cequence energy ltd

2017 ANNUAL REPORT

FINANCIAL HIGHLIGHTS

(000's except per share and per unit amounts)	2017	Three months ended December 31, 2016	% Change	2017	Twelve months ended December 31, 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 and 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

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

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

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

	Three months ended December 31,		Twelve months ended December 31,	
$(000's)	**2017**	2016	**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.

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL INFORMATION

The accompanying financial statements and all information in the MD&A have been prepared by management and approved by the Board of Directors of Cequence Energy Ltd. The financial statements have been prepared in accordance with International Financial Reporting Standards and, where appropriate, reflect management's best estimates and judgments. Management is responsible for the accuracy, integrity and objectivity of the financial statements within reasonable limits of materiality and for the consistency of financial data included in the text of the MD&A with that in the financial statements.

To assist management in the discharge of these responsibilities, the Company maintains a system of internal controls designed to provide reasonable assurance that accounting records are reliable, transactions are properly authorized and assets are safeguarded from loss or unauthorized use. The Audit Committee is appointed by the Board of Directors, with all of its members being independent directors. The Audit Committee meets with management, as well as with the external auditors, to satisfy itself that management is properly discharging its financial reporting responsibilities and to review the financial statements and the auditor's report. The Audit Committee reports its findings to the Board of Directors for consideration in approving the financial statements for presentation to the shareholders. The external auditors have direct access to the Audit Committee of the Board of Directors.

The financial statements have been audited independently by Deloitte LLP on behalf of the Company in accordance with generally accepted auditing standards. Their report outlines the nature of their audits and expresses their opinion on the financial statements.

"signed"

Todd Brown
Chief Executive Officer

"signed"

Dave Gillis
Executive Vice President
and Chief Financial Officer

March 12, 2018

INDEPENDENT AUDITOR'S REPORT

TO THE SHAREHOLDERS OF CEQUENCE ENERGY LTD.

We have audited the accompanying consolidated financial statements of Cequence Energy Ltd., which comprise the consolidated balance sheets as at December 31, 2017 and 2016, and the consolidated statements of comprehensive loss, consolidated statements of changes in equity and consolidated statements of cash flows for the years then ended, and a summary of significant accounting policies and other explanatory information.

MANAGEMENT'S RESPONSIBILITY FOR THE CONSOLIDATED FINANCIAL STATEMENTS

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

AUDITOR'S RESPONSIBILITY

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

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

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

OPINION

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

EMPHASIS OF MATTER

Without qualifying our opinion, we draw attention to note 2 of the consolidated financial statements which describe matters and conditions that indicate the existence of material uncertainties that cast significant doubt about Cequence Energy Ltd.'s ability to continue as a going concern.

/s/ Deloitte LLP

Chartered Professional Accountants
March 12, 2018
Calgary, Alberta

CONSOLIDATED BALANCE SHEETS

(Expressed in thousands of Canadian dollars)

	December 31, 2017	December 31, 2016
	$	$
ASSETS		
CURRENT		
Cash	**10,971**	17,778
Accounts receivable (Note 7)	**14,739**	14,145
Deposits and prepaid expenses	**514**	877
Commodity contracts (Note 19)	**1,274**	–
	27,498	32,800
Property and equipment (Note 4)	**257,230**	356,058
	284,728	388,858
LIABILITIES		
CURRENT		
Accounts payable and accrued liabilities (Note 8)	**33,106**	36,124
Share-based payment liability (Note 16)	**153**	341
Provisions (Note 13)	**1,466**	366
Commodity contracts (Note 19)	**998**	4,491
Senior notes (Note 6)	**59,341**	–
	95,064	41,322
Commodity contracts (Note 19)	**–**	159
Senior notes (Note 6)	**–**	58,557
Provisions (Note 13)	**37,012**	37,795
	132,076	137,833
GOING CONCERN (Note 2)		
COMMITMENTS (Note 18)		
SHAREHOLDERS' EQUITY		
Share capital (Note 15)	**633,846**	633,848
Warrants (Note 15)	**1,300**	1,300
Contributed surplus	**31,076**	30,085
Deficit	**(513,570)**	(414,208)
	152,652	251,025
	284,728	388,858

APPROVED BY THE BOARD

[signed] "Donald Archibald"
Donald Archibald, Director

[signed] "Brian Felesky"
Brian Felesky, Director

CONSOLIDATED STATEMENTS OF COMPREHENSIVE LOSS

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

	Year ended December 31, 2017	2016
	$	$
REVENUE		
Production revenue (Note 9)	**57,886**	50,726
Gain (loss) on derivative financial instruments (Note 19)	**9,739**	(1,489)
	67,625	49,237
EXPENSES		
Operating costs	**27,584**	27,436
Transportation	**5,571**	4,018
Depletion and depreciation (Note 4)	**24,606**	31,622
Impairment (Note 4)	**96,200**	–
General and administrative (Note 12)	**4,408**	8,951
Finance costs (Note 11)	**7,805**	7,743
Share-based payment (Note 16)	**1,028**	1,082
Other income (Note 10)	**(215)**	(3,558)
	166,987	77,294
LOSS BEFORE INCOME TAXES	**(99,362)**	(28,057)
INCOME TAXES (Note 14)	**–**	–
NET LOSS AND COMPREHENSIVE LOSS	**(99,362)**	(28,057)
Loss per share (Note 17)		
Basic and diluted	**($0.40)**	($0.13)

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(Expressed in thousands of Canadian dollars)

	Year ended December 31, 2017	2016
	$	$
SHARE CAPITAL		
Common Shares (Note 15)		
Balance, beginning of year	**633,848**	624,619
Proceeds on issuance of flow-through shares	**–**	10,005
Share issue costs	**(2)**	(776)
Balance, end of year	**633,846**	633,848
Warrants (Note 15)		
Balance, beginning of year	**1,300**	1,300
Balance, end of year	**1,300**	1,300
CONTRIBUTED SURPLUS		
Balance, beginning of year	**30,085**	29,377
Share-based payment expense (Note 16)	**991**	708
Balance, end of year	**31,076**	30,085
DEFICIT		
Balance, beginning of year	**(414,208)**	(386,151)
Net loss	**(99,362)**	(28,057)
Balance, end of year	**(513,570)**	(414,208)
TOTAL EQUITY	**152,652**	251,025

