cequence energy ltd

2016
ANNUAL REPORT

FINANCIAL HIGHLIGHTS

(000's except per share and per unit amounts)	Three months ended December 31, 2016	2015	% Change	Twelve months ended December 31, 2016	2015	% Change
FINANCIAL						
Total revenue [1]	**17,253**	16,112	7	**59,074**	80,891	(27)
Comprehensive loss	**(9,077)**	(146,585)	(94)	**(28,057)**	(250,072)	(89)
Per share – basic and diluted	**(0.04)**	(0.69)	(94)	**(0.13)**	(1.19)	(89)
Funds flow from operations [2] [5]	**6,625**	4,874	36	**11,250**	25,578	(56)
Per share, basic and diluted	**0.03**	0.02	50	**0.05**	0.12	(58)
Capital expenditures,						
before acquisitions (dispositions)	**11,460**	15,175	(24)	**22,590**	62,261	(64)
Capital expenditures,						
including acquisitions (dispositions)	**11,406**	16,351	(30)	**17,296**	18,560	(7)
Net debt [3] [6]	**(64,031)**	(65,447)	(2)	**(64,031)**	(65,447)	(2)
Weighted average shares outstanding						
- basic and diluted	**235,028**	211,028	11	**217,061**	211,028	3
OPERATING						
Production volumes						
Natural gas (Mcf/d)	**45,005**	41,794	8	**45,442**	47,589	(5)
Crude oil (bbls/d)	**140**	225	(38)	**177**	160	11
Natural gas liquids (bbls/d)	**209**	300	(30)	**237**	475	(50)
Condensate (bbls/d)	**760**	723	5	**841**	918	(8)
Total (boe/d)	**8,609**	8,213	5	**8,826**	9,485	(7)
Sales prices						
Natural gas, including realized hedges ($/Mcf)	**2.92**	2.89	1	**2.27**	3.27	(31)
Crude oil and condensate,						
including realized hedges ($/bbl)	**56.27**	52.32	8	**52.17**	53.78	(3)
Natural gas liquids ($/bbl)	**25.61**	16.45	56	**21.94**	17.04	29
Total ($/boe)	**21.78**	21.32	2	**18.29**	23.37	(22)
Netback ($/boe)						
Price, including realized hedges	**21.78**	21.32	2	**18.29**	23.37	(22)
Royalties	**(0.59)**	0.67	188	**(0.48)**	(0.84)	(43)
Transportation	**(1.45)**	(1.77)	(18)	**(1.24)**	(1.83)	(32)
Operating costs	**(7.81)**	(9.30)	(16)	**(8.49)**	(9.17)	(7)
Operating netback	**11.93**	10.92	9	**8.08**	11.53	(30)
General and administrative [5]	**(1.81)**	(2.65)	(32)	**(2.77)**	(2.30)	20
Interest [4]	**(1.92)**	(2.15)	(11)	**(1.93)**	(1.96)	(2)
Cash netback	**8.20**	6.12	34	**3.38**	7.27	(54)

(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 $nil ($nil/boe) and $2,341 ($0.72/ boe) in restructuring charges, respectively.

(6) Prior period amounts have been adjusted to confirm to current period presentation.

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, 2016 and 2015.

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

This MD&A is dated March 13, 2017.

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 2016 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 2016 WTI average price of $43.34 (US$/Bbl) for crude oil and the 2016 NYMEX average price of $2.55 (US$/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.

2016 was a challenging year for natural gas prices as AECO averaged $2.18/mcf, representing the lowest annual average natural gas price in over 10 years. The Company responded by reducing capital expenditures, periodically curtailing uneconomic production, and pursuing initiatives to reduce both operating and general and administrative expenses. Through the reduction of staff and office space, as well as other cost-saving initiatives, the Company achieved a 22 percent reduction in general and administrative expenses in 2016 as compared to 2015. Cequence undertook a number of operating cost efficiency projects at Simonette, resulting in a decrease of 7 percent in operating expenses compared to 2015 field costs.

Capital expenditures, prior to dispositions, were $22,590 in 2016 a decrease of 64 percent from 2015. Expenditures were focused on the Company's primary development property at Simonette. In the first quarter, the Simonette gas plant (50% working interest) was completed which is expected to provide the Company with improved long term market access for its natural gas production. In addition, Cequence completed one Montney well (16-33) at Simonette in the first quarter using a new well design that included a longer lateral and increased frac stages. Results of the well are encouraging and production data for the first 10 months has demonstrated increased gas and condensate recoveries compared to the Company's average historical results.

As commodity prices improved, the Company raised $10 million in the fourth quarter through the issuance of flow-through common shares and started a drilling program that includes 4 gross (3 net) development wells to be drilled at Simonette. The winter drilling program includes two Montney wells (100% working interest) to follow up the successful 16-33 well. If successful, the new Montney wells, will support improved well performance and economics observed in the 16-33 well. The Company expects initial results from these wells in the first half of 2017.

FINANCIAL AND OPERATING RESULTS

PRODUCTION

	Three months ended December 31,		Twelve months ended December 31,	
	2016	2015	**2016**	2015
Natural gas (Mcf/d)	**45,005**	41,794	**45,422**	47,589
Crude oil (bbls/d)	**140**	225	**177**	160
Natural gas liquids (bbls/d)	**209**	300	**237**	475
Condensate (bbls/d)	**760**	723	**841**	918
Total (boe/d)	**8,609**	8,213	**8,826**	9,485
Total production (boe)	**792,069**	755,634	**3,230,434**	3,461,850

Production for the three and twelve months ended December 31, 2016 averaged 8,609 boe/d and 8,826 boe/d compared to production of 8,213 boe/d and 9,485 boe/d, respectively in 2015.

Average production declined 7 percent in 2016 as the Company's reduced drilling program was insufficient to offset natural production declines. In 2016, the Company brought 1.5 net wells onstream compared to 6.7 net wells in 2015. The Company expects to complete 3 net wells in the first half of 2017 and forecasts average production in the first half of 2017 to increase to 9,000 – 9,500 boe/d.

Fourth quarter production increased by 5 percent from prior year. The fourth quarter of 2015 included significant production downtime as the entire Simonette field was shut in for 14 days to accommodate the construction of the company's plant upgrade.

PRODUCTION REVENUE

	Three months ended December 31,		Twelve months ended December 31,	
$(000's)	**2016**	2015	**2016**	2015
Sales of natural gas, oil and condensate	**17,428**	13,341	**52,269**	71,496
Royalties	**(467)**	507	**(1,543)**	(2,900)
Production revenue	**16,961**	13,848	**50,726**	68,596

Production revenue was $16,961 in the fourth quarter of 2016 compared to $13,848 in 2015. The increase in production revenue is attributable to a five percent increase in production, a two percent increase in realized sales prices offset by increased royalty expense in 2016. For the twelve months ended December 31, 2016, total production revenue decreased 26 percent to $50,726 from $68,596 in the comparable period of 2015. The decrease in revenue is attributable to the 22 percent decrease in realized sales prices and seven percent decrease in production.

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:

$(000's)	Natural gas	Crude oil and condensate	Natural gas liquids	**2016 Total**	2015 Total
	Three months ended December 31,				
Sales of natural gas, oil and condensate	12,194	4,741	493	**17,428**	13,341
Realized gain (loss) on commodity contracts	(90)	(85)	–	**(175)**	2,771
Total revenue[1]	12,104	4,656	493	**17,253**	16,112

[1] Refer to non-GAAP measurements.

$(000's)	Natural gas	Crude oil and condensate	Natural gas liquids	**2016 Total**	2015 Total
	Twelve months ended December 31,				
Sales of natural gas, oil and condensate	32,020	18,345	1,904	**52,269**	71,496
Realized gain on commodity contracts	5,697	1,108	–	**6,805**	9,395
Total revenue[1]	37,717	19,453	1,904	**59,074**	80,891

[1] Refer to non-GAAP measurements.

Total revenue was $17,253 in the fourth quarter of 2016 compared to $16,112 in 2015. The increase in revenue is attributable to a five percent increase in production and a two percent increase in realized sales prices. For the twelve months ended December 31, 2016, total revenue decreased 27 percent to $59,074 from $80,891 in the comparable period of 2015. The decrease in revenue is attributable to the 22 percent decrease in realized sales prices and seven percent decrease in production.

