Western ENERGY SERVICES CORP.

Second Quarter Interim Report

Date: July 26, 2016

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, 2015 and 2014, the Company's management discussion and analysis ("MD&A") for the year ended December 31, 2015, as well as the condensed consolidated financial statements and notes as at and for the three and six months ended June 30, 2016 and 2015. This Management Discussion and Analysis ("MD&A") is dated July 26, 2016. All amounts are denominated in Canadian dollars (CDN$) unless otherwise identified.

Financial Highlights	**Three months ended June 30**			**Six months ended June 30**		
(stated in thousands, except share and per share amounts)	**2016**	**2015**	**Change**	**2016**	**2015**	**Change**
Revenue	12,890	32,037	(60%)	46,827	137,887	(66%)
Operating Revenue[1]	12,393	30,719	(60%)	44,593	131,677	(66%)
Gross Margin[1]	2,703	10,403	(74%)	11,570	58,294	(80%)
Gross Margin as a percentage of Operating Revenue	22%	34%	(35%)	26%	44%	(41%)
Adjusted EBITDA[1]	(1,990)	4,255	(147%)	1,374	44,892	(97%)
Adjusted EBITDA as a percentage of Operating Revenue	(16%)	14%	(214%)	3%	34%	(91%)
Cash flow from operating activities	8,444	41,009	(79%)	17,049	80,346	(79%)
Capital expenditures	423	7,688	(94%)	1,344	25,551	(95%)
Net income (loss)	(24,172)	(12,607)	92%	(30,491)	2,687	(1,235%)
-basic net income (loss) per share	(0.33)	(0.17)	94%	(0.41)	0.04	(1,125%)
-diluted net income (loss) per share	(0.33)	(0.17)	94%	(0.41)	0.04	(1,125%)
Weighted average number of shares						
-basic	73,648,192	74,579,889	(1%)	73,647,241	74,633,065	(1%)
-diluted	73,648,192	74,579,889	(1%)	73,647,241	74,652,435	(1%)
Outstanding common shares as at period end	73,648,484	74,435,928	(1%)	73,648,484	74,435,928	(1%)
Dividends declared	-	5,591	(100%)	-	11,184	(100%)
Dividends declared per common share	-	0.075	(100%)	-	0.15	(100%)
Operating Highlights						
Contract Drilling						
Canadian Operations						
Average contract drilling rig fleet	52	49	6%	52	49	6%
Operating Revenue per Revenue Day[1]	16,441 [3]	20,589	(20%)	19,001 [3]	25,015	(24%)
Operating Revenue per Operating Day[1]	17,369 [3]	22,285	(22%)	21,260 [3]	27,570	(23%)
Drilling rig utilization - Revenue Days[1]	4%	11%	(64%)	12%	33%	(64%)
Drilling rig utilization - Operating Days[1]	3%	10%	(70%)	11%	30%	(63%)
CAODC industry average utilization[1][2]	7%	13%	(46%)	14%	24%	(42%)
United States Operations						
Average contract drilling rig fleet	5	5	-	5	5	-
Operating Revenue per Revenue Day (US$)[1]	24,568	27,766 [4]	(12%)	25,832	28,888 [4]	(11%)
Operating Revenue per Operating Day (US$)[1]	27,092	32,181 [4]	(16%)	29,240	33,118 [4]	(12%)
Drilling rig utilization - Revenue Days[1]	20%	36%	(44%)	20%	45%	(56%)
Drilling rig utilization - Operating Days[1]	18%	31%	(42%)	18%	39%	(54%)
Production Services						
Average well servicing rig fleet	66	66	-	66	66	-
Service rig Operating Revenue per Service Hour[1]	589	794	(26%)	682	833	(18%)
Service rig utilization[1]	11%	26%	(58%)	14%	34%	(59%)

(1) See "Non-IFRS measures" on page 17 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 three and six months ended June 30, 2016.

(4) Excludes shortfall commitment and standby revenue from take or pay contracts of US$0.7 million and US$4.5 million for the three and six months ended June 30, 2015 respectively.

Financial Position at (stated in thousands)	June 30, 2016	June 30, 2015	December 31, 2015
Working capital	60,278	79,618	70,679
Property and equipment	735,765	840,231	773,647
Total assets	814,757	1,025,776	876,608
Long term debt	264,145	264,234	264,155

Overall Performance and Results of Operations

Western is an oilfield service company focused on three core business lines: contract drilling, well servicing and oilfield rental equipment services. Western provides contract drilling services through its division, Horizon Drilling ("Horizon") in Canada, and its wholly owned subsidiary, Stoneham Drilling Corporation ("Stoneham") in the United States ("US"). 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 17 of this MD&A. Abbreviations for standard industry terms are included on page 19 of this MD&A.

Western currently has a drilling rig fleet of 56 rigs specifically suited for drilling horizontal wells of increased complexity. Western is the sixth largest drilling contractor in Canada with a fleet of 51 rigs operating through Horizon. Of the Canadian fleet, 24 are classified as Cardium rigs, 19 as Montney rigs and eight as Duvernay 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. Additionally, Western has five Duvernay class triple drilling rigs deployed in the United States operating through Stoneham. Western is also the fourth largest well servicing company in Canada with a fleet of 66 rigs operating through Eagle. Western's oilfield rental equipment division, which operates through Aero, provides oilfield rental equipment for frac 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. Overall performance of the Company for the three and six months ended June 30, 2016 was affected by the continued low crude oil and natural gas prices. While West Texas Intermediate ("WTI") on average increased by 36% in the second quarter of 2016, as compared to the first quarter of 2016 when prices were at their lowest levels in over a decade, WTI was still 21% and 25% lower for the three and six months ending June 30, 2016 respectively, as compared to the same periods in the prior year. The following table summarizes average crude oil and natural gas prices, as well as average foreign exchange rates for the three and six months ended June 30, 2016 and 2015.

	Three months ended June 30			Six months ended June 30		
	2016	2015	Change	2016	2015	Change
Average crude oil and natural gas prices(1)						
Crude Oil						
West Texas Intermediate (US$/bbl)	45.53	57.87	(21%)	39.69	53.22	(25%)
Western Canadian Select (CDN$/bbl)	42.31	56.76	(25%)	34.49	49.96	(31%)
Natural Gas						
30 day Spot AECO (CDN$/mcf)	1.40	2.68	(48%)	1.61	2.71	(41%)
Average foreign exchange rates						
US dollar to Canadian dollar	1.29	1.23	5%	1.33	1.24	7%

(1) See "Abbreviations" on page 19 of this MD&A.