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Expressed in thousands of Canadian dollars)

	Year ended December 31, 2017	2016
	$	$
CASH FLOWS RELATED TO THE FOLLOWING ACTIVITIES:		
OPERATING		
Net loss	(99,362)	(28,057)
Adjustments for non-cash items:		
Depletion and depreciation expense	24,606	31,622
Impairment expense	96,200	–
Finance costs related to provisions (Note 11)	870	803
Share-based payment expense (Note 16)	1,028	1,082
Amortization of transaction costs on senior notes (Note 11)	443	399
Accretion on senior notes (Note 11)	341	309
Unrealized (gain) loss on derivative financial instruments (Note 19)	(4,927)	8,294
Loss (gain) on sale of property and equipment (Note 10)	130	(3,202)
Decommissioning liabilities expenditures (Note 13)	(1,079)	(1,852)
Net change in non-cash working capital (Note 20)	1,634	2,243
	19,884	11,641
INVESTING		
Property and equipment expenditures (Note 4)	(25,857)	(22,590)
Property acquisitions (Note 4)	7	60
Proceeds from sale of property and equipment (Note 4)	4,270	5,234
Net change in non-cash working capital (Note 20)	(4,883)	1,268
	(26,463)	(16,028)
FINANCING		
Proceeds from demand credit facilities (Note 5)	–	6,200
Repayment of demand credit facilities (Note 5)	–	(6,200)
Cash settlement of share-based payments (Note 16)	(226)	(203)
Issue of common shares (Note 15)	–	10,005
Share issue costs (Note 15)	(2)	(776)
Net change in non-cash working capital (Note 20)	–	(107)
	(228)	8,919
NET INCREASE (DECREASE) IN CASH	(6,807)	4,532
CASH, BEGINNING OF YEAR	17,778	13,246
CASH, END OF YEAR	10,971	17,778

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 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 Financial Reporting Standards ("IFRS"), as issued by the International Accounting Standards Board ("IASB").

The consolidated financial statements were authorized for issue by the Company's Board of Directors on March 12, 2018.

Basis of presentation

The consolidated financial statements have been prepared using historical costs, except for financial instruments carried at fair value, on a going concern basis and have been presented in Canadian dollars, which is also the Company's functional currency. The accounting policies set out below have been applied consistently in all material respects.

Going concern

These 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.

As at December 31, 2017, the Company had a working capital deficiency of $67,566, including senior notes outstanding with a carrying value and face value of $59,341 and $60,000, respectively. The Company has a $12 million senior credit facility with a syndicate of chartered banks that is currently undrawn other than letters of credit outstanding of $1,540. The senior credit facility is a demand loan with a maturity date of May 31, 2018.

The senior notes mature on October 3, 2018 and the Company is engaged in ongoing discussions with the lender in a review of potential financing alternatives to modify or replace the senior notes prior to maturity. The Company is also in the process of identifying and pursuing alternative financing arrangements, property acquisitions or divestitures, corporate mergers and acquisitions and other recapitalization opportunities to repay the principal amount of the senior notes as it comes due. There is no assurance that any financing or other arrangement, or cash generated by operations, will be available or sufficient to meet these requirements, or if debt or equity financing is available, that it will be on terms acceptable to the Company.

The Company's ability to continue as a going concern is dependent upon the generation of profits from operations, obtaining additional financing or maintaining continued support from its creditors. While the Company has been successful in obtaining financing in the past, there is no assurance that such financing will continue to be available or be available on favourable terms in the future. The inability to raise additional financing or maintain current financing arrangement with existing creditors may impact the assessment of the Company as a going concern. These circumstances result in a material uncertainty surrounding the Company's ability to continue as a going concern and create significant doubt as to the ability of the Company to meet its obligations as they come due and, accordingly the appropriateness of the use of accounting principles applicable to a going concern.

These consolidated financial statements do not reflect the adjustments and classifications of assets, liabilities, revenues and expenses which would be necessary if the Company were unable to continue as a going concern.

Basis of consolidation

The consolidated financial statements include the accounts of the Company and its consolidated subsidiaries, which are the entities over which the Company has control. Control exists when the Company has the power to govern the financial and operating policies of an entity so as to obtain benefit from its activities. All intercompany transactions and balances are eliminated on consolidation.

Business combinations

The acquisition method of accounting is used to account for acquisitions of subsidiaries and assets that meet the definition of a business under IFRS. The cost of an acquisition is measured as the fair value of the assets given, equity instruments issued and liabilities incurred or assumed at the date of exchange. Acquisition-related costs are recognized in comprehensive loss as incurred. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured initially at their fair values at the acquisition date. The excess of the cost of acquisition over the fair value of the identifiable assets and liabilities acquired and contingent liabilities for which a provision is provided is recorded as goodwill. If the cost of acquisition is less than the fair value of the net assets of the subsidiary acquired, the difference is recognized as a bargain purchase gain in comprehensive loss. Results of subsidiaries are included in the consolidated statement of comprehensive loss from the closing date of acquisition.

Financial instruments

A financial instrument is any contract that gives rise to a financial asset of one entity and a financial liability or equity instrument of another entity. Financial assets and financial liabilities are recognized on the consolidated balance sheet at the time the Company becomes a party to the contractual provisions. Upon initial recognition, financial instruments are measured at fair value. Measurement in subsequent periods is dependent on the classification of the financial instrument.

The Company has made the following classifications:

- Cash is classified as a financial asset recorded at fair value through profit or loss and is carried at fair value. Gains and losses from revaluation are recognized in comprehensive loss.

- Accounts receivable are classified as loans and receivables and are initially measured at fair value plus directly attributable transaction costs. Subsequently, they are recorded at amortized cost using the effective interest method.

- Deposits if refundable in cash are classified as a financial asset recorded at fair value through profit or loss and are carried at fair value. Gains and losses from revaluation are recognized in comprehensive loss.
- Demand credit facilities, senior notes, accounts payable and accrued liabilities are classified as other liabilities and are initially measured at fair value less directly attributable transaction costs. Subsequently, they are recorded at amortized cost using the effective interest method.
- Derivative instruments, including embedded derivative instruments, that do not qualify as hedges, or are not designated as hedges for accounting purposes, including commodity contracts, are classified as fair value through profit or loss and are recorded and carried at fair value with changes in fair value recognized in comprehensive loss. Derivative instruments are used by the Company to manage economic exposure to market risks relating to commodity prices. Cequence's policy is to not utilize derivative financial instruments for speculative purposes.

