ANNUAL REPORT

AS AT AND FOR THE YEAR ENDED

DECEMBER 31, 2018

FINANCIAL AND OPERATIONAL HIGHLIGHTS	Three months ended December 31			Year ended December 31		
(CA$ thousands, except as otherwise indicated)	**2018**	2017	%	**2018**	2017	%
FINANCIAL						
Petroleum and natural gas revenue, before royalties	**100,350**	80,838	24	**389,277**	257,557	51
Cash provided by operating activities	**63,656**	36,458	75	**186,383**	115,222	62
Adjusted funds from operations [(1)]	**47,140**	32,898	43	**186,839**	108,011	73
Basic ($/ common share) [(1)]	**0.26**	0.18	44	**1.02**	0.61	67
Diluted ($/ common share) [(1)]	**0.26**	0.18	44	**1.01**	0.61	66
Profit (loss) and comprehensive income (loss)	**2,843**	(5,389)	-153	**8,154**	(23,178)	-135
Basic ($/ common share)	**0.02**	(0.03)	-167	**0.04**	(0.13)	-131
Diluted ($/ common share)	**0.02**	(0.03)	-167	**0.04**	(0.13)	-131
Total capital expenditures, net of dispositions	**70,332**	55,778	26	**285,498**	127,977	123
Total assets	**1,423,521**	1,276,567	12	**1,423,521**	1,276,567	12
Net debt [(1)]	**196,416**	136,729	44	**196,416**	136,729	44
Convertible debentures	**78,390**	74,517	5	**78,390**	74,517	5
Shareholders' equity	**893,796**	845,701	6	**893,796**	845,701	6
Weighted average shares outstanding (000s)						
Basic	**183,994**	178,220	3	**182,576**	176,466	3
Diluted	**184,682**	179,898	3	**184,393**	177,920	4
OPERATIONS						
Average daily production						
Oil (bbls/d)	**9,301**	7,902	18	**8,403**	6,634	27
NGLs (bbls/d)	**3,783**	3,379	12	**3,186**	2,608	22
Gas (mcf/d)	**93,759**	82,689	13	**92,502**	77,330	20
Combined (BOE/d)	**28,711**	25,063	15	**27,006**	22,130	22
Production per million common shares (BOE/d) [(1)]	**156**	141	11	**148**	125	18
Average realized prices, before financial instruments [(1)]						
Oil ($/bbl)	**38.77**	65.13	-40	**65.82**	59.10	11
NGLs ($/bbl)	**27.75**	29.62	-6	**33.81**	27.72	22
Gas ($/mcf)	**6.37**	2.79	128	**3.76**	3.01	25
Operating netbacks ($/BOE) [(1)]						
Petroleum and natural gas revenue	**37.99**	35.06	8	**39.49**	31.89	24
Cost of purchases	**(1.05)**	(1.32)	-20	**(2.19)**	(0.38)	476
Average realized price, before financial instruments [(1)]	**36.94**	33.74	9	**37.30**	31.51	18
Realized gain (loss) on financial instruments	**(2.23)**	(0.32)	597	**(0.60)**	(0.13)	362
Average realized price, after financial instruments [(1)]	**34.71**	33.42	4	**36.70**	31.38	17
Royalties	**(2.10)**	(3.12)	-33	**(3.11)**	(2.92)	7
Production expense	**(8.58)**	(11.01)	-22	**(9.11)**	(10.05)	-9
Transportation expense	**(4.64)**	(3.11)	49	**(3.92)**	(3.13)	25
Operating netback [(1)]	**19.39**	16.18	20	**20.56**	15.28	35
Undeveloped land						
Gross acres	**710,981**	755,455	-6	**710,981**	755,455	-6
Net acres	**614,644**	637,823	-4	**614,644**	637,823	-4
Reserves – proved plus probable						
Crude oil (mbbls)	**23,752**	21,438	11	**23,752**	21,438	11
NGLs (mbbls)	**105,095**	80,350	31	**105,095**	80,350	31
Gas (mmcf)	**1,042,987**	802,875	30	**1,042,987**	802,875	30
Combined (mBOE)	**302,678**	235,601	28	**302,678**	235,601	28

(1) Refer to advisories regarding non-GAAP financial measures and other key performance indicators.

MESSAGE TO SHAREHOLDERS

Kelt Exploration Ltd. (“Kelt” or the “Company”) reports its financial and operating results to shareholders for the fourth quarter and year ended December 31, 2018.

The Canadian energy sector experienced high volatility during 2018 with fluctuating commodity prices and macro headlines driven by political decisions and economic factors. WTI crude oil prices averaged a high of US$70.98 per barrel in July, then plummeting 30% to average US$49.52 per barrel in December. Canadian light oil prices and condensate prices also experienced much volatility during the year, trading at unprecedented discounts to the equivalent Canadian dollar WTI oil price during November and December. Kelt was able to mitigate the reduced revenue during the fourth quarter of 2018 resulting from the wide oil differentials through its diversified natural gas marketing strategy whereby the Company realized significantly higher gas prices compared to AECO and Station 2 pricing at its price points in the Sumas, Malin, Chicago and Dawn hubs.

Average production for the three months ended December 31, 2018 was a Company record high quarterly production of 28,711 BOE per day, up 15% compared to average production of 25,063 BOE per day during the fourth quarter of 2017. Daily average production in the fourth quarter of 2018 was 10% higher than average production of 26,204 BOE per day in the third quarter of 2018. In addition, Kelt achieved a record high calendar year average production in 2018. Average production for 2018 was 27,006 BOE per day, up 22% from average production of 22,130 BOE per day in 2017 and within the Company’s guidance range. Production for 2018 was weighted 43% oil and NGLs and 57% gas.

Kelt’s realized average oil price during the fourth quarter of 2018 was $38.77 per barrel, down 52% from $80.62 per barrel in the third quarter of 2018 and down 40% from $65.13 per barrel in the fourth quarter of 2017. The Company’s realized average NGLs price during the fourth quarter of 2018 was $27.75 per barrel, down 33% from $41.20 per barrel in the third quarter of 2017 and down 6% from $29.62 per barrel in the corresponding quarter of 2017. Kelt’s realized average gas price for the fourth quarter of 2018 was $6.37 per MCF, up 127% from $2.81 per MCF in the third quarter of 2017 and up 128% from the realized average gas price of $2.79 per MCF in the fourth quarter of the previous year.

For the three months ended December 31, 2018, revenue was $100.3 million and adjusted funds from operations was $47.1 million ($0.26 per share, diluted), compared to $80.8 million and $32.9 million ($0.18 per share, diluted) respectively, in the fourth quarter of 2017. At December 31, 2018, net debt was $196.4 million, up 44% from $136.7 million at December 31, 2017. The ratio of net debt to adjusted funds from operations for the year improved to 1.1 times at December 31, 2018 compared to 1.3 times at December 31, 2017.

Net capital expenditures incurred during the three months ended December 31, 2018 were $70.3 million and for the year ended December 31, 2018, net capital expenditures were $285.5 million. During 2018, the Company spent $168.7 million on drill and complete operations, $118.5 million on equipment, facilities and pipelines (includes $10.0 million of inventory) and $5.5 million on land and seismic. During the year, Kelt realized proceeds of $10.1 million from asset dispositions and incurred $2.9 million on asset acquisitions.

As at December 31, 2018, Kelt’s net working interest land holdings were 838,990 acres (1,310 sections) of which 614,644 net acres (960 sections) are undeveloped. Kelt is focused on long-term value creation by accumulating significant undeveloped land acreage on resource style plays, with a primary focus on Triassic Montney oil and liquids-rich gas plays. At December 31, 2018, Kelt’s net Montney land holdings were 511,851 acres (800 sections).

At December 31, 2018, Kelt had a significant inventory of drilled and completed horizontal wells, as well as horizontal wells that were drilled but not yet completed (DUCs). Capital expenditures incurred in 2018 associated with these wells were approximately $60.0 million, for which the benefit of production and income are expected to commence in 2019. At Wembley/Pipestone, the Company drilled and completed five horizontal wells and had one DUC horizontal well. Four of these wells are expected to be put on production in the third quarter of 2019 upon completion of the construction of the Tidewater Pipestone Sour Deep-Cut Gas Plant. At Fireweed, the Company had five DUC horizontal wells and on its initial 24-well pad at Inga, Kelt had four DUC horizontal wells. The Inga/Fireweed wells are expected to be put on production in the second and third quarters of 2019.

At Inga, Kelt expects to commence completion operations on the first six wells from its 24-well pad program in March 2019, which is located in an area that is expected to have high liquids ratios. Two wells were drilled targeting each of the Upper Montney, IBZ Middle Montney and Middle Montney formations. The Company plans to complete three wells (one in each formation) using the open hole ball-drop completion method with 50 fracture stages and three wells (one in each formation) using the plug and perf completion method with 28 fracture stages and 3 clusters per stage.

The open hole ball-drop fracturing method is a series of open-hole packers combined with ball-activated fracture ports between each set of packers that allow individual fracs to be pumped into low-permeability, tight-rock formations in order to access reservoir hydrocarbons in one continuous pumping operation. The plug and perf fracturing method is employed in wells with cemented liners, it involves pumping down a bridge plug and perforating guns on electric wireline. Fracture stimulation is pumped through the perforated clusters and the process is repeated along the length of the horizontal lateral until the entire wellbore has been stimulated.

In addition to the comparision of the two completion techniques, the initial six wells on the Inga pad will be monitored using both mircoseismic and chemical tracing techniques. The microseismic program will consist of approximately 20 surface monitoring stations strategically located around the pad, in addition to a 30-level, 3-component, 15 meter spacing downhole array in the 2-4-88-23W6 monitoring well. All six wells will also be chemically traced with both an Oil Soluble and Frac Fluid Tracer in 114 stages over the estimated 24 days of completion operations. This information will provide the Company with data to determine optimal horizontal spacing. Based on the results (productivity and costs) from the two completion methods, the Company will pick the more favourable method to complete the remaining 18 wells on the Inga 24-well pad.

At Wembley/Pipestone, Kelt expects to drill and complete seven horizontal wells during the first half of 2019. These wells, in addition to the four wells from the 2018 capital program, are expected to commence production in the third quarter of 2019 upon completion of the construction of the Tidewater Pipestone Sour Deep-Cut Gas Plant. During the fourth quarter of 2018, Kelt drilled an injection well located at 03-11-072-08W6 which is expected to significantly reduce completion costs and operating expenses. This well is expected to be operational for flowback of the 2019 wells.

2019 GUIDANCE

Kelt has not changed its previously reported 2019 Budget, however, the Company has prepared a 2019 Pro-forma case that reflects lower oil prices and lower capital expenditures, as summarized in the table below:

(CA$ millions, except as otherwise indicated)	**2019 Budget**	2019 Pro-forma	Percent Change
Average Production			
Oil & NGLs (bbls/d)	**15,500 – 16,400**	15,500 – 16,400	N/C
Gas (MMcf/d)	**105.0 – 112.0**	105.0 – 112.0	N/C
Combined (BOE/d)	**33,500 – 34,500**	33,500 – 34,500	N/C
Production per million common shares (BOE/d)	**174 – 179**	174 – 179	N/C
Forecasted Average Commodity Prices			
WTI oil price (US$/bbl)	**67.50**	55.00	− 19%
WTI differential to Mixed Sweet Blend Edmonton (CA$/bbl)	(19.43)	(8.85)	54%
Mixed Sweet Blend Edmonton (CA$/bbl)	**66.97**	63.75	− 5%
NYMEX natural gas price (US$/MMBtu)	**3.00**	3.00	N/C
AECO natural gas price (US$/MMBtu)	**1.60**	1.50	− 6%
Average exchange rate (US$/CA$)	**0.781**	0.758	− 3%
Capital Expenditures			
Drilling & completions	**201.0**	171.0	− 15%
Facilities, pipeline & well equipment	**60.0**	60.0	N/C
Land, seismic & property acquisitions	**9.0**	9.0	N/C
Net Capital Expenditures	**270.0**	240.0	− 11%
Adjusted funds from operations	**240.0**	220.0	− 8%

(CA$ millions, except as otherwise indicated)	2019 Budget	2019 Pro-forma	Percent Change
Per common share, diluted	**1.23**	1.13	− 8%
Net debt, at year-end (1)	**225.0**	220.0	− 2%
Net debt to adjusted funds from operations ratio	**0.9 x**	1.0 x	+ 11%
Weighted average common shares outstanding (MM)	**192.4**	192.4	N/C

(1) In addition to bank debt, the Company has $89.9 million principal amount of convertible debentures outstanding with a coupon of 5% per annum, maturing May 31, 2021. 2019 Budget and Pro-forma estimates have been prepared assuming the convertible debentures convert to 16.3 million common shares on July 1, 2019.

The Company will re-evaluate its spending plans for the remainder of 2019 after the first quarter is complete. Kelt expects to update shareholders with its updated 2019 forecasts at the same time as when it reports its 2019 first quarter results, on or about May 8, 2019.

On behalf of the Board of Directors,

[signed]

David J. Wilson
President and Chief Executive Officer
March 5, 2019

MANAGEMENT'S DISCUSSION & ANALYSIS

INTRODUCTION

Kelt Exploration Ltd. ("Kelt" or the "Company") is an oil and gas company based in Calgary, Alberta, focused on the exploration, development and production of crude oil and natural gas resources in Western Canada. Kelt's business plan is for long-term profitable growth by implementing a full cycle exploration program, with emphasis on low-cost land accumulation and maintaining a large inventory of drilling prospects. Kelt has an active exploration and development drilling program that it may complement with acquisitions and dispositions that optimize its asset base.

The Company was incorporated under the *Business Corporations Act* (Alberta) on October 11, 2012. Kelt's land holdings are located in two core areas, namely: (a) Grande Prairie, Alberta (including Pouce Coupe, Progress, La Glace and Wembley), held directly by Kelt; and (b) Fort St. John, BC (including Inga, Fireweed, Stoddart and Oak), held by the Company's wholly-owned subsidiary, Kelt Exploration (LNG) Ltd. ("Kelt LNG"). The head office of the Company is located at Suite 300, 311 - 6th Avenue S.W., Calgary, Alberta T2P 3H2. The Company's common shares and 5% convertible debentures are listed on the Toronto Stock Exchange ("TSX") under the symbol "KEL" and "KEL.DB", respectively. Additional information relating to Kelt can be found on SEDAR at www.sedar.com.

This Management's Discussion and Analysis ("MD&A") is dated March 6, 2019 and should be read in conjunction with the Company's audited consolidated annual financial statements and related notes as at and for the year ended December 31, 2018. The accompanying financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP") as set out in the CPA Canada Handbook – Accounting ("CPA Handbook"). The CPA Handbook incorporates International Financial Reporting Standards ("IFRS") and publicly accountable enterprises, including Kelt, are required to apply such standards. The Company's Board of Directors approved and authorized the consolidated annual financial statements for issue on March 5, 2019.

GENERAL ADVISORY

This MD&A uses "funds flow", "adjusted funds from operations", "funds flow per common share", "netback", "operating netback", "Kelt revenue", "operating income", "net debt", "total revenue", "average realized prices", "net debt to trailing adjusted funds from operations ratio", "debt to cash flow", "finding, development and acquisition", "recycle ratio", "net asset value" and "net asset value per common share" which do not have standardized meanings prescribed by generally accepted accounting principles ("GAAP") and therefore may not be comparable to similar measures presented by other companies where similar terminology is used. For further information and reconciliation to GAAP measures, see "*Non-GAAP Financial Measure and Other Key Performance Indicators*" in this MD&A.

This MD&A contains forward-looking information within the meaning of applicable Canadian securities laws. The use of and of the words "will", "expects", "believe", "plans", potential", "forecasts" and similar expressions are intended to identify forward-looking statements. Such forward-looking information is based upon certain expectations and assumptions and actual results may differ materially from those expressed or implied by such forward-looking information. For further information regarding the forward-looking information contained herein, including the assumptions underlying such forward-looking information, see *"Advisories Regarding Forward-Looking Statements"* in this MD&A.

BASIS OF PRESENTATION

All dollar amounts are referenced in thousands of Canadian dollars, except when noted otherwise. This MD&A contains various references to the abbreviation BOE which means barrels of oil equivalent. Where amounts are expressed on a BOE basis, natural gas volumes have been converted to oil equivalence at six thousand cubic feet per barrel and sulphur volumes have been converted to oil equivalence at 0.6 long tons per barrel. The term BOE may be misleading, particularly if used in isolation. A BOE conversion ratio of six thousand cubic feet per barrel is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead and is significantly different than the value ratio based on the current price of crude oil and natural gas. This conversion factor is an industry accepted norm and is not based on either energy content or current prices. Such abbreviation may be misleading, particularly if used in isolation. References to "oil" in this MD&A include crude oil and field condensate. References to "natural gas liquids" or "NGLs" include pentane, butane, propane, and ethane. References to "liquids" include field condensate and NGLs. References to "gas" in this discussion include natural gas and sulphur.

FINANCIAL AND OPERATING SUMMARY

	Three months ended December 31			Year ended December 31		
(CA$ thousands, except as otherwise indicated)	**2018**	2017	%	**2018**	2017	%
FINANCIAL PERFORMANCE						
Petroleum and natural gas revenue, before royalties	**100,350**	80,838	24	**389,277**	257,557	51
Cash provided by operating activities	**63,656**	36,458	75	**186,383**	115,222	62
Adjusted funds from operations (1)	**47,140**	32,898	43	**186,839**	108,011	73
Diluted ($/ common share) (1)	**0.26**	0.18	44	**1.01**	0.61	66
Profit (loss) and comprehensive income (loss)	**2,843**	(5,389)	-153	**8,154**	(23,178)	-135
Diluted ($/ common share)	**0.02**	(0.03)	-167	**0.04**	(0.13)	-131
Total capital expenditures, net of dispositions	**70,332**	55,778	26	**285,498**	127,977	123
Net debt (1)	**196,416**	136,729	44	**196,416**	136,729	44
OPERATIONAL PERFORMANCE						
Average daily production (BOE/d)	**28,711**	25,063	15	**27,006**	22,130	22
Average realized price, after financial instruments (1)	**34.71**	33.42	4	**36.70**	31.38	17
Operating netback (1)	**19.39**	16.18	20	**20.56**	15.28	35
Reserves – proved plus probable (mboe)	**302,678**	235,601	28	**302,678**	235,601	28

(1) Refer to advisories regarding non-GAAP financial measures and other key performance indicators.

In 2018, Kelt delivered strong financial and operating results as highlighted by the following:

- Achieved record high average production during the fourth quarter and year ended December 31, 2018;
    - Production averaged 28,711 BOE per day (46% oil/NGLs) during the fourth quarter of 2018, up 10% from 26,204 BOE per day (39% oil/NGLs) in the third quarter of 2018 and up 15% from 25,063 BOE per day (45% oil and NGLs) in the fourth quarter of 2017.
    - Calendar year average production for 2018 was 27,006 BOE per day (43% oil/NGLs), up 22% from average production of 22,130 BOE per day (42% oil/NGLs) in 2017. Production per million shares was 148 BOE per day, up from 125 BOE per day in 2017.
- Improved operating netbacks by 35% primarily due to improvements in benchmark crude oil and natural gas prices and a significant reduction in production expenses. Petroleum and natural gas revenues increased 8% to $37.99 per BOE and production expense per BOE decreased by 22% to $8.58 per BOE for the year ended December 31, 2018 as the Company continues to maintain its cost discipline while production ramps up.
- Increased annual adjusted funds from operations by 73% to $186.8 million ($1.01 per share, diluted). Adjusted funds from operations of $47.1 million ($0.26 per share, diluted) during the fourth quarter of 2018 increased 43% from $32.9 million ($0.18 per share, diluted) in the fourth quarter of 2017.
- Capital expenditures totaled $285.5 million focusing on the development of the Company's Montney aceage at Inga/Fireweed, Pouce Coupe and Wembley. Drilling and completion expenditures of $168.7 included the drilling of 32.1 net wells and the completion of 28.1 net wells. Facility expenditures included $50.6 million for the Company's Inga 2-10 processing facility which became operational in the first quarter of 2019.

- The Company maintained a strong balance sheet with net debt of $196.4 million at December 31, 2018 (1.1 times trailing adjusted funds from operations) compared to a senior credit facility of $250.0 million.
- The Company reported significant growth in reserves as at December 31, 2018:
  - Proved developed producing reserves increased 8% to 40.7 million BOE;
  - Total proved reserves increased 19% to 158.4 million BOE;
  - Total proved plus probable reserves increased 28% to 302.7 million BOE.

PRODUCTION

	Three months ended December 31			Year ended December 31		
(CA$ thousands, except as otherwise indicated)	**2018**	2017	%	**2018**	2017	%
Average daily production:						
Oil (bbls/d)	**9,301**	7,902	18	**8,403**	6,634	27
NGLs (bbls/d)	**3,783**	3,379	12	**3,186**	2,608	22
Gas (mcf/d)	**93,759**	82,689	13	**92,502**	77,330	20
Combined (BOE/d)	**28,711**	25,063	15	**27,006**	22,130	22
Oil and NGLs weighting	**46%**	45%		**43%**	42%	

Average production for the three months and twelve months ended December 31, 2018 increased 15% and 22%, respectively, over the comparative periods in 2017. The increase in production in 2018 was driven by strong drilling results in its core areas in Alberta and BC targeting its oil and condensate rich Montney acreage.

Oil and NGLs weighting of total production increased in 2018 to 46% during the fourth quarter and 43% for the year. Average oil production during the fourth quarter of 2018 increased by 18% to 9,301 BOE per day compared to average oil production in the fourth quarter of 2017. Average oil production during the year ended 2018 increased by 27% compared to average oil production for the year ended 2017.

Production in 2018 was impacted by a delay in the completion of a five-well pad drilled at Fireweed BC during the fourth quarter of 2018 due to a “pause” implemented by the BC Oil and Gas Commission while it negotiated interim measures for applications that fall within sensitive areas of the Blueberry River First Nations. At the end of 2018, Kelt received the required approvals from the BC Oil and Gas Commission, with production from the delayed five-well pad expected to be brought on-stream in the third quarter of 2019. In addition, four wells drilled and completed at Wembley in 2018 are expected to be brought on-stream in the third quarter of 2019 once the Tidewater Pipestone Sour Deep-cut Gas Plant commences operations.

REVENUE

All references to revenue in this discussion are before royalties. Petroleum and natural gas revenue (before royalties) as reported in the Consolidated Statement of Profit (Loss) and Comprehensive Income (Loss) has been abbreviated as "total revenue". "Kelt Revenue" includes total revenue, net of the cost of the third party volumes purchased and is before royalties – refer to additional information under the heading of "Non-GAAP Financial Measures and Other Key Performance Indicators".

	Three months ended December 31			Year ended December 31		
(CA$ thousands, except as otherwise indicated)	**2018**	2017	%	**2018**	2017	%
Revenue, before royalties and financial instruments:						
Oil	**32,893**	47,252	-30	**201,287**	142,999	41
NGLs	**9,659**	9,208	5	**39,310**	26,382	49
Gas	**50,448**	21,227	138	**121,752**	85,025	43
Revenue, before marketing	**93,000**	77,687	20	**362,349**	254,406	42
Marketing revenue (2)	**7,350**	3,151	133	**26,928**	3,151	755
Total revenue (1)	**100,350**	80,838	24	**389,277**	257,557	51
Cost of purchases (3)	**(2,770)**	(3,052)	-9	**(21,616)**	(3,052)	608
Kelt Revenue (4)	**97,580**	77,786	25	**367,661**	254,505	44
Average realized prices (5)						
Oil ($/bbl)	**38.77**	65.13	-40	**65.82**	59.10	11
NGLs ($/bbl)	**27.75**	29.62	-6	**33.81**	27.72	22
Gas ($/mcf)	**6.37**	2.79	128	**3.76**	3.01	25
Combined ($/BOE)	**36.94**	33.74	9	**37.30**	31.51	18

(1) Petroleum and natural gas revenue (before royalties) as reported in the consolidated financial statements is abbreviated as "total revenue".

