards a more constructive macro environment.

Respectfully,

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

April 6, 2017

2016 Management Discussion & Analysis — Date: February 22, 2017

The following discussion of the financial condition, changes in financial condition and results of operations of Western Energy Services Corp. (the "Company" or "Western") should be read in conjunction with the audited consolidated financial statements and accompanying notes of the Company for the years ended December 31, 2016 and 2015. This Management Discussion and Analysis ("MD&A") is dated February 22, 2017. 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)	**2016**	**2015**	**2016**	**2015**	**2014**
Revenue	45,126	42,678	124,438	227,524	507,832
Operating Revenue[1]	41,649	40,458	116,907	216,485	474,120
Gross Margin[1]	8,507	13,372	25,762	85,951	207,231
Gross Margin as a percentage of Operating Revenue	20%	33%	22%	40%	44%
Adjusted EBITDA[1]	3,506	7,573	5,775	60,545	176,777
Adjusted EBITDA as a percentage of Operating Revenue	8%	19%	5%	28%	37%
Cash flow from operating activities	(1,327)	11,139	16,631	90,955	181,351
Capital expenditures	2,724	3,259	4,719	33,562	108,604
Net income (loss)	(14,509)	(55,010)	(61,973)	(129,139)	36,450
-basic net income (loss) per share	(0.20)	(0.75)	(0.84)	(1.74)	0.49
-diluted net income (loss) per share	(0.20)	(0.75)	(0.84)	(1.74)	0.48
Weighted average number of shares					
-basic	73,795,896	73,655,198	73,703,437	74,238,320	74,396,701
-diluted	73,795,896	73,655,198	73,703,437	74,238,320	75,427,149
Outstanding common shares as at period end	73,795,944	73,646,292	73,795,944	73,646,292	74,866,028
Dividends declared	-	3,682	-	20,392	22,376
Dividends declared per common share	-	0.05	-	0.275	0.30
Operating Highlights[1]					
Contract Drilling					
Canadian Operations					
Average active rig count	16.2	11.4	10.0	14.3	31.5
Operating Revenue per Revenue Day	16,657	22,038	16,984 [3]	23,458	26,178
Operating Revenue per Operating Day	18,811	24,228	19,058 [3]	25,821	28,699
Drilling rig utilization - Revenue Days	32%	22%	20%	29%	64%
Drilling rig utilization - Operating Days	28%	20%	17%	26%	58%
CAODC industry average utilization[2]	25%	20%	17%	23%	44%
United States Operations					
Average active rig count	1.7	1.0	1.4	1.6	4.7
Operating Revenue per Revenue Day (US$)	20,197	31,350	21,805	29,483 [4]	26,124
Operating Revenue per Operating Day (US$)	23,440	34,217	25,166	33,166 [4]	29,680
Drilling rig utilization - Revenue Days	34%	20%	28%	32%	94%
Drilling rig utilization - Operating Days	29%	18%	24%	29%	83%
Production Services					
Average active rig count	17.6	16.7	12.9	19.5	35.0
Service rig Operating Revenue per Service Hour	638	703	643	779	817
Service rig utilization	27%	25%	20%	30%	54%

(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 $1.8 million for the year ended December 31, 2016.

(4) 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, 2016	December 31, 2015	December 31, 2014
Working capital	51,118	70,679	78,336
Property and equipment	708,567	773,647	827,306
Total assets	793,525	876,608	1,057,118
Long term debt	264,070	264,155	264,165

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"). On December 28, 2015, Western wound up its partnership, Western Energy Services Partnership (the "Partnership"), and rolled all of the Partnership's assets into IROC Drilling and Production Services Corp., which then changed its name to Western Production Services Corp. ("Western Production Services"). As a result, Western now provides well servicing operations in Canada through Western Production Services' division, Eagle Well Servicing ("Eagle") and oilfield rental equipment services in Canada through Western Production Services' division, Aero Rental Services ("Aero"). Financial and operating results for Horizon and Stoneham are included in Western's contract drilling segment, while Eagle and Aero's financial and operating results 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 51 rigs operating through Horizon. Of the Canadian fleet, 24 are classified as Cardium class rigs, 19 as Montney class rigs and eight as Duvernay class rigs. As compared to the Cardium classified rigs, the Montney class rigs have a larger hookload, while the Duvernay class rigs have the largest hookload allowing the rig to support more drill pipe downhole. Additionally, Western has five Duvernay class triple drilling rigs deployed in the United States operating through Stoneham. Western is also the third largest well servicing company in Canada, based on CAODC registered rigs, 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. While commodity prices improved in the fourth quarter of 2016, they were still well below previous highs and overall performance of the Company throughout 2016 was impacted by the continued low crude oil and natural gas price environment. West Texas Intermediate ("WTI") on average improved in the fourth quarter of 2016 as compared to the third quarter of 2016, increasing by 10%, and was 17% higher compared to the same period in the prior year. However, for the year ended December 31, 2016, WTI on average was 11% lower than 2015. Canadian natural gas prices, such as AECO, improved quarter over quarter, increasing on average by 31% from the third quarter of 2016 to the fourth quarter of 2016. For the three months ended December 31, 2016, AECO increased on average by 25% as compared to the same period in the prior year, however remained 20% lower for the year ended December 31, 2016, as compared to 2015. 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, 2016 and 2015 and for the years ended December 31, 2016 and 2015.

	Three months ended December 31			Year ended December 31		
	2016	2015	Change	2016	2015	Change
Average crude oil and natural gas prices[(1)(2)]						
Crude Oil						
West Texas Intermediate (US$/bbl)	49.16	42.18	17%	43.37	48.80	(11%)
Western Canadian Select (CDN$/bbl)	45.84	36.86	24%	39.27	44.83	(12%)
Natural Gas						
30 day Spot AECO (CDN$/mcf)	3.11	2.48	25%	2.18	2.71	(20%)
Average foreign exchange rates[(2)]						
US dollar to Canadian dollar	1.33	1.34	(1%)	1.32	1.28	3%

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

(2) Source: Bloomberg

The significant reduction in commodity prices has led to a corresponding decrease 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") decreased approximately 31% in 2016, as compared to 2015. Similarly, as reported by Baker Hughes Incorporated, the number of active drilling rigs in the United States decreased approximately 51% in 2016, as compared to 2015.

Operational results for the three months ended December 31, 2016 include:

- Operating Revenue for the three months ended December 31, 2016 continued to be impacted by low commodity prices, which are still well below previous highs. Fourth quarter Operating Revenue increased by $1.2 million (or 3%) to $41.6 million in 2016 as compared to $40.4 million in 2015. In the contract drilling segment, Operating Revenue totalled $29.0 million in the fourth quarter of 2016 as compared to $27.0 million in the fourth quarter of 2015, an increase of 7%; while in the production services segment, Operating Revenue totalled $12.7 million for the three months ended December 31, 2016 as compared to $13.5 million in the fourth quarter of 2015, a decrease of 6%. Commodity prices began to recover in the fourth quarter of 2016, which combined with built up demand due to weather related delays in the third quarter of 2016, resulted in higher industry activity. However, higher utilization in the fourth quarter, offset by continued pricing pressure, impacted Operating Revenue in the contract drilling and production services segments as described below:
    - Drilling rig utilization – Operating Days (or "Drilling Rig Utilization") in Canada was 28% in the fourth quarter of 2016 compared to 20% in the fourth quarter of 2015, reflecting an 800 basis points ("bps") increase and the highest Drilling Rig Utilization experienced by the Company since the first quarter of 2015. Fourth quarter 2016 Drilling Rig Utilization represented a premium of 300 bps to the CAODC industry average of 25%, whereas in the fourth quarter of 2015, Drilling Rig Utilization of 20% was the same as the industry average. The increase in the Company's utilization premium from 2015 is attributable to the efforts by the Company's marketing group to reposition the Company's rigs for existing and new customers. Despite increased activity, the highly competitive environment and commodity prices still well below previous highs, resulted in downward pricing pressure on all drilling rig classes, which reduced Operating Revenue per Revenue Day in the contract drilling segment in Canada by 24%, as compared to the fourth quarter of 2015;
    - In the United States, the Company had two drilling rigs operating during the quarter, one of which was working on a long term contract, resulting in Drilling Rig Utilization of 29% in the fourth quarter of 2016, as compared to 18% in the same period of the prior year. Operating Revenue per Revenue Day in the United States decreased by 35% in the fourth quarter of 2016 due to renegotiating the day rate, as a result of extending the term on the long term contract, coupled with pricing pressure on spot market rates; and
    - Well servicing utilization of 27% in the fourth quarter of 2016 compared to 25% in the same period of the prior year. Improvements in commodity prices, and built up demand due to weather related delays in the third quarter of 2016, helped improve activity quarter over quarter. However, pricing pressure in all areas continued and resulted in a 9% decrease in well servicing hourly rates, which led to a $0.5 million (or 5%) decrease in well servicing Operating Revenue in the period.
- Fourth quarter Adjusted EBITDA decreased by $4.1 million to $3.5 million in 2016 as compared to $7.6 million in the fourth quarter of 2015. The year over year change in Adjusted EBITDA is due to lower pricing in both the contract drilling and production services segments, offset partially by cost reduction measures, including a reduced headcount year over year, wage reductions to all employees and other cost control measures.
- Administrative expenses, excluding depreciation and stock based compensation, in the fourth quarter of 2016 decreased by $0.8 million (or 14%) to $5.0 million as compared to $5.8 million in the fourth quarter of 2015. The decrease in administrative expenses is due to a reduced employee headcount, a 10% rollback to all salaried employee wages and directors' fees implemented in the first quarter of 2016, as well as additional cost control measures.
- The Company incurred a net loss of $14.5 million in the fourth quarter of 2016 (a loss of $0.20 per basic common share) as compared to a net loss of $55.0 million in the same period in 2015 (a loss of $0.75 per basic common share). The change in the fourth quarter net loss in 2016, relative to the fourth quarter of 2015, can be attributed to the following:
    - Prior year impairment losses on property and equipment of $41.9 million and losses on asset decommissioning of $26.6 million recorded in the fourth quarter of 2015.

    Offsetting the above mentioned items are the following:

    - A $16.1 million decrease in income tax recovery due to the prior year impairment losses on property and equipment and losses on asset decommissioning;

- An increase of $7.9 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; and
- A $4.1 million decrease in Adjusted EBITDA due to lower pricing in both the contract drilling and production services segments.

- Fourth quarter 2016 capital expenditures of $2.7 million included $2.1 million of expansion capital and $0.6 million of maintenance capital. In total, capital spending in the fourth quarter of 2016 decreased by 18% from the $3.3 million incurred in the fourth quarter of 2015, as the Company deployed strategic expansion capital and incurred only necessary maintenance capital to preserve cash during the current slowdown in oilfield service activity.

