HIGHLIGHTS

(000's except per share and per unit amounts)	Three months ended December 31,			Twelve months ended December 31,		
	2018	**2017**	% Change	**2018**	**2017**	% Change
FINANCIAL						
Total revenue[(1), (5)]	**12,184**	13,585	**(10)**	**58,921**	65,836	**(11)**
Comprehensive loss	**(3,802)**	(6,638)	**(43)**	**(9,699)**	(99,362)	**(90)**
Per share – basic and diluted [(6)]	**(0.16)**	(0.54)	**(70)**	**(0.61)**	(8.09)	**(92)**
Funds flow from operations [(2), (5)]	**2,071**	1,583	**31**	**13,087**	19,329	**(32)**
Per share, basic and diluted [(6), (7)]	**0.08**	0.13	**(38)**	**0.82**	1.57	**(48)**
Capital expenditures, before acquisitions (dispositions)	**13,397**	5,593	**140**	**23,800**	25,857	**(8)**
Capital expenditures, including acquisitions (dispositions)	**12,463**	1,316	**847**	**20,937**	21,580	**(3)**
Net debt [(3), (5)]	**(72,103)**	(68,501)	**5**	**(72,103)**	(68,501)	**5**
Weighted average shares outstanding – basic [(6)]	**24,553**	12,277	**100**	**15,942**	12,277	**30**
Weighted average shares outstanding – diluted [(6)]	**24,553**	12,277	**100**	**15,942**	12,277	**30**
Common shares outstanding – end of period	**24,553**	12,277	**100**	**24,553**	12,277	**100**
OPERATING						
Production volumes						
Natural gas (Mcf/d)	**27,645**	33,331	**(17)**	**30,098**	40,466	**(26)**
Crude oil (bbls/d)	**736**	283	**160**	**763**	344	**122**
Natural gas liquids (bbls/d)	**227**	257	**(12)**	**250**	254	**(2)**
Condensate (bbls/d)	**427**	617	**(31)**	**478**	797	**(40)**
Total (boe/d)	**5,997**	6,713	**(11)**	**6,507**	8,139	**(20)**
Sales prices						
Natural gas, including realized hedges ($/Mcf)	**2.91**	2.33	**25**	**2.49**	2.53	**(2)**
Crude oil and condensate, including realized hedges ($/bbl)	**37.74**	66.73	**(43)**	**61.89**	61.44	**1**
Natural gas liquids ($/bbl)	**35.37**	38.55	**(8)**	**38.18**	30.72	**24**
Total ($/boe)	**22.08**	22.00	**1**	**24.81**	22.16	**12**
Netback ($/boe)						
Price, including realized hedges	**22.08**	22.00	**1**	**24.81**	22.16	**12**
Royalties	**(1.33)**	(0.63)	**111**	**(1.67)**	(1.06)	**58**
Transportation	**(3.84)**	(1.66)	**131**	**(3.01)**	(1.88)	**60**
Operating costs	**(9.86)**	(12.91)	**(24)**	**(10.14)**	(9.29)	**9**
Operating netback [(5)]	**7.05**	6.80	**4**	**9.99**	9.93	**1**
General and administrative	**(2.07)**	(1.88)	**10**	**(2.22)**	(1.48)	**50**
Interest[(4)]	**(1.42)**	(2.46)	**(42)**	**(1.98)**	(2.07)	**(4)**
Cash netback [(5)]	**3.56**	2.46	**45**	**5.79**	6.38	**(9)**

(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 (excluding commodity contracts) plus the principal value of the Senior Notes and Term Loan.
(4) Represents finance costs less refinancing expenses, amortization on transaction costs, accretion expense on Senior Notes and provisions.
(5) Refer to *"Non-GAAP Measures"*.
(6) On October 22, 2018, the Company's shareholders approved a share consolidation based on one post-consolidation common share for every 20 pre-consolidation shares. This Management's Discussion and Analysis and all information relating to issued and common shares, stock options, warrants, restricted share units and per share amounts, have been restated to reflect the share consolidation for all periods presented.
(7) Funds flow per share calculated as if the ending 24,553,000 common shares at December 31, 2018 were outstanding for the entire period would be $0.53 per share for the twelve months ended December 31, 2018 respectively.

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, 2018 and 2017.

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

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

This MD&A is dated March 12, 2019.

BASIS OF PRESENTATION

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

On October 22, 2018, the Company's shareholders approved a share consolidation based on one post-consolidation common share for every 20 pre-consolidation common shares. This MD&A and all information relating to issued and common shares, stock options, warrants, restricted share units and per share amounts, have been restated to reflect the share consolidation for all periods presented.

The reporting and the measurement currency is the Canadian dollar, and all dollar amounts in this MD&A are stated in Canadian dollars unless otherwise indicated.

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 2018 the ratio between the average price of West Texas Intermediate ("WTI") crude oil at Cushing and NYMEX natural gas was approximately 20:1 ("Value Ratio"). The Value Ratio is obtained using the 2018 WTI average price of $65.20 (US$/bbl) for crude oil and the 2018 NYMEX average price of $3.20 (US$/mcf) 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 MEASURES

Within this MD&A references are made to terms and financial measures commonly used in the oil and gas industry but that do not have a standardized meaning and are not defined by IFRS in Canada. These terms and financial measures are therefore unlikely to be comparable to similar measures presented by other companies, and should not be used to make comparisons between companies, including Cequence. These terms and financial measures, which are referred to in this MD&A as "Non-GAAP Measures", include 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 considered 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 considered 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 (excluding commodity contracts) plus the principal value of the Term Loan (previously Senior Notes) which reflects the estimated 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 Measure 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.

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 with other non-core 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.

The majority of the Company's 2018 exploration and development capital has been allocated to the Dunvegan oil prospect with 3.0 gross (2.0 net) horizontal wells completed and tied into permanent facilities in the first quarter of 2018, 1.0 gross (1.0 net) vertical stratigraphic test well drilled in the first quarter of 2018 and 2.0 gross (2.0 net) horizontal oil wells drilled and completed in the fourth quarter of 2018 and brought on production December 28, 2018. In the fourth quarter of 2018, Corporate crude oil and liquids production has increased to approximately 23 percent of the Company's total production. Oil prices strengthened in the second quarter of 2018 to their highest levels since 2014 and held consistent in the third quarter of 2018. In the fourth quarter of 2018, oil prices decreased with WTI pricing averaging US$60.70/bbl and Edmonton City Gate averaging $44.14/bbl. In Canada the decreased pricing has been the result of an imbalance in supply and export capacity along with decreased demand due to US refinery maintenance. This resulted in light oil differentials reaching record highs of US$35/bbl in December 2018. Although refineries are back online the supply glut and egress challenges continue which has caused the Alberta government to take action with mandatory oil curtailment to reduce the excess storage imbalance and light oil differentials. Cequence is exempt from these production curtailments.