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. As a result, second quarter drilling rig counts in both Canada and the United States were at or near 30 year lows in 2016. The Canadian Association of Oilwell Drilling Contractors ("CAODC") reported that for drilling in Canada, the total number of Operating Days in the Western Canadian Sedimentary Basin ("WCSB") decreased approximately 47% and 46% respectively, for the three and six months ended June 30, 2016, as compared to the three and six months ended June 30, 2015. Similarly, as reported by Baker Hughes Incorporated, the number of active drilling rigs in the United States decreased approximately 54% and 57% for the three and six months ended June 30, 2016 respectively, as compared to the same periods in the prior year.

Operational results for the three months ended June 30, 2016 include:

- Second quarter Operating Revenue decreased by $18.3 million (or 60%) to $12.4 million in 2016 as compared to $30.7 million in 2015. In the contract drilling segment, Operating Revenue totaled $7.4 million in the second quarter of 2016 as compared to $16.7 million in the second quarter of 2015; while in the production services segment, Operating Revenue totaled $5.0 million for the three months ended June 30, 2016 as compared to $14.0 million in the same period of the prior year. While WTI prices recovered somewhat in the second quarter of 2016, Operating Revenue was impacted by decreased commodity prices, as both crude oil and natural gas prices were still significantly lower year over year. Activity levels remained at 30 year lows with utilization experiencing no meaningful post spring breakup recovery until subsequent to the end of the second quarter of 2016. Operating Revenue in the contract drilling and production services segments were impacted by lower utilization and pricing as described below:
    - Drilling rig utilization – Operating Days (or "Drilling Rig Utilization") in Canada was 3% in the second quarter of 2016 compared to 10% in the second quarter of 2015, reflecting a 70% decrease. Second quarter 2016 Drilling Rig Utilization represented a discount of 400 basis points ("bps") to the CAODC industry average of 7%, as compared to the 300 bps discount to the industry average realized in the second quarter of 2015. The CAODC industry average utilization for the three months ended June 30, 2016 was the lowest quarterly industry utilization on record. The Company's discount relative to the CAODC average is partially due to a number of Western's customers, who typically have substantial drilling programs, significantly cutting their capital spending in 2016. Additionally, lower activity and increased competition in the second quarter of 2016 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 20%, as compared to the second quarter of 2015;
    - In the United States, the Company had one drilling rig working on a long term contract throughout the quarter, resulting in Drilling Rig Utilization of 18% in the second quarter of 2016, as compared to 31% in the same period of the prior year, while Operating Revenue per Revenue Day in the United States decreased by 12% in the second quarter of 2016 due to renegotiating the day rate and extending the term on the contract; and
    - Well servicing utilization of 11% in the second quarter of 2016 compared to 26% in the same period of the prior year. Reduced activity, coupled with a 26% decrease in well servicing hourly rates, due to pricing pressure in all areas, resulted in an $8.6 million (or 69%) decrease in well servicing Operating Revenue in the period.
- Second quarter Adjusted EBITDA decreased by $6.3 million to a loss of $2.0 million in 2016 as compared to $4.3 million in the second quarter of 2015. The year over year change in Adjusted EBITDA is due to lower utilization and pricing in both the contract drilling and production services segments, offset partially by cost reduction measures, including an approximate one third reduction to salaried headcount year over year, wage reductions to all employees and other cost control measures.
- Administrative expenses, excluding depreciation and stock based compensation, in the second quarter of 2016 decreased by $1.4 million (or 23%) to $4.7 million as compared to $6.1 million in the second 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.
- 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 $12.7 million of additional depreciation expense for the three months ended June 30, 2016, over what would have been expensed had the previous assumptions using the unit of production methodology continued to be used in the period. The estimated additional depreciation expense for the year ending December 31, 2016 from this change is approximately $24.7 million.
- 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 June 30, 2016 Horizon had a fleet of 51 drilling rigs.

- The Company incurred a net loss of $24.2 million in the second quarter of 2016 (a loss of $0.33 per basic common share) as compared to a net loss of $12.6 million in the same period in 2015 (a loss of $0.17 per basic common share). The decrease in net income in 2016 can be attributed to the following:
  - A $6.3 million decrease in Adjusted EBITDA due to lower utilization and pricing in both the contract drilling and production services segments;
  - An increase of $10.4 million in depreciation expense due to the Company changing from unit of production to straight line depreciation;
  - Losses on asset decommissioning of $5.2 million in the contract drilling segment; and
  - A $1.0 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 period.

  Offsetting the above mentioned items was a $12.8 million decrease in income tax expense due to lower taxable income in the second quarter of 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.
- Second quarter 2016 capital expenditures of $0.4 million included $0.2 million of expansion capital and $0.2 million of maintenance capital. In total, capital spending in the second quarter of 2016 decreased by 94% from the $7.7 million incurred in the second quarter of 2015, as the Company is only incurring necessary maintenance capital 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") totaling $10.0 million. Western's decision to reduce its Revolving Facility and Operating Facility (the "Credit Facilities") is estimated to save the Company $1.5 million in standby fees annually.
- Subsequent to June 30, 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 increased Revolving Facility reinstates an interest coverage ratio when $30.0 million or more is drawn on the Company's Credit Facilities. The interest coverage ratio has been waived during the covenant relief period, which ends after December 31, 2017. Subsequent to the covenant relief period, 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.