(2) Sales of third party volumes related to the Company's oil blending operations and natural gas activities.

(3) Cost of third party volumes purchased for use and resale in the Company's oil blending operations and natural gas activities.

(4) "Kelt Revenue" is a non-GAAP measure and includes petroleum and natural gas revenue (before royalties), net of the cost of the third party volumes purchased.

(5) Average realized prices are calculated based on Kelt Revenue (4) and reflect Kelt's realized commodity prices plus the net benefit of oil blending and natural gas marketing activities (2)(3). Refer to additional information under the heading of *"Non-GAAP Financial Measures and Other Key Performance Indicators"*.

Revenue for the fourth quarter of 2018 was $93.0 million, up 20% from $77.8 million from the fourth quarter of 2017. Revenue for the year ended December 31, 2018 was $362.3 million, up 42% from the comparable period in 2017. The increase in revenue was driven by a combination of higher production volumes and higher combined average realized prices. Average realized prices increased 9% to $36.94 per BOE in the fourth quarter of 2018 and increased 18% to $37.30 per BOE in the year ended December 31, 2018 versus the comparable periods in 2017. The increase in Kelt's average realized oil and NGLs price was primarily due to higher benchmark commodity prices in 2018. The weakening of Canadian crude oil prices in the fourth quarter of 2018 was more than offset by a higher average realized natural gas price, which benefited from the Company's diversified gas marketing strategy that includes exposure to different North American sales hubs. Kelt's average realized natural gas price of $6.37 in the fourth quarter and $3.76 for 2018 outperformed the AECO 5A benchmark pricing of $1.47/MMBtu in the fourth quarter and $1.48/MMBtu for 2018.

OIL REVENUE

References to "oil" in this discussion includes crude oil and field condensate (see "Other Measurements" for additional references). All references to "oil revenue" are before oil royalties.

	Three months ended December 31			Year ended December 31		
(CA$ thousands, except as otherwise indicated)	**2018**	2017	%	**2018**	2017	%
Oil production (average bbls per day)	**9,301**	7,902	18	**8,403**	6,634	27
Oil revenue, before marketing	**32,893**	47,252	-30	**201,287**	142,999	41
Marketing revenue, net of cost of purchases (1)	**286**	99	189	**623**	99	529
Kelt Oil Revenue	**33,179**	47,351	-30	**201,910**	143,098	41
Average realized oil prices ($/bbl) (2)(3)	**38.77**	65.13	-40	**65.82**	59.10	11
Average realized price, percentage of MSW	**91%**	94%		**95%**	94%	
Benchmark oil prices:						
WTI Cushing, Oklahoma (US$/bbl) (5)	**59.08**	55.37	7	**64.94**	50.88	28
WTI Cushing, Oklahoma (CA$/bbl) (5)	**78.25**	70.36	11	**84.20**	66.10	27
Mixed Sweet Blend Edmonton ("MSW") (CA$/bbl) (4)	**42.72**	68.99	-38	**69.29**	62.89	10
MSW % of CA$WTI	**55%**	98%	-44	**82%**	95%	-14
Average exchange rate (CA$/US$) (6)	**1.3281**	1.2704	5	**1.2977**	1.2966	-

(1) Net of marketing revenue related to the purchase and resale of third party volumes used in the Company's oil blending operations.

(2) Calculated based on Kelt Oil Revenue and reflects Kelt's realized oil price plus the net benefit of the Company's oil blending operations.

(3) The Company's realized oil price is discounted to benchmark oil prices as the base price paid by purchasers is adjusted for quality and is net of all applicable fees and deductions, including pipeline tariffs or location differentials. These tariffs and differentials vary depending on the delivery point, but do not fluctuate with oil prices. Pipeline tariffs are classified as transportation expenses when the Company has firm commitments or contractual arrangements on the pipeline. Refer to further discussion under the heading of *"Transportation Expenses"*.

(4) Source: Tidal Energy Marketing.

(5) Source: U.S Energy Information Administration, Canadian dollar equivalent price WTI price ("CA$WTI") is calculated based on the monthly average U.S. dollar WTI price and the monthly average CA$/US$ exchange rate (6).

(6) Source: Bank of Canada.

Kelt realized an average oil price of $38.77 per barrel during the three months ended December 31, 2018, down from $65.13 per barrel during the comparative period of 2017. Kelt realized an average oil price of $65.82 per barrel during the year ended December 31, 2018, up from $59.10 per barrel during the comparative period of 2017.

Global benchmark crude oil price strengthened significantly during the nine months ended September 30, 2018. However during the last three months of 2018 Canadian crude oil benchmark prices experienced a sharp decline as compared to international benchmark prices due to market access constraints resulting from pipeline and rail transport to the US markets reaching maximum capacity. During the three months ended December 31, 2018, WTI averaged US$59.08 (CA$78.25) per barrel. However, widening differentials for Canadian crude oil resulted in an average realized price of $38.77 per barrel in the fourth quarter of 2018. The differential between Canadian and global crude oil prices returned to historical levels by the end of December as the Government of Alberta announced mandated province wide crude oil curtailments for major Alberta oil producers. These oil curtailments did not impact Kelt's production volumes, however the Company expects to benefit from the curtailments in the first quarter of 2019 as a result of a narrowing of the Canadian crude oil differential.

During the twelve months ended December 31, 2018, WTI averaged US$64.94 (CA$84.20) per barrel, up 28% from US$50.88 (CA$66.10) per barrel in the year ended December 31, 2017.

NGL REVENUE

References to "NGLs" in this discussion includes pentanes (C5 and C5+), butane (C4), propane (C3) and ethane (C2) (see "Other Measurements" for additional references). All references to "NGLs revenue" are before NGLs royalties.

	Three months ended December 31			Year ended December 31		
(CA$ thousands, except as otherwise indicated)	**2018**	2017	%	**2018**	2017	%
NGLs production (average bbls per day)	**3,783**	3,379	12	**3,186**	2,608	22
NGLs barrels per mmcf of natural gas sales	**40**	41	-2	**34**	34	-
NGLs revenue	**9,659**	9,208	5	**39,310**	26,382	49
Average realized NGLs price ($/bbl):						
Before financial instruments	**27.75**	29.62	-6	**33.81**	27.72	22
Realized gain (loss) on financial instruments	**-**	(1.94)	-100	**-**	(1.07)	-100
After financial instruments	**27.75**	27.68	-	**33.81**	26.65	27
Average realized price, percentage of CA$WTI (1)	**35%**	42%		**40%**	42%	
Benchmark NGLs prices (2) ($/bbl):						
Edmonton Pentane	**65.08**	73.71	-12	**79.46**	67.21	18
% of CA$WTI	**83%**	105%	-21	**94%**	102%	-8
Edmonton Butane	**15.44**	53.19	-71	**34.18**	44.08	-22
% of CA$WTI	**20%**	76%	-74	**41%**	67%	-39
Edmonton Propane	**25.32**	40.29	-37	**27.29**	28.74	-5
% of CA$WTI	**32%**	57%	-44	**32%**	43%	-26
Edmonton Ethane	**6.06**	4.78	27	**4.66**	6.11	-24
% of CA$WTI	**8%**	7%	14	**6%**	9%	-33

(1) Average realized NGLs price, before financial instruments, divided by the CA$WTI reference price for the period.

(2) Source: Sproule Associates Limited.

Kelt's NGLs revenue increased by 5% in the fourth quarter of 2018, and increased by 49% for the year ended December 31, 2018 compared to the same periods in 2017. The increase in revenues resulted from a combination of both higher NGLs production and higher benchmark WTI prices.

Kelt realized an average price before financial instruments for its NGL sales of $27.75 per barrel (35% of CA$WTI) during the fourth quarter of 2018, down from $29.62 per barrel (42% of CA$WTI) during the fourth quarter of 2017. Kelt realized an average price before financial instruments for its NGL sales of $33.81 per barrel (40% of CA$WTI) during the twelve months ended December 31 2018, up from $27.72 per barrel (42% of CA$WTI) during the comparable period in 2017. The increase in NGLs prices was driven primarily by the increase in benchmark WTI crude oil prices.

GAS REVENUE

References to “gas” in this discussion includes natural gas and sulphur (see “Other Measurements” for additional references). All references to “gas revenue” are before gas royalties.

	Three months ended December 31			Year ended December 31		
(CA$ thousands, except as otherwise indicated)	**2018**	2017	%	**2018**	2017	%
Gas production (MCF per day)	**93,759**	82,689	13	**92,502**	77,330	20
Gas revenue, before marketing	**50,448**	21,227	138	**121,752**	85,025	43
Marketing revenue, net of cost of purchases (10)	**4,295**	-		**4,690**	-	
Kelt Gas Revenue	**54,743**	21,227	158	**126,442**	85,025	49
Average realized gas price ($/MCF)						
Before financial instruments	**6.37**	2.79	128	**3.76**	3.01	25
Realized gain (loss) on financial instruments	**(0.70)**	(0.02)	3,400	**(0.19)**	-	-
After financial instruments	**5.67**	2.77	103	**3.57**	3.01	19
Kelt average premium to AECO 5A (1)	**286%**	65%	-	**141%**	39%	-
Benchmark gas prices:						
NYMEX Henry Hub (US$/MMBtu) (2)	**3.55**	2.91	22	**3.04**	3.07	-1
Average exchange rate (CA$/US$) (3)	**1.3281**	1.2713	5	**1.2977**	1.2986	-
NYMEX Henry Hub (CA$/MMBtu) (2)	**4.73**	3.70	28	**3.95**	3.98	-1
AECO 5A (CA$/MMBtu) (4)	**1.47**	1.69	-13	**1.48**	2.16	-31
Chicago-City Gate (CA$/MMBtu) (5)	**4.89**	3.60	36	**3.92**	3.75	5
Dawn (CA$/MMBtu) (6)	**5.00**	3.72	34	**4.05**	3.95	3
Malin (CA$/MMBtu) (7)	**5.22**	3.43	52	**3.51**	3.67	-4
Sumas (CA$/MMBtu) (8)	**15.05**	3.45	334	**5.73**	3.59	61
Station 2 (CA$/MMBtu) (9)	**0.67**	0.56	19	**1.25**	1.56	-20

(1) Kelt’s average realized price, before financial instruments, relative to AECO 5A (CA$/MMBtu) assumes 1 MMBtu = 1 MCF.

(2) Source: Canadian Gas Price Reporter “Henry Hub 3-Day Average Close” (US$/MMBtu). The Canadian dollar equivalent NYMEX price is calculated based on the monthly average US$ price and the monthly average CA$/US$ exchange rate (3).

(3) Source: Bank of Canada.

(4) Source: Canadian Gas Price Reporter “NGX AB-NIT Same Day Index 5A” (CA$/GJ) converted to CA$/MMBtu.

(5) Source: Platts “Alliance, into Interstates” Daily Midpoint Average (US$/MMBtu). The Canadian dollar equivalent Chicago-City Gate price is calculated based on the monthly average US$ price and the monthly average CA$/US$ exchange rate (3).

(6) Source: Canadian Gas Price Reporter “NGX Union-Dawn Spot Day Ahead Index” (CA$/GJ) converted to CA$/MMBtu.

(7) Source: Platts “P&G Malin” Monthly Bidweek Spot Gas Price (US$/MMBtu). The Canadian dollar equivalent Malin price is calculated based on the monthly average US$ price and the monthly average CA$/US$ exchange rate (3).

(8) Source: Platts "Northwest, Canadian Border (Sumas)" Monthly Bidweek Spot Gas Price (US$/MMBtu). The Canadian dollar equivalent Sumas price is calculated based on the monthly average US$ price and the monthly average CA$/US$ exchange rate (3).

(9) Source: Canadian Gas Price Reporter “NGX Spectra Station #2 Day Ahead Index” (CA$/GJ) converted to CA$/MMBtu.

(10) Net marketing revenue related to the purchase and resale of third party volumes.

Natural gas revenue before marketing increased 138% to $50.4 million in the fourth quarter of 2018 and increased 43% to $121.8 million in the twelve months ended December 31, 2018 as compared to the same periods in 2017. Revenues increased primarily due to an increase in production and sales price versus the comparable periods in 2017.

Beginning in 2017, Kelt has diversified its natural gas sales in order to reduce its exposure to a single market. The Company maintains price exposure to the Dawn, Malin, Sumas and Chicago markets in addition to domestic markets at Station 2 and AECO, which have been weak in recent years. The Company estimates that 1% of its natural gas production was sold at AECO in 2018 and 16% at Station 2. Based on current production estimates, the Company anticipates selling approximately less than 20% of its 2019 production at AECO or Station 2.

Kelt's market diversification resulted in an average premium to AECO 5A of 286% in the fourth quarter of 2018 and 141% year to date in 2018, versus 65% and 39% for the comparable periods in 2017. Many US markets experienced higher natural gas prices in the fourth quarter of 2018 due to a cold start to the winter heating season and lower than historical storage volumes. The impact of the higher realized gas price on Kelt's funds from operations is partially offset by higher transportation tolls which are included in transportation expenses.

As of December 31, 2018, Kelt's gas market sales portfolio consists of the following firm contracts:

Market Term (Sales)	Firm Volume (MMBtu/d)	Price Hub
Nov/1/17 – Oct/31/27	23,695	DAWN
Nov/1/17 – Oct/31/20	15,000	MALIN
Nov/1/17 – Oct/31/20	16,990	SUMAS
Nov/1/18 – Oct/31/19 (1)	35,619	CHICAGO
Dec/1/17 – Oct/31/20 (1)	2,146	CHICAGO
Apr/1/18 – Oct/31/20 (1)	2,275	CHICAGO
Nov/1/18 – Mar/31/19	4,739	CHICAGO

(1) The Company also has access to priority interruptible transportation service equating to 25% (10,257 MMBtu/d) of its firm service volume on the Alliance pipeline system under which Kelt can increase the amount of gas sales from its properties into the Chicago market.

ROYALTIES

	Three months ended December 31			Year ended December 31		
(CA$ thousands, except as otherwise indicated)	**2018**	2017	%	**2018**	2017	%
Royalties	**5,542**	7,185	-23	**30,701**	23,557	30
Average royalty rate (1)	**6.0%**	9.2%	-35	**8.5%**	9.3%	-9
$ per BOE	**2.10**	3.12	-33	**3.11**	2.92	7

(1) Average royalty rate is calculated based on total royalties as a percentage of "Revenue, before marketing" which excludes revenue related to the sale of third party production volumes used in oil blending operations (see table under the heading of *"Revenue"*).

Kelt's average royalty rate was 6.0% during the fourth quarter of 2018, compared to 9.2% during the fourth quarter of 2017. Kelt's average royalty rate was 8.5% for the twelve months ended December 31, 2018 compared to 9.3% for the year ended December 31, 2017.

A widening of the pricing differential between the Company's natural gas realized prices and domestic market prices in the fourth quarter of 2018 resulted in a reduction in the average royalty rate in both the fourth quarter of 2018 and for the year ended December 31, 2018 versus the comparable periods in 2017 as Alberta royalty rates are based domestic market reference prices.

PRODUCTION EXPENSES

	Three months ended December 31			Year ended December 31		
(CA$ thousands, unless otherwise indicated)	**2018**	2017	%	**2018**	2017	%
Production expense	**22,674**	25,385	-11	**89,792**	81,201	11
$ per BOE	**8.58**	11.01	-22	**9.11**	10.05	-9

The Company incurred total production expenses of $22.7 million during the fourth quarter of 2018 down 11% compared to the same period in 2017. Production expenses per BOE decreased to $8.58 per BOE during the fourth quarter of 2018, compared to $11.01 per BOE in the same period in 2017. The decrease in production expenses is due to lower average costs on new wells added in 2018 and to a one-time $5.2 million expense in the fourth quarter of 2017 for third-party gas plant equalizations.

Production expenses of $89.8 million for the year ended December 31, 2018, increased 11% from the twelve months ended December 31, 2017. On a per boe basis, production expense decreased by 9% in 2018 to average $9.11 per BOE. The decrease in production expense per BOE is a result of annual production growth from new wells with lower average production costs.

TRANSPORTATION EXPENSES

	Three months ended December 31			Year ended December 31		
(CA$ thousands, unless otherwise indicated)	**2018**	2017	%	**2018**	2017	%
Transportation expense (1)	**12,263**	7,172	71	**38,646**	25,301	53
$ per BOE	**4.64**	3.11	49	**3.92**	3.13	25

(1) Pipeline tariffs are classified as transportation expenses when the Company has firm commitments or contractual arrangements on the pipeline. Pipeline tariffs may also be incurred indirectly by way of deduction from the base price paid by the purchasers of the Company's oil, NGLs and gas sales. In the latter case, and in the absence of a firm contractual obligation on the pipeline, the pipeline tariffs are presented as a reduction of revenue rather than as transportation expense.

Transportation expenses averaged $4.64 per BOE during the fourth quarter of 2018, an increase of 49% from $3.11 per BOE in the fourth quarter of 2017. Transportation expenses averaged $3.92 per BOE during the twelve months ending December 31, 2018, an increase of 25% from $3.13 per BOE in the twelve months ended December 31, 2017. The increase in average per unit transportation expenses compared to 2017 was due to higher pipeline tolls under marketing arrangements entered into in the fourth quarter of 2018 to deliver natural gas on the Alliance pipeline to Chicago, as well as higher oil and liquids trucking costs in British Columbia due to third-party pipeline downtime.

FINANCING EXPENSES

	Three months ended December 31			Year ended December 31		
(CA$ thousands, unless otherwise indicated)	**2018**	2017	%	**2018**	2017	%
Interest and fees on bank debt	**1,770**	1,013	75	**5,556**	3,310	68
Interest on convertible debentures	**1,133**	1,134	-	**4,497**	4,500	-
Total interest expense	**2,903**	2,147	35	**10,053**	7,810	29
Accretion of convertible debentures	**1,040**	933	11	**3,949**	3,539	12
Accretion of decommissioning obligations	**846**	774	9	**3,193**	2,981	7
Total financing expense	**4,789**	3,854	24	**17,195**	14,330	20
Interest expense per BOE (1)	**1.10**	0.93	18	**1.02**	0.97	5
Average principal amount outstanding during period:						
Bank debt	**155,063**	89,758	73	**127,437**	67,282	89
Convertible debentures	**89,910**	90,000	-	**89,949**	90,000	-
	244,973	179,758	36	**217,386**	157,282	38
Average interest rates:						
Bank debt (2)	**4.5%**	4.5%	-	**4.4%**	4.9%	-10
Convertible debentures	**5.0%**	5.0%	-	**5.0%**	5.0%	-

(1) Interest expense used in the calculation of "Interest expense per BOE" includes interest and fees on bank debt and accrued cash interest on convertible debentures.

(2) Average interest rate inclusive of fees on bank debt.

The Company's average bank debt outstanding increased for both the three months and year ended December 31, 2018 resulting in an increase in total interest expense from the prior year.

GENERAL AND ADMINISTRATIVE ("G&A") EXPENSES

The following table summarizes significant components of the Company's G&A expenses:

	Three months ended December 31			Year ended December 31		
(CA$ thousands, unless otherwise indicated)	**2018**	2017	%	**2018**	2017	%
Salaries and benefits	**2,336**	2,067	13	**9,383**	8,247	14
Other G&A expenses	**1,429**	1,326	8	**4,664**	4,323	8
Gross G&A expenses	**3,765**	3,393	11	**14,047**	12,570	12
Overhead recoveries	**(1,329)**	(1,125)	18	**(5,695)**	(5,006)	14
Net G&A expenses	**2,436**	2,268	7	**8,352**	7,564	10
Gross G&A ($ per BOE)	**1.43**	1.47	-3	**1.43**	1.56	-8
Net G&A ($ per BOE)	**0.92**	0.98	-6	**0.85**	0.94	-10

Net G&A expenses for the fourth quarter of 2018 were $2.4 million compared to $2.3 million in the prior year. For the year ended December 31, 2018, Net G&A expenses were $8.4 million compared to $7.6 million in 2017. The increase is due to the additional costs to manage the Company's larger production, reserve and land base. On a per boe basis, Net G&A decreased 6% for the three months ended December 31, 2018 and by 10% for the year ended December 31, 2018.

Total overhead recoveries for 2018 increased slightly from 2017 in conjunction with the increase in capital expenditures.

SHARE BASED COMPENSATION ("SBC")

	Three months ended December 31			Year ended December 31		
(CA$ thousands, unless otherwise indicated)	**2018**	2017	%	**2018**	2017	%
Stock options	**942**	1,180	-20	**3,964**	3,867	3
Restricted share units ("RSUs")	**802**	386	108	**2,144**	1,572	36
Total SBC expense	**1,744**	1,566	11	**6,108**	5,439	12
$ per BOE	**0.66**	0.68	-3	**0.62**	0.67	-7

The increase in SBC expense in 2018 is a result of a greater number of RSUs granted and the higher average fair value of new stock options and RSU's granted. The increase was partially offset by a decrease in the number of new stock options granted in 2018.

As at December 31, 2018, stock options and RSUs outstanding represent 6% of total shares outstanding (December 31, 2017 – 6%).

EXPLORATION AND EVALUATION ("E&E") EXPENSES

	Three months ended December 31			Year ended December 31		
(CA$ thousands, unless otherwise indicated)	**2018**	2017	%	**2018**	2017	%
Expired mineral leases	**1,716**	324	430	**5,211**	1,311	297
$ per BOE	**0.65**	0.14	364	**0.53**	0.16	231

The Company expensed $1.7 million of costs related to the expiry of non-core land holdings during the quarter ended December 31, 2018 and $5.2 million in the year ended December 31, 2018, compared to lease expiries of $0.3 million and $1.3 million expensed in the comparative period. The lease expiry's in 2018 all relate to non-core land holdings as the Company continues to focus on the development of its core areas, with the majority of the lease expiry's related to previous leases acquired under corporate acquisitions.

DEPLETION, DEPRECIATION AND IMPAIRMENT

	Three months ended December 31			Year ended December 31		
(CA$ thousands, unless otherwise indicated)	**2018**	2017	%	**2018**	2017	%
Depletion of D&P assets	**36,120**	35,731	1	**144,691**	126,531	14
Depreciation of corporate assets	**101**	219	-54	**608**	967	-37
Depletion and depreciation	**36,221**	35,950	1	**145,299**	127,498	14
Impairment	**7,668**	6,864	12	**10,668**	6,864	55
Total depletion, depreciation and impairment	**43,889**	42,814	-3	**155,967**	134,362	16
Depletion and depreciation ($/BOE)	**13.71**	15.59	-12	**14.74**	15.78	-7
Impairment ($/BOE)	**2.91**	2.98	-2	**1.09**	0.85	28

The Company calculates depletion of development and production ("D&P") assets based on production relative to total proved reserves for each depletion unit. Depletion and depreciation per BOE for the quarter ended December 31, 2018 was $13.71 per BOE compared to $15.59 per BOE in the prior year. Depletion per BOE for the fourth quarter decreased 15% from the prior year after incorporating the increase in proved reserves and future capital assumptions from the Company's December 31, 2018 reserve report.

Depletion and depreciation of $145.3 million for the year ended December 31, 2018 increased by 14% from comparable period in 2017, with the increase attributed to a 22% increase in average production partially offset by an increase in proved reserves which lowered the depletion and depreciation rate per BOE.

On July 31, 2018, the Company completed the disposition of the Leduc-Woodbend Cash Generating Unit ("CGU") for $2.6 million after closing adjustments. The Leduc-Woodbend CGU had a carrying value of $2.6 million, resulting in a gain on sale of $0.05 million. In the second quarter of 2018, the Leduc-Woodbend CGU was impaired by $3.0 million based on the sale in the third quarter of 2018.

As at December 31, 2018 Kelt's net asset value was greater than its market capitalization. As such, an impairment test was conducted over all Kelt's CGUs; however no impairment was recognized for the Company's core oil weighted CGUs in British Columbia and Greater Grande Prairie as the estimated recoverable amount of these CGUs significantly exceeded their carrying value.

