HIGHLIGHTS

(000's except per share and per unit amounts)	Three months ended December 31,			Twelve months ended December 31,		
	2017	**2016**	% Change	**2017**	**2016**	% Change
FINANCIAL						
Total revenue[1]	**13,585**	17,253	**(21)**	**65,836**	59,074	**11**
Comprehensive loss	**(6,638)**	(9,077)	**(27)**	**(99,362)**	(28,057)	**(254)**
Per share – basic and diluted	**(0.03)**	(0.04)	**(25)**	**(0.40)**	(0.13)	**(208)**
Funds flow from operations [2][5]	**1,583**	6,625	**(76)**	**19,329**	11,250	**72**
Per share, basic and diluted	**0.01**	0.03	**(67)**	**0.08**	0.05	**60**
Capital expenditures, before acquisitions (dispositions)	**5,593**	11,460	**(51)**	**25,857**	22,590	**14**
Capital expenditures, including acquisitions (dispositions)	**1,316**	11,406	**(88)**	**21,580**	17,296	**25**
Net debt [3]	**(68,501)**	(64,031)	**7**	**(68,501)**	(64,031)	**7**
Weighted average shares outstanding – basic & diluted	**245,528**	235,028	**4**	**245,528**	217,061	**13**
OPERATING						
Production volumes						
Natural gas (Mcf/d)	**33,331**	45,005	**(26)**	**40,466**	45,442	**(11)**
Crude oil (bbls/d)	**283**	140	**102**	**344**	177	**94**
Natural gas liquids (bbls/d)	**257**	209	**23**	**254**	237	**7**
Condensate (bbls/d)	**617**	760	**(19)**	**797**	841	**(5)**
Total (boe/d)	**6,713**	8,609	**(22)**	**8,139**	8,826	**(8)**
Sales prices						
Natural gas, including realized hedges ($/Mcf)	**2.33**	2.92	**(20)**	**2.53**	2.27	**11**
Crude oil and condensate, including realized hedges ($/bbl)	**66.73**	56.27	**19**	**61.44**	52.17	**18**
Natural gas liquids ($/bbl)	**38.55**	25.61	**51**	**30.72**	21.94	**40**
Total ($/boe)	**22.00**	21.78	**1**	**22.16**	18.29	**21**
Netback ($/boe)						
Price, including realized hedges	**22.00**	21.78	**1**	**22.16**	18.29	**21**
Royalties	**(0.63)**	(0.59)	**7**	**(1.06)**	(0.48)	**121**
Transportation	**(1.66)**	(1.45)	**14**	**(1.88)**	(1.24)	**52**
Operating costs	**(12.91)**	(7.81)	**65**	**(9.29)**	(8.49)	**9**
Operating netback	**6.80**	11.93	**(43)**	**9.93**	8.08	**23**
General and administrative[5]	**(1.88)**	(1.81)	**4**	**(1.48)**	(2.77)	**(47)**
Interest[4]	**(2.46)**	(1.92)	**28**	**(2.07)**	(1.93)	**7**
Cash netback	**2.46**	8.20	**(70)**	**6.38**	3.38	**89**

(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 twelve months ended December 31, 2016, general and administrative expenses and funds flow from operations includes $nil and $2,341 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 audited consolidated financial statements (the "annual financial statements") and related notes for the years ended December 31, 2017 and 2016.

The consolidated financial statements have been prepared on the basis that the Company will continue as a going concern, which asserts that the Company has the ability to realize its assets and discharge its liabilities and commitments in the normal course of business. Further details are provided in note 2 of the consolidated financial statements.

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 March 12, 2018.

BASIS OF PRESENTATION

The Financial Statements and comparative information have been prepared in accordance with International Financial Reporting Standards ("IFRS").

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 fiscal 2017 the ratio between the average price of West Texas Intermediate ("WTI") crude oil at Cushing and NYMEX natural gas was approximately 17:1 ("Value Ratio"). The Value Ratio is obtained using the 2017 WTI average price of $50.81 (US$/Bbl) for crude oil and the 2017 NYMEX average price of $3.02 (US$/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.

Natural gas prices remained low in both 2016 and 2017 with AECO prices averaging $2.18/mcf and $2.23/mcf, respectively. During this period the Company has lowered capital spending to adjust for lower funds flow from operations and the reduced economics of the Company's natural gas weighted drilling inventory. The Company's 2017 capital expenditure program has focused on wells with higher oil and liquids content. In the fourth quarter 3.0 (2.0 net) Dunvegan oil wells were drilled with initial production results expected in March 2018.

Financial leverage has improved over the past year as the Company managed total debt levels by reducing capital expenditures. December 31, 2017 net debt is $68,501 (December 31, 2016 - $64,031) or 3.5 times trailing annual funds flow (December 31, 2016 - 5.7 times). The Company's financial condition is described in additional detail in the Liquidity and Capital Resources section of this MD&A.

The Company has undertaken a number of initiatives over the past two years to manage its balance sheet through a prolonged weakness in natural gas prices. Capital expenditures have been restricted to cash flow or funded by equity. The Company's funds flow for the year ended December 31, 2017 has increased by 72 percent from prior year due to cost structure improvements, higher average sales prices and lower general and administrative expenses. The Company continues to be committed to pursuing initiatives to improve its liquidity, long term sustainability and enhance shareholder value.

FINANCIAL AND OPERATING RESULTS

PRODUCTION

	Three months ended December 31,		Twelve months ended December 31,	
	2017	2016	**2017**	2016
Natural gas (Mcf/d)	**33,331**	45,005	**40,466**	45,422
Crude oil (bbls/d)	**283**	140	**344**	177
Natural gas liquids (bbls/d)	**257**	209	**254**	237
Condensate (bbls/d)	**617**	760	**797**	841
Total (boe/d)	**6,713**	8,609	**8,139**	8,826
Total production (boe)	**617,568**	792,069	**2,970,828**	3,230,434

Production for the three and twelve months ended December 31, 2017 averaged 6,713 boe/d and 8,139 boe/d compared to production of 8,609 boe/d and 8,826 boe/d, respectively in 2016. Sequentially, fourth quarter production decreased 19 percent from the third quarter of 2017. Late in the third quarter the Company shut in 600 boe/d uneconomic production as spot AECO prices were below $1/mcf. Weak prices persisted in October and this production remained shut in until November 1. In addition, the Company shut in most of the Simonette field for a week in October to conduct a field water transfer project that resulted in a production loss of 250 boe/d for the quarter. The remaining decrease in quarterly volumes relates primarily to natural production declines as no new production additions occurred in the quarter. The production downtime was longer than expected and 2017 annual production was 8,139 boe/d compared to revised guidance of 8,250 boe/d.