Operational results for the six months ended June 30, 2016 include:

- Operating Revenue for the six month period ended June 30, 2016 decreased by $87.1 million (or 66%) to $44.6 million in 2016, as compared to $131.7 million in the same period of the prior year. In the contract drilling segment, Operating Revenue totaled $29.7 million for the six month period ended June 30, 2016 compared to $92.4 million in the same period of the prior year; while in the production services segment, Operating Revenue totaled $14.9 million compared to $39.6 million in the same period of the prior year. Operating Revenue in the contract drilling and production services segments for the six month period ended June 30, 2016 were impacted by lower utilization and pricing as described below:
  - Drilling Rig Utilization in Canada of 11% for the six month period ended June 30, 2016, compared to 30% for the six month period ended June 30, 2015, reflects a 63% decrease. Drilling Rig Utilization on a year to date basis in 2016 represented a discount of 300 bps to the CAODC industry average of 14%, as compared to the 600 bps premium to the CAODC industry average realized in the first six months of 2015. The change in the Company's utilization relative to the CAODC industry average, as mentioned for the second quarter of 2016, is partially due to a number of Western's customers who typically have substantial drilling programs, significantly cutting their capital spending in 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 in the first six months of 2016 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 first six months of 2015;
  - In the United States, the Company had one drilling rig working on a long term contract throughout the period, resulting in Drilling Rig Utilization of 18% for the six months ended June 30, 2016, as compared to 39% in the same period of the prior year, while Operating Revenue per Revenue Day in the United States decreased by 11% in the first six months of 2016 due to renegotiating the day rate and extending the term on the contract; and

- Well servicing utilization of 14% for the six months ended June 30, 2016 compared to 34% in the same period of the prior year. Reduced activity as well as an 18% reduction in well servicing hourly rates, due to pricing pressure in all areas, resulted in a $22.1 million (or 66%) decrease in well servicing Operating Revenue in the period.

- Adjusted EBITDA for the six months ended June 30, 2016 decreased by $43.5 million to $1.4 million, as compared to $44.9 million for the six months ended June 30, 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 an approximate one third reduction to salaried headcount, wage reductions to all employees and other cost control measures.
- Year to date administrative expenses, excluding depreciation and stock based compensation, for the six month period ended June 30, 2016 decreased by $3.2 million (or 24%) to $10.2 million as compared to $13.4 million in the same period of the prior year. 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.
- The Company incurred a net loss of $30.5 million for the six months ended June 30, 2016 (a loss of $0.41 per basic common share) as compared to net income of $2.7 million for the same period in 2015 ($0.04 per basic common share). The reduction in net income in 2016 can be attributed to the following:
  - A $43.5 million decrease in Adjusted EBITDA due to lower utilization and pricing in both the contract drilling and production services segments;
  - An increase of $4.3 million in depreciation expense due to the Company changing from unit of production to straight line depreciation in the second quarter of 2016; and
  - A $1.8 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 period.

  Offsetting the above mentioned items was a $21.7 million decrease in income tax expense due to lower taxable income for the six months ended June 30, 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.
- Year to date capital expenditures of $1.3 million included $0.6 million of expansion capital and $0.7 million of maintenance capital. In total, capital spending for the six months ended June 30, 2016 decreased by 95% from the $25.6 million incurred in the same period of 2015, as the Company minimized its capital expenditures to preserve cash balances during the current slowdown in oilfield service activity.

Outlook

Currently, 16 of Western's drilling rigs are operating and five of Western's 56 drilling rigs (or 9%) are under long term take or pay contracts providing a base level of future revenue, with one of these contracts expected to expire in 2016, three expected to expire in 2017, and one expected to expire in 2018. These contracts each typically generate between 250 and 350 Revenue Days per year.

Western's capital budget for 2016 of $7 million remains unchanged, and is comprised of $2 million of expansion capital and $5 million of maintenance capital. Western believes the 2016 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.

Commodity prices, while remaining well below previous highs, have improved significantly since hitting 10 year lows in the first quarter of 2016. As such, North American drilling rig counts appear to have bottomed out and the Company is expecting improved year over year activity levels in the second half of 2016. However, the Company expects pricing pressure will continue to be challenging as activity levels begin to recover. As at June 30, 2016, the Company had seven drilling rigs operating; since that time, activity has improved and at July 26, 2016, the Company has 16 drilling rigs operating, with a full complement of experienced crews. Lower than normal activity levels and pricing pressure will continue to impact Western's Adjusted EBITDA and cash flow from operating activities if low commodity prices persist. As discussed, the Company has taken a proactive approach to reducing administrative and fixed overhead costs including reducing fixed headcount since the beginning of 2015 by a third and implementing a 10% company wide wage rollback to salaried employees and directors' fees in the first quarter of 2016, as well as reducing various other office related costs. In addition, Western's variable cost structure, under which approximately 80% of operating and administrative costs are variable, the previously announced suspension of the Company's quarterly dividend and a prudent capital budget will aid in preserving balance sheet strength. In addition to $57 million in cash and cash equivalents at June 30, 2016, Western has $60 million undrawn on the Company's

Credit Facilities, which do not mature until December 17, 2018 and no principal repayments due on the $265 million 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 liquefied natural gas projects, increased crude oil transportation capacity through rail and pipeline development and foreign investment into Canada. Currently, the largest challenge facing the oilfield service industry is customer spending constraints as a result of lower commodity prices. 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 June 30**			**Six months ended June 30**		
(stated in thousands)	**2016**	**2015**	**Change**	**2016**	**2015**	**Change**
Revenue						
Operating Revenue[1]	7,388	16,746	(56%)	29,712	92,353	(68%)
Third party charges	214	857	(75%)	1,215	4,362	(72%)
Total revenue	7,602	17,603	(57%)	30,927	96,715	(68%)
Expenses						
Operating						
Cash operating expenses	4,910	11,403	(57%)	21,478	51,903	(59%)
Depreciation	13,717	4,164	229%	19,053	14,263	34%
Stock based compensation	127	63	102%	164	178	(8%)
Total operating expenses	18,754	15,630	20%	40,695	66,344	(39%)
Administrative						
Cash administrative expenses	2,853	3,402	(16%)	5,690	7,297	(22%)
Depreciation	83	95	(13%)	169	175	(3%)
Stock based compensation	97	168	(42%)	179	270	(34%)
Total administrative expenses	3,033	3,665	(17%)	6,038	7,742	(22%)
Gross Margin[1]	2,692	6,200	(57%)	9,449	44,812	(79%)
Gross Margin as a percentage of Operating Revenue	36%	37%	(3%)	32%	49%	(35%)
Adjusted EBITDA[1]	(161)	2,798	(106%)	3,759	37,515	(90%)
Adjusted EBITDA as a percentage of Operating Revenue	(2%)	17%	(112%)	13%	41%	(68%)
Operating Earnings[1]	(13,961)	(1,461)	856%	(15,463)	23,077	(167%)
Capital expenditures	236	6,047	(96%)	550	21,076	(97%)