Transaction costs related to financial instruments classified as fair value through profit or loss are expensed as incurred. All other transaction costs related to financial instruments are recorded as part of the instrument and are amortized using the effective interest method.

The Company's senior notes are classified as debt with a portion of proceeds allocated to equity representing the residual value allocated to the warrants issued to the lender. The debt component associated with the senior notes accretes over time to the amount owing on maturity and such increases in the debt component are reflected as non-cash interest expense in comprehensive loss. The issue costs are amortized to comprehensive loss using the effective interest rate method. The senior notes are carried net of transaction costs on the statement of financial position.

Contracts that are entered into for the purpose of the receipt or delivery of a non-financial item in accordance with the Company's expected purchase, sale or usage requirements (such as physical delivery commodity contracts) do not qualify as financial instruments and thus, are accounted for in accordance with other applicable standards and are not recorded as assets or liabilities.

Embedded derivatives are separated from the host contract and accounted for separately if the economic characteristics and risks of the host contract and the embedded derivative are not closely related, a separate instrument with the same terms as the embedded derivative would meet the definition of a derivative, and the combined instrument is not measured at fair value through profit or loss. Changes in the fair value of separable embedded derivatives are recognized immediately in comprehensive loss.

IFRS establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The three levels of the fair value hierarchy are described below:

Level 1: Values based on quoted prices in active markets that are accessible at the measurement date for identical assets or liabilities.

Level 2: Values based on quoted prices in markets that are not active or model inputs that are observable either directly or indirectly for substantially the full term of the asset or liability.

Level 3: Values based on prices or valuation techniques that require inputs that are both unobservable and significant to the overall fair value measurement.

When the inputs used to measure fair value fall within different levels of the hierarchy, the level within which the fair value measurement is categorized is based on the lowest level input that is significant to the fair value measure in its entirety.

Impairment of financial assets

Financial assets, other than those classified as fair value through profit or loss, are assessed for indicators of impairment at the end of each reporting period. Financial assets are considered to be impaired when there is objective evidence that, as a result of one or more events that occurred after the initial recognition of the financial asset, the estimated future cash flows of the investment have been negatively affected.

For financial assets carried at amortized cost, the amount of the impairment loss recognized in comprehensive loss is the difference between the asset's carrying amount and the present value of estimated future cash flows, discounted at the financial asset's original effective interest rate.

The carrying amount of the financial asset is reduced by the impairment loss directly for all financial assets with the exception of trade receivables, where the carrying amount is reduced through the use of an allowance account. When a trade receivable is considered uncollectible, it is written off against the allowance account. Subsequent recoveries of amounts previously written off are recognized in comprehensive loss. Changes in the carrying amount of the allowance accounts are recognized in comprehensive loss.

PROPERTY AND EQUIPMENT AND EXPLORATION AND EVALUATION ASSETS

Recognition and measurement

Exploration and evaluation expenditures

Pre-license costs, geological and geophysical costs are recognized in comprehensive loss as incurred.

Exploration and evaluation ("E&E") costs, including the costs of acquiring licenses, drilling exploratory wells and other directly attributable costs, are initially capitalized as E&E assets to the extent that they do not relate to a field with proven reserves attributed. The costs are accumulated in cost centers by field or exploration area pending determination of technical feasibility and commercial viability.

The Company enters into E&E farm-in arrangements to fund a portion of the partner's (farmor's) exploration and/or future development expenditures ("carried interests"), these expenditures are reflected in the consolidated financial statements when the exploration and development work progresses. For E&E farm-out arrangements where the farmee correspondingly undertakes to fund carried interests as part of the consideration no gain or loss is recognized by the Company.

E&E assets are assessed for impairment if sufficient data exists to determine technical feasibility and commercial viability, or if facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

The technical feasibility and commercial viability of extracting a mineral resource is considered to be determinable when proven reserves are determined to exist and are capable of economic production. A review of each exploration field is carried out, at least annually, to ascertain whether proven reserves have been discovered that are capable of economic production. Upon determination of proven reserves, E&E assets attributable to those reserves are first tested for impairment and then reclassified from E&E assets to development and production assets included in property and equipment.

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, net of any reversals.

Development and production assets are grouped into Cash Generating Units ("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).

Gains and losses on disposal of an item of property and equipment, including oil and natural gas interests, are determined by comparing the proceeds from disposal with the carrying amount of the related property and equipment and are recognized net within "other expense (income)".

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.

For any asset that does not generate largely independent cash flows, the recoverable amount is determined for the CGU to which the asset belongs. If the carrying amount of an asset (or CGU) exceeds its recoverable amount, the asset (or CGU) is written down.

The recoverability of the carrying amount of an E&E 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 E&E 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 in comprehensive loss.

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 (or CGU) exceeds its recoverable amount, the excess is recognized immediately in comprehensive 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.

Subsequent costs

Costs incurred subsequent to the determination of technical feasibility and commercial viability and the costs of replacing parts of property and equipment are recognized as oil and natural gas interests only when they increase the future economic benefits embodied in the specific asset to which they relate. All other expenditures are recognized in comprehensive loss as incurred. Such capitalized oil and natural gas interests generally represent costs incurred in developing proved and/or probable reserves and bringing in or enhancing production from such reserves, and are accumulated on a field or area basis. The carrying amount of any replaced or sold component is derecognized. The costs of the day-to-day servicing of property and equipment are recognized as operating costs as incurred.

Depletion and depreciation

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. For the purpose of this calculation, production and reserves of petroleum and natural gas are converted to a common unit of measurement on the basis of their relative energy content, where six thousand cubic feet of natural gas equates to one barrel of oil. Costs are only depleted once production in a given area begins.

Cequence depletes separately, where applicable, any significant components within development and production assets, such as fields, processing facilities and pipelines, which are significant in relation to the total cost of a development and production asset and have a different useful life than such assets.

