FINANCIAL HIGHLIGHTS

(000's except per share and per unit amounts)	Three months ended June 30, 2017	2016	% Change	Six months ended June 30, 2017	2016	% Change
FINANCIAL						
Total revenue [1]	**17,810**	11,343	57	**37,164**	27,115	37
Comprehensive loss	**(94,899)**	(12,212)	677	**(89,648)**	(18,100)	395
Per share – basic and diluted	**(0.39)**	(0.06)	550	**(0.37)**	(0.09)	311
Funds flow from operations [2] [5]	**6,781**	1,554	336	**14,127**	1,240	1,039
Per share, basic and diluted	**0.03**	0.01	200	**0.06**	0.01	500
Capital expenditures, before acquisitions (dispositions)	**2,536**	958	165	**17,582**	8,320	111
Capital expenditures, including acquisitions (dispositions)	**2,536**	1,096	131	**17,582**	8,247	113
Net debt [3]	**(67,862)**	(73,507)	(8)	**(67,862)**	(73,507)	(8)
Weighted average shares outstanding - basic & diluted	**245,528**	211,028	16	**245,528**	211,028	16
OPERATING						
Production volumes						
Natural gas (Mcf/d)	**42,719**	40,127	6	**43,959**	46,190	(5)
Crude oil (bbls/d)	**224**	178	26	**352**	198	78
Natural gas liquids (bbls/d)	**239**	244	(2)	**255**	240	6
Condensate (bbls/d)	**919**	748	23	**867**	904	(4)
Total (boe/d)	**8,502**	7,857	8	**8,800**	9,040	(3)
Sales prices						
Natural gas, including realized hedges ($/Mcf)	**2.83**	1.73	64	**2.81**	1.94	45
Crude oil and condensate, including realized hedges ($/bbl)	**60.11**	54.01	11	**61.37**	49.76	23
Natural gas liquids ($/bbl)	**26.11**	21.50	21	**28.12**	19.13	47
Total ($/boe)	**23.02**	15.86	45	**23.33**	16.48	42
Netback ($/boe)						
Price, including realized hedges	**23.02**	15.86	45	**23.33**	16.48	42
Royalties	**(1.20)**	0.17	806	**(1.43)**	(0.27)	430
Transportation	**(2.13)**	(1.08)	97	**(1.86)**	(1.13)	65
Operating costs	**(7.53)**	(8.13)	(7)	**(7.92)**	(9.13)	(13)
Operating netback	**12.16**	6.82	78	**12.12**	5.95	104
General and administrative [5]	**(1.53)**	(2.51)	(39)	**(1.40)**	(3.37)	(58)
Interest [4]	**(1.98)**	(2.24)	(12)	**(1.97)**	(1.93)	2
Cash netback	**8.65**	2.07	318	**8.75**	0.65	1,246

(1) Total revenue is presented gross of royalties and includes realized gains (loss) on commodity contracts.

(2) Funds flow from operations is calculated as cash flow from operating activities before adjustments for decommissioning liabilities expenditures and net changes in non-cash working capital.

(3) Net debt is calculated as working capital (deficiency) less the principal value of senior notes.

(4) Represents finance costs less amortization on transaction costs and accretion expense on senior notes and provisions.

(5) For the three and six months ended June 30, 2016, general and administrative expenses and funds flow from operations includes $201 and $1,931 in restructuring charges (2017 - $nil).

MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis ("MD&A") of the financial and operating results of Cequence Energy Ltd. ("Cequence" or the "Company") should be read in conjunction with the Company's unaudited condensed consolidated financial statements (the "consolidated financial statements") and related notes for the three and six months ended June 30, 2017 as well with the audited consolidated financial statements (the "annual financial statements ") and related notes for the years ended December 31, 2016 and 2015.

Additional information relating to the Company, including its MD&A for the prior year and the annual information form is available on SEDAR at www.sedar.com.

This MD&A is dated August 10, 2017.

BASIS OF PRESENTATION

The consolidated financial statements and comparative information have been prepared in accordance with International Accounting Standard ("IAS") 34, "Interim Financial Reporting". The financial information presented reflects the consolidated financial statements of Cequence.

The reporting and the measurement currency is the Canadian dollar. For the purpose of calculating unit costs, natural gas is converted to a barrel of oil equivalent ("boe") using six thousand cubic feet of natural gas equal to one barrel of oil unless otherwise stated. The term barrel of oil equivalent (boe) may be misleading, particularly if used in isolation. A boe conversion ratio for gas of 6 Mcf:1 boe is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

For the six months ended June 30, 2017 the ratio between the average price of West Texas Intermediate ("WTI") crude oil at Cushing and NYMEX natural gas was approximately 16:1 ("Value Ratio"). The Value Ratio is obtained using the first six months of 2017 WTI average price of $49.91 (US$/Bbl) for crude oil and the first six months of 2017 NYMEX average price of $3.10 (US$/MMbtu) for natural gas. This Value Ratio is significantly different from the energy equivalency ratio of 6:1 and using a 6:1 ratio would be misleading as an indication of value.

Unless otherwise stated and other than per unit items, all figures are presented in thousands.

NON-GAAP MEASUREMENTS

Within the MD&A references are made to terms commonly used in the oil and gas industry, including operating netback, cash netback, net debt, funds flow from (used in) operations and total revenue.

Operating netback is not defined by IFRS in Canada and is referred to as a non-GAAP measure. Operating netback equals per boe revenue less royalties, operating costs and transportation costs. Management utilizes this measure to analyze operating performance of its assets and operating areas, compare results to peers and to evaluate drilling prospects.

Cash netback is not defined by IFRS in Canada and is referred to as a non-GAAP measure. Cash netback equals operating netback less per boe general and administrative expenses and interest expense. Management utilizes this measure to analyze the Company's per boe profitability for future capital investment or repayment of debt after considering cash costs not specifically attributable to its assets or operating areas.

Net debt is a non-GAAP measure that is calculated as working capital (deficiency) less the principal value of senior notes. For this calculation, Cequence uses the principal value of the senior notes rather than the carrying value on the statement of financial position as it reflects the amount that will be repaid upon maturity. Cequence uses net debt as it provides an estimate of the Company's assets and obligations expected to be settled in cash.

Funds flow from (used in) operations is a non-GAAP term that represents cash flow from operating activities before adjustments for decommissioning liabilities expenditures and net changes in non-cash working capital. The Company evaluates its performance based on earnings and funds flow from (used in) operations. The Company considers funds flow from (used in) operations a key measure as it demonstrates the Company's ability to generate the cash flow necessary to fund future growth through capital investment and to repay debt. The Company's calculation of funds flow from (used in) operations may not be comparable to that reported by other companies. Funds flow from (used in) operations per share is calculated using the same weighted average number of shares outstanding used in the calculation of comprehensive income (loss) per share.

Total revenue equals production revenue gross of royalties and including realized gain (loss) on commodity contracts. Management utilizes this measure to analyze revenue and commodity pricing and its impact on operating performance.

Non-GAAP financial measures do not have a standardized meaning prescribed by IFRS and are therefore unlikely to be comparable to similar measures presented by other issuers.

DESCRIPTION OF THE BUSINESS

Cequence is engaged in the exploration for and the development of oil and natural gas reserves. Cequence's primary focus is the development of its Simonette asset in the Alberta Deep Basin. The Company also has assets in Northeast British Columbia and the Peace River Arch of Alberta. The common shares of Cequence trade on the Toronto Stock Exchange under the symbol CQE.

Commodity prices in the first six months of 2017 improved significantly from the comparable period in 2016 and the Company's average sales price before hedging increased 79 percent. Combined with the improvements achieved in both operating and general and administrative costs, funds flow from operations was $6,781 in the second quarter and $14,127 year to date, an increase of 336% and 1039%, respectively, from the same periods in 2016. Despite the improved financial performance, the Company remains cautious on the outlook for commodity prices over the next twelve months as forward commodity prices remain low.

The Company is reducing its annual capital expenditure guidance to $24,000 from $29,000 to correspond with lower expected commodity prices and funds flow from operations. Drilling operations are set to commence in December with 3.0 (2.0 net) Dunvegan wells that are expected to be on production in March 2018. To reduce significant access costs the Company has elected to defer the start of its winter drilling program until December 2017. Drilling activity for the remainder of the winter is not expected to be finalized until the fourth quarter of 2017.

December 31, 2017 net debt is forecast to be approximately $65,000 (December 31, 2016 - $64,031) or 2.8 times trailing annual funds flow (December 31, 2016 - 5.7 times). Financial leverage has significantly improved over recent quarters as the Company prudently managed total debt levels, capital spending and costs as commodity prices remained low.

FINANCIAL AND OPERATING RESULTS

PRODUCTION

	Three months ended June 30, 2017	2016	Six months ended June 30, 2017	2016
Natural gas (Mcf/d)	**42,719**	40,127	**43,959**	46,190
Crude oil (bbls/d)	**224**	178	**352**	198
Natural gas liquids (bbls/d)	**239**	244	**255**	240
Condensate (bbls/d)	**919**	748	**867**	904
Total (boe/d)	**8,502**	7,857	**8,800**	9,040
Total production (boe)	**773,666**	714,975	**1,592,777**	1,645,248

Production for the three and six months ended June 30, 2017 averaged 8,502 boe/d and 8,800 boe/d compared to production of 7,857 boe/d and 9,040 boe/d, respectively in 2016. Sequentially, second quarter production decreased 7 percent from the first quarter of 2017. Wet weather conditions in the Simonette field reduced the ability to truck out oil and condensate and perform certain field operations. Production volumes were negatively impacted by approximately 850 boe/d in the second quarter.

The Company has deferred the start of its Duvegan drilling to December 2017 and does not anticipate any further production additions until Q1 2018. As a result of the deferred drilling program and weather related downtime, 2017 annual production guidance has been reduced to 8,500 – 8,700 boe/d from between 9,000 to 9,200 boe/d.

PRODUCTION REVENUE

$(000's)	Three months ended June 30, 2017	2016	Six months ended June 30, 2017	2016
Sales of natural gas, oil and condensate	**17,308**	8,512	**36,908**	21,318
Royalties	**(927)**	125	**(2,282)**	(440)
Production revenue	**16,381**	8,637	**34,626**	20,878

Production revenue was $16,381 and $34,626 in the three and six months ended June 2017 compared to $8,637 and $20,878 in 2016. The increase in year to date production revenue is attributable to a 79 percent increase in realized sales prices before hedging offset by a three percent decrease in production and increased royalty expense in 2017.