Based on the impairment test performed on the Grande Cache CGU, it was determined that its carrying value was in excess of the recoverable amount resulting in an impairment loss of $7.7 million (before-tax). The impairment was a result of a decrease in forecast natural gas prices as at December 31, 2018 compared to forecast prices as at December 31, 2017. Despite being a low-cost property, the decrease in forecast natural gas prices had a pervasive impact on the recoverable amount calculated for the Grande Cache CGU, given that 99% of proved plus probable reserves of the Grande Cache property are natural gas. As at December 31, 2018, the net carrying amount of PP&E for the Grande Cache CGU was $12.1 million (including $14.5 million of accumulated impairment).

GAIN (LOSS) ON SALE OF ASSETS

	Three months ended December 31			Year ended December 31		
(CA$ thousands, unless otherwise indicated)	**2018**	2017	%	**2018**	2017	%
Gain on sale of assets	**3,365**	8,850	-62	**3,562**	10,436	-66

On December 20, 2018 the Company completed the disposition of its non- operated assets in the Karr area for $7.1 million after closing adjustments. The Karr non-operated assets had a carrying value of $3.7 million, resulting in a gain on sale of $3.4 million.

On July 31, 2018, the Company completed the disposition of the Leduc-Woodbend Cash Generating Unit ("CGU") for $2.6 million after closing adjustments. The Leduc-Woodbend CGU had a carrying value of $2.6 million, resulting in a gain on sale of $0.05 million.

On January 18, 2017, Kelt completed the Karr Property Disposition (as hereafter defined) for proceeds of $103.1 million after closing adjustments. Closing of the Karr Property Disposition had a minimal impact on the gain on sale of assets reported in 2017 because the assets and associated decommissioning obligations disposed were classified as held for sale at December 31, 2016. Kelt reported an impairment reversal of $32.2 million during the fourth quarter ended December 31, 2016, based on the increase in fair value of the Karr property evidenced by the cash purchase price.

DERIVATIVE FINANCIAL INSTRUMENTS

The Company may enter into fixed price contracts and derivative financial instruments for commodity prices, currency exchange and interest rates in order to secure future cash flows or to protect a desired level of capital spending. Fair value accounting for derivative financial instruments may cause significant fluctuations in the reported amounts of derivative financial instrument assets and liabilities and the resultant magnitude of unrealized gains and losses.

The table below summarizes realized and unrealized gains (losses) on risk management contracts:

	Three months ended December 31			Year ended December 31		
(CA$ thousands, unless otherwise indicated)	**2018**	2017	%	**2018**	2017	%
Realized gain (loss)	**(5,900)**	(720)	719	**(5,900)**	(1,050)	462
Unrealized gain (loss)	**2,596**	726	258	**2,596**	599	333
Gain (loss) on derivative financial instruments	**(3,304)**	6	-	**(3,304)**	(451)	633
$ per BOE	**(1.25)**	-	-	**(0.34)**	(0.06)	467

Commodity price risk

Commodity price risk is the price uncertainty to the Company's financial performance upon fluctuations in the prices of commodities that are out of the control of the Company. Commodity prices are primarily driven by market forces that dictate the levels of supply and demand as well as the currency exchange rate relationship between the Canadian and U.S. dollar.

As at December 31, 2018, the following commodity price risk management contracts are outstanding:

Contract Type	Notional Volume	Reference Prices	Fixed Contract Price	Term
Financial Swap Natural Gas	10,000 MMBtu/d	NYMEX to Chicago Citygate Basis Differential	NYMEX Henry Hub less USD$0.14 per MMBtu	January 2019 to October 2019
Financial Swap Natural Gas	10,000 MMBtu/d	NYMEX to Union Dawn Basis Differential	NYMEX Henry Hub less USD$0.0975 per MMBtu	January 2019 to December 2019
Financial Swap Natural Gas	7,500 MMBtu/d	Sumas	USD$5.97 per MMBTU	November 2018 to March 2019
Financial Swap Natural Gas	5,000 MMBtu/d	Malin	USD$4.55 per MMBtu	January 2019 to March 2019

Interest rate risk

The Company is exposed to interest rate risk as changes in market interest rates will impact the Company's credit facility which is subject to a floating interest rate. Based on average bank debt outstanding of $127.4 million during the year ended December 31, 2018, an increase (decrease) in the market rate of interest by 25 basis points would have increased (decreased) annualized interest expense by $0.3 million.

As at December 31, 2018, there are no interest rate risk management contracts outstanding.

Foreign exchange risk

Kelt is exposed to fluctuations of the Canadian to U.S. dollar exchange rate as benchmark oil and natural gas prices are denominated in U.S. dollars and the Company has both sales and transportation contracts in U.S. dollars.

As at December 31, 2018, the following foreign exchange risk management contract is outstanding:

Contract Type	Notional Amount per month	Fixed Contract Price	Term
FX swap	US$1,000,000	CA$/US$ 1.3050	January 2019 to December 2019

PREMIUM ON FLOW-THROUGH SHARES

	Three months ended December 31			Year ended December 31		
(CA$ thousands, unless otherwise indicated)	**2018**	2017	%	**2018**	2017	%
Premium on flow-through shares	**-**	1,511	-	**4,141**	2,309	79

Management has utilized the Company's strong tax position to raise capital by issuing common shares on a "flow-through" basis which are typically issued at a premium to the market price of the Company's common shares. The premium received by the Company in excess of the fair value of its common shares at the time of the offering, is initially deferred and subsequently recognized in income as the premium is earned by incurring qualifying capital expenditures.

In April 2018, the Company issued 2.7 million common shares for aggregate gross proceeds of $24.8 million (the "2018 Flow-through"), of which: 2.3 million CDE flow through shares were issued at a price of $8.85 per share for gross proceeds of $20.8 million; and 0.4 million CEE flow-through shares were at a price of $9.75 per share for gross proceeds of $4.0 million. After estimated expenses related to the private placements, net proceeds were approximately $24.0 million and resulted in a total premium $3.1 million relative to the fair value of Kelt's common shares. As at December 31, 2018, the Company fully satisfied all obligations related to 2018 Flow-through. The deferred premium of $3.1 million was recognized in income as expenditures in 2018.

In October 2017, the Company issued 2.6 million flow-through common shares for aggregate gross proceeds of $20.6 million; of which: 2.0 million CDE flow-through shares (the "2017 CDE Flow-through") were issued at a price of $7.75 per share for gross proceeds of $15.6 million; and 0.6 million CEE flow-through shares (the "2017 CEE Flow-through") were issued at a price of $8.75 per share for gross proceeds of $5.0 million. After estimated expenses related to the private placements, net proceeds were approximately $20.3 million and resulted in a total premium $2.6 million relative to the fair value of Kelt's common shares.

As at December 31, 2017, the Company fully satisfied all its obligations related to 2017 CDE Flow-through and renounced the qualifying expenditures to the subscribers with an effective date of December 31, 2017. The deferred premium of $1.5 million ($0.75 per share) was recognized in income as expenditures were incurred during the fourth of 2017. As at March 31, 2018, the Company fully satisfied all obligations related to 2017 CEE Flow-through and renounced the qualifying expenditures to the subscribers with an effective date of December 31, 2017. The deferred premium of $1.0 million ($1.82 per share) was recognized in income as expenditures were incurred during the first quarter of 2018.

INCOME TAXES

	Three months ended December 31			Year ended December 31		
(CA$ thousands, unless otherwise indicated)	**2018**	2017	%	**2018**	2017	%
Deferred income tax expense (recovery)	**1,167**	2,920	-60	**14,699**	(3,142)	-568
Profit (Loss) before taxes	**4,010**	(2,469)	-262	**22,853**	(26,320)	-187
Effective tax recovery rate	**29.1%**	(118)%	-125	**64.3%**	12%	439

Kelt's consolidated combined federal and provincial statutory tax rate averaged 27.0% and 26.7% during the twelve months ended December 31, 2018 and 2017, respectively.

The increase in Kelt's effective tax rate in the year ended December 31, 2018 was primarily due to $29.8 million of qualifying expenditures which have been renounced to subscribers of the flow-through private placements.

Kelt does not expect to pay income taxes in the current year as the Company had sufficient income tax deductions available to shelter taxable income. The Company's consolidated tax pools are estimated to be approximately $1,048.6 million as of December 31, 2018 as summarized in the table below.

(CA$ thousands, unless otherwise indicated)	Rate	**December 31 2018**	December 31 2017	% change
Canadian oil and gas property expenses (COGPE)	10%	**128,254**	146,010	-12
Canadian development expenses (CDE)	30%	**216,975**	195,362	11
Canadian exploration expenses (CEE)	100%	**105,921**	102,708	3
Undepreciated capital cost (1) (UCC)	25%	**254,430**	187,426	36
Share and debt issue costs	5 years	**4,010**	7,340	-45
Non-capital losses (2) (NCL)	100%	**339,031**	338,978	-
Estimated tax deductions available, end of period		**1,048,621**	977,824	7

(1) The majority of the Company's undepreciated capital cost deductions relate to Class 41 assets, which are deductible at a rate of 25% per year.

(2) The Company's non-capital losses expire in years 2023 to 2038.

PROFIT (LOSS) AND COMPREHENSIVE INCOME

	Three months ended December 31			Year ended December 31		
(CA$ thousands, unless otherwise indicated)	**2018**	2017	%	**2018**	2017	%
Profit (loss) and comprehensive income (loss)	**2,843**	(5,389)	-153	**8,154**	(23,178)	-135
$ per common share, basic	**0.02**	(0.03)	-167	**0.04**	(0.13)	-131
$ per common share, diluted (1)(2)	**0.02**	(0.03)	-167	**0.04**	(0.13)	-131
$ per BOE	**1.08**	(2.34)	-146	**0.81**	(2.87)	-128
Wtd avg. shares outstanding, basic (000s)	**183,994**	178,220	3	**182,576**	176,466	3
Wtd avg. shares outstanding, diluted (000s) (1)(2)	**184,682**	178,220	4	**184,393**	176,466	4

(1) The Company uses the treasury stock method to determine the dilutive effect of stock options and RSUs. Under this method, only "in-the-money" dilutive instruments impact the calculation of diluted profit per common share. In computing the diluted loss per common share for the fourth quarter ended December 31, 2017 the Company excluded the effect of stock options and RSUs as they were anti-dilutive. In computing the diluted loss per common share for the fourth quarter ended December 31, 2018 the dilutive impact of the effect of stock options and RSUs did not result in a change in the $ per common share.

(2) The common shares potentially issuable on conversion of the debentures are excluded from the calculation of diluted weighted average shares outstanding as they were anti-dilutive to the loss reported for all periods outstanding.

Kelt reported a profit of $2.8 million ($0.02 per common share, diluted) for the quarter ended December 31, 2018, compared to a loss of $5.4 million ($0.03 per common share, diluted) in the same quarter of 2017. The increase in profit is primarily due to an increase of $14.2 million in adjusted funds from operations, partially offset by an increase in depreciation, depletion and impairment expense of $1.1 million and a decrease in the deferred income tax expense of $1.8 million.

Kelt reported a profit of $8.2 million ($0.04 per common share, diluted) for the year ended December 31, 2018, compared to a loss of $23.2 million ($0.13 per common share, diluted) in the prior year. The increase in profit is primarily due to an increase of $78.8 million in adjusted funds from operations, partially offset by an increase in depletion, depletion and impairment expense of $21.6 million and an increase in the deferred income tax expense of $17.8 million.

ADJUSTED FUNDS FROM OPERATIONS

The following table provides a continuity of income and expenses included in the Company's calculation of operating income and adjusted funds from operations generated during the three months and year ended December 31, 2018 and 2017.

THREE MONTHS ENDED DECEMBER 31TH	2018		2017		% change	
(CA$ thousands, unless otherwise indicated)	**Amount**	**$/BOE**	Amount	$/BOE	Amount	$/BOE
Petroleum and natural gas revenue	**100,350**	**37.99**	80,838	35.06	24	8
Cost of purchases	**(2,770)**	**(1.05)**	(3,052)	(1.32)	-9	-20
Realized loss on financial instruments (1)	**(5,900)**	**(2.23)**	(720)	(0.32)	719	597
Royalties	**(5,542)**	**(2.10)**	(7,185)	(3.12)	-23	-33
Revenue, after royalties and financial instruments	**86,138**	**32.61**	69,881	30.30	23	8
Production expense	**(22,674)**	**(8.58)**	(25,385)	(11.01)	-11	-22
Transportation expense	**(12,263)**	**(4.64)**	(7,172)	(3.11)	71	49
Operating income (2)	**51,201**	**19.39**	37,324	16.18	37	20
Financing expense (3)	**(2,903)**	**(1.10)**	(2,147)	(0.93)	35	18
G&A expense	**(2,436)**	**(0.92)**	(2,268)	(0.98)	7	-6
Other income	**845**	**0.32**	-	-	-	-
Realized gain (loss) on foreign exchange	**433**	**0.16**	(11)	-	-4036	-
Adjusted funds from operations (4)	**47,140**	**17.85**	32,898	14.27	43	25
Basic ($ per common share) (5)	**0.26**		0.18		44	
Diluted ($ per common share) (5)	**0.26**		0.18		44	
Common shares outstanding (000s):						
Basic, weighted average	**183,994**		178,220		3	
Diluted, weighted average	**184,682**		179,898		3	

(1) Includes realized gains (losses) on commodity price and foreign exchange derivatives. Excludes realized gains (losses) on interest rate swaps.

(2) "Operating income" is a non-GAAP financial measure which is calculated by deducting royalties, production expenses and transportation expenses from petroleum and natural gas revenue, after realized gains or losses on associated financial instruments.

(3) Excludes non-cash accretion of decommissioning obligations and convertible debentures.

(4) "Adjusted funds from operations" is a non-GAAP financial measure which is calculated as cash provided by operating activities before changes in non-cash operating working capital, and adding back (if applicable): transaction costs, provisions for potential credit losses, and settlement of decommissioning obligations. Adjusted funds from operations is used by Kelt as key measures of performance; refer advisories under the heading of "Non-GAAP Financial Measure and Other Key Performance Indicators" for a reconciliation of adjusted funds from operations. Management feels that adjusted funds from operations and operating income or netbacks provides useful information to the Company's stakeholders as it provides the ability to better analyze operational performance with information that is commonly used by other crude oil and natural gas producers.

(5) Adjusted funds from operations per common share is calculated on a consistent basis with profit (loss) per common share, using basic and diluted weighted average common shares as determined in accordance with GAAP.

During the three months ended December 31, 2018, adjusted funds from operations of $47.1 million ($0.26 per share, diluted) increased by 43% from $32.9 million ($0.18 per share, diluted) during the fourth quarter ended December 31, 2017. The increase in adjusted funds from operations is primarily attributed to the increase in Kelt's revenues (after royalties and financial instruments) which are up 23% to $86.1 million compared to $69.9 million in the fourth quarter of 2017. The increase is driven primarily by a 15% increase in average production, and a 12% increase in the benchmark WTI (CA$/bbl) oil price.

YEAR ENDED DECEMBER 31TH	2018		2017		% change	
(CA$ thousands, unless otherwise indicated)	**Amount**	**$/BOE**	Amount	$/BOE	Amount	$/BOE
Petroleum and natural gas revenue	**389,277**	**39.49**	257,557	31.89	51	24
Cost of purchases	**(21,616)**	**(2.19)**	(3,052)	(0.38)	608	476
Realized gain (loss) on financial instruments (1)	**(5,900)**	**(0.60)**	(1,060)	(0.13)	457	362
Royalties	**(30,701)**	**(3.11)**	(23,557)	(2.92)	30	7
Revenue, after royalties and financial instruments	**331,060**	**33.59**	229,888	28.46	44	18
Production expense	**(89,792)**	**(9.11)**	(81,201)	(10.05)	11	-9
Transportation expense	**(38,646)**	**(3.92)**	(25,301)	(3.13)	53	25
Operating income (2)	**202,622**	**20.56**	123,386	15.28	64	35
Financing expense (3)	**(10,053)**	**(1.02)**	(7,810)	(0.97)	29	5
G&A expense	**(8,352)**	**(0.85)**	(7,564)	(0.94)	10	-10
Other income	**1,960**	**0.19**	-	-	-	-
Realized gain (loss) on foreign exchange	**662**	**0.07**	(11)	-	-6118	-
Realized gain (loss) on financial instruments (4)	**-**	**-**	10	-	-100	-
Adjusted funds from operations (5)	**186,839**	**18.95**	108,011	13.37	73	42
Basic ($ per common share) (6)	**1.02**		0.61		67	
Diluted ($ per common share) (6)	**1.01**		0.61		66	
Common shares outstanding (000s):						
Basic, weighted average	**182,576**		176,466		3	
Diluted, weighted average	**184,393**		177,920		4	

(1) Includes realized gains (losses) on commodity price and foreign exchange derivatives. Excludes realized gains (losses) on interest rate swaps.

(2) "Operating income" is a non-GAAP financial measure which is calculated by deducting royalties, production expenses and transportation expenses from petroleum and natural gas revenue, after realized gains or losses on associated financial instruments.

(3) Excludes non-cash accretion of decommissioning obligations and convertible debentures.

(4) Includes realized gains (losses) on interest rate swaps.

(5) "Adjusted funds from operations" is a non-GAAP financial measure which is calculated as cash provided by operating activities before changes in non-cash operating working capital, and adding back (if applicable): transaction costs, provisions for potential credit losses, and settlement of decommissioning obligations.

(6) Adjusted funds from operations per common share is calculated on a consistent basis with profit (loss) per common share, using basic and diluted weighted average common shares as determined in accordance with GAAP.

During the year ended December 31, 2018, adjusted funds from operations of $186.8 million ($1.01 per share, diluted) increased by 73% from $108.0 million ($0.61 per share, diluted) during the year ended December 31, 2017. The increase in adjusted funds from operations is primarily attributed to the increase in Kelt's revenues (after royalties and financial instruments) which are up 44% to $331.1 million compared to $229.9 million in the prior year. The increase is driven primarily by a 22%, increase in average production, and a 27% increase in the benchmark WTI (CA$/bbl) oil price which has mitigated the impact of lower gas prices for the year ended 2018. On a BOE basis, adjusted funds from operations per BOE increased 42% from the year ended December 31, 2017.

INVESTING ACTIVITIES

CAPITAL EXPENDITURES

The Company's total capital expenditures, including acquisitions and dispositions ("A&D"), are summarized in the following table:

	Three months ended December 31			Year ended December 31		
(CA$ thousands, unless otherwise indicated)	**2018**	2017	%	**2018**	2017	%
Capital expenditures:						
Lease acquisition and retention	**686**	1,789	-62	**4,829**	9,185	-47
Geological and geophysical	**415**	4	10,275	**714**	1,925	-63
Drilling and completion of wells	**44,738**	39,889	12	**168,655**	154,667	9
Facilities, pipeline and well equipment	**31,657**	23,592	34	**117,748**	77,199	53
Corporate assets	**10**	24	-58	**762**	793	-4
Capital expenditures, before A&D	**77,506**	65,298	19	**292,708**	243,769	20
Property acquisitions	**11**	464	-98	**2,860**	531	439
Property dispositions	**(7,185)**	(9,984)	-28	**(10,070)**	(116,323)	-91
Total capital expenditures, net of dispositions	**70,332**	55,778	26	**285,498**	127,977	123

DRILLING

Drilling and completion expenditures for the three month period ended December 31, 2018, and during the year ended December 31, 2018 were focused on Montney wells in the Company's core Alberta and BC areas. During the year ended December 31, 2018, the Company drilled 33 (32.1 net) wells compared to 40 (31.2 net) wells in 2017 and completed 29 wells (28.1 net) in 2018 compared to 32 wells (24.2 net) in 2017.

At the end of 2018 Kelt had five wells drilled and completed in Wembley and Valhalla, four of which will be brought on-production once the Tidewater Pipestone Sour Deep-cut Gas Plant commences operations which is expected in the third quarter of 2019. In addition, the Company had 10 oil and gas wells drilled but not completed as at December 31, 2018 which will be brought on-production throughout 2019 in alignment with various other facilities and pipelines currently under construction.

	Year ended December 31, 2018		**Year ended December 31, 2018**	
	Drilling		**Completion**	
2018	**Gross**	**Net**	**Gross**	**Net**
Oil	**14**	**13.1**	**19**	**18.1**
Gas	**18**	**18.0**	**10**	**10.0**
Service	**1**	**1.0**	**-**	**-**
Dry	**-**	**-**	**-**	**-**
Total wells	**33**	**32.1**	**29**	**28.1**

	Year ended December 31, 2017		**Year ended December 31, 2017**	
	Drilling		**Completion**	
2017	**Gross**	**Net**	**Gross**	**Net**
Oil	**27**	**18.2**	**21**	**12.2**
Gas	**13**	**13.0**	**12**	**12.0**
Service	**-**	**-**	**-**	**-**
Dry	**-**	**-**	**-**	**-**
Total wells	**40**	**31.2**	**33**	**24.2**

FACILITIES AND INFRASTRUCTURE EXPENDITURES

In 2017 the Company purchased a major infrastructure package located in northeastern British Columbia for $12.5 million that included a total of 100 mmcf per day of natural gas compression and dehydration and related facilities. In 2018, the Company reconstructed the facility at Inga 2-10, while also adding additional large diameter gas and emulsion pipelines as well as a large diameter water line which will enable Kelt to reuse frac water as well as access additional water from two large water ponds being constructed at the facility. This infrastructure will allow Kelt to continue with its multi-well pad development at Inga, in a cost effective manner that is expected to lower future production expenses, with the facility began testing and ramp-up operations in the first quarter of 2019. During the fourth quarter of 2018 and the year ended December 31, 2018, Kelt incurred $15.9 million and $50.6 million of costs, respectively, related to the construction of this facility.

PROPERTY ACQUITISIONS AND DISPOSITIONS

During 2018 the Company completed acquisitions with total cash consideration of $2.9 million, primarily for undeveloped land interests. Total cash proceeds (net of disposal costs) from non-core property dispositions were $10.1 million, resulting in a gain on dispositions of $3.6 million for the year ended December 31, 2018. In the comparative period, total cash proceeds from non-core assets were $13.3 million which resulted in a gain on sale of $10.4 million (after estimated closing adjustments).

On January 18, 2017, Kelt completed the disposition of the majority of its oil and gas assets in the Karr area of Alberta (the “Karr Property Disposition”) for proceeds of $103.1 million after closing adjustments.

LAND HOLDINGS

Kelt has significant undeveloped land acreage of 614,644 net acres and developed land acreage of 224,346 net acres of which 61% include Montney rights that are prospective for oil and liquids-rich gas.

	As at December 31, 2018		As at December 31, 2017		Percentage Change	
(Acres)	**Gross**	**Net**	Gross	Net	Gross	Net
Developed	**364,109**	**224,346**	392,936	214,358	-7	5
Undeveloped	**710,981**	**614,644**	755,455	637,823	-6	-4
Total	**1,075,090**	**838,990**	1,148,391	852,181	-6	-2
Average working interest		**78%**		74%		

The table below sets-out Kelt’s Montney land holdings as at December 31, 2018:

MONTNEY RIGHTS	**Net Acres**	Net Sections
British Columbia	**363,852**	569
Alberta	**147,999**	231
Total	**511,851**	800

RESERVES

Kelt retained Sproule Associates Limited (“Sproule”), an independent qualified reserve evaluator to prepare a report on its oil and gas reserves (the “Sproule Report”). The Company has a Reserves Committee which oversees the selection, qualifications and reporting procedures of the independent engineering consultants. Reserves as at December 31, 2018 and at December 31, 2017 were determined using the guidelines and definitions set out under National Instrument 51-101 (“NI 51-101”). The Sproule Report is dated February 12, 2019 and is effective as of December 31, 2018.

At December 31, 2018, Kelt’s proved plus probable reserves were 302.7 million BOE, up 28% from 235.6 million BOE at December 31, 2017. The Company’s net present value of proved plus probable reserves at December 31, 2018, discounted at 10% before tax, was $3.1 billion, an increase of 48% from $2.1 billion at December 31, 2017. This increase was achieved despite lower forecasted oil and gas prices for the future years in the December 31, 2018 evaluation (see "Future Commodity Price Forecast" table below). Sproule's forecasted commodity prices for 2019 used to determine the present value of the Company's reserves at December 31, 2018, are US$63.00 per barrel for WTI oil and $1.85 per GJ for AECO-C gas.