Provisions

Provisions are recognized when the Company has a present obligation as a result of a past event that can be estimated with reasonable certainty and are measured at the amount that the Company would rationally pay to be relieved of the present obligation. To the extent that provisions are estimated using a present value technique, such amounts are determined by discounting the expected future cash flows at a risk-free pre-tax rate and adjusting the liability for the risks specific to the liability.

Decommissioning liabilities

The Company records the present value of the estimated cost of legal and constructive obligations to restore operating locations in the period in which the obligation arises. The nature of restoration activities includes the removal of facilities, abandonment of wells and restoration of affected areas. Provision is made for the estimated cost of restoration and capitalized in the relevant asset category.

Decommissioning liabilities are measured at the present value of management's best estimate of the expenditure required to settle the present obligation at the balance sheet date. Subsequent to the initial measurement, the obligations are adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation as well as changes to the discount rate. The increase in the provision due to the passage of time is recognized as finance cost whereas increases or decreases due to changes in the estimated future cash flows or changes in the discount rate are capitalized. Actual costs incurred upon settlement of the decommissioning liabilities are charged against the decommissioning liabilities.

Onerous contracts

Present obligations arising under onerous contracts are recognized and measured as provisions. An onerous contract is considered to exist where the Company has a contract under which the unavoidable costs of meeting the obligations under the contract exceed the economic benefits expected to be received from the contract.

Jointly controlled assets

A significant portion of the Company's oil and natural gas activities involve jointly controlled assets and any related liabilities incurred. The consolidated financial statements include the Company's share of these jointly controlled assets and liabilities and a proportionate share of the relevant revenues and related costs, classified according to their nature.

Share-based payments

The Company has a stock option plan and issues stock options to 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 Company issues Restricted Share Units ("RSU") under the RSU Plan to directors, officers and other service providers. RSUs are accounted as cash-settled share-based payments and are originally measured at the grant date fair value and subsequently remeasured each period end until the vesting date when the RSUs are settled in cash. Share-based payment expense on the RSUs is charged to net earnings or loss in the period they vest 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.

Revenue

Revenue from the sale of petroleum and natural gas is recognized when the risks and rewards of ownership of the product are transferred to the customer, based on volumes delivered to customers at contractual delivery points and rates. The costs associated with the delivery, including operating and maintenance costs, transportation and production-based royalty expenses are recognized in the same period in which the related revenue is earned and recorded. Revenue is measured net of related royalties.

Interest income is recognized as it accrues, using the effective interest method.

Flow-through shares

The Company, from time to time, issues flow-through shares to finance a portion of its capital expenditure program. Pursuant to the terms of the flow-through share agreements, the tax deductions associated with the expenditures are renounced to the subscribers. The difference between the value ascribed to flow-through shares issued and the value that would have been received for common shares at the date of issuance of the flow-through shares is initially recognized as a liability on the consolidated balance sheet. When the expenditures are renounced and incurred, the liability is drawn down, a deferred income tax liability is recorded equal to the estimated amount of deferred income tax payable by the Company as a result of the renunciation, and the difference is recognized as income tax expense.

Earnings per share

Basic per share amounts are computed by dividing the net loss by the weighted average number of common shares outstanding during the period. Diluted per share amounts are calculated giving effect to the potential dilution that would occur if stock options, RSUs and warrants were exercised. The dilutive effect of stock options, RSUs and warrants is calculated with the assumption that proceeds received from the exercise of options, RSUs and warrants for which the exercise price is less than the market price plus the unamortized portion of share-based payments are used to repurchase common shares at the average market price for the period.

Taxation

Income tax expense represents the sum of the tax currently payable and deferred tax.

Current tax

The tax currently payable is based on taxable income for the year. Taxable income differs from income as reported in the consolidated statement of comprehensive loss because of items of income or expense that are taxable or deductible in other years and items that are never taxable or deductible. The Company's liability for current tax is calculated using tax rates that have been enacted or substantively enacted by the end of the reporting period.

Deferred tax

Deferred tax is recognized on temporary differences between the carrying amounts of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable income.

Deferred tax assets are generally recognized for all deductible temporary differences to the extent that it is probable that taxable profits will be available against which such deductible temporary differences can be utilized. Such deferred tax assets and liabilities are not recognized if the temporary difference arises from goodwill or from the initial recognition (other than in a business combination) of other assets and liabilities in a transaction that affects neither taxable income nor the accounting income.

The carrying amount of deferred tax assets is reviewed at the end of each reporting period and reduced to the extent that it is no longer probable that sufficient taxable income will be available to allow all or part of the asset to be recovered.

Deferred tax assets and liabilities are measured at the tax rates that are expected to apply in the period in which the liability is settled or the asset realized, based on tax rates (and tax laws) that have been enacted or substantively enacted by the end of the reporting period. The measurement of deferred tax liabilities and assets reflects the tax consequences that would follow from the manner in which the Company expects, at the end of the reporting period, to recover or settle the carrying amount of its assets and liabilities.

Deferred tax assets and liabilities are offset when there is a legally enforceable right to set off current tax assets against current tax liabilities and when they relate to income taxes levied by the same taxation authority and the Company intends to settle its current tax assets and liabilities on a net basis.

Current and deferred tax for the period

Current and deferred tax are recognized as an expense or income in comprehensive loss, except when they relate to items that are recognized outside profit or loss (whether in other comprehensive income or directly in equity), in which case the tax is also recognized outside profit or loss, or where they arise from the initial accounting for a business combination. In the case of a business combination, the tax effect is included in the accounting for the business combination.

Significant accounting judgments, estimates and assumptions

The preparation of the consolidated financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the reported amount of assets, liabilities, and contingent liabilities at the date of the consolidated financial statements and reported amounts of revenues and expenses during the reporting period. Estimates and judgments are continuously evaluated and are based on management's experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances.

In particular, information about significant areas of estimation uncertainty considered by management in preparing the consolidated financial statements are described in the following notes:

Note 4: Property and equipment

Note 13: Provisions

Note 16: Share-based payment plans

Note 18: Commitments

Note 19: Financial instruments and risk management

Estimates of recoverable quantities of proved and probable reserves include assumptions regarding commodity prices, exchange rates, discount rates and production and transportation costs for future cash flows. It also requires interpretation of geological and geophysical models in order to make an assessment of the size, shape, depth and quality of reservoirs, and their anticipated recoveries. The economic, geological and technical factors used to estimate reserves may change from period to period. Changes in reported reserves can impact asset carrying values, the provision for decommissioning liabilities and the recognition of deferred tax assets, due to changes in expected future cash flows. Reserve estimates are prepared in accordance with the Canadian Oil and Gas Evaluation Handbook and are reviewed by third party reservoir engineers.