Natural gas prices have continued to remain low and volatile throughout 2018 with AECO prices averaging $1.52/mcf for the year ended December 31, 2018. Concerns around oversupply in the Western Canadian Sedimentary Basin, egress constraints and planned pipeline outages have limited existing transportation access and placed downward pressure on pricing. The LNG Canada announcement is a positive for future gas demand however additional LNG export capacity beyond the two-train facility will be required for any significant and sustained price increase. Since April 1, 2018, the Company has been selling 10,850 GJ/d of gas in the Dawn, Ontario market. The Dawn marketing arrangement has provided the Company diversification away from the volatile AECO prices for approximately 1/3 of its gas production. For the year ended December 31, 2018, Dawn prices averaged approximately $4.15/mcf compared to the AECO pricing of approximately $1.52/mcf. During 2017 and 2018 the Company has lowered natural gas capital spending to adjust for lower funds flow from operations and the reduced economics of the Company's natural gas weighted drilling inventory.

The Company has refinanced its Term Loan and undertaken a number of initiatives over the past two years to manage its balance sheet through a prolonged weakness in commodity prices. Capital expenditures have been restricted to cash flow or funded by equity. The Company continues to be committed to pursuing initiatives to improve its liquidity, long term sustainability and enhance shareholder value. Additional details are discussed in the *"Liquidity and Capital Resources"* section of this MD&A.

FOURTH QUARTER AND SUBSEQUENT HIGHLIGHTS

The Company completed its fourth quarter 2018 drilling program with 2.0 gross (2.0 net) Dunvegan oil wells drilled and completed and brought on production December 28, 2018. The drilling program was funded by the Rights Offering, (as defined herein under "*Outstanding Share Data*"), as previously disclosed by the Company in its Rights Offering Circular dated July 27, 2018 and its press release dated September 13, 2018.

The Company's fourth quarter 2018 crude oil production was 736 bbls/d up from 245 bbls/d reported in the first quarter of 2018. This resulted in an overall crude oil and liquids production percentage of 23% in the fourth quarter of 2018 up from 17% reported in the first quarter of 2018.

On October 22, 2018, the Company's shareholders approved a share consolidation on the basis of one post-consolidation common share for every 20 pre-consolidation common shares (the "Share Consolidation"). The common shares began trading on a consolidated basis on October 29, 2018. The objective of the Share Consolidation was to improve the terms of trading for the Common Shares, including possible margin trading, and attract further institutional interest and investment from potential investors that may have policies in place that prohibit or discourage them from purchasing stocks trading below a certain minimum price.

FINANCIAL AND OPERATING RESULTS

PRODUCTION

	Three months ended December 31,		Twelve months ended December 31,	
	2018	2017	**2018**	2017
Natural gas (Mcf/d)	**27,645**	33,331	**30,098**	40,466
Crude oil (bbls/d)	**736**	283	**763**	344
Natural gas liquids (bbls/d)	**227**	257	**250**	254
Condensate (bbls/d)	**427**	617	**478**	797
Total (boe/d)	**5,997**	6,713	**6,507**	8,139
Crude oil and liquids production (%)	**23**	17	**23**	17
Total production (boe)	**551,767**	617,568	**2,375,089**	2,970,828

Production for the three and twelve months ended December 31, 2018 averaged 5,997 boe/d and 6,507 boe/d compared to production of 6,713 boe/d and 8,139 boe/d, respectively in 2017.

For the three and twelve months ended December 31, 2018, oil production increased by 160 per cent and 122 per cent, respectively, as compared to the same periods of the prior year. The increase reflects the Company's 3.0 gross (2.0 net) Dunvegan horizontal oil wells that were completed and tied into permanent facilities in the first quarter of 2018. For the three and twelve months ended December 31, 2018, natural gas production decreased 17 per cent and 26 per cent, respectively, as compared to the same periods of the prior year. Effective May 1, 2018 approximately 800 mcf/d of gas was sold in Gordondale for $1.5 million.

PRODUCTION REVENUE

	Three months ended December 31,		**Twelve months ended December 31,**	
$(000's)	**2018**	2017	**2018**	2017
Sales of natural gas	**7,654**	5,332	**26,327**	33,121
Sales of crude oil and condensate	**4,199**	5,561	**30,389**	25,056
Sales of natural gas liquids	**738**	911	**3,480**	2,847
Royalties	**(736)**	(391)	**(3,969)**	(3,138)
Production revenue	**11,855**	11,413	**56,227**	57,886

Production revenue was $11,855 in the three months ended December 31, 2018 compared to $11,413 in 2017. The marginal increase in production revenue is mainly due to increased crude oil volumes and improved natural gas pricing. These increases more than offset the declines in natural gas, condensate and liquids volumes and decreased crude oil and condensates prices in the fourth quarter of 2018.

For the year ended December 31, 2018, production revenue was $56,227 compared to $57,886 in 2017. The decrease in production revenue in 2018 is directly related to lower natural gas production volumes and pricing in 2018 compared to 2017 offset by increased crude oil volumes.

With increased oil production from the Dunvegan wells in 2018, Cequence's sales revenue contribution is more heavily weighted to crude oil and liquids production as shown by the table below even with a higher overall corporate per boe production weighted more to natural gas. The exception to this was during the fourth quarter of 2018 where the widening light oil differentials in December resulted in the production volumes and revenue amounts for natural gas and crude oil being proportionate.

	Three months ended December 31,		**Twelve months ended December 31,**	
	2018	2017	**2018**	2017
Natural gas production revenue (%)	**61**	45	**44**	54
Crude oil and liquids production revenue (%)	**39**	55	**56**	46
Total production revenue before royalties (%)	**100**	100	**100**	100

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)	Three months ended December 31, Natural gas	Crude oil and condensate	Natural gas liquids	**2018 Total**	2017 Total
Sales of natural gas, oil and condensate	7,654	4,199	738	**12,591**	11,804
Realized gain (loss) on commodity contracts	(246)	(161)	-	**(407)**	1,781
Total revenue (1)	7,408	4,038	738	**12,184**	13,585

(1) Refer to *"Non-GAAP Measures"*

$(000's)	Twelve months ended December 31, Natural gas	Crude oil and condensate	Natural gas liquids	**2018 Total**	2017 Total
Sales of natural gas, oil and condensate	26,327	30,389	3,480	**60,196**	61,024
Realized gain (loss) on commodity contracts	1,077	(2,352)	-	**(1,275)**	4,812
Total revenue (1)	27,404	28,037	3,480	**58,921**	65,836

(1)Refer to *"Non-GAAP Measures"*

Total revenue was $12,184 in the fourth quarter of 2018 compared to $13,585 in 2017. The decrease in revenue is mainly attributable to the Company recognizing $407 in realized loss on commodity contracts in 2018 compared to $1,781 in realized gains on commodity contracts in 2017.

For the twelve months ended December 31, 2018, total revenue decreased 11 percent to $58,921 from $65,836 in the comparable period of 2017. The decrease in total revenue is attributable to a 20 percent decrease in production which more that offset the 12 percent increase in realized sales prices after hedging.