Operational results for the year ended December 31, 2016 include:

- Operating Revenue in 2016 decreased by $99.6 million (or 46%) to $116.9 million, as compared to $216.5 million in the prior year. In the contract drilling segment, Operating Revenue totalled $78.9 million in 2016 compared to $150.2 million in the prior year; while in the production services segment, Operating Revenue totalled $38.1 million in 2016 compared to $66.6 million in the prior year. Operating Revenue in the contract drilling and production services segments for the year ended December 31, 2016 continued to be impacted by low commodity prices which resulted in decreased utilization and pricing as described below:
  - Drilling Rig Utilization in Canada of 17% for the year ended December 31, 2016, compared to 26% for the prior year, reflects a 35% decrease. Drilling Rig Utilization in 2016 was on par with the CAODC industry average of 17%, as compared to the 300 bps premium to the CAODC industry average realized in 2015. The change in the Company's utilization relative to the CAODC industry average is partially due to a number of Western's customers who typically have substantial drilling programs, significantly cutting their capital spending, particularly in the first three quarters of 2016. Additionally, changes in the industry rig mix, as competitors continue to decommission older and less competitive rigs in the WCSB, and add rigs that directly compete with Western's drilling rig fleet, impacts Western's relative utilization as compared to the CAODC industry average. Lower activity and increased competition resulted in downward pricing pressure on all drilling rig classes, which reduced Operating Revenue per Revenue Day in the contract drilling segment in Canada by 28% in 2016, as compared to 2015;
  - In the United States, Drilling Rig Utilization of 24% for the year ended December 31, 2016, compared to 29% in the prior year. Operating Revenue per Revenue Day in the United States decreased by 26% in 2016 due to renegotiating the day rate as a result of extending the term on a long term contract, coupled with pricing pressure on spot market rates; and
  - Well servicing utilization of 20% for the year ended December 31, 2016 compared to 30% in the prior year. Reduced activity as well as a 17% reduction in well servicing hourly rates, due to pricing pressure in all areas, resulted in a $25.1 million (or 45%) decrease in well servicing Operating Revenue in 2016.
- Adjusted EBITDA decreased by $54.7 million to $5.8 million in 2016, as compared to $60.5 million in 2015. The year over year decrease in Adjusted EBITDA is due to lower utilization and pricing in both the contract drilling and production services segments, offset by cost reduction measures, including a reduced headcount, wage reductions to all employees and other cost control measures.
- Administrative expenses in 2016, excluding depreciation and stock based compensation, decreased by $5.4 million (or 21%) to $20.0 million as compared to $25.4 million in 2015. The decrease in administrative expenses is due to a reduced employee headcount, a 10% rollback to all salaried employee wages and directors' fees implemented in the first quarter of 2016, coupled with additional cost control measures.
- As a result of the Company's review of estimated useful lives and methodology for depreciating its drilling and well service rig fleet and related equipment, effective April 1, 2016, Western changed the method for depreciating its drilling and well service rigs and related equipment from unit of production to straight line and changed certain estimates related to useful lives and salvage values. The change in depreciation methodology reflects the technological developments within the industry. The Company expects that straight line depreciation will better reflect the future economic benefit related to these assets, which are expected to depreciate over time instead of on a unit of production basis. Additionally, the change will result in idle or underutilized assets being depreciated more quickly in periods of low activity, better reflecting the cyclical nature of the oilfield service industry. These adjustments were applied prospectively and resulted in an increase of approximately $6.8 million and $28.1 million respectively, of additional depreciation expense for the three and twelve months ended December 31, 2016 over what would have been expensed had the previous assumptions using the unit of production methodology continued to be used in the periods.

- During the second quarter of 2016, the Company decommissioned one of its Cardium class drilling rigs, resulting in a loss on asset decommissioning of $5.2 million, and as a result at December 31, 2016 Horizon had a fleet of 51 drilling rigs.
- The Company incurred a net loss of $62.0 million for the year ended December 31, 2016 (a loss of $0.84 per basic common share) as compared to a net loss of $129.1 million for the year ended December 31, 2015 (a loss of $1.74 per basic common share). The change in net loss in 2016 can be attributed to the following:
  - A prior year goodwill impairment loss of $71.3 million recorded in the third quarter of 2015;
  - Prior year impairment losses on property and equipment of $41.9 million and losses on asset decommissioning of $26.6 million recorded in the fourth quarter of 2015, partially offset by losses on asset decommissioning of $5.2 million in 2016; and
  - A $9.5 million decrease in income tax expense due to lower taxable income for the year ended December 31, 2016, along with the impact of the Alberta corporate tax rate increase in 2015, which increased income tax expense in the prior period by approximately $6.0 million.

  Offsetting the above mentioned items are the following:
  - A $54.7 million decrease in Adjusted EBITDA due to lower utilization and pricing in both the contract drilling and production services segments;
  - An increase of $20.0 million in depreciation expense due to the Company changing from unit of production to straight line depreciation for drilling and well servicing rigs in the second quarter of 2016; and
  - A $2.1 million increase in finance costs, due to lower capitalized interest as a result of the completion of the 2014 rig build program in the prior year.
- Year to date capital expenditures of $4.7 million included $3.0 million of expansion capital and $1.7 million of maintenance capital. In total, capital spending for 2016 decreased by 86% from the $33.6 million incurred in 2015, as the Company deployed strategic expansion capital and incurred only necessary maintenance capital to preserve cash during the current slowdown in oilfield service activity.
- On April 27, 2016, the Company amended the covenants and elected to reduce its syndicated revolving credit facility (the “Revolving Facility”) from $175.0 million to $40.0 million and reduced its previously uncommitted operating demand revolving loan of $20.0 million to a committed operating line (the “Operating Facility”) totalling $10.0 million. Western’s decision to reduce its Revolving and Operating Facilities (the “Credit Facilities”) is estimated to save the Company $1.5 million in standby fees annually. On July 25, 2016, the Company added a lender to its syndicated Revolving Facility and increased the amount available by $10.0 million to $50.0 million, from $40.0 million previously.

Outlook

Currently, 34 of Western’s drilling rigs are operating and four of Western’s 56 drilling rigs (or 7%) are under long term take or pay contracts, with two of these contracts expected to expire in 2017 and two expected to expire in 2018. These contracts each typically generate between 250 and 350 Revenue Days per year.

Western’s capital budget for 2017 is expected to total $13 million, with $2 million allocated for expansion capital and $11 million for maintenance capital. Western believes the 2017 capital budget provides a prudent use of cash resources and will allow it to maintain its premier drilling and well servicing rig fleets, while remaining responsive to customer requirements. Western will continue to manage its operations in a disciplined manner and make any required adjustments to its capital program as customer demand changes. The following table summarizes the capital spending incurred in 2016 and the total 2017 capital budget:

Capital Expenditures (stated in millions)	Revised 2016 Budget Announced February 25, 2016	Incremental Approved Capital Expenditures	Capital Expenditures Year Ended December 31, 2016	Cancellations 2016	Carry Forward Capital Spending 2017	Budgeted Capital Expenditures Year Ended December 31, 2017	Total 2017 Budget
Expansion	2	2	(3)	-	1	1	2
Maintenance	5	1	(2)	(3)	1	10	11
Total Capital Expenditures	**7**	**3**	**(5)**	**(3)**	**2**	**11**	**13**

Since hitting 10 year lows in the first quarter of 2016, commodity prices, while remaining well below previous highs, have improved significantly, particularly during the fourth quarter of 2016. As such, North American drilling rig counts have begun to recover and the Company is expecting increased year over year activity levels in 2017. However, improved pricing for the Company's services is expected to lag the recovery in activity. Improving gross margin is a priority for the Company, as the worst of the downturn in crude oil and natural gas prices appears to have past. Low prices for Western's services will continue to impact Adjusted EBITDA and cash flow from operating activities in the near term. However, Western's variable cost structure and a prudent capital budget will aid in preserving balance sheet strength. In addition to $44.6 million in cash and cash equivalents at December 31, 2016, Western has $60.0 million undrawn on the Company's Credit Facilities, which do not mature until December 17, 2018 and no principal repayments due on the Senior Notes until they mature on January 30, 2019.

Oilfield service activity in Canada will be impacted by the development of resource plays in Alberta and northeast British Columbia including those related to increased crude oil transportation capacity through pipeline development, increased environmental regulations including the implementation of a carbon tax in Alberta, and foreign investment into Canada. Currently, the largest challenges facing the oilfield service industry are 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)	**2016**	**2015**	**2016**	**2015**
Revenue				
Operating Revenue[(1)]	28,965	26,978	78,887	150,252
Third party charges	2,762	1,414	5,167	7,627
Total revenue	31,727	28,392	84,054	157,879
Expenses				
Operating				
Cash operating expenses	26,382	18,975	66,010	93,120
Depreciation	13,113	5,871	45,324	26,340
Stock based compensation	83	93	287	391
Total operating expenses	39,578	24,939	111,621	119,851
Administrative				
Cash administrative expenses	2,819	3,477	11,297	14,380
Depreciation	75	94	322	364
Stock based compensation	102	(10)	345	412
Total administrative expenses	2,996	3,561	11,964	15,156
Gross Margin[(1)]	5,345	9,417	18,044	64,759
Gross Margin as a percentage of Operating Revenue	18%	35%	23%	43%
Adjusted EBITDA[(1)]	2,526	5,940	6,747	50,379
Adjusted EBITDA as a percentage of Operating Revenue	9%	22%	9%	34%
Operating Earnings[(1)]	(10,662)	(25)	(38,899)	23,675
Capital expenditures	2,158	2,037	3,154	26,314

Operating Highlights

Canadian Operations				
Contract drilling rig fleet:				
Average active rig count[(1)]	16.2	11.4	10.0	14.3
End of period	51	52	51	52
Operating Revenue per Revenue Day[(1)]	16,657	22,038	16,984 [(3)]	23,458
Operating Revenue per Operating Day[(1)]	18,811	24,228	19,058 [(3)]	25,821
Operating Days[(1)]	1,317	955	3,276	4,748
Number of meters drilled	349,172	220,296	822,293	1,038,946
Number of wells drilled	106	66	255	289
Average Operating Days per well	12.5	14.5	12.9	16.4
Drilling rig utilization - Revenue Days[(1)]	32%	22%	20%	29%
Drilling rig utilization - Operating Days[(1)]	28%	20%	17%	26%
CAODC industry average utilization[(1)(2)]	25%	20%	17%	23%

United States Operations				
Contract drilling rig fleet:				
Average active rig count[(1)]	1.7	1.0	1.4	1.6
End of period	5	5	5	5
Operating Revenue per Revenue Day (US$)[(1)]	20,197	31,350	21,805	29,483 [(4)]
Operating Revenue per Operating Day (US$)[(1)]	23,440	34,217	25,166	33,166 [(4)]
Operating Days[(1)]	134	84	440	526
Number of meters drilled	32,915	18,985	127,691	138,891
Number of wells drilled	7	3	27	24
Average Operating Days per well	20.6	25.5	16.4	21.9
Drilling rig utilization - Revenue Days[(1)]	34%	20%	28%	32%
Drilling rig utilization - Operating Days[(1)]	29%	18%	24%	29%

(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 $1.8 million for the year ended December 31, 2016.

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

For the year ended December 31, 2016, Operating Revenue in the contract drilling segment totalled $78.9 million, a $71.3 million decrease (or 47%), as compared to the prior year. Reduced demand for contract drilling services in both Canada and the United States, due to the decreased commodity price environment, led to significantly lower year over year activity and put continued downward pressure on day rates in Canada and the United States in 2016.

Contract drilling Adjusted EBITDA in 2016 decreased by $43.7 million (or 87%) to $6.7 million, as compared to $50.4 million in the prior year. The decrease for 2016 is mainly due to fewer Operating Days, coupled with lower Operating Revenue per Revenue Day in both Canada and the United States. The decrease in activity and pricing was partially offset by cost control measures implemented throughout the Company.

Cash administrative expenses for 2016, which exclude depreciation and stock based compensation, totalled $11.3 million reflecting a decrease of $3.1 million (or 22%), as compared to the prior year, mainly due to lower employee costs and effective cost control measures.

Depreciation expense in 2016 increased by $18.9 million to $45.6 million as compared to 2015. The increase is 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, the change in depreciation method resulted in depreciation expense increasing in the current period.

Capital expenditures in the contract drilling segment totalled $3.2 million in 2016, and include $2.1 million of expansion capital and $1.1 million of maintenance capital. Contract drilling capital expenditures for 2016 represent an 88% decrease from the $26.3 million incurred in 2015, when the Company was completing the 2014 drilling rig build program. The Company deployed strategic expansion capital relating to rig upgrades in the fourth quarter of 2016 and incurred only necessary maintenance capital to preserve cash during the current slowdown in oilfield service activity.