The amounts recorded for depletion and depreciation of property and equipment, the provision for decommissioning liabilities, and the valuation of property and equipment are based on estimates of proved and probable reserves, production rates, future petroleum and natural gas prices, future costs and the remaining lives and period of future benefit of the related assets.

The Company makes judgments in determining its CGUs and evaluates the geography, geology, production profile and infrastructure of its assets in making such determinations, which are based on estimates of reserves. 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.

Costs associated with acquiring oil and natural gas licenses and exploratory drilling are accumulated as E&E assets pending determination of technical feasibility and commercial viability. Establishment of technical feasibility and commercial viability is subject to judgement which management has determined to be based on the allocation of commercial reserves to the exploration area. Upon determination of commercial reserves, E&E assets attributable to those reserves are first tested for impairment and then reclassified from E&E assets to development and production assets included in property and equipment.

The amount recorded as decommissioning liabilities is based on current legal and constructive requirements, technology, price levels and expected plans for remediation. Actual costs and cash outflows can differ from estimates because of changes in laws and regulations, public expectations, market conditions, discovery and analysis of site conditions and changes in technology.

The amounts recorded for deferred income tax assets and deferred tax expense (recovery) are based on estimates of the probability of the Company utilizing certain tax pools and assets which, in turn, is dependent on estimates of proved and probable reserves, production rates, future petroleum and natural gas prices, and changes in legislation, tax rates and interpretations by taxation authorities.

The fair value of derivative contracts is estimated, wherever possible, based on quoted market prices, and if not available, on estimates from third-party brokers. Another significant assumption used by the Company in determining the fair value of derivatives is market data or assumptions that market participants would use when pricing the asset or liability, including assumptions about risk. The actual settlement of derivatives could differ materially from the value recorded and could impact future results.

The above judgments, estimates and assumptions relate primarily to unsettled transactions and events as of the date of the consolidated financial statements. Actual results could differ from these estimates and the differences could be material.

3. FUTURE ACCOUNTING PRONOUNCEMENTS

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 year ended December 31, 2017.

4. 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	**25,857**
Decommissioning obligation additions and change in estimates	**1,302**
Acquisitions	**(7)**
Disposals	**(23,311)**
Balance at December 31, 2017	**928,935**
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	**(24,606)**
Impairment loss	**(96,200)**
Disposals	**18,137**
Balance at December 31, 2017	**(671,705)**
Carrying amounts:	
At December 31, 2016	356,058
At December 31, 2017	**257,230**

Costs subject to depletion include $840,601 of estimated future capital costs (December 31, 2016 – $921,573).

The Company's credit facilities are secured by a demand debenture with a first floating charge over all assets of the Company (see note 5).

Sale of assets

In 2016, the Company disposed of certain pipeline and facilities at Simonette for proceeds of $5,074 prior to closing adjustments. The sale resulted in a gain recognized in comprehensive loss of $2,964.

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).

Impairment

December 31, 2016

At December 31, 2016, Cequence evaluated its development and production assets for indicators of any potential impairment or related reversal. As a result of this assessment, no indicators were identified and no impairment or related reversal was recorded on Cequence's development and production assets for the year ended December 31, 2016.

June 30, 2017

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 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 management's best estimate of current price forecasts and consideration to acquisition metrics of recent transactions completed on similar assets to those contained within the relevant CGU. The Company also included the fair value of undeveloped land based on an internal evaluation with consideration of recent land sales. 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	Condensate	Crude Oil
	AECO Spot ($/mmbtu)	Edmonton Pentanes Plus ($/bbl)	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 an after-tax 11% 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 test at June 30, 2017 are as follows:

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

As at 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 year ended December 31, 2017.

December 31, 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.

As a result, impairment tests were carried out at December 31, 2017. The recoverable amounts of each of the Company's CGUs at December 31, 2017 were estimated as their fair value less cost to sell, based on the 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, 2017 updated for management's best estimate of current price forecasts and to acquisition metrics of recent transactions completed on similar assets to those contained within the relevant CGU. The Company also included the fair value of undeveloped land based on an internal evaluation with consideration of recent land sales. 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 Company used a after-tax 11% discount rate for the December 31, 2017 impairment tests which took into account the risks specific to the CGUs and current market assessment of the time value of money.

Based on the impairment tests performed at December 31, 2017, the Company determined that the recoverable amounts of each of the Company's CGUs exceeded its carrying value and accordingly, no impairment expense was recorded. The determination of impairment is sensitive to changes in key judgments, including reserve or resource revisions, change in forward commodity prices and exchange rates, and changes in costs and timing of development. Changes in these key judgments would impact the recoverable amount of the Company's CGUs, therefore resulting in additional impairment charges or recoveries. As at December 31, 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 $7,100 (2016 – $nil), whereas a ten percent decrease in forward commodity prices would result in additional impairment of $9,900 (2016 – $nil) recognized in comprehensive loss for the year ended December 31, 2017.

5. DEMAND CREDIT FACILITIES

As at December 31, 2017, the Company has an extendible revolving term credit facility ("senior credit facility") of $12,000 (December 31, 2016 – $20,000) with a syndicate of Canadian chartered banks and has drawn $nil (December 31, 2016 – $nil) under the facility. In November 2017, the Company's senior credit facility was reduced to $12,000 from $20,000. 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 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 December 31, 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 effective annualized interest rate, including standby fees and commitment fees, for the year ended December 31, 2017 was nil percent as the credit facility was undrawn during the year (2016 – nil percent). The next scheduled review is to take place in May 2018.

6. SENIOR NOTES

	December 31, 2017	December 31, 2016
Senior notes	**56,503**	56,503
Add transaction costs	**2,838**	2,054
Total senior notes	**59,341**	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 are unsecured and are subordinate to Cequence's credit facilities. 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. A standby charge of 0.7% is applied to the further $60,000 of senior notes available at a future date. The senior notes require quarterly interest payment of 2.25% of the outstanding balance of the senior notes and no principal payments are required prior to maturity on October 3, 2018.