The Company estimated that production will be approximately 7,000 boe/d in the first quarter of 2018.

PRODUCTION REVENUE

	Three months ended December 31,		Twelve months ended December 31,	
$(000's)	**2017**	2016	**2017**	2016
Sales of natural gas, oil and condensate	**11,804**	17,428	**61,024**	52,269
Royalties	**(391)**	(467)	**(3,138)**	(1,543)
Production revenue	**11,413**	16,961	**57,886**	50,726

Production revenue was $11,413 and $57,886 in the three and twelve months ended December 2017 compared to $16,961 and $50,726 in 2016. Fourth quarter production revenue declined from prior year due to reductions in production volumes of 22 percent and average prices before hedging of 13 percent.

Annual production revenue increased due to a 27 percent increase in realized sales prices before hedging offset by a 8 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. The Company hedges forward crude oil and natural gas production and includes the realized hedging gains and losses in assessing total revenue.

	Three months ended December 31,				
$(000's)	Natural gas	Crude oil and condensate	Natural gas liquids	**2017 Total**	2016 Total
Sales of natural gas, oil and condensate	5,332	5,561	911	**11,804**	17,428
Realized gain (loss) on commodity contracts	1,814	(33)	-	**1,781**	(175)
Total revenue (1)	7,146	5,528	911	**13,585**	17,253

(1)Refer to non-GAAP measurements.

	Twelve months ended December 31,				
$(000's)	Natural gas	Crude oil and condensate	Natural gas liquids	**2017 Total**	2016 Total
Sales of natural gas, oil and condensate	33,121	25,056	2,847	**61,024**	52,269
Realized gain on commodity contracts	4,281	531	-	**4,812**	6,805
Total revenue (1)	37,402	25,587	2,847	**65,836**	59,074

(1)Refer to non-GAAP measurements.

Total revenue in the fourth quarter of 2017 decreased 21 percent compared to 2016 as higher realized hedging gains partially offset the 32 percent decline in sales of natural gas, oil and condensate. For the twelve months ended December 31, 2017, total revenue increased 11 percent from the comparable period of 2016 as the average realized sales prices before hedging increased by 27 percent from the prior year.

	Three months ended December 31,		Twelve months ended December 31,	
	2017	2016	**2017**	2016
Average prices				
Natural gas ($/Mcf)	**1.74**	2.95	**2.24**	1.93
Realized natural gas hedges ($/Mcf)	**0.59**	(0.03)	**0.29**	0.34
Natural gas including hedges ($/Mcf)	**2.33**	2.92	**2.53**	2.27
Crude oil and condensate ($/bbl)	**67.12**	57.30	**60.16**	49.20
Realized crude oil hedges ($/bbl)	**(0.39)**	(1.03)	**1.28**	2.97
Crude oil and condensate including hedges ($/bbl)	**66.73**	56.27	**61.44**	52.17
Natural gas liquids ($/bbl)	**38.55**	25.61	**30.72**	21.94
Average sales price before hedges ($/boe)	**19.11**	22.00	**20.54**	16.18
Average sales price including hedges ($/boe)	**22.00**	21.78	**22.16**	18.29
Benchmark pricing				
AECO-C spot (CDN$/Mcf)	**1.67**	3.11	**2.23**	2.18
NYMEX HH Gas (US$/Mcf)	**2.93**	3.18	**3.02**	2.55
WTI crude oil (US$/bbl)	**55.28**	49.16	**50.81**	43.34
Edmonton par price (CDN$/bbl)	**66.68**	60.76	**62.49**	52.95
US$/CDN$ exchange rate	**0.79**	0.75	**0.77**	0.76

Following a constructive start to 2017 AECO benchmark natural gas prices began to decline in the third quarter. AECO natural gas prices averaged $1.66/mcf in the second half of 2017 after averaging $2.74/mcf for the first six months. AECO basis differentials to NYMEX widened as WCSB supply has remained strong despite lower prices caused by reduced capacity during pipeline maintenance and limited available storage.

The Company realized natural gas prices before hedging for three months ended December 31, 2017 of $1.74/mcf compared to $2.95/mcf in 2016. For the twelve months ended December 31, 2017, realized natural gas prices increased to $2.24/mcf compared to $1.93/mcf in 2016.

The Company’s average natural gas price realization in the fourth quarter of 2017 was a four percent premium to AECO compared to a discount of five percent in 2016 which reflects the improved cost of the Company’s marketing contracts. In both 2016 and 2017 the Company marketed its gas using short term transportation and sales contracts on both the Alliance and TCPL pipeline systems. The limited availability of transportation often resulted in contracts to purchase gas from the Company at a discount to market or to acquire transportation at a premium to firm service.

In the third quarter, the Company advanced the start date of approximately 26 mmcf/d of natural gas transportation to December 17, 2017 from April 2018, increasing it total firm service from its Simonette property to AECO of 35 mmcf/d until March 2026. The Company will no longer rely on short term and interruptible service which is expected to improve the Company’s netbacks by approximately $0.20/mcf or $1.20/boe, with all other variables remaining consistent. The cost of this transportation will be reported as transportation expense and the Company expects its sales pricing to be at a premium to AECO based on its heat content.

In September 2017 the National Energy Board approved TransCanada Pipelines application for new transportation service from Empress, Alberta to Dawn, Ontario. The Company has contracted to ship 10,850 GJ/d of natural gas to the Dawn hub at a cost of $0.77/GJ for a period of 10 years beginning April 1, 2018. The transportation commitment provides market diversification for approximately 20 percent of its current natural gas production. Historically, pricing at the Dawn hub has been at a premium to AECO. As part of this commitment, the Company entered into a five year contract to transport AECO gas to Empress at an annual cost of approximately $750.

For the three and twelve months ended December 31, 2017, benchmark Edmonton par crude oil prices increased ten percent and 18 percent from 2016. Strong demand in Alberta for condensate results in Canadian benchmark condensate prices that are a premium to par prices. For the three and twelve months ended December 31, 2017, condensate benchmark prices were a 10 percent and 6 percent premium to Edmonton par. Crude oil and condensate prices before hedges for the three and twelve months ended December 31, 2017 were $67.12/bbl and $60.16/bbl up 17 percent and 22 percent respectively from the same period in 2016. Natural gas liquids prices for the three and twelve months ended December 31, 2017 were $38.55/bbl and $30.72/bbl up 51 percent and 40 percent from the same time period in 2016.