TOTAL REVENUE AND PRICING

The following tables present total revenue which is a non-GAAP financial measure, with no standardized meaning under the Company's GAAP and therefore may not be comparable to similar measures presented by other issuers:

			Three months ended June 30,		
$(000's)	Natural gas	Crude oil and condensate	Natural gas liquids	**2017 Total**	2016 Total
Sales of natural gas, oil and condensate	10,660	6,080	568	**17,308**	8,512
Realized gain on commodity contracts	330	172	–	**502**	2,831
Total revenue [1]	10,990	6,252	568	**17,810**	11,343

[1] Refer to non-GAAP measurements.

$(000's)	Natural gas	Crude oil and condensate	Natural gas liquids	Six months ended June 30, **2017 Total**	2016 Total
Sales of natural gas, oil and condensate	22,298	13,314	1,296	**36,908**	21,318
Realized gain on commodity contracts	32	224	–	**256**	5,797
Total revenue [1]	22,330	13,538	1,296	**37,164**	27,115

[1] Refer to non-GAAP measurements.

Total revenue was $17,810 in the second quarter of 2017 compared to $11,343 in 2016. The increase in revenue is attributable to a eight percent decrease in production and a 45 percent increase in realized sales prices including hedging. For the six months ended June 30, 2017, total revenue increased 37 percent to $37,164 from $27,115 in the comparable period of 2016. The increase in revenue is attributable to the 42 percent increase in realized sales prices after hedging and three percent decrease in production.

	Three months ended June 30,		Six months ended June 30,	
	2017	2016	**2017**	2016
Average prices				
Natural gas ($/Mcf)	**2.74**	1.02	**2.80**	1.36
Realized natural gas hedges ($/Mcf)	**0.09**	0.71	**0.01**	0.58
Natural gas including hedges ($/Mcf)	**2.83**	1.73	**2.81**	1.94
Crude oil and condensate ($/bbl)	**58.46**	51.17	**60.36**	45.05
Realized crude oil hedges ($/bbl)	**1.65**	2.84	**1.01**	4.71
Crude oil and condensate including hedges ($/bbl)	**60.11**	54.01	**61.37**	49.76
Natural gas liquids ($/bbl)	**26.11**	21.50	**28.12**	19.13
Average sales price before hedges ($/boe)	**22.37**	11.91	**23.17**	12.96
Average sales price including hedges ($/boe)	**23.02**	15.86	**23.33**	16.48
Benchmark pricing				
AECO-C spot (CDN$/Mcf)	**2.78**	1.40	**2.74**	1.61
NYMEX HH Gas (US$/Mcf)	**3.14**	2.25	**3.10**	2.11
WTI crude oil (US$/bbl)	**48.11**	45.53	**49.91**	39.47
Edmonton par price (CDN$/bbl)	**61.51**	55.10	**63.11**	53.99
US$/CDN$ exchange rate	**0.74**	0.78	**0.75**	0.75

For the three and six months ended June 30, 2017, benchmark AECO natural gas prices averaged $2.78/mcf and $2.74/mcf a significant increase from $1.40/mcf and $1.61/mcf in 2016, respectively. Year to date benchmark prices are 70 percent higher than 2016 due to lower North American natural gas production growth, increased U.S. natural gas exports and increased natural gas usage for power generation during periods of low prices. AECO basis differentials to NYMEX have remained wide due to the high marginal transportation costs associated with clearing Western Sedimentary Basin supply.

The Company realized natural gas prices before hedging for three and six months ended June 30, 2017 of $2.74/mcf and $2.80/mcf compared to $1.02/mcf and $1.36/mcf in 2016, respectively. The Company's average natural gas price realization in the second quarter of 2017 was a one percent discount to AECO compared to a discount of 27 percent in 2016 reflecting an improvement in the cost of the company's marketing contracts from prior year.

The Company has a contracted firm transportation or sales contracts through the month of August 2017 for all of its expected natural gas sales volumes. The Company has approximately 35,500 GJ/d of firm service for the period between July 1, 2017 and October 31, 2017 and 10,000 GJ/d for the period between November 1, 2017 and March 31, 2018. Beginning, April 1, 2018 the Company will have 35,000 GJ/d of firm service. The Company continues to rely on interruptible service on both the Alliance and TCPL pipeline systems to deliver incremental production volumes to market. Interruptible transportation service is expected to be more volatile than firm service which may result in higher transportation charges, increased realized priced differentials or inconsistent production times until additional firm service is contracted.

For the three and six months ended June 30, 2017, benchmark Edmonton par crude oil prices increased 12 percent and 17 percent from 2016. Benchmark condensate prices for the three and six months ended June 30, 2017 sold at a four percent and six percent premium to Edmonton par. Crude oil and condensate prices before hedges for the three and six months ended June 30, 2017 were $58.46/bbl and $60.36/bbl up 14 percent and 34 percent respectively from the same period in 2016. Natural gas liquids prices for the three and six months ended June 30, 2017 were $26.11/bbl and $28.12/bbl up 21 percent and 47 percent from the same time period in 2016.

COMMODITY PRICE MANAGEMENT

$(000's)	**Three months ended June 30, 2017**	2016	Six months ended June 30, **2017**	2016
Realized gain on commodity contracts	**502**	2,831	**256**	5,797
Unrealized gain (loss) on commodity contracts	**2,152**	(7,154)	**7,610**	(3,964)
Total	**2,654**	(4,323)	**7,866**	1,833

Cequence has a commodity price risk management program which provides the Company flexibility to enter into derivative and physical commodity contracts to protect future cash flows for planned capital expenditures against an unpredictable commodity price environment.

The fair value of the commodity contracts outstanding at June 30, 2017 was a current asset of $2,961 (December 31, 2016 - current liability of $4,491 and non-current liability of $159). Cequence has the following natural gas and crude oil hedges as at the date of this MD&A:

Term	Product	Type	Average Volume (GJ/d)	Average Price ($/GJ)	Average Price ($/mcf)[1]	Basis
July 1, 2017 to September 30, 2017	Gas	Swap	27,500	$2.80	$3.00	AECO
October 1, 2017 to December 31, 2017	Gas	Swap	20,027	$2.76	$2.96	AECO
January 1, 2018 to March 31, 2018	Gas	Swap	12,500	$3.01	$3.22	AECO

(1) The conversion from GJ to Mcf is based on estimated average natural gas heat content of 37.8 MJ/m^3

Term	Product	Type	Average Volume (bbl/d)	Average Price (Cdn$/bbl)	Basis
July 1, 2017 to December 31, 2017	Oil	Swap	400	$69.58	WTI
January 1, 2018 to March 31, 2018	Oil	Swap	300	$67.58	WTI
April 1, 2018 to June 30, 2018	Oil	Swap	300	$61.22	WTI

OPERATING NETBACK

$(boe)	**Three months ended June 30, 2017**	2016	**Six months ended June 30, 2017**	2016
Total revenue [1]	**23.02**	15.86	**23.33**	16.48
Royalty expense	**(1.20)**	0.17	**(1.43)**	(0.27)
Transportation expense	**(2.13)**	(1.08)	**(1.86)**	(1.13)
Operating costs	**(7.53)**	(8.13)	**(7.92)**	(9.13)
Operating netback, $/boe	**12.16**	6.82	**12.12**	5.95
Operating netback, excluding realized hedges , $/boe	**11.51**	2.87	**11.96**	2.42

(1) Total revenue is presented gross of royalties and includes realized gain (loss) on commodity contracts.

(2) See Non-GAAP measures for definition of operating netback.

Cequence's operating netback per boe, excluding realized hedging for the three months ended June 30, 2017 increased 301 percent. Including realized hedges, operating netbacks per boe increased by 78 percent. For the six months ended June 30, 2017 operating netback per boe, excluding realized hedging increased 394 percent. The increase in operating netbacks was driven by higher commodity prices and lower operating costs.

ROYALTY EXPENSE

$(000's)	**Three months ended June 30, 2017**	2016	**Six months ended June 30, 2017**	2016
Crown	**495**	(342)	**1,242**	(236)
Freehold / Overriding	**432**	217	**1,040**	676
Total royalties	**927**	(125)	**2,282**	440
Royalties as a percentage of revenue, before hedging	**5%**	(1%)	**6%**	2%
Per unit of production ($/boe)	**1.20**	(0.17)	**1.43**	0.27

Royalties as a percentage of revenue, before hedging for the three and six months ended June 30, 2017 was higher than prior year at five percent and six percent, respectively. Royalties increased from prior year as commodity prices have recovered from historic lows in the first half of 2016.

OPERATING COSTS

$(000's)	**Three months ended June 30, 2017**	2016	**Six months ended June 30, 2017**	2016
Operating costs	**5,829**	5,812	**12,608**	15,024
Per unit of production ($/boe)	**7.53**	8.13	**7.92**	9.13

In 2016, the Company focused on reducing field operating costs which resulted in improvements to chemical usage, trucking costs, field rentals and water handling. Operating costs for the three and six months ended June 30, 2017, were $7.53/boe and $7.92/boe, respectively, compared to $8.13/boe and $9.13/boe in 2016. The Company estimates annual operating costs to be approximately $8.40/boe.

TRANSPORTATION EXPENSE

$(000's)	Three months ended June 30, 2017	2016	Six months ended June 30, 2017	2016
Transportation	**1,650**	774	**2,958**	1,866
Per unit of production ($/boe)	**2.13**	1.08	**1.86**	1.13

Transportation expense for the second quarter of 2017 was $2.13/boe an increase of 97 percent from the comparative period in 2016. For the six months ended June 30, 2017, transportation expense was $1.86/boe an increase of 65 percent from $1.13/boe in 2016. The increase relates to a firm service natural gas transportation contract that commenced in July 2016, and increased oil and condensate trucking volumes in 2017 with higher costs in the second quarter of 2017 due to wet field operating conditions.