$(000's)	Three months ended December 31, 2016	2015	Twelve months ended December 31, 2016	2015
Average prices				
Natural gas ($/Mcf)	**2.95**	2.16	**1.93**	2.73
Realized natural gas hedges ($/Mcf)	**(0.03)**	0.73	**0.34**	0.54
Natural gas including hedges ($/Mcf)	**2.92**	2.89	**2.27**	3.27
Crude oil and condensate ($/bbl)	**57.30**	52.32	**49.20**	53.78
Realized crude oil hedges ($/bbl)	**(1.03)**	–	**2.97**	–
Crude oil and condensate including hedges ($/bbl)	**56.27**	52.32	**52.17**	53.78
Natural gas liquids ($/bbl)	**25.61**	16.45	**21.94**	17.04
Average sales price before hedges ($/boe)	**22.00**	17.65	**16.18**	20.65
Average sales price including hedges ($/boe)	**21.78**	21.32	**18.29**	23.37
Benchmark pricing				
AECO-C spot (CDN$/Mcf)	**3.11**	2.48	**2.18**	2.71
WTI crude oil (US$/bbl)	**49.16**	42.02	**43.34**	48.68
Edmonton par price (CDN$/bbl)	**60.76**	52.88	**52.95**	57.62
US$/CDN$ exchange rate	**0.75**	0.75	**0.76**	0.78

For the year ended December 31, 2016, natural gas prices averaged $2.27/mcf down $1.00/mcf from $3.27/mcf in 2015. Prices remained low throughout most of 2016 as an unseasonably warm North American winter in 2015/16 resulted in record high North American natural gas inventories. Prices increased during the second half of the year through a combination of lower North American natural gas drilling activity, increased natural gas usage for power generation and U.S. exports that resulted in an improvement of supply/demand fundamentals and alleviated the large gas storage surplus. For the fourth quarter of 2016 natural gas prices averaged $2.92/mcf consistent with $2.89/mcf in 2015.

The Company realized natural gas prices before hedging for the three and twelve months ended December 31, 2016 of $2.95/mcf and $1.93/mcf. The Company's average natural gas price realization in the fourth quarter of 2016 was a five percent discount to AECO compared to a discount of 13 percent in 2015. The Company is currently marketing most of its natural gas at Simonette with short term sales contracts at fixed differentials to AECO. For the fourth quarter and year ended December 31, 2016, the Company realized an average price discount to AECO of $0.35/GJ and $0.45/GJ, respectively, prior to adjustments for heat content.

For the first quarter of 2017, Cequence has contracts on Alliance and TCPL that average 40,366 GJ/d at a blended discount to AECO of $0.31/GJ. Beginning April 1, 2017 the contracted volume drops down to 20,000 GJ/d then to 10,000 GJ/d on November 1, 2016. The Company is pursuing additional firm service but there is no guarantee that it will be able to secure it. If the Company cannot secure firm service it will be relying on interruptible service on both the Alliance and TCPL pipeline systems. Interruptible transportation service is expected to be more volatile than firm service which may result in higher transportation charges or inconsistent production times until additional firm service is contracted. Beginning, April 1, 2018 the Company will have 35,000 GJ/d of firm service with TCPL from its Simonette property.

Crude oil and condensate prices remained low throughout 2015 and 2016 with average Edmonton par prices declining eight percent in 2016. Crude oil and condensate prices before hedges for the fourth quarter of 2016 and twelve months ended December 31, 2016 were $57.30/bbl and $49.20/bbl, respectively, up ten percent and down nine percent from the same time period in 2015.

Natural gas liquids prices for the three and twelve months ended December 31, 2016 were $25.61/bbl and $21.94/bbl, respectively, up 56 percent and 29 percent from the same time period in 2015.

COMMODITY PRICE MANAGEMENT

	Three months ended December 31,		Twelve months ended December 31,	
$(000's)	**2016**	2015	**2016**	2015
Realized gain (loss) on commodity contracts	**(175)**	2,771	**6,805**	9,395
Unrealized gain (loss) on commodity contracts	**(4,402)**	396	**(8,294)**	(4,541)
Total	**(4,577)**	3,167	**(1,489)**	4,854

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. In both 2015 and 2016, declining current crude oil and natural gas prices resulted in realized gains on commodity contracts that resulted in an increase in average sales prices of 13 percent in both years.

The fair value of the commodity contracts outstanding at December 31, 2016 was a current liability of $4,491 and non-current liability of $159 (December 31, 2015 – current asset of $3,644). 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, 2017 to March 31, 2017	Gas	Swap	20,000	$2.66	$2.85	AECO
April 1, 2017 to September 30, 2017	Gas	Swap	22,500	$2.78	$2.98	AECO
October 1, 2017 to December 31, 2017	Gas	Swap	19,185	$2.76	$2.96	AECO
January 1, 2018 to March 31, 2018	Gas	Swap	7,500	$3.02	$3.23	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, 2017 to December 31, 2017	Oil	Swap	366	$69.26	WTI

OPERATING NETBACK

($/boe)	Three months ended December 31, 2016	2015	Twelve months ended December 31, 2016	2015
Total revenue[1]	**21.78**	21.32	**18.29**	23.37
Royalty expense	**(0.59)**	0.67	**(0.48)**	(0.84)
Transportation expense	**(1.45)**	(1.77)	**(1.24)**	(1.83)
Operating costs	**(7.81)**	(9.30)	**(8.49)**	(9.17)
Operating netback, $/boe	**11.93**	10.92	**8.08**	11.53
Operating netback, excluding realized hedges, $/boe	**12.15**	7.25	**5.97**	8.81

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

See Non-GAAP measures for definition of operating netback.

Cequence's operating netback for the three months ended December 31, 2016 increased nine percent to $11.93 per boe from $10.92 per boe in 2015. Excluding realized hedges, fourth quarter operating netbacks increased by 68 percent. Fourth quarter operating netbacks increased from prior year due to higher commodity prices and lower operating expenses.

For the twelve months ended December 31, 2016, the operating netback decreased by 30 percent to $8.08/boe from $11.53/boe in the comparative period of 2015. Excluding realized hedges, operating netbacks decreased by 32 percent. The decrease in 2016 annual operating netbacks is mainly due to lower total revenue that was partially offset by the reduction in operating costs.

ROYALTY EXPENSE

$(000's)	Three months ended December 31, 2016	2015	Twelve months ended December 31, 2016	2015
Crown	**(219)**	(893)	**(218)**	324
Freehold / Overriding	**686**	386	**1,761**	2,576
Total royalties	**467**	(507)	**1,543**	2,900
Royalties as a percentage of revenue, before hedging	**3%**	0%	**3%**	4%
Per unit of production ($/boe)	**0.59**	(0.67)	**0.48**	0.84

Royalty expense for the twelve months ended December 31, 2016 was consistent with prior year at three percent of sales of natural gas, oil and condensate. The average crown royalty rate remains low due to depressed commodity prices in both 2015 and 2016. Crown royalties operate on a sliding scale and royalty rates decrease when commodity prices decrease. In addition, credits against crown royalties for gas cost allowance remain at a similar amount despite lower crown royalties effectively reducing crown royalties to zero.

Royalty expense in the fourth quarter of 2015 included an adjustment for royalty credits received for gas cost allowance, capital cost allowance and custom processing fees received from prior period's royalty calculations.

In 2016, the Alberta government announced a Modernized Royalty Framework ("MRF") that came into effect on January 1, 2017. The royalty structure for wells drilled prior to January 1, 2017 will not change for a 10 year period from the royalty program's implementation date. The MRF will utilize a revenue minus cost framework with different royalty rates pre and post payout based on commodity prices and with a reduction in royalty rates for mature wells. Ninety percent of the Company's production is in Alberta and will be subject to the MRF. The economics of drilling wells at its Simonette property within expected price ranges, are estimated to improve modestly under the MRF. Cequence will continue to monitor the impact of the MRF on its operations in Alberta.

OPERATING COSTS

	Three months ended December 31,		Twelve months ended December 31,	
$(000's)	**2016**	2015	**2016**	2015
Operating costs	**6,184**	7,030	**27,436**	31,746
Per unit of production ($/boe)	**7.81**	9.30	**8.49**	9.17

In 2016, the Company focused on reducing field operating costs which resulted in improvements to chemical usage, trucking costs, field rentals and water handling. Operating costs for the three and twelve months ended December 31, 2016 improved by 12 percent and 14 percent, respectively, compared to 2015.

The operating cost improvements were achieved despite an increase in midstream capital costs following the Company's midstream transaction in June 2015. For the year ended December 31, 2016, midstream capital costs were $1.15/boe, an increase of $0.83/boe compared to 2015.