COMMODITY PRICE MANAGEMENT

	Three months ended December 31,		**Twelve months ended December 31,**	
$(000's)	**2017**	2016	**2017**	2016
Realized gain (loss) on commodity contracts	**1,781**	(175)	**4,812**	6,805
Unrealized gain (loss) on commodity contracts	**(2,042)**	(4,402)	**4,927**	(8,294)
Total	**(261)**	(4,577)	**9,739**	(1,489)

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 December 31, 2017 was a current asset of $1,274 and current liability of $998 (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**
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**
January 1, 2018 to March 31, 2018	Oil	Swap	500	$67.17	WTI
April 1, 2018 to June 30, 2018	Oil	Swap	500	$63.35	WTI
July 1, 2018 to December 31, 2018	Oil	Swap	300	$71.72	WTI

OPERATING NETBACK

($/boe)	Three months ended December 31, 2017	2016	Twelve months ended December 31, 2017	2016
Total revenue[1]	**22.00**	21.78	**22.16**	18.29
Royalty expense	**(0.63)**	(0.59)	**(1.06)**	(0.48)
Transportation expense	**(1.66)**	(1.45)	**(1.88)**	(1.24)
Operating costs	**(12.91)**	(7.81)	**(9.29)**	(8.49)
Operating netback, $/boe	**6.80**	11.93	**9.93**	8.08
Operating netback, excluding realized hedges, $/boe	**3.91**	12.15	**8.31**	5.97

(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 December 31, 2017 declined 68 percent to $3.91/boe. Including realized hedges, operating netbacks per boe decreased by 43 percent. The decrease in operating netbacks was driven by higher quarterly operating expenses and transportation costs.

For the twelve months ended December 31, 2017 operating netback per boe, excluding realized hedging increased 39 percent. The increase in operating netbacks was driven by higher commodity prices which more than offset higher operating, transportation and royalty expenses.

ROYALTY EXPENSE

$(000's)	Three months ended December 31, 2017	2016	Twelve months ended December 31, 2017	2016
Crown	**141**	(219)	**1,568**	(218)
Freehold / Overriding	**250**	686	**1,570**	1,761
Total royalties	**391**	467	**3,138**	1,543
Royalties as a percentage of revenue, before hedging	**3%**	3%	**5%**	3%
Per unit of production ($/boe)	**0.63**	0.59	**1.06**	0.48

Royalties as a percentage of revenue, before hedging for the three months ended December 31, 2017 was consistent with prior year. For the twelve months ended December 31, 2017 royalties increased to 5 percent as year to date average sales prices are higher than in 2016.

OPERATING COSTS

$(000's)	Three months ended December 31, 2017	2016	Twelve months ended December 31, 2017	2016
Operating costs	**7,972**	6,184	**27,584**	27,436
Per unit of production ($/boe)	**12.91**	7.81	**9.29**	8.49

Operating costs for the three and twelve months ended December 31 2017, were $12.91/boe and $9.29/boe, respectively, compared to $7.81/boe and $8.49/boe in 2016. In the second half of 2017 the Company executed a water handling project to manage its surface water at its Simonette field. Total costs of the project were $1,330 ($2.15/boe) for the fourth quarter and $3,285 year to date ($1.36/boe) and were associated with storing water at surface, transferring water to a water disposal well and dismantling surface tanks. The project was completed in December and is expected to reduce ongoing water handling beginning in January 2018. In addition, 600 boe/d of low netback volumes were shut-in during the quarter, reducing volumes and therefore increasing per boe costs for the period. Total operating costs are expected to return to historical levels of approximately $9.50 - $10.50/boe in the first quarter or 2018.

The Company will continue to monitor production in periods of low commodity and may shut in higher cost, uneconomic production. Per unit operating costs are expected to increase in this case as fixed costs will be allocated to a smaller production base.

TRANSPORTATION EXPENSE

$(000's)	Three months ended December 31, 2017	2016	Twelve months ended December 31, 2017	2016
Transportation	**1,023**	1,151	**5,571**	4,018
Per unit of production ($/boe)	**1.66**	1.45	**1.88**	1.24

Transportation expense for the fourth quarter of 2017 was $1.66/boe an increase of 14 percent from the comparative period in 2016. For the twelve months ended December 31, 2017, transportation expense was $1.88/boe an increase of 52 percent from $1.24/boe in 2016. The increase relates to increased clean oil and condensate volumes resulting in higher trucking and pipeline costs. Year to date, transportation expense also increased due to the impact of a full year of firm service natural gas transportation contract that commenced in July 2016.

GENERAL AND ADMINISTRATIVE EXPENSES

$(000's)	Three months ended December 31, 2017	2016	Twelve months ended December 31, 2017	2016
G&A expenses, prior to restructuring charges	**1,284**	1,597	**4,795**	6,926
Restructuring charges	**-**	-	**-**	2,341
G&A expenses	**1,284**	1,597	**4,795**	9,267
Administrative and capital recovery	**(123)**	(164)	**(387)**	(316)
Total G&A expenses	**1,161**	1,433	**4,408**	8,951
Per unit of production, excluding restructuring charges ($/boe)	**1.88**	1.81	**1.48**	2.05
Per unit of production ($/boe)	**1.88**	1.81	**1.48**	2.77

In 2016, the Company reduced its G&A costs by reducing its staff and relocating the Company's office. For the twelve months ended December 31, 2017, G&A expenses were reduced by 48 percent from 2016 to $4,795. Prior to restructuring costs G&A expenses decreased by 31 percent.

FINANCE COSTS

	Three months ended December 31,		Twelve months ended December 31,	
	2017	2016	**2017**	2016
Interest and standby fees expense on credit facility	**56**	53	**331**	411
Interest expense and standby fees on senior notes	**1,466**	1,464	**5,820**	5,821
Amortization of transaction costs	**117**	107	**443**	400
Accretion expense on senior notes	**90**	81	**341**	308
Accretion expense on provisions	**211**	220	**870**	803
Total finance costs	**1,940**	1,925	**7,805**	7,743
Per unit of production ($/boe)	**3.14**	2.43	**2.63**	2.40
Interest per unit of production ($/boe)	**2.46**	1.92	**2.07**	1.93

Finance costs for the three and twelve months ended December 31, 2017 were $1,940 and $7,805 compared to $1,925 and $7,743 in 2016. There was no change to the Company's unsecured debt in the year and interest and standby fees remained consistent to 2016. The credit facility remained undrawn in 2017 other than letters of credit. Interest and standby fees on the facility were lower in 2017 as the facility size was reduced.