$(000's)	**Three months ended December 31,**		**Twelve months ended December 31,**	
	2018	2017	**2018**	2017
Average prices				
Natural gas ($/Mcf)	**3.01**	1.74	**2.40**	2.24
Realized natural gas hedges ($/Mcf)	**(0.10)**	0.59	**0.09**	0.29
Natural gas including hedges ($/Mcf)	**2.91**	2.33	**2.49**	2.53
Crude oil and condensate ($/bbl)	**39.24**	67.12	**67.08**	60.16
Realized crude oil hedges ($/bbl)	**(1.50)**	(0.39)	**(5.19)**	1.28
Crude oil and condensate including hedges ($/bbl)	**37.74**	66.73	**61.89**	61.44
Natural gas liquids ($/bbl)	**35.37**	38.55	**38.18**	30.72
Average sales price before hedges ($/boe)	**22.82**	19.11	**25.34**	20.54
Average sales price including hedges ($/boe)	**22.08**	22.00	**24.81**	22.16
Benchmark pricing				
AECO-C spot gas (CDN$/Mcf)	**1.58**	1.67	**1.52**	2.23
Ontario Dawn gas (CDN$/Mcf)	**5.74**	3.78	**4.15**	4.01
WTI crude oil (US$/bbl)	**60.70**	55.28	**65.20**	50.81
Edmonton City Gate oil (CDN$/bbl)	**44.14**	68.23	**68.89**	62.89
US$/CDN$ exchange rate	**0.75**	0.79	**0.77**	0.77

For the three and twelve months ended December 31, 2018, benchmark AECO natural gas prices averaged $1.58/mcf and $1.52/mcf a decrease from $1.67/mcf and $2.23/mcf in 2017, respectively.

The Company realized natural gas prices before hedging for three and twelve months ended December 31, 2018 of $3.01/mcf and $2.40/mcf compared to $1.74/mcf and $2.24/mcf in 2017, respectively. The Company's average natural gas price realization in 2018 was a 58 percent premium to AECO compared to a premium of 1 percent in 2017. This increase in pricing is a result from an improvement in the cost of the company's marketing and transportation contracts from prior year with less short term and interruptible service and a diversification away from AECO only pricing.

Beginning in December 2017, the Company increased its firm service with Nova Gas Transmission Ltd ("NGTL") to 35,000 GJ/d at its Simonette property. The first quarter of 2018 reflects all of the Simonette gas flowing under this direct transportation contract. Gas contracts in 2017 were primarily obtained through third parties with pricing at a discount to market or to acquire transportation at a premium to firm service.

On April 1, 2018 the Company began shipping 10,850 GJ/d from AECO to the Dawn, Ontario market providing the Company with some pricing diversification from the AECO hub. Based on current forward looking natural gas prices and currency, Dawn prices, net of transportation costs and fuel, represent a premium to AECO prices.

For the three and twelve months ended December 31, 2018, benchmark Edmonton City Gate crude oil prices decreased 35 percent and increased 10 percent from 2017. Benchmark condensate prices for the three and twelve months ended December 31, 2018 were at a 46 percent and 12 percent premium to Edmonton City Gate crude oil prices. Crude oil and condensate prices before hedges for the three and twelve months ended December 31, 2018 were $39.24/bbl and $67.08/bbl down 42 percent and up 12 percent from the same period in 2017. Natural gas liquids prices for the three and twelve months ended December 31, 2018 were $35.37/bbl and $38.18/bbl down eight percent and up 24 percent from the same time period in 2017.

COMMODITY PRICE MANAGEMENT

$(000's)	**Three months ended December 31, 2018**	2017	**Twelve months ended December 31, 2018**	2017
Realized gain (loss) on commodity contracts	**(407)**	1,781	**(1,275)**	4,812
Unrealized gain (loss) on commodity contracts	**4,309**	(2,042)	**3,303**	4,927
Total	**3,902**	(261)	**2,028**	9,739

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

The fair value of the commodity contracts outstanding at December 31, 2018 was a current asset of $3,580 (December 31, 2017 - current asset of $1,274 and current liability of $998). 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, 2019 to March 31, 2019	Gas	Swap	7,500	$4.92	$5.27	Dawn
April 1, 2019 to June 30, 2019	Gas	Swap	5,000	$3.20	$3.43	Dawn
July 1, 2019 to September 30, 2019	Gas	Swap	2,500	$3.04	$3.26	Dawn
April 1, 2019 to October 31, 2019	Gas	Swap	5,000	$1.37	$1.47	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, 2019 to December 31, 2019	Oil	Swap	400	$85.29	WTI

OPERATING NETBACK

($/boe)	Three months ended December 31, 2018	2017	Twelve months ended December 31, 2018	2017
Total revenue[1]	**22.08**	22.00	**24.81**	22.16
Royalty expense	**(1.33)**	(0.63)	**(1.67)**	(1.06)
Transportation expense	**(3.84)**	(1.66)	**(3.01)**	(1.88)
Operating costs	**(9.86)**	(12.91)	**(10.14)**	(9.29)
Operating netback [2], $/boe	**7.05**	6.80	**9.99**	9.93
Operating netback [2], excluding realized hedges , $/boe	**7.79**	3.91	**10.52**	8.31

(1) Total revenue is presented gross of royalties and includes realized gain (loss) on commodity contracts.
(2) See *"Non-GAAP Measures"* for the definition of operating netback

Cequence's operating netback per boe, excluding realized hedging for the three and twelve months ended December 31, 2018 was $7.79/boe and $10.52/boe compared to $3.91/boe and $8.31/boe in 2017. Including realized hedges, operating netbacks per boe increased by four percent and one percent, respectively. Operating netbacks were consistent with prior year as higher average sales prices offset higher year-to-date per unit royalty, operating and transportation expenses.

ROYALTY EXPENSE

$(000's)	Three months ended December 31, 2018	2017	Twelve months ended December 31, 2018	2017
Crown	**542**	141	**2,814**	1,568
Freehold / Overriding	**194**	250	**1,155**	1,570
Total royalties	**736**	391	**3,969**	3,138
Royalties as a percentage of revenue, before hedging	**6%**	3%	**7%**	5%
Per unit of production ($/boe)	**1.33**	0.63	**1.67**	1.06

Royalties as a percentage of revenue, before hedging for the twelve months ended December 31, 2018 was higher by two percent from prior year. For the three months ended December 31, 2018 royalty expense increased to six percent as a result of the expiry of drilling and completion cost allowance (C*) on the Dunvegan wells and lower credits against crown royalties for gas cost allowances. Crown royalties operate on a sliding scale and royalty rates increase when commodity prices increase.

OPERATING COSTS

$(000's)	Three months ended December 31, 2018	2017	Twelve months ended December 31, 2018	2017
Operating costs	**5,440**	7,972	**24,080**	27,584
Per unit of production ($/boe)	**9.86**	12.91	**10.14**	9.29

Operating costs for the three and twelve months ended December 31, 2018, was $9.86/boe and $10.14/boe compared to $12.91/boe and $9.29/boe for the same period in 2017. Operating costs for the fourth quarter were $9.86/boe down 24% from the fourth quarter of 2017 with reduced expenses in 2018 associated with water handling and associated long term field rentals ($1.3 million or $2.15/boe). The increase in per unit operating costs year-to-date is also due to the decrease in production volumes year over year with natural gas production decreasing by 17 percent and 26 percent for the three and twelve-month periods ended December 31, 2018. In the fourth quarter of 2018, Cequence successfully completed a second water disposal well which will continue to reduce trucking and water disposal costs in Simonette.