	Three months ended June 30			**Six months ended June 30**		
Operating Highlights	**2016**	**2015**	**Change**	**2016**	**2015**	**Change**
Canadian Operations						
Contract drilling rig fleet:						
Average	52	49	6%	52	49	6%
End of period	51	49	4%	51	49	4%
Operating Revenue per Revenue Day[1]	16,441 [3]	20,589	(20%)	19,001 [3]	25,015	(24%)
Operating Revenue per Operating Day[1]	17,369 [3]	22,285	(22%)	21,260 [3]	27,570	(23%)
Operating Days[1]	157	464	(66%)	1,018	2,617	(61%)
Number of meters drilled	31,103	110,435	(72%)	203,676	511,066	(60%)
Number of wells drilled	7	33	(79%)	64	148	(57%)
Average Operating Days per well	22.8	14.1	62%	15.9	17.7	(10%)
Drilling rig utilization - Revenue Days[1]	4%	11%	(64%)	12%	33%	(64%)
Drilling rig utilization - Operating Days[1]	3%	10%	(70%)	11%	30%	(63%)
CAODC industry average utilization[1][2]	7%	13%	(46%)	14%	24%	(42%)
United States Operations						
Contract drilling rig fleet:						
Average	5	5	-	5	5	-
End of period	5	5	-	5	5	-
Operating Revenue per Revenue Day (US$)[1]	24,568	27,766 [4]	(12%)	25,832	28,888 [4]	(11%)
Operating Revenue per Operating Day (US$)[1]	27,092	32,181 [4]	(16%)	29,240	33,118 [4]	(12%)
Operating Days[1]	83	142	(42%)	161	356	(55%)
Number of meters drilled	31,550	37,366	(16%)	55,383	98,224	(44%)
Number of wells drilled	7	7	(1%)	12	17	(28%)
Average Operating Days per well	12.0	20.3	(41%)	13.1	20.9	(37%)
Drilling rig utilization - Revenue Days[1]	20%	36%	(44%)	20%	45%	(56%)
Drilling rig utilization - Operating Days[1]	18%	31%	(42%)	18%	39%	(54%)

(1) See "Non-IFRS measures" on page 17 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 three and six months ended June 30, 2016.

(4) Excludes shortfall commitment and standby revenue from take or pay contracts of US$0.7 million and US$4.5 million for the three and six months ended June 30, 2015 respectively.

For the three months ended June 30, 2016, Operating Revenue in the contract drilling segment totaled $7.4 million, a $9.3 million decrease (or 56%), as compared to the second quarter of 2015. For the six months ended June 30, 2016, Operating Revenue in the contract drilling segment totaled $29.7 million, a $62.7 million decrease (or 68%), as compared to the same period in 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 has put downward pressure on day rates in Canada and the United States for both the three and six months ended June 30, 2016.

During the three months ended June 30, 2016, Adjusted EBITDA in the contract drilling segment decreased by $3.0 million (or 106%) to a loss of $0.2 million, as compared to $2.8 million in the same period of 2015. For the six months ended June 30, 2016, Adjusted EBITDA in the contract drilling segment decreased by $33.7 million (or 90%) to $3.8 million, as compared to $37.5 million for the six months ended June 30, 2015. The decrease for the three and six months ended June 30, 2016, is mainly due to fewer Operating Days, in addition to 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.

For the three and six months ended June 30, 2016, cash administrative expenses, which exclude depreciation and stock based compensation, totaled $2.9 million and $5.7 million respectively, reflecting decreases of 16% and 22% respectively, as compared to the same periods of the prior year. The decrease in cash administrative expenses for the three and six months ended June 30, 2016 is mainly due to lower employee costs and effective cost control measures.

Depreciation expense for the quarter ended June 30, 2016 increased by $9.5 million to $13.8 million, while for the six months ended June 30, 2016 depreciation expense increased by $4.8 million to $19.2 million as compared to the same periods in the prior year. The increase for both the three and six months ended June 30, 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 method resulted in depreciation expense increasing in the current periods.

Capital expenditures in the contract drilling segment totaled $0.2 million and $0.6 million for the three and six months ended June 30, 2016 respectively. Capital expenditures in both periods of 2016 mainly relate to maintenance capital and represent a 96% and 97% decrease respectively, from the $6.0 million and $21.1 million incurred in the three and six months ended June 30, 2015.

Canadian Operations

During the second quarter of 2016, drilling rig utilization – Operating Days (or "Drilling Rig Utilization") in Canada decreased to 3% as compared to 10% in the second quarter of 2015. On a year to date basis, Drilling Rig Utilization in Canada decreased to 11% in 2016 as compared to 30% in the same period of the prior year. The decrease in utilization is due to reduced demand in the lower commodity price environment, resulting in the Company's Operating Days decreasing by 66% and 61% respectively, for the three and six month periods ended June 30, 2016, as compared to the same periods of 2015.

The Company's Drilling Rig Utilization in Canada of 3% for the second quarter of 2016 reflects an approximate 400 bps discount to the CAODC industry average of 7%, as compared to the 300 bps discount realized in the same period of 2015. Drilling Rig Utilization in Canada of 11% for the six months ended June 30, 2016 reflects an approximate 300 bps discount to the CAODC industry average of 14%, as compared to the 600 bps premium for the six months ended June 30, 2015. The decrease in the Company's utilization premium in 2016 as compared to 2015 is partially due to a 12% reduction in the industry rig count from 761 rigs at June 30, 2015 to 672 rigs at June 30, 2016 as competitors continue to decommission older less competitive rigs given the current market conditions. From June 30, 2015 to June 30, 2016, 23 drilling rigs were added to the industry fleet while 112 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 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.

For the quarter ended June 30, 2016, Operating Revenue per Revenue Day in Canada totaled $16,441 compared to $20,589 in the prior year, a 20% decrease. For the six months ended June 30, 2016, Operating Revenue per Revenue Day in Canada totaled $19,001 compared to $25,015 in the same period of the prior year, a reduction of 24%. The decrease in Operating Revenue per Revenue Day in Canada for both periods in 2016 is mainly due to downward pricing pressure on day rates in all rig categories in Canada as reduced commodity prices have led to lower customer spending and resulted in decreased activity and increased competition. Third party charges per Revenue Day decreased for both the three and six months ended June 30, 2016 to approximately $1,200 and $1,000 per Revenue Day respectively, as compared to approximately $1,300 per Revenue Day for both comparable periods of 2015, mainly due to lower fuel prices.