GENERAL AND ADMINISTRATIVE EXPENSES

$(000's)	Three months ended June 30, 2017	2016	Six months ended June 30, 2017	2016
G&A expenses, prior to restructuring charges	**1,223**	1,615	**2,457**	3,728
Restructuring charges	**–**	201	**–**	1,931
G&A expenses	**1,223**	1,816	**2,457**	5,659
Administrative and capital recovery	**(41)**	(19)	**(225)**	(114)
Total G&A expenses	**1,182**	1,797	**2,232**	5,545
Per unit of production, excluding restructuring charges ($/boe)	**1.53**	2.23	**1.40**	2.20
Per unit of production ($/boe)	**1.53**	2.51	**1.40**	3.37

In 2016, the Company made several improvements to its G&A cost structure including a significant staff reduction and relocation of the Company's office after its lease expired. For the six months ended June 30, 2017, G&A expenses, prior to restructuring charges decreased by $1,271 or 34 percent from 2016. G&A expenses are forecast to be approximately $5,000 or $1.60/boe in 2017.

FINANCE COSTS

	Three months ended June 30, 2017	2016	Six months ended June 30, 2017	2016
Interest and standby fees expense on credit facilities	**81**	157	**243**	279
Interest expense and standby fees on senior notes	**1,453**	1,446	**2,887**	2,894
Amortization of transaction costs	**108**	97	**214**	192
Accretion expense on senior notes	**83**	75	**164**	149
Accretion expense on provisions	**208**	193	**428**	402
Total finance costs	**1,933**	1,968	**3,936**	3,916
Per unit of production ($/boe)	**2.50**	2.75	**2.47**	2.38
Interest per unit of production ($/boe)	**1.98**	2.24	**1.97**	1.93

Finance costs for the three and six months ended June 30, 2017 were $1,933 and $3,936 compared to $1,968 and $3,916 in 2016. The Company remains undrawn on its senior credit facility other than letters of credit of $4,182.

OTHER INCOME

$(000's)	Three months ended June 30, 2017	2016	Six months ended June 30, 2017	2016
Gain on sale of property and equipment	**(60)**	–	**(120)**	–
Interest income	**(21)**	(11)	**(60)**	(38)
Other	**(72)**	(61)	**(113)**	(135)
Total other income	**(153)**	(72)	**(293)**	(173)

DEPLETION, DEPRECIATION AND IMPAIRMENT

$(000's)	Three months ended June 30, 2017	2016	Six months ended June 30, 2017	2016
Depletion and depreciation expense	**6,927**	6,049	**13,858**	14,146
Impairment loss	**96,200**	–	**96,200**	–
Total depletion, depreciation and impairment	**103,127**	6,049	**110,058**	14,146
Per unit of production ($/boe)	**133.30**	8.46	**69.10**	8.60
Per unit of production, excluding impairment ($/boe)	**8.95**	8.46	**8.70**	8.60

Depletion and depreciation expense for the three and six months ended June 30, 2017 was $6,927 ($8.95/boe) and $13,858 ($8.70/boe). Depletion and depreciation rates are comparable to the prior year.

At June 30, 2017, the continued decline in crude oil and natural gas prices and the further reduction in the Company's enterprise value were considered to be an indicator of potential impairment and impairment tests were conducted. The Company uses the price deck of its third-party reserves evaluator in its impairment test. Forward looking commodity prices for the first 8 years of the GLJ price deck have decreased by an average of 14% for natural gas and 16% for crude oil from December 31, 2016. In addition, the Company's stock price has declined by 50% from December 31, 2016.

Impairment is recognized when the carrying value of an asset or cash generating units ("CGU") exceeds its recoverable amount which is determined as the higher of its value in use or fair value less cost to sell. Aggregate impairment expense recognized for the six months ended June 30, 2017 was $96,200. The impairments are largely a result of the decrease in commodity prices reducing the economic value of the Company's oil and gas reserves.

Estimates of impairment are sensitive to changes in any of the key judgments, such as a revision in reserves or resources, a change in forecast commodity prices, expected royalties, required future development expenditures or expected future production costs, which could decrease or increase the recoverable amounts of assets and result in additional impairment charges or recovery of impairment charges.

$(000's)	Three months ended June 30, 2017	2016	Six months ended June 30, 2017	2016
Northeast British Columbia	**–**	–	**–**	–
Peace River Arch	**2,200**	–	**2,200**	–
Deep Basin	**94,000**	–	**94,000**	–
Total	**96,200**	–	**96,200**	–

SHARE BASED PAYMENTS

Stock Options

The Company has 15,092 stock options outstanding with an average exercise price of $0.65. The options have a five year life and vest evenly over a three year period on the anniversary date of their grant. For the six months ended June 30, 2017, Cequence recorded $557 (2016 – $386) in share based payment expense related to stock options with a corresponding increase to contributed surplus.

Restricted Share Units

The Company issues RSUs as part of its long term incentive program. The program is designed to offer cash compensation based on the underlying value of the RSU unit. RSUs are granted to directors, officers and employees of the Company and vest annually in equal amounts over a three year period. For the six months ended June 30, 2017, Cequence recognized $84 (2016 – $101) in share based payment expense related to RSUs with a corresponding increase to share based payment liability.

	RSUs		Stock Options	
Number (000's)	**2017**	2016	**2017**	2016
Outstanding, beginning of period	**3,010**	1,707	**11,003**	11,395
Granted	**700**	–	**5,025**	–
Settled	**(849)**	–	**–**	–
Cancelled/Forfeited	**(18)**	(354)	**(108)**	(2,585)
Expired	**–**	–	**(828)**	(1,615)
Outstanding, end of period	**2,843**	1,353	**15,092**	7,195

CAPITAL EXPENDITURES

	Three months ended June 30,		Six months ended June 30,	
$(000's)	**2017**	2016	**2017**	2016
Land	**259**	275	**427**	463
Geological & geophysical and capitalized overhead	**146**	156	**310**	447
Drilling, completions and workovers	**1,088**	453	**13,728**	2,670
Equipment, facilities and tie-ins	**1,040**	74	**3,114**	4,739
Office furniture & equipment	**3**	–	**3**	1
Capital expenditures	**2,536**	958	**17,582**	8,320
Property acquisitions (1)	**–**	7	**–**	7
Property dispositions (1)	**–**	131	**–**	(80)
Total capital expenditures	**2,536**	1,096	**17,582**	8,247

(1) Represent the cash proceeds from the sale of assets and cash paid for the acquisition of assets, as applicable.

For the six months ended June 30, 2017, capital expenditures, excluding acquisitions and dispositions, increased to $17,582 from $8,320 in 2016. Capital expenditures in 2017 include the completion of the Company's winter drilling program which commenced in the fourth quarter of 2016. The drilling program consisted of 2 gross (1 net) Dunvegan wells and 2 gross (2 net) Montney wells. All four wells were spud in the fourth quarter of 2016 with the Duvengan wells completed and on production in the first quarter of 2017 and the Montney wells on production late in March 2017.

Total capital expenditures for 2017 are budgeted to be approximately $24 million. The Company does not expect to spud any new wells until December 2017.

INCOME TAXES

As at June 30, 2017, the Company has tax pools and available losses of $617,519 (December 31, 2016 - $613,777). Due to the uncertainty of future realization, a deferred tax asset has not been recognized.

At June 30, 2017, Cequence has the following tax pools:

Classification	Amount $(000's)	Annual Deductibility
Canadian exploration expense	151,078	100%
Non-capital losses	308,865	100%
Undepreciated capital cost	50,946	Primarily 25%, declining balance
Canadian oil and gas property expense	9,154	10%, declining balance
Canadian development expense	69,444	30%, declining balance
Other	28,032	Various
	617,519	

The Company's non-capital losses expire in 2027 and thereafter. Based on the Company's expected cash flow and available tax pools, Cequence does not expect to be taxable for the next three years.

PROVISIONS – DECOMMISSIONING LIABILITIES

Decommissioning liabilities represent the estimated future cost of abandoning and reclaiming the company's oil and natural gas wells and related facilities. Total decommissioning liabilities at June 30, 2017 were $40,495 compared to $38,161 at December 31, 2016. Decommissioning obligations are adjusted periodically for revisions to the future liability costs and the estimated timing of costs to be incurred in future years. The Company estimates that it will incur $342 of decommissioning obligations in the twelve months ended June 30, 2018. The following table summarizes the changes in decommissioning liabilities for the respective periods:

	June 30, 2017	December 31, 2016
Balance, beginning of period	**38,161**	40,708
Property dispositions	**(119)**	(364)
Accretion expense	**428**	803
Liabilities incurred	**181**	286
Abandonment costs incurred	**(314)**	(1,852)
Revisions in estimated cash flows	**(141)**	(126)
Revisions due to change in discount rates	**2,299**	(1,294)
Balance, end of period	**40,495**	38,161

The total estimated, undiscounted cash flows, inflated at 2 percent, required to settle the obligations are $65,715 (December 31, 2016 - $66,240). These cash flows have been discounted using a risk-free interest rate of 2.06 percent (December 31, 2016 – 2.34 percent) based on Government of Canada long-term benchmark bonds. The Company expects these obligations to be settled in approximately 1 to 50 years (December 31, 2016 – 1 to 50 years).

LIQUIDITY AND CAPITAL RESOURCES

The Company's capital comprises shareholders' equity, demand credit facilities, senior notes and working capital. Cequence manages the capital structure and makes adjustments in light of economic conditions and the risk characteristics of the underlying assets.

$(000's)	**As at June 30, 2017**	As at December 31, 2016
Cash	**3,367**	17,778
Demand credit facility	**-**	–
Senior notes – principal	**(60,000)**	(60,000)
Accounts payable and accrued liabilities	**(24,005)**	(36,124)
Share based payment liability	**(222)**	(341)
Provisions - current	**(342)**	(366)
Accounts receivable	**12,357**	14,145
Deposits and prepaid expenses	**983**	877
Net debt [1]	**(67,862)**	(64,031)
Funds flow from operations[1] - trailing twelve months	**24,137**	11,250
Net debt to funds flow from operations trailing twelve months	**2.8:1**	5.7:1

(1) Refer to non-GAAP measurements

Cequence's objective is to maintain a flexible capital structure in order to meet its financial obligations and to execute its business plan throughout the commodity cycle. The oil and gas business involves a number of factors, including the timing of capital expenditures and volatile commodity prices that may cause the Company's net debt to funds flow from operations ratio to fluctuate on a quarterly basis. Historically, the Company has managed its debt levels and working capital through its hedging program, issuing common shares, adjusting capital expenditures, and executing asset dispositions. The Company typically carries a working capital deficiency as cash balances are used to repay short term borrowings. Based on current projections, the Company expects to be able to fund its working capital deficiency and 2017 capital expenditure program with funds flow from operations.