In addition, Cequence granted to the lender of the senior notes 3.0 million warrants at an exercise price of $2.03 to purchase common shares.

The senior notes are subject to the same financial covenants as the Company credit facilities 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 21). The Company was in compliance with the senior notes covenants at December 31, 2017 and December 31, 2016.

At any time prior to the maturity of October 3, 2018, the Company has the option to redeem all or part of the principal amount plus accrued and unpaid interest on the senior notes in accordance with the provisions of the trust indenture. Prior to October 3, 2016 the Company had the option to redeem all or part of the senior notes at 100% of the principal amount plus accrued and unpaid interest plus 75% of the present value of the remaining scheduled payments of interest from the redemption date until the maturity date. The Company can redeem all or part of the senior notes at 105% of the principal amount plus accrued and unpaid interest during the period October 3, 2016 to October 3, 2017 and at 100% of the principal amount plus accrued and unpaid interest during the period October 3, 2017 to October 3, 2018. The prepayment options within the senior notes are considered embedded derivatives. The value of these embedded derivatives at October 3, 2013, December 31, 2015, 2016 and 2017 is negligible. Upon specified change of control events or upon certain sales of assets, the Company must offer to repurchase the senior notes.

The senior notes have been classified as debt, net of transaction costs with the residual value related to the warrants allocated to equity. The transaction costs will be amortized over the life of senior notes and the debt portion of the senior notes will be accreted up to the principal value of $60,000 using an effective interest rate of 10.51%.

	December 31, 2017	December 31, 2016
Debt component		
Beginning balance	**58,557**	57,849
Amortization of transaction costs	**443**	400
Accretion	**341**	308
Total debt component	**59,341**	58,557
Equity component		
Warrant issuance, net of allocated transaction costs and deferred tax	**1,300**	1,300
Total equity component	**1,300**	1,300

7. ACCOUNTS RECEIVABLE

	December 31, 2017	December 31, 2016
Trade receivables	**6,572**	5,826
Allowance for doubtful accounts	**(659)**	(647)
Net trade receivables	**5,913**	5,179
Accrued receivables	**8,609**	8,533
Other receivables	**217**	433
Total accounts receivable	**14,739**	14,145

8. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

	December 31, 2017	December 31, 2016
Accounts payable	**9,549**	12,736
Accrued liabilities	**23,557**	23,388
Total accounts payable and accrued liabilities	**33,106**	36,124

9. PRODUCTION REVENUE

	Year ended December 31,	
	2017	2016
Sales of oil and natural gas	**61,024**	52,269
Royalties	**(3,138)**	(1,543)
Total production revenue	**57,886**	50,726

10. OTHER INCOME

	Year ended December 31,	
	2017	2016
Gain (loss) on sale of property and equipment	**130**	(3,202)
Interest income	**(102)**	(115)
Other	**(243)**	(241)
Total other income	**(215)**	(3,558)

11. FINANCE COSTS

	Year ended December 31,	
	2017	2016
Interest expense on demand credit facilities	**331**	411
Interest expense on senior notes	**5,820**	5,821
Amortization of transaction costs	**443**	399
Accretion expense on senior notes	**341**	309
Accretion expense on provisions	**870**	803
Total finance costs	**7,805**	7,743

12. COMPENSATION COSTS AND KEY MANAGEMENT PERSONNEL EXPENSES

Total wages, salaries, benefits, severances, and other personnel costs included in comprehensive loss for the year ended December 31, 2017 were $2,968 (2016 – $5,880).

The aggregate expense of key management personnel, defined as the Company's Chief Executive Officer, Executive Vice President and Chief Financial Officer and the Company's Board of Directors, was as follows:

	Year ended December 31, 2017	2016
Wages, salaries, benefits and other personnel costs	**906**	1,641 (i)
Share-based payments (ii)	**532**	676
Total remuneration	**1,438**	2,317

(i) Wages, salaries, benefits and other personnel costs includes $770 of severance to the former Chief Executive Officer.

(ii) Represents the total fair value of share-based payment awards granted to officers and directors in the year of grant, as determined using a Black-Scholes option pricing model (see note 16).

13. PROVISIONS

Decommissioning liabilities

The following table summarizes the changes in decommissioning liabilities for the years ended December 31, 2017 and 2016:

	2017	2016
Balance, beginning of year	**38,161**	40,708
Property dispositions (Note 4)	**(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
Current	**1,466**	366
Non-current	**37,012**	37,795
	38,478	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 $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). As at December 31, 2017 and 2016, no funds have been set aside to settle these liabilities.

14. INCOME TAXES

The following table sets forth the components of the Company's deferred income tax asset:

	December 31, 2017	December 31, 2016
Excess of net book value of assets and liabilities over related tax pools	**(97,137)**	(89,894)
Non-capital loss carry-forwards	**87,955**	80,456
Scientific research and development expenses and investment tax credits	**9,056**	9,056
Other tax assets	**126**	382
Total net deferred income tax asset	**–**	–

At December 31, 2017, Cequence has total tax pools of $616,660 (December 31, 2016 – $613,777) including non-capital loss carry-forwards, investment tax credit carry-forwards and Scientific Research and Experimental Development ("SRED") expenses available to reduce future years' income for tax purposes. Deferred income tax assets have been recognized to the extent that estimated future taxable profits are sufficient to realize the deferred income tax assets in the allowable timeframes. The ongoing period of low commodity prices has created uncertainty regarding the future realization of the Company's deferred tax assets. As a result, a deferred income tax asset of $109,081 has not been recognized (December 31, 2016 – $82,398). The SRED expenses of approximately $22,704 available for carry-forward do not expire (2016 – $22,704). The non-capital loss carry-forwards expire in 7 to 20 years and the investment tax credit carry-forwards expire in 3 to 7 years.