United States Operations

For the quarter ended June 30, 2016, Operating Days decreased by 59 days (or 42%) resulting in Drilling Rig Utilization of 18% compared to 31% in the same period of the prior year. For the first six months of 2016, Operating Days decreased by 195 days (or 55%) resulting in Drilling Rig Utilization of 18% compared to 39% in the same period of the prior year. Additionally, second quarter and year to date 2016 Operating Revenue per Revenue Day in the United States decreased by 12% and 11% to US$24,568 and US$25,832 respectively. The decrease in both utilization and pricing for the three and six months ended June 30, 2016 is due to the decreased commodity price environment, resulting in decreased activity and increased competition. In the Williston basin in North Dakota, where the Company operates in the United States, drilling rig counts decreased by approximately 65% to 26 active drilling rigs at June 30, 2016, as compared to 74 active drilling rigs at June 30, 2015.

Production Services

	Three months ended June 30			Six months ended June 30		
(stated in thousands)	**2016**	**2015**	**Change**	**2016**	**2015**	**Change**
Revenue						
Operating Revenue[(1)]	5,008	14,004	(64%)	14,894	39,577	(62%)
Third party charges	283	461	(39%)	1,019	1,848	(45%)
Total revenue	5,291	14,465	(63%)	15,913	41,425	(62%)
Expenses						
Operating						
Cash operating expenses	5,286	10,262	(48%)	13,796	27,943	(51%)
Depreciation	3,612	2,720	33%	5,587	5,986	(7%)
Stock based compensation	168	129	30%	238	165	44%
Total operating expenses	9,066	13,111	(31%)	19,621	34,094	(42%)
Administrative						
Cash administrative expenses	1,441	1,560	(8%)	3,007	3,357	(10%)
Depreciation	109	104	5%	222	208	7%
Stock based compensation	89	113	(21%)	190	167	14%
Total administrative expenses	1,639	1,777	(8%)	3,419	3,732	(8%)
Gross Margin[(1)]	5	4,203	(100%)	2,117	13,482	(84%)
Gross margin as a percentage of Operating Revenue	-	30%	(100%)	14%	34%	(59%)
Adjusted EBITDA[(1)]	(1,436)	2,643	(154%)	(890)	10,125	(109%)
Adjusted EBITDA as a percentage of Operating Revenue	(29%)	19%	(253%)	(6%)	26%	(123%)
Operating Earnings[(1)]	(5,157)	(181)	2,749%	(6,699)	3,931	(270%)
Capital expenditures	187	1,631	(89%)	793	4,440	(82%)
Well servicing rig fleet:						
Average	66	66	-	66	66	-
End of period	66	66	-	66	66	-
Service rig Operating Revenue per Service Hour[(1)]	589	794	(26%)	682	833	(18%)
Service Hours[(1)]	6,402	15,596	(59%)	16,788	40,308	(58%)
Service rig utilization [(1)]	11%	26%	(58%)	14%	34%	(59%)

(1) See "Non-IFRS measures" on page 17 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. For the quarter ended June 30, 2016, Operating Revenue decreased by $9.0 million (or 64%) to $5.0 million, compared to $14.0 million in the same period of the prior year. Operating Revenue for the six months ended June 30, 2016 decreased by $24.7 million (or 62%) to $14.9 million, compared to $39.6 million in the same period of the prior year. For the three months ended June 30, 2016, Eagle's contribution to Operating Revenue in the production services segment of $3.8 million compared to $12.4 million in the prior year, whereas Aero's contribution to Operating Revenue in the production services segment of $1.2 million compared to $1.6 million in the prior year. For the six months ended June 30, 2016, Eagle's contribution to Operating Revenue in the production services segment of $11.5 million compared to $33.6 million in the prior year, whereas Aero's contribution to Operating Revenue in the production services segment of $3.4 million compared to $6.0 million in the prior year. The decrease in Operating Revenue for both Eagle and Aero for the three and six months ended June 30, 2016, as compared to the same periods in 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 59% in the quarter ended June 30, 2016 to 6,402 (11% utilization) as compared to 15,596 (26% utilization) in the same period of the prior year. Service Hours for the first six months of 2016 decreased by 58% to

16,788 (14% utilization) as compared to 40,308 (34% utilization) in the same period of the prior year. The reduction in Service Hours for both the three and six months ended June 30, 2016 is due to lower demand across all geographic areas. Additionally, a number of Eagle's service rigs located in northern Alberta were impacted by wildfires in the second quarter of 2016, which limited activity in that geographic area. Operating Revenue per Service Hour decreased by 26% and 18% for the three and six months ended June 30, 2016 to $589 and $682 respectively, as compared to the same periods of the prior year due to competitive pricing pressure across all operating areas.

Adjusted EBITDA decreased by $4.0 million to a loss of $1.4 million during the second quarter of 2016 compared to $2.6 million in the same period of 2015. For the six months ended June 30, 2016, Adjusted EBITDA decreased by $11.0 million to a loss of $0.9 million from $10.1 million in the same period of the prior year. The lower Adjusted EBITDA for both the three and six months ended June 30, 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 three and six months ended June 30, 2016, cash administrative expenses, which exclude depreciation and stock based compensation, decreased by 8% and 10% respectively, to $1.4 million and $3.0 million respectively, as compared to the same periods of the prior year.

For the three and six months ended June 30, 2016, depreciation expense increased by 32% to $3.7 million and decreased by 6% to $5.8 million respectively. The increase for the three months ended June 30, 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 method resulted in depreciation expense increasing in the current period. The decrease for the six months ended June 30, 2016 is mainly due to higher activity in the prior year, offset partially by higher depreciation expense as a result of changing to straight line depreciation in the second quarter of 2016.

During the three months ended June 30, 2016, capital expenditures in the production services segment totaled $0.2 million and included maintenance capital and the purchase of additional rental equipment. During the six months ended June 30, 2016, capital expenditures in the production services segment totaled $0.8 million and included expansion capital of $0.5 million and maintenance capital of $0.3 million. Total capital expenditures for the three and six months ended June 30, 2016, represent an 89% and 82% decrease respectively, from the $1.6 million and $4.4 million incurred in the same periods of the prior year.