At June 30, 2017, the Company's net debt to funds flow from operations of 2.8:1 is higher than the Company's long term target of 2:1 due to the prolonged period of low commodity prices beginning in 2015. To manage its leverage and limit borrowing on its senior credit facility, the Company has significantly reduced capital expenditures in recent quarters, lowered its operating and G&A expenses and partly financed its 2016/17 winter drilling program with an equity financing. In 2017 the Company's net debt to funds flow from operations trailing twelve months has improved as commodity prices have increased and the Company realized the benefits of its costs saving initiatives.

SENIOR CREDIT FACILITY

As at June 30, 2017, Cequence had a $20,000 (December 31, 2016 - $20,000) term credit facility available from a syndicate of Canadian chartered banks. The senior credit facility is secured by a first floating charge debenture, general assignment of book debts and Cequence's oil and natural gas properties and equipment. The senior credit facility has a term date of May 31, 2018 and may be extended beyond the initial term, if requested by the Company and accepted by the lenders. If the credit facility does not continue to revolve, amounts borrowed under the facility must be repaid on the term date. The senior credit facility is reviewed on a semi-annual basis with the lender holding the right to request an additional review. The next scheduled review is in November 2017.

As at June 30, 2017 and December 31, 2016, the senior credit facility is undrawn. The company has letters of credit outstanding of $4,128 (December 31, 2016 - $3,307). The senior credit facility has a covenant that requires Senior Debt to twelve month trailing net income (loss) plus finance costs, share based payment expense, income tax expense (recovery), unrealized loss (gain) on commodity contracts, loss (gain) on sale of property and equipment, depletion and depreciation less costs related to onerous contracts to be less than 3:0 to 1:0, respectively. Senior Debt is defined as the sum of Consolidated Debt less the period end balance of the senior notes. Consolidated Debt is defined as the sum of the Company's period end balance of the credit facility and senior notes. The Company was in compliance with the lender's covenant at June 30, 2017 with a ratio of 0.1 times (December 31, 2016 – 0.2 times). At June 30, 2017, there are no restrictions on the Company's ability to draw on its credit facility.

SENIOR NOTES

In October 2013, Cequence closed an investment with CPPIB Credit Investments Inc., ("CII"), a wholly-owned subsidiary of Canada Pension Plan Investment Board ("CPPIB"), for an initial investment by CII of $60,000 in unsecured five year senior notes with a further $60,000 of notes available at a future date, subject to the approval of both CII and Cequence on terms to be confirmed at the time of issuance. In addition, Cequence granted CII 3.0 million warrants to purchase common shares. The initial investment of $60,000 of senior notes were issued at par and carry a 9% coupon rate per annum. A standby charge of 0.7% is applied to the further $60,000 of notes available at a future date.

The Company is engaged in a review of financing alternatives to modify or replace the senior notes that mature in October 2018.

The senior notes contain incurrence covenants that use a Debt to Cashflow test of 2.5 times to limit the incurrence of certain indebtedness and restricted payments without debtholder approval. The incurrence covenants do not contain provisions that make the notes callable. For this purpose, Debt is defined as the Company's period end balance of the credit facility and senior notes. Cashflow is equivalent to the Company's calculation of funds flow from operations for the trailing twelve months. At June 30, 2017, the Company's Debt to Cashflow ratio was more than 2.5 times. Based on the current forward commodity prices, the Company expects that its Debt to Cashflow ratio will remain at more than 2.5 times for the remainder of 2017.

The incurrence covenants limit the incurrence of additional debt, unless permitted by the debtholder, as follows:

- Senior secured debt is restricted to the maximum of $125,000; the current borrowing base; 30 percent of Adjusted Consolidated Net Tangible Assets ("ACTNA") and 75 percent of the NPV 10% of the Company's PDP reserves as determined by GLJ Petroleum;
- Capital lease obligations exceeding $6,250 or 1.25% of ACTNA;
- Non-recourse debt exceeding $10,000;
- Other indebtedness exceeding $12,500;
- Debt subordinated to the senior notes; and
- Certain liens in connection with indebtedness.

The Company's ACTNA is defined as the value of the Company's total proved reserves before taxes, plus the value of tangible assets less working capital. At June 30, 2017 ACTNA is $237,924. The Company does not currently expect the incurrence covenants in the senior note indenture to restrict its planned activities.

Generally, the incurrence covenants also restrict payments as follows:

- dividends and other distributions;
- stock repurchases;
- subordinated debt prepayment; and
- certain investments outside of the oil and gas business.

Certain restricted payments are excluded from the general restrictions or are permitted, including a general lifetime exclusion of $12,500. A full detail of the Trust Indenture dated October 3, 2013 is filed at sedar.com. The Company does not currently anticipate initiating a payment that would be restricted by the trust indenture.

COMMITMENTS

Cequence has assumed various commitments in the normal course of operations and financing activities.

	2017	2018	2019	2020	2021+	Total
Office leases	**179**	359	262	–	–	800
Pipeline transportation	**296**	1,915	2,350	2,350	12,328	19,239
Gas processing	**2,094**	4,154	4,154	4,166	38,780	53,348
Total	**2,569**	6,428	6,766	6,516	51,108	73,387

Cequence has a take or pay agreement for gas processing with the operator of the Simonette gas plant. The minimum commitment under the take or pay of 42 mmcf/d or approximately $4,154 per year concluding April 30, 2030. In addition, the Company has firm transportation on a major pipeline system for 9 mmcf/d for the period January 1, 2016 to March 31, 2018 and 35 mmcf/d for the period April 1, 2018 to March 30, 2026.

In addition to the commitments listed above, the Company has entered into binding contracts to ship natural gas to the Empress receipt point in Alberta and to the Dawn hub in Ontario. The Company has committed to ship 11,250 GJ/d of natural gas on the Nova system from its field to empress for an approximate cost of $0.20/GJ for a five year term. In addition, the Company has entered into a binding contract to ship 10,850 GJ/d of natural gas on the TransCanada mainline system from the Empress receipt point to the Dawn hub in Ontario for a cost of $0.77/GJ. The term of the contract is 10 years and has early termination rights that can be exercised following the initial five years of service. The contracts are conditional to final regulatory approval with the National Energy Board. The Company currently expects to begin shipping gas under these arrangements on April 1, 2018. The contracts provide Cequence with pricing diversification for approximately 20 percent of its natural gas production.

OUTSTANDING SHARE DATA

Details of share capital and share awards outstanding are as follows:

	June 30, 2017	December 31, 2016
Common shares	**245,528**	245,528
Stock options	**15,092**	11,003
Restricted share units	**2,843**	3,010
Warrants	**3,000**	3,000

Cequence has an unlimited number of common voting shares and common non-voting shares with no par value.
Warrants have an exercise price of $2.03 to purchase common shares.

As of the date of this MD&A, Cequence had the following securities outstanding: 245,528 common voting shares, 3,000 warrants to purchase common shares, 15,092 stock options and 2,843 RSUs.

SELECTED FINANCIAL INFORMATION

A reconciliation of cash flow from operating activities to funds flow from operations and other selected financial information is as follows:

	Six months ended June 30,		
$(000's)	**2017**	2016	2015
Cash flow from operating activities	**12,458**	3,142	12,023
Decommissioning liabilities expenditures	**314**	1,597	393
Net change in non-cash working capital	**1,355**	(3,499)	3,150
Funds flow from operations	**14,127**	1,240	15,566
Per share, basic and diluted ($)	**0.06**	0.01	0.07
Total revenue	**37,164**	27,115	45,396
Comprehensive loss	**(89,648)**	(18,100)	(4,416)
Per share – basic and diluted ($)	**(0.37)**	(0.09)	(0.02)
Total assets	**285,589**	379,867	654,028
Demand credit facilities	**–**	2,160	5,000
Senior notes – principal	**60,000**	60,000	60,000

Funds flow from operations was $14,127 for the six months ended June 30, 2017 compared to 1,240 in 2016. The quarterly increase in funds flow from operations is due to increased realized prices combined with lower operating and G&A expenses.

Cequence recorded a comprehensive loss of $89,648 for the six months ended June 30, 2017 compared to a loss of $18,100 in 2016. The decrease is due to an impairment charge of $96,200 recognized in 2017.

QUARTERLY INFORMATION

FINANCIAL

($ thousands except per share data)	**2017 Q2**	2017 Q1	2016 Q4	2016 Q3	2016 Q2	2016 Q1	2015 Q4	2015 Q3
Total revenue [1]	**17,810**	19,354	17,253	14,707	11,343	15,772	16,112	19,383
Royalties expense	**927**	1,355	467	636	(125)	565	(507)	368
Transportation expense	**1,650**	1,308	1,151	1,001	774	1,092	1,339	1,323
Operating costs	**5,829**	6,779	6,184	6,228	5,812	9,212	7,031	8,951
Comprehensive income (loss)	**(94,899)**	5,251	(9,077)	(880)	(12,212)	(5,888)	(146,585)	(99,070)
Per share – basic & diluted	**(0.39)**	0.02	(0.04)	(0.00)	(0.06)	(0.03)	(0.69)	(0.47)
Funds flow from (used in) operations [2]	**6,781**	7,346	6,625	3,385	1,554	(314)	4,874	5,139
Per share – basic	**0.03**	0.03	0.03	0.02	0.01	(0.00)	0.02	0.02
Per share – diluted	**0.03**	0.03	0.03	0.02	0.01	(0.00)	0.02	0.02
Capital expenditures, net	**2,536**	15,046	11,460	2,810	958	7,362	15,175	4,656
Net acquisitions (dispositions) [3]	**–**	–	(54)	(5,167)	138	(211)	1,176	1,136
Total capital expenditures	**2,536**	15,046	11,406	(2,357)	1,096	7,151	16,351	5,792

[1] Total revenue is presented gross of royalties and includes realized gains (loss) on commodity contracts.
[2] Funds flow from (used in) operations is calculated as cash flow from operating activities before adjustments for decommissioning liabilities expenditures and net changes in non-cash working capital.
[3] Represents the cash proceeds from the sale of assets and cash paid for the acquisition of assets, as applicable.