Canadian Operations

For the year ended December 31, 2016, Drilling Rig Utilization in Canada decreased to 17% as compared to 26% in the prior year. The decrease in utilization is due to reduced demand as the lower commodity price environment continued, resulting in the Company's Operating Days decreasing by 31% on a year over year basis in 2016.

The Company's Drilling Rig Utilization in Canada of 17% in 2016 was consistent with the CAODC industry average of 17%, however lower than the 300 bps premium realized in 2015. The decrease in the Company's utilization premium in 2016 as compared to 2015 is partially due to a 13% reduction in the industry rig count from 765 rigs at December 31, 2015 to 668 rigs at December 31, 2016 as competitors continue to decommission older less competitive rigs given current market conditions. From December 31, 2015 to December 31, 2016, 12 drilling rigs were added to the industry fleet while 109 drilling rigs were removed by decommissioning or movement out of the WCSB. Of the rigs added year over year, the majority of new additions directly compete with Western's Montney and Duvernay class rig fleet, which impacts Western's utilization premium to the industry average. Additionally, the year over year change relative to the CAODC industry average is partially due to a number of Western's customers, who typically have substantial drilling programs, significantly cutting their capital spending in 2016, particularly in the first three quarters of 2016.

For the year ended December 31, 2016, Operating Revenue per Revenue Day in Canada totalled $16,984 compared to $23,458 in the prior year, a reduction of 28%. The decrease is mainly due to downward pricing pressure on day rates across all rig categories, as reduced commodity prices have led to lower customer spending and resulted in decreased activity and increased competition. Third party charges per Revenue Day of $1,300 in 2016 were consistent with the prior year.

United States Operations

For the year ended December 31, 2016, Operating Days decreased by 86 days (or 16%) resulting in Drilling Rig Utilization of 24% compared to 29% in the prior year. Additionally, 2016 Operating Revenue per Revenue Day in the United States decreased by 26% to US$21,805 due to renegotiating the day rate, as a result of extending the term on a long term contract, coupled with pricing pressure on spot market rates. In the Williston basin in North Dakota, where the Company operates in the United States, drilling rig counts decreased by approximately 38% to 33 active drilling rigs at December 31, 2016, as compared to 53 active drilling rigs at December 31, 2015.

Production Services

Financial Highlights (stated in thousands)	Three months ended December 31 2016	2015	Year ended December 31 2016	2015
Revenue				
Operating Revenue[(1)]	12,710	13,525	38,064	66,550
Third party charges	715	806	2,364	3,412
Total revenue	13,425	14,331	40,428	69,962
Expenses				
Operating				
Cash operating expenses	10,264	10,376	32,710	48,770
Depreciation	3,438	2,562	12,579	11,133
Stock based compensation	54	142	345	406
Total operating expenses	13,756	13,080	45,634	60,309
Administrative				
Cash administrative expenses	1,546	1,578	6,014	6,694
Depreciation	84	102	398	415
Stock based compensation	8	127	253	384
Total administrative expenses	1,638	1,807	6,665	7,493
Gross Margin[(1)]	3,161	3,955	7,718	21,192
Gross margin as a percentage of Operating Revenue	25%	29%	20%	32%
Adjusted EBITDA[(1)]	1,615	2,377	1,704	14,498
Adjusted EBITDA as a percentage of Operating Revenue	13%	18%	4%	22%
Operating Earnings[(1)]	(1,907)	(287)	(11,273)	2,950
Capital expenditures	566	1,188	1,564	7,109

Operating Highlights				
Well servicing rig fleet:				
Average active rig count[(1)]	17.6	16.7	12.9	19.5
End of period	66	66	66	66
Service rig Operating Revenue per Service Hour[(1)]	638	703	643	779
Service Hours[(1)]	16,182	15,352	47,305	71,225
Service rig utilization [(1)]	27%	25%	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, 2016 decreased by $28.5 million (or 43%) to $38.1 million, compared to $66.6 million in the prior year. In 2016, Eagle's contribution to Operating Revenue in the production services segment of $30.4 million compared to $55.5 million in the prior year, whereas Aero's contribution to Operating Revenue in the production services segment of $7.7 million compared to $11.1 million in the prior year. The decrease in Operating Revenue for both Eagle and Aero for the year ended December 31, 2016, as compared to the prior year, is due to reduced customer spending resulting from the decreased commodity price environment leading to lower pricing and activity.

Eagle's Service Hours decreased by 34% in 2016 to 47,305 (20% utilization) as compared to 71,225 (30% utilization) in the prior year. The reduction in Service Hours in 2016 is due to lower demand and increased competition across all geographic areas. Operating Revenue per Service Hour decreased by 17% for the year ended December 31, 2016 to $643, as compared to the prior year, due to competitive pricing pressure across all operating areas.

Adjusted EBITDA decreased by 88% to $1.7 million in 2016 compared to $14.5 million in 2015. The lower Adjusted EBITDA in 2016 was due to the decreased commodity price environment, which impacted the demand and pricing for the Company's services, and was partially offset by lower employee costs and cost control measures.

During the year ended December 31, 2016, cash administrative expenses, which exclude depreciation and stock based compensation, decreased by 10% to $6.0 million as compared to the prior year, due to lower employee costs and effective cost control measures.

Depreciation expense for 2016 increased by 13% to $13.0 million, as compared to $11.5 million in 2015. The increase in 2016 is 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, the change in depreciation methodology resulted in depreciation expense increasing in the current period.

During the year ended December 31, 2016, capital expenditures in the production services segment totalled $1.6 million and included expansion capital of $0.9 million and maintenance capital of $0.7 million. Total production services capital expenditures in 2016, represent a 77% decrease from the $7.1 million incurred in 2015, as the Company only incurred necessary maintenance capital to preserve cash during the current slowdown in oilfield service activity.

Corporate

	Three months ended December 31		Year ended December 31	
(stated in thousands)	**2016**	**2015**	**2016**	**2015**
Administrative				
Cash administrative expenses	635	744	2,676	4,332
Depreciation	206	420	849	1,215
Stock based compensation	375	804	2,537	2,724
Total administrative expenses	1,216	1,968	6,062	8,271
Finance costs	5,478	5,412	22,522	20,441
Other items	(83)	(221)	(1,549)	(1,709)
Income taxes				
Current tax recovery	(511)	(2,692)	(1,708)	(8,732)
Deferred tax recovery	(4,672)	(18,581)	(20,247)	(3,816)
Total income taxes	(5,183)	(21,273)	(21,955)	(12,548)
Operating earnings (1)	(841)	(1,164)	(3,525)	(5,547)
Capital expenditures	-	34	1	139

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

Corporate cash administrative expenses, which exclude depreciation and stock based compensation, for the year ended December 31, 2016 decreased by 37% to $2.7 million as compared to the prior year, mainly due to lower headcount year over year and a 10% salary rollback implemented in the first quarter of 2016.

Finance costs in 2016 on a consolidated basis increased by $2.1 million as compared to the prior year, mainly due to higher capitalized interest in 2015, as a result of the completion of the 2014 rig build program. The Company had an effective interest rate on its borrowings of 8.5% throughout 2016 and 8.2% throughout 2015.

Other items, which totalled a net gain of $1.5 million for the year ended December 31, 2016, consist of gains and losses on foreign exchange, asset sales and derivatives.

For the year ended December 31, 2016, income taxes on a consolidated basis totalled a recovery of $22.0 million, representing an effective tax rate of 26.2%, as compared to an effective tax rate of 8.9% in 2015. The tax rate in 2015 was impacted by the prior year goodwill impairment of $71.3 million, as well as the increase in the Alberta corporate tax rate to 12% in the second quarter of 2015 from 10% previously. The effective tax rate of 26.2% for 2016 represents a more normalized period of operations. The current tax recovery for the year ended December 31, 2016 of $1.7 million is due to the recognition of tax losses during the period, expected to be carried back to prior taxation years.

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 existing credit facilities, new debt instruments, equity issuances and proceeds from the sale of assets. As at December 31, 2016, Western had cash and cash equivalents of $44.6 million, a decrease of $13.8 million from December 31, 2015. Western's consolidated Net Debt balance at December 31, 2016 was $220.2 million. During the year ended December 31, 2016, Western had Adjusted EBITDA of $5.8 million, net income tax refunds of $8.3 million, $2.7 million in foreign exchange gains, proceeds on the sale of property and equipment of $0.5 million and a positive change in non-cash working capital of $0.4 million, which was offset by cash interest payments of $21.6 million, capital expenditures of $4.7 million, dividend payments of $3.7 million and long term debt repayments of $0.7 million.

As at December 31, 2016, Western had a working capital balance of $51.1 million, a $19.6 million decrease as compared to December 31, 2015 mainly due to the decrease in cash and cash equivalents in 2016. Currently, the Company has $265.0 million in Senior Notes outstanding. In addition to the $60.0 million of available credit under the 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. The Credit Facilities include a covenant relief period from January 1, 2016 to December 31, 2017, during which the interest coverage ratio has been waived. During the covenant relief period, there are restrictions on exercising the accordion and on certain payments made by the Company, including dividends, share repurchases and capital expenditures in excess of Western's approved budget. The Credit Facilities mature on December 17, 2018.

Additionally, advances under the Credit Facilities will be limited by the Company's borrowing base. 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 $40.0 million, with a seasonal increase to $50.0 million each quarter ending June 30).

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, 2016, the Revolving Facility and the Operating Facility were undrawn. A summary of the Company's financial covenants as at December 31, 2016 is as follows:

December 31, 2016	**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 Consolidated EBITDA to Consolidated Interest Expense Ratio (1)(2)	Not applicable
Minimum Current Ratio (1)	1.15:1.0 or more

(1) See covenant definitions in Note 12 of the December 31, 2016 annual financial statements.

(2) Consolidated EBITDA to Consolidated interest Expense is only applicable after December 31, 2017, when $30.0 million or more is drawn on the Credit Facilities. Subsequent to December 31, 2017, the ratio must exceed 1.0 and 1.25 in the first and second quarters of 2018 respectively, and 1.5 thereafter.

At December 31, 2016, Western is in compliance with all debt covenants under its Credit Facilities and has no scheduled long term debt repayments until January 2019. As such, cash from operations coupled with Western's working capital, including cash balances, and available Credit Facilities are expected to be sufficient to cover Western's financial obligations.

For the years ended December 31, 2016 and 2015 the Company had one significant customer comprising 10.0% and 10.7% respectively, of the Company's total revenue. The trade receivable balance outstanding relating to the significant customer in 2016 as at December 31, 2016 represented 3.8% of the Company's total trade and other receivables. The Company's significant customers may change from period to period.

Fourth Quarter 2016

Selected Financial Information

Financial Highlights	**Three months ended December 31**	
(stated in thousands, except share and per share amounts)	**2016**	**2015**
Total Revenue	45,126	42,678
Operating Revenue	41,649	40,458
Gross Margin (1)	8,507	13,372
Gross Margin as a percentage of operating revenue	20%	33%
EBITDA (1)	3,506	7,573
EBITDA as a percentage of operating revenue	8%	19%
Cash flow from operating activities	(1,327)	11,139
Capital expenditures	2,724	3,259
Net loss	(14,509)	(55,010)
-basic net loss per share	(0.20)	(0.75)
-diluted net loss per share	(0.20)	(0.75)
Weighted average number of shares		
-basic	73,795,896	73,655,198
-diluted	73,795,896	73,655,198
Outstanding common shares as at period end	73,795,944	73,646,292
Dividends declared	-	3,682
Dividends declared per common share	-	0.05

Operating Highlights		
Contract Drilling		
Canadian Operations		
Average active rig count (1)	16.2	11.4
Contract drilling rig fleet - end of period	51	52
Operating Revenue per Revenue Day (1)	16,657	22,038
Operating Revenue per Operating Day (1)	18,811	24,228
Operating Days (1)	1,317	955
Number of meters drilled	349,172	220,296
Number of wells drilled	106	66
Average operating days per well	12.5	14.5
Drilling rig utilization - Revenue Days (1)	32%	22%
Drilling rig utilization - Operating Days (1)	28%	20%
CAODC industry average utilization rate (2)	25%	20%
United States Operations		
Average active rig count (1)	1.7	1.0
Contract drilling rig fleet - end of period	5	5
Operating Revenue per Revenue Day (US$) (1)	20,197	31,350
Operating Revenue per Operating Day (US$) (1)	23,440	34,217
Operating Days (1)	134	84
Number of meters drilled	32,915	18,985
Number of wells drilled	7	3
Average operating days per well	20.6	25.5
Drilling rig utilization - Revenue Days (1)	34%	20%
Drilling rig utilization - Operating Days (1)	29%	18%
Production Services		
Average active rig count (1)	17.6	16.7
Well servicing rig fleet - end of period	66	66
Service rig Operating Revenue per Service Hour (1)	638	703
Service Hours (1)	16,182	15,352
Service rig utilization (1)	27%	25%

(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.