Corporate

	Three months ended June 30			Six months ended June 30		
(stated in thousands)	**2016**	**2015**	**Change**	**2016**	**2015**	**Change**
Administrative						
Cash administrative expenses	393	1,186	(67%)	1,495	2,748	(46%)
Depreciation	214	286	(25%)	435	531	(18%)
Stock based compensation	782	526	49%	1,528	1,182	29%
Total administrative expenses	1,389	1,998	(30%)	3,458	4,461	(22%)
Finance costs	5,798	4,763	22%	11,336	9,521	19%
Other items	398	(819)	(149%)	(1,732)	(1,413)	23%
Income taxes						
Current tax (recovery) expense	(408)	(2,286)	(82%)	(827)	(3,771)	(78%)
Deferred tax (recovery) expense	(7,826)	6,836	(214%)	(9,902)	14,743	(167%)
Total income taxes	(8,234)	4,550	(281%)	(10,729)	10,972	(198%)
Operating earnings[1]	(607)	(1,472)	(59%)	(1,930)	(3,279)	(41%)
Capital expenditures	-	10	(100%)	1	35	(97%)

(1) See "Non-IFRS measures" on page 17 of this MD&A.

Corporate cash administrative expenses, which exclude depreciation and stock based compensation, for the three and six months ended June 30, 2016 decreased by 67% and 46% to $0.4 million and $1.5 million respectively, as compared to the same periods in the prior year. The reduction for both the three and six months ended June 30, 2016 is due to one time employee related costs incurred in the prior year, in addition to lower headcount year over year and a 10% salary rollback implemented in the first quarter of 2016.

For the three and six month periods ended June 30, 2016, finance costs on a consolidated basis increased by $1.0 million and $1.8 million respectively, as compared to the same periods in the prior year. The increase is 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 8.6% throughout the first six months of June 30, 2016 and 8.4% throughout 2015.

Other items for the three and six months ended June 30, 2016 consist of gains and losses on foreign exchange, asset sales and derivatives.

For the three month period ended June 30, 2016, income taxes on a consolidated basis totaled a recovery of $8.2 million, representing an effective tax rate of 25.4%, as compared to an effective tax rate of negative 56.5% in the same period of 2015. For the six month period ended June 30, 2016, income taxes on a consolidated basis totaled a recovery of $10.7 million, representing an effective tax rate of 26.0%, as compared to 80.3% in the same period of 2015. The tax rate in the prior periods was impacted by the increase in the Alberta corporate tax rate to 12% in the second quarter of 2015 from 10% previously, while the effective tax rate for both the three and six months ended June 30, 2016 represents a more normalized period of operations. The current tax recovery for the three and six months ended June 30, 2016 of $0.4 and $0.8 million respectively, 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 June 30, 2016, Western had cash and cash equivalents of $57.4 million, a decrease of $1.0 million from December 31, 2015. Western's consolidated Net Debt balance at June 30, 2016 was $207.4 million. During the six months ended June 30, 2016, Western had Adjusted EBITDA of $1.4 million, a positive change in non-cash working capital of $10.3 million mainly due to the collection of prior year receivables, $2.5 million in foreign exchange gains, net income tax refunds of $1.3 million and proceeds on the sale of property and equipment of $0.4 million, which was offset by cash interest payments of $11.0 million, dividend payments of $3.7 million and capital expenditures of $1.3 million.

As at June 30, 2016, Western had a working capital balance of $60.3 million, a $10.4 million decrease as compared to December 31, 2015. Currently, the Company has $265.0 million in senior unsecured notes (the "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 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 maturity date of December 17, 2018 remains unchanged.

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.

The Credit Facilities are secured by the assets of Western and its subsidiaries. As at June 30, 2016, the Revolving Facility and the Operating Facility were undrawn. A summary of the Company's financial covenants as at June 30, 2016 is as follows:

	June 30, 2016 Covenants
Maximum Consolidated Senior Debt to Consolidated EBITDA Ratio (1)(2)	4.0:1.0 or less
Maximum Consolidated Debt to Consolidated Capitalization Ratio (1)	0.6:1.0 or less
Minimum Current Ratio (1)	1.15:1.0 or more

(1) See covenant definitions in Note 6 of the June 30, 2016 interim financial statements.

(2) Consolidated Senior Debt to Consolidated EBITDA adjusts to 3.0:1.0 or less subsequent to January 1, 2018.

At June 30, 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 including the 2016 capital budget.

For the three months ended June 30, 2016 the Company had two significant customers comprising 22.4% and 13.8% respectively, of the Company's total revenue. As at June 30, 2016, there was no trade receivable balance owing relating to one of the significant customers, while the other significant customer's trade receivable balance was 6.8% of the Company's total trade and other receivables balance. One of the previously mentioned customers was also a significant customer for the six months ended June 30, 2016, comprising 13.5% of the Company's total revenue. For the three months ended June 30, 2015, the Company had three significant customers comprising 12.2%, 11.5% and 10.4% respectively, of the Company's total revenue. One of these previously mentioned customers was also a significant customer for the six months ended June 30, 2015, comprising 11.8% of the Company's total revenue. The Company's significant customers may change from period to period.

Summary of Quarterly Results

In addition to other market factors, quarterly results of Western are markedly affected by weather patterns throughout its operating areas. Historically, the first quarter of the calendar year is very active, followed by a much slower second quarter due to what is known in the Canadian oilfield service industry as "spring breakup", where due to the spring thaw, provincial and county road bans restrict movement of heavy equipment. As a result of this, the variation of Western's results on a quarterly basis, particularly in the first and second quarters, can be significant quarter over quarter independent of other demand factors.

The following is a summary of selected financial information of the Company for the last eight completed quarters.

Three months ended **(stated in thousands, except per share amounts)**	**Jun 30, 2016**	**Mar 31, 2016**	**Dec 31, 2015**	**Sep 30, 2015**	**Jun 30, 2015**	**Mar 31, 2015**	**Dec 31, 2014**	**Sep 30, 2014**
Revenue	12,890	33,937	42,678	46,959	32,037	105,850	139,210	125,225
Operating Revenue[(1)]	12,393	32,200	40,458	44,350	30,719	100,958	129,181	117,960
Gross Margin[(1)]	2,703	8,867	13,372	14,285	10,403	47,891	57,826	50,570
Adjusted EBITDA[(1)]	(1,990)	3,364	7,573	8,080	4,255	40,637	50,419	42,782
Cash flow from operating activities	8,444	8,604	11,139	(530)	41,009	39,337	47,830	22,975
Net income (loss)	(24,172)	(6,319)	(55,010)	(76,816)	(12,607)	15,294	(8,164)	14,718
per share - basic	(0.33)	(0.09)	(0.75)	(1.04)	(0.17)	0.20	(0.11)	0.20
per share - diluted	(0.33)	(0.09)	(0.75)	(1.04)	(0.17)	0.20	(0.11)	0.19
Total assets	814,757	842,492	876,608	947,137	1,025,776	1,049,145	1,057,118	1,040,973
Long term debt	264,145	264,118	264,155	264,219	264,234	264,207	264,165	263,624
Dividends declared	-	-	3,682	5,526	5,591	5,593	5,614	5,615

(1) See "Non-IFRS measures" on page 17 of this MD&A.