TRANSPORTATION EXPENSE

	Three months ended December 31,		Twelve months ended December 31,	
$(000's)	**2016**	2015	**2016**	2015
Transportation	**1,151**	1,339	**4,018**	6,323
Per unit of production ($/boe)	**1.45**	1.77	**1.24**	1.83

Transportation expense for the three and twelve months ended December 31, 2016 was $1.45/boe and $1.24/boe, respectively, a decrease of 18 percent and 32 percent from the comparative period in 2015. Transportation expenses decreased in 2016 compared to the prior year as the Company's firm gas transportation commitment on Alliance terminated in the fourth quarter of 2015. In addition, the Company observed an increase in trucking expenses in the first six months of 2015 due to wet weather in the field.

GENERAL AND ADMINISTRATIVE EXPENSES

	Three months ended December 31,		Twelve months ended December 31,	
$(000's)	**2016**	2015	**2016**	2015
G&A expenses, prior to restructuring charges	**1,597**	2,203	**6,926**	8,823
Restructuring charges	**–**	–	**2,341**	–
G&A expenses	**1,597**	2,203	**9,267**	8,823
Administrative and capital recovery	**(164)**	(199)	**(316)**	(864)
Total G&A expenses	**1,433**	2,004	**8,951**	7,959
Per unit of production, excluding restructuring charges ($/boe)	**1.81**	2.65	**2.05**	2.30
Per unit of production ($/boe)	**1.81**	2.65	**2.77**	2.30

In 2016, the Company made several improvements to its G&A cost structure including a significant staff reduction and relocation of the Company's office after its lease expired. Prior to restructuring charges G&A expenses were $6,926 or 22 percent lower than 2015. Annual G&A expense, excluding administrative and capital recovery, totalled $9,267 and includes $2,341 of non-recurring restructuring charges related to severance obligations.

In the fourth quarter of 2016, total G&A expenses were $1,433 or $1.81/boe, representing a 29 percent decrease from the fourth quarter of 2015. Fourth quarter G&A expenses do not include any restructuring charges and are representative of the Company's improved cost structure. G&A expenses are forecast be approximately $6,000 in 2017.

FINANCE COSTS

	Three months ended December 31,		Twelve months ended December 31,	
	2016	2015	**2016**	2015
Interest and standby fees expense on credit facilities	**53**	155	**411**	966
Interest expense and standby fees on senior notes	**1,464**	1,466	**5,821**	5,820
Amortization of transaction costs	**107**	95	**400**	360
Accretion expense on senior notes	**81**	74	**308**	277
Accretion expense on provisions	**220**	217	**803**	853
Total finance costs	**1,925**	2,007	**7,743**	8,276
Per unit of production ($/boe)	**2.43**	2.66	**2.40**	2.39
Interest per unit of production ($/boe)	**1.92**	2.15	**1.93**	1.96

Finance costs for the three and twelve months ended December 31, 2016 were $1,925 and $7,743 compared to $2,007 and $8,276 in 2015. Cequence incurred lower interest expense on its credit facility which was undrawn for the majority of 2016 and lower standby fees due to the reduced size of the senior credit facility.

OTHER INCOME

	Three months ended December 31,		Twelve months ended December 31,	
$(000's)	**2016**	2015	**2016**	2015
Gain on sale of property and equipment	**(220)**	(258)	**(3,202)**	(5,537)
Interest income	**(75)**	(183)	**(115)**	(357)
Other	**(49)**	(69)	**(241)**	(234)
Total other income	**(344)**	(510)	**(3,558)**	(6,128)

Other income for the twelve months ended December 31, 2016, includes a gain in 2016 of $2,964 from the sale of certain infrastructure assets that were partially depreciated. During the twelve months ended December 31, 2015, the Company completed sales of certain oil and gas properties, including the disposition of a 50 percent interest of existing Simonette facilities and related infrastructure, for total cash consideration of $44,763, subject to final adjustments. The sales in 2015 resulted in a gain recognized in comprehensive loss of $5,537.

DEPLETION AND DEPRECIATION

$(000's)	Three months ended December 31, 2016	2015	Twelve months ended December 31, 2016	2015
Depletion and depreciation expense	**10,757**	7,556	**31,622**	39,191
Impairment loss	**–**	144,000	**–**	230,400
Total depletion, depreciation and impairment	**10,757**	151,556	**31,622**	269,591
Per unit of production ($/boe)	**13.58**	200.57	**9.79**	77.87
Per unit of production, excluding impairment ($/boe)	**13.58**	10.00	**9.79**	11.32

Depletion and depreciation expense for the three and twelve months ended December 31, 2016, was $10,757 ($13.58/boe) and $31,622 ($9.79/boe). Depletion and depreciation rates for the twelve months ended December 31, 2016 have decreased from prior year due to reduced book values from impairment charges in 2015. During the fourth quarter of 2016, the remaining productive life of certain non-core areas was reduced resulting in additional depletion in the quarter.

On December 31, 2015, Cequence recorded a $144,000 impairment charge related to its Deep Basin and Peace River Arch CGUs. The impairments were a result of a lower outlook for future crude oil and natural gas prices compared to September 30, 2015. Commodity prices further deteriorated in the fourth quarter, in particular natural gas prices used in the first three years of the Company's third party reservoir engineers price forecast decreased by 20 percent, 10 percent and 7 percent, respectively. The impact of lower forecasted benchmark commodity prices was only partially offset by an increase in proved plus probable reserves of 7 percent and the positive impact of lower future development capital.

On September 30, 2015, Cequence recorded impairment of $86,400 related to its Deep Basin, Peace River Arch and Northeast British Columbia CGUs. The impairments were a result of a lower outlook for crude oil and natural gas prices.

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

$(000's)	Three months ended December 31, 2016	2015	Twelve months ended December 31, 2016	2015
Northeast British Columbia	**–**	–	**–**	10,000
Peace River Arch	**–**	2,000	**–**	7,500
Deep Basin	**–**	142,000	**–**	212,900
Total	**–**	144,000	**–**	230,400

SHARE BASED PAYMENTS

Stock Options

The Company has 11,003 stock options outstanding with an average exercise price of $0.86. 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, 2016, Cequence recorded $708 (2015 – $1,107) 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, 2016, Cequence recognized $374 (2015 – $100) in share based payment expense related to RSUs with a corresponding increase to share based payment liability.

	RSUs		Stock Options	
Number (000's)	**2016**	2015	**2016**	2015
Outstanding, beginning of year	**1,707**	814	**11,395**	18,252
Granted	**2,622**	1,235	**6,295**	1,085
Cancelled/Forfeited	**(677)**	(17)	**(3,900)**	(12)
Settled	**(642)**	(325)	**–**	–
Expired	**–**	–	**(2,787)**	(7,930)
Outstanding, end of year	**3,010**	1,707	**11,003**	11,395

CAPITAL EXPENDITURES

	Three months ended December 31,		Twelve months ended December 31,	
$(000's)	**2016**	2015	**2016**	2015
Land	**199**	254	**886**	1,267
Geological and geophysical and capitalized overhead	**551**	271	**1,141**	1,218
Drilling, completions and workovers	**9,111**	12,844	**14,192**	26,380
Equipment, facilities and tie-ins	**1,595**	1,803	**6,366**	33,336
Office furniture and equipment	**4**	3	**5**	60
Capital expenditures	**11,460**	15,175	**22,590**	62,261
Property acquisitions(1)	**23**	–	**(60)**	1,062
Property dispositions(1)	**(77)**	1,176	**(5,234)**	(44,763)
Total capital expenditures	**11,406**	16,351	**17,296**	18,560

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

For the twelve months ended December 31, 2016, capital expenditures, excluding acquisitions and dispositions, decreased to $22,590 from $62,261 in 2015. The Company reduced its drilling activity for most of 2016 as commodity prices remained low.

In the first quarter of 2016, the Company completed the addition of a shallow cut refrigeration upgrade at the Company's Simonette natural gas plant (50% working interest). The gas plant is currently expected to have sufficient spare capacity for the company's growth plans without additional large facility expenditures. The gas plant was operational in the first quarter of 2016 and is expected to provide Cequence with greater long term flexibility and improved pricing for natural gas and liquids from its Simonette property. Capital expenditures during the year also include the drilling of a water injection well at Simonette.

In the fourth quarter, commodity prices began to improve and the Company commenced a drilling program that includes 2 gross (1 net) Dunvegan wells and 2 gross (2 net) Montney wells. All four wells were spud in the fourth quarter with the Duvengan wells completed and on production in the first quarter of 2017 and the Montney wells expected to be on production in the second quarter of 2017.