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

TRANSPORTATION EXPENSE

	Three months ended December 31,		**Twelve months ended December 31,**	
$(000's)	**2018**	2017	**2018**	2017
Transportation	**2,116**	1,023	**7,160**	5,571
Per unit of production ($/boe)	**3.84**	1.66	**3.01**	1.88

Transportation expense for the fourth quarter of 2018 was $3.84/boe, representing an increase of 131 percent from the comparative period in 2017. For the twelve months ended December 31, 2018, transportation expense was $3.01/boe, representing an increase of 60 percent from $1.88/boe in 2017. The Company's new Simonette NGTL firm service of 35,000 GJ/d was recognized in the first quarter of 2018 as a transportation expense. On April 1, 2018, the Company's Empress to Dawn, Ontario gas contract began with 10,850 GJ/d of volumes contracted at a cost of $0.77 per GJ for a period of 10 years. In the comparable periods of 2017, a portion of the gas contracts obtained through third parties would have been secured as a commodity price offset instead of a transportation expense.

GENERAL AND ADMINISTRATIVE EXPENSES ("G&A")

	Three months ended December 31,		**Twelve months ended December 31,**	
$(000's)	**2018**	2017	**2018**	2017
G&A expenses	**1,310**	1,284	**5,714**	4,795
Administrative and capital recovery	**(167)**	(123)	**(447)**	(387)
Total G&A expenses	**1,143**	1,161	**5,267**	4,408
Per unit of production ($/boe)	**2.07**	1.88	**2.22**	1.48

G&A costs have increased in 2018 with the Company incurring additional consulting, legal and advisor fees associated with the evaluation of strategic financial alternatives throughout the year. G&A costs for the fourth quarter of 2018 were consistent with 2017 expenses. Unit costs have increased as production volumes are lower in 2018 compared to 2017.

FINANCE COSTS

$(000's)	Three months ended December 31, 2018	2017	Twelve months ended December 31, 2018	2017
Interest and standby fees expense on Credit Facility	**27**	56	**121**	331
Interest expense on Senior Notes and Term Loan	**757**	1,466	**4,592**	5,820
Refinancing expenses – warrants	**-**	-	**737**	-
Refinancing expense – legal, advisory and professional fees on Term Loan	**-**	-	**962**	-
Amortization of transaction costs	**-**	117	**371**	443
Accretion expense on Senior Notes	**-**	90	**288**	341
Accretion expense on provisions	**191**	211	**803**	870
Total finance costs	**975**	1,940	**7,874**	7,805
Per unit of production ($/boe)	**1.77**	3.14	**3.32**	2.63
Interest per unit of production ($/boe)	**1.42**	2.46	**1.98**	2.07

Finance costs for the three and twelve months ended December 31, 2018 were $975 and $7,874 compared to $1,940 and $7,805 in 2017. Cash interest expense decreased in 2018 with the closing of the Term Loan and a decrease in the interest rate from 9.7% to 5.0%. Finance costs in 2018 included additional warrant fair value expense and legal and professional advisor fees associated with the negotiation and refinancing of the Senior Notes which were restructured and extended as announced on July 27, 2018. These expenditures have not been offset or netted against the new Term Loan (as such term is defined in "*Liquidity and Capital Resources – Senior Notes and Term Loan"*) given that it was not an issuance of new debt. Interest and standby fees on the demand Credit Facility were lower in 2018 as the facility size was reduced. The Company remains undrawn on its Credit Facility.

OTHER INCOME

$(000's)	Three months ended December 31, 2018	2017	Twelve months ended December 31, 2018	2017
Gain (loss) on sale of property and equipment	**1,445**	(248)	**3,890**	(130)
Interest income	**55**	21	**126**	102
Other	**51**	46	**191**	243
Total other income	**1,551**	(181)	**4,207**	215

During the twelve months ended December 31, 2018, the Company disposed of certain oil and properties and associated decommissioning liabilities for proceeds of $2,863 (2017 - $4,270) prior to closing adjustments. The sales resulted in a gain recognized in comprehensive loss of $3,890 (2017 - $130 loss).

DEPLETION, DEPRECIATION AND IMPAIRMENT

$(000's)	Three months ended December 31, 2018	2017	Twelve months ended December 31, 2018	2017
Depletion and depreciation expense	**11,322**	5,348	**27,480**	24,606
Impairment loss	**-**	-	**-**	96,200
Total depletion, depreciation and impairment	**11,322**	5,348	**27,480**	120,806
Per unit of production ($/boe)	**20.52**	8.66	**11.57**	40.66
Per unit of production, excluding impairment ($/boe)	**20.52**	8.66	**11.57**	8.28

Depletion and depreciation expense for the three and twelve months ended December 31, 2018 was $11,322 ($20.52/boe) and $27,480 ($11.57/boe). Depletion and depreciation expense in 2018 is higher than prior year due to the Company recording additional depletion of $7,331 for properties that were fully depleted where no reserves were assigned at December 31, 2018. In addition, unit costs have increased as production volumes are lower between the periods.

The Company reviewed each CGU comprising its property and equipment at December 31, 2018 for indicators of impairment and determined that indicators were present, related to the Company's market capitalization being less than the carrying amount of its net assets and the continued commodity price downturn. Impairment tests were conducted at December 31, 2018, however based on the results of the tests no impairment expense was required to be booked for the year ended December 31, 2018.

Impairment expense recognized for the twelve months ended December 31, 2017 was $96,200. The impairment was a result of decreased commodity prices in 2017.

$(000's)	Three months ended December 31, 2018	2017	Twelve months ended December 31, 2018	2017
Northeast British Columbia	**-**	-	**-**	-
Peace River Arch	**-**	-	**-**	2,200
Deep Basin	**-**	-	**-**	94,000
Total	**-**	-	**-**	96,200

SHARE BASED PAYMENTS

Stock Options

As at December 31, 2018, the Company had 1,476 stock options outstanding with an average exercise price of $3.61. The options have a five-year term and vest evenly over a three-year period on the anniversary date of their grant. For the three and twelve months ended December 31, 2018, Cequence recorded $113 and $344 (2017 – $209 and $991) 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 three and twelve months ended December 31, 2018, Cequence recognized $1 and ($44) (2017 – ($44) and $37) in share based payment expense related to RSUs with a corresponding increase / (decrease) to share based payment liability.

A summary of the status of the Company's stock option and RSU plans during the years ended December 31, 2018 and December 31, 2017 is as follows:

Number (000's) [1]	RSUs 2018	RSUs 2017	Stock Options 2018	Stock Options 2017
Outstanding, beginning of year	**133**	150	**661**	550
Granted	**393**	35	**980**	251
Cancelled/Forfeited	**(19)**	(1)	**(112)**	(5)
Expired	**-**	-	**(53)**	(135)
Settled	**(63)**	(51)	**-**	-
Outstanding, end of year	**444**	133	**1,476**	661

(1) On October 22, 2018, the Company's shareholders approved the Share Consolidation, which was completed on October 29, 2018. This MD&A and all information relating to issued and common shares, stock options, warrants, restricted share units and per share amounts, have been restated to reflect the share consolidation for all periods presented.