OTHER INCOME

	Three months ended December 31,		Twelve months ended December 31,	
$(000's)	**2017**	2016	**2017**	2016
Loss (gain) on sale of property and equipment	**248**	(220)	**130**	(3,202)
Interest income	**(21)**	(75)	**(102)**	(115)
Other	**(46)**	(49)	**(243)**	(241)
Total other income	**181**	(344)	**(215)**	(3,558)

In December, 2017, the Company disposed a non-core property in Northeast British Columbia and lower Montney rights at Simonette for proceeds of $4,270 prior to closing adjustments resulting in a loss recognized in comprehensive loss of $250. The sale included approximately 100 boe/d of production in Northeast British Columbia and 25 sections of lower Montney rights in Simonette.

During the year ended December 31, 2017, the Company completed additional sales of certain oil and gas properties, including associated decommissioning obligation liabilities, for total cash consideration of $nil (2016 - $160), subject to final adjustments. The sales resulted in a gain recognized in comprehensive loss of $120 (2016 - $238 gain).

Other income includes a gain in 2016 of $2,964 from the sale of certain infrastructure assets that were partially depreciated.

DEPLETION, DEPRECIATION AND IMPAIRMENT

$(000's)	Three months ended December 31, 2017	2016	Twelve months ended December 31, 2017	2016
Depletion and depreciation expense	**5,348**	10,757	**24,606**	31,622
Impairment loss	**-**	-	**96,200**	-
Total depletion, depreciation and impairment	**5,348**	10,757	**120,806**	31,622
Per unit of production ($/boe)	**8.66**	13.58	**40.66**	9.79
Per unit of production, excluding impairment ($/boe)	**8.66**	13.58	**8.28**	9.79

Depletion and depreciation expense for the three and twelve months ended December 31, 2017 was $5,348 ($8.66/boe) and $120,806 ($40.66/boe). Depletion and depreciation rates are lower than the prior year due to the reduction in net book value resulting from the impairment charge in the second quarter of 2017.

The Company reviewed each CGU comprising its property and equipment at December 31, 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. Impairment tests were conducted at December 31, 2017, however based on the results of the tests no additional impairment expense was required to be booked for the year ended December 31, 2017.

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 at June 30, 2017 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 had 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 twelve months ended December 31, 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 December 31, 2017	2016	Twelve months ended December 31, 2017	2016
Northeast British Columbia	**-**	-	**-**	-
Peace River Arch	**-**	-	**2,200**	-
Deep Basin	**-**	-	**94,000**	-
Total	**-**	-	**96,200**	-

SHARE-BASED PAYMENTS

Stock Options

The Company has 13,220 stock options outstanding with an average exercise price of $0.56. The options have a five year life and vest evenly over a three year period on the anniversary date of their grant. For the twelve months ended December 31, 2017, Cequence recorded $991 (2016 – $708) 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 twelve months ended December 31, 2017, Cequence recognized $37 (2016 – $374) in share-based payment expense related to RSUs with a corresponding increase to share-based payment liability.

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

	RSUs		**Stock Options**	
Number (000's)	**2017**	2016	**2017**	2016
Outstanding, beginning of period	**3,010**	1,707	**11,003**	11,395
Granted	**700**	2,622	**5,025**	6,295
Settled	**(1,015)**	(642)	**-**	-
Cancelled/Forfeited	**(29)**	(677)	**(107)**	(3,900)
Expired	**-**	-	**(2,701)**	(2,787)
Outstanding, end of period	**2,666**	3,010	**13,220**	11,003

CAPITAL EXPENDITURES

	Three months ended December 31,		**Twelve months ended December 31,**	
$(000's)	**2017**	2016	**2017**	2016
Land	**250**	199	**875**	886
Geological & geophysical and capitalized overhead	**203**	551	**1,021**	1,141
Drilling, completions and workovers	**3,597**	9,111	**18,140**	14,192
Equipment, facilities and tie-ins	**1,543**	1,595	**5,818**	6,366
Office furniture & equipment	**-**	4	**3**	5
Capital expenditures	**5,593**	11,460	**25,857**	22,590
Property acquisitions [1]	**(7)**	23	**(7)**	(60)
Property dispositions [1]	**(4,270)**	(77)	**(4,270)**	(5,234)
Total capital expenditures	**1,316**	11,406	**21,580**	17,296

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

Capital expenditures in the fourth quarter consisted of drilling 3.0 gross (2.0 net) Dunvegan wells and related facility and pipeline expenditures.

For the year ended December 31, 2017, capital expenditures included the drilling of 3.0 gross (2.0 net) Duvegan wells and the completion of 2.0 Montney wells and related surface facilities plus the completion and equipping of a water disposal well.

In December 2017, the Company disposed a non-core property in Northeast British Columbia and lower Montney rights at Simonette for proceeds of $4,270 prior to closing adjustments. The sale resulted in a loss recognized in comprehensive loss of $250.

During the year ended December 31, 2017, the Company completed additional sales of certain oil and gas properties, including associated decommissioning obligation liabilities, for total cash consideration of $nil (2016 - $160), subject to final adjustments. The sales resulted in a gain recognized in comprehensive loss of $120 (2016 - $238 gain).

INCOME TAXES

As at December 31, 2017, the Company has tax pools and available losses of $616,660 (December 31, 2016 - $613,777). Due to the uncertainty of future realization, a deferred tax asset has not been recognized.