During the twelve months ended December 31, 2016, the Company completed sales of certain non-producing oil and gas properties for total cash consideration of $5,234 (2015 – $44,763), subject to final adjustments. The sales resulted in a gain recognized in comprehensive loss of $3,202 (2015 – $5,537 gain).

INCOME TAXES

As at December 31, 2016, the Company has tax pools and available losses of $613,777 (December 31, 2015 – $616,084). Due to the uncertainty of future realization, a deferred tax asset has not been recognized.

At December 31, 2016, Cequence has the following tax pools:

Classification	Amount $(000's)	Annual Deductibility
Canadian exploration expense	153,846	100%
Non-capital losses	299,491	100%
Undepreciated capital cost	53,070	Primarily 25%, declining balance
Canadian oil and gas property expense	10,191	10%, declining balance
Canadian development expense	69,079	30%, declining balance
Other	28,100	Various
	613,777	

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

PROVISIONS – DECOMMISSIONING LIABILITIES

Decommissioning liabilities represent the estimated future cost of abandoning and reclaiming the company's oil and natural gas wells and related facilities. Total decommissioning liabilities at December 31, 2016 were $38,161 compared to $40,708 at December 31, 2015. 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 $366 of decommissioning obligations in 2017. The following table summarizes the changes in decommissioning liabilities for the respective periods:

	December 31, 2016	December 31, 2015
Balance, beginning of year	**40,708**	37,263
Property dispositions	**(364)**	(3,283)
Accretion expense	**803**	853
Liabilities incurred	**286**	1,819
Abandonment costs incurred	**(1,852)**	(720)
Revisions in estimated cash flows	**(126)**	3,195
Revisions due to change in discount rates	**(1,294)**	1,581
Balance, end of year	**38,161**	40,708

The total estimated, undiscounted cash flows, inflated at 2 percent, required to settle the obligations are $66,240 (December 31, 2015 – $69,020). These cash flows have been discounted using a risk-free interest rate of 2.34 percent (December 31, 2015 – 2.16 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, 2015 – 1 to 50 years).

LIQUIDITY AND CAPITAL RESOURCES

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

$(000's)	**As at December 31, 2016**	As at December 31, 2015
Cash	**17,778**	13,246
Demand credit facility	**–**	–
Senior notes – principal	**(60,000)**	(60,000)
Accounts payable and accrued liabilities	**(36,124)**	(41,688)
Share based payment liability	**(341)**	(169)
Provisions – current	**(366)**	(826)
Accounts receivable	**14,145**	22,321
Deposits and prepaid expenses	**877**	1,669
Net debt[(1)(2)]	**(64,031)**	(65,447)
Funds flow from operations[(1)] – trailing twelve months	**11,250**	25,578
Net debt to funds flow from operations trailing twelve months[(2)]	**5.7:1**	2.6:1

(1) Refer to non-GAAP measurements.

(2) Prior period amounts have been adjusted to conform to current period presentation.

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

At December 31, 2016, the Company's net debt to funds flow of 5.7:1 is higher than the Company's long term target of 2:1 due to the prolonged period of low commodity prices through 2015 and 2016. To manage its leverage and limit borrowing on its senior credit facility, the Company significantly reduced capital expenditures in 2016. The Company did not conduct any drilling activity for the first three quarters and focused its efforts on reducing both operating and general and administrative costs.

AECO prices improved in the latter half of 2016 and the Company began to realize the benefits of its costs saving initiatives. To illustrate the impact of these changes, the Company analyzed its December 31, 2016 net debt compared to fourth quarter annualized funds flow which resulted in an improved net debt to funds flow ratio of 2.4:1.

On October 28, 2016, Cequence completed the sale of 34,500 common voting shares on a Canadian development expenses "flow-through" basis at $0.29 per share for gross proceeds of $10,005. Proceeds of the offering allowed the Company to commence a winter drilling program in the fourth quarter without incurring additional bank debt in 2016. Based on the Company's anticipated funds flow, the winter drilling program will be financed by the proceeds of the financing, funds flow from operations and bank debt.

Senior Credit Facility

At December 31, 2016, Cequence had a $20,000 (December 31, 2015 – $60,000) term credit facility available from a syndicate of Canadian chartered banks. The senior credit facility is secured by a first floating charge debenture, general assignment of book debts and Cequence's oil and natural gas properties and equipment. The senior credit facility has a term date of May 31, 2017 and may be extended beyond the initial term, if requested by the Company and accepted by the lenders. If the credit facility does not continue to revolve, amounts borrowed under the facility must be repaid on the term date. The senior credit facility is reviewed on a semi-annual basis with the lender holding the right to request an additional review.

As at December 31, 2016 and 2015, the senior credit facility is undrawn. The company has letters of credit outstanding of $3,307 (December 31, 2015 – $3,207). 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, 2016 with a ratio of 0.2 times (December 31, 2015 – 0 times). At December 31, 2016, 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 senior notes diversify the Company's capital structure by providing longer term debt that is not reserve-based or subject to periodic redetermination. 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 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 for the trailing twelve months. At December 31, 2016, the Company's Debt to Cashflow ratio was more than 2.5 times. If current commodity prices persist, the Company expects that its Debt to Cashflow ratio will remain in excess of 2.5 times in 2017.

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

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

The Company's ACTNA is defined as the value of the Company's total proved reserves before taxes, plus the value of tangible assets less working capital. At December 31, 2016 ACTNA is $241,779. The Company does not currently expect the incurrence covenants in the senior note indenture to restrict its planned activities.

Generally, the incurrence covenants also restrict payments as follows:

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

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

Commitments

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

	2017	2018	2019	2020	2021+	Total
Office leases	367	350	262	–	–	979
Pipeline transportation	588	1,915	2,350	2,350	12,328	19,531
Gas processing	4,154	4,154	4,154	4,166	38,780	55,408
Total	5,109	6,419	6,766	6,516	51,108	75,918

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

Subsequent to December 31, 2016, the Company has entered into a binding contract to ship 10,850 GJ/d of natural gas on the TransCanada mainline system from the Empress receipt point to the Dawn hub in Ontario subject to regulatory approval with the National Energy Board and financial assurances. The term of the contract is 10 years and has early termination rights that can be exercised following the initial five years of service. The toll for this service is $0.77/GJ. The Company currently expects to begin shipping gas under these arrangements on April 1, 2018. The contract provides Cequence with pricing diversification for approximately 20 percent of its natural gas production.

OUTSTANDING SHARE DATA

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

	December 31, 2016	December 31, 2015
Common shares	**245,528**	211,028
Stock options	**11,003**	11,395
Restricted share units	**3,010**	1,707
Warrants	**3,000**	3,000

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

Warrants have an exercise price of $2.03 to purchase common shares.

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 “flow-through” basis at $0.29 per share for gross proceeds of $10,005. The financing allowed the Company to resume drilling operations in the fourth quarter.

As of the date of this MD&A, Cequence had the following securities outstanding: 245,528 common voting shares, 3,000 warrants to purchase common shares, 15,878 stock options and 3,711 RSUs.

SELECTED FINANCIAL INFORMATION

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

	Three months ended December 31,		Twelve months ended December 31,		
$(000's)	**2016**	2015	**2016**	2015	2014
Cash flow from operating activities	**6,084**	3,266	**11,641**	31,884	68,132
Decommissioning liabilities expenditures	**259**	376	**1,852**	720	1,382
Net change in non-cash working capital	**282**	1,232	**(2,243)**	(7,026)	1,136
Funds flow from operations	**6,625**	4,874	**11,250**	25,578	70,650
Per share – basic ($)	**0.03**	0.02	**0.05**	0.12	0.33
Per share – diluted ($)	**0.03**	0.02	**0.05**	0.12	0.33
Total revenue	**17,253**	16,112	**59,074**	80,891	136,893
Comprehensive income (loss)	**(9,077)**	(146,585)	**(28,057)**	(250,072)	79,368
Per share – basic ($)	**(0.04)**	(0.69)	**(0.13)**	(1.19)	0.38
Per share – diluted ($)	**(0.04)**	(0.69)	**(0.13)**	(1.19)	0.37
Total assets	**388,858**	409,559	**388,858**	409,559	678,831
Demand credit facilities	**–**	–	**–**	–	–
Senior notes – principal	**60,000**	60,000	**60,000**	60,000	60,000

Funds flow from operations was $6,625 for the three months ended December 31, 2016 compared to $4,874 in 2015. The quarterly increase in funds flow is due to increased production volumes combined with lower operating, G&A and interest expenses. Annual funds flow from operations decreased by 56 percent from 2015. The decrease in annual funds flow is primarily a result of lower commodity prices and to a lesser extent lower production volumes.