At December 31, 2018, the weighting of proved plus probable reserves was 43% oil/NGLs and 57% natural gas. At December 31, 2017, the weighting of proved plus probable reserves was 43% oil/NGLs and 57% natural gas.

The following table outlines a summary of the Company's reserves volumes at December 31, 2018:

SUMMARY OF RESERVE VOLUMES	Crude Oil (mbbls)	Liquids[1] (mbbls)	Natural Gas (mmcf)	**Combined (mBOE)**	**FDC Costs ($ thousands)**
Proved developed producing	6,028	9,359	151,889	**40,701**	**501**
Proved developed non-producing	912	3,073	20,191	**7,350**	**13,600**
Proved undeveloped	6,170	38,185	396,218	**110,392**	**857,447**
Total Proved	**13,110**	**50,617**	**568,298**	**158,443**	**871,548**
Probable additional	10,642	54,478	474,689	**144,235**	**602,550**
Total Proved plus Probable	**23,752**	**105,095**	**1,042,987**	**302,678**	**1,474,098**

(1) "Liquids" include field condensate and NGLs.

CHANGE IN RESERVES – YEAR OVER YEAR (mBOE)	**December 31 2018**	December 31 2017	% Change
Proved developed producing	**40,701**	37,858	8
Proved developed non-producing	**7,350**	2,833	159
Proved undeveloped	**110,392**	92,282	20
Total Proved	**158,443**	132,973	**19**
Probable additional	**144,235**	102,628	41
Total Proved plus Probable	**302,678**	235,601	**28**

The following tables reconcile the change in total proved ("1P") reserves and the change in total proved plus probable ("2P") reserves during the year:

RESERVES RECONCILIATION – 1P TOTAL PROVED	Crude Oil (mbbls)	Liquids[1] (mbbls)	Natural Gas (mmcf)	**Combined (mBOE)**
Balance, December 31, 2017	12,510	42,476	467,924	**132,973**
Extensions	3,878	7,996	48,478	**19,954**
Infill drilling	37	4,860	39,776	**11,526**
Technical revisions	(946)	(2,235)	50,120	**5,172**
Economic factors	22	(136)	(3,292)	**(663)**
Acquisitions	37	3	156	**67**
Dispositions	(467)	(78)	(1,275)	**(758)**
Net additions	**2,561**	**10,410**	**133,963**	**35,298**
2018 Production [2]	(1,961)	(2,269)	(33,589)	**(9,828)**
Balance, December 31, 2018 [2]	**13,110**	**50,617**	**568,298**	**158,443**

(1) "Liquids" include field condensate and NGLs.

(2) Sulphur production of 29 MBOE and 1P sulphur reserves of 19 MBOE have been excluded in the above table.

RESERVES RECONCILIATION – 2P **TOTAL PROVED PLUS PROBABLE**	Crude Oil (mbbls)	Liquids[1] (mbbls)	Natural Gas (mmcf)	**Combined** **(mBOE)**
Balance, December 31, 2017	21,438	80,350	802,875	**235,601**
Extensions	6,237	23,424	132,119	**51,681**
Infill drilling	382	11,692	85,284	**26,288**
Technical revisions	(1,633)	(7,829)	62,143	**895**
Economic factors	22	(146)	(3,887)	**(772)**
Acquisitions	49	5	211	**89**
Dispositions	(782)	(132)	(2,169)	**(1,276)**
Net additions	**4,275**	**27,014**	**273,701**	**76,905**
2018 Production [2]	(1,961)	(2,269)	(33,589)	**(9,828)**
Balance, December 31, 2018 [2]	**23,752**	**105,095**	**1,042,987**	**302,678**

(1) “Liquids” include field condensate and NGLs.

(2) Sulphur production of 29 MBOE and 2P sulphur reserves of 45 MBOE have been excluded in the above table.

The following table outlines FDC (as hereafter defined) expenditures outlays for total proved reserves and total proved plus probable reserves included in the December 31, 2018 reserve evaluations:

FDC EXPENDITURES ($ thousands)	2019	2020	2021	2022	2023	Thereafter	Total
Proved reserves	81,657	200,114	206,375	125,310	110,138	147,954	871,548
Proved plus probable	145,307	310,072	305,672	246,408	204,997	261,643	1,474,099

The following table outlines FDC expenditures and future wells to be drilled by province, included in the December 31, 2018 and 2017 reserve evaluations for proved plus probable reserves:

FDC EXPENDITURES	**Year ended December 31, 2018**		Year ended December 31, 2017	
TOTAL PROVED PLUS PROBABLE	**FDC ($M)**	**Net Wells**	FDC ($M)	Net Wells
Alberta Montney HZ Wells	**331,835**	**59.3**	175,728	37.3
B.C. Montney HZ Wells	**743,803**	**140.0**	638,203	102.5
Total Montney HZ Wells	**1,075,638**	**199.3**	813,931	139.8
Other formations HZ wells	**355,088**	**76.6**	342,441	74.5
Other expenditures	**43,372**	**-**	7,220	n/a
Total FDC Expenditures	**1,474,098**	**275.9**	1,163,592	214.3

The WTI oil price during the three years from 2015 to 2018 averaged US$52.03 per barrel, after a precipitous decline from US$93.00 in 2014. Sproule is forecasting an average WTI oil price of US$63.00 per barrel in 2019. Natural gas prices during the 2015 to 2018 period at AECO-C averaged $2.04 per GJ. Sproule is forecasting an average AECO-C gas price of $1.85 per GJ in 2019.

The following table outlines forecasted future prices that Sproule has used in their evaluation of the Company's reserves at December 31, 2018:

FUTURE COMMODITY PRICE FORECAST	WTI Cushing Oklahoma US$/bbl	Canadian Light Sweet CA$/bbl	NYMEX Henry Hub US$/MMBtu	AECO-C Spot CA$/GJ	USD/CAD Exchange US$/CA$
2019	63.00	75.27	3.00	1.85	0.77
2020	67.00	77.89	3.25	2.31	0.80
2021	70.00	82.25	3.50	2.84	0.80
2022	71.40	84.79	3.57	3.04	0.80
2023	72.83	87.39	3.64	3.13	0.80
Five year average	**68.85**	**81.52**	**3.39**	**2.63**	**0.79**

The Company's net present value of proved plus probable reserves, discounted at 10% before tax, was $3.1 billion as at December 31, 2018, up 48% from $2.1 billion as of December 31, 2017. The undiscounted future net cash flow, before tax, was $6.7 billion as of December 31, 2018, an increase of 50% from $4.4 billion as of December 31, 2017.

The following table summarizes the net present value of the Company's reserves (before tax) as at December 31, 2018:

NET PRESENT VALUE (BEFORE TAX)

(CA$ millions)	Undiscounted	NPV 5% BT	NPV 10% BT
Proved developed producing	637.8	551.2	481.1
Proved developed non-producing	146.1	115.3	95.0
Proved undeveloped	2,199.1	1,371.9	923.1
Total Proved	**2,983.0**	**2,038.4**	**1,499.2**
Probable additional	3,676.3	2,327.5	1,629.4
Total Proved plus Probable	**6,659.3**	**4,365.9**	**3,128.6**

The Company's net present value of proved plus probable reserves, discounted at 10% after tax, was $2.4 billion as of December 31, 2018, up 44% from $1.7 billion as of December 31, 2017. The undiscounted future net cash flow, after tax, was $5.1 billion as of December 31, 2018, an increase of 47% from $3.5 billion as of December 31, 2017.

The following table summarizes the net present value of the Company's reserves (after tax) as at December 31, 2018:

NET PRESENT VALUE (AFTER TAX)

(CA$ millions)	Undiscounted	NPV 5% AT	NPV 10% AT
Proved developed producing	637.8	551.2	481.1
Proved developed non-producing	146.1	115.3	95.0
Proved undeveloped	1,668.9	1,041.4	698.8
Total Proved	**2,452.8**	**1,707.9**	**1,274.9**
Probable additional	2,678.5	1,688.2	1,174.3
Total Proved plus Probable	**5,131.3**	**3,396.1**	**2,449.2**

During 2018, the Company's capital expenditures, net of dispositions, resulted in proved plus probable reserve additions of 78.2 million BOE, resulting in 2P FD&A costs of $7.75 per BOE, including FDC expenditures. Proved reserve additions in 2018 were 36.1 million BOE, resulting in 1P FD&A costs of $10.80 per BOE, including FDC expenditures. Despite a significant disposition in 2018, Kelt was able to show significant reserve additions from new wells and from certain existing wells that have produced at rates that have exceeded previous estimates. Capital expenditures in 2018 were $285.5 million, up 123% from $128.0 million in 2017. The Company considers the calculated FD&A (as hereafter defined) costs in 2018 to be a good result considering it also increased its undeveloped land acreage in its core areas including the newer Montney plays located at Oak/Flatrock in BC and at Wembley/Pipestone in Alberta, and made significant infrastructure expenditures in 2018.

"FD&A cost per BOE" is a key performance indicator commonly used in the oil and gas industry. Readers are cautioned that these amounts may not be directly comparable to other companies, as the term "FD&A cost" does not have a standardized meaning under GAAP or NI 51-101 (refer to advisories under the heading of *"Non-GAAP Financial Measures and Other Key Performance Indicators"*).

The recycle ratio is a measure for evaluating the effectiveness of a company's re-investment program. The ratio measures the efficiency of capital investment. It accomplishes this by comparing the operating netback per BOE to the same period's reserve FD&A cost per BOE. With the purchase and construction of facilities and infrastructure in 2018 and 2017, along with land and asset acquisitions during the year, Kelt has positioned itself to achieve high efficiencies in production additions and finding and development costs over the upcoming years, as it continues to transition to development/pad drilling.

The following table outlines the calculation of the Company's 1P FD&A costs and 1P recycle ratio:

FINDING, DEVELOPMENT & ACQUISITION COSTS – 1P	Year ended December 31	
(CA$ thousands, except as otherwise noted)	**2018**	2017
Proved (1P) reserves:		
Total capital expenditures, net of dispositions (1)	**285,498**	127,977
Change in FDC costs required to develop 1P reserves	**95,548**	187,459
Total capital costs	**381,046**	315,436
1P Reserve additions, net (mBOE)	**35,297**	32,837
FD&A cost, before FDC ($/BOE)	**8.09**	3.90
1P FD&A cost, including FDC ($/BOE)	**10.80**	9.61
Operating netback ($/BOE) (2)	**20.56**	15.28
1P Recycle ratio	**1.9 x**	1.6 x

(1) Comprised of the Company's total exploration and development capital expenditures, as well as acquisitions, net of proceeds from dispositions. Refer to "*Capital Expenditures*" table in this MD&A.

(2) Kelt's "Operating netback" calculation is provided under the heading of "*Non-GAAP Financial Measures and Other Key Performance Indicators*".

The following table outlines the calculation of the Company's 2P FD&A costs and 2P recycle ratio:

FINDING, DEVELOPMENT & ACQUISITION COSTS – 2P	Year ended December 31	
(CA$ thousands, except as otherwise noted)	**2018**	2017
Proved plus probable (2P) reserves:		
Total capital expenditures, net of dispositions (1)	**285,498**	127,977
Change in FDC costs required to develop 2P reserves	**310,506**	215,976
Total capital costs	**596,004**	343,953
2P Reserve additions, net (mBOE)	**76,905**	49,592
FD&A cost, before FDC ($/BOE)	**3.71**	2.58
2P FD&A cost, including FDC ($/BOE)	**7.75**	6.94
Operating netback ($/BOE) (2)	**20.56**	15.28
2P Recycle ratio	**2.7 x**	2.2 x

(1) Comprised of the Company's total exploration and development capital expenditures, as well as acquisitions, net of proceeds from dispositions. Refer to "*Capital Expenditures*" table in this MD&A.

(2) Kelt's "Operating netback" calculation is provided under the heading of "*Non-GAAP Financial Measures and Other Key Performance Indicators*".

Kelt's 2018 capital investment program resulted in net reserve additions that replaced 2018 production by a factor of 3.6 times on a proved basis (2017 – 4.1 times) and 7.8 times on a proved plus probable basis (2017 – 6.2 times).

The tables below summarize production replacement for 2018:

PRODUCTION REPLACEMENT **TOTAL PROVED RESERVES**	Crude Oil (mbbls)	Liquids[1] (mbbls)	Natural Gas (mmcf)	Combined (mBOE)
Reserve additions, including revisions	2,561	10,410	133,963	**35,298**
2018 Production [2]	1,961	2,269	33,589	**9,828**
Production replacement ratio – 1P	**1.3 x**	**4.6 x**	**4.0 x**	**3.6 x**

(1) "Liquids" include field condensate and NGLs.

(2) Sulphur production of 29 MBOE has been excluded in the above tables.

PRODUCTION REPLACEMENT **TOTAL PROVED PLUS PROBABLE RESERVES**	Crude Oil (mbbls)	Liquids[1] (mbbls)	Natural Gas (mmcf)	Combined (mBOE)
Reserve additions, including revisions	4,275	27,014	273,701	**76,905**
2018 Production [2]	1,961	2,269	33,589	**9,828**
Production replacement ratio – 2P	**2.2 x**	**11.9 x**	**8.1 x**	**7.8 x**

(1) "Liquids" include field condensate and NGLs.

(2) Sulphur production of 29 MBOE has been excluded in the above tables.

NET ASSET VALUE

The Company estimates its net asset value to be $3.2 billion or $15.51 per common share as at December 31, 2018. The components of Kelt's net asset value calculation are set-forth in the table below. The reader is cautioned that these amounts may not be directly comparable to other companies, as the term "net asset value" does not have a standardized meaning under GAAP or NI 51-101. The net present value of petroleum and natural gas ("P&NG") reserves was determined by Sproule in their year-end evaluation reports, based on a discount rate of 10% before-tax. Undeveloped land at December 31, 2018 was internally valued at an average price of $455 per acre (2017 – $375 per acre). The Company's total decommissioning obligations, as determined in accordance with GAAP and as reported in the consolidated financial statements as of the calculation dates, were revalued using a discount rate of 10% to match the discount rate applied to value P&NG reserves. The net present value of decommissioning obligations reported in the table below is the amount incremental to abandonment and reclamation costs assigned for existing locations by Sproule, which are already reflected in the present value of P&NG reserves.

(CA$ thousands, except per share amounts)	**December 31, 2018**	December 31, 2017
Present value of 2P P&NG reserves, discounted at 10% before tax	**3,128,636**	2,111,574
Undeveloped land	**279,739**	239,118
Present value of decommissioning obligations	**(9,044)**	(12,815)
Net debt [4]	**(196,416)**	(136,729)
Proceeds from exercise of stock options [1]	**6,404**	60,361
Net asset value	**3,209,319**	2,261,509
Fully diluted common shares outstanding (000s) [1][2][3]	**206,978**	204,410
Net asset value ($ per common share)	**15.51**	11.06

(1) The calculation of proceeds from exercise of stock options and the fully diluted number of common shares outstanding only includes stock options that are "in-the-money" based on the closing price of Kelt common shares of $4.64 and $7.19 as at December 31, 2018 and 2017, respectively.

(2) For purposes of the net asset value calculation, the Company does not apply the treasury stock-method prescribed by GAAP. Rather, the fully diluted number of common shares outstanding is determined by adding the total number of outstanding RSUs and "in-the-money" stock options (1) to the number of common shares outstanding at the calculation date.

(3) The 5% convertible debentures that mature on May 31, 2021 are convertible to common shares at $5.50 per share. At the December 31, 2018 closing price of Kelt common shares of $4.64, the convertible debentures are not "in-the-money" and shares issuable upon conversion are not included in diluted common shares outstanding.

(4) Refer to advisories regarding non-GAAP financial measures and other key performance indicators.

CAPITAL RESOURCES AND LIQUIDITY

MARKET CAPITALIZATION

The Company's total capitalization was $1.3 billion as of December 31, 2018, down 22% from December 31, 2017. The market value of common shares, based on the closing share price on the TSX, represented 63% of the total capitalization.

The following table summarizes the Company's capitalization:

CAPITALIZATION	**As at December 31, 2018**		As at December 31, 2017		%
(CA$ thousands, except per share amounts)	**Amount**	**% of total**	Amount	% of total	change
Common shares outstanding (000s)	**184,003**		178,858		3
Share price (1)	**$4.64**		$7.19		-35
Capitalization of common shares	**853,774**	**63**	1,285,989	74	-34
Convertible debentures outstanding	**89,910**		90,000		-
Market price of Debentures (1)	**$110.73**		$150.00		-26
Capitalization of convertible debentures	**99,557**	**7**	135,000	8	-26
Market capitalization	**953,331**	**71**	1,420,989	82	-33
Net debt (2)	**196,416**	**15**	136,729	8	44
Decommissioning obligations	**143,763**	**11**	135,343	8	6
Deferred income tax liability	**53,606**	**3**	39,131	2	38
Total capitalization	**1,347,116**	**100**	1,732,192	100	-22

(1) Last price traded at in the year.

(2) Refer to advisories regarding non-GAAP financial measures and other key performance indicators.

As at December 31, 2018, the Company had $168.9 million of bank debt outstanding on its $250.0 million Credit Facility. Net debt was $196.4 million at December 31, 2018, representing 1.1 times 2018 annual adjusted funds from operations of $186.8 million. By comparison, net debt of $136.7 million at December 31, 2017 was 1.3 times 2017 annual adjusted funds from operations of $108.0 million.

LIQUIDITY

Kelt's capital management objective is to maintain a flexible capital structure and sufficient liquidity to allow the Company to execute on its capital investment program and strategic growth plan. The Company strives to actively manage its capital structure in response to changes in economic conditions and the risk characteristics of its underlying oil and natural gas assets. As at December 31, 2018, Kelt's capital structure was comprised of shareholders' capital, convertible debentures, bank debt and working capital.

The Company monitors its capital structure and short-term financing requirements using a net debt to trailing adjusted funds from operations ratio, which is a non-GAAP financial measure. Kelt targets a net debt to trailing adjusted funds from operations ratio of less than 2.0 times.

The capital intensive nature of Kelt's operations may result in increases to bank debt or working capital deficiency during periods with high levels of capital investment. For the year ended 2018 the Company's capital expenditures of $285.5 million were in excess of the Company's funds from operations of $186.8 million and net proceeds from the flow-through private placement of $24.1 million. As a result, Kelt's net debt increased to $196.4 million at December 31, 2018 from $136.7 million at December 31, 2017. The increase in net debt was broadly in alignment with an increase in funds from operations due to increased production and higher commodity prices, resulting in a net debt to trailing adjusted funds from operations ratio increasing only slightly to 1.1 times as at December 31, 2018 from 1.0 times as at December 31, 2017.

	December 31, 2018	December 31, 2017
Bank debt	**168,881**	91,465
Working capital deficiency	**27,535**	45,264
Net debt (1)	**196,416**	136,729
Trailing annualized fourth quarter adjusted funds from operations (2)(3)	**186,839**	131,592
Net debt to trailing adjusted funds from operations ratio (1)	**1.1**	1.0

(1) Refer to advisories regarding non-GAAP financial measures and other key performance indicators.

(2) Adjusted funds from operations is a non-GAAP financial measure which is calculated as cash provided by operating activities before changes in non-cash operating working capital, and adding back (if applicable): transaction costs, provisions for potential credit losses, and settlement of decommissioning obligations.

(3) Trailing adjusted funds from operations is annualized based on the most recent quarter's adjusted funds from operations.

The Company targets to maintain sufficient unused bank credit lines to satisfy working capital deficiencies. As at December 31, 2018, the Company's working capital deficit of $27.5 million combined with outstanding bank debt of $168.9 million, represented 79% of the authorized borrowing amount available under the credit facility of $250.0 million.

Future capital expenditures are expected to be funded through a combination of cash flow from operations and bank debt, and may be supplemented by new equity or debt offerings.

CREDIT FACILITY

The Company has a revolving committed term credit facility of $250 million ("the Credit Facility") with a syndicate of financial institutions. On April 18, 2018 the facility was amended and the revolving period was extended to April 28, 2019 with a 364 day term-out period if not renewed. On November 8, 2018 the facility was further amended to provide for various changes. The pricing grid ranges to bank prime plus 0.5% to bank prime plus 2.5% and the stamping fee range is 1.5% to 3.5% depending upon the Company's then current debt to EBITDA ratio of between less than one half times to greater than three times. Refer to information in note 7 of the consolidated annual financial statements.

There are no financial covenants under the Credit Facility and Kelt is in compliance with all other covenants. The Credit Facility is subject to semi-annual borrowing base reviews, occurring approximately in April and October of each year.

CONVERTIBLE DEBENTURES

At December 31, 2018, the Company has $89.9 million of convertible unsecured subordinated debentures outstanding (the "Debentures"). The Debentures mature on May 31, 2021 (the "Maturity Date") and bear interest at 5.0% per annum payable semi-annually on May 31st and November 30th. At the holder's option, the Debentures may be converted into common shares of the Company at any time prior to the close of business on the earlier of the business day immediately preceding (i) the Maturity Date, (ii) if called for redemption, the date fixed for redemption by the Company, or (iii) if called for repurchase in the event of a change of control, the payment date, at a conversion price of $5.50 per share (the "Conversion Price"), being a conversion rate of approximately 181.8182 common shares per $1,000 principal amount of Debentures, subject to adjustment in certain circumstances.

The Debentures trade on the TSX under the symbol "KEL.DB". As at December 31, 2018, the Debentures are not "in-the-money" based on the closing price of Kelt common shares on the TSX of $4.64, on the last trading day in the quarter. As at December 31, 2018, the fair value of the Debentures was $99.6 million (2017 - $135 million) based on the closing market price of $110.73 per Debenture, being the price at which the Debentures last traded in the fourth quarter.

The Debentures are redeemable by the Company after May 31, 2019 and prior to May 31, 2020, in whole or in part, on not more than 60 days and not less than 40 days prior notice at a redemption price equal to their principal amount plus accrued and unpaid interest provided that the volume weighted average trading price of the common shares on the TSX for the 20 consecutive trading days ended five trading days (the "Current Market Price") prior to the date on which notice of redemption is provided is at least 125% of the Conversion Price. On or after May 31, 2020 and prior to the Maturity Date, the Debentures may be redeemed by the Company, in whole or in part on not more than 60 days and not less than 40 days prior notice at a redemption price equal to their principal amount plus accrued and unpaid interest.

The Company may elect to satisfy its obligation to repay all or any portion of the principal amount of the Debentures upon redemption or at maturity, by issuing common shares instead of cash (subject to the receipt of any required regulatory approvals and provided that no event of default has occurred). The number of common shares to be issued would be obtained by dividing the principal amount of the Debentures by 95% of the Current Market Price on the date fixed for redemption or maturity.

The following table outlines Kelt's Debenture trading activity during 2018 and 2017:

DEBENTURE TRADING ACTIVITY (KEL.DB)	**YTD 2018**	YTD 2017
High ($)	**186.05**	155.35
Low ($)	**106.00**	133.51
Close ($)	**110.73**	150.00
Volume traded (number of Debentures)	**63,200**	169,690
Value of Debentures traded ($ thousands)	**9,778**	24,757
Weighted average trading price ($)	**154.71**	145.89

SHARE INFORMATION

The Company is authorized to issue an unlimited number of common shares and an unlimited number of preferred shares. As at December 31, 2018 there were 184.0 million common shares issued and outstanding. There are no preferred shares issued or outstanding.

The Company's common shares trade on the TSX under the symbol "KEL". During the year ended December 31, 2018, 217.9 million common shares traded on the TSX at a weighted average price of $7.10 per common share. In the comparative period, 192.3 million common shares traded on the TSX at a weighted average price of $6.66 per common share.