Revenue and Adjusted EBITDA were impacted by lower commodity prices in 2015 and 2016, declining throughout the second half of 2015, and into the first half of 2016. Prior to the second quarter of 2015, revenue was significantly higher due to greater activity levels in both the contract drilling and production services segments throughout 2014 as WTI averaged US$97/bbl and US$73/bbl respectively, in the third and fourth quarters of 2014, and AECO averaged approximately $4/mcf, in both the third and fourth quarters of 2014. In comparison, WTI averaged US$48/bbl, US$58/bbl, US$46/bbl, US$42/bbl in the first, second, third and fourth quarters of 2015 respectively, and AECO averaged approximately $3/mcf throughout the first, second and third quarters of 2015 and $2/mcf in the fourth quarter of 2015.

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 oil and natural gas prices. In addition, the Company recorded impairments in the fourth quarter of 2014 totaling $29.9 million, $71.3 million in the third quarter of 2015 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 June 30, 2016 are as follows:

(stated in thousands)	2016	2017	2018	2019	2020	Thereafter	Total
Senior Notes	$ -	$ -	$ -	$ 265,000	$ -	$ -	$ 265,000
Senior Notes interest	10,406	20,869	20,869	10,520	-	-	62,664
Trade payables and other current liabilities (1)	9,027	-	-	-	-	-	9,027
Operating leases	2,120	3,887	3,706	3,550	3,525	10,632	27,420
Purchase commitments	385	-	-	-	-	-	385
Other long term debt	423	719	84	-	-	-	1,226
Total	$ 22,361	$ 25,475	$ 24,659	$ 279,070	$ 3,525	$ 10,632	$ 365,722

(1) Trade payables and other current liabilities exclude the Company's interest accrued as at June 30, 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 three months ended June 30, 2016.

Outstanding Share Data

	July 26, 2016	June 30, 2016	December 31, 2015
Common shares outstanding	73,649,515	73,648,484	73,646,292
Restricted share units outstanding	727,310	725,740	759,504
Stock options outstanding	5,699,264	5,722,298	6,058,906

Off Balance Sheet Arrangements

As at June 30, 2016, Western had no off balance sheet arrangements in place.

Transactions with Related Parties

During the three and six months ended June 30, 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 on the financial asset in a transaction in which substantially all the risks and rewards of ownership of the financial asset are transferred. The Company derecognizes a financial liability when its contractual obligations are discharged, cancelled or expired.

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

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

The Company has the following non-derivative financial assets:

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

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

Interest Rate Risk

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

Foreign Exchange Risk

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

Liquidity Risk

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

Disclosure Controls and Procedures and Internal Controls Over Financial Reporting

As Western's common shares trade on the Toronto Stock Exchange, per National Instrument 52-109, CERTIFICATION OF DISCLOSURE IN ISSUERS' ANNUAL AND INTERIM FILINGS, the Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") of the Company have certified as at June 30, 2016 that they have designed or caused to be designed under their supervision, disclosure controls and procedures ("DC&P") to provide reasonable assurance that: (i) material information relating to the Company, including its consolidated subsidiaries, is made known to the CEO and the CFO by others within those entities, particularly during the periods in which the interim filings of the Company are being prepared; and (ii) information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation.

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

During the three months ended June 30, 2016, there were no changes in internal control over financial reporting that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Critical Accounting Estimates

This MD&A of the Company's financial condition and results of operations is based on the condensed consolidated financial statements for the three and six months ended June 30, 2016, which were prepared in accordance with IFRS. The presentation of these financial statements in conformity with IFRS requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of provisions at the date of the financial statements and the reported amounts of revenue and expenses during the reporting period. These estimates and judgements are based on historical experience and on various assumptions that are believed to be reasonable under the circumstances. Anticipating future events cannot occur with absolute certainty, therefore these estimates may change as new events occur, more experience is acquired and as the Company's operating environment changes. The Company's key accounting estimates relate to impairment, depreciation, income taxes and the determination of the fair value of share based payments.

The accounting estimates believed to be the most difficult, subjective or require complex judgements and which are the most critical to the reporting of results of operations and financial positions of the Company are as follows:

Impairment

The Company assesses impairment at each reporting date by evaluating conditions specific to the organization that may lead to impairment of assets. Where an impairment indicator exists, or annually in the case of goodwill, the recoverable amount of the asset or cash generating unit ("CGU") is determined using a value-in-use calculation, where estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset or CGU. The application of judgement is required in determining if an impairment test is required. 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 June 30, 2016, the Company completed its assessments of impairment and determined there were no indicators of property and equipment impairment. There were no reversals of previous property and equipment impairment losses during the three or six months ended June 30, 2016.

Depreciation

The Company's property and equipment is depreciated based upon estimates of useful lives and salvage values. These estimates are based on industry practice and the Company's own experience and may change as more experience is gained, market conditions shift or new technological advancements are made.

The componentization of the Company's property and equipment, specifically drilling rig equipment and well servicing rig equipment, is based on management's judgment as to which components constitute a significant cost in relation to the entire item. The componentization process also requires management's judgement in assessing whether individual components have similar consumption patterns and useful lives.

Income taxes

Preparation of the consolidated financial statements involves determining an estimate of, or provision for, income taxes in each of the jurisdictions in which the Company operates. The process also involves making an estimate of taxes currently payable and taxes expected to be payable or recoverable in future periods, referred to as deferred taxes. Deferred taxes result from the effects of temporary differences due to items that are treated differently for tax and accounting purposes. The tax effects of these differences are reflected in the consolidated balance sheet as deferred tax assets and liabilities. An assessment must also be made to determine the likelihood that the Company's future taxable income will be sufficient to permit the recovery of deferred tax assets. To the extent that such recovery is not probable, recognized deferred tax assets must be reduced to their recoverable amount. Judgement is required in determining the provision for income taxes and recognition of deferred tax assets and liabilities. Management must also exercise judgement in its assessment of continually changing tax interpretations, regulations and legislation, to ensure deferred tax assets and liabilities are complete and fairly presented. The effects of differing assessments and applications could be material.