Cequence recorded a comprehensive loss of $9,077 for the three months ended December 31, 2016 compared to a loss of $146,585 in 2015. The decrease is mainly due to the recording of $144,000 of impairment expense in the fourth quarter of 2015.

Cequence recorded a comprehensive loss of $28,057 for the twelve months ended December 31, 2016 compared to a loss of $250,072 in 2015. The decrease in comprehensive loss is mainly due to impairments recorded in 2015.

QUARTERLY INFORMATION

FINANCIAL

($(000's) except per share data)	**2016 Q4**	**2016 Q3**	**2016 Q2**	**2016 Q1**	2015 Q4	2015 Q3	2015 Q2	2015 Q1
Total revenue[(1)]	**17,253**	14,707	11,343	15,772	16,112	19,383	21,802	23,594
Royalties expense	**467**	636	(125)	565	(507)	368	1,016	2,023
Transportation expense	**1,151**	1,001	774	1,092	1,339	1,323	1,757	1,903
Operating costs	**6,184**	6,228	5,812	9,212	7,031	8,951	7,954	7,811
Comprehensive income (loss)	**(9,077)**	(880)	(12,212)	(5,888)	(146,585)	(99,070)	246	(4,662)
Per share – basic and diluted	**(0.04)**	(0.00)	(0.06)	(0.03)	(0.69)	(0.47)	0.00	(0.02)
Funds flow from (used in) operations[(2)]	**6,625**	3,385	1,554	(314)	4,874	5,139	7,283	8,283
Per share – basic	**0.03**	0.02	0.01	(0.00)	0.02	0.02	0.03	0.04
Per share – diluted	**0.03**	0.02	0.01	(0.00)	0.02	0.02	0.03	0.04
Capital expenditures, net	**11,460**	2,810	958	7,362	15,175	4,656	19,848	22,582
Net acquisitions (dispositions)[(3)]	**(54)**	(5,167)	138	(211)	1,176	1,136	(43,078)	(2,935)
Total capital expenditures	**11,406**	(2,357)	1,096	7,151	16,351	5,792	(23,230)	19,647

(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

	2016 Q4	**2016 Q3**	**2016 Q2**	**2016 Q1**	2015 Q4	2015 Q3	2015 Q2	2015 Q1
Production volumes								
Natural gas (Mcf/d)	**45,005**	44,320	40,127	52,253	41,794	43,987	48,665	56,105
Oil (bbls/d)	**140**	175	178	218	225	199	100	115
NGLs (bbls/d)	**209**	261	244	235	300	485	562	554
Condensate (bbls/d)	**760**	798	748	1,061	723	807	953	1,197
Total (boe/d)	**8,609**	8,621	7,857	10,223	8,213	8,822	9,726	11,217
Average selling price, including realized hedges								
Natural gas ($/Mcf)	**2.92**	2.28	1.73	2.10	2.89	3.46	3.35	3.33
Crude oil and condensate ($/bbl)	**56.27**	53.78	54.01	46.69	52.31	50.08	63.18	50.13
NGLs ($/bbl)	**25.61**	24.09	21.50	16.68	16.45	16.80	17.49	17.10
Total ($/boe)	**21.78**	18.54	15.86	16.95	21.32	23.88	24.63	23.37
Operating netback, including realized hedges ($/boe)								
Price	**21.78**	18.54	15.86	16.95	21.32	23.88	24.63	23.37
Royalties	**(0.59)**	(0.80)	0.17	(0.61)	0.67	(0.45)	(1.15)	(2.00)
Transportation	**(1.45)**	(1.26)	(1.08)	(1.17)	(1.77)	(1.63)	(1.99)	(1.88)
Operating costs	**(7.81)**	(7.85)	(8.13)	(9.90)	(9.30)	(11.03)	(8.99)	(7.74)
Operating netback	**11.93**	8.63	6.82	5.27	10.92	10.77	12.50	11.75

Funds flow from operations is impacted from quarter to quarter primarily due to changes in productions volumes, realized average selling prices, royalties, operating expenses, transportation costs and G&A expense. The Company's production volumes are approximately 85 percent natural gas and fluctuations in natural gas prices have the greatest impact on the Company's revenue and funds flow from operations.

The decline in production revenue and funds flow beginning in the first quarter 2015 can be attributed to declining commodity prices and lower production volumes. Canadian AECO natural gas prices averaged $2.18/mcf in 2016, a decrease of 20% from $2.71/mcf in 2015. Production volumes decreased in the both 2015 and 2016 as the Company reduced capital expenditures on new wells due to the extended period of low gas prices.

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 2015, the Company recorded impairment expense of $230,400, including $144,000 in the fourth quarter. Impairments recognized were mainly the result of declining benchmark natural gas prices. These impairments cause significant reductions and increased volatility in the Company's net comprehensive income (loss).

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

OUTLOOK INFORMATION

On November 10, 2016, the Company updated its 2016 guidance and provided preliminary guidance for the first half of 2017:

(000's, except per share and per unit references)	May 2016 Guidance 2016	Revised Guidance 2016	Actual 2016	Six Months Ended June 30, 2017
Average production, BOE/d(1)	8,500	8,800	8,826	9,000-9,500
Funds flow from operations ($)(2)(4)	2,000	8,000	11,250	11,000-12,000
Funds flow from operations per share(2)	0.01	0.04	0.05	0.05
Capital expenditures, prior to dispositions ($)	14,000	22,000	22,590	15,500
Capital expenditures, net of dispositions ($)	7,000	17,000	17,296	15,500
Operating and transportation costs ($/boe)	11.30	10.25	9.73	10.25
G&A costs ($)(4)	8,500	8,800	8,951	3,000
Royalties (% revenue)	6	4	4	8
Crude – WTI (US$/bbl)	43.00	43.50	43.34	50.00
Natural gas – AECO (CDN$/GJ)	1.90	2.00	2.18	2.75
Period end, net debt ($)(3)	70,000	64,000	64,031	67,000-69,000
Weighted average basic shares outstanding	211,000	216,900	217,060	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.

(4) 2016 annual G&A costs include $2,341 in restructuring charges.

The Company revised its original guidance twice in 2016 to incorporate lower operating costs realized from its costs reduction efforts throughout the year, increased capital expenditures following the October financing and the impact of higher pricing and production volumes. As a result, the company's 2016 funds flow of $11,250 exceeded its revised guidance of $8,000.

The Company has provided guidance for the first half of 2017. Capital expenditures are expected to be $15,500 and include the completion of the Company's winter drilling program of two Montney wells and one net Dunvegan well at Simonette. The Company forecasts average production for the first half of 2017 to be between 9,000 – 9,500 boe/d. The Company does not expect to issue full year guidance until it has assessed the results of the company's winter drilling program which is not expected until Q2 2017.

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, 2016, 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

In April 2016, the IASB issued its final amendments to IFRS 15 "Revenue from Contracts with Customers", which replaces IAS 18 "Revenue", IAS 11 "Construction Contracts", and related interpretations. IFRS 15 provides a single, principles-based five-step model to be applied to all contracts with customers. The standard requires an entity to recognize revenue to reflect the transfer of goods and services for the amount it expects to receive, when control is transferred to the purchaser. Disclosure requirements have also been expanded. The standard is required to be adopted either retrospectively or using a modified retrospective approach for annual periods beginning on or after January 1, 2018, with earlier adoption permitted. 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.

Since November 2009, the IASB has been in the process of completing a three phase project to replace IAS 39, “Financial Instruments: Recognition and Measurement” with IFRS 9 “Financial Instruments”, which includes requirements for hedge accounting, accounting for financial assets and liabilities and impairment of financial instruments. As of February 2014, the mandatory effective date of IFRS 9 has been tentatively set to January 1, 2018. The Company is assessing the effect of this future pronouncement on its consolidated financial statements.

In January 2016, the IASB issued IFRS 16 “Leases”. For lessees applying IFRS 16, a single recognition and measurements model for leases would apply, with required recognition of assets and liabilities for most leases. The standard will come into effect for annual periods beginning on or after January 1, 2019, with earlier adoption permitted if the entity is also applying IFRS 15 “Revenue from Contracts with Customers”. 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.

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, 2016 includes $6,805 of realized gain (2015 – $9,395 realized gain) and $8,294 of unrealized loss (2015 – $4,541 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, 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, 2016.