Consolidated

Fourth quarter Operating Revenue increased by $1.2 million (or 3%) to $41.7 million in 2016 as compared to $40.4 million in the same period of the prior year. In the contract drilling segment, Operating Revenue increased by $2.0 million (or 7%) to $29.0 million in the fourth quarter of 2016 as compared to $27.0 million in the fourth quarter of 2015; while in the production services segment, Operating Revenue decreased by $0.8 million (or 6%) during the three months ended December 31, 2016 to $12.7 million as compared to $13.5 million in the same period of the prior year. The increase in consolidated Operating Revenue is a result of higher utilization due to built up demand due to wet weather in the previous quarter, which was partially offset by lower pricing in both the contract drilling and production services segments, which continued to be impacted by cyclically low commodity prices.

Adjusted EBITDA decreased by $4.1 million (or 54%) to $3.5 million in the fourth quarter of 2016, as compared to $7.6 million in 2015. The decrease in Adjusted EBITDA is due to lower pricing in both the contract drilling and production services segments, offset partially by improved activity in the fourth quarter of 2016, coupled with cost reduction measures, including a reduced headcount year over year, and wage reductions to all employees.

Contract Drilling

During the fourth quarter of 2016, Operating Revenue in the contract drilling segment totalled $29.0 million, a $2.0 million increase (or 7%), as compared to the fourth quarter of 2015. The fourth quarter of 2016 saw improvements in utilization in Canada, as weather related delays experienced in the third quarter of 2016 resulted in Western's customers postponing their drilling programs into the fourth quarter, which increased overall demand in the latter half of the quarter. While commodity prices began to improve in the fourth quarter of 2016, the continued low commodity price environment put downward pressure on day rates in Canada and the United States in 2016. Operating Revenue per Revenue Day in Canada and the United States decreased 24% and 36% respectively, in the fourth quarter of 2016, as compared to the fourth quarter of 2015.

During the fourth quarter of 2016, Adjusted EBITDA in the contract drilling segment decreased by $3.4 million (or 58%) to $2.5 million, as compared to $5.9 million in the fourth quarter of 2015. The decrease in the fourth quarter of 2016, is mainly due to lower Operating Revenue per Revenue Day in both Canada and the United States. The decrease in pricing was partially offset by improved utilization, as well as cost control measures implemented throughout the Company.

For the three months ended December 31, 2016, cash administrative expenses, which exclude depreciation and stock based compensation, decreased 20% to $2.8 million, compared to $3.5 million in the same period of the prior year. The decrease is mainly due to lower employee costs and effective cost control measures.

Depreciation expense for the quarter ended December 31, 2016 increased by $7.2 million, as compared to the same period in the prior year, mainly 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, the change in depreciation method resulted in depreciation expense increasing in the current period.

Capital expenditures in the contract drilling segment totalled $2.2 million in the fourth quarter of 2016 and include $1.8 million related to expansion capital, and $0.4 million related to maintenance capital. Contract drilling capital expenditures represent a 6% increase from the $2.0 million incurred in the three months ended December 31, 2015. During the fourth quarter of 2016, the Company incurred expansion capital relating to rig upgrades and only incurred necessary maintenance capital to preserve cash during the current slowdown in oilfield service activity.

Canadian Operations

During the fourth quarter of 2016, Drilling Rig Utilization improved on a year over year basis to 28%, as compared to 20% in the same period of the prior year. Fourth quarter Drilling Rig Utilization of 28% was also higher than the third quarter of 2016, when Drilling Rig Utilization of 20% was impacted by weather related delays. Additionally, the Company achieved a 300 bps premium to the CAODC average in the fourth quarter of 2016, as compared to the same period of the prior year when the Company's utilization was consistent with the CAODC average of 20%. While activity levels improved during the quarter, increased pricing pressure due to the current competitive environment in which the Company operates resulted in Operating Revenue per Revenue Day in Canada decreasing 24% to $16,657, compared to $22,038 in the same period of the prior year. Third party charges per Revenue Day increased in the fourth quarter of 2016 to approximately $1,800 as compared to approximately $1,300 per Revenue Day in the fourth quarter of 2015, due to increased fuel purchases, which are subsequently recharged to the customer.

United States Operations

For the quarter ended December 31, 2016, Operating Days increased by 50 (or 59%), resulting in Drilling Rig Utilization of 29% compared to 18% in the same period of the prior year and 32% in the third quarter of 2016. Additionally, fourth quarter 2016 Operating Revenue per Revenue Day in the United States decreased by 36%, mainly due to the renegotiation of the day rate as a result of extending the term on a long term contract, and pricing pressure on spot market rates due to the decreased commodity price environment resulting in lower activity and increased competition.

Production Services

During the fourth quarter of 2016, Operating Revenue decreased by $0.8 million (or 6%) to $12.7 million, compared to $13.5 million in the fourth quarter of 2015. For the quarter ended December 31, 2016, Eagle's contribution to Operating Revenue in the production services segment decreased by $0.5 million (or 5%) to $10.3 million as compared to $10.8 million in the same period of the prior year, whereas Aero's contribution to Operating Revenue in the production services segment decreased by $0.3 million (or 11%) to $2.4 million, compared to $2.7 million in the fourth quarter of 2015. The decrease in Operating Revenue for both Eagle and Aero for the three months ended December 31, 2016, as compared to the same period in the prior year, is due to reduced customer spending resulting from the decreased commodity price environment as well as increased competition, leading to lower pricing.

While competition and the low commodity price environment continued to impact the fourth quarter of 2016, Eagle's utilization improved to 27% in the fourth quarter of 2016, as compared to 24% in the third quarter of 2016 and 25% in the fourth quarter of 2015. Additionally, Eagle's Operating Revenue per Service Hour in the fourth quarter of 2016 improved by 6% to $638 per hour from the third quarter of 2016, however was 9% lower than the fourth quarter of 2015.

The increased activity for the three months ended December 31, 2016 was partially due to built up demand resulting from weather related delays experienced in the third quarter of 2016, forcing customers to delay their programs until the fourth quarter of 2016.

Adjusted EBITDA decreased by 33% to $1.6 million during the fourth quarter of 2016 from $2.4 million in the fourth quarter of 2015 mainly due to the decreased commodity price environment impacting the pricing for the Company's services, which was partially offset by improved activity, lower employee costs and cost control measures. However, Adjusted EBITDA continued to recover in the fourth quarter of 2016 to $1.6 million, the highest quarterly Adjusted EBITDA for the production services segment in 2016, due to continued marketing efforts and cost control measures.

During the fourth quarter of 2016, cash administrative expenses, which exclude depreciation and stock based compensation, decreased by 6% to $1.5 million as compared to $1.6 million in the same period of the prior year due to lower employee costs and effective cost control measures.

For the three months ended December 31, 2016, depreciation expense increased by 30% to $3.5 million mainly 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, the change in depreciation method resulted in depreciation expense increasing in the current period.

During the three months ended December 31, 2016, capital expenditures in the production services segment totalled $0.6 million, representing a 50% decrease from the $1.2 million incurred in the fourth quarter of 2015, and mainly related to necessary maintenance capital and the purchase of additional oilfield rental equipment.

Corporate

Corporate cash administrative expenses, which exclude depreciation and stock based compensation, for the three month period ended December 31, 2016 decreased by 14% to $0.6 million mainly due to lower headcount year over year and a 10% salary rollback implemented in the first quarter of 2016.

For the three month period ended December 31, 2016, finance costs on a consolidated basis remained relatively consistent at $5.5 million, as compared to $5.4 million in the same period of the prior year. The Company had an effective interest rate on its borrowings of 8.2% during the fourth quarter of 2016, as compared to 8.1% in the same period of the prior year.

Other items of $0.1 million for the three months ended December 31, 2016 consist of net gains and losses on foreign exchange, asset sales and derivatives.

For the three months ended December 31, 2016, income taxes on a consolidated basis totalled a recovery of $5.2 million and represent an effective tax rate of 26.3%, as compared to an effective tax rate of 27.9% during the three months ended December 31, 2015. The current tax recovery for the three months ended December 31, 2016 of $0.5 million is mainly due to the recognition of tax losses during the period, expected to be carried back to prior taxation years.

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, 2016	Sept 30, 2016	Jun 30, 2016	Mar 31, 2016	Dec 31, 2015	Sep 30, 2015	Jun 30, 2015	Mar 31, 2015
Revenue	45,126	32,485	12,890	33,937	42,678	46,959	32,037	105,850
Operating Revenue [(1)]	41,649	30,665	12,393	32,200	40,458	44,350	30,719	100,958
Gross Margin [(1)]	8,507	5,685	2,703	8,867	13,372	14,285	10,403	47,891
Adjusted EBITDA [(1)]	3,506	896	(1,990)	3,364	7,573	8,080	4,255	40,637
Cash flow from operating activities	(1,327)	909	8,444	8,604	11,139	(530)	41,009	39,337
Net income (loss)	(14,509)	(16,973)	(24,172)	(6,319)	(55,010)	(76,816)	(12,607)	15,294
per share - basic	(0.20)	(0.23)	(0.33)	(0.09)	(0.75)	(1.04)	(0.17)	0.20
per share - diluted	(0.20)	(0.23)	(0.33)	(0.09)	(0.75)	(1.04)	(0.17)	0.20
Total assets	793,525	794,170	814,757	842,492	876,608	947,137	1,025,776	1,049,145
Long term debt	264,070	264,118	264,145	264,118	264,155	264,219	264,234	264,207
Dividends declared	-	-	-	-	3,682	5,526	5,591	5,593

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

Revenue and Adjusted EBITDA were impacted by lower commodity prices in 2015 and 2016, declining significantly following the first quarter of 2015, and throughout 2016. During the first quarter of 2015, revenue and Adjusted EBITDA were significantly higher due to greater activity levels and pricing in both the contract drilling and production services segments as the full impact of the downturn in the oilfield service industry had not yet been realized. Subsequent to the first quarter of 2015, the lower commodity price environment has significantly impacted revenue and Adjusted EBITDA, with Revenue and Adjusted EBITDA beginning to recover in the fourth quarter of 2016.

Net income has fluctuated throughout the last eight quarters in part due to the seasonal nature of the oilfield service industry in Canada and the prolonged decline in crude oil and natural gas prices. In addition, the Company recorded impairments in the third quarter of 2015 totalling $71.3 million and $68.5 million in the fourth quarter of 2015, significantly impacting net income in each of the respective periods. A decommissioning loss of $5.2 million was recorded and the Company changed its depreciation methodology from unit of production to straight line in the second quarter of 2016, which significantly impacted net income.