As at December 31, 2018, officers, directors, and employees have been granted options to purchase 9.8 million common shares of the Company at an average exercise price of $6.20 per common share. In addition, there are 1.1 million RSUs outstanding. Options and RSUs outstanding at December 31, 2018 represented 6% of total common shares issued and outstanding. Additional information regarding the Company's stock options and RSUs is included in note 10 of the consolidated annual financial statements.

The following table outlines Kelt's common share trading activity during 2018 and 2017:

SHARE TRADING ACTIVITY (KEL)	**YTD 2018**	YTD 2017
High ($)	**10.01**	7.70
Low ($)	**3.97**	5.56
Close ($)	**4.64**	7.19
Volume traded (thousands)	**217,872**	192,255
Value traded ($ thousands)	**1,546,138**	1,281,353
Weighted average trading price ($)	**7.10**	6.66

COMMITMENTS AND CONTRACTUAL OBLIGATIONS

As of December 31, 2018, the Company is committed to future payments under the following agreements:

(CA$ thousands)	2019	2020	2021	2022	2023	Thereafter
Operating lease - office buildings	973	1,043	1,064	1,085	379	-
Operating lease - vehicles	470	322	154	-	-	-
Firm processing commitments (1)	13,278	13,386	19,481	20,429	19,073	106,952
Firm transportation commitments (2)	43,922	27,332	23,246	22,717	19,784	161,863
Total annual commitments	**58,643**	**42,083**	**43,945**	**44,231**	**39,236**	**268,815**

(1) Includes gas gathering related to the Company's firm processing commitments

(2) A portion of Kelt's commitments on the Alliance pipeline are denominated in US dollars. The volumes committed vary over the term of the contracts, which is effective until October 31, 2020. Amounts are translated to Canadian dollars at the spot rate on December 31, 2018 of CA$/US$1.3642.

Payments under the office building operating leases relate to the Company's head office in Calgary, Alberta, and field offices in Grande Prairie, Alberta and Fort St. John, British Columbia. The leases expire on April 30, 2023, February 28, 2020, and July 31, 2023, respectively, if not extended.

During 2018 firm transportation and processing commitments increased by $357 million primarily due to take or pay commitments on the North Montney Mainline, a firm processing agreement for 30 mmcf per day of raw gas over a 10 year term, and a firm processing agreement of 75 mmcf per day under a 10 year term.

RELATED PARTY TRANSACTIONS

A director of the Company is also a partner at a law firm which Kelt has engaged to provide legal services. During the year ended December 31, 2018, the Company incurred $0.4 million (2017 – $0.3 million) in legal fees and disbursements.

OFF-BALANCE SHEET TRANSACTIONS

The Company did not engage in any off-balance sheet transactions during the periods ended December 31, 2018 and 2017.

SUMMARY OF QUARTERLY RESULTS

The following tables summarize the Company's financial and operating results over the past eight quarters:

(CA$ thousands, except as otherwise indicated)	**Q4 2018**	Q3 2018	Q2 2018	Q1 2018
Petroleum and natural gas revenue, before royalties	**100,350**	100,219	98,715	89,993
Cash provided by operating activities	**63,656**	29,881	39,183	53,663
Adjusted funds from operations (1)	**47,140**	46,876	47,099	45,724
Per share – basic ($/common share) (1)	**0.26**	0.25	0.26	0.25
Per share – diluted ($/common share) (1)	**0.26**	0.25	0.25	0.25
Profit (loss) and comprehensive income (loss)	**2,843**	3,246	1,702	(23)
Per share – basic ($/common share)	**0.02**	0.02	0.01	-
Per share – diluted ($/common share)	**0.02**	0.02	0.01	-
Total capital expenditures, net of dispositions	**70,332**	68,427	54,702	92,037
Total assets	**1,423,521**	1,378,114	1,346,701	1,337,688
Net debt (1)	**196,416**	176,046	157,058	173,587
Convertible debentures	**78,390**	77,350	76,348	75,443
Shareholders' equity	**893,796**	889,275	882,916	857,019
Average daily production (BOE/d)	**28,711**	26,204	26,120	26,978
Average realized price ($/BOE) (1)(2)	**34.71**	37.74	38.51	36.07
Operating netback ($/BOE) (1)	**19.39**	20.93	21.57	20.47
Operating netback % of average realized price (2)	**56%**	55%	56%	57%

	Q4 2017	Q3 2017	Q2 2017	Q1 2017
Petroleum and natural gas revenue, before royalties	80,838	56,422	60,072	60,225
Cash provided (used in) by operating activities	36,458	24,394	28,480	25,890
Adjusted funds from operations (1)	32,898	22,957	25,333	26,823
Per share – basic ($/common share) (1)	0.18	0.13	0.14	0.15
Per share – diluted ($/common share) (1)	0.18	0.13	0.14	0.15
Profit (loss) and comprehensive income (loss)	(5,389)	(10,653)	(4,869)	(2,267)
Per share – basic ($/common share)	(0.03)	(0.06)	(0.03)	(0.01)
Per share – diluted ($/common share)	(0.03)	(0.06)	(0.03)	(0.01)
Total capital expenditures, net of dispositions	55,778	75,933	31,630	(35,364)
Total assets	1,276,567	1,227,962	1,203,174	1,193,644
Net debt (1)	136,729	134,759	80,618	75,765
Convertible debentures	74,517	73,584	72,685	71,810
Shareholders' equity	845,701	830,344	839,485	842,351
Average daily production (BOE/d)	25,063	22,510	20,684	20,204
Average realized price ($/BOE) (1)(2)	33.42	27.26	31.70	33.13
Operating netback ($/BOE) (1)	16.18	12.86	15.49	16.63
Operating netback as a % of average realized price (2)	48%	47%	49%	50%

(1) Refer to advisories regarding non-GAAP financial measures and other key performance indicators.

(2) In this table, average realized prices are after financial instruments.

In the five years since commencing active operations in 2013, Kelt has grown production from approximately 3,500 BOE per day to over 28,000 BOE per day in the fourth quarter of 2018. Production has increased significantly in 2017 and 2018 as the Company executed on an active and successful Montney drilling program in the Company's core British Columbia and Alberta areas.

In the second half of 2014, global crude oil prices began a precipitous decline that subsequently resulted in massive cutbacks in capital spending on energy projects worldwide. After averaging US$93.00 per barrel in 2014, WTI oil prices averaged US$48.80 per barrel in 2015 and bottomed with a low average price of US$33.45 per barrel during the first quarter of 2016. A positive momentum for global crude oil prices commenced in November 2016 when OPEC and certain non-OPEC countries agreed to cut oil production, which led to a slow balancing of global oil demand and supply. During the first nine months of 2018, a balancing of global oil supply and demand, heighted geopolitical risks, combined with a risk of future oil demand growth outpacing supply growth resulted in oil prices in WTI reaching its highest monthly level at US$70.98 per barrel in July 2018. In the fourth quarter of 2018, prices retracted to a monthly low in December 2018 of US$49.52 per barrel as global trade tensions reduced forecasted oil demand and placed downward pressure on oil prices. In the domestic market, international access constraints due to capacity issues on Canadian pipelines in the fourth quarter of 2018 resulted in a significant widening of price differentials for Canadian crude oil compared to international benchmark prices. This differential narrowed back to historical levels by the end of December as the Government of Alberta announced mandated province wide crude oil curtailments for major Alberta oil producers.

The recovery of oil prices and the increase in the Company's average oil production weighting, taken together with higher average production, drove the significant increase in revenues, cash provided by operating activities, and operating netbacks during the year ended 2018. The decrease in oil revenues in the fourth quarter of 2018 was offset by higher natural gas revenues as a result of Kelt's market diversification strategy which was introduced in 2017 and was further advanced in 2018.

Refer to the *"Financial and Operating Summary"* section of this MD&A for further discussion. Additional information relating to Kelt, including the Company's MD&A for previous quarters, is filed on SEDAR and can be viewed at www.sedar.com.

SELECTED ANNUAL INFORMATION

The following table summarizes key annual financial and operating information over the three most recently completed financial years.

(CA$ thousands, except as otherwise indicated)	**2018**	2017	2016
Petroleum and natural gas revenue, before royalties	**389,277**	257,557	184,613
Cash provided by operating activities	**186,383**	115,222	44,720
Adjusted funds from operations (1)	**186,839**	108,011	58,380
Per share – basic ($/common share)	**1.02**	0.61	0.34
Per share – diluted ($/common share)	**1.01**	0.61	0.34
Profit (loss) and comprehensive income (loss)	**8,154**	(23,178)	(49,774)
Per share – basic ($/common share)	**0.04**	(0.13)	(0.29)
Per share – diluted ($/common share)	**0.04**	(0.13)	(0.29)
Total capital expenditures, net of dispositions	**285,498**	127,977	98,268
Total assets	**1,423,521**	1,276,567	1,255,958
Net debt (1)	**196,416**	136,729	138,042
Convertible debentures	**78,390**	74,517	70,978
Shareholders' equity	**893,796**	845,701	843,301
Average daily production (BOE/d)	**27,006**	22,130	20,947
Average realized price ($/BOE) (1)(2)	**36.70**	31.38	24.10
Operating netback ($/BOE) (1)	**20.56**	15.28	9.87
Operating netback as a % of average realized price (2)	**56%**	49%	41%

(1) Refer to advisories regarding non-GAAP financial measures and other key performance indicators.

(2) In this table, average realized prices are after financial instruments.

CHANGES IN ACCOUNTING POLICIES

Revenue

Kelt adopted IFRS 15 *Revenue* from contracts with customers with a date of initial application of January 1, 2018. IFRS 15 will replace IAS 18 *Revenue*, IAS 11 *Construction Contracts*, and other related interpretations. Kelt used the modified retrospective approach to adopt the new standard, electing to use a practical expedient to apply the standard retrospectively only to contracts that were not completed contracts on January 1, 2017. There was no change or adjustment to the Company's consolidated Financial Statements as a result of the adoption of IFRS 15. However IFRS 15 contains additional disclosure requirements which are detailed in note 13 of the consolidated annual financial statements.

Kelt recognizes revenue at a point in time when control of the product has been transferred to the customer and performance obligations have been satisfied. This is generally met when the customer obtains legal title to the product and physical delivery at a delivery point has taken place. Revenue is measured based on the consideration specified in the contracts the Company has with its customers.

The Company applies a practical expedient and does not disclose quantitative or qualitative information on remaining performance obligations that have an original duration of one year or less. Kelt also applies a practical expedient that allows any incremental costs of obtaining contracts with customer to be recognized as an expense when incurred rather than being capitalized.

In the prior year, under IAS 18, revenue from the sale of oil and natural gas was recorded when the significant risks and rewards of ownership of the product were transferred to the buyer which was usually when legal title passes to the external party and collectability was reasonably assured. This was generally at the time product enters the pipeline.

Kelt evaluates its arrangements with 3rd parties and partners to determine if a principal or agent relationship exists. In making this evaluation, management considers if it maintains control of the product, which is indicated by the Company having the primary responsibility for the delivery of the product, having the ability to establish prices or having inventory risk. If an agency relationship exists, then the revenue is recognized on a net-basis, only reflecting the fee, if any, realized by the party from the transaction.

Royalty income is recognized as it accrues in accordance with the terms of the overriding royalty agreements.

Investments in Securities

Investments in securities are classified as fair value through profit or loss. Investments in the securities of private entities are carried at fair value, which is estimated using values based on equity issuances and other indications of value from time-to-time (level three fair value hierarchy estimates).

ACCOUNTING STANDARDS ISSUED BUT NOT YET EFFECTIVE

IFRS 16 *Leases,* is intended to replace IAS 17 and will bring fundamental changes for all companies, including Kelt, who lease assets. The new standard is effective for annual reporting periods beginning on or after January 1, 2019, with early application permitted. The most significant financial reporting impacts of the changes include: all leases will be on the balance sheet of lessees, except those that meet the limited exception criteria; the measurement and presentation of expenses will be impacted and replaced by the recording of depreciation and financing expenses; the amount of profit (loss) recognized in a period will likely change as the timing of expenses is accelerated when applying the new standard which uses a finance lease model compared to a straight line operating lease expense; and key ratios may be impacted with the introduction of lease assets and liabilities on the balance sheet and changes to the timing of expenses. Management is currently in the implementation phase of IFRS 16, with the impact on the Company's consolidated financial statements still being assessed; however the additional leases being brought on the balance sheet will likely be material.

SIGNIFICANT JUDGMENTS AND ESTIMATES

The significant accounting policies applied by the Company are disclosed in note 3 of the consolidated annual financial statements as at and for the year ended December 31, 2018. The timely preparation of the financial statements requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amount of assets, liabilities, income and expenses. Actual results may differ materially from these estimates. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are reviewed and for any future years affected. Significant judgments, estimates and assumptions made by management in these financial statements are discussed below.

Depletion, depreciation and reserves

The Company calculates depletion based on total proved reserves as determined in accordance with the Canadian Oil and Gas Evaluation Handbook ("COGEH"). The process of determining reserves is complex. Significant judgments are based on available geological, geophysical, engineering, and economic data. These judgments are based on estimates and assumptions that may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates are based on production forecasts, prices and economic conditions. As circumstances change and additional data becomes available, reserve estimates also change. Estimates made are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and governmental restrictions.

Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation can be impacted by subjective decisions, new geological or production information and a changing environment. In addition, revisions to reserve estimates can arise from changes in forecast oil and gas prices and reservoir performance. Such revisions can be either positive or negative.

Changes in reserve estimates impact the financial results of the Company as reserves and estimated future development costs are used to calculate depletion. Reserves are used in measuring the fair value less costs of disposal ("FVLCD") of property, plant and equipment for impairment calculations and for determining the fair value of PP&E acquired in a business combination. Reserves also impact the Company's assessment of the commercial viability and technical feasibility of an exploration project and the decision to transfer exploration and evaluation assets to PP&E.

Exploration and evaluation assets

Judgment is required to determine the level at which E&E is assessed for impairment. For Kelt, the carrying value of E&E assets is assessed for overall impairment at the operating segment level and on a specific identification basis prior to transferring E&E assets to PP&E. The decision to transfer assets from E&E to PP&E requires judgment as it is based on estimated proved reserves, which are used, in part, to determine a project's technical feasibility and commercial viability.

Determination of Cash Generating Units ("CGUs")

The determination of CGUs requires judgment in defining a group of assets that generate cash inflows that are largely independent of the cash inflows from other assets or groups of assets. CGUs are determined by similar geological structure, shared infrastructure, geographical proximity, commodity type, similar exposure to market risks and materiality. As at December 31, 2018, the Company has one CGU for its assets located in the province of British Columbia and two CGUs for its assets located in the province of Alberta. Refer to additional information regarding the disposition of non-core Alberta assets under the heading of "*Property acquisition and disposition*" in this MD&A and in note 4 of the consolidated financial statements for details

Impairment of non-financial assets

Significant judgment is required to assess the Company's non-financial assets, namely E&E and PP&E, for impairment or potential reversals of previously recorded impairment. Management must first determine whether indicators of impairment exist that suggest the carrying value may not be recoverable through the asset's continued use or sale. In addition, judgment is required to assess whether a previously recognized impairment for an asset (other than goodwill) no longer exists or has decreased.

Significant judgment and estimates are required to calculate the recoverable amount of PP&E and goodwill in an impairment test. Management calculates the recoverable amount of each CGU based on its FVLCD, using an after-tax discounted cash flow analysis derived from proved plus probable reserves. Reserve estimates and expected future cash flows from production of reserves are subject to measurement uncertainty as discussed above and are subject to variability due to changes in forecasted commodity prices. In addition, the present value of forecast future cash flows is highly sensitive to the discount rate. Judgment is required to determine an appropriate discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. Refer to information under the heading of "*Depletion, depreciation and impairment*" in this MD&A (and in note 6 of the consolidated annual financial statements) for a discussion of the specific estimates and assumptions applied in the calculation of the recoverable amount.

Business combinations

Business combinations are accounted for using the acquisition method of accounting. The determination of fair value often requires management to make assumptions and estimates about future events. The assumptions and estimates with respect to determining the fair value of exploration and evaluation assets and property, plant and equipment acquired generally require significant judgment and include estimates of reserves acquired, forecast benchmark commodity prices and discount rates. Assumptions are also required to determine the fair value of decommissioning obligations associated with the properties. Changes in any of these assumptions or estimates used in determining the fair value of acquired assets and liabilities could impact the amounts assigned to assets, liabilities and goodwill (or gain from a bargain purchase) in the acquisition equation. Future profit (loss) can be affected as a result of changes in future depletion and depreciation or impairment. Refer to additional information regarding business combinations completed during the years ended December 31, 2018 and 2017 under the heading of "*Capital expenditures*" of this MD&A and in note 4 of the consolidated annual financial statements.

Decommissioning obligations

The Company estimates the decommissioning obligations for oil and gas wells and their associated production facilities and infrastructure. In most instances, dismantling of assets and remediation occurs many years into the future. The value of the ultimate decommissioning obligation can fluctuate in response to many factors including changes to relevant legal requirements, the emergence of new restoration techniques, experience at other production sites, and changes to the risk-free discount rate. The expected timing and amount of expenditure can also change, for example, in response to changes in reserves or changes in laws and regulations or their interpretation. Judgments include the most appropriate discount rate to use, which management has determined to be a risk-free rate. Key assumptions are disclosed in note 9 of the consolidated annual financial statements.

Kelt estimates abandonment and reclamation costs based on a combination of publically available industry benchmarks and internal site specific information. For producing wells and facilities, the expected timing of settlement is estimated based on the proved plus probable period to abandonment for each field, as per the independent reserve report. For non-producing wells, the expected timing of settlement is estimated to be half of the period applied to producing wells in that field, unless the timing to abandon and reclaim a specific well site or facility is known based on budgeted expenditures.

Deferred income taxes

The Company follows the liability method for calculating deferred income taxes. Tax interpretations, regulations and legislation in the jurisdictions in which the Company operates are subject to change. As such, deferred income taxes are subject to measurement uncertainty. The provision for deferred income taxes also includes the following significant judgments of management:

• Deferred income tax assets are assessed by management at the end of the reporting period to determine the likelihood that they will be realized from future taxable earnings. The deferred tax liability reported in the Consolidated Statement of Financial Position is presented net of offsetting deferred income tax assets. The Company's non-capital losses expire in years 2023 to 2037. Management believes that Kelt and Kelt LNG will have sufficient taxable income in the future in order to utilize the non-capital losses and has concluded that recognition of the associated deferred income tax assets is appropriate;

• Classification of intangible drilling and completion costs as Canadian exploration expenses ("CEE") or Canadian development expenses ("CDE") – CEE is deductible at a rate of 100% per year, whereas CDE may be deducted on a declining basis at 30% per year. Accordingly, the allocation of resource deductions will impact the period in which Kelt may become taxable in the future. In addition, the designation of certain expenditures as CEE and/or CDE impacts the Company's ability to satisfy its flow-through share obligations; and

• Recognition of unrecognized deferred income tax asset – per IAS 12, deferred income taxes are not initially recognized on transactions that are not business combinations. The Company did not initially recognize a deferred income tax asset of $14.4 million that arose on the spin-out certain assets from Celtic Exploration Ltd. ("Celtic") at Kelt's inception on February 26, 2013. The initially unrecognized deferred tax asset is now being amortized at a rate of 2.5% per quarter, which management believes is a reasonable estimate as it reflects the weighted average depletion rate of the properties at the time of the spin-out and is aligned with Kelt's corporate average depletion rate.

Share based compensation

The Company uses the fair value method of accounting for its long-term incentive plans, which include an Incentive Stock Option Plan and a Restricted Share Unit Plan. Judgments include which valuation model is most appropriate for the grant of the award to estimate its fair value. Estimates and assumptions are then used in the valuation model to determine fair value.

For stock options, the Company uses the Black-Scholes option pricing model which requires that management make assumptions for the expected life of the option, the anticipated volatility of the share price over the life of the option, the risk-free interest rate for the life of the option, and the number of options that will ultimately vest. The assumptions used by the Company are discussed in note 10 of these financial statements.

The fair value of restricted share units is estimated based on the volume weighted average trading price ("VWAP") on the TSX over three trading days immediately prior to the date of grant. Judgment is also required to estimate the number of restricted share units that will ultimately vest, in other words, the rate of forfeiture. The assumptions used by the Company are discussed in note 10 of these financial statements.

Flow-through shares

There is no IFRS guidance that specifically addresses accounting for flow-through shares, therefore the Company is required to develop an accounting policy. Consistent with prior years, and as set-forth in note 3 of the consolidated annual financial statements, the Company has applied the residual method. Under this method, judgement is required to determine of the fair value of ordinary shares. Typically, it is based on the share price at the time the parties agree to the transaction. In situations where flow-through shares are issued concurrent with an ordinary common share offering, the difference in subscription prices is used to value the premium. Otherwise, the Company uses the VWAP of KEL common shares for the five trading days immediately preceding the date of the binding agreement, to value the ordinary common shares.

Judgment is also required to determine when the Company has fulfilled its obligation to pass on the tax deduction to investors, at which time, the premium on flow-through shares is recognized in income. The Company deems the obligation to have been fulfilled in the period that eligible expenditures are incurred, regardless of the period in which the tax deductions are legally renounced. This is based on the view that the renunciation is perfunctory and that the accounting should be reflected when the expenditure is made.

DISCLOSURE CONTROLS AND PROCEDURES

The Chief Executive Officer ("CEO") and the Chief Financial Officer ("CFO") have designed, or caused to be designed under their supervision, disclosure controls and procedures as defined in National Instrument 52-109 of the Canadian Securities Administrators, to provide reasonable assurance that: (i) material information relating to the Company is made known to the CEO and the CFO by others, particularly during the period in which the annual and interim filings are being prepared; and (ii) 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 securities legislation.

The CEO and the CFO have evaluated the effectiveness of Kelt's disclosure controls and procedures as at December

31, 2018 and have concluded that such disclosure controls and procedures are effective. The assessment was based on the framework in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

INTERNAL CONTROLS OVER FINANCIAL REPORTING

The CEO and the CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting as defined in National Instrument 52-109 of the Canadian Securities Administrators, 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.

There were no changes to the Company's internal controls over financial reporting during the interim period from October 1, 2018 to December 31, 2018. The CEO and the CFO have evaluated the effectiveness of Kelt's internal controls over financial reporting as at December 31, 2018 and have concluded that such internal controls over financial reporting are effective. The assessment was based on the framework in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Due to its inherent limitations, internal controls over financial reporting may not prevent or detect misstatements. In addition, projections of any evaluation relating to the effectiveness in future periods are subject to the risk that controls may become inadequate as a result of changes in conditions, or that the degree of compliance with policies and procedures may deteriorate.

BUSINESS RISKS

The Company is exposed to various operational and financial risks inherent in the exploration, development, production and marketing of crude oil, NGLs and natural gas liquids. These inherent risks include, but are not limited to, the following:

- The ability to find, produce and replace reserves at a reasonable cost, including the risk of reserve revisions due to economic and technical factors. Reserve revisions can have a positive or negative impact on asset valuations, ARO, lending capacity and depletion rates;
- Reservoir quality and the uncertainty of reserves estimates;
- Volatility in the prevailing prices of crude oil, NGLs and natural gas;
- Regulatory risk related to the approval for exploration and development activities, which can add to costs or cause delays in projects;
- Labour risk to complete projects in a timely and cost efficient manner;
- Operating hazards inherent in the exploration, development, production and sale of crude oil and natural gas;
- Credit risk related to non-payment for sales contracts or other counterparties;
- Interest rate risk associated with the Company's ability to ability to secure financing on commercially acceptable terms;
- Foreign exchange risk as commodity sales are predominantly based on US dollar denominated benchmarks;
- Business interruptions because of unexpected events such as fires or explosions whether caused by human error or nature, severe storms and other calamitous acts of nature, blowouts, freeze-ups, mechanical or equipment failures of facilities and infrastructure and other similar events affecting the Company or other parties whose operations or assets directly or indirectly impact the Company and that may or may not be financially recoverable;
- Geopolitical risks associated with changing governments or governmental policies, social instability and other political, economic or diplomatic developments in the regions where the Company has its operations;

- Environmental impact risk associated with exploration and development activities, including GHG;
- Future legislative and regulatory developments related to environmental regulation;
- Potential actions of governments, regulatory authorities and other stakeholders that may result in costs or restrictions in the jurisdictions where the Company has operations;
- Changing royalty regimes;
- The ability to secure adequate transportation for products which could be affected by pipeline constraints, the construction by third parties of new or expansion of existing pipeline capacity and other factors;
- The access to markets for the Company's products;
- The risk of significant interruption or failure of the Company's information technology systems and related data and control systems or a significant breach that could adversely affect the Company's operations.