At December 31, 2017, Cequence has the following tax pools:

Classification	**Amount $(000's)**	**Annual Deductibility**
Canadian exploration expense	151,078	100%
Non-capital losses	325,760	100%
Undepreciated capital cost	46,137	Primarily 25%, declining balance
Canadian oil and gas property expense	7,700	10%, declining balance
Canadian development expense	58,832	30%, declining balance
Other	27,153	Various
	616,660	

The Company's non-capital losses expire in 2028 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 obligations

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 December 31, 2017 were $38,478 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 $1,466 of decommissioning obligations in the twelve months ended December 31, 2018. The following table summarizes the changes in decommissioning liabilities for the respective periods:

	December 31, 2017	December 31, 2016
Balance, beginning of year	**38,161**	40,708
Property dispositions	**(776)**	(364)
Accretion expense	**870**	803
Liabilities incurred	**371**	286
Abandonment costs incurred	**(1,079)**	(1,852)
Revisions in estimated cash flows	**(185)**	(126)
Revisions due to change in discount rates	**1,116**	(1,294)
Balance, end of year	**38,478**	38,161

The total estimated, undiscounted cash flows, inflated at 2 percent, required to settle the obligations are $63,742 (December 31, 2016 - $66,240). These cash flows have been discounted using a risk-free interest rate of 2.20 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 adjusts considering economic conditions and the risk characteristics of the underlying assets. 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.

$(000's)	**As at December 31, 2017**	As at December 31, 2016
Cash	**10,971**	17,778
Demand credit facility	**-**	-
Senior notes – principal	**(60,000)**	(60,000)
Accounts payable and accrued liabilities	**(33,106)**	(36,124)
Share-based payment liability	**(153)**	(341)
Provisions – current	**(1,466)**	(366)
Accounts receivable	**14,739**	14,145
Deposits and prepaid expenses	**514**	877
Net debt (1)	**(68,501)**	(64,031)
Funds flow from operations(1) - trailing twelve months	**19,329**	11,250
Net debt to funds flow from operations trailing twelve months	**3.5:1**	5.7:1

(1) Refer to non-GAAP measurements

At December 31, 2017, the Company's net debt to funds flow from operations of 3.5:1 is higher than the Company's long term target of 2:1. The Company's net debt to funds flow from operations trailing twelve months has improved in 2017 as commodity prices have increased and the Company realized the benefits of its costs saving initiatives.

The prolonged period of low commodity prices, in particular natural gas, beginning in 2015 has reduced the Company's funds flow from operations and limited the availability of new capital to repay debt or expand development activity. During this period, the Company has lowered capital spending, issued flow through shares and reduced its G&A to manage its leverage and to limit borrowing on its senior credit facility. Based on the current outlook for natural gas in 2018 the Company expects to continue to manage capital expenditures and limit drilling expenditures to oil weighted prospects. Refer to going concern discussions in note 2 of the consolidated financial statements.

Senior Credit Facility

As at December 31, 2017, Cequence had a $12,000 (December 31, 2016 - $20,000) term credit facility available from a syndicate of Canadian chartered banks. In November 2017, the Company's senior credit facility was reduced to $12,000 from $20,000 as the lenders adjusted for lower forecasted commodity prices and the pending maturity of the Company's senior credit facility. As at December 31, 2017 and December 31, 2016, the senior credit facility is undrawn. The company has letters of credit outstanding of $1,540 (December 31, 2016 - $3,307).

The senior credit facility has a term date of May 31, 2018 and 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 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 expected to be completed May 2018 and there is no assurance that credit facility will extend beyond that date..

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 December 31, 2017 with a ratio of 0.1 times (December 31, 2016 – 0.2 times). At December 31, 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 senior notes mature in October 2018 and Cequence is engaged in a review of potential financing alternatives to modify or replace the senior notes or otherwise improve the long term sustainability of the Company. If Cequence does not find a financing alternative for the Notes, it appears unlikely that Cequence will be able to repay the principal amount of the Notes on or before October 2018 as Cequence's current and anticipated earnings and available liquidity are not likely to provide enough cash to do so. The Company is actively pursuing various strategies to improve its liquidity position including ongoing discussions with CPPIB, debt or equity financing, potential business combinations or other restructuring. Management believes that it will be able to implement one or more of these strategies prior to the senior notes maturing.

Senior Note Covenants

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 December 31, 2017, the Company's Debt to Cashflow ratio was 2.4 times (December 31, 2016 – in excess of 2.5 times).

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 December 31, 2017 ACTNA is $224,772. 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.

	2018	2019	2020	2021	2022+	Total
Office leases	359	261	-	-	-	620
Pipeline transportation	5,178	6,117	6,117	6,117	32,134	55,663
Gas processing	4,154	4,154	4,166	4,154	34,625	51,253
Total	9,691	10,532	10,283	10,271	66,759	107,536

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 the third quarter of 2017, the Company advanced the start date of approximately 26 mmcf/d of natural gas transportation to December 17, 2017 from April 2018. The contract reduces the Company's reliance on short term and interruptible transportation contracts and is expected to improve netbacks by lowering the cost of transportation or improving sales prices. Beginning December 17, 2017, the Company will have firm transportation to AECO on the NGLT pipeline system for approximately 35 mmcf/d until March 2026.

In September 2017 the National Energy Board approved TransCanada Pipelines application for new transportation service from Empress, Alberta to Dawn, Ontario. The Company has contracted to ship 10,850 GJ/d of natural gas to the Dawn hub at a cost of $0.77/GJ for a period of 10 years beginning April 1, 2018. The transportation commitment provides market diversification for approximately 20 percent of its current natural gas production. Historically, pricing at the Dawn hub has been at a premium to AECO. As part of this commitment, the Company entered into a five year contract to transport AECO gas to Empress at an annual cost of approximately $750.

OUTSTANDING SHARE DATA

	March 13, 2017	**December 31, 2017**	December 31, 2016
Common shares	**245,528**	**245,528**	245,528
Stock options	**13,220**	**13,220**	11,003
Restricted share units	**2,666**	**2,666**	3,010
Warrants	**3,000**	**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.