As at December 31, 2016, 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) (2015 – $nil ($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, 2016, the Company has an allowance for doubtful accounts of $647 (2015 – $682).

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, 2016 is as follows:

	< 1 Year	1 – 2 Years	2 – 5 Years	Thereafter
Senior notes – principal	–	60,000	–	–
Accounts payable and accrued liabilities	36,124	–	–	–
	36,124	60,000	–	–

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 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, raw materials, supplies or qualified personnel;
- Dependence upon oil and gas infrastructure, certain of which the Company does not control;
- The ability to satisfy obligations under the Company's firm commitment transportation and gas processing arrangements;
- The possibility that the Company's drilling activities may encounter sour gas;
- The concentration of the Company's assets in the Simonette area;
- First Nations claims;
- Limited intellectual property protection for operating practices and dependence on employees and contractors;
- Environmental, health and safety requirements;
- Extensive competition in the Company's industry;
- Third party credit risk including dependence on limited customers and counterparties;
- Variations in foreign exchange rates and interest rates;
- Litigation.

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

FORWARD-LOOKING STATEMENTS

Certain statements contained within this MD&A constitute forward-looking statements. These statements relate to future events or the Company's future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek", "anticipate", "budget", "plan", "continue", "estimate", "expect", "forecast", "may", "will", "project", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe", and similar expressions. Forward-looking statements in this MD&A include, but are not limited to, statements with respect to: projections with respect to natural gas production; the projection of future royalty, operating, transportation and G&A expenses; the projected impact of land access and regulatory issues; projections relating to the volatility of crude oil and natural gas prices in 2017 and beyond ; the Company's projected capital investment levels for 2017 and the source of funding therefore; the effect of the Company's risk management program, including the impact of derivative financial instruments; the impact of the climate change initiatives on operating costs; the impact of Western Canada pipeline constraints. Readers are cautioned not to place undue reliance on forward-looking statements, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur.

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

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

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

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

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. 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, Finance
and Chief Financial Officer

March 13, 2017

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, 2016 and 2015, 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, 2016 and December 31, 2015, and their financial performance and their cash flows for the years then ended in accordance with International Financial Reporting Standards.

/s/ Deloitte LLP

Chartered Professional Accountants
March 13, 2017
Calgary, Alberta

CONSOLIDATED BALANCE SHEETS

(Expressed in thousands of Canadian dollars)

	December 31, 2016	December 31, 2015
	$	$
ASSETS		
CURRENT		
Cash	**17,778**	13,246
Accounts receivable (Note 7)	**14,145**	22,321
Deposits and prepaid expenses	**877**	1,669
Commodity contracts (Note 19)	**–**	3,644
	32,800	40,880
Property and equipment (Note 4)	**356,058**	368,679
	388,858	409,559
LIABILITIES		
CURRENT		
Accounts payable and accrued liabilities (Note 8)	**36,124**	41,688
Share based payment liability (Note 16)	**341**	169
Provisions (Note 13)	**366**	826
Commodity contracts (Note 19)	**4,491**	–
	41,322	42,683
Commodity contracts (Note 19)	**159**	–
Senior notes (Note 6)	**58,557**	57,849
Provisions (Note 13)	**37,795**	39,882
	137,833	140,414
COMMITMENTS (Note 18)		
SHAREHOLDERS' EQUITY		
Share capital (Note 15)	**633,848**	624,619
Warrants (Note 15)	**1,300**	1,300
Contributed surplus	**30,085**	29,377
Deficit	**(414,208)**	(386,151)
	251,025	269,145
	388,858	409,559

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, 2016	2015
	$	$
REVENUE		
Production revenue (Note 9)	**50,726**	68,596
Gain (loss) on derivative financial instruments (Note 19)	**(1,489)**	4,854
	49,237	73,450
EXPENSES		
Depletion and depreciation (Note 4)	**31,662**	39,191
Impairment (Note 4)	**–**	230,400
General and administrative (Note 12)	**8,951**	7,959
Finance costs (Note 11)	**7,743**	8,276
Operating costs	**27,436**	31,746
Share based payment (Note 16)	**1,082**	1,207
Transportation	**4,018**	6,323
Other income (Note 10)	**(3,558)**	(6,128)
	77,294	318,974
LOSS BEFORE INCOME TAXES	**(28,057)**	(245,524)
INCOME TAXES (Note 14)	**–**	4,548
NET LOSS AND COMPREHENSIVE LOSS	**(28,057)**	(250,072)
Loss per share (Note 17)		
Basic and diluted	**($0.13)**	($1.19)

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(Expressed in thousands of Canadian dollars)

	Year ended December 31, 2016	2015
	$	$
SHARE CAPITAL		
Common Shares (Note 15)		
Balance, beginning of year	**624,619**	624,619
Proceeds on issuance of flow-through shares	**10,005**	–
Share issue costs	**(776)**	–
Balance, end of year	**633,848**	624,619
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	**29,337**	28,270
Share based payment expense (Note 16)	**708**	1,107
Balance, end of year	**30,085**	29,377
DEFICIT		
Balance, beginning of year	**(386,151)**	(136,079)
Comprehensive loss	**(28,057)**	(250,072)
Balance, end of year	**(414,208)**	(386,151)
TOTAL EQUITY	**251,025**	269,145

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Expressed in thousands of Canadian dollars)

	Year ended December 31, 2016	2015
	$	$
CASH FLOWS RELATED TO THE FOLLOWING ACTIVITIES:		
OPERATING		
Net loss	(28,057)	(250,072)
Adjustments for non-cash items:		
Depletion and depreciation expense	31,622	39,191
Impairment expense	–	230,400
Finance costs related to provisions (Note 11)	803	853
Share based payment expense (Note 16)	1,082	1,207
Amortization of transaction costs on senior notes (Note 11)	399	360
Accretion on senior notes (Note 11)	309	277
Unrealized loss on derivative financial instruments (Note 19)	8,294	4,541
Costs related to onerous contracts	–	(190)
Gain on sale of property and equipment (Note 10)	(3,202)	(5,537)
Deferred income tax expense (Note 14)	–	4,548
Decommissioning liabilities expenditures (Note 13)	(1,852)	(720)
Net change in non-cash working capital (Note 20)	2,243	7,026
	11,641	31,884
INVESTING		
Property and equipment expenditures (Note 4)	(22,590)	(62,261)
Property acquisitions (Note 4)	60	(1,062)
Proceeds from sale of property and equipment (Note 4)	5,234	44,763
Net change in non-cash working capital (Note 20)	1,268	(27,522)
	(16,028)	(46,082)
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)	(203)	(107)
Issue of common shares (Note 15)	10,005	–
Share issue costs (Note 15)	(776)	–
Net change in non-cash working capital (Note 20)	(107)	(128)
	8,919	(235)
NET INCREASE (DECREASE) IN CASH	4,532	(14,433)
CASH, BEGINNING OF YEAR	13,246	27,679
CASH, END OF YEAR	17,778	13,246
SUPPLEMENTARY INFORMATION		
Income taxes paid	–	–
Interest paid	6,342	6,606

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 13, 2017.

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.

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.

Revenue from 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

In April 2016, the IASB issued its final amendments to IFRS 15 “Revenue from Contracts with Customers”, which replaces IAS 18 “Revenue”, IAS 11 “Construction Contracts”, and related interpretations. IFRS 15 provides a single, principles-based five-step model to be applied to all contracts with customers. The standard requires an entity to recognize revenue to reflect the transfer of goods and services for the amount it expects to receive, when control is transferred to the purchaser. Disclosure requirements have also been expanded. The standard is required to be adopted either retrospectively or using a modified retrospective approach for annual periods beginning on or after January 1, 2018, with earlier adoption permitted. 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.

Since November 2009, the IASB has been in the process of completing a three phase project to replace IAS 39, “Financial Instruments: Recognition and Measurement” with IFRS 9 “Financial Instruments”, which includes requirements for hedge accounting, accounting for financial assets and liabilities and impairment of financial instruments. As of February 2014, the mandatory effective date of IFRS 9 has been tentatively set to January 1, 2018. The Company is assessing the effect of this future pronouncement on its consolidated financial statements.

In January 2016, the IASB issued IFRS 16 “Leases”. For lessees applying IFRS 16, a single recognition and measurements model for leases would apply, with required recognition of assets and liabilities for most leases. The standard will come into effect for annual periods beginning on or after January 1, 2019, with earlier adoption permitted if the entity is also applying IFRS 15 “Revenue from Contracts with Customers”. 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.