Income tax expense differs from that which would be expected from applying the effective Canadian federal and provincial tax rates of 27 percent (2016 – 27 percent) to loss before income taxes as follows:

	Year ended December 31,	
	2017	2016
Expected income tax recovery	**(26,828)**	(7,575)
Effect of share-based payments	**278**	292
Change in previously estimated tax pools	**(424)**	565
Change in unrecorded deferred income tax asset	**27,107**	6,699
Other	**(133)**	19
Deferred income tax expense	**–**	–
Current income tax	**–**	–
Income tax expense	**–**	–

Movements in deferred income tax balances are as follows:

	Balance, December 31, 2016	Recognized in comprehensive loss	Recognized in liabilities	Recognized in equity	**Balance, December 31, 2017**
Property and equipment and provisions	(90,959)	**(5,972)**	**–**	**–**	**(96,931)**
Unrealized (gain) loss on financial instruments	1,255	**(1,330)**	**–**	**–**	**(75)**
Senior notes	(190)	**59**	**–**	**–**	**(131)**
Non-capital losses	80,456	**7,499**	**–**	**–**	**87,955**
SRED expenses and investment tax credits	9,056	**–**	**–**	**–**	**9,056**
Other	382	**(256)**	**–**	**–**	**126**
Total	–	**–**	**–**	**–**	**–**

	Balance, December 31, 2015	Recognized in comprehensive loss	Recognized in liabilities	Recognized in equity	Balance, December 31, 2016
Property and equipment and provisions	(75,040)	(15,919)	–	–	(90,959)
Unrealized (gain) loss on financial instruments	(984)	2,239	–	–	1,255
Senior notes	(233)	43	–	–	(190)
Non-capital losses	66,693	13,763	–	–	80,456
SRED expenses and investment tax credits	9,056	–	–	–	9,056
Other	508	(126)	–	–	382
Total	–	–	–	–	–

15. SHARE CAPITAL

Cequence has an unlimited number of common voting shares and common non-voting shares with no par value authorized.

	Year ended December 31, 2017		Year ended December 31, 2016	
Issued common voting shares	**Number**	**Stated Value**	Number	Stated Value
	(000's)	**$**	(000's)	$
Balance, beginning of year	**245,528**	**633,848**	211,028	624,619
Flow-through common shares	**–**	**–**	34,500	10,005
	245,528	**633,848**	245,528	634,624
Share issue costs	**–**	**(2)**	–	(776)
Balance, end of year	**245,528**	**633,846**	245,528	633,848
Warrants				
Balance, beginning of year	**3,000**	**1,300**	3,000	1,300
Balance, end of year	**3,000**	**1,300**	3,000	1,300

On October 28, 2016, the Company completed the sale, on a private placement basis, of 34,500 common voting shares on a Canadian development expenses ("CDE") "flow-through" basis at $0.29 per share for gross proceeds of $10,005. An obligation related to flow-through shares has not been recorded as the flow-through shares were not issued at a premium to the fair value of the Company's common shares. In accordance with the terms of the agreement and pursuant to certain provisions of the Income Tax Act (Canada), the Company is required to renounce to the holders of the flow-through common shares, for income tax purposes, development expenditures of $8,500 and $1,505 effective December 31, 2016 and 2017, respectively. As at December 31, 2017, the Company has incurred $10,005 of development expenditures that were renounced to the holders of the flow-through common shares.

16. SHARE-BASED PAYMENT PLANS

Stock options

The Company has a stock option plan for directors, officers, employees and consultants of the Company and its subsidiaries. The number of common shares granted with respect to options may not exceed a rolling maximum of 10 percent of the Company's outstanding common shares. Options typically vest over a three year period, expire five years from the date of grant and are settled by issuing shares of the Company.

During the year ended December 31, 2017, the Company issued 5,025 stock options (2016 – 6,295) at an exercise price of $0.32 (2016 – $0.33) to employees, officers and directors. The options have a five year life and one third vest annually commencing one year following the grant date.

A summary of the inputs used to value stock options is as follows:

	2017	2016
Risk-free interest rate	**1.12%**	0.60%
Expected life of options	**5 years**	5 years
Expected volatility	**60%**	60%
Expected dividend rate	**0%**	0%
Expected forfeiture rate	**15%**	15%
Weighted average fair value	**$0.17**	$0.17

Expected volatility is determined by reference to the Company's industry peers as, due largely to changes in the size and structure of the Company in recent years, this was determined to be a more meaningful measure than the historical volatility of the Company's shares.

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

		2017		2016
	Number of Options	**Weighted Average Exercise Price**	Number of Options	Weighted Average Exercise Price
	(000's)	**$**	(000's)	$
Outstanding, beginning of year	**11,003**	**0.86**	11,395	2.08
Granted	**5,025**	**0.32**	6,295	0.33
Cancelled/Forfeited	**(107)**	**1.33**	(3,900)	1.53
Expired	**(2,701)**	**1.28**	(2,787)	3.70
Outstanding, end of year	**13,220**	**0.56**	11,003	0.86

The following table summarizes information about stock options outstanding at December 31, 2017:

		Options Outstanding		Options Exercisable	
Range of Exercise Price,	Weighted Average Exercise Price	Number of Options	Weighted Average Contractual Life Remaining	Number of Options	Weighted Average Exercise Price
$	$	(000's)	(years)	(000's)	$
0.29 – 0.99	0.35	11,390	3.70	2,345	0.42
1.00 – 1.99	1.69	1,230	0.69	1,230	1.69
2.00 – 2.22	2.22	600	1.64	600	2.22
	0.56	13,220	3.33	4,175	1.05

During the year ended December 31, 2017, $991 (2016 – $708) in share-based payment expense related to equity-settled stock options has been recognized in comprehensive loss.

RESTRICTED SHARE UNITS

The Company has a RSU plan for directors, officers, employees and consultants of the Company and its subsidiaries. An RSU is a conditional grant to receive a Cequence common share, or the cash equivalent, as determined by the Company, upon vesting of the RSUs and in accordance with the terms of the RSU plan and grant agreement. The value of one RSU is notionally equivalent to one Cequence common share. RSUs vest over a three year period and management plans to settle the RSUs in cash on the respective vesting date.

A summary of the status of the Company's RSU plan and changes for the years ended December 31, 2017 and 2016 is as follows:

Number of RSUs (000's)	**2017**	2016
Outstanding, beginning of year	**3,010**	1,707
Granted	**700**	2,622
Cancelled/Forfeited	**(29)**	(677)
Exercised	**(1,015)**	(642)
Outstanding, end of year	**2,666**	3,010

During the year ended December 31, 2017, the Company recognized $37 (2016 – $374) in share-based payment expense related to the cash-settled RSUs in comprehensive loss.