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

Contractual Obligations

In the normal course of business the Company incurs contractual obligations. The expected maturities of the Company's contractual obligations as at December 31, 2016 are as follows:

(stated in thousands)	2017	2018	2019	2020	2021	Thereafter	Total
Senior Notes	-	-	265,000	-	-	-	265,000
Senior Notes interest	20,869	20,869	10,520	-	-	-	52,258
Trade payables and other current liabilities [(1)]	24,044	-	-	-	-	-	24,044
Operating leases	3,879	3,705	3,550	3,525	2,818	7,814	25,291
Purchase commitments	2,449	-	-	-	-	-	2,449
Other long term debt	719	168	-	-	-	-	887
Total	51,960	24,742	279,070	3,525	2,818	7,814	369,929

(1) Trade payables and other current liabilities exclude the Company's interest accrued as at December 31, 2016 on the Senior Notes.

There have been no material changes in the contractual obligations detailed above, other than in the normal course of business, during the year ended December 31, 2016.

Outstanding Share Data

	February 22, 2017	December 31, 2016	December 31, 2015
Common shares outstanding	73,795,944	73,795,944	73,646,292
Restricted share units outstanding - equity settled	415,717	410,311	410,269
Stock options outstanding	6,211,701	6,153,886	6,058,906

Off Balance Sheet Arrangements

As at December 31, 2016, Western had no off balance sheet arrangements in place.

Transactions with Related Parties

During the years ended December 31, 2016 and 2015, the Company had no transactions with related parties.

Financial Instruments

Fair Values

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

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

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

Derivatives embedded in other instruments or host contracts are separated from the host contract and accounted for separately when their economic characteristics and risks are not closely related to the host contract. Embedded derivatives are recorded on the balance sheet at their estimated fair value and changes in the fair value are recorded through net income. The asset is recognized in other assets on the balance sheet, while a change in the value of the embedded derivative is included in other items within net income.

The Company has the following non-derivative financial assets:

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

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

(ii) Loans and receivables:

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

(iii) Available for sale:

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

The Company has the following non-derivative financial liabilities:

(i) Other financial liabilities:

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

(ii) Equity instruments:

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

Credit Risk

The Company's trade receivables are with customers in the crude oil and natural gas industry and are subject to normal industry credit risk. The Company's practice is to manage credit risk by performing a detailed analysis of the credit worthiness of new customers before the Company's standard payment terms are offered. Additionally, the Company constantly reviews individual customer trade receivables, taking into consideration payment history and the aging of the trade receivable to monitor collectability. The Company records an allowance for doubtful accounts if an account is determined to be uncollectible. Any provisions recorded by the Company are reviewed regularly to determine if any of the balances provided for should be written off. The allowance for doubtful accounts could materially change as a result of fluctuations in the financial position of the Company's customers.

Interest Rate Risk

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

Foreign Exchange Risk

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

Liquidity Risk

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

Disclosure Controls and Procedures and Internal Controls Over Financial Reporting

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

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

In accordance with the requirements of National Instrument 52-109 "Certification of Disclosure in Issuers' Annual and Interim Filings", an evaluation of the effectiveness of DC&P and ICFR was carried out under the supervision of the CEO and CFO at December 31, 2016. 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, 2016, 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 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 cash generating unit ("CGU") to which the asset belongs. A CGU is the smallest identifiable group of assets that generates cash inflows that are largely independent of the cash inflows from other assets or groups of assets. The determination of CGUs is based on management judgement.

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

If indicators conclude that the asset is no longer impaired, the Company will reverse impairment losses on assets. Impairment losses on goodwill are not reversed. Similar to determining if an impairment exists, judgment is required in assessing if a reversal of an impairment loss is required. Value-in-use and fair value less cost to sell calculations performed in assessing the recoverable amounts incorporate a number of key estimates. As at 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 results of the impairment test indicated no impairment existed as at December 31, 2016. Additionally, there were no reversals of previous property and equipment impairment losses during the year ended December 31, 2016.

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

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.

Non-derivative financial liabilities

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

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

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

Allowance for doubtful accounts

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

Business Risks

For a comprehensive listing of the Company's business risks please see the most recent Annual Information Form for the year ended December 31, 2016 as filed on SEDAR at www.sedar.com. The Company's primary business risks as at December 31, 2016 are as follows:

- The Company's business relies on the crude oil and natural gas exploration and production industry which is subject to a number of risks including general economic conditions, fluctuations in demand and supply of crude oil and natural gas production, fluctuations in commodity prices, competition and increases in operating costs. In addition, changes may occur in government regulations, including regulations relating to foreign acquisitions, prices, taxes, royalties, land tenure, allowable production, importing and exporting of crude oil and natural gas and environmental protection for the crude oil and natural gas industry as a whole. Risks impacting the crude oil and natural gas exploration and production industry, including the ability of crude oil and natural gas companies to accumulate capital or variations in their exploration and development budgets, may also affect the Company's business. The exact impact of these risks cannot be accurately predicted.

- The current low commodity price environment is expected to continue throughout 2017. If a low commodity price environment persists as expected, the demand for the Company's equipment and services will remain lower than normal and the Company's utilization rates and revenue will continue to be adversely affected during such time. In addition, lower utilization and revenue could result in the Company not being in compliance with certain covenants in its Credit Facilities and under its Senior Note indenture, which in turn could restrict the Company's ability to access its Credit Facilities, pay distributions and incur additional debt in the future.
- The Company's exploration and production customers' facilities and other operations emit greenhouse gases and require them to comply with legislation in those provinces and states where they operate. On November 22, 2015, the Alberta government announced new emissions regulations, including an economy wide price on carbon emissions effective January 1, 2017 and methane emission reductions. In September 2016, the Canadian Federal government announced its intention to impose a national carbon price on the provinces, requiring provinces to adopt either a carbon price or cap-and-trade approach and to meet a federally established minimum price. The direct or indirect costs of these new greenhouse gas emission reduction regulations, as well as regulations which may be adopted in these or other jurisdictions in the future, may have a material adverse effect on the Company's business, financial condition and results of operations and cash flows, as well as impacting the Company's customers' operations.
- In addition to global economic events and uncertainty, the capacity within North America to ship commodities to market introduces uncertainties in levels of activity and pricing for crude oil and natural gas production.
- The Company is vulnerable to market prices. Fixed costs, including costs associated with operations, leases, and labour costs account for a significant portion of the Company's expenses. As a result, reduced productivity resulting from reduced demand, equipment failure, or other factors could significantly affect its financial results.
- Competition among oilfield service companies offering related services is significant. Some competitors are larger and have greater revenue than the Company and overall greater financial resources. The Company's ability to generate revenue depends on its ability to attract and win contracts and to perform services.
- Currently, the Company is focused on providing services in the WCSB as well as certain geographic areas in the United States, which may expose the Company to more extreme market fluctuations relating to items such as weather and general economic conditions which may be more extreme than the broader industry conditions.
- The success of the Company is dependent upon the efforts and abilities of its management team. The loss of any member of the management team could have a material adverse effect upon the business and prospects of the Company.
- During the prolonged downturn many oilfield service workers have left the industry and, therefore, if activity increases it may be difficult for the Company to attract and retain field crews. This could have a material adverse effect on the Company's business and financial results.
- The Company's business is subject to the operating risks inherent to the oilfield service industry. On occasion, substantial liabilities to third parties may be incurred. The Company will have the benefit of insurance maintained by it and industry standard contracts, however, it may become liable for damages against which it cannot adequately insure or against which it may elect not to insure because of high costs or other reasons.
- The ability of the Company to make payments, dividends or enter into certain transactions will be subject to the applicable laws and contractual restrictions in the instruments governing its indebtedness, including the Credit Facilities and Senior Notes.
- The oilfield service industry has experienced a high degree of invention and innovation. It is possible that new technology will be developed which will compete with the Company's products and services.
- A portion of the operations of the Company are in the United States which subject the Company to currency fluctuations and different tax and regulatory laws.
- The loss of a significant customer or customers, or any decrease in services provided or prices charged to a significant customer or customers could have a material adverse effect on the Company's business and financial results.
- The Company relies on various information systems to manage its business. If these systems were compromised as a result of a successful cyber-attack, this could have a material adverse effect on the Company business and financial results.

Non-IFRS Measures

Western uses certain measures in this MD&A which do not have any standardized meaning as prescribed by IFRS. These measures, which are derived from information reported in the 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, 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)	**2016**	**2015**	**2016**	**2015**
Operating Revenue				
Drilling	28,965	26,978	78,887	150,252
Production services	12,710	13,525	38,064	66,550
Less: inter-company eliminations	(26)	(45)	(44)	(317)
	41,649	**40,458**	**116,907**	**216,485**
Third party charges	3,477	2,220	7,531	11,039
Revenue	**45,126**	**42,678**	**124,438**	**227,524**
Less: operating expenses	(53,308)	(37,974)	(157,212)	(179,843)
Add:				
Depreciation - operating	16,551	8,433	57,903	37,473
Stock based compensation - operating	138	235	633	797
Gross Margin	**8,507**	**13,372**	**25,762**	**85,951**

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 income 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 Earnings (Loss):

	Three months ended December 31		Year ended December 31	
(stated in thousands)	**2016**	**2015**	**2016**	**2015**
Net loss	**(14,509)**	**(55,010)**	**(61,973)**	**(129,139)**
Add:				
Finance costs	5,478	5,412	22,522	20,441
Income tax recovery	(5,183)	(21,273)	(21,955)	(12,548)
Depreciation - operating	16,551	8,433	57,903	37,473
Depreciation - administrative	365	616	1,569	1,994
EBITDA	**2,702**	**(61,822)**	**(1,934)**	**(81,779)**
Add:				
Stock based compensation - operating	138	235	633	797
Stock based compensation - administrative	484	921	3,135	3,520
Impairment of goodwill	-	-	-	71,256
Impairment of property and equipment	-	41,862	-	41,862
Loss on asset decommissioning	265	26,598	5,490	26,598
Other items	(83)	(221)	(1,549)	(1,709)
Adjusted EBITDA	**3,506**	**7,573**	**5,775**	**60,545**
Subtract:				
Depreciation - operating	(16,551)	(8,433)	(57,903)	(37,473)
Depreciation - administrative	(365)	(616)	(1,569)	(1,994)
Operating Earnings (Loss)	**(13,410)**	**(1,476)**	**(53,697)**	**21,078**

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, 2016**	**December 31, 2015**
Long term debt	264,070	264,155
Current portion of long term debt	684	761
Less: cash and cash equivalents	(44,597)	(58,445)
Net Debt	**220,157**	**206,471**

Defined Terms:

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

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 quarter or year.

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

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

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

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

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, 366 days per year in 2016 (2015: 365 days).

Contract Drilling Rig Classifications:

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

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

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

Abbreviations:

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

Forward-Looking Statements and Information

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

In particular, forward-looking information in this MD&A includes, but is not limited to, statements relating to commodity pricing; the future demand for and utilization of the Company's services and equipment; the pricing for the Company's services and equipment; the terms of existing and future drilling contracts in Canada and the US and the revenue resulting therefrom (including the number of Operating Days typically generated from the Company's contracts); the Company's expansion and maintenance capital plans for 2017; the Company's liquidity needs including the ability of current capital resources to cover Western's financial obligations and the 2017 capital budget; the Company's expected sources of funding to support such capital plans and the Company's ability to adjust capital spending for the remainder of 2017 if market conditions, including customer demand changes; the expected benefits from cost control measures; the use and availability of the Company's Credit Facilities; the Company's ability to maintain certain covenants under its Credit Facility; the future declaration of dividends; expectations as to the increase in crude oil transportation capacity through pipeline development; changes to environmental laws and regulations; the implementation of a carbon tax in Alberta; the expectation of continued foreign investment into the Canadian crude oil and natural gas industry; the expectation that producer spending constraints, and finding and maintaining enough field crew members will continue to be large challenges facing the Company in 2017; the Company's change to its depreciation assumptions; and forward-looking statements under the heading "Critical Accounting Estimates".