OPERATIONAL

	2017 Q2	2017 Q1	2016 Q4	2016 Q3	2016 Q2	2016 Q1	2015 Q4	2015 Q3
Production volumes								
Natural gas (Mcf/d)	**42,719**	45,214	45,005	44,320	40,127	52,253	41,794	43,987
Oil (bbls/d)	**224**	481	140	175	178	218	225	199
NGLs (bbls/d)	**239**	270	209	261	244	235	300	485
Condensate (bbls/d)	**919**	814	760	798	748	1,061	723	807
Total (boe/d)	**8,502**	9,101	8,609	8,621	7,857	10,223	8,213	8,822
Average selling price, including realized hedges								
Natural gas ($/Mcf)	**2.83**	2.79	2.92	2.28	1.73	2.10	2.89	3.46
Crude oil and condensate ($/bbl)	**60.11**	62.50	56.27	53.78	54.01	46.69	52.32	50.08
NGLs ($/bbl)	**26.11**	29.92	25.61	24.09	21.50	16.68	16.45	16.80
Total ($/boe)	**23.02**	23.63	21.78	18.54	15.86	16.95	21.32	23.88
Operating netback, including realized hedges ($/boe)								
Price	**23.02**	23.63	21.78	18.54	15.86	16.95	21.32	23.88
Royalties	**(1.20)**	(1.65)	(0.59)	(0.80)	0.17	(0.61)	0.67	(0.45)
Transportation	**(2.13)**	(1.60)	(1.45)	(1.26)	(1.08)	(1.17)	(1.77)	(1.63)
Operating costs	**(7.53)**	(8.28)	(7.81)	(7.85)	(8.13)	(9.90)	(9.30)	(11.03)
Operating netback	**12.16**	12.10	11.93	8.63	6.82	5.27	10.92	10.77

The decline in production revenue, funds flow from operations and comprehensive incomes (loss) in 2016 can be attributed to low commodity prices and declining production volumes. Canadian AECO natural gas prices averaged $2.18/mcf in 2016, significantly lower than previous years. Production volumes decreased in the both 2015 and 2016 as the Company reduced capital expenditures on new wells due to the extended period of low gas prices. Total capital expenditures for the past 8 quarters have been constrained by lower funds flow from operations and restricted access to cost effective capital. In both the fourth quarter of 2016 and first half of 2017 commodity prices increased from recent levels and the Company's production revenue, funds flow from operations and comprehensive income has improved.

The Company's quarterly net comprehensive income (loss) is affected by fluctuations in non-cash charges, in particular, depletion, depreciation and impairment expense, accretion of decommissioning obligations, gains/losses on derivative financial instruments, share based payments and other expense (income). During the three months ended June 30, 2017, the Company recorded impairment expense of $96,200. During 2015, the Company recorded impairment expense of $230,400, including $144,000 in the fourth quarter. Impairments recognized were mainly the result of declining benchmark natural gas prices. These impairments cause significant reductions and increased volatility in the Company's net comprehensive income (loss).

Please refer to the results of operations and other sections of this MD&A and the Company's previously issued MD&A for detailed discussions on variances between reporting periods and changes in prior periods.

OUTLOOK INFORMATION

On May 11, 2017, the Company updated its first half 2017 guidance. Actual results were comparable to the revised guidance and are presented in the table below. Funds flow exceeded budget by 9 percent as operating expenses, royalties and G&A expenses were lower than expected. Production was two percent below budget as wet second quarter weather restricted production from the Company's Simonette field.

(000's, except per share and per unit references)	**Actual Results Six Months Ended June 30, 2017**	Revised Guidance Six Months Ended June 30, 2017
Average production, BOE/d [1]	**8,800**	9,000
Funds flow from operations ($)[2]	**14,127**	13,000
Funds flow from operations per share [2]	**0.06**	0.05
Capital expenditures, ($)	**17,582**	17,500
Operating and transportation costs ($/boe)	**9.78**	10.20
G&A costs ($/boe)	**1.40**	1.72
Royalties (% revenue)	**6**	8
Crude – WTI (US$/bbl)	**49.91**	51.00
Natural gas – AECO (CDN$/GJ)	**2.78**	2.65
Period end, net debt ($) [3]	**67,862**	68,500
Weighted average basic shares outstanding	**245,528**	245,500

(1) Average production estimates on a per BOE basis are comprised of 85% natural gas and 15% oil and natural gas liquids.
(2) Funds flow from operations is calculated as cash flow from operating activities before adjustments for decommissioning liabilities expenditures and net changes in non-cash working capital.
(3) Net debt is calculated as working capital (deficiency) less the aggregate principal amount of the senior notes.

On May 11, 2017 the Company issued guidance for the year ended December 31, 2017 which is updated in the table below. Production estimates have been lowered by 5 percent due to weather outages in the second quarter and the deferral of the Company's drilling program until December 2017. The Company plans to drill 3.0 (2.0 net) Dunvegan wells beginning in December 2017 with production additions not expected until the first quarter of 2018. As a result, the 2017 capital expenditure budget has been reduced by 17 percent to $24,000. The Company may adjust its capital expenditure program should commodity prices increase or decrease significantly. In addition, natural gas prices have been volatile in July and August resulting in some periods of very low prices. Should these conditions persist the Company may choose to shut in some natural gas wells until prices improve to preserve well economics.

Funds flow from operations has been reduced to $23,000 reflecting lower expected commodity prices and production volumes. With the corresponding decrease in capital expenditure, expected year end net debt has been adjusted to $65,000.

(000's, except per share and per unit references)	**Revised Guidance Year Ended December 31, 2017**	Original Guidance Year Ended December 31, 2017
Average production, BOE/d [(1)]	**8,500 - 8,700**	9,000 - 9,200
Funds flow from operations ($)[(2)]	**23,000**	28,000 - 29,000
Funds flow from operations per share [(2)]	**0.10**	0.12
Capital expenditures, ($)	**24,000**	29,000
Operating and transportation costs ($/boe)	**10.25**	10.00
G&A costs ($/boe)	**1.60**	1.65
Royalties (% revenue)	**8**	8
Crude – WTI (US$/bbl)	**49.25**	50.00
Natural gas – AECO (CDN$/GJ)	**2.50**	2.75
Period end, net debt ($) [(3)]	**65,000**	64,000 - 65,000
Weighted average basic shares outstanding	**245,500**	245,500

(1) Average production estimates on a per BOE basis are comprised of 85% natural gas and 15% oil and natural gas liquids.
(2) Funds flow from operations is calculated as cash flow from operating activities before adjustments for decommissioning liabilities expenditures and net changes in non-cash working capital.
(3) Net debt is calculated as working capital (deficiency) less the aggregate principal amount of the senior notes.

DISCLOSURE CONTROLS AND INTERNAL CONTROLS OVER FINANCIAL REPORTING

The Chief Executive Officer ("CEO") and Executive Vice President, Finance and Chief Financial Officer ("CFO") are responsible for designing internal controls over financial reporting or causing them to be designed under their supervision in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The Company's CEO and CFO have designed, or caused to be designed under their supervision, disclosure controls and procedures to provide reasonable assurance that 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 periods specified in the securities legislation and include controls and procedures designed to ensure that information required to be disclosed by an issuer in its annual filings, interim filings or other reports filed or submitted under securities legislation is accumulated and communicated to the Company's management, including its CEO and CFO, as appropriate to allow timely decisions regarding required disclosure.

The Committee of Sponsoring Organizations ("COSO") framework provides the basis for management's design of internal controls over financial reporting. Management and the Board work to mitigate the risk of a material misstatement in financial reporting; however, a control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met and it should not be expected that the disclosure and internal control procedures will prevent all errors or fraud.

As at June 30, 2017, CEO and CFO have concluded, based on their evaluation of the design and operating effectiveness of the Company's disclosure controls and procedures and internal controls over financial reporting ("ICFR") that disclosure controls and procedures and ICFR are effective.

FUTURE ACCOUNTING POLICIES

As at the date of this MD&A, the following standards and interpretations relevant to the Company's operations were issued by IASB but are not yet mandatory:

IFRS 9 'Financial Instruments' was issued by the IASB in July 2014 as a complete standard, including the requirements previously issued related to classification and measurement of financial assets and liabilities, and additional amendments to introduce a new expected loss impairment model for financial assets including credit losses. Retrospective application of this standard with certain exemptions is effective for fiscal years beginning on or after January 1, 2018, with earlier application permitted. The Company is in the process of assessing the impact of the adoption of this standard on the Company's consolidated financial statements.

IFRS 15 'Revenue from Contracts with Customers' was issued by the IASB in May 2014 and amended in September 2015 for application beginning on or after January 1, 2018. IFRS 15 replaces existing revenue recognition guidance and provides a single, principles-based five-step model to be applied to all contracts with customers. The standard requires revenue to be recognized at an amount that reflects the expected consideration receivable in exchange for transferring goods or services to a customer by applying the following five step model:

1. Identify the contract with a customer
2. Identify the performance obligations in the contract
3. Determine the transaction price
4. Allocate the transaction price to the performance obligations in the contract
5. Recognize revenue when (or as) the entity satisfies a performance obligation

IFRS 15 also provides guidance relating to the treatment of contract acquisition and contract fulfillment costs. Additional disclosures will also be required under the new standard. IFRS 15 will be applied by Cequence on January 1, 2018. The Company is currently evaluating the impact of adoption of this standard and the effect on Cequence's consolidated financial statements has not yet been determined.

IFRS 16 'Leases' was issued by the IASB in January 2016. IFRS 16 replaces the existing standard IAS 17 and requires the recognition of most leases on the balance sheet. IFRS 16 effectively removes the classification of leases as either finance or operating leases and treats all leases as finance leases for lessees with exemptions for short-term leases where the term is twelve months or less and for leases of low value items. The accounting treatment for lessors remains the same. IFRS 16 is effective January 1, 2019, with earlier application permitted. The Company is in the process of assessing the impact of the adoption of this standard on the Company's consolidated financial statements.

The Company did not adopt any new accounting standards in the three and six months ended June 30, 2017.

RISK ASSESSMENT

The acquisition, exploration and development of oil and natural gas properties and the production, transportation and marketing of oil and natural gas involves many risks, which may influence the ultimate success of the Company.