CAPITAL EXPENDITURES

$(000's)	Three months ended December 31, 2018	Three months ended December 31, 2017	Twelve months ended December 31, 2018	Twelve months ended December 31, 2017
Land	**213**	250	**739**	875
Geological & geophysical and capitalized overhead	**184**	203	**1,015**	1,021
Drilling, completions and workovers	**10,426**	3,597	**17,209**	18,140
Equipment, facilities and tie-ins	**2,573**	1,543	**4,836**	5,818
Office furniture & equipment	**1**	-	**1**	3
Capital expenditures	**13,397**	5,593	**23,800**	25,857
Property acquisitions [1]	**-**	(7)	**-**	(7)
Property dispositions [1]	**(934)**	(4,270)	**(2,863)**	(4,270)
Total capital expenditures	**12,463**	1,316	**20,937**	21,580

(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, 2018, capital expenditures were $20,937 (2017 - $21,580). Capital expenditures were focused at Simonette where the Company completed and tied in 3.0 gross (2.0 net) horizontal Dunvegan wells in the first quarter of 2018, drilled 1.0 gross (1.0 net) vertical stratigraphic test well in the first quarter of 2018 and drilled 2.0 gross (2.0 net) horizontal Dunvegan wells in the fourth quarter of 2018.

During the twelve months ended December 31, 2018, the Company disposed of certain oil and properties and associated decommissioning liabilities for proceeds of $2,863 (2017 - $4,270) prior to closing adjustments. The sales resulted in a gain recognized in comprehensive loss of $3,890 (2017 - $130 loss).

INCOME TAXES

As at December 31, 2018, the Company has tax pools and available losses of $608,780 (December 31, 2017 - $616,660). Due to the uncertainty of future realization, a deferred tax asset has not been recognized.

At December 31, 2018, Cequence has the following tax pools:

Classification	Amount $(000's)	Annual Deductibility
Canadian exploration expense	166,167	100%
Non-capital losses	317,682	100%
Undepreciated capital cost	37,281	Primarily 25%, declining balance
Canadian oil and gas property expense	8,048	10%, declining balance
Canadian development expense	52,352	30%, declining balance
Other	27,250	Various
	608,780	

The non-capital loss carry-forwards expire in 6 to 20 years. Based on the Company's expected cash flow and available tax pools, Cequence does not expect to be taxable in the near future.

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, 2018 were $35,555 compared to $38,478 at December 31, 2017. Decommissioning obligations are adjusted periodically for revisions to the future liability costs and the estimated timing of costs to be incurred in future years. The Company estimates that it will incur $1,782 of decommissioning obligations in the twelve months ended December 31, 2019. The following table summarizes the changes in decommissioning liabilities for the respective periods:

	December 31, 2018	December 31, 2017
Balance, beginning of year	**38,478**	38,161
Property dispositions	**(2,149)**	(776)
Accretion expense	**803**	870
Liabilities incurred	**192**	371
Abandonment costs incurred	**(3,756)**	(1,079)
Revisions in estimated cash flows	**1,870**	(185)
Revisions due to change in discount rates	**117**	1,116
Balance, end of year	**35,555**	38,478

The total estimated, undiscounted cash flows, inflated at 2 percent, required to settle the obligations are $55,390 (December 31, 2017 - $63,742). These cash flows have been discounted using a risk-free interest rate of 2.15 percent (December 31, 2017 – 2.20 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, 2017 – 1 to 50 years).

LIQUIDITY AND CAPITAL RESOURCES

The Company's capital comprises shareholders' equity, the Credit Facility (as defined below), the Term Loan (as defined below) and working capital. Cequence manages the capital structure and makes adjustments considering economic conditions and the risk characteristics of the underlying assets. The Company typically carries a working capital deficiency as cash balances are used to fund ongoing operations and the drilling program. However, Cequence has and will continue to manage its working capital needs through its hedging program, issuing common shares, adjusting capital expenditures, and executing asset dispositions. The Dunvegan oil development and operating results achieved to-date in 2018 and the Company's cost-saving initiatives are anticipated to continue to have a positive impact on funds flow from operations and the working capital deficiency. The Company also has available a $7,000 on the Credit Facility with no amounts drawn on as at December 31, 2018 (excluding letters of credit of $1,590).

$(000's)	**As at December 31, 2018**	As at December 31, 2017
Cash	**14,496**	10,971
Credit Facility	**-**	-
Senior Notes – principal	**-**	(60,000)
Term Loan – principal	**(60,000)**	-
Accounts payable and accrued liabilities	**(35,736)**	(33,106)
Share-based payment liability	**(38)**	(153)
Provisions – current	**(1,782)**	(1,466)
Accounts receivable	**10,324**	14,739
Deposits and prepaid expenses	**633**	514
Net debt [(1)]	**(72,103)**	(68,501)
Funds flow from operations - trailing twelve months [(1)]	**13,087**	19,329
Net debt to funds flow from operations trailing twelve months[(1)]	**5.5:1**	3.5:1

[(1)] Refer to *"Non-GAAP Measures"*

At December 31, 2018, the Company's net debt to funds flow from operations of 5.5 is higher than the Company's long-term internal target of 2:1. The prolonged period of low commodity prices, in particular natural gas pricing in 2017 and 2018, has reduced the Company's funds flow from operations and limited the availability of new capital to repay debt or expand development activity. During this time period, the Company has lowered capital spending, announced a flow-through share rights offering and reduced its G&A to manage its leverage and to limit borrowing on its senior Credit Facility. The Dunvegan oil development and operating results achieved in 2018 are anticipated to have a positive impact on funds flow from operations.

The Company remains focused on developing the Dunvegan property, identifying and pursuing alternative financing arrangements, property dispositions, corporate mergers or other recapitalization opportunities to further reduce the net debt to funds flow from operations ratio. The Company continuously monitors changes in forecasted funds flow from operations as a result of changes to forward commodity prices and will make adjustments to planned capital expenditures as appropriate.

On July 27, 2018, Cequence announced a series of transactions to refinance the Company's balance sheet and provide greater flexibility and liquidity to execute the ongoing business plan of the Company. The Rights Offering, the extension on the Credit Facility and the restructuring of the Senior Notes are described in more detail below.

Senior Credit Facility

As at December 31, 2018, Cequence had a $7,000 (December 31, 2017 - $12,000) on demand credit facility available from one Canadian chartered bank (the "Credit Facility") and has drawn $nil (December 31, 2017 - $nil) under the facility except for letters of credit outstanding of $1,590 (December 31, 2017 - $1,540).