The Company uses a variety of means to help mitigate or minimize these risks. The Company maintains a comprehensive insurance program to reduce risk. Operational control is enhanced by focusing on large core areas with high working interests and operatorship of drilling and completion operations. Product mix is diversified between natural gas, NGLs and oil which reduces price risk in certain market conditions. Accounts receivable from the sale of crude oil and natural gas are mainly with customers in the crude oil and natural gas industry and are subject to normal industry credit risks. The Company manages these risks by monitoring exposure to individual customers, contractors, suppliers and joint venture partners on a regular basis and when appropriate, ensuring parental guarantees or letters of credit are in place, and as applicable, taking other mitigating actions to minimize the impact in the event of a default. The Company is exposed to possible losses in the event of non-performance by counterparties to derivative financial instruments; however, the Company manages this credit risk by entering into agreements with counterparties that are substantially all investment grade financial institutions. The Company has implemented cyber security protocols and procedures to reduce the risk of failure or a significant breach of the Company's information technology systems and related data and control systems. The Company's capital structure mix is also monitored on a continual basis to ensure that it optimizes flexibility, minimizes cost and offers the greatest opportunity for growth. This includes the determination of a reasonable level of debt and any interest rate exposure risk that may exist.

A more detailed description of the Company's risks is included in the Annual Information Form as at December 31, 2018, dated March 6, 2019 which can be found at www.sedar.com.

BUSINESS OUTLOOK

CURRENT ECONOMIC ENVIRONMENT

The current economic environment in the energy industry remains volatile despite a 28% increase in WTI (US$/bbl) from 2017. Bottlenecks in the Canadian crude oil pipeline network have resulted in oversupply in the Canadian market and a significant widening of the Canadian light and heavy crude differentials in the fourth quarter as compared to US benchmark prices. There are a number of factors that are expected to narrow price discounts over time including an increase in crude delivered by rail, government mandated production curtailments, the restarting of Midwest refineries currently offline for seasonal maintenance and new pipeline capacity.

Natural gas infrastructure and capacity constraints have continued to impact realized natural gas prices in domestic western Canadian markets relative to other North American markets. Kelt has taken measures to diversify its gas sales markets in order to mitigate the effect of low prices in Alberta and British Columbia. U.S. natural gas storage continues to be well below the five-year average however, the price impact has been muted due to the significant natural gas supply growth in 2018.

In the current business environment, Kelt continues to focus on maintaining a strong balance sheet, giving the Company the ability to take advantage of opportunities as they arise. The Company's capital expenditure program is also flexible, with the ability to defer expenditures into the future if the current economic environment deteriorates rapidly. Kelt continues to be optimistic about the long-term outlook for oil and gas commodity prices.

OUTLOOK AND GUIDANCE

Kelt expects to drill 33.0 gross (33.0 net) wells and complete 36.0 gross (36.0 net) wells. All of the Company's 2019 drilling is expected to target the Montney formation with 20.0 net wells planned at Inga/Fireweed, 7.0 net wells at Wembley, 4.0 net wells at Oak and 1 net well at each of Stoddart and Progress. Facility expenditures are expected to decrease by 49% in 2019 to $60.0 million as there is no major facility expenditures planned for 2019. Approximately $30.0 million of capital expenditures that is currently included in the previously announced guidance may be deferred to 2020 if realized commodity prices in 2019 are significantly lower than currently forecasted.

Forecasted average production for 2019 is estimated to be between 33,500 BOE/d to 34,500 BOE/d, representing an increase of 23% - 24% from 2018. It is estimated that production will be weighted approximately 47% to oil and NGLs and 53% to natural gas.

WTI crude oil prices are forecasted to average US$67.50 in 2019 and Mixed Sweet Blend Edmonton is forecasted to average $66.97/bbl. Natural gas prices are forecast to average $1.94CAD/GJ for AECO and $3.00 USD/mmbtu for NYMEX. After taking in account its marketing arrangements, Kelt expects to realize a natural gas price of $3.28/mcf in 2019 which is a premium to AECO of 60%.

The Company is forecasting 2019 funds from operations of $240.0 million and $1.23 per common share, diluted. Net debt is estimated to be $225.0 million at December 31, 2019 representing a Net Debt to Funds Flow from Operations ratio of 0.9X.

The table below outlines the Company's forecast assumptions and financial and operating results for 2019 with a comparison to 2018:

(CA$ millions, except as otherwise indicated)	**2019 Budget**	**2018 Actuals**	**% Change**
Average Production			
Oil and NGLs (bbls/d)	**15,500 – 16,400**	**11,589**	**34% - 42%**
Gas (mmcf/d)	**105.0 – 112.0**	**92,502**	**14% - 21%**
Combined (BOE/d)	**33,500 – 34,500**	**27,006**	**24% - 28%**
Production per million common shares (BOE/d)	**174 - 179**	**148**	**18% - 21%**
Forecasted Average Commodity Prices			
WTI oil price (US$/bbl)	**67.50**	**65.03**	**4%**
Mixed Sweet Blend Edmonton ($/bbl)	**66.97**	**69.29**	**-3%**
NYMEX natural gas price (US$/MMBTU)	**3.00**	**3.04**	**-1%**
AECO natural gas price (US$/MMBTU)	**1.60**	**1.40**	**14%**
Average Exchange Rate (US$/CA$)	**0.781**	**0.772**	**1%**
Revenue	**473.9**	**389.3**	**22%**
Operating income	**261.5**	**202.6**	**29%**
Adjusted funds from operations	**240.0**	**186.8**	**28%**
Per share – diluted ($/share)	**1.23**	**1.01**	**22%**
Capital Expenditures			
Drilling & completions	**201.0**	**168.7**	**19%**
Facilities, pipeline & well equipment	**60.0**	**117.7**	**-49%**
Land, seismic & property acquisitions	**9.0**	**9.2**	**-2%**
Property dispositions	**-**	**(10.1)**	**-100%**
Net Capital Expenditures	**270.0**	**285.5**	**-5%**

(CA$ millions, except as otherwise indicated)	**2019 Budget**	**2018 Actuals**	**% Change**
Net debt, at year-end [1]	**225.0**	**196.4**	15%
Net debt to trailing annual funds from operations ratio	**0.9 x**	**1.1 x**	-18%
Weighted average common shares outstanding (millions) [1]	**192.4**	**182.6**	5%
Common shares issued and outstanding (millions) [1]	**200.5**	**184.4**	9%
2019 Funds Flow from Operations Sensitivities:			
Oil price minus 10%	**(24.1)**		
NGLs price minus 10%	**(4.5)**		
Natural gas price minus 10%	**(13.8)**		
CAD/USD minus $0.05	**(15.3)**		

The table below outlines the Company's forecasted pro-forma for 2019 and the comparative to the previously announced 2019 budget included in Kelt's press release dated November 9, 2018.

The pro-forma assumes that the Company does not spend $40.0 million of capital expenditures which would be deferred to 2019 if commodity prices in 2019 are significantly lower than currently forecasted. WTI crude oil prices are forecasted in the pro-forma to average US$55.00 in 2019. The Company's funds from operations is forecasted in the pro-forma of $220.0 million and $1.13 per common share, diluted. Net Debt is estimated to be $210.0 million at December 31, 2019 representing a Net Debt to Funds Flow from Operations ratio of 1.0X.

(CA$ millions, except as otherwise indicated)	**2019 Budget**	**2019 Pro-forma**	**% Change**
Average Production			
Oil and NGLs (bbls/d)	**15,500 – 16,400**	**15,500 – 16,400**	**-**
Gas (mmcf/d)	**105.0 – 112.0**	**105.0 – 112.0**	**-**
Combined (BOE/d)	**33,500 – 34,500**	**33,500 – 34,500**	**-**
Production per million common shares (BOE/d)	**174 - 179**	**174 - 179**	-
Forecasted Average Commodity Prices			
WTI oil price (US$/bbl)	**67.50**	**55.00**	-19%
Mixed Sweet Blend Edmonton (CA$/bbl)	**66.97**	**63.75**	**− 5%**
NYMEX natural gas price (US$/MMBTU)	**3.00**	**3.00**	-
AECO natural gas price (US$/MMBtu)	**1.60**	**1.50**	-6%
Average Exchange Rate (US$/CA$)	**0.781**	**0.758**	-3%
Capital Expenditures			
Drilling & completions	**201.0**	**171.0**	-15%
Facilities, pipeline & well equipment	**60.0**	**60.0**	-
Land, seismic & property acquisitions	**9.0**	**9.0**	-
Net Capital Expenditures	**270.0**	**240.0**	-11%
Funds from operations	**240.0**	**220.0**	-8%
Per common share, diluted	**1.23**	**1.13**	-8%
Net debt, at year-end [1]	**225.0**	**220.0**	-2%
Net debt to trailing annual funds from operations ratio	**0.9 x**	**1.0 x**	11%
Weighted average common shares outstanding (millions) [1]	**192.4**	**192.4**	-
Common shares issued and outstanding (millions) [1]	**200.5**	**200.5**	**-**

(1) In addition to bank debt, the Company has $89.9 million principal amount of convertible debentures outstanding with a coupon of 5% per annum, maturing May 31, 2021. 2019 Budget and Pro-forma estimates have been prepared assuming the convertible debentures convert to 16.3 million common shares on July 1, 2019.

ADVISORY REGARDING FORWARD-LOOKING STATEMENTS

The information set out herein is “financial outlook” within the meaning of applicable securities laws. The purpose of this financial outlook is to provide readers with disclosure regarding Kelt’s reasonable expectations as to the anticipated results of its proposed business activities for the calendar year 2019. Readers are cautioned that this financial outlook may not be appropriate for other purposes.

Certain information with respect to Kelt contained herein, including management’s assessment of future plans and operations, contains forward-looking statements. These forward-looking statements are based on assumptions and are subject to numerous risks and uncertainties, many of which are beyond Kelt’s control, including the impact of general economic conditions, industry conditions, volatility of commodity prices, currency exchange rate fluctuations, imprecision of reserve estimates, environmental risks, competition from other explorers, stock market volatility and ability to access sufficient capital. As a result, Kelt’s actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurance can be given that any events anticipated by the forward-looking statements will transpire or occur.

In addition, the reader is cautioned that historical results are not necessarily indicative of future performance. The forward-looking statements contained herein are made as of the date hereof and the Company does not intend, and does not assume any obligation, to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise unless expressly required by applicable securities laws.

This MD&A contains forward-looking statements and forward-looking information within the meaning of applicable securities laws. The use of any of the words “expect”, “anticipate”, “continue”, “estimate”, “objective”, “ongoing”, “may”, “will”, “project”, “should”, “believe”, “plans”, “intends”, “potentially” and similar expressions are intended to identify forward-looking information or statements. In particular, this MD&A contains forward-looking statements pertaining to the following: Kelt’s expected price realizations and future commodity prices; the cost and timing of future capital expenditures and expected results; the Company’s ability to continue accumulating land at a low-cost in its core operating areas and potentially monetize non-core assets; the expected timing of well completions, the expected timing of wells bring brought on-production, the expected timing of facility expenditures, the expected timing of facility start-up dates, the expected timing of production additions from capital expenditures; and the Company's expected future financial position and operating results. Statements relating to "reserves" or “resources” are deemed to be forward looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated and that the reserves can be profitably produced in the future. Actual reserves may be greater than or less than the estimates provided herein.

Although Kelt believes that the expectations and assumptions on which the forward-looking statements are based are reasonable, undue reliance should not be placed on the forward-looking statements because Kelt cannot give any assurance that they will prove to be correct. Since forward-looking statements address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results could differ materially from those currently anticipated due to a number of factors and risks. These include, but are not limited to, the risks associated with the oil and gas industry in general, operational risks in development, exploration and production; delays or changes in plans with respect to exploration or development projects or capital expenditures; the uncertainty of reserve estimates; the uncertainty of estimates and projections relating to production, costs and expenses; failure to obtain necessary regulatory approvals for planned operations; health, safety and environmental risks; uncertainties resulting from potential delays or changes in plans with respect to exploration or development projects or capital expenditures; volatility of commodity prices, currency exchange rate fluctuations; imprecision of reserve estimates; as well as general economic conditions, stock market volatility; and the ability to access sufficient capital. We caution that the foregoing list of risks and uncertainties is not exhaustive.

Certain information set out herein may be considered as “financial outlook” within the meaning of applicable securities laws. The purpose of this financial outlook is to provide readers with disclosure regarding Kelt’s reasonable expectations as to the anticipated results of its proposed business activities for the periods indicated. Readers are cautioned that the financial outlook may not be appropriate for other purposes.

NON-GAAP FINANCIAL MEASURES AND OTHER KEY PERFORMANCE INDICATORS

This MD&A contains certain financial measures, as described below, which do not have standardized meanings prescribed by GAAP. In addition, this MD&A contains other key performance indicators ("KPI"), financial and non-financial, that do not have standardized meanings under the applicable securities legislation. As these non-GAAP financial measures and KPI are commonly used in the oil and gas industry, the Company believes that their inclusion is useful to investors. The reader is cautioned that these amounts may not be directly comparable to measures for other companies where similar terminology is used.

Non-GAAP financial measures

"Operating income" is calculated by deducting royalties, production expenses and transportation expenses from petroleum and natural gas revenue, net of the cost of purchases and after realized gains or losses on associated financial instruments. The Company refers to operating income expressed per unit of production as an "operating netback". "Adjusted funds from operations" is calculated as cash provided by operating activities before changes in non-cash operating working capital, and adding back (if applicable): transaction costs associated with acquisitions and dispositions, provisions for potential credit losses, and settlement of decommissioning obligations. Adjusted funds from operations per common share is calculated on a consistent basis with profit (loss) per common share, using basic and diluted weighted average common shares as determined in accordance with GAAP. Adjusted funds from operations and operating income or netbacks are used by Kelt as key measures of performance and are not intended to represent operating profits nor should they be viewed as an alternative to cash provided by operating activities, profit or other measures of financial performance calculated in accordance with GAAP.

Adjusted funds from operations and operating income or netbacks ($ perBOE) are Non-GAAP measures used by management to measure operating performance. Adjusted funds from operations and operating income or netbacks is is useful to the Company's stakeholders as it provides better ability to analyze performance and to compare with information that it commonly used by other oil and gas producers. The following table reconciles cash provided by operating activities reported in accordance with GAAP to *Adjusted funds from operations*, which is a non-GAAP financial measure used by Kelt as a key measures of performance:

	Three months ended December 31			Year ended December 31		
(CA$ thousands, unless otherwise indicated)	**2018**	2017	%	**2018**	2017	%
Cash provided by operating activities	**63,656**	36,458	75	**186,383**	115,222	62
Change in non-cash working capital	**(16,623)**	(4,044)	311	**(538)**	(8,723)	-94
Funds from operations	**47,033**	32,414	45	**185,845**	106,499	75
Provision for potential credit losses	**(128)**	-	-	**(128)**	-	-
Settlement of decommissioning obligations	**235**	484	-51	**1,122**	1,512	-26
Adjusted funds from operations	**47,140**	32,898	43	**186,839**	108,011	73

Throughout this MD&A, reference is made to "total revenue", "Kelt Revenue" and "average realized prices". "Total revenue" refers to petroleum and natural gas revenue (before royalties) as reported in the consolidated financial statements in accordance with GAAP, and is before realized gains or losses on financial instruments. "Kelt Revenue" is a non-GAAP measure and is calculated by deducting the cost of purchases from petroleum and natural gas revenue (before royalties). "Average realized prices" are calculated based on "Kelt Revenue" divided by production and reflect the Company's realized selling prices plus the net benefit of oil blending/marketing activities, which commenced during the fourth quarter of 2017. In addition to using its own production, the Company may purchase butane and crude oil from fourth parties for use in its blending operations, with the objective of selling the blended oil product at a premium. Marketing revenue from the sale of third party volumes is included in total petroleum and natural gas revenue as reported in the Consolidated Statement of Profit (Loss) and Comprehensive Income (Loss) in accordance with GAAP. Given the Company's per unit operating statistics disclosed throughout this MD&A are calculated based on Kelt's production volumes, management believes that disclosing its average realized prices based on Kelt Revenue is more appropriate and useful, because the cost of third party volumes purchased to generate the incremental marketing revenue has been deducted.

“Average realized prices” referenced throughout this MD&A are before financial instruments, except as otherwise indicated as being after financial instruments.

The term “net debt” is used synonymously with, and is equal to, “bank debt, net of working capital”. “Net debt” is calculated by adding the working capital deficiency to bank debt. The working capital deficiency is equal to total current assets net of total current liabilities. The Company uses a “net debt to trailing adjusted funds from operations ratio” as a benchmark on which management monitors the Company’s capital structure and short-term financing requirements. Management believes that this ratio, which is a non-GAAP financial measure, provides investors with information to understand the Company’s liquidity risk. The “net debt to trailing adjusted funds from operations ratio” is also indicative of the “debt to cash flow” calculation used to determine the applicable margin for a quarter under the Company’s Credit Facility agreement (though the calculation may not always be a precise match, it is representative).

Other KPI

“Production per common share” is calculated by dividing total production by the basic weighted average number of common shares outstanding, as determined in accordance with GAAP.

“Finding, development and acquisition” (“FD&A”) cost is the sum of capital expenditures incurred in the period and the change in future development capital (“FDC”) required to develop reserves. FD&A cost per BOE is determined by dividing current period net reserve additions into the corresponding period’s FD&A cost. Readers are cautioned that the aggregate of capital expenditures incurred in the year, comprised of exploration and development costs and acquisition costs, and the change in estimated FDC generally will not reflect total FD&A costs related to reserves additions in the year.

“Recycle ratio” is a measure for evaluating the effectiveness of a company’s re-investment program. The ratio measures the efficiency of capital investment by comparing the operating netback per BOE to FD&A cost per BOE.

“Net asset value” is calculated by adding the present value of petroleum and natural gas reserves, undeveloped land value and proceeds from exercise of stock options, less the present value of decommissioning obligations and bank debt, net of working capital. “Net asset value per common share” is calculated by dividing the “Net Asset Value” by the diluted number of common shares outstanding. The calculation of proceeds from exercise of stock options and the diluted number of common shares outstanding only include stock options that are “in-the-money” based on the closing price of KEL common shares as at the calculation date. The diluted number of common shares outstanding includes common shares issuable upon conversion of the convertible debentures that are “in-the-money” based on the closing price of KEL common shares as at the calculation date.

ADDITIONAL INFORMATION

Additional information relating to Kelt, including the Company’s Annual Information Form (“AIF”) dated March 6, 2019 is filed on SEDAR and can be viewed on their website at www.sedar.com. Copies of the AIF can also be obtained by contacting Sadiq H. Lalani, Vice President and Chief Financial Officer at Kelt Exploration Ltd., Suite 300, 311 Sixth Avenue SW, Calgary, Alberta, Canada, T2P 3H2. Further information relating to Kelt is also available on its website at www.keltexploration.com.

MANAGEMENT'S REPORT

The accompanying financial statements of Kelt Exploration Ltd. (the "Company") are the responsibility of management. The financial statements have been prepared by management in Canadian dollars in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") and include certain estimates that reflect management's best judgments. When alternative accounting methods exist, management has chosen those it deems most appropriate in the circumstances.

Management has the overall responsibility for internal controls and maintains a system of internal controls over financial reporting that provides reasonable assurance that the financial information is relevant, reliable and accurate and that the Company's assets are properly accounted for and adequately safeguarded.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board exercises this responsibility with the assistance of the Audit Committee. This Committee, consisting of non-management directors, meets with management and independent auditors to ensure that each group is properly discharging its responsibilities and to discuss adequacy of internal controls, accounting policies and financial reporting matters. The Audit Committee has reviewed the financial statements and has reported thereon to the Board of Directors. The Board of Directors has approved the financial statements and authorized them for issuance to shareholders.

PricewaterhouseCoopers LLP, an independent firm of Chartered Professional Accountants, has been engaged, as approved by the shareholders of the Company, to provide an independent audit opinion on the Company's financial statements. Their report, contained herein, outlines the nature of their audit and expresses an unqualified opinion on the financial statements.

[signed]

David J. Wilson
President and Chief Executive Officer
March 6, 2019

[signed]

Sadiq H. Lalani
Vice President and Chief Financial Officer
March 6, 2019

Independent auditor’s report

To the Shareholders of Kelt Exploration Ltd.

Our opinion

In our opinion, the accompanying consolidated financial statements present fairly, in all material respects, the financial position of Kelt Exploration Ltd. and its subsidiary (together, the Company) as at December 31, 2018 and 2017, and its financial performance and its cash flows for the years then ended in accordance with International Financial Reporting Standards (IFRS).

What we have audited
The Company’s consolidated financial statements comprise:

- the consolidated statements of financial position as at December 31, 2018 and 2017;
- the consolidated statements of profit (loss) and comprehensive income (loss) for the years then ended;
- the consolidated statements of changes in shareholders’ equity for the years then ended;
- the consolidated statements of cash flows for the years then ended; and
- the notes to the consolidated financial statements, which include a summary of significant accounting policies.

Basis for opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the *Auditor’s responsibilities for the audit of the consolidated financial statements* section of our report.

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

Independence
We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the consolidated financial statements in Canada. We have fulfilled our other ethical responsibilities in accordance with these requirements.

Other information

Management is responsible for the other information. The other information comprises the Management’s Discussion and Analysis and the information, other than the consolidated financial statements and our auditor’s report thereon, included in the annual report.

PricewaterhouseCoopers LLP
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T: +1 403 509 7500, F: +1 403 781 1825

Our opinion on the consolidated financial statements does not cover the other information and we do not express any form of assurance conclusion thereon.

In connection with our audit of the consolidated financial statements, our responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the consolidated financial statements or our knowledge obtained in the audit, or otherwise appears to be materially misstated.

If, based on the work we have performed, we conclude that there is a material misstatement of this other information, we are required to report that fact. We have nothing to report in this regard.

Responsibilities of management and those charged with governance for the consolidated financial statements

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

In preparing the consolidated financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company's financial reporting process.

Auditor's responsibilities for the audit of the consolidated financial statements

Our objectives are to obtain reasonable assurance about whether the consolidated financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these consolidated financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the consolidated financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the consolidated financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Company to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the consolidated financial statements, including the disclosures, and whether the consolidated financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Obtain sufficient appropriate audit evidence regarding the financial information of the entities or business activities within the Company to express an opinion on the consolidated financial statements. We are responsible for the direction, supervision and performance of the group audit. We remain solely responsible for our audit opinion.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

We also provide those charged with governance with a statement that we have complied with relevant ethical requirements regarding independence, and to communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, related safeguards.

The engagement partner on the audit resulting in this independent auditor's report is Ryan McKay.