While the management of Cequence realizes these risks cannot be eliminated, they are committed to monitoring and mitigating these risks. These risk include, but are not limited to:

- Volatility in market prices and demand for oil, NGLs and natural gas and hedging activities related thereto;
- Variance of the Company's actual capital costs, operating costs, transportation costs and economic returns from those anticipated;
- The ability to find, develop or acquire additional reserves and the availability of the capital or financing necessary to do so on satisfactory terms;
- Risks related to the exploration, development and production of oil and natural gas reserves and resources;
- Negative public perception of oil sands development, oil and natural gas development and transportation, hydraulic fracturing and fossil fuels;
- Actions by governmental authorities, including changes in government regulation, royalties, taxation, and wildlife management including the Caribou Action and Range Planning that may impact the Company's Simonette area;
- Actions by governmental authorities, including changes in government regulation, royalties and taxation;
- The availability, cost or shortage of service equipment, oil and natural gas transportation, raw materials, supplies or qualified personnel;
- Dependence upon oil and gas infrastructure, certain of which the Company does not control;
- The ability to satisfy obligations under the Company's firm commitment transportation and gas processing arrangements;
- The possibility that the Company's drilling activities may encounter sour gas;
- The concentration of the Company's assets in the Simonette area;
- First Nations claims;
- Limited intellectual property protection for operating practices and dependence on employees and contractors;
- Environmental, health and safety requirements;
- Extensive competition in the Company's industry;
- Third party credit risk including dependence on limited customers and counterparties;
- Variations in foreign exchange rates and interest rates;
- Litigation.

For additional information regarding the risks that the Company is exposed to, see the disclosure provided under the heading "Risk Factors" in the AIF, which is available on the SEDAR website at www.sedar.com

FORWARD-LOOKING STATEMENTS

Certain statements contained within this MD&A constitute forward-looking statements. These statements relate to future events or the Company's future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek", "anticipate", "budget", "plan", "continue", "estimate", "expect", "forecast", "may", "will", "project", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe", and similar expressions. Forward-looking statements in this

MD&A include, but are not limited to, statements with respect to: projections with respect to natural gas production; the projection of future royalty, operating, transportation and G&A expenses; the projected impact of land access and regulatory issues; projections relating to the volatility of crude oil and natural gas prices in 2017 and beyond ; the Company's projected capital investment levels for 2017 and the source of funding therefore; the effect of the Company's risk management program, including the impact of derivative financial instruments; the impact of the climate change initiatives on operating costs; the impact of Western Canada pipeline constraints. Readers are cautioned not to place undue reliance on forward-looking statements, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur.

By their nature, forward-looking statements involve numerous assumptions, known and unknown risks and uncertainties, both general and specific, that contribute to the possibility that the predictions, forecasts, projections and other forward-looking statements will not occur, which may cause the Company's actual performance and financial results in future periods to differ materially from any estimates or projections of future performance or results expressed or implied by such forward-looking statements. These assumptions, risks and uncertainties include, among other things: volatility of and assumptions regarding oil and natural gas prices; assumptions based upon Cequence's current guidance; fluctuations in currency and interest rates; product supply and demand; market competition; risks inherent in the Company's marketing operations, including credit risks; imprecision of reserves estimates and estimates of recoverable quantities of oil, natural gas and liquids from resource plays and other sources not currently classified as proved; the Company's ability to replace and expand oil and gas reserves; the Company's ability to generate sufficient cash flow from operations to meet its current and future obligations; the Company's ability to access external sources of debt and equity capital; the timing and cost of well and pipeline constructions; the Company's ability to secure adequate product transportation; changes in royalty, tax, environmental and other laws or regulations or the interpretations of such laws or regulations; risks associated with existing and potential future lawsuits and regulatory actions made against the Company; and other risks and uncertainties described from time to time in the reports and filings made with securities regulatory authorities by Cequence. Statements relating to "reserves" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the resources and reserves described can be profitably produced in the future.

The forward looking statements contained herein concerning production, sales prices, operating expenses and capital spending are based on Cequence's 2017 capital program. The material assumptions supporting the 2017 capital program are provided in the table above under the heading "Outlook Information".

Financial outlook information contained in this MD&A about prospective results of operations, financial position or cash flows is based on assumptions about future events, including economic conditions and proposed courses of action, based on management's assessment of the relevant information currently available. The purpose of such financial outlook is to enrich this MD&A. Readers are cautioned that such financial outlook information contained in this MD&A should not be used for purposes other than for which it is disclosed herein.

Although Cequence believes that the expectations represented by such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Readers are cautioned that the foregoing list of important factors is not exhaustive. Furthermore, the forward-looking statements contained in this MD&A are made as of the date of this MD&A and, except as required by law, Cequence does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained in this MD&A are expressly qualified by this cautionary statement.

CONDENSED CONSOLIDATED BALANCE SHEETS

(Unaudited) (Expressed in thousands of Canadian dollars)

	June 30, 2017	December 31, 2016
	$	$
ASSETS		
CURRENT		
Cash	**3,367**	17,778
Accounts receivable	**12,357**	14,145
Deposits and prepaid expenses	**983**	877
Commodity contracts (Note 10)	**2,961**	–
	19,668	32,800
Property and equipment (Note 3)	**265,921**	356,058
	285,589	388,858
LIABILITIES		
CURRENT		
Accounts payable and accrued liabilities	**24,005**	36,124
Commodity contracts (Note 10)	**–**	4,491
Share based payment liability (Note 8)	**222**	341
Provisions (Note 7)	**342**	366
	24,569	41,322
Commodity contracts (Note 10)	**–**	159
Senior notes (Note 5)	**58,935**	58,557
Provisions (Note 7)	**40,153**	37,795
	123,657	137,833
SHAREHOLDERS' EQUITY		
Share capital	**633,846**	633,848
Warrants	**1,300**	1,300
Contributed surplus	**30,642**	30,085
Deficit	**(503,856)**	(414,208)
	161,932	251,025
	285,589	388,858

APPROVED BY THE BOARD

[signed] "Donald Archibald"
Donald Archibald, Director

[signed] "Brian Felesky"
Brian Felesky, Director

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE LOSS

(Unaudited) (Expressed in thousands of Canadian dollars except per share amounts)

	Three months ended June 30,		Six months ended June 30,	
	2017	2016	**2017**	2016
	$	$	**$**	$
REVENUE				
Production revenue	**16,381**	8,637	**34,626**	20,878
Gain (loss) on derivative financial instruments (Note 10)	**2,654**	(4,323)	**7,866**	1,833
	19,035	4,314	**42,492**	22,711
EXPENSES				
Depletion and depreciation (Note 3)	**6,927**	6,049	**13,858**	14,146
Impairment (Note 3)	**96,200**	–	**96,200**	–
General and administrative	**1,182**	1,797	**2,232**	5,545
Finance costs (Note 6)	**1,933**	1,968	**3,936**	3,916
Operating costs	**5,829**	5,812	**12,608**	15,024
Share based payment (Note 8)	**366**	198	**641**	487
Transportation	**1,650**	774	**2,958**	1,866
Other income	**(153)**	(72)	**(293)**	(173)
	113,934	16,526	**132,140**	40,811
LOSS BEFORE INCOME TAXES	**(94,899)**	(12,212)	**(89,648)**	(18,100)
INCOME TAXES	**–**	–	**–**	–
NET LOSS AND COMPREHENSIVE LOSS	**(94,899)**	(12,212)	**(89,648)**	(18,100)
Loss per share (Note 9)				
Basic and diluted	**($0.39)**	($0.06)	**($0.37)**	($0.09)

CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(Unaudited) (Expressed in thousands of Canadian dollars)

	Six months ended June 30,	
	2017	2016
	$	$
SHARE CAPITAL		
Common Shares		
Balance, beginning of period	**633,848**	624,619
Share issue costs	**(2)**	–
Balance, end of period	**633,846**	624,619
Warrants		
Balance, beginning of period	**1,300**	1,300
Balance, end of period	**1,300**	1,300
CONTRIBUTED SURPLUS		
Balance, beginning of period	**30,085**	29,377
Share based payment expense (Note 8)	**557**	386
Balance, end of period	**30,642**	29,763
DEFICIT		
Balance, beginning of period	**(414,208)**	(386,151)
Comprehensive loss	**(89,648)**	(18,100)
Balance, end of period	**(503,856)**	(404,251)
TOTAL EQUITY	**161,932**	251,431

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited) (Expressed in thousands of Canadian dollars)

	Three months ended June 30,		Six months ended June 30	
	2017	2016	**2017**	2016
	$	$	**$**	$
CASH FLOWS RELATED TO THE FOLLOWING ACTIVITIES:				
OPERATING				
Net loss	**(94,899)**	(12,212)	**(89,648)**	(18,100)
Adjustments for non-cash items:				
Depletion and depreciation expense (Note 3)	**6,927**	6,049	**13,858**	14,146
Impairment expense (Note 3)	**96,200**	–	**96,200**	–
Finance costs related to provisions (Note 6)	**208**	193	**428**	402
Share based payment expense (Note 8)	**366**	198	**641**	487
Amortization of transaction costs on senior notes (Note 6)	**108**	97	**214**	192
Accretion on senior notes (Note 6)	**83**	75	**164**	149
Unrealized loss (gain) on derivative financial instruments (Note 10)	**(2,152)**	7,154	**(7,610)**	3,964
Gain on sale of property and equipment	**(60)**	–	**(120)**	–
Decommissioning liabilities expenditures (Note 7)	**(90)**	(573)	**(314)**	(1,597)
Net change in non-cash working capital (Note 11)	**(1,665)**	(2,732)	**(1,355)**	3,499
	5,026	(1,751)	**12,458**	3,142
INVESTING				
Property and equipment expenditures (Note 3)	**(2,536)**	(958)	**(17,582)**	(8,320)
Property acquisitions (Note 3)	**–**	(7)	**–**	(7)
Proceeds from sale of property and equipment	**–**	(131)	**–**	80
Net change in non-cash working capital (Note 11)	**(11,146)**	(4,989)	**(9,082)**	(10,199)
	(13,682)	(6,085)	**(26,664)**	(18,446)
FINANCING				
Proceeds from demand credit facility (Note 4)	**–**	2,160	**–**	2,160
Cash settlement of share based payments (Note 8)	**(203)**	–	**(203)**	–
Share issue costs	**–**	–	**(2)**	–
Net change in non-cash working capital (Note 11)	**3**	(33)	**–**	(102)
	(200)	2,127	**(205)**	2,058
NET DECREASE IN CASH	**(8,856)**	(5,709)	**(14,411)**	(13,246)
CASH, BEGINNING OF PERIOD	**12,223**	5,709	**17,778**	13,246
CASH, END OF PERIOD	**3,367**	–	**3,367**	–
SUPPLEMENTARY INFORMATION				
Income taxes paid	**–**	–	**–**	–
Interest paid	**1,556**	1,639	**3,152**	3,277

1. NATURE AND DESCRIPTION OF THE COMPANY

Cequence Energy Ltd. (the “Company” or “Cequence”) is incorporated under the laws of Alberta with common shares that are widely held and listed on the Toronto Stock Exchange. Cequence is engaged in the acquisition, exploration and production of petroleum and natural gas reserves in Western Canada. The registered office of the Company is located at Suite 1400, 215 – 9th Avenue. SW, Calgary, Alberta, T2P 1K3.