The Credit Facility has a term maturity date of May 31, 2019 and is secured by a first floating charge debenture, general assignment of book debts and Cequence's oil and natural gas properties and equipment. The Credit Facility may be extended beyond the initial term, if requested by the Company and accepted by the lenders. If the Credit Facility does not continue to revolve, amounts borrowed under the facility must be repaid on the term maturity date. The Credit Facility is reviewed on a semi-annual basis with the lender holding the right to request an additional review. The next scheduled review is expected to be completed in May 2019.

The 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, 2018 with a ratio of 0.1 times (December 31, 2017 – 0.1 times).

Senior Notes and Term Loan

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 (the "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 pre-consolidation warrants to purchase common shares. The initial investment of $60,000 of Senior Notes were issued at par and carried a 9% coupon rate per annum. A standby charge of 0.7% was applicable to the further $60,000 of notes available at a future date.

On July 27, 2018, Cequence entered into a second lien secured loan agreement with CII for a $60,000 loan facility due October 3, 2022 (the "Term Loan") to refinance the existing Senior Notes. Interest on the Term Loan will be paid quarterly at the rate of 5% per annum if the 12-month trailing Funds Flow from Operations is equal to or less than $40 million; and 10% per annum if the 12-month trailing Funds Flow from Operations is greater than $40 million. Funds Flow from Operations is defined as cash flow from operating activities before decommissioning liability expenditures and net change in non-cash working capital (see "*Non-GAAP Measures*").

Cequence has granted CII second lien security over all of the Company's assets (with the exception of its Simonette joint venture property) through a $100,000 demand debenture, which will rank junior in priority to the security securing the obligations under the Company's Credit Facility pursuant to an intercreditor agreement among the Company's lenders. As part of the refinancing of the Senior Notes, Cequence also issued 1,841,459 share purchase warrants (equivalent to 36,829,182 pre-Share Consolidation warrants) (the "Warrants") entitling CII to purchase common shares of the Company at a price of $2.00 per common share (equivalent to a pre-Share Consolidation $0.10 per common share) which are exercisable for four years from the date of issuance of September 13, 2018.

The Term Loan was conditional upon the Company raising proceeds of not less than $5 million under the Rights Offering (as defined below under "*Outstanding Share Data*") which closed on September 13, 2018 and raised gross proceeds of $8,593.

On December 17, 2018 the Term Loan and the Warrants were purchased from the lender by an individual who, in subsequent transactions, sold interests in the Term Loan and Warrants to a small group of persons, including two of the Company's directors who at December 31, 2018 hold $11.5 million of the outstanding Term Loan. Interest expense of $49 was incurred and owing at December 31, 2018 to the two directors. There have been no changes to the terms and conditions of the Term Loan.

The Term Loan is subject to a cross default clause and the same financial covenants as the Company's Credit Facility (described above) as well as certain other non-financial covenants and restrictive covenants, including restrictions over asset sales, restricted payments, the incurrence of additional indebtedness, a limit on the Credit Facility borrowing limit of $20 million, and other transactions outside of the ordinary course of business.

Contractual Obligations and Commitments

Cequence has assumed various contractual obligations and commitments in the normal course of operations and financing activities, which are summarized and discussed below:

	2019	2020	2021	2022	2023+	Total
Term Loan [(1)]	-	-	-	60,000	-	60,000
Interest payments [(1)]	3,000	3,000	3,000	2,250	-	11,250
Accounts payable and accrued liabilities	35,736	-	-	-	-	35,736
Office leases	262	-	-	-	-	262
Pipeline transportation	6,535	6,535	6,535	6,118	26,016	51,739
Gas processing	4,154	4,166	4,154	4,154	30,471	47,099
Total	49,687	13,701	13,689	72,522	56,487	206,086

(1) On July 27, 2018, Cequence refinanced the existing Senior Notes with a second lien secured loan for $60 million due October 3, 2022. The maturity date and the revised interest rate of 5% have been reflected in the above table.

Cequence has a take or pay agreement for gas processing with the operator of the Simonette gas plant. The minimum commitment under the take or pay is 42 mmcf/d or approximately $4,154 per year concluding April 30, 2030.

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

In September 2017 the National Energy Board approved TransCanada Pipelines application for new transportation service from Empress, Alberta to Dawn, Ontario. The Company has contracted to ship 10,850 GJ/d of natural gas to the Dawn hub at a cost of $0.77/GJ for a period of 10 years beginning April 1, 2018. The transportation commitment provides market diversification for approximately 33 percent of its current natural gas production. Historically, pricing at the Dawn hub has been at a premium to AECO. As part of this commitment, the Company entered into a five-year contract to transport AECO gas to Empress at an annual cost of approximately $750.

OUTSTANDING SHARE DATA

	March 12, 2019	**December 31, 2018**	December 31, 2017
Common shares [(1) (3)]	**24,553**	**24,553**	12,277
Stock options [(3)]	**1,506**	**1,476**	661
Restricted share units [(3)]	**474**	**444**	133
Warrants [(2) (3)]	**1,841**	**1,841**	150

(1) Cequence is authorized to issue an unlimited number of common voting shares and common non-voting shares with no par value.
(2) Under the Term Loan 1,841,459 warrants were issued at an exercise price of $2.00 which expire September 13, 2022.
(3) On October 22, 2018, the Company's shareholders approved the Share Consolidation, based on one post-consolidation common share for every 20 pre-consolidation common shares. The Share Consolidation was completed on October 29, 2018. This MD&A and all information relating to issued and common shares, stock options, warrants, restricted share units and per share amounts, have been restated to reflect the Share Consolidation for all periods presented.

On July 27, 2018, Cequence launched a Rights Offering, which entitled holders of its common shares as of August 9, 2018 to subscribe for up to 12,276,394 common shares (equivalent to 245,527,883 pre-Share Consolidation common shares) on a Canadian development expenses ("CDE") "flow-through" basis at a price of $0.70 per share (equivalent to a pre-Share Consolidation price of $0.035 per share) (the "Rights Offering"). The Rights Offering closed on September 13, 2018 and 12,276,394 flow-through common shares were issued for gross proceeds of $8,593.

As part of the refinancing of the Senior Notes, Cequence issued the Warrants to CII and on December 17, 2018 the Warrants were purchased from CII by an individual who, in subsequent transactions, sold interests in the Warrants to a small group of persons, including two of the Company's directors.

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,**		
$(000's)	**2018**	2017	**2018**	2017	2016
Cash flow from operating activities	**5,201**	1,657	**11,758**	19,884	11,641
Decommissioning liabilities expenditures	**(246)**	540	**3,756**	1,079	1,852
Net change in non-cash working capital	**(2,884)**	(614)	**(2,427)**	(1,634)	(2,243)
Funds flow from operations [(3)]	**2,071**	1,583	**13,087**	19,329	11,250
Per share – basic and diluted ($)[(1)]	**0.08**	0.13	**0.82**	1.57	1.04
Total revenue [(2)]	**12,184**	13,585	**58,921**	65,836	59,074
Comprehensive loss	**(3,802)**	(6,638)	**(9,699)**	(99,362)	(28,057)
Per share – basic and diluted ($)[(1)]	**(0.16)**	(0.54)	**(0.61)**	(8.09)	(2.59)
Total assets	**283,640**	284,728	**283,640**	284,728	388,858
Credit Facility	**-**	-	**-**	-	-
Senior Notes and Term Loan– principal	**60,000**	60,000	**60,000**	60,000	60,000

(1) On October 22, 2018, the Company's shareholders approved the Share Consolidation, which was completed on October 29, 2018. This MD&A and all information relating to issued and common shares, stock options, warrants, restricted share units and per share amounts, have been restated to reflect the share consolidation for all periods presented.
(2) Total revenue is presented gross of royalties and includes realized gains (loss) on commodity contracts.
(3) 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. See *"Non-GAAP Measures"*.