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

Although Western believes that the expectations and assumptions on which such forward-looking statements and information are based on are reasonable, undue reliance should not be placed on the forward-looking statements and information as Western cannot give any assurance that they will prove to be correct. Since forward-looking statements and information address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results could differ materially from those currently anticipated due to a number of factors and risks. These include, but are not limited to, the risk that the demand for oilfield services will not improve for the remainder of 2017 and that commodity prices will remain low, and other general industry, economic, market and business conditions. Readers are cautioned that the foregoing list of risks, uncertainties and assumptions are not exhaustive. Additional information on these and other risk factors that could affect Western's operations and financial results are included in Western's annual information form which may be accessed through the SEDAR website at www.sedar.com. The forward-looking statements and information contained in this MD&A are made as of the date hereof and Western does not undertake any obligation to update publicly or revise any forward-looking statements and information, whether as a result of new information, future events or otherwise, unless so required by applicable securities laws.

Additional data

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

Western Energy Services Corp.

Consolidated Financial Statements

December 31, 2016 and 2015

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 22, 2017

Deloitte.

Deloitte LLP
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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, 2016 and 2015, and the consolidated statements of operations and comprehensive 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, 2016 and 2015, 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 22, 2017
Calgary, Alberta

Western Energy Services Corp.

Consolidated Balance Sheets
(thousands of Canadian dollars)

	Note	December 31, 2016	December 31, 2015
Assets			
Current assets			
Cash and cash equivalents		$ 44,597	$ 58,445
Trade and other receivables	6	34,998	38,438
Other current assets	7	5,253	5,177
		84,848	102,060
Non current assets			
Property and equipment	8	708,567	773,647
Other non current assets	7	110	901
		$ 793,525	$ 876,608
Liabilities			
Current liabilities			
Trade payables and other current liabilities	10	$ 32,906	$ 26,793
Dividends payable		-	3,682
Current portion of provisions	11	140	145
Current portion of long term debt	12	684	761
		33,730	31,381
Non current liabilities			
Provisions	11	1,534	1,674
Long term debt	12	264,070	264,155
Deferred taxes	18	86,984	107,702
		386,318	404,912
Shareholders' equity			
Share capital	13	418,509	417,622
Contributed surplus		12,666	10,148
Retained earnings (deficit)		(58,308)	3,734
Accumulated other comprehensive income		32,258	37,794
Non controlling interest		2,082	2,398
		407,207	471,696
		$ 793,525	$ 876,608

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, 2016	Year ended December 31, 2015
Revenue		$ 124,438	$ 227,524
Operating expenses		157,212	179,843
Gross profit (loss)		(32,774)	47,681
Administrative expenses		24,691	30,920
Finance costs	16	22,522	20,441
Other items	17	(1,549)	(1,709)
Impairment of goodwill	9	-	71,256
Impairment of property and equipment	8	-	41,862
Loss on asset decommissioning	8	5,490	26,598
Loss before income taxes		(83,928)	(141,687)
Income tax recovery	18	(21,955)	(12,548)
Net loss		(61,973)	(129,139)
Other comprehensive income (loss) (1)			
Loss (gain) on translation of foreign operations		1,964	(12,741)
Unrealized foreign exchange loss (gain) on net investment in subsidiary		3,572	(9,928)
Comprehensive loss		$ (67,509)	$ (106,470)
Net income (loss) attributable to:			
Shareholders of the Company		$ (62,042)	$ (129,417)
Non controlling interest		69	278
Comprehensive income (loss) attributable to:			
Shareholders of the Company		$ (67,578)	$ (106,748)
Non controlling interest		69	278
Net loss per share:			
Basic		$ (0.84)	$ (1.74)
Diluted		(0.84)	(1.74)
Weighted average number of shares:			
Basic	15	73,703,437	74,238,320
Diluted	15	73,703,437	74,238,320

(1) Other comprehensive income 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, 2014	$ 423,633	$ 6,815	$ 153,544	$ 15,125	$ 2,086	$ 601,203
Common shares:						
Issued for cash on exercise of stock options	154	-	-	-	-	154
Issued on vesting of restricted share units	471	(471)	-	-	-	-
Purchased under normal course issuer bid	(6,691)	(28)	-	-	-	(6,719)
Fair value of exercised options	55	(55)	-	-	-	-
Stock based compensation	-	3,887	-	-	-	3,887
Dividends declared	-	-	(20,393)	-	-	(20,393)
Contributions from non controlling interest	-	-	-	-	34	34
Comprehensive income (loss)	-	-	(129,417)	22,669	278	(106,470)
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

(1) Contributed surplus relates to stock based compensation described in Note 14.

(2) At December 31, 2016, 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, 2016	Year ended December 31, 2015
Operating activities			
Net loss		$ (61,973)	$ (129,139)
Adjustments for:			
Depreciation included in operating expenses	8	57,903	37,473
Depreciation included in administrative expenses	8	1,569	1,994
Non cash stock based compensation included in operating expenses	14	466	571
Non cash stock based compensation included in administrative expenses	14	2,939	3,316
Finance costs	16	22,522	20,441
Impairment of goodwill	9	-	71,256
Impairment of property and equipment	8	-	41,862
Loss on asset decommissioning	8	5,490	26,598
Income tax recovery	18	(21,955)	(12,548)
Other		985	8
Income taxes received (paid)		8,278	(8,404)
Change in non cash working capital		407	37,527
Cash flow from operating activities		16,631	90,955
Investing activities			
Additions to property and equipment	8	(4,719)	(33,562)
Proceeds on sale of property and equipment		549	946
Changes in non cash working capital		20	(12,891)
Cash flow used in investing activities		(4,150)	(45,507)
Financing activities			
Issue of common shares	13	-	154
Shares purchased under normal course issuer bid	13	-	(6,719)
Repayment of long term debt		(709)	(1,056)
Finance costs paid		(21,553)	(19,752)
Dividends paid		(3,682)	(22,326)
Contributions from (distributions to) non controlling interest		(385)	34
Cash flow used in financing activities		(26,329)	(49,665)
Decrease in cash and cash equivalents		(13,848)	(4,217)
Cash and cash equivalents, beginning of year		58,445	62,662
Cash and cash equivalents, end of year		$ 44,597	$ 58,445
Cash and cash equivalents:			
Bank accounts		$ 24,553	$ 12,913
Short term investments		20,044	45,532
		$ 44,597	$ 58,445

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, 2016 and 2015 (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. On December 28, 2015, Western wound up its partnership, Western Energy Services Partnership (the "Partnership") and rolled all of the Partnership's assets into IROC Drilling and Production Services Corp., which changed its name to Western Production Services Corp. ("Western Production Services"). As a result, Western now provides well servicing operations in Canada through Western Production Services' division, Eagle Well Servicing ("Eagle") and oilfield rental equipment services in Canada through Western Production Services' division, Aero Rental Services ("Aero"). 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 22, 2017.

(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 current 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 and other payables, 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.

(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.

The only embedded derivative the Company has as at December 31, 2016 and 2015 relates to the early redemption option on the Senior Notes.

(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 will result in idle or underutilized assets being depreciated more quickly in periods of low activity. These adjustments were applied prospectively as detailed in Note 8. A summary of depreciation methodologies for the Company's property and equipment as at December 31, 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 as at December 31, 2015 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 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.

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 to employees are recognized as an employee 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 employee 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.

Minimum lease 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.

All other leases that are determined not to be 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.

(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, 2016 and 2015.

(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, 2016, 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 and does not anticipate early adopting IFRS 15. 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 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. It is not expected that IFRS 15 will have a significant impact on the production services segment.

- 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 Company is currently evaluating the impact of the adoption of this new standard on its financial statements.

3. Significant accounting policies (continued):

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

- 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. 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.

  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.

4. Critical accounting estimates (continued):

(a) Impairment (continued):

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

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

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.

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

4. Critical accounting estimates (continued):

(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 20 details further information on the Company's allowance for doubtful accounts.

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 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 oil and natural gas exploration and production companies and in the case of oilfield rental equipment, to other oilfield service companies as well.

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, 2016 and 2015:

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.

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

5. Operating segments (continued):

Year ended December 31, 2015	Contract Drilling	Production Services	Corporate	Inter-segment Elimination	Total
Revenue	$ 157,879	$ 69,962	$ -	$ (317)	$ 227,524
Operating earnings (loss)	23,675	2,950	(5,547)	-	21,078
Finance costs	-	-	20,441	-	20,441
Loss on asset decommissioning	26,482	116	-	-	26,598
Impairment of property and equipment	18,997	22,865	-	-	41,862
Depreciation	26,704	11,548	1,215	-	39,467
Additions to property and equipment (1)	26,393	7,233	139	-	33,765

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

The following is a summary of the Company's goodwill by operating segment:

Goodwill	Contract Drilling	Production Services	Total
Balance at December 31, 2014	$ 57,378	$ 12,229	$ 69,607
Foreign exchange adjustment	1,649	-	1,649
Impairment of goodwill	(59,027)	(12,229)	(71,256)
Balance at December 31, 2015 and 2016	$ -	$ -	$ -

Total assets and liabilities by operating segment are as follows:

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

As at December 31, 2015	Contract Drilling	Production Services	Corporate	Total
Total assets	$ 654,285	$ 158,432	$ 63,891	$ 876,608
Total liabilities	104,260	32,423	268,229	404,912

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

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)

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

5. Operating segments (continued):

Year ended December 31, 2015	Contract Drilling	Production Services	Corporate	Total
Operating earnings (loss)	$ 23,675	$ 2,950	$ (5,547)	$ 21,078
Add (deduct):				
Stock based compensation	(803)	(790)	(2,724)	(4,317)
Finance costs	-	-	(20,441)	(20,441)
Other items	-	-	1,709	1,709
Impairment of goodwill	(59,027)	(12,229)	-	(71,256)
Impairment of property and equipment	(18,997)	(22,865)	-	(41,862)
Loss on asset decommissioning	(26,482)	(116)	-	(26,598)
Loss before income taxes	$ (81,634)	$ (33,050)	$ (27,003)	$ (141,687)

Segmented information by geographic area is as follows:

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

As at December 31, 2015	Canada	United States	Total
Property and equipment	$ 644,510	$ 129,137	$ 773,647
Total assets	742,824	133,784	876,608

	Canada	United States	Total
Revenue - year ended December 31, 2016	$ 109,588	$ 14,850	$ 124,438
Revenue - year ended December 31, 2015	199,265	28,259	227,524

Significant Customers:

For the years ended December 31, 2016 and 2015, the Company had one significant customer comprising 10.0% and 10.7% respectively, of the Company’s total revenue. The trade receivable balance outstanding relating to the significant customer in 2016 as at December 31, 2016 represented 3.8% of the Company’s total trade and other receivables.

6. Trade and other receivables:

The Company’s trade and other receivables as at December 31, 2016 and 2015 are as follows:

	December 31, 2016	December 31, 2015
Trade receivables	$ 23,508	$ 24,609
Accrued trade receivables	9,375	3,295
Income tax receivable	1,685	10,350
Other receivables	453	1,273
Allowance for doubtful accounts	(23)	(1,089)
Total	$ 34,998	$ 38,438

The Company’s exposure to credit risk related to trade and other receivables is disclosed in Note 20.