Share based payments

Stock based compensation expense associated with stock options and equity settled restricted share units is based on various assumptions, using a Black-Scholes option pricing model to calculate an estimate of fair value. The inputs into the model include interest rates, expected life, expected volatility, expected forfeitures, expected dividends and share prices which all affect the estimated fair value calculated. Determining the estimated expected life, volatility, forfeitures and expected dividends requires management's judgement.

Business Risks

For a comprehensive listing of the Company's business risks please see the most recent Annual Information Form for the year ended December 31, 2015 as filed on SEDAR at www.sedar.com. The Company's primary business risks as at June 30, 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 oil and natural gas and environmental protection for the oil and gas industry as a whole. Risks impacting the crude oil and natural gas exploration and production industry, including the ability of oil and gas companies to accumulate capital or variations in their exploration and development budgets, may also affect the Company's business. The exact impact of these risks cannot be accurately predicted.
- The current low commodity price environment is expected to continue throughout 2016. 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 facility and under its Senior Note indenture, which in turn could restrict the Company's ability to access its credit facility, pay distributions and incur additional debt in the future.
- The Company's exploration and production customer's 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. The direct or indirect costs of greenhouse gas emission reduction regulations 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 customer's 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.
- The Company's business is subject to the operating risks inherent to the oilfield service industry. On occasion, substantial liabilities to third parties may be incurred. The Company will have the benefit of insurance maintained by it and industry standard contracts, however, it may become liable for damages against which it cannot adequately insure or against which it may elect not to insure because of high costs or other reasons.

- The oilfield service industry has experienced a high degree of invention and innovation. It is possible that new technology will be developed which will compete with the Company's products and services.
- A portion of the operations of the Company are in the United States which subject the Company to currency fluctuations and different tax and regulatory laws.
- 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.

Non-IFRS Measures

Western uses certain measures in this MD&A which do not have any standardized meaning as prescribed by IFRS. These measures, which are derived from information reported in the condensed consolidated financial statements, may not be comparable to similar measures presented by other reporting issuers. These measures have been described and presented in this MD&A in order to provide shareholders and potential investors with additional information regarding the Company. These Non-IFRS measures are identified and defined as follows:

Operating Revenue

Management believes that in addition to revenue, Operating Revenue is a useful supplemental measure as it provides an indication of the revenue generated by Western's principal operating activities, excluding flow through third party charges such as rig fuel, which at the customer's request may be paid for initially by Western, then recharged in its entirety to Western's customers.

Gross Margin

Management believes that in addition to net income, Gross Margin is a useful supplemental measure as it provides an indication of the results generated by Western's principal operating activities prior to considering administrative expenses, depreciation and amortization, how those activities are financed, the impact of foreign exchange, how the results are taxed, how funds are invested, and how non-cash items and one-time gains and losses affect results.

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

	Three months ended June 30		**Six months ended June 30**	
(stated in thousands)	**2016**	**2015**	**2016**	**2015**
Operating Revenue				
Drilling	7,388	16,746	29,712	92,353
Production services	5,008	14,004	14,894	39,577
Less: inter-company eliminations	(3)	(31)	(13)	(253)
	12,393	**30,719**	**44,593**	**131,677**
Third party charges	497	1,318	2,234	6,210
Revenue	**12,890**	**32,037**	**46,827**	**137,887**
Less: operating expenses	(27,814)	(28,710)	(60,303)	(100,185)
Add:				
Depreciation - operating	17,329	6,884	24,640	20,249
Stock based compensation - operating	298	192	406	343
Gross Margin	**2,703**	**10,403**	**11,570**	**58,294**

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 condensed 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 June 30		Six months ended June 30	
(stated in thousands)	**2016**	**2015**	**2016**	**2015**
Net income (loss)	**(24,172)**	**(12,607)**	**(30,491)**	**2,687**
Add:				
Finance costs	5,798	4,763	11,336	9,521
Income tax (recovery) expense	(8,234)	4,550	(10,729)	10,972
Depreciation - operating	17,329	6,884	24,640	20,249
Depreciation - administrative	406	485	826	914
EBITDA	**(8,873)**	**4,075**	**(4,418)**	**44,343**
Add:				
Stock based compensation - operating	298	192	406	343
Stock based compensation - administrative	962	807	1,893	1,619
Loss on asset decommissioning	5,225	-	5,225	-
Other items	398	(819)	(1,732)	(1,413)
Adjusted EBITDA	**(1,990)**	**4,255**	**1,374**	**44,892**
Subtract:				
Depreciation - operating	(17,329)	(6,884)	(24,640)	(20,249)
Depreciation - administrative	(406)	(485)	(826)	(914)
Operating Earnings (Loss)	**(19,725)**	**(3,114)**	**(24,092)**	**23,729**

Net Debt

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

(stated in thousands)	**June 30, 2016**	**December 31, 2015**
Long term debt	264,145	264,155
Current portion of long term debt	647	761
Less: cash and cash equivalents	(57,397)	(58,445)
Net Debt	**207,395**	**206,471**

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 of 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”);
- Western Canadian Sedimentary Basin (“WCSB”); and
- Western Canadian Select (“WCS”).

Forward-Looking Statements and Information

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

In particular, forward-looking information in this MD&A includes, but is not limited to, statements relating to future declaration of dividends; commodity pricing; the future demand for and utilization of 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 2016; the Company’s liquidity needs including the ability of current capital resources to cover Western’s financial obligations and the 2016 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 2016 if market conditions, including customer demand, continue to change; 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; expectations as to the increase in crude oil transportation capacity through rail and pipeline development; expectations as to the necessary approvals for liquefied natural gas projects being obtained; the expectation of continued foreign investment into the Canadian crude oil and natural gas industry; the expectation that producer spending constraints will continue to be a large challenge facing the Company in 2016; 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; the development of liquefied natural gas projects, crude oil transport and pipeline approval and development; the Company’s ability to finance its operations; the effects of seasonal and weather conditions on operations and facilities; the competitive environment to which the various business segments are, or may be, exposed in all aspects of their business; the ability of the Company’s various business segments to access equipment (including spare parts and new technologies); changes in laws or regulations; currency exchange fluctuations; the ability of the Company to attract and retain skilled labour and qualified management; the ability to retain and attract significant customers; and other unforeseen conditions which could impact the use of services supplied by Western including Western’s ability to respond to such conditions.

Although Western believes that the expectations and assumptions on which such forward-looking statements and information are based 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 2016 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.