17. LOSS PER SHARE

Loss per share has been calculated based on the weighted average number of common shares outstanding during the year. For the years ended December 31, 2017 and 2016, the Company has 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:

	Year ended December 31, **2017**	2016
Basic weighted average shares	**245,528**	217,061
Effect of dilutive instruments	**–**	–
Diluted weighted average shares	**245,528**	217,061

18. COMMITMENTS

	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 with the operator of the Simonette facility. The volume commitment under the take or pay is 42 mmcf/d until April 30, 2030.

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 December 17, 2017 to March 30, 2026.

The Company has a 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 subject to regulatory approval with the National Energy Board and financial assurances. The term of the contract begins on April 1, 2018, is 10 years in duration and has early termination rights that can be exercised following the initial five years of service. The toll for this service is $0.77 per GJ/d. 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.

During the year ended December 31, 2017, the Company recognized $250 (2016 – $1,116) of expense related to office leases, included with general and administrative expense.

19. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

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

The Company's cash, accounts receivable, deposits, 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's fair value hierarchy for those assets and liabilities measured at fair value comprises cash measured at level 1 and commodity contracts measured at level 2 under the Company's fair value hierarchy as of December 31, 2017. The fair value of commodity contracts is determined by discounting the remaining contracted petroleum and natural gas volumes by the difference between the contracted price and published forward price curves as at the balance sheet date.

The nature of these financial instruments and the Company's operations expose the Company to market risk, credit risk and liquidity risk. The Company manages its exposure to these risks by operating in a manner that minimizes these risks. Senior management employs risk management strategies and policies to ensure that any exposure to risk is in compliance with the Company's business objectives and risk tolerance levels. The Board of Directors has overall responsibility for the establishment and oversight of the Company's risk management framework. The Board has established policies in setting risk limits and controls and monitors these risks in relation to market conditions.

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.

During the year ended December 31, 2017, the Company entered into several commodity derivative financial instrument contracts. The following information presents all outstanding positions for commodity derivative financial instruments at December 31, 2017:

Term	Product	Type	Volume	Price	Basis
January 1, 2018 to March 31, 2018	Gas	Swap	12,500 gj/day	$3.01	AECO
January 1, 2018 to March 31, 2018	Oil	Swap	500 bbl/day	$67.17	WTI
April 1, 2018 to June 30, 2018	Oil	Swap	500 bbl/day	$63.35	WTI
July 1, 2018 to December 31, 2018	Oil	Swap	100 bbl/day	$68.25	WTI

For the year ended December 31, 2017, realized gain from commodity derivative contracts recognized in comprehensive loss were $4,812 (2016 – $6,805 gain).

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).

For the year ended December 31, 2017, the Company recorded an unrealized gain of $4,927 from derivative commodity contracts (2016 – $8,294 unrealized loss).

As at December 31, 2017, a change in gas price of $0.50/gj and oil price of $1.00/bbl results in a change in the fair value of the commodity contracts of $563 ($411 after tax) and $109 ($80 after tax) (2016 – $3,954 ($2,886 after tax) and $73 ($53 after tax)) respectively and a commensurate increase to comprehensive loss.

Foreign exchange risk

The Company is exposed to foreign currency fluctuations as crude oil and natural gas prices are referenced to U.S. dollar denominated prices. As at December 31, 2017, the Company had no forward, foreign exchange contracts in place, nor any significant working capital items denominated in foreign currencies (2016 – nil).

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 (2016 – nil).

As at December 31, 2017, a 1 percent change in interest rates on the Company's outstanding credit facilities, 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 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 December 31, 2017, the accounts receivable balance was $14,739 (December 31, 2016 – $14,145) of which $956 (December 31, 2016 – $664) 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
12,251	795	737	956	14,739

At December 31, 2017, the Company has an allowance for doubtful accounts of $659 (December 31, 2016 – $647). As at December 31, 2017, 35.0 percent (December 31, 2016 – 44.3) of the total receivables balance is due from marketers of the Company's oil and natural gas production. A reconciliation of the Company's allowance for doubtful accounts is as follows:

	Year ended December 31,	
	2017	2016
Balance, beginning of year	**647**	682
Amounts collected	**(78)**	(115)
Amounts written off to accounts receivable	**–**	(164)
Additional provision	**90**	244
Balance, end of year	**659**	647

As at December 31, 2017, the maximum exposure to credit risk was $26,984 (December 31, 2016 – $31,923) being the carrying value of the Company's cash, accounts receivable and commodity contract assets.

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. Refer to note 21 for disclosure related to the management of capital.

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	–	–	–

20. CHANGES IN NON-CASH WORKING CAPITAL

	Year ended December 31,	
	2017	2016
Accounts receivable	**(594)**	8,176
Deposits and prepaid expenses	**363**	792
Accounts payable and accrued liabilities	**(3,018)**	(5,564)
Net change in non-cash working capital	**(3,249)**	3,404
Allocated to:		
Operating activities	**1,634**	2,243
Investing activities	**(4,883)**	1,268
Financing activities	**–**	(107)
	(3,249)	3,404

21. CAPITAL MANAGEMENT

Cequence's objectives are to maintain a flexible capital structure in order to meet its financial obligations and to execute on strategic opportunities throughout the business cycle. 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.

In order to maintain or adjust the capital structure, Cequence may issue new common shares, issue new debt or replace existing debt, adjust capital expenditures and acquire or dispose of assets. The Company evaluates its capital structure based on net debt to cash flow from operating activities and the current credit available to Cequence compared to its budgeted capital expenditures. Refer to going concern discussions in note 2.

At December 31, 2017, Cequence has $60,000 in senior notes due in 2018 and a $12,000 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 May 2018.

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

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.

CORPORATE INFORMATION

MANAGEMENT

Todd Brown, P.Eng
Chief Executive Officer

David Gillis, CA
Executive Vice President & CFO

David P. Robinson
Vice President, Geology

Christopher C. Soby
Vice President, Land

Erin Thorson, CMA
Controller

DIRECTORS

Don Archibald
Chairman

Peter Bannister
Todd Brown
Howard Crone
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