(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, 2016 and 2015 are as follows:

	December 31, 2016	December 31, 2015
Current:		
Prepaid expenses	$ 1,899	$ 1,432
Inventory	2,770	3,058
Deposits	475	506
Deferred charges and other	109	181
Total current portion of other assets	5,253	5,177
Non current:		
Deferred charges and other	110	901
Total non current portion of other assets	110	901
Total other assets	$ 5,363	$ 6,078

8. Property and Equipment:

The following table summarizes the Company's property and equipment as at December 31, 2016 and 2015:

	Land	Buildings	Contract drilling equipment	Production services equipment	Office and shop equipment	Vehicles under finance leases	Total
Cost:							
Balance at December 31, 2014	$ 5,089	$ 4,048	$ 779,921	$ 196,564	$ 12,540	$ 3,840	$ 1,002,002
Additions	-	157	26,224	6,918	263	-	33,562
Finance lease additions	-	-	-	-	-	203	203
Loss on asset decommissioning	-	-	(40,020)	(198)	-	-	(40,218)
Disposals	-	-	(1,438)	(1,066)	(308)	(483)	(3,295)
Foreign exchange adjustment	-	-	25,994	-	109	71	26,174
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
Accumulated depreciation:							
Balance at December 31, 2014	$ -	$ 637	$ 143,807	$ 23,918	$ 5,261	$ 1,073	$ 174,696
Depreciation for the year	-	189	25,930	10,632	1,929	787	39,467
Loss on asset decommissioning	-	-	(13,538)	(82)	-	-	(13,620)
Impairment on property and equipment	-	-	18,997	22,865	-	-	41,862
Disposals	-	-	(1,174)	(665)	(273)	(390)	(2,502)
Foreign exchange adjustment	-	-	4,771	-	75	32	4,878
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
Carrying amounts:							
At December 31, 2015	$ 5,089	$ 3,379	$ 611,888	$ 145,550	$ 5,612	$ 2,129	$ 773,647
At December 31, 2016	$ 5,089	$ 3,184	$ 560,868	$ 133,681	$ 4,378	$ 1,367	$ 708,567

Assets under construction:

Included in property and equipment at December 31, 2016 are assets under construction of $2.3 million (December 31, 2015: $1.4 million) which includes ancillary drilling and well servicing equipment.

8. Property and Equipment (continued):

Depreciation:

Effective April 1, 2016, the Company 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 the 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 will result in idle or underutilized assets being depreciated more quickly in periods of low activity. These adjustments were applied prospectively and resulted in an increase in depreciation expense of approximately $28.1 million for the year ended December 31, 2016.

Impairment:

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. 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, 2016, the recoverable amounts allocated to these CGUs were determined based on a fair value less costs to sell calculation which uses after-tax cash flow projections based on historical results and incorporates the Company's most recent 2017 forecast. The fair value of each CGU was classified as level III fair value based on unobservable inputs used, such as expected future market conditions. For the purposes of completing the impairment analysis on the contract drilling CGU, assumptions were made relating to average contract drilling utilization. These rates range 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 range from 30% to 50% per year. Management has reflected that the current downturn in the oilfield service industry will begin to recover in 2017 and 2018. Cash flow projections for 2019 to 2021 have assumed a gradual recovery to historical activity levels. Cash flow projections thereafter for the remaining economic life, based on an average life ranging from 10 years to 18 years, have been extrapolated based on a 2% per annum growth rate. An average tax rate of 26.7% was used in the cash flow projections. Salvage values have been based on management's best estimate based on historical experience and range between 0% and 20%.

The forecasted cash flows are based on management's best estimates of future pricing, asset utilization, rates 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. Additionally, at December 31, 2016, the Company evaluated its property and equipment and decommissioned $5.5 million (December 31, 2015: $26.6 million) of equipment for which it was determined that no further economic benefit would be realized.

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 result in an impairment of $1.2 million in the well servicing CGU and no change in the results of the impairment test on the contract drilling or oilfield rental equipment CGUs.

As at December 31, 2015, 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, 2015 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 2016 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 25% to 60% 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 20% to 60% per year. The forecasted cash flows were based on management's best estimates of future pricing, asset utilization, rates for available equipment, costs to maintain that equipment and a pre-tax discount rate of 17% per annum.

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

8. Property and Equipment (continued):

The results of the tests indicated an impairment of property and equipment at December 31, 2015 of $41.9 million, with $19.0 million and $22.9 million related to the contract drilling and well servicing CGUs respectively. The property and equipment impairment losses were due to the declining commodity price environment, which resulted in reductions to the capital spending plans for Western's customers and resulted in a reduced outlook for oilfield service activity. Based on the discounted cash flow calculation, the recoverable amount of the contract drilling, well servicing and oilfield rental equipment CGUs was $617.9 million, $114.3 million and $37.4 million respectively, as at December 31, 2015.

9. Goodwill:

The following table summarizes the Company's goodwill as at December 31, 2016 and 2015:

		Goodwill
Balance at December 31, 2014	$	69,607
Foreign exchange adjustment		1,649
Impairment of goodwill		(71,256)
Balance at December 31, 2015 and 2016	$	-

As at September 30, 2015, the Company identified impairment indicators related to the prolonged commodity price downturn and as such performed an impairment analysis. For impairment testing purposes, goodwill was allocated to the Company's CGUs that were expected to benefit from the synergies of the business combinations which resulted in the initial recognition of the goodwill. 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 September 30, 2015, the recoverable amounts of goodwill allocated to these CGUs were determined based on a value in use calculation which uses cash flow projections based on historical results and incorporated the Company's most recent 2015 and 2016 internal forecasts. For the purposes of completing the impairment analysis on the contract drilling CGU, assumptions were made relating to average contract drilling utilization. These rates range from 30% to 60% per year. Management reflected that the downturn in the oilfield service industry would continue through 2016. Cash flow projections for 2017 to 2020 assumed a gradual recovery to historical activity levels. Cash flow projections thereafter were extrapolated based on a 2% per annum growth rate. The forecasted cash flows were based on management's best estimates of future pricing, asset utilization, rates for available equipment, costs to maintain that equipment and a pre-tax discount rate of 14% per annum.

The results of the tests indicated a goodwill impairment at September 30, 2015 of $71.3 million, with $59.1 million related to the contract drilling CGU and $12.2 million related to the oilfield rental equipment CGU. This impairment represented the total amount of goodwill allocated to each CGU. The goodwill impairment was due to the declining commodity price environment, which resulted in reductions to the capital spending plans for Western's customers, and resulted in a reduced outlook for oilfield service activity. The recoverable amount of the contract drilling and oilfield rental equipment CGUs was $664.0 million and $32.6 million respectively, as at September 30, 2015.

10. Trade payable and other current liabilities:

Trade payables and current liabilities as at December 31, 2016 and 2015 are as follows:

		December 31, 2016		December 31, 2015
Trade payables	$	13,976	$	7,340
Accrued trade payables and expenses		18,930		19,453
Total	$	32,906	$	26,793

The Company's exposure to foreign exchange and liquidity risk related to trade payables and other current liabilities is disclosed in Note 20.

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

11. Provisions:

As at December 31, 2016 and 2015, the Company has recognized a provision for the deferral of an office lease inducement received, which is 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, 2014	$ 1,958
Provisions used during the year	(139)
Balance at December 31, 2015	1,819
Provisions used during the year	(145)
Balance at December 31, 2016	$ 1,674

The following table summarizes the balance sheet classification of the Company's provisions as at December 31, 2016 and 2015:

	December 31, 2016	December 31, 2015
Current	$ 140	$ 145
Non current	1,534	1,674
	$ 1,674	$ 1,819

12. Long term debt:

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

	December 31, 2016	December 31, 2015
Current:		
Other long term debt – current portion [(1)]	$ 684	$ 761
Total current portion of long term debt	684	761
Non current:		
Senior Notes	265,000	265,000
Less: net unamortized premium and issue costs on Senior Notes	(1,088)	(1,607)
Other long term debt – non current portion [(1)]	158	762
Total non current portion of long term debt	264,070	264,155
Total long term debt	$ 264,754	$ 264,916

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

Credit facilities:

On April 27, 2016, the Company elected to reduce its syndicated revolving credit facility (the "Revolving Facility") from $175.0 million to $40.0 million and reduced its previously uncommitted operating demand revolving loan of $20.0 million to a committed operating facility (the "Operating Facility") totaling $10.0 million.

On July 25, 2016, the Company added a lender to its syndicated Revolving Facility and increased the amount available by $10.0 million to $50.0 million, from $40.0 million previously. The Revolving Facility has an interest coverage ratio when $30.0 million or more is drawn on the Company's Revolving Facility and Operating Facility (the "Credit Facilities"). The interest coverage ratio has been waived during the covenant relief period, which began on January 1, 2016 and ends after December 31, 2017. Subsequent to the covenant relief period, and when $30.0 million or more is drawn on the Company's Credit Facilities, the interest coverage ratio must exceed 1.0 and 1.25 in the first and second quarters of 2018 respectively, and 1.5 thereafter. Additionally, the Consolidated Senior Debt to Consolidated EBITDA ratio has been reduced during the covenant relief period to 3.0 to 1.0 under the increased Revolving Facility from 4.0 to 1.0 previously.

At December 31, 2016, in addition to the $60.0 million of available credit under the Credit Facilities, Western had access to an accordion feature whereby an incremental $50.0 million of borrowing would become available, subject to the approval of the lenders. During the covenant relief period, there are restrictions on exercising the accordion and on certain payments made by the Company, including dividends, normal course issuer bid purchases and capital expenditures in excess of Western's approved budget. The Credit Facilities mature on December 17, 2018.

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

12. Long term debt (continued):

Additionally, advances under the Credit Facilities will be limited by the Company's borrowing base. 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 $40.0 million, with a seasonal increase to $50.0 million each quarter ending June 30).

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.

The Credit Facilities are secured by the assets of Western and its subsidiaries. As at December 31, 2016, the Revolving Facility and the Operating Facility were undrawn. The Company's Credit Facilities are subject to the following financial covenants:

	Covenant	December 31, 2016
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	0.35:1.0
Minimum Consolidated EBITDA to Consolidated Interest Expense Ratio (5)	Not applicable	Not applicable
Minimum Current Ratio (6)	1.15:1.0 or more	2.57:1.0

(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 outstanding principal on 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) Consolidated EBITDA to Consolidated Interest in the Credit Facilities is defined on a trailing twelve month basis as Consolidated EBITDA (as previously defined) divided by all interest of the Company accrued, including capitalized interest and interest related to lease obligations. The interest coverage ratio is only applicable after December 31, 2017 when $30.0 million or more is drawn on the Credit Facilities. Subsequent to December 31, 2017, the interest coverage ratio must exceed 1.0 and 1.25 in the first and second quarters of 2018 respectively, and 1.5 thereafter.
(6) Current Ratio in the Credit Facilities is defined as current assets, including cash and cash equivalents, divided by current liabilities, excluding any current portion of long term debt.

As at December 31, 2016 and December 31, 2015, the Company was in compliance with all covenants related to its Credit Facilities.

Senior Notes:

The Company has $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.

At December 31, 2016, the fair value of the Senior Notes was approximately $249.4 million (December 31, 2015: $245.5 million).

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

13. 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, 2014	74,866,028	$	423,633
Issued for cash on exercise of stock options	26,800		154
Issued on vesting of restricted share units	50,764		471
Shares purchased under normal course issuer bid	(1,297,300)		(6,691)
Fair value of exercised stock options	-		55
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

During the year ended December 31, 2016, no dividends were declared (December 31, 2015: $20.4 million). The Company had no dividends payable as at December 31, 2016 (December 31, 2015: $3.7 million).

On December 15, 2014, Western initiated a normal course issuer bid (the "NCIB"). Pursuant to the NCIB, Western could purchase for cancellation up to 5,550,000 common shares of the Company. On December 16, 2015, Western renewed its NCIB, which was filed with and accepted by the TSX. Pursuant to the renewed NCIB, Western could purchase for cancellation up to 4,550,000 common shares of the Company. The renewed NCIB commenced on December 18, 2015 and expired on December 17, 2016.

For the year ended December 31, 2016, no common shares were repurchased, cancelled or charged to share capital or contributed surplus under the renewed NCIB. For the year ended December 31, 2015, 1,297,300 common shares for a total cost of $6.7 million were repurchased, cancelled, and charged to share capital or contributed surplus under the NCIB.