PricewaterhouseCoopers LLP

Chartered Professional Accountants

Calgary, Alberta
March 5, 2019

KELT EXPLORATION LTD.
CONSOLIDATED STATEMENT OF FINANCIAL POSITION
AS AT DECEMBER 31, 2018 AND DECEMBER 31, 2017

(CA$ thousands)	[Notes]	**December 31, 2018**	December 31, 2017
ASSETS			
Current assets			
Cash and cash equivalents		**6,455**	3,695
Accounts receivable and accrued revenue	[11]	**46,180**	39,446
Prepaid expenses and deposits		**1,668**	2,005
Derivative financial instruments	[11]	**3,247**	-
Total current assets		**57,550**	45,146
Investment in securities	[11]	**1,000**	-
Exploration and evaluation assets	[5]	**119,282**	123,349
Property, plant and equipment	[6]	**1,245,689**	1,108,072
Total assets		**1,423,521**	1,276,567
LIABILITIES			
Current liabilities			
Accounts payable and accrued liabilities		**83,530**	87,783
Derivative financial instruments	[11]	**651**	-
Deferred premium on flow-through shares	[10]	**-**	1,042
Decommissioning obligations	[9]	**904**	1,585
Total current liabilities		**85,085**	90,410
Bank debt	[7]	**168,881**	91,465
Convertible debentures	[8]	**78,390**	74,517
Decommissioning obligations	[9]	**143,763**	135,343
Deferred income tax liability	[12]	**53,606**	39,131
Total liabilities		**529,725**	430,866
SHAREHOLDERS' EQUITY			
Shareholders' capital	[10]	**1,119,232**	1,078,773
Reserve from common control transaction		**(57,668)**	(57,668)
Equity component of convertible debentures	[8]	**12,843**	12,856
Contributed surplus		**19,713**	20,218
Retained earnings (deficit)		**(200,324)**	(208,478)
Total shareholders' equity		**893,796**	845,701
Total liabilities and shareholders' equity		**1,423,521**	1,276,567
Commitments	[15]		

The accompanying notes form an integral part of these consolidated financial statements.

On behalf of the Board of Directors:

[signed]
David J. Wilson, Director

[signed]
Neil G. Sinclair, Director

KELT EXPLORATION LTD.
CONSOLIDATED STATEMENT OF PROFIT (LOSS) AND COMPREHENSIVE INCOME (LOSS)
FOR THE YEARS ENDED DECEMBER 31, 2018 AND DECEMBER 31, 2017

		Year ended December 31	
(CA$ thousands, except per share amounts)	[Notes]	**2018**	2017
Revenue			
Petroleum and natural gas revenue	[13]	**389,277**	257,557
Royalties		**(30,701)**	(23,557)
		358,576	234,000
Expenses			
Production		**89,792**	81,201
Transportation		**38,646**	25,301
Cost of purchases		**21,616**	3,052
Financing	[14]	**17,195**	14,330
General and administrative	[16]	**8,352**	7,564
Provision for potential credit losses	[11]	**(128)**	-
Share based compensation	[10]	**6,108**	5,439
Exploration and evaluation	[5]	**5,211**	1,311
Depletion, depreciation and impairment	[6]	**155,967**	134,362
		342,759	272,560
Loss on derivative financial instruments	[11]	**(3,304)**	(451)
Foreign exchange gain (loss)		**677**	(54)
Premium on flow-through shares	[10]	**4,141**	2,309
Gain on sale of assets	[4]	**3,562**	10,436
Other income		**1,960**	-
Profit (loss) before taxes		**22,853**	(26,320)
Deferred income tax recovery (expense)	[12]	**(14,699)**	3,142
Profit (loss) and comprehensive income (loss)		**8,154**	(23,178)
Profit (loss) per common share			
Basic	[10]	**0.04**	(0.13)
Diluted	[10]	**0.04**	(0.13)

The accompanying notes form an integral part of these consolidated financial statements.

KELT EXPLORATION LTD.
CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS' EQUITY
AS AT AND FOR THE YEARS ENDED DECEMBER 31, 2018 AND DECEMBER 31, 2017

(CA$ thousands)	[Notes]	Shareholders' capital Number of Shares (000s)	Shareholders' capital Amount ($ thousands)	Reserve	Convertible debentures – equity portion	Contributed surplus	Retained earnings (deficit)	Total shareholders' equity
Balance at December 31, 2017		178,858	1,078,773	(57,668)	12,856	20,218	(208,478)	845,701
Profit and comprehensive income		-	-	-	-	-	8,154	8,154
Common shares issued, net of costs:								
Private placements	[10]	2,758	24,776	-	-	-	-	24,776
Premium on flow-through shares	[10]	-	(3,099)	-	-	-	-	(3,099)
Share issue costs, net of tax	[10]	-	(607)	-	-	-	-	(607)
Conversion of convertible debentures	[8]	16	89	-	(13)	-	-	76
Exercise of stock options	[10]	2,081	17,694	-	-	(5,007)	-	12,687
Vesting of restricted share units	[10]	290	1,606	-	-	(1,606)	-	-
Share based compensation	[10]	-	-	-	-	6,108	-	6,108
Balance at December 31, 2018		**184,003**	**1,119,232**	**(57,668)**	**12,843**	**19,713**	**(200,324)**	**893,796**

(CA$ thousands)	[Notes]	Shareholders' capital Number of Shares (000s)	Shareholders' capital Amount ($ thousands)	Reserve	Convertible debentures – equity portion	Contributed surplus	Retained earnings (deficit)	Total shareholders' equity
Balance at December 31, 2016		175,672	1,055,959	(57,668)	12,856	17,454	(185,300)	843,301
Loss and comprehensive loss		-	-	-	-	-	(23,178)	(23,178)
Common shares issued, net of costs:								
Private placements	[10]	2,585	20,605	-	-	-	-	20,605
Premium on flow-through shares	[10]	-	(2,553)	-	-	-	-	(2,553)
Share issue costs, net of tax	[10]	-	(212)	-	-	-	-	(212)
Exercise of stock options	[10]	415	3,234	-	-	(935)	-	2,299
Vesting of restricted share units	[10]	186	1,740	-	-	(1,740)	-	-
Share based compensation	[10]	-	-	-	-	5,439	-	5,439
Balance at December 31, 2017		**178,858**	**1,078,773**	**(57,668)**	**12,856**	**20,218**	**(208,478)**	**845,701**

The accompanying notes form an integral part of these consolidated financial statements.

KELT EXPLORATION LTD.
CONSOLIDATED STATEMENT OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2018 AND DECEMBER 31, 2017

		Year ended December 31	
(CA$ thousands)	[Notes]	**2018**	2017
Operating activities			
Profit (loss) and comprehensive income (loss)		**8,154**	(23,178)
Items not affecting cash:			
Accretion of convertible debentures	[8,14]	**3,949**	3,539
Accretion of decommissioning obligations	[9,14]	**3,193**	2,981
Share based compensation		**6,108**	5,439
Exploration and evaluation		**5,211**	1,311
Depletion, depreciation and impairment		**155,967**	134,362
Unrealized gain on derivative financial instruments	[11]	**(2,596)**	(599)
Unrealized (gain) loss on foreign exchange		**(15)**	43
Premium on flow-through shares		**(4,141)**	(2,309)
Gain on sale of assets		**(3,562)**	(10,436)
Deferred income tax expense (recovery)		**14,699**	(3,142)
Settlement of decommissioning obligations	[9]	**(1,122)**	(1,512)
Change in non-cash operating working capital	[17]	**538**	8,723
Cash provided by operating activities		**186,383**	115,222
Financing activities			
Net increase (decrease) in bank debt	[7]	**77,416**	(20,228)
Issue of common shares, net of costs	[10]	**23,945**	20,315
Proceeds on exercise of stock options	[10]	**12,687**	2,299
Cash provided by financing activities		**114,048**	2,386
Investing activities			
Exploration and evaluation assets		**(44,283)**	(42,627)
Property, plant and equipment		**(248,425)**	(201,142)
Property acquisitions	[4]	**(2,860)**	(531)
Property dispositions	[4]	**10,070**	116,323
Investment in securities	[11]	**(1,000)**	-
Change in non-cash investing working capital	[17]	**(11,188)**	13,547
Cash used in investing activities		**(297,686)**	(114,430)
Net change in cash and cash equivalents		**2,745**	3,178
Foreign exchange on cash and cash equivalents		**15**	(43)
Cash and cash equivalents, beginning of period		**3,695**	560
Cash and cash equivalents, end of period		**6,455**	3,695

The accompanying notes form an integral part of these consolidated financial statements.

(All tabular amounts in thousands of Canadian dollars, except as otherwise indicated)

1. DESCRIPTION OF THE BUSINESS

Kelt Exploration Ltd. ("Kelt" or the "Company") is an oil and gas company based in Calgary, Alberta, focused on the exploration, development and production of crude oil and natural gas resources, primarily in northwestern Alberta and northeastern British Columbia. Kelt's land holdings are located in two core areas, namely: (a) Grande Prairie (including Pouce Coupe, Wembley, Progress and La Glace), Alberta; and (b) Fort St. John (including Inga, Fireweed, Stoddart and Oak), British Columbia. The Company's British Columbia assets are operated by Kelt Exploration (LNG) Ltd.), a wholly owned subsidiary of Kelt. The Company's common shares and 5% convertible debentures are listed on the Toronto Stock Exchange ("TSX") under the symbol "KEL" and "KEL.DB", respectively.

The head office of Kelt and Kelt LNG is located at Suite 300, 311 - 6th Avenue S.W., Calgary, Alberta T2P 3H2.

2. BASIS OF PRESENTATION

The Company's Board of Directors approved and authorized these consolidated annual financial statements on March 5, 2019 for issue on March 6, 2019.

a) Statement of compliance

The Company prepares its financial statements in accordance with Canadian generally accepted accounting principles ("GAAP") as set out in the *CPA Canada Handbook - Accounting*. These consolidated annual financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS"), as issued by the International Accounting Standards Board ("IASB"), applicable to the preparation of annual financial statements.

b) Basis of measurement

All references to dollar amounts in these financial statements and related notes are thousands of Canadian dollars, unless otherwise indicated.

The financial statements have been prepared on a historical cost basis, except for certain financial instruments which are recorded at fair value. The methods used to measure fair values are described in note 11 of these financial statements.

c) Significant judgments and estimates

The timely preparation of the financial statements requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amount of assets, liabilities, income and expenses. Actual results may differ materially from these estimates. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are reviewed and for any future years affected. Significant judgments, estimates and assumptions made by management in these financial statements are discussed below.

Depletion, depreciation and reserves

The Company calculates depletion based on total proved reserves as determined in accordance with the Canadian Oil and Gas Evaluation Handbook ("COGEH"). The process of determining reserves is complex. Significant judgments are based on available geological, geophysical, engineering, and economic data. These judgments are based on estimates and assumptions that may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates are based on production forecasts, prices and economic conditions. As circumstances change and additional data becomes available, reserve estimates also change. Estimates made are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and governmental restrictions.

Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation can be impacted by subjective decisions, new geological or production information and a changing environment. In addition, revisions to reserve estimates can arise from changes in forecast oil and gas prices and reservoir performance. Such revisions can be either positive or negative.

Changes in reserve estimates impact the financial results of the Company as reserves and estimated future development costs are used to calculate depletion. Reserves are used in measuring the fair value less costs of disposal ("FVLCD") of property, plant and equipment for impairment calculations and for determining the fair value of PP&E acquired in a business combination. Reserves also impact the Company's assessment of the commercial viability and technical feasibility of an exploration project and the decision to transfer exploration and evaluation assets to PP&E.

Exploration and evaluation assets

Judgment is required to determine the level at which E&E is assessed for impairment. For Kelt, the carrying value of E&E assets is assessed for overall impairment at the operating segment level and on a specific identification basis prior to transferring E&E assets to PP&E. The decision to transfer assets from E&E to PP&E requires judgment as it is based on estimated proved reserves, which are used, in part, to determine a project's technical feasibility and commercial viability. Refer to additional information regarding E&E assets in note 5 of these financial statements.

Determination of Cash Generating Units ("CGUs")

The determination of CGUs requires judgment in defining a group of assets that generate cash inflows that are largely independent of the cash inflows from other assets or groups of assets. CGUs are determined by similar geological structure, shared infrastructure, geographical proximity, commodity type, similar exposure to market risks and materiality. As at December 31, 2018, the Company has one CGU for its assets located in the province of British Columbia and two CGUs for its assets located in the province of Alberta. Refer to specific information regarding the Company's CGUs in note 6 of the consolidated financial statements.

Impairment of non-financial assets

Significant judgment is required to assess the Company's non-financial assets, namely E&E and PP&E, for impairment or potential reversals of previously recorded impairment. Management must first determine whether indicators of impairment exist that suggest the carrying value may not be recoverable through the asset's continued use or sale. In addition, judgment is required to assess whether a previously recognized impairment for an asset (other than goodwill) no longer exists or has decreased.

Significant judgment and estimates are required to calculate the recoverable amount of PP&E and goodwill in an impairment test. Management calculates the recoverable amount of each CGU based on its FVLCD, using an after-tax discounted cash flow analysis derived from proved plus probable reserves. Reserve estimates and expected future cash flows from production of reserves are subject to measurement uncertainty as discussed above and are subject to variability due to changes in forecasted commodity prices. In addition, the present value of forecast future cash flows is highly sensitive to the discount rate. Judgment is required to determine an appropriate discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. Refer to note 6 of the consolidated annual financial statements for a discussion of the specific estimates and assumptions applied in the impairment test performed at December 31, 2018.

Business combinations

Business combinations are accounted for using the acquisition method of accounting. The determination of fair value often requires management to make assumptions and estimates about future events. The assumptions and estimates with respect to determining the fair value of exploration and evaluation assets and property, plant and equipment acquired generally require significant judgment and include estimates of reserves acquired, forecast benchmark commodity prices and discount rates. Assumptions are also required to determine the fair value of decommissioning obligations associated with the properties. Changes in any of these assumptions or estimates used in determining the fair value of acquired assets and liabilities could impact the amounts assigned to assets, liabilities and goodwill (or gain from a bargain purchase) in the acquisition equation. Future profit (loss) can be affected as a result of changes in future depletion and depreciation or impairment. Refer to additional information regarding business combinations in note 4 of these financial statements.

Decommissioning obligations

The Company estimates the decommissioning obligations for oil and gas wells and their associated production facilities and infrastructure. In most instances, dismantling of assets and remediation occurs many years into the future. The value of the ultimate decommissioning obligation can fluctuate in response to many factors including changes to relevant legal requirements, the emergence of new restoration techniques, experience at other production sites, and changes to the risk-free discount rate. The expected timing and amount of expenditure can also change, for example, in response to changes in reserves or changes in laws and regulations or their interpretation. Judgments include the most appropriate discount rate to use, which management has determined to be a risk-free rate. Key assumptions are disclosed in note 9 of these financial statements.

Kelt estimates abandonment and reclamation costs based on a combination of publically available industry benchmarks and internal site specific information. For producing wells and facilities, the expected timing of settlement is estimated based on the proved plus probable period to abandonment for each depletable area, as per the independent reserve report. For non-producing wells, the expected timing of settlement is estimated to be half of the period applied to producing wells in that field, unless the timing to abandon and reclaim a specific well site or facility is known based on budgeted expenditures.

Deferred income taxes

The Company follows the liability method for calculating deferred income taxes. Tax interpretations, regulations and legislation in the jurisdictions in which the Company operates are subject to change. As such, deferred income taxes are subject to measurement uncertainty. The provision for deferred income taxes also includes the following significant judgments of management:

• Deferred income tax assets are assessed by management at the end of the reporting period to determine the likelihood that they will be realized from future taxable earnings. The deferred tax liability reported in the Consolidated Statement of Financial Position is presented net of offsetting deferred income tax assets. The Company's non-capital losses expire in years 2023 to 2037. Management believes that Kelt and Kelt LNG will have sufficient taxable income in the future in order to utilize the non-capital losses and has concluded that recognition of the associated deferred income tax assets is appropriate;

• Classification of intangible drilling and completion costs as Canadian exploration expenses ("CEE") or Canadian development expenses ("CDE") – CEE is deductible at a rate of 100% per year, whereas CDE may be deducted on a declining basis at 30% per year. Accordingly, the allocation of resource deductions will impact the period in which Kelt may become taxable in the future. In addition, the designation of certain expenditures as CEE and/or CDE impacts the Company's ability to satisfy its flow-through share obligations; and

• Recognition of unrecognized deferred income tax asset – per IAS 12, deferred income taxes are not initially recognized on transactions that are not business combinations. The Company did not initially recognize a deferred income tax asset of $14.4 million that arose on the spin-out certain assets from Celtic Exploration Ltd. ("Celtic") at Kelt's inception on February 26, 2013. The initially unrecognized deferred tax asset is now being amortized at a rate of 2.5% per quarter, which management believes is a reasonable estimate as it reflects the weighted average depletion rate of the properties at the time of the spin-out and is aligned with Kelt's corporate average depletion rate.

Share based compensation

The Company uses the fair value method of accounting for its long-term incentive plans, which include an Incentive Stock Option Plan and a Restricted Share Unit Plan. Judgments include which valuation model is most appropriate for the grant of the award to estimate its fair value. Estimates and assumptions are then used in the valuation model to determine fair value.

For stock options, the Company uses the Black-Scholes option pricing model which requires that management make assumptions for the expected life of the option, the anticipated volatility of the share price over the life of the option, the risk-free interest rate for the life of the option, and the number of options that will ultimately vest. The assumptions used by the Company are discussed in note 10 of these financial statements.

The fair value of restricted share units is estimated based on the volume weighted average trading price ("VWAP") on the TSX over three trading days immediately prior to the date of grant. Judgment is also required to estimate the number of restricted share units that will ultimately vest, in other words, the rate of forfeiture. The assumptions used by the Company are discussed in note 10 of these financial statements.

Flow-through shares

There is no IFRS guidance that specifically addresses accounting for flow-through shares, therefore the Company is required to develop an accounting policy. Consistent with prior years, and as set-forth in note 3, the Company has applied the residual method. Under this method, judgement is required to determine of the fair value of ordinary shares. Typically, it is based on the share price at the time the parties agree to the transaction. In situations where flow-through shares are issued concurrent with an ordinary common share offering, the difference in subscription prices is used to value the premium. Otherwise, the Company uses the VWAP of KEL common shares for the five trading days immediately preceding the date of the binding agreement, to value the ordinary common shares.

Judgment is also required to determine when the Company has fulfilled its obligation to pass on the tax deduction to investors, at which time, the premium on flow-through shares is recognized in income. The Company deems the obligation to have been fulfilled in the period that eligible expenditures are incurred, regardless of the period in which the tax deductions are legally renounced.

3. SIGNIFICANT ACCOUNTING POLICIES

Joint interests

A portion of the Company's exploration, development and production activities is conducted jointly with others through unincorporated joint ventures. These financial statements reflect only the Company's proportionate interest of these jointly controlled assets and the proportionate share of the relevant revenue and related costs.

Foreign currency translation

The financial statements are presented in Canadian dollars, which is the Company's functional and presentation currency. Transactions in U.S. dollars are initially recorded at the exchange rate in effect at the time of the transactions. Monetary assets and liabilities denominated in U.S. dollars are translated to Canadian dollars using the closing exchange rate at the Consolidated Statement of Financial Position date. The resulting exchange rate differences are included in the Consolidated Statement of Profit (Loss) and Comprehensive Income (Loss).

Business combinations

Business combinations are accounted for using the acquisition method. The identifiable net assets acquired are measured at their fair value at the date of acquisition. Any excess of the purchase price over the fair value of the net assets acquired is recognized as goodwill. Any deficiency of the purchase price below the fair value of the net assets acquired is recorded as a gain in the Consolidated Statement of Profit (Loss) and Comprehensive Income (Loss). Transaction costs associated with the acquisition are expensed when incurred.

Principles of consolidation

The consolidated financial statements include the accounts of Kelt and its subsidiaries. Subsidiaries are entities controlled by the Company. Control exists when the Company has the power to govern the financial and operating policies of an entity so as to obtain benefits from its activities. As at December 31, 2018, the Company has one wholly-owned subsidiary, Kelt LNG. The financial statements of subsidiaries are prepared for the same reporting period as Kelt, using uniform accounting policies. Subsidiaries are consolidated from the date of acquisition of control and continue to be consolidated until the date there is a loss of control. All intercompany balances, transactions, revenue and expenses are eliminated on consolidation

Assets held for sale

Non-current assets are classified as held for sale if their carrying amounts will be recovered through a sale transaction rather than through continuing use. This condition is regarded as met only when the sale is highly probable and the asset or disposal group is available for immediate sale in its present condition subject only to terms that are usual and customary for sales of such assets. Management must be committed to the sale, which should be expected to qualify for recognition as a completed sale within one year from the date of classification as held for sale. Non-current assets and disposal groups classified as held for sale are measured at the lower of the carrying amount and fair value less costs of disposal, and depletion & depreciation ceases at the time this designation is made.

If a non-current asset or disposal group has been classified as held for sale, but subsequently ceases to meet the criteria to be classified as held for sale, the Company ceases to classify the asset or disposal group as held for sale. Non-current assets and disposal groups that cease to be classified as held for sale are measured at the lower of carrying amount before the asset or disposal group was classified as held for sale (adjusted for any depreciation, amortization or revaluation that would have been recognized had the asset or disposal group not been classified as held for sale) and its recoverable amount at the date of the subsequent decision not to sell. Any adjustment to the carrying amount is recognized in profit or loss in the period in which the asset ceases to be classified as held for sale.

Financial instruments

Financial assets and liabilities are recognized when the Company becomes a party to the contractual provisions of the instrument. Financial assets are derecognized when the rights to receive cash flows from the assets have expired or have been transferred and the Company has transferred substantially all risks and rewards of ownership.

Financial assets and liabilities are offset and the net amount is reported in the Consolidated Statement of Financial Position when there is a legally enforceable right to offset the recognized amounts and there is an intention to settle on a net basis, or realize the asset and settle the liability simultaneously.

At initial recognition, the Company classifies its financial instruments in the following categories depending on the purpose for which the instruments were acquired:

i) Financial assets and liabilities at fair value through profit or loss

A financial asset or liability is classified in this category if acquired principally for the purpose of selling or repurchasing in the short-term. Derivatives are also included in this category unless they are designated as hedges.

Financial instruments in this category are recognized initially and subsequently at fair value. Transaction costs are expensed in the Consolidated Statement of Profit (Loss) and Comprehensive Income (Loss). Gains and losses arising from changes in fair value are presented in profit or loss in the period in which they arise.

Financial assets and liabilities at fair value through profit or loss are classified as current in the Consolidated Statement of Financial Position, except for any portion expected to be realized or paid beyond twelve months of the Consolidated Statement of Financial Position date.

ii) Loans and receivables

Loans and receivables are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market. The Company’s loans and receivables are comprised of cash and cash equivalents, accounts receivable and deposits. They are included in current assets due to their short-term nature.

Loans and receivables are initially recognized at the amount expected to be received less any required discount to reduce the loans and receivables to fair value. Subsequently, loans and receivables are measured at amortized cost using the effective interest method less any provision for impairment.

iii) Financial liabilities at amortized cost

Financial liabilities at amortized cost include accounts payable and bank debt. Accounts payable are initially recognized at the amount required to be paid less any required discount to reduce the payables to fair value. Bank debt is recognized initially at fair value, net of any transaction costs incurred, and subsequently at amortized cost using the effective interest method. Financial liabilities are classified as current liabilities if payment is due within twelve months. Otherwise, they are presented as non-current liabilities.

iv) Derivative financial instruments

The Company may use derivative financial instruments for risk management purposes. All derivatives have been classified at fair value through profit or loss. Financial instruments are included on the Consolidated Statement of Financial Position within derivative financial instruments and are classified as current or non-current based on the contractual terms specific to the instrument. Gains and losses on re-measurement of derivatives are included in profit or loss in the period in which they arise.

Investments in securities

Investments in securities are classified as fair value through profit or loss. Investments in the securities of private entities are carried at fair value, which is estimated using values based on equity issuances and other indications of value from time-to-time (level three fair value hierarchy estimates).

Exploration and evaluation assets ("E&E") and property, plant and equipment ("PP&E")

i) Recognition and measurement

Pre-license costs

Costs incurred prior to acquiring the legal rights to explore an area are charged directly to profit or loss as exploration expense in the period incurred. The Company did not incur pre-license costs in the current or prior period.

Exploration and evaluation assets

All costs directly associated with the exploration and evaluation of petroleum and natural gas reserves are initially capitalized. Exploration and evaluation costs include unproved property acquisition costs such as undeveloped land and mineral leases, geological and geophysical costs, and costs associated with exploratory drilling and appraisals. Such costs are not subject to depletion or depreciation until they are reclassified from E&E to PP&E.