These interim condensed consolidated financial statements (“consolidated financial statements”) include all assets, liabilities, revenues and expenses of Cequence and its wholly-owned subsidiary, 1175043 Alberta Ltd.

2. SIGNIFICANT ACCOUNTING POLICIES

Statement of compliance and authorization

These consolidated financial statements have been prepared in accordance with International Accounting Standard (“IAS”) 34, “Interim Financial Reporting”, as issued by the International Accounting Standards Board (“IASB”). Accordingly, certain information or footnote disclosure normally included in the annual consolidated financial statements prepared in accordance with International Financial Reporting Standards (“IFRS”) have been condensed or omitted.

These consolidated financial statements should be read in conjunction with the Company’s consolidated financial statements for the year ended December 31, 2016.

The consolidated financial statements were authorized for issue by the Company’s Board of Directors on August 10, 2017.

Basis of presentation

The consolidated financial statements have been prepared using the same accounting policies and methods as those used in the consolidated financial statements for the year ended December 31, 2016. The consolidated financial statements have been presented in Canadian dollars, which is also the Company’s functional currency, rounded to the nearest thousand, unless otherwise indicated.

Future accounting pronouncements

As at the date of authorization of these consolidated financial statements, the following standards and interpretations relevant to the Company’s operations were issued by IASB but are not yet mandatory:

IFRS 9 ‘Financial instruments’ was issued by the IASB in July 2014 as a complete standard, including the requirements previously issued related to classification and measurement of financial assets and liabilities, and additional amendments to introduce a new expected loss impairment model for financial assets including credit losses. Retrospective application of this standard with certain exemptions is effective for fiscal years beginning on or after January 1, 2018, with earlier application permitted. The Company is in the process of assessing the impact of the adoption of this standard on the Company’s consolidated financial statements.

IFRS 15 'Revenue from contracts with customers' was issued by the IASB in May 2014 and amended in September 2015 for application beginning on or after January 1, 2018. IFRS 15 replaces existing revenue recognition guidance and provides a single, principles-based five-step model to be applied to all contracts with customers. The standard requires revenue to be recognized at an amount that reflects the expected consideration receivable in exchange for transferring goods or services to a customer by applying the following five step model:

1. Identify the contract with a customer
2. Identify the performance obligations in the contract
3. Determine the transaction price
4. Allocate the transaction price to the performance obligations in the contract
5. Recognize revenue when (or as) the entity satisfies a performance obligation

IFRS 15 also provides guidance relating to the treatment of contract acquisition and contract fulfillment costs. Additional disclosures will also be required under the new standard. IFRS 15 will be applied by Cequence on January 1, 2018. The Company is currently evaluating the impact of adoption of this standard and the effect on Cequence's consolidated financial statements has not yet been determined.

IFRS 16 'Leases' was issued by the IASB in January 2016. IFRS 16 replaces the existing standard IAS 17 and requires the recognition of most leases on the balance sheet. IFRS 16 effectively removes the classification of leases as either finance or operating leases and treats all leases as finance leases for lessees with exemptions for short-term leases where the term is twelve months or less and for leases of low value items. The accounting treatment for lessors remains the same. IFRS 16 is effective January 1, 2019, with earlier application permitted. The Company is in the process of assessing the impact of the adoption of this standard on the Company's consolidated financial statements.

The Company did not adopt any new accounting standards in the three and six months ended June 30, 2017.

3. PROPERTY AND EQUIPMENT

Cost:	
Balance at December 31, 2015	906,545
Additions	22,590
Decommissioning obligation additions and change in estimates	(1,134)
Acquisitions	(60)
Disposals	(2,847)
Balance at December 31, 2016	925,094
Additions	**17,582**
Decommissioning obligation additions and change in estimates	**2,339**
Balance at June 30, 2017	**945,015**
Depletion, depreciation and impairment:	
Balance at December 31, 2015	(537,866)
Depletion and depreciation	(31,622)
Disposals	452
Balance at December 31, 2016	(569,036)
Depletion and depreciation	**(13,858)**
Impairment loss	**(96,200)**
Balance at June 30, 2017	**(679,094)**
Carrying amounts:	
At December 31, 2016	356,058
At June 30, 2017	**265,921**

Costs subject to depletion include $908,080 of estimated future capital costs (December 31, 2016 – $921,573).

The Company's credit facility is secured by a demand debenture with a first floating charge over all assets of the Company (see note 4).

Impairment

The Company reviewed each CGU comprising its property and equipment at June 30, 2017 for indicators of impairment and determined that indicators were present, related to the further reduction in the Company's enterprise value and decreases to future crude oil and natural gas prices used to estimate the value in use and fair value less cost to sell of each of the Company's CGUs.

As a result, impairment tests were carried out at June 30, 2017. The recoverable amounts of each of the Company's CGUs at June 30, 2017 were estimated as their fair value less cost to sell, based on the pre-tax net present value of discounted future cash flows from oil and gas reserves as estimated by the Company's independent reserves evaluator at December 31, 2016 updated for current price forecasts. The Company also included the fair value of undeveloped land based on an internal evaluation. Consideration was also given to acquisition metrics of recent transactions completed on similar assets to those contained within the relevant CGU. The fair value less costs of disposal values used to determine the recoverable amounts are classified as Level 3 fair value measurements as certain key assumptions are not based on observable market data but, rather, management's best estimates.

The benchmark escalated prices on which the June 30, 2017 impairment tests are based are as follows:

	Natural Gas AECO Spot ($/mmbtu)	Condensate Edmonton Pentanes Plus ($/bbl)	Crude Oil Edmonton Par ($/bbl)
2017	2.83	65.63	61.33
2018	2.93	67.02	63.23
2019	3.05	70.89	66.88
2020	3.22	74.52	70.30
2021	3.39	77.32	72.94
2022	3.58	81.06	76.47
2023	3.76	83.60	80.00
2024	3.95	87.29	83.53
2025	4.03	90.98	87.06
2026	4.11	94.04	89.99

Prices increase at a rate of approximately 2.0 percent per year for natural gas, condensate and crude oil after 2026. Adjustments were made to the benchmark prices, for purposes of the impairment tests, to reflect varied delivery points and quality differentials in the products delivered.

The Company used a pre-tax 15% discount rate for the June 30, 2017 impairment tests which took into account the risks specific to the CGUs and current market assessment of the time value of money.

The estimated recoverable amounts used in the June 30, 2017 impairment tests were $7,425 for the Northeast British Columbia CGU, $2,497 for the Peace River Arch CGU and $255,999 for the Deep Basin CGU.

Results of the Company's impairment tests for the six months ended June 30, 2017 and 2016 are as follows:

	2017	2016
Northeast British Columbia	**–**	–
Peace River Arch	**2,200**	–
Deep Basin	**94,000**	–
Total Impairment	**96,200**	–

For the quarter ended June 30, 2017, a one percent increase in the discount rate applied to the Company's future estimated cash flows would result in an additional impairment of $22,286 (2016 - $nil), whereas a ten percent decrease in forward commodity prices would result in additional impairment of $106,947 (2016 - $nil) recognized in comprehensive loss for the six months ended June 30, 2017.

4. DEMAND CREDIT FACILITY

As at June 30, 2017, the Company has an extendible revolving term credit facility ("senior credit facility") of $20,000 (December 31, 2016 - $20,000) with a syndicate of Canadian chartered banks and has drawn $nil (December 31, 2016 - $nil) under the facility. The company has letters of credit outstanding of $4,128 (December 31, 2016 - $3,307). The senior credit facility has a term date of May 31, 2018 and may be extended beyond the initial term, if requested by the Company and accepted by the lenders. If the senior credit facility does not continue to revolve, amounts borrowed under the facility must be repaid on the term date. Prime loans and U.S. Base Rate Loans on the facility bear interest at the bank prime rate or U.S. Base Rate, respectively, plus 1.0 percent to 3.5 percent on a sliding scale, depending on the Company's debt to adjusted

EBITDA ratio (ranging from being less than or equal to 1.0:1.0 to greater than 3.5:1.0). Banker's Acceptances, Libor Loans and letters of credit on the facility bear interest at the Banker's Acceptance rate, Libor rate or letter of credit rate, as applicable, plus 2.0 percent to 4.5 percent based on the same sliding scale as above. The credit facility is secured by a general assignment of book debts and a $250,000 demand debenture with a first floating charge over all assets of the Company. The Company is permitted to hedge up to 67 percent of its production under the lending agreement. The Company has a covenant that requires Senior Debt to EBITDA, as defined in the bank agreement, to be less than 3:0 to 1:0. Senior Debt is defined as the sum of Consolidated Debt less the period end balance of the senior notes. Consolidated Debt is defined as the sum of the Company's period end balance of the senior credit facility and senior notes. The Company was in compliance with the lender's covenants at June 30, 2017 and December 31, 2016. The senior credit facility is reviewed on a semi-annual basis with the lender holding the right to request an additional review. The next scheduled review is to take place in November 2017.

5. SENIOR NOTES

	June 30, 2017	December 31, 2016
Senior notes	**56,503**	56,503
Add transaction costs	**2,432**	2,054
	58,935	58,557

On October 3, 2013, Cequence issued $60,000 of unsecured five year term notes ("senior notes") at par with a 9% coupon per annum for gross proceeds net of transaction costs of $57,974. The senior notes have a term of five years, are unsecured and are subordinate to Cequence's senior credit facility. The senior notes were issued pursuant to a trust indenture with a Canadian trust company, which provides for an additional $60,000 of unsecured senior notes at a future date, subject to approval of both the lender and the Company on terms to be confirmed at the time of issuance.