14. 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, 2014	5,093,972	$	8.23
Granted	2,509,831		5.10
Exercised	(26,800)		5.75
Forfeited	(1,307,994)		7.91
Expired	(210,103)		5.74
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

For the years ended December 31, 2016 and December 31, 2015, no stock options were cancelled. The average fair value of the stock options granted in 2016 was $0.82 per stock option (2015: $1.29 per stock option). For the year ended December 31, 2016, the Company recorded approximately $2.4 million in stock based compensation expense related to stock options (December 31, 2015: $3.0 million).

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

14. Stock based compensation (continued):

Stock options (continued):

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

As at December 31, 2016 Exercise Price ($/share)	Number of options outstanding	Weighted average contractual life remaining (years)	Number of options exercisable
2.22-4.50	1,330,324	4.62	-
4.51-7.00	2,686,960	3.01	1,354,453
7.01-9.50	1,016,069	1.66	846,902
9.51-11.14	1,120,533	2.60	749,688
	6,153,886	3.06	2,951,043

As at December 31, 2016, Western had 2,951,043 (December 31, 2015: 1,966,647) exercisable stock options outstanding at a weighted average exercise price equal to $7.49 (December 31, 2015: $7.98) 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, 2016	Year ended December 31, 2015
Risk-free interest rate	1%	1%
Average forfeiture rate	15%	16%
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%	6%
Expected share price volatility	46%	60%

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 1% 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, 2014	177,338	126,999	304,337
Granted	328,845	322,151	650,996
Issued as a result of dividends	11,627	9,333	20,960
Vested	(50,764)	(38,931)	(89,695)
Forfeited	(56,777)	(70,317)	(127,094)
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

The estimated fair value of the equity settled RSUs granted during the year ended December 31, 2016 was $0.5 million (December 31, 2015: $1.2 million) and will be recognized as an expense over the vesting period of the RSUs.

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

14. Stock based compensation (continued):

Restricted share unit plan (continued):

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, 2016	Year ended December 31, 2015
Risk-free interest rate	1%	1%
Average forfeiture rate	7%	17%
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%	6%
Expected share price volatility	46%	60%

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

	Year ended December 31, 2016	Year ended December 31, 2015
Stock options	$ 2,429	$ 2,991
Restricted share units – equity settled grants	976	896
Total equity settled stock based compensation expense	3,405	3,887
Restricted share units – cash settled grants	363	430
Total stock based compensation expense	$ 3,768	$ 4,317

The outstanding liability related to cash settled RSUs at December 31, 2016 was $0.4 million (December 31, 2015: $0.4 million).

15. Earnings per share:

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

	Year ended December 31, 2016	Year ended December 31, 2015
Issued common shares, beginning of period	73,646,292	74,866,028
Weighted average number of common shares issued	57,145	37,260
Weighted average number of common shares purchased under NCIB	-	(664,968)
Weighted average number of common shares (basic)	73,703,437	74,238,320
Dilutive effect of equity securities	-	-
Weighted average number of common shares (diluted)	73,703,437	74,238,320

For the year ended December 31, 2016, 6,153,886 stock options (December 31, 2015: 6,058,906 stock options) and 410,311 RSUs (December 31, 2015: 410,269 RSUs) were excluded from the diluted weighted average number of common shares calculation as their effect would have been anti-dilutive.

16. Finance costs:

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

	Year ended December 31, 2016	Year ended December 31, 2015
Interest expense on long term debt	$ 21,679	$ 21,870
Amortization of debt financing fees and provisions	984	520
Interest income	(141)	(515)
Total finance costs before capitalized interest	22,522	21,875
Capitalized interest	-	(1,434)
Total finance costs	$ 22,522	$ 20,441

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

16. Finance Costs (continued):

The Company had an effective interest rate of 8.5% on its borrowings for the year ended December 31, 2015 (December 31, 2015: 8.2%).

17. Other items:

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

	Year ended December 31, 2016	Year ended December 31, 2015
Loss (gain) on sale of fixed assets	$ 580	$ (154)
Mark-to-market loss on fair value of derivatives	552	301
Realized foreign exchange gain	(2,678)	(1,856)
Unrealized foreign exchange gain	(3)	-
Total other items	$ (1,549)	$ (1,709)

18. Income taxes:

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

	Year ended December 31, 2016	Year ended December 31, 2015
Current tax recovery	$ (1,708)	$ (8,732)
Deferred tax recovery	(20,247)	(3,816)
Total income tax recovery	$ (21,955)	$ (12,548)

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

		Year ended December 31, 2016		Year ended December 31, 2015
Income (loss) before income taxes		$ (83,928)		$ (141,687)
Federal and provincial statutory rates	26.7%	(22,438)	26.8%	(37,941)
Income (loss) taxed at higher rates		(408)		(539)
Impairment of goodwill		-		19,090
Stock based compensation		893		932
Non controlling interest		(19)		(75)
Non-deductible expenses		258		392
Change in effective tax rate on temporary differences		(165)		5,986
Return to provision adjustment		(37)		40
Other		(39)		(433)
Total income taxes		$ (21,955)		$ (12,548)

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

18. Income taxes (continued):

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

	December 31, 2016	December 31, 2015
Property and equipment	$ (141,226)	$ (139,075)
Other assets	-	(148)
Deferred charges and accruals	65	(20)
Provisions	446	483
Long term debt	(210)	59
Other tax pools	1,159	1,114
Tax loss carry-forwards	52,782	29,885
Net deferred tax liabilities	$ (86,984)	$ (107,702)

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

	Balance Dec 31, 2015	Recognized in other comprehensive income (loss)	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)

Movements of the Company's temporary differences for the year ended December 31, 2015 is as follows:

	Balance Dec 31, 2014	Recognized in other comprehensive income (loss)	Recognized in net income (loss)	Impact of foreign exchange	Balance Dec 31, 2015
Property and equipment	$ (129,832)	$ -	$ (1,974)	$ (7,269)	$ (139,075)
Other assets	(216)	-	68	-	(148)
Deferred charges and accruals	(4,433)	-	4,400	13	(20)
Provisions	490	-	(7)	-	483
Long term debt	363	-	(304)	-	59
Foreign exchange on inter-company loan	(912)	758	154	-	-
Share issue costs	263	-	(263)	-	-
Other tax pools	603	-	454	57	1,114
Tax loss carry-forwards	24,230	-	1,288	4,367	29,885
Net deferred tax liabilities	$ (109,444)	$ 758	$ 3,816	$ (2,832)	$ (107,702)

In June 2015, the Alberta corporate tax rate was increased to 12% from 10% previously. As a result, the Company's deferred tax liability increased by $6.0 million, with a corresponding increase to deferred tax expense for the year ended December 31, 2015. This tax rate increase received Royal Assent on June 29, 2015.

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

18. Income taxes (continued):

As at December 31, 2016, the Company has gross loss carry-forwards equal to approximately $94.7 million in Canada, which will expire by 2036. In the United States, the Company has approximately US$52.2 million gross loss carry forwards which expire between 2028 and 2036.

19. 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, 2016	Year ended December 31, 2015
Depreciation of property and equipment (Note 8)	$ 59,472	$ 39,467
Employee benefits: salaries and benefits	76,087	112,189
Employee benefits: stock based compensation (Note 14)	3,768	4,317
Repairs and maintenance	8,707	10,798
Third party charges	7,531	11,039

20. 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, derivatives and long term debt instruments such as the Credit Facilities and the Senior Notes. Cash and cash equivalents and derivatives 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, 2016.

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, 2016 and 2015 as there was no balance outstanding on the credit facilities during the years ended December 31, 2016 and 2015. 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 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, 2016, 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, 2016 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 less than $0.2 million and $0.5 million, respectively (December 31, 2015: $0.3 million and $0.6 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, 2016, approximately 99% of the Company's trade receivables were less 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.

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

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

The table below provides an analysis of the aging of the Company's trade receivables as at December 31, 2016 and 2015:

	December 31, 2016	December 31, 2015
Trade receivables:		
Current	$ 14,931	$ 13,534
Outstanding for 31 to 60 days	6,219	7,031
Outstanding for 61 to 90 days	2,261	2,715
Outstanding for over 90 days	97	1,329
Accrued trade receivables	9,375	3,295
Other receivables	453	1,273
Income tax receivable	1,685	10,350
Allowance for doubtful accounts	(23)	(1,089)
Total	$ 34,998	$ 38,438

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, 2016, the Company impaired less than $0.1 million in trade receivables (December 31, 2015: $1.1 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 flow from operating activities, existing credit facilities and excess working capital 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.

The table below provides an analysis of the expected maturities of the Company's outstanding obligations at December 31, 2016:

	Total	Due prior to December 31					
	amount	2017	2018	2019	2020	2021	Thereafter
Financial liabilities:							
Trade and other current liabilities	$ 32,906	$ 32,906	$ -	$ -	$ -	$ -	$ -
Senior notes	265,000	-	-	265,000	-	-	-
Other long-term debt	842	684	158	-	-	-	-
Total	$ 298,748	$ 33,590	$ 158	$ 265,000	$ -	$ -	$ -

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 21.

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.

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

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

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 and the early redemption option on the Senior Notes are the only financial assets or liabilities 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. The estimated fair value of the early redemption option on the Senior Notes is based on Level II inputs as the inputs are directly observable through correlation with market data.

Capital management:

The overall capitalization of the Company at December 31, 2016 and 2015 is as follows:

	Note	December 31, 2016	December 31, 2015
Other long term debt	12	$ 842	$ 1,523
Senior Notes	12	265,000	265,000
Total debt		265,842	266,523
Shareholders' equity		407,207	471,696
Less: cash and cash equivalents		(44,597)	(58,445)
Total capitalization		$ 628,452	$ 679,774

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, 2016, the Company had $60.0 million in undrawn credit under its Credit Facilities and was in compliance with all debt covenants (see Note 12).

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

21. Commitments:

As at December 31, 2016, the Company has total commitments which require payments based on the maturity terms as follows:

	2017	2018	2019	2020	2021	Thereafter	Total
Senior Notes	$ -	$ -	$ 265,000	$ -	$ -	$ -	$ 265,000
Senior Notes interest	20,869	20,869	10,520	-	-	-	52,258
Trade payables and other current liabilities(1)	24,044	-	-	-	-	-	24,044
Operating leases	3,879	3,705	3,550	3,525	2,818	7,814	25,291
Purchase commitments	2,449	-	-	-	-	-	2,449
Other long term debt	719	168	-	-	-	-	887
Total	$ 51,960	$ 24,742	$ 279,070	$ 3,525	$ 2,818	$ 7,814	$ 369,929

(1) Trade payables and other current liabilities exclude interest accrued as at December 31, 2016 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.

22. Related party transactions:

During the years ended December 31, 2016 and 2015, the Company did not have any sales transactions with related parties. At December 31, 2016, there are no significant balances outstanding in trade and other receivables with related parties (December 31, 2015: $nil).

23. Key management personnel:

	Year ended December 31, 2016	Year ended December 31, 2015
Short-term employee benefits	$ 1,315	$ 1,564
Stock based compensation (1)	1,131	1,164
	$ 2,446	$ 2,728

(1) The total fair value of stock options and RSUs granted to key management personnel for the year ended December 31, 2016 was equal to $0.5 million (December 31, 2015: $1.2 million), which is being recognized in net income (loss) over the stock option's and RSU's vesting period.

24. 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, 2016	December 31, 2015
Stoneham Drilling Corporation	USA	100	100
Western Production Services Corp.	Canada	100	100

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

Tim J. Sebastian
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

Computershare
Calgary, Alberta

Western
ENERGY SERVICES CORP.

1700, 215 – 9th Avenue SW Calgary, Alberta T2P 1K3
Telephone: (403) 984-5916

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