4. PROPERTY AND EQUIPMENT

Cost:	
Balance at December 31, 2014	883,838
Additions	62,261
Decommissioning obligation additions and change in estimates	6,595
Acquisitions	1,062
Disposals	(47,211)
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**
Depletion, depreciation and impairment:	
Balance at December 31, 2014	(272,978)
Depletion and depreciation	(39,191)
Impairment loss	(230,400)
Disposals	4,703
Balance at December 31, 2015	(537,866)
Depletion and depreciation	(31,622)
Disposals	452
Balance at December 31, 2016	**(569,036)**
Carrying amounts:	
At December 31, 2015	368,679
At December 31, 2016	**356,058**

Costs subject to depletion include $921,573 of estimated future capital costs (December 31, 2015 – $799,624).

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

On June 17, 2015, Cequence sold a 50% interest in its existing Simonette facilities and related infrastructure for total cash consideration of approximately $41,827, including estimated purchase price adjustments. The sale resulted in a gain recognized in comprehensive loss of $5,083.

On August 11, 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.

During the year ended December 31, 2016, the Company completed additional sales of certain oil and gas properties for total cash consideration of $160 (2015 - $2,936), subject to final adjustments. The sales resulted in a gain recognized in comprehensive loss of $238 (2015 - $454 gain).

Impairment

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.

The Company reviewed each CGU comprising its property and equipment at December 31, 2015 for indicators of impairment and determined that indicators were present in all CGUs, related to decreases to future commodity 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 carried out at December 31, 2015 and the recoverable amounts of each of the Company's CGUs at December 31, 2015 were estimated as their value in use, based on the pre-tax net present value of discounted future cash flows from oil and gas reserves as estimated by the Company's independent reserves evaluator. The Company also included the fair value of undeveloped land based on an internal evaluation. Land values are determined using relevant precedent market transactions, industry conventions by CGU and consideration of the remaining tenure of the land. Consideration was also given to acquisition metrics of recent transactions completed on similar assets to those contained within the relevant CGU.

The benchmark escalated prices on which the December 31, 2015 impairment tests are based are as follows:

	Natural Gas	Condensate	Crude Oil
	AECO Spot (CDN$/mmbtu)	Edmonton Pentanes Plus (CDN$/bbl)	Edmonton Par (CDN$/bbl)
2016	2.76	60.79	55.86
2017	3.27	68.48	64.00
2018	3.45	73.17	68.39
2019	3.63	78.91	73.75
2020	3.81	84.30	78.79
2021	3.90	88.12	82.35
2022	4.10	94.41	88.24
2023	4.30	100.71	94.12
2024	4.50	103.24	96.48
2025	4.60	105.30	98.41
2026+	+2%/yr	+2%/yr	+2%/yr

(1) Source: GLJ Petroleum Consultants, January 1, 2016.

(2) The forecast benchmark prices listed above are adjusted for quality differentials, heat content and distance to market in performing the Company's impairment tests.

Prices increase at a rate of approximately 2.0 percent per year for natural gas, condensate and crude oil after 2025. Adjustments were made to the benchmark prices, for purposes of the impairment tests, to reflect varied delivery points and quality differentials in the products delivered.

The Company used a pre-tax 15% discount rate for the December 31, 2015 impairment tests based on the approximate industry average peer group weighted average cost of capital as appropriate for each CGU and the current market assessment of the time value of money.

The estimated recoverable amounts used in the December 31, 2015 impairment tests were $13,016 for the Northeast British Columbia CGU, $7,203 for the Peace River Arch CGU and $349,323 for the Deep Basin CGU.

The result of the Company's impairment test for the year ended December 31, 2015 is as follows:

	2015
Northeast British Columbia	10,000
Peace River Arch	7,500
Deep Basin	212,900
Total	230,400

As at December 31, 2015, a one percent increase in the discount rate applied to the Company's future estimated cash flows would result in an additional impairment of $25,900 whereas a ten percent decrease in forward commodity prices would result in additional impairment of $120,000 recognized in comprehensive loss for the year ended December 31, 2015.

5. DEMAND CREDIT FACILITIES

As at December 31, 2016, the Company has an extendible revolving term credit facility ("senior credit facility") of $20,000 (December 31, 2015 - $60,000) with a syndicate of Canadian chartered banks and has drawn $nil (December 31, 2015 - $nil) under the facility. The company has letters of credit outstanding of $3,307 (December 31, 2015 - $3,207). The senior credit facility has a term date of May 31, 2017 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. 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 senior credit facility is reviewed on a semi-annual basis with the lender holding the right to request an additional review. 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, 2016 and December 31, 2015. The effective annualized interest rate, including standby fees and commitment fees, for the year ended December 31, 2016 was nil percent as the credit facility was undrawn for the majority of the year (2015 – nil percent). The next scheduled review is to take place in May 2017.

In June 2016, the Company's senior credit facility was reduced to $20,000 from $60,000 and the Consolidated Debt to earnings before interest, taxes and depletion and depreciation covenant was removed. In addition, the interest rates and sliding scale on the facility were revised. Prime loans and U.S. Base Rate Loans on the facility now 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 now 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.

6. SENIOR NOTES

	December 31, 2016	December 31, 2015
Senior notes	**56,503**	56,503
Add transaction costs	**2,054**	1,346
Total senior notes	**58,557**	57,849

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, 2016 and December 31, 2015.

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 and December 31, 2015 and 2016 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, 2016	December 31, 2015
Debt component		
Beginning balance	**57,849**	57,212
Amortization of transaction costs	**400**	360
Accretion	**308**	277
Total debt component	**58,557**	57,849
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, 2016	December 31, 2015
Trade receivables	**5,826**	11,753
Allowance for doubtful accounts	**(647)**	(682)
Net trade receivables	**5,179**	11,071
Accrued receivables	**8,533**	9,709
Other receivables	**433**	1,541
Total accounts receivable	**14,145**	22,321

8. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

	December 31, 2016	December 31, 2015
Accounts payable	**12,736**	12,630
Accrued liabilities	**23,388**	29,058
Total accounts payable and accrued liabilities	**36,124**	41,688

9. PRODUCTION REVENUE

	Year ended December 31,	
	2016	2015
Sales of oil and natural gas	**52,269**	71,496
Royalties	**(1,543)**	(2,900)
Total production revenue	**50,726**	68,596

10. OTHER INCOME

	Year ended December 31,	
	2016	2015
Gain on sale of property and equipment (Note 4)	**(3,202)**	(5,537)
Interest income	**(115)**	(357)
Other	**(241)**	(234)
Total other income	**(3,558)**	(6,128)

11. FINANCE COSTS

	Year ended December 31, 2016	2015
Interest expense on demand credit facilities	**411**	966
Interest expense on senior notes	**5,821**	5,820
Amortization of transaction costs	**400**	360
Accretion expense on senior notes	**308**	277
Accretion expense on provisions	**803**	853
Total finance costs	**7,743**	8,276

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, 2016 were $5,880 (2015 - $4,498).

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

	Year ended December 31, 2016	2015
Wages, salaries, benefits and other personnel costs(i)	**1,641**	1,272
Share based payments(ii)	**676**	292
Total remuneration	**2,317**	1,564

(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, 2016 and 2015:

	2016	2015
Balance, beginning of year	**40,708**	37,263
Property dispositions (Note 4)	**(364)**	(3,283)
Accretion expense	**803**	853
Liabilities incurred	**286**	1,819
Abandonment costs incurred	**(1,852)**	(720)
Revisions in estimated cash flows	**(126)**	3,195
Revisions due to change in discount rates	**(1,294)**	1,581
Balance, end of year	**38,161**	40,708
Current	**366**	826
Non-current	**37,795**	39,882
	38,161	40,708

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 $66,240 (December 31, 2015 - $69,020). These cash flows have been discounted using a risk-free interest rate of 2.34 percent (December 31, 2015 – 2.16 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, 2015 – 1 to 50 years). As at December 31, 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, 2016	December 31, 2015
Excess of net book value of assets and liabilities over related tax pools	**(89,894)**	(76,256)
Non-capital loss carry-forwards	**80,456**	66,693
Scientific research and development expenses and investment tax credits	**9,056**	9,056
Other tax assets	**382**	507
Total net deferred income tax asset	**–**	–

At December 31, 2016, Cequence has total tax pools of $613,777 (2015 - $616,084) 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 $82,398 has not been recognized (2015 – $77,994). The Scientific Research and Development expenses of approximately $22,704 available for carry-forward do not expire (2015 - $22,704). The non-capital loss carry-forwards expire in 10 to 20 years and the investment tax credit carry-forwards expire in 4 to 8 years.