The senior notes are subject to the same financial covenants as the Company's senior credit facility as well as other non-financial covenants and restrictive covenants, including restrictions over asset sales, restricted payments and the incurrence of additional indebtedness (see note 12)

6. FINANCE COSTS

	Three months ended June 30,		Six months ended June 30,	
	2017	2016	2017	2016
Interest expense on demand credit facilities	**81**	157	**243**	279
Interest expense on senior notes	**1,453**	1,446	**2,887**	2,894
Amortization of transaction costs	**108**	97	**214**	192
Accretion expense on senior notes	**83**	75	**164**	149
Accretion expense on provisions	**208**	193	**428**	402
	1,933	1,968	**3,936**	3,916

7. PROVISIONS

Decommissioning liabilities

The following table summarizes the changes in decommissioning liabilities for the six months ended June 30, 2017 and year ended December 31, 2016:

	2017	2016
Balance, beginning of period	**38,161**	40,708
Property dispositions	**(119)**	(364)
Accretion expense	**428**	803
Liabilities incurred	**181**	286
Abandonment costs incurred	**(314)**	(1,852)
Revisions in estimated cash flows	**(141)**	(126)
Revisions due to change in discount rates	**2,299**	(1,294)
Balance, end of period	**40,495**	38,161
Current	**342**	366
Non-current	**40,153**	37,795
	40,495	38,161

The Company's decommissioning liabilities result from its ownership in oil and natural gas assets including well sites, facilities and gathering systems. The total estimated, undiscounted cash flows, inflated at 2 percent, required to settle the obligations are $65,715 (December 31, 2016 - $66,240). These cash flows have been discounted using a risk-free interest rate of 2.06 percent (December 31, 2016 – 2.34 percent) based on Government of Canada long-term benchmark bonds. The Company expects these obligations to be settled in approximately 1 to 50 years (December 31, 2016 – 1 to 50 years). As at June 30, 2017, no funds have been set aside to settle these liabilities

8. SHARE BASED PAYMENT PLANS

The Company has a stock option and RSU plan for directors, officers, employees and consultants of the Company and its subsidiaries. For the three and six months ended June 30, 2017, Cequence recognized share based payment expense on equity-settled stock options of $300 and $557 (2016 - $140 and $386) and RSUs of $66 and $84 (2016 - $58 and $101).

A summary of the status of the Company's stock option and RSU plans during the six months ended June 30, 2017 and year ended December 31, 2016 is as follows:

Number of Options (000's)	**2017**	2016
Outstanding, beginning of period	**11,003**	11,395
Granted [1]	**5,025**	6,295
Cancelled/Forfeited	**(108)**	(3,900)
Expired	**(828)**	(2,787)
Outstanding, end of period	**15,092**	11,003

[1] The company issued 5,025,000 stock options (2016 – 6,295,000) at a weighted average exercise price of $0.32 (2016 - $0.33) to employees, officers and directors.

Number of RSUs (000's)	**2017**	2016
Outstanding, beginning of period	**3,010**	1,707
Granted	**700**	2,622
Settled	**(849)**	–
Cancelled/Forfeited	**(18)**	(677)
Exercised	**–**	(642)
Outstanding, end of period	**2,843**	3,010

9. LOSS PER SHARE

Loss per share has been calculated based on the weighted average number of common shares outstanding during the period. For the three and six months ended June 30, 2017 and 2016, the Company excluded all dilutive instruments as their inclusion would be anti-dilutive. The following table reconciles the denominators used for the basic and diluted loss per share calculations:

	Three months ended June 30,		Six months ended June 30,	
	2017	2016	**2017**	2016
Basic weighted average shares	**245,528**	211,028	**245,528**	211,028
Effect of dilutive instruments	**–**	–	**–**	–
Diluted weighted average shares	**245,528**	211,028	**245,528**	211,028

10. RISK MANAGEMENT

There have been no changes to the Company's exposure to risks, or the objectives, policies and processes to manage these risks from December 31, 2016.

Market risk

Market risk is the risk that changes in market prices, such as foreign exchange rates, commodity prices, and interest rates will affect the Company's comprehensive loss to the extent the Company has outstanding financial instruments. The objective of the Company is to mitigate market risk exposures within acceptable limits, while maximizing returns.

Commodity price risk

The nature of the Company's operations results in exposure to fluctuations in commodity prices. Management continuously monitors commodity prices and initiates instruments to manage exposure to these risks when it deems appropriate. As a means of managing commodity price volatility, the Company enters into various derivative financial instrument agreements and physical contracts. The fair values of the derivative financial instruments are based on mark-to-market assessments and estimates of fair value and are recorded on the consolidated balance sheet as either an asset or liability with the change in fair value recognized in comprehensive loss.

The following information presents all outstanding positions for commodity derivative financial instruments at June 30, 2017:

Term	Product	Type	Volume	Price	Basis
July 1, 2017 to September 30, 2017	Gas	Swap	27,500 gj/day	$2.80	AECO
October 1, 2017 to December 31, 2017	Gas	Swap	20,027 gj/day	$2.76	AECO
January 1, 2018 to March 31, 2018	Gas	Swap	12,500 gj/day	$3.01	AECO
July 1, 2017 to December 31, 2017	Oil	Swap	400 bbl/day	$69.58	WTI
January 1, 2018 to March 31, 2018	Oil	Swap	200 bbl/day	$70.00	WTI

For the three and six months ended June 30, 2017, realized gains from commodity derivative contracts recognized in comprehensive loss were $502 and $256 (2016 - $2,831 and $5,797 gains).

The fair value of the commodity contracts outstanding at June 30, 2017 was a current asset of $2,961 (December 31, 2016 – current liability of $4,491 and non-current liability of $159).

For the three and six months ended June 30, 2017, the Company recorded unrealized gains of $2,152 and $7,610 from derivative commodity contracts (2016 - $7,154 and $3,964 unrealized losses).

As at June 30, 2017, an increase in gas price of $0.50/gj and oil price of $1.00/bbl results in a decrease in the fair value of the commodity contracts of $2,749 ($2,006 after tax) and $92 ($67 after tax) respectively and a commensurate increase to comprehensive loss.

Credit risk

Credit risk is the risk of financial loss to the Company if a counterparty to a financial instrument fails to meet its contractual obligation. The Company is exposed to credit risk with respect to its cash, accounts receivable and commodity contract assets.

The Company's cash is held with a large established financial institution. The majority of the Company's accounts receivable are due from joint venture partners in the oil and gas industry and from marketers of the Company's petroleum and natural gas production. The Company mitigates its credit risk by entering into contracts with established counterparties that have strong credit ratings and reviewing its exposure to individual counterparties on a regular basis.

As at June 30, 2017, the accounts receivable balance was $12,357 of which $666 was past due. The Company considers all amounts greater than 90 days past due. These past due accounts are considered to be collectible, except as provided in the allowance for doubtful accounts. When determining whether past due accounts are uncollectible, the Company factors in the past credit history of the counterparties. The following table provides an aging analysis of the Company's accounts receivables:

Current	30-60 days	60-90 days	90+days	Total
10,947	324	420	666	12,357

At June 30, 2017, the Company has an allowance for doubtful accounts of $695 (December 31, 2016 - $647).

11. CHANGES IN NON-CASH WORKING CAPITAL

	Three months ended June 30,		Six months ended June 30,	
	2017	2016	**2017**	2016
Accounts receivable	**(1,050)**	4,623	**1,788**	10,881
Deposits and prepaid expenses	**(25)**	140	**(106)**	235
Accounts payable and accrued liabilities	**(11,733)**	(12,517)	**(12,119)**	(17,918)
Net change in non-cash working capital	**(12,808)**	(7,754)	**(10,437)**	(6,802)
Allocated to:				
Operating activities	**(1,665)**	(2,732)	**(1,355)**	3,499
Investing activities	**(11,146)**	(4,989)	**(9,082)**	(10,199)
Financing activities	**3**	(33)	**–**	(102)
	(12,808)	(7,754)	**(10,437)**	(6,802)

12. CAPITAL MANAGEMENT

There have been no changes to the Company's objectives, policies and processes to manage capital from December 31, 2016.

At June 30, 2017, Cequence has $60,000 in senior notes due in 2018 and a $20,000 senior credit facility which the Company had drawn $nil. The Company's senior credit facility is based on the lenders' review of the Company's oil and natural gas reserves with the next scheduled review expected to be completed in November 2017. On October 28, 2016, the Company completed the sale, on a private placement basis, of 34,500 common voting shares on a CDE "flow-through" basis at $0.29 per share for gross proceeds of $10,005.

The senior credit facility has a covenant that requires Senior Debt to twelve month trailing EBITDA, as defined in the bank agreement, to be less than 3:0 to 1:0. The Company was in compliance with the lender's covenant at June 30, 2017 with a ratio of 0.1 times (December 31, 2016 – 0.2 times).

The senior notes contain incurrence covenants that use a Debt to Cashflow test that is in excess of 2.5 times for the preceding four quarters to limit the incurrence of additional debt, the creation of liens in connection with indebtedness, dividends and other distributions, asset sales and other matters, and customary events of default. At June 30, 2017 the Company's Debt to Cashflow ratio was in excess of 2.5 times. If low commodity prices persist, the Company expects the Debt to Cashflow ratio to remain in excess of 2.5 times. The Company does not currently anticipate initiating an action that would be restricted by the incurrence covenants.

The Company continues to review its options to improve its financial leverage including the sale of assets, further adjustments to the capital program, hedging or the issuance of equity. Over the next twelve months, the Company believes that it has the ability to manage its cash flow and net capital expenditures within its available credit and will be in compliance with its financial covenants.

The Company has also engaged in a preliminary review of financing alternatives to modify or replace the senior notes that mature in October 2018.

CORPORATE INFORMATION

MANAGEMENT

Todd Brown, P.Eng
Chief Executive Officer

David Gillis, CA
Executive Vice President, Finance & CFO

David P. Robinson
Vice President, Geology

Christopher C. Soby
Vice President, Land

Erin Thorson, CMA
Controller

DIRECTORS

Don Archibald
Chairman

Peter Bannister
Howard Crone
Brian Felesky
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