SELECTED FINANCIAL INFORMATION

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

	Three months ended December 31,		**Twelve months ended December 31,**		
$(000's)	**2017**	2016	**2017**	2016	2015
Cash flow from operating activities	**1,657**	6,084	**19,884**	11,641	31,884
Decommissioning liabilities expenditures	**540**	259	**1,079**	1,852	720
Net change in non-cash working capital	**(614)**	282	**(1,634)**	(2,243)	(7,026)
Funds flow from operations	**1,583**	6,625	**19,329**	11,250	25,578
Per share – basic and diluted ($)	**0.01**	0.03	**0.08**	0.05	0.12
Total revenue	**13,585**	17,253	**65,836**	59,074	80,891
Comprehensive loss	**(6,638)**	(9,077)	**(99,362)**	(28,057)	(250,072)
Per share – basic and diluted ($)	**(0.03)**	(0.04)	**(0.40)**	(0.13)	(1.19)
Total assets	**284,728**	388,858	**284,728**	388,858	409,559
Demand credit facilities	**-**	-	**-**	-	-
Senior notes – principal	**60,000**	60,000	**60,000**	60,000	60,000

Funds flow from operations was $1,583 for the three months ended December 31, 2017 compared to $6,625 in 2016. The decrease in funds flow from operations is due to decreased production volumes, realized prices before hedges and higher operating expenses partially offset by lower transportation and G&A expenses. Annual funds flow from operations increased by 72 percent from 2016 primarily a result of higher commodity prices and lower G&A expenses. The increase was partially offset by the impact of lower realized hedging gains and higher royalty and transportation expense.

Cequence recorded a comprehensive loss of $6,638 for the three months ended December 31, 2017 compared to a loss of $9,077 in 2016. The decrease is mainly due to lower DD&A expense, unrealized loss and increased realized gains on commodity contracts more than offsetting decreases in production revenues and increased operating expenses.

Cequence recorded a comprehensive loss of $99,362 for the twelve months ended December 31, 2017 compared to a loss of $28,057 in 2016. The decrease is mainly due to an impairment charge of $96,200 recognized in 2017.

QUARTERLY INFORMATION

FINANCIAL

($ thousands except per share data)	2017 Q4	2017 Q3	2017 Q2	2017 Q1	2016 Q4	2016 Q3	2016 Q2	2016 Q1
Total revenue[1]	**13,585**	15,087	17,810	19,354	17,253	14,707	11,343	15,772
Royalties expense	**391**	465	927	1,355	467	636	(125)	565
Transportation expense	**1,023**	1,590	1,650	1,308	1,151	1,001	774	1,092
Operating costs	**7,972**	7,004	5,829	6,779	6,184	6,228	5,812	9,212
Comprehensive income (loss)	**(6,638)**	(3,076)	(94,899)	5,251	(9,077)	(880)	(12,212)	(5,888)
Per share – basic & diluted	**(0.03)**	(0.01)	(0.39)	0.02	(0.04)	(0.00)	(0.06)	(0.03)
Funds flow from (used in) operations [2]	**1,583**	3,619	6,781	7,346	6,625	3,385	1,554	(314)
Per share – basic & diluted	**0.01**	0.01	0.03	0.03	0.03	0.02	0.01	(0.00)
Capital expenditures, net	**5,593**	2,682	2,536	15,046	11,460	2,810	958	7,362
Net acquisitions (dispositions) [3]	**(4,277)**	-	-	-	(54)	(5,167)	138	(211)
Total capital expenditures	**1,316**	2,682	2,536	15,046	11,406	(2,357)	1,096	7,151

(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 Q4	2017 Q3	2017 Q2	2017 Q1	2016 Q4	2016 Q3	2016 Q2	2016 Q1
Production volumes								
Natural gas (Mcf/d)	**33,331**	40,729	42,719	45,214	45,005	44,320	40,127	52,253
Oil (bbls/d)	**283**	388	224	481	140	175	178	218
NGLs (bbls/d)	**257**	250	239	270	209	261	244	235
Condensate (bbls/d)	**617**	841	919	814	760	798	748	1,061
Total (boe/d)	**6,713**	8,266	8,502	9,101	8,609	8,621	7,857	10,223
Average selling price, including realized hedges								
Natural gas ($/Mcf)	**2.33**	2.12	2.83	2.79	2.92	2.28	1.73	2.10
Crude oil and condensate ($/bbl)	**66.73**	57.70	60.11	62.50	56.27	53.78	54.01	46.69
NGLs ($/bbl)	**38.55**	27.86	26.11	29.92	25.61	24.09	21.50	16.68
Total ($/boe)	**22.00**	19.84	23.02	23.63	21.78	18.54	15.86	16.95
Operating netback, including realized hedges ($/boe)								
Price	**22.00**	19.84	23.02	23.63	21.78	18.54	15.86	16.95
Royalties	**(0.63)**	(0.61)	(1.20)	(1.65)	(0.59)	(0.80)	0.17	(0.61)
Transportation	**(1.66)**	(2.09)	(2.13)	(1.60)	(1.45)	(1.26)	(1.08)	(1.17)
Operating costs	**(12.91)**	(9.21)	(7.53)	(8.28)	(7.81)	(7.85)	(8.13)	(9.90)
Operating netback	**6.80**	7.93	12.16	12.10	11.93	8.63	6.82	5.27

The company's funds flow from operations and comprehensive incomes (loss) has been negatively impacted by low commodity prices, in particular natural gas prices. AECO natural gas prices averaged $2.18/mcf in 2016 and $2.23/mcf in 2017, significantly lower than previous years. The Company has reduced capital expenditures on new wells during this time period due to lower funds flow from operations and restricted access to cost effective capital.

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 the impact of declining benchmark natural gas prices on the estimated future value of the Company's oil and gas reserves. 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

The Company's guidance for the year ended December 31, 2017 is updated in the table below. Production estimates have been lowered by four percent due to production curtailments in the third and fourth quarters as a result of low natural gas prices. 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.

Guidance has not been set for 2018, however the Company does not expect to drill any additional wells in the first half of 2018.

(000's, except per share and per unit references)	Actual Results Year ended December 31, 2017	Revised Guidance Year ended December 31, 2017
Average production, boe/d (1)	8,139	8,250
Funds flow from operations ($)(2)	19,329	20,000
Funds flow from operations per share(2)	0.08	0.08
Capital expenditures ($)	25,857	24,000
Net acquisitions (dispositions) ($)	(4,277)	-
Operating and transportation costs ($/boe)	11.17	10.50
G&A costs ($/boe)	1.48	1.50
Royalties (% revenue)	5	6
Crude – WTI (US$/bbl)	50.81	50.25
Natural gas – AECO (CDN$/GJ)	2.04	2.08
Period end, net debt ($) (3)	68,501	68,000
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.

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 December 31, 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:

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 twelve months ended December 31, 2017.

APPLICATION OF CRITICAL ACCOUNTING ESTIMATES

The significant accounting policies used by Cequence are disclosed in note 2 to the consolidated financial statements. Certain accounting policies require that management make appropriate decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. Management reviews its estimates on a regular basis. The emergence of new information and changed circumstances may result in actual results or changes to estimate amounts that differ materially from current estimates. The following discussion identifies the critical accounting policies and practices of the Company and helps to assess the likelihood of materially different results being reported.