Funds flow from operations was $2,071 for the three months ended December 31, 2018 compared to $1,583 in 2017. The increase in funds flow from operations is mainly due to increased production revenue, lower operating expenses and interest expense on the Term Loan.

Cequence recorded a comprehensive loss of $3,802 for the three months ended December 31, 2018 compared to a loss of $6,638 in 2017. The decrease is mainly due to increased production revenue, unrealized hedging gains, lower operating expenses and interest expense on the Term Loan.

Cequence recorded a comprehensive loss of $9,699 for the twelve months ended December 31, 2018 compared to comprehensive loss of $99,362 in 2017. The decrease is mainly due to the impact of the impairment of $96 million recorded in 2017 and decreases in volumes year over year.

QUARTERLY INFORMATION

FINANCIAL

($ thousands except per share data)	2018 Q4	2018 Q3	2018 Q2	2018 Q1	2017 Q4	2017 Q3	2017 Q2	2017 Q1
Total revenue[(1)]	**12,184**	17,680	14,613	14,443	13,585	15,087	17,810	19,354
Royalties expense	**736**	1,453	1,043	737	391	465	927	1,355
Transportation expense	**2,116**	1,876	1,728	1,440	1,023	1,590	1,650	1,308
Operating costs	**5,440**	5,493	6,758	6,389	7,972	7,004	5,829	6,779
Comprehensive income (loss)	**(3,802)**	573	(2,745)	(3,725)	(6,638)	(3,076)	(94,899)	5,251
Per share – basic [(4)]	**(0.16)**	0.04	(0.22)	(0.30)	(0.54)	(0.25)	(7.73)	0.43
Per share – diluted [(4)]	**(0.16)**	0.04	(0.22)	(0.30)	(0.54)	(0.25)	(7.73)	0.42
Funds flow from operations [(2)]	**2,071**	5,589	2,191	3,236	1,583	3,619	6,781	7,346
Per share – basic [(4)]	**0.08**	0.38	0.18	0.26	0.13	0.29	0.55	0.60
Per share – diluted [(4)]	**0.08**	0.38	0.18	0.26	0.13	0.29	0.55	0.59
Capital expenditures	**13,397**	1,119	1,830	7,454	5,593	2,682	2,536	15,046
Net acquisitions (dispositions) [(3)]	**(934)**	(500)	(1,433)	4	(4,277)	-	-	-
Net capital expenditures	**12,463**	619	397	7,458	1,316	2,682	2,536	15,046

(1) Total revenue is presented gross of royalties and includes realized gains (loss) on commodity contracts. See *"Non-GAAP Measures"*.

(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. See *"Non-GAAP Measures"*.

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

(4) On October 22, 2018, the Company's shareholders approved the Share Consolidation, which was completed on October 29, 2018. This MD&A and all information relating to issued and common shares, stock options, warrants, restricted share units and per share amounts, have been restated to reflect the share consolidation for all periods presented.

OPERATIONAL

	2018 Q4	2018 Q3	2018 Q2	2018 Q1	2017 Q4	2017 Q3	2017 Q2	2017 Q1
Production volumes								
Natural gas (Mcf/d)	**27,645**	29,376	28,628	34,828	33,331	40,729	42,719	45,214
Oil (bbls/d)	**736**	1,198	864	245	283	388	224	481
NGLs (bbls/d)	**227**	259	240	274	257	250	239	270
Condensate (bbls/d)	**427**	382	459	647	617	841	919	814
Total (boe/d)	**5,997**	6,734	6,334	6,970	6,713	8,266	8,502	9,101
Average selling price, including realized hedges								
Natural gas ($/Mcf)	**2.91**	2.20	2.14	2.70	2.33	2.12	2.83	2.79
Crude oil and condensate ($/bbl)	**37.74**	73.57	68.79	62.59	66.73	57.70	60.11	62.50
NGLs ($/bbl)	**35.37**	43.51	34.91	38.30	38.55	27.86	26.11	29.92
Total ($/boe)	**22.08**	28.53	25.35	23.02	22.00	19.84	23.02	23.63
Operating netback, including realized hedges ($/boe)								
Price	**22.08**	28.53	25.35	23.02	22.00	19.84	23.02	23.63
Royalties	**(1.33)**	(2.35)	(1.81)	(1.18)	(0.63)	(0.61)	(1.20)	(1.65)
Transportation	**(3.84)**	(3.03)	(3.00)	(2.30)	(1.66)	(2.09)	(2.13)	(1.60)
Operating costs	**(9.86)**	(8.87)	(11.72)	(10.18)	(12.91)	(9.21)	(7.53)	(8.28)
Operating netback	**7.05**	14.28	8.82	9.36	6.80	7.93	12.16	12.10

The company's funds flow from operations and comprehensive income (loss) has been negatively impacted by low commodity prices, in particular natural gas prices. AECO natural gas prices averaged $2.23/Mcf in 2017 and $1.52/Mcf in 2018, significantly lower than previous years. The Company has reduced capital expenditures on new gas wells during this time period due to lower funds flow from operations and restricted access to cost effective capital.

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

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

OUTLOOK INFORMATION

The Company's guidance for the year ended December 31, 2019 includes the results of the fourth quarter 2018 oil wells, the restructured $60 million Term Loan (with its 5% interest rate), and an additional planned 2 gross (2 net) Dunvegan oil wells drilled and on production at the end of the third quarter of 2019. Cequence will continue to monitor volatility in commodity prices with the focus that 2019 capital activity will remain within funds flow from operations.

(000's, except per share and per unit references)	**Guidance year ended December 31, 2019**
Average production, BOE/d [(1)]	5,800
Funds flow from operations ($)[(2)]	17,000
Funds flow from operations per share[(2)]	0.69
Exploration and development expenditures ($)	13,000
Net wells	2.0
Operating and transportation costs ($/boe)	15.00
G&A costs ($/boe)	2.30
Royalties (% revenue)	10
Crude – WTI (US$/bbl)	57.50
Natural gas – AECO (CDN$/GJ)	1.69
Period end, net debt ($) [(3)]	69,000
Common shares outstanding end of period	24,553

[(1)] Average production estimates on a per BOE basis are comprised of 72% natural gas and 28% oil and natural gas liquids in 2019.
[(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. See *"Non-GAAP Measures"*.
[(3)] Net debt is calculated as working capital deficiency (excluding commodity contracts) plus the aggregate principal amount of the Term Loan (previously Senior Notes).