Income tax expense differs from that which would be expected from applying the effective Canadian federal and provincial tax rates of 27 percent (2015 – 26 percent) to loss before income taxes as follows:

	Year ended December 31, 2016	2015
Expected income tax recovery	**(7,575)**	(63,836)
Effect of share based payments	**292**	314
Change in previously estimated tax pools	**565**	(188)
Change in effective tax rate applied	**–**	(2,559)
Change in unrecorded deferred income tax asset	**6,699**	70,537
Other	**19**	280
Deferred income tax expense	**–**	4,548
Current income tax	**–**	–
Income tax expense	**–**	4,548

Movements in deferred income tax balances are as follows:

	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	–	**–**	**–**	**–**	**–**

	Balance December 31, 2014	Recognized in comprehensive loss	Recognized in liabilities	Recognized in equity	Balance December 31, 2015
Property and equipment and provisions	(46,232)	(28,808)	-	-	(75,040)
Unrealized (gain) loss on financial instruments	(2,046)	1,062	-	-	(984)
Senior notes	(249)	16	-	-	(233)
Non-capital losses	43,791	22,902	-	-	66,693
SRED expenses and investment tax credits	8,602	454	-	-	9,056
Other	682	(174)	-	-	508
Total	4,548	(4,548)	-	-	–

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, 2016		Year ended December 31, 2015	
Issued common voting shares	**Number**	**Stated Value**	Number	Stated Value
	(000's)	**$**	(000's)	$
Balance, beginning of year	**211,028**	**624,619**	211,028	624,619
Flow-through common shares	**34,500**	**10,005**	–	–
	245,528	**634,624**	211,028	624,619
Share issue costs	**–**	**(776)**	–	–
Balance, end of year	**245,528**	**633,848**	211,028	624,619
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, 2016, the Company has incurred $8,500 of development expenditures that were renounced to the holders of the flow-through common shares effective December 31, 2016.

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, 2016, the Company issued 6,295 stock options (2015 - 1,085) at an exercise price of $0.33 (2015 - $0.81) 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:

	2016	2015
Risk-free interest rate	**0.60%**	1.0%
Expected life of options	**5 years**	5 years
Expected volatility	**60%**	55%
Expected dividend rate	**0%**	0%
Expected forfeiture rate	**15%**	10%
Weighted average fair value	**$0.17**	$0.38

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, 2016 and 2015 is as follows:

		2016		2015
	Number of Options	**Weighted Average Exercise Price**	Number of Options	Weighted Average Exercise Price
	000's	**$**	000's	$
Outstanding, beginning of year	**11,395**	**2.08**	18,252	2.11
Granted	**6,295**	**0.33**	1,085	0.81
Cancelled/forfeited	**(3,900)**	**1.53**	(12)	1.93
Expired	**(2,787)**	**3.70**	(7,930)	1.98
Outstanding, end of year	**11,003**	**0.86**	11,395	2.08

The following table summarizes information about stock options outstanding at December 31, 2016:

			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	0.38	6,370	4.43	228	0.81
1.00 – 1.99	1.41	4,033	0.89	4,026	1.41
2.00 – 2.22	2.22	600	2.64	400	2.22
	0.86	11,003	3.03	4,654	1.45

During the years ended December 31, 2016, $708 (2015 - $1,107) 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, 2016 and 2015 is as follows:

Number of RSUs (000's)	2016	2015
Outstanding, beginning of year	**1,707**	814
Granted	**2,622**	1,235
Cancelled/forfeited	**(677)**	(17)
Exercised	**(642)**	(325)
Outstanding, end of year	**3,010**	1,707

During the years ended December 31, 2016, the Company recognized $374 (2015 - $100) 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, 2016 and 2015, 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, 2016	2015
Basic weighted average shares	**217,061**	211,028
Effect of dilutive instruments	**–**	–
Diluted weighted average shares	**217,061**	211,028

18. COMMITMENTS

	2017	2018	2019	2020	2021+	Total
Office leases	367	350	262	-	-	979
Pipeline transportation	588	1,915	2,350	2,350	12,328	19,531
Gas processing	4,154	4,154	4,154	4,166	38,780	55,408
Total	5,109	6,419	6,766	6,516	51,108	75,918

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 April 1, 2018 to March 30, 2026.

Subsequent to December 31, 2016, the Company has entered into a binding contract to ship 10,850 GJ/d of natural gas to 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/GJ.

During the year ended December 31, 2016, the Company recognized expense of $1,116 (2015 – $1,428) 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, 2016. 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, 2016, 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, 2016:

Term	Product	Type	Volume	Price	Basis
January 1, 2017 to March 31, 2017	Gas	Swap	20,000 gj/day	$2.66	AECO
April 1, 2017 to September 30, 2017	Gas	Swap	22,500 gj/day	$2.78	AECO
October 1, 2017 to December 31, 2017	Gas	Swap	19,185 gj/day	$2.76	AECO
January 1, 2018 to March 31, 2018	Gas	Swap	2,500 gj/day	$2.80	AECO
January 1, 2017 to December 31, 2017	Oil	Swap	200 bbl/day	$65.50	WTI

For the year ended December 31, 2016, realized gain from commodity derivative contracts recognized in comprehensive loss were $6,805 (2015 - $9,395 gain).

The fair value of the commodity contracts outstanding at December 31, 2016 was a current liability of $4,491 and non-current liability of $159 (December 31, 2015 – current asset $3,644).

For the year ended December 31, 2016, the Company recorded an unrealized loss of $8,294 from derivative commodity contracts (2015 - $4,541 unrealized loss).

As at December 31, 2016, an 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 $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, 2016 the Company had no forward, foreign exchange contracts in place, nor any significant working capital items denominated in foreign currencies (2015 – 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, 2016 (2015 - nil).

As at December 31, 2016, 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) (2015 - $nil ($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 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, 2016, the accounts receivable balance was $14,145 of which $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
12,743	529	209	664	14,145

At December 31, 2016, the Company has an allowance for doubtful accounts of $647 (2015 – $682). As at December 31, 2016, 44.3 percent (2015 – 19.5) 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, 2016	2015
Balance, beginning of year	**682**	944
Amounts collected	**(115)**	(431)
Amounts written off to accounts receivable	**(164)**	16
Additional provision	**244**	153
Balance, end of year	**647**	682

As at December 31, 2016, the maximum exposure to credit risk was $31,923 (2015 - $39,211) 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, 2016 is as follows:

	< 1 Year	1 – 2 Years	2 – 5 Years	Thereafter
Senior notes – principal	–	60,000	–	–
Accounts payable and accrued liabilities	36,124	–	–	–
	36,124	60,000	–	–

20. CHANGES IN NON-CASH WORKING CAPITAL

	Year ended December 31,	
	2016	2015
Accounts receivable	**8,176**	2,460
Deposits and prepaid expenses	**792**	1,110
Accounts payable and accrued liabilities	**(5,564)**	(24,194)
Net change in non-cash working capital	**3,404**	(20,624)
Allocated to:		
Operating activities	**2,243**	7,026
Investing activities	**1,268**	(27,522)
Financing activities	**(107)**	(128)
	3,404	(20,624)

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.

At December 31, 2016, Cequence has $60,000 in senior notes due in 2018 and a $20,000 senior credit facility which the Company had drawn $nil. The Company's senior credit facility is based on the lenders' review of the Company's oil and natural gas reserves with the next scheduled review expected to be completed in May 2017. On October 28, 2016, the Company completed the sale, on a private placement basis, of 34,500 common voting shares on a CDE "flow-through" basis at $0.29 per share for gross proceeds of $10,005. Over the next twelve months, the Company believes that it has the ability to manage its cash flow and net capital expenditures within its available credit and will be in compliance with its financial covenants.

The 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, 2016 with a ratio of 0.2 times (December 31, 2015 - 0 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, 2016 the Company's Debt to Cashflow ratio was in excess of 2.5 times. If low commodity prices persist, the Company expects the Debt to Cashflow ratio to remain in excess of 2.5 times. The Company does not currently anticipate initiating an action that would be restricted by the incurrence covenants.

The Company continues to review its options to improve its financial leverage including the sale of assets, further adjustments to the capital program, hedging or the issuance of equity.

CORPORATE INFORMATION

MANAGEMENT

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Chief Executive Officer

David Gillis, CA
Executive Vice President, Finance & CFO

David P. Robinson
Vice President, Geology

Christopher C. Soby
Vice President, Land

Erin Thorson, CMA
Controller

DIRECTORS

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Peter Bannister
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