RESERVES

Oil and gas reserves are estimates made using all available geological and reservoir data, as well as historical production data. All of the Company’s reserves were evaluated and reported on by an independent qualified reserves evaluator. However, revisions can occur as a result of various factors including: actual reservoir performance, change in price and cost forecasts or a change in the Company’s plans. Reserve changes will impact the financial results as reserves are used in the calculation of depletion and are used to assess whether asset impairment occurs.

DEPLETION

The net carrying value of development and production assets plus future development costs on proved plus probable reserves is depleted using the unit of production method based on proved and probable reserves, gross of royalties, as determined by independent engineers, on an area by area basis. An increase in estimated proved plus probable reserves would result in a reduction in depletion expense. A decrease in estimated future development costs would also result in a reduction in depletion expense.

DEVELOPMENT AND PRODUCTION COSTS

Items of property and equipment, which include oil and gas development and production assets, are measured at cost less accumulated depletion and depreciation and accumulated impairment losses.

Development and production assets are grouped into CGUs for impairment testing. CGUs are defined as the smallest identifiable group of assets that generates cash inflows that are largely independent of the cash inflows from other assets or groups of assets. The Company evaluates the geography, geology, production profile and infrastructure of its assets in determining its CGUs. Based on this assessment, Cequence’s CGUs are generally composed of significant development areas. The Company reviews the composition of its CGUs at each reporting date to assess whether any changes are required in light of new facts and circumstances. When significant parts of an item of property and equipment, including oil and natural gas interests, have different useful lives, they are accounted for as separate items (major components).

IMPAIRMENT

The carrying amounts of all assets, other than financial assets and deferred tax assets, are reviewed at each reporting date to determine whether there is indication of an impairment loss. If any such indication exists, the asset’s recoverable amount is estimated.

The recoverability of the carrying amount of an exploration and evaluation asset is dependent on successful development and commercial exploitation, or alternatively, sale of the respective area of interest. Where a potential impairment is indicated, an assessment is performed for each field or area to which the exploration and evaluation expenditure is attributed. To the extent that capitalized expenditures are not expected to be recovered, the excess of the carrying amount over the recoverable amount is recognized immediately.

The recoverable amount of a development and production asset (or CGU) or other intangible asset (or CGU) is determined as the higher of its value in use and fair value less cost to sell. Value in use is determined by estimating future cash flows after taking into account the risks specific to the asset (or group of assets within a CGU) and discounting them to their present value using a pre-tax discount rate that reflects the current market assessment of the time value of money. In determining fair value less cost to sell, an appropriate valuation model is used. These calculations are corroborated by external valuation metrics or other available fair value indicators wherever possible.

Where the carrying amount of a development and production asset (or CGU) or other intangibles asset exceeds its recoverable amount, the excess is recognized immediately in comprehensive income (loss).

Where an impairment loss subsequently reverses, the carrying amount of the asset (or CGU) is increased to the revised estimate of its recoverable amount, but only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depreciation or depletion, if no impairment loss had been recognized.

DECOMMISSIONING LIABILITIES

The Company records a liability for the fair value of legal obligations associated with the retirement of petroleum and natural gas assets. The liability is equal to the discounted fair value of the obligation in the period in which the asset is recorded with an equal offset to the carrying amount of the asset. The liability then accretes to its fair value with the passage of time and the accretion is recognized as finance costs in the financial statements. The total amount of the decommissioning liability is an estimate based on the Company's net ownership interest in all wells and facilities, the estimated costs to abandon and reclaim the wells and facilities and the estimated timing of the costs to be incurred in future periods. The total amount of the estimated cash flows required to settle the decommissioning liabilities, the timing of those cash flows and the discount rate used to calculate the present value of those cash flows are all estimates subject to measurement uncertainty. Any change in these estimates would impact the decommissioning liabilities and the accretion expense.

SHARE-BASED PAYMENTS

The Company utilizes stock options and RSUs for its long term compensation program for directors, officers, employees and other service providers. Compensation costs attributable to stock options granted are measured at fair value at the date of grant and are expensed over the vesting period, using a graded vesting schedule, with a corresponding increase in contributed surplus. When stock options are exercised, the cash proceeds together with the amount previously recorded as contributed surplus are recorded as share capital. The Company incorporates an estimated forfeiture rate for stock options that will not vest, and subsequently adjusts for actual forfeitures as they occur.

The RSUs are accounted for in accordance with the requirements for cash-settled share-based payment transactions with the value of one RSU being notionally equivalent to one Cequence common share. Cequence has the option to settle the RSUs with cash or with Cequence common shares, however, management's intent is to settle the RSUs in cash and the amount settled is expected to be deductible for income tax purposes. Compensation costs attributable to RSU granted are measured at fair value at the date of grant and subsequently remeasured each period end date and are expensed over the vesting period, using a graded vesting schedule, with a corresponding adjustment to share-based payment liability. The Company incorporates an estimated forfeiture rate for RSUs that will not vest, and subsequently adjusts for actual forfeitures as they occur.

SENIOR NOTES

The Corporation uses estimates to allocate the proceeds from senior notes issuances between debt and the equity components, as appropriate.

INCOME TAXES

The determination of income and other tax assets and liabilities requires interpretation of complex laws and regulations. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax asset may differ significantly from that estimated and recorded by management.

The recognition of a deferred income tax asset is also based on estimates of whether it is probable that the Company is able to realize these assets. This estimate, in turn, is based on estimates of proved and probable reserves, future oil and natural gas prices, royalty rates and costs. Changes in these estimates could materially impact comprehensive income (loss) and the deferred income tax asset recognized.

COMMODITY CONTRACTS

The fair value of commodity contracts and the resultant unrealized gains (loss) on commodity contracts is based on estimates of future natural gas and crude oil prices.

OTHER ESTIMATES

Management estimates of revenues, royalties and operating costs as at a specific reporting date but for which actual revenues and costs have not yet been received. In addition, estimates are made on capital projects which are in progress or recently completed where actual costs have not been received by the reporting date. The Company obtains the estimates from the individuals with the most knowledge of the activity and from all project documentation received. The estimates are reviewed for reasonableness and compared to past performance to assess the reliability of the estimates. Past estimates are compared to actual results in order to make informed decisions on future estimates.

FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Company’s financial instruments, including derivative financial instruments, recognized in the consolidated balance sheet consist of cash, accounts receivable, commodity contracts, demand credit facilities, senior notes and accounts payable and accrued liabilities.

The Company's cash, accounts receivable, demand credit facilities and accounts payable and accrued liabilities approximate their carrying values due to their short terms to maturity and the floating interest rate on the Company's debt. The senior notes bear interest at rates available to Cequence and accordingly the fair value approximates the carrying value excluding deferred financing costs.

The Company is engaged in the exploration, development, production and acquisition of crude oil and natural gas. This business is inherently risky and there is no assurance that hydrocarbon reserves will be discovered and economically produced. Financial risks associated with the petroleum industry include fluctuations in commodity prices, interest rates and currency exchange rates along with the credit risk of the Company’s industry partners. Operational risks include reservoir performance uncertainties, the reliance on operators of the Company’s non-operated properties, competition, environmental and safety issues, and a complex and changing regulatory environment.

The primary risks and how the Company mitigates them are as follows:

Commodity price and exchange rate volatility

Revenues and consequently cash flows fluctuate with commodity prices and the U.S. / Canadian dollar exchange rate. Commodity prices are determined on both a regional and global basis and circumstances that occur locally in various parts of the world are outside of the control of the Company. The Company protects itself from fluctuations in prices by maintaining an appropriate hedging strategy and managing its balance sheet in light of prevailing economic conditions. Cequence enters into commodity price contracts to actively manage the risks associated with price volatility and thereby protect the Company's cash flows used to fund its capital program. Comprehensive loss for the year ended December 31, 2017 includes $4,812 of realized gain (2016 – $6,805 realized gain) and $4,927 of unrealized gain (2016 - $8,294 loss) on these transactions.

Cequence is also exposed to fluctuations in the exchange rate between the Canadian and U.S. dollar. Most commodity prices are based on U.S. dollar benchmarks that results in the Company's realized prices being influenced mainly by the U.S. / Canadian currency exchange rates. As at December 31, 2017 and 2016, the Company has a no forward contracts, foreign exchange contracts or other significant items denominated in foreign currencies.

Interest rate risk

The Company is exposed to interest rate risk to the extent that changes in market interest rates impact its borrowings under the floating rate credit facilities. The floating rate debt is subject to interest rate cash flow risk, as the required cash flows to service the debt will fluctuate as a result of changes in market rates. The Company has no interest rate swaps or financial contracts in place as at or during the year ended December 31, 2017.

As at December 31, 2017, a 1 percent change in interest rates on the Company's outstanding debt, with all other variables constant, would result in a change in comprehensive loss of $nil ($nil after tax) (2016 - $nil ($nil after tax)).

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 obligations. 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. At December 31, 2017, the Company has an allowance for doubtful accounts of $659 (2016 – $647).

Liquidity Risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they are due. The nature of the oil and gas industry is capital intensive and the Company maintains and monitors a certain level of cash flow to finance operating and capital expenditures. The Company believes it currently has sufficient credit facilities to satisfy its financial obligations as they come due.

The Company's ongoing liquidity is impacted by various external events and conditions, including commodity price fluctuations and the global economic environment.

The expected timing of cash flows relating to financial liabilities as at December 31, 2017 is as follows:

	< 1 Year	1 – 2 Years	2 – 5 Years	Thereafter
Senior notes – principal	60,000	-	-	-
Accounts payable and accrued liabilities	33,106	-	-	-
	93,106	-	-	-

Access to Capital Risk

The Company anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. As the Company's revenues have declined as a result of decreased commodity pricing, capital expenditures have been reduced. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Company. The inability of the Company to access sufficient capital for its operations could have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Environmental Risk

The oil and natural gas industry is subject to environmental regulation pursuant to local, provincial and federal legislation. Such legislation may be changed to impose higher standards and potentially more costly obligations on Cequence. Furthermore, management believes the federal and provincial political parties appear to favor new programs for environmental laws and regulation, particularly in relation to the reduction of emissions, and there is no assurance that any such programs, laws or regulations, if proposed and enacted, will not contain emission reduction targets which Cequence cannot meet, and financial penalties or charges could be incurred as a result of the failure to meet such targets. In particular there is uncertainty regarding the Federal Government's future regulation of air emissions.

The provincial government of Alberta released its Climate Leadership Plan which will impact all consumers and businesses that contribute to carbon emissions in Alberta. This plan includes imposing carbon pricing that is applied across all sectors, starting at $20 per tonne on January 1, 2017 and moving to $30 per tonne on January 1, 2018, the phase-out of coal-fired power generation by 2030, a cap on oil sands emissions production of 100 megatonnes, and a 45 per cent reduction in methane emissions by the oil and gas sector by 2025. The Company expects the Climate Leadership Plan to increase energy costs and the cost of operating its properties located in Alberta.

Regulatory Risk

There can be no assurance that government royalties, income tax laws, environmental laws and regulatory requirements relating to the oil and gas industry will not be changed in a manner which adversely affects the Company or its shareholders. Although the Company has no control over these regulatory risks, it continuously monitors changes in these areas by participating in industry organizations and conferences, exchanging information with third party experts and employing qualified individuals to assess the impact of such changes on the Company's financial and operating results.

Exploration, Development and Production Risks

The long term commercial success of the Company depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the addition of new reserves, the Company's reserves will decline over time as existing reserves are exploited. A future increase in the Company's reserves will depend not only on its ability to explore and develop any properties but also on its ability to select and acquire suitable producing properties or prospects.

Future oil and natural gas exploration may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological or mechanical conditions.

Production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees. To the extent the Company is not the operator of its oil and gas properties, the Company is dependent on such operators for the timing of activities related to such properties and will be largely unable to direct or control the activities of the operators.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, cratering, sour gas releases and spills, each of which could result in substantial damage to oil and natural gas wells, pipelines, production facilities, other property and the environment or in personal injury. The Company employs prudent risk management practices and maintains suitable liability insurance but may become liable for damages arising from such events against which it cannot insure, elects not to insure or because of high premium costs or other reasons. Costs incurred to repair such damage or pay such liabilities will reduce the cash flow of the Company.

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 2018 and beyond ; the Company’s projected capital investment levels for 2018 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 2018 capital program. The material assumptions supporting the 2018 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.