DISCLOSURE CONTROLS AND INTERNAL CONTROLS OVER FINANCIAL REPORTING

The Chief Executive Officer ("CEO") and Contract Interim Chief Financial Officer ("CFO") are responsible for designing disclosure controls and procedures ("DC&P") and internal controls over financial reporting ("ICFR") 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, DC&P 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 applicable 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 ICFR. The Company's management and 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, 2018, the CEO and CFO have concluded, based on their evaluation of the design and operating effectiveness of the Company's DC&P and ICFR that the DC&P and ICFR are effective.

CHANGES IN ACCOUNTING POLICIES

IFRS 15 "Revenue from contracts with customers"

Cequence adopted IFRS 15 with a date of initial application of January 1, 2018. IFRS 15 replaces existing revenue recognition guidance and provides a single, principles-based five-step model to be applied to all contracts with customers. Cequence used the modified retrospective approach to adopt the new standard, applying the standard retrospectively only to contracts that were not completed contracts on January 1, 2018. Under the transitional provision, the cumulative effect of initially applying IFRS 15 is recognized on the date of initial application as an adjustment to deficit. As a result of applying the requirements of IFRS 15, including the application of certain practical expedients such as the right to invoice method of measuring the Company's progress towards complete satisfaction of its performance obligations, there was no change or adjustments to the Company's consolidated financial statements as a result of the adoption of IFRS 15. Additional disclosure requirements required by IFRS 15 are detailed in Notes 3 and 9 of the consolidated financial statements.

IFRS 9 "Financial Instruments"

On January 1, 2018, Cequence adopted IFRS 9 as issued by the IASB. IFRS 9 includes a new classification and measurement approach for financial assets and liabilities, and a new expected loss impairment model for financial assets including credit losses. The adoption of IFRS 9 did not have a material impact on Cequence's consolidated financial statements. Additional disclosures related to Cequence's financial assets are included in Note 3 and 19 of the consolidated financial statements.

FUTURE ACCOUNTING POLICIES

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

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.

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 sheets consist of cash, accounts receivable, deposits, commodity contracts, Credit Facility, Senior Notes, Term Loan and accounts payable and accrued liabilities.

The Company's cash, accounts receivable, deposits, Credit Facility 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 and Term Loan 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, 2018 includes $1,275 of realized loss (2017 – $4,812 realized gain) and $3,303 of unrealized gain (2017 - $4,927 gain) 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, 2018 and 2017, 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 Facility. 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, 2018 (2017 - nil).

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 and commodity contract assets is held with a large established financial institution. The majority of the Company's accounts receivable are due from marketers of the Company's petroleum and natural gas production which are typically collected on the 25th day of the month following the prior month's production and from joint venture partners in the oil and gas industry. 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, 2018, the Company has an allowance for doubtful accounts of $760 (December 31, 2017 – $659).

As at December 31, 2018, the maximum exposure to credit risk was $28,400 (December 31, 2017 - $26,984) 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. The Company believes its current Credit Facility is sufficient 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, 2018 is as follows:

	< 1 Year	1 – 2 Years	2 – 5 Years	Thereafter
Term Loan	-	-	60,000	-
Accounts payable and accrued liabilities	35,736	-	-	-
	35,736	-	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.

OFF BALANCE SHEET ARRANGEMENTS

The Company has certain lease agreements that are entered into in the normal course of operations, including operating leases for which no asset or liability value has been recorded on the consolidated balance sheet as at December 31, 2018.

The Company has not entered into any guarantee or off balance sheet arrangements that would materially impact the financial position or results of operations as at December 31, 2018.

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 or forward-looking information under applicable securities legislation. These statements relate to future events or the Company’s future performance and are provided for the purpose of providing information about management’s current expectations and plans relating to the future. Forward-looking statements or information typically contain statements with words such as “anticipate”, “believe”, “continue”, “could”, “estimate” "expect", “forecast”, “forward”, “future”, “may”, “plan”, “predict”, “potential”, "propose", “schedule”, “target”, “thereafter”, “will”, “would” or similar words suggesting future outcomes or statements regarding an outlook. Forward-looking statements or information in this MD&A may include, but are not limited to, statements with respect to: the fact that the Company will continue as a going concern; future capital investments and the repayment of the Company’s debt; the Company’s plans to continue to seek opportunities to divest its British Columbia non-core assets and other property dispositions, and to pursue alternative financing arrangements, mergers or other recapitalization opportunities; the Company’s future cash flows, planned capital expenditures and the source of funding thereof; the Company’s guidance under the heading “Outlook Information”; projections with respect to the Company’s production; future performance expectations of the recently completed Dunvegan wells; drilling, completion and planned production of the new Dunvegan wells, the possible curtailing of gas production due to low AECO prices; the estimated number of oil locations remaining on the Company’s land, the Company’s lender’s support for the extension and the new borrowing base of the Company’s Credit Facility; the projection of future royalty, operating, transportation and G&A expenses; the projection of the Company’s future taxability; the projected impact of land access and regulatory issues; the amount of future decommissioning liabilities; projections relating to the volatility of crude oil and natural gas prices in 2019 and beyond; 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; and the impact of Western Canada pipeline constraints. 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.

Readers are cautioned not to place undue reliance on forward-looking statements or information, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. Forward-looking statements or information are based on a number of factors and 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 or information. These assumptions, risks and uncertainties include, among other things: the Company’s ability to realize its assets and discharge its liabilities and commitments in the normal course of business; the Company’s ability to enter into derivative and physical commodity contracts; future production volumes; the impact of increasing competition; the timely receipt of any

required regulatory approvals; the Company's lender's support for the extension and the new borrowing base of the Credit Facility; the ability of the Company to obtain qualified staff, equipment and services in a timely and cost efficient manner; the ability of the operator of the projects which the Company has an interest in to operate the field in a safe, efficient and effective manner; field production and decline rates; the ability to replace and expand oil and natural gas reserves through acquisition, development of exploration; forward commodity prices; the timing and costs of pipeline, storage and facility construction; the ability of the Company to secure adequate product transportation; future oil and natural gas prices; currency, exchange and interest rates; changes in the regulatory framework regarding royalties, taxes and environmental matters; the ability of the Company to successfully market its oil and natural gas products; assumptions based upon Cequence's current guidance; product supply and demand; 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 generate sufficient cash flow from operations to meet its current and future obligations; and other risks and uncertainties described from time to time in the reports and filings made with securities regulatory authorities by Cequence. Readers are cautioned that the foregoing list is not exhaustive of all factors and assumptions which have been used. The material risk factors affecting the Company and its business are contained in the Company's Annual Information Form which is available on SEDAR at www.sedar.com.

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 may not be appropriate for other purposes, such as making investment decisions .

Although Cequence believes that the expectations represented by such forward-looking statements or information are reasonable, there can be no assurance that such expectations will prove to be correct. Furthermore, the forward-looking statements or information 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 or information, whether as a result of new information, future events or otherwise. The forward-looking statements or information contained in this MD&A are expressly qualified by this cautionary statement.