The costs are accumulated by exploration area pending determination of technical feasibility and commercial viability. The technical feasibility and commercial viability is considered to be achieved when proved reserves are determined to exist. Prior to being transferred to PP&E, E&E costs are first tested for impairment. If proved/probable reserves have not been established through the completion of exploration and evaluation activities and there are no future plans for activity in that exploration area, then the costs are determined to be impaired and the amounts are charged to the Consolidated Statement of Profit (Loss) and Comprehensive Income (Loss).

Property, plant and equipment

Property, plant, and equipment primarily consists of petroleum and natural gas development and production assets, and is measured at cost less accumulated depletion and depreciation and accumulated impairment losses. These costs include property acquisitions, development drilling, completion, gathering and infrastructure, estimated decommissioning costs and transfers from E&E. In addition, borrowing costs incurred for the construction of qualifying assets are capitalized during the period of time that is required to complete and prepare the assets for their intended use.

ii) Subsequent costs

Costs incurred subsequent to the determination of technical feasibility and commercial viability and the costs of replacing components of equipment are recognized as property, plant and equipment only when they increase the future economic benefits embodied in the specific asset to which they relate. All other expenditures are expensed as incurred. Such capitalized amounts generally represent costs incurred in developing proved and/or probable reserves and bringing in or enhancing production from such reserves. The carrying amount of any replaced or sold component is derecognized.

The gain or loss from the divestitures of property, plant and equipment is recognized in the Consolidated Statement of Profit (Loss) and Comprehensive Income (Loss). In addition, risk-sharing agreements in which the Company cedes a portion of its working interest to a third-party are generally considered to be disposals of property, plant and equipment, potentially resulting in a gain or loss on disposition.

Exchanges of property, plant and equipment are measured at fair value unless the exchange transaction lacks commercial substance or the fair value of neither the asset received nor the asset given up is reliably measurable. Unless the fair value of the asset received is more clearly evident, the cost of the acquired asset is measured at the fair value of the asset given up. Where fair value is not used, the cost of the acquired asset is measured at the carrying amount of the asset given up. The gain or loss on derecognition of the asset given up is recognized in profit or loss.

Property, plant and equipment is derecognized upon disposal or when no future economic benefits are expected to arise from the continued use of the asset. Any gain or loss arising on derecognition of the asset (calculated as the difference between the net disposal proceeds and the carrying value of the asset) is included in profit or loss in the period in which the item is derecognized.

iii) Depletion and depreciation

Development and production costs are accumulated on a geotechnical area basis ("depletion units"). The net carrying value of each depletion unit is depleted using the unit of production method by reference to the ratio of production in the year to the related proved reserves, taking into account estimated future development costs necessary to bring those reserves into production. These estimates are reviewed by independent reserve engineers at least annually. Where significant components of development and production ("D&P") assets have different useful lives, they are accounted for and depreciated as separate items of property, plant and equipment.

iv) Major maintenance expenditures

The costs of major maintenance associated with turnaround activities that benefit future years of operations are capitalized and depreciated over the period to the next major maintenance turnaround. All other maintenance costs are expensed as incurred.

Impairment of assets

Non-financial assets

The Company reviews the carrying value of its non-financial assets, including PP&E and E&E, on a quarterly basis to determine whether there is any indication of impairment. For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or CGUs. The recoverable amount of an asset or a CGU is the greater of its value in use and its FVLCD. E&E assets are assessed for overall impairment at the operating segment level and individual E&E assets are assessed for impairment prior to transferring to PP&E.

FVLCD is defined as the amount obtainable from the sale of an asset or cash generating unit in an arm's length transaction between knowledgeable, willing parties, less the costs of disposal. The Company calculates FVLCD by reference to the after-tax future cash flows expected to be derived from production of proved plus probable reserves, less estimated selling costs. The estimated after-tax future cash flows are discounted to their present value using a discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. Value in use is generally computed by reference to the present value of the future cash flows expected to be derived from production of proved reserves.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in the Consolidated Statement of Profit (Loss) and Comprehensive Income (Loss). Impairment losses recognized in respect of CGUs are allocated to reduce the carrying amounts of the assets in the CGU on a pro rata basis.

Impairment losses recognized in prior years are assessed at each reporting date for any indication that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimate used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depletion and depreciation, if no impairment loss had been recognized.

Financial assets

A financial asset measured at amortized cost is assessed at each reporting date using an expected credit loss ("ECL") model to determine whether it is impaired. The Company applies the simplified approach to providing for ECLs prescribed by IFRS 9, which permits the use of the lifetime expected loss provision for all trade receivables. The Company uses a combination of historical and forward looking information to determine the appropriate loss allowance provision. ECLs are a probability-weighted estimate of all possible default events over the expected life of the financial asset which is based on credit quality since initial recognition.

All impairment losses are recognized in profit or loss. An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized. For financial assets measured at amortized cost the reversal is recognized in profit or loss.

Leases

Leases where the Company assumes substantially all the risks and rewards of ownership are classified as finance leases. Upon initial recognition, the leased asset is measured at an amount equal to the lower of its fair value and the present value of the minimum lease payments. Subsequent to initial recognition, the asset is accounted for in accordance with the accounting policy applicable to that asset. Minimum lease payments made under finance leases are apportioned between the finance expenses and the reduction of the outstanding liability. The finance expenses are allocated to each year during the lease term so as to produce a constant periodic rate of interest on the remaining balance of the liability. The Company does not currently have any finance leases.

All of the Company's leases are operating leases, which are not recognized on the Consolidated Statement of Financial Position. Rather, payments in respect of operating leases are recognized in the Consolidated Statement of Profit (Loss) and Comprehensive Income (Loss) on a straight-line basis over the term of the lease. In the event that lease inducements are received to enter into operating leases, such inducements are recognized as a deferred credit. The aggregate benefit of inducements is recognized as a reduction of the related rental expense on a straight-line basis, except where another systematic basis is more representative of the time pattern in which economic benefits from the leased asset are consumed.

Provisions and contingencies

Provisions are recognized when the Company has a present obligation as a result of a past event, if it is probable that an outflow of resources will be required and if a reliable estimate can be made of the amount of the obligation. Provisions are measured based on the best estimate of discounted future cash outflows.

Decommissioning obligations

The Company's activities give rise to dismantling, decommissioning and site disturbance remediation activities. An obligation is accrued for the estimated cost of site restoration and the corresponding amount is included in the cost of the assets to which the obligations relate. Decommissioning obligations are measured at the present value of management's best estimate of the expenditure required to settle the present obligation at the Consolidated Statement of Financial Position date. Subsequent to the initial measurement, the obligation is adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation, changes to the expected timing of site restoration, as well as any changes in the risk-free discount rate. Increases in the provision due to the passage of time are recognized as a financing expense in the Consolidated Statement of Profit (Loss) and Comprehensive Income (Loss) whereas increases/decreases due to changes in the estimated future cash flows are capitalized. Actual costs incurred upon settlement of the decommissioning obligations are charged against the provision to the extent the provision is established.

Contingencies

Contingent liabilities are possible obligations whose existence will only be confirmed by future events not wholly within the control of the Company. When a contingency is substantiated by confirming events, can be reliably measured and will likely result in an economic outflow, a liability is recognized in the financial statements as the best estimate required to settle the obligation. A contingent liability is disclosed where the existence of an obligation will only be confirmed by future events, or where the amount of a present obligation cannot be measured reliably or will likely not result in an economic outflow.

Contingent assets are only disclosed when the inflow of economic benefits is probable. When the economic benefit becomes virtually certain, the asset is no longer contingent and is recognized in the financial statements.

Convertible debentures

The Debentures are a non-derivative financial instrument that creates a financial liability of the entity and grants an option to the holder of the instrument to convert it into common shares of the Company. The liability component of the Debentures is initially recorded at the fair value of a similar liability that does not have a conversion option. The equity component is recognized initially, net of deferred income taxes, as the difference between gross proceeds and the fair value of the liability component. Transaction costs are allocated to the liability and equity components in proportion to the allocation of proceeds. Subsequent to initial recognition, the liability component of the Debentures is measured at amortized cost using the effective interest method and is accreted each period, such that the carrying value will equal the principal amount outstanding at maturity. The equity component is not re-measured. The carrying amounts of the liability and equity components of the Debentures are reclassified to shareholders' capital on conversion to common shares.

Income taxes

Total income tax expense is composed of both current and deferred income taxes.

Current tax is the expected tax payable on taxable income for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

The Company follows the liability method of accounting for income taxes. Under this method, deferred income tax is recognized in respect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred taxes are allocated between income and equity depending on the nature of the account balance or transaction that gives rise to the temporary difference.

Deferred tax liabilities are recognized for taxable temporary differences. Deferred tax assets are recognized for deductible temporary differences, unused tax losses and unused tax credits only if it is probable that sufficient future taxable income will be available to utilize those temporary differences and losses. Such deferred tax liabilities and assets are not recognized if the temporary difference arises from goodwill or from the initial recognition of an asset or liability in a transaction which is not a business combination and, at the time of the transaction, affects neither accounting profit nor taxable income. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date. The effect of a change in income tax rates on deferred tax assets and liabilities is recognized in the Consolidated Statement of Profit (Loss) and Comprehensive Income (Loss) in the period that the change occurs.

Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset current tax liabilities and assets, and they relate to income taxes levied by the same tax authority on the same taxable entity or on different tax entities but they intend to settle current tax liabilities and assets on a net basis or their tax assets and liabilities will be realized simultaneously. Deferred tax assets and liabilities are recorded on a non-discounted basis.

Revenue recognition

Kelt adopted IFRS 15 Revenue from contracts with customers with a date of initial application of January 1, 2018 as detailed in note 13. IFRS 15 replaces IAS 18 Revenue, IAS 11 Construction Contracts, and other related interpretations. Kelt used the modified retrospective approach to adopt the new standard, electing to use a practical expedient to apply the standard retrospectively only to contracts that were not completed on January 1, 2017. There was no change or adjustment to the Company's consolidated financial statements as a result of the adoption of IFRS 15; however IFRS 15 contains additional disclosure requirements which are detailed in note 13.

Kelt recognizes revenue at a point in time when control of the product has been transferred to the customer and performance obligations have been satisfied. This is generally met when the customer obtains legal title to the product and physical delivery at a delivery point has taken place. Revenue is measured based on the consideration specified in the contracts the Company has with its customers.

The Company applies a practical expedient and does not disclose quantitative or qualitative information on remaining performance obligations that have an original duration of one year or less. Kelt also applies a practical expedient that allows any incremental costs of obtaining contracts with customer to be recognized as an expense when incurred rather than being capitalized.

In the prior year, under IAS 18, revenue from the sale of oil and natural gas was recorded when the significant risks and rewards of ownership of the product were transferred to the buyer which was usually when legal title passes to the external party and collectability was reasonably assured. This was generally at the time product enters the pipeline.

Kelt evaluates its arrangements with 3rd parties and partners to determine if a principal or agent relationship exists. In making this evaluation, management considers if it maintains control of the product, which is indicated by the Company having the primary responsibility for the delivery of the product, having the ability to establish prices or having inventory risk. If an agency relationship exists, then the revenue is recognized net of fees, if any, realized by the party from the transaction.

Royalty income is recognized as it accrues in accordance with the terms of the overriding royalty agreements.

Financing expense

Financing expenses include interest expense on borrowings and accretion of the discount on decommissioning obligations due to the passage of time.

Borrowing costs incurred for the construction of qualifying assets are capitalized during the period of time required to complete and prepare the assets for their intended use. All other borrowing costs are recognized in financing expense using the effective interest method.

Share based compensation

The Company has an Incentive Stock Option Plan and Restricted Share Unit Plan (collectively, the “Plans”). Pursuant to the Plans, stock options and restricted share units (“RSUs”) may be granted to officers, directors, employees and certain consultants, which call for settlement through the issuance of new common shares of the Company.

The Company applies the fair value method of accounting for stock options, whereby each tranche in an award is valued separately on the grant date using the Black-Scholes option pricing model. The fair value of RSUs is calculated based on the volume weighted average trading price over three trading days immediately prior to the date of grant. The total fair value associated the stock options and RSUs is recognized over the service period using graded vesting, as share based compensation expense with a corresponding increase to contributed surplus. An estimated forfeiture rate is applied against the total fair value on the grant date and is adjusted to reflect the actual number of options that ultimately vest each period. The consideration received by the Company on the exercise of stock options is recorded as an increase in shareholders’ capital, together with the corresponding amounts previously recognized in contributed surplus.

Flow-through shares

Canadian tax legislation permits entities meeting specified criteria to issue securities to investors whereby the deductions for tax purposes related to eligible expenditures may be claimed by the investors rather than by the entity (herein referred to as “flow-through shares”). The Company uses the residual method to account for flow-through shares. Under this method, the proceeds from the issuance are allocated between i) the proceeds of the offering of shares, and ii) the renunciation of tax deductions. At the time the flow-through shares are issued: i) shareholders’ capital is credited based on the fair value of ordinary common shares, and ii) the tax deductions to be renounced are deferred and presented a liability in the Consolidated Statement of Financial Position, at an amount equal to the residual difference between the fair value of the Company’s ordinary common shares relative to the amount the investor pays for the flow-through shares. At the time the Company fulfills its obligation to pass on the tax deductions to investors, which is deemed to occur when the eligible expenditures are incurred, the liability (deferred premium) is drawn down in proportion to the eligible expenditures incurred in the period and the premium on flow-through shares is recognized as income in the Consolidated Statement of Profit (Loss) and Comprehensive Income (Loss). Concurrently, a deferred income tax liability is recognized for the taxable temporary difference that arises from the difference between the carrying amount of the eligible expenditures capitalized as an asset for accounting purposes and a tax base of nil, because the deduction has been renounced to investors.

Per share amounts

Basic profit (loss) per common share is calculated by dividing profit (loss) for the period attributable to common shareholders of the Company by the weighted average number of common shares outstanding during the period. Common shares issued as part of the consideration transferred in a business combination or common control transaction are included in the weighted average number of common shares starting from the acquisition date.

Diluted profit (loss) per common share is calculated giving effect to the potential dilution that would occur if all outstanding "in-the-money" stock options were exercised or converted to common shares. The weighted average number of common shares outstanding during the period is adjusted by the incremental number of shares calculated in accordance with the treasury stock method. The treasury stock method assumes that the proceeds received from the exercise of all potentially dilutive instruments are used to repurchase common shares at the volume weighted average market price during the period.

Accounting standards issued but not yet effective

IFRS 16 *Leases,* is intended to replace IAS 17 and will bring fundamental changes for all companies, including Kelt, who lease assets. The new standard is effective for annual reporting periods beginning on or after January 1, 2019, with early application permitted. The most significant financial reporting impacts of the changes include: all leases will be on the balance sheet of lessees, except those that meet the limited exception criteria; the measurement and presentation of expenses will be impacted and replaced by the recording of depreciation and financing expenses; the amount of profit (loss) recognized in a period will likely change as the timing of expenses is accelerated when applying the new standard which uses a finance lease model compared to a straight line operating lease expense; and key ratios may be impacted with the introduction of lease assets and liabilities on the balance sheet and changes to the timing of expenses. Management is currently finalizing the implementation of IFRS 16, with the impact on the Company's consolidated financial statements still being assessed; however the additional leases being brought on the balance sheet will likely be material.

4. PROPERTY ACQUISITIONS AND DISPOSITIONS

The following table summarizes the fair value of net assets acquired pursuant to property acquisitions during the year ended December 31, 2018 and the prior year ended December 31, 2017:

	December 31, 2018	December 31, 2017
Exploration and evaluation assets	**2,976**	531
Property, plant and equipment	**496**	-
Decommissioning obligations	**(612)**	-
Cash consideration and fair value, after closing adjustments	**2,860**	531

The table below summarizes the aggregate proceeds received and carrying values of the assets and associated decommissioning obligations disposed during the year ended December 31, 2018 and the prior year ended December 31, 2017, as well as the resulting net gain (loss) on sale in each period:

	December 31, 2018	December 31, 2017
Exploration and evaluation assets	**122**	7,310
Property, plant and equipment	**8,914**	102,985
Decommissioning obligations	**(2,528)**	(4,408)
Carrying value of net assets (liabilities) disposed	**6,508**	105,887
Cash proceeds, after closing adjustments (1)	**10,070**	116,323
Gain on sale of assets (1)	**3,562**	10,436

(1) The amounts reported in the table above were estimated based on information available at the time of preparation of these consolidated financial statements. In particular, closing adjustments were estimated based on an interim statement of adjustments. The actual gain or loss recognized by the Company will be based upon determination of final closing adjustments which may differ from these estimates.

Karr Non-Operated Disposition

On December 20, 2018 the Company completed the disposition of its non- operated assets in the Karr area for $7.1 million after closing adjustments. The Karr non-operated assets had a net carrying value of $3.7 million (costs of $10.9 million, accumulated depletion, depreciation and impairment of $6.5 million, and abandonment obligations of $0.7 million), resulting in a gain on sale of $3.4 million.

Leduc Disposition

On July 31, 2018, the Company completed the disposition of the Leduc-Woodbend CGU, a non-core oil weighted property for $2.6 million after closing adjustments. The Leduc-Woodbend CGU had a net carrying value of $2.6 million (costs of $25.1 million, accumulated depletion, depreciation and impairment of $20.7 million, and abandonment obligations of $1.8 million), resulting in a gain on sale of $0.05 million. In the second quarter of 2018, the Leduc-Woodbend CGU was impaired by $3.0 million based on the sale in the third quarter of 2018.

5. EXPLORATION AND EVALUATION ASSETS

Exploration and evaluation assets consist of the Company’s undeveloped land, geological and geophysical assets, and exploratory drilling costs for projects in which the technical feasibility or commercial viability has yet to be determined. At the time sufficient information becomes available to determine whether the project is technically feasible or commercially viable, which is generally the point at which proved reserves are discovered, the costs are either transferred to property, plant, and equipment or charged to exploration and evaluation expense.

The following table reconciles movements of exploration and evaluation assets:

	December 31, 2018	December 31, 2017
Balance, beginning of period	**123,349**	120,166
Additions	**44,283**	42,627
Property acquisitions [note 4]	**2,976**	531
Reclassification (to) from held for sale [note 4]	**-**	4,377
Property dispositions [note 4]	**(122)**	(7,310)
Transfers to property, plant and equipment	**(45,993)**	(35,731)
Expired mineral leases	**(5,211)**	(1,311)
Balance, end of period	**119,282**	123,349

The Company concluded that there are no indicators of potential impairment of its E&E assets at December 31, 2018.

6. PROPERTY, PLANT AND EQUIPMENT

Net carrying value	**December 31, 2018**	December 31, 2017
Development and production ("D&P") assets	**1,245,178**	1,107,715
Corporate assets	**511**	357
Total net carrying value of property, plant and equipment	**1,245,689**	1,108,072

The following table reconciles movements of property, plant and equipment ("PP&E") during the period:

Property, plant and equipment, at cost	D&P Assets	Corporate Assets	Total PP&E
Balance at December 31, 2016	1,377,416	2,474	1,379,890
Additions	200,349	793	201,142
Reclassification (to) from held for sale [note 4]	163,166	-	163,166
Property dispositions [note 4]	(172,821)	-	(172,821)
Decommissioning costs	9,288	-	9,288
Transfers from E&E	35,731	-	35,731
Balance at December 31, 2017	**1,613,129**	**3,267**	**1,616,396**
Additions	**247,663**	**762**	**248,425**
Property acquisitions [note 4]	**496**	-	**496**
Property dispositions [note 4]	**(36,222)**	**-**	**(36,222)**
Decommissioning costs	**7,584**	**-**	**7,584**
Transfers from E&E	**45,993**		**45,993**
Balance at December 31, 2018	**1,878,643**	**4,029**	**1,882,672**

Accumulated depletion, depreciation and impairment	D&P Assets	Corporate Assets	Total PP&E
Balance at December 31, 2016	379,770	1,943	381,713
Depletion and depreciation expense	126,531	967	127,498
Impairments	6,864	-	6,864
Reclassification (to) from held for sale [note 4]	62,085	-	62,085
Property dispositions [note 4]	(69,836)	-	(69,836)
Balance at December 31, 2017	**505,414**	**2,910**	**508,324**
Depletion and depreciation expense	**144,691**	**608**	**145,299**
Property dispositions [note 4]	**(27,308)**	**-**	**(27,308)**
Impairments	**10,668**	**-**	**10,668**
Balance at December 31, 2018	**633,465**	**3,518**	**636,983**

There were no borrowing costs capitalized in the current or prior year. Future capital costs required to develop proved reserves in the amount of $871.5 million (December 31, 2017 – $776.0 million) are included in the depletion calculation for development and production assets. At December 31, 2018, the balance of assets under construction not subject to depreciation or depletion was $66.3 million (December 31, 2017 – $13.5 million) and relate to the construction of a gas processing facility.

On July 31, 2018, the Company completed the disposition of the Leduc-Woodbend Cash Generating Unit ("CGU") for $2.6 million after closing adjustments. The Leduc-Woodbend CGU had a carrying value of $2.6 million, resulting in a gain on sale of $0.05 million. In the second quarter of 2018, the Leduc-Woodbend CGU was impaired by $3.0 million based on the sale in the third quarter of 2018.

As at December 31, 2018 Kelt's net asset value was greater than its market capitalization. As such, an impairment test was conducted over all Kelt's CGUs; however no impairment was recognized for the Company's core oil weighted CGUs in British Columbia and Greater Grande Prairie as the estimated recoverable amount of these CGUs significantly exceeded their carrying value.

Based on the impairment test performed on the Grande Cache CGU, it was determined that its carrying value was in excess of the recoverable amount resulting in an impairment loss of $7.7 million (before-tax). The impairment was a result of a decrease in forecast natural gas prices as at December 31, 2018 compared to forecast prices as at December 31, 2017. Despite being a low-cost property, the decrease in forecast natural gas prices had a pervasive impact on the recoverable amount calculated for the Grande Cache CGU, given that 99% of proved plus probable reserves of the Grande Cache property are natural gas. As at December 31, 2018, the net carrying amount of PP&E for the Grande Cache CGU was $12.1 million (which includes $14.5 million of accumulated impairment).

Recoverable amounts for each CGU were estimated based on FVLCD methodology which is calculated using the present value of the CGUs' expected future cash flows (after-tax). The cash flow information was derived from a report on the Company's oil and gas reserves which was prepared by an independent qualified reserve evaluator, Sproule Associates Limited ("Sproule") as of December 31, 2018. The projected cash flows used in the FVLCD calculation reflect market assessments of key assumptions as at December 31, 2018, including long-term forecasts of commodity prices, inflation rates, and foreign exchange rates (Level 3 fair value inputs). Cash flow forecasts are also based on Sproule's evaluation of the Company's reserves and resources to determine production profiles and volumes, operating costs, maintenance and future development capital expenditures. Future cash flow estimates are discounted using after-tax risk-adjusted discount rates. The after-tax discount rates applied in the impairment calculation as at December 31, 2018 ranged from 9.5% to 12% depending on the risks specific to the assets in the CGUs.

The recoverable amounts estimated pursuant to FVLCD calculations are sensitive to the discount rate and future commodity price assumptions. As at December 31, 2018, holding all other variables in the FVLCD calculation for each CGU constant:

- if the discount rate increased (decreased) by 1%, the impairment of the Grande Cache CGU would increase (decrease) by approximately $1.0 million; and
- if the forecast combined average realized price decreased (increased) by 5%, the impairment of the Grande Cache CGU would increase (decrease) by approximately $3.1 million.

Given the significant cushion between the carrying value and the recoverable amounts in the British Columbia CGU and the Grande Prairie CGU, the sensitivity analysis did not have an impact on the conclusions from the impairment calculation, being that a 1% increase (decrease) in the discount rate or 5% decrease (increase) in the forecast combined average realized price would not trigger an impairment for those CGUs as at December 31, 2018.

Forecast future prices used in the impairment evaluations as at December 31, 2018 and December 31, 2017, reflect the benchmark prices set-forth in the tables below, adjusted for basis differentials to determine local reference prices, transportation costs and tariffs, heat content and quality.

As at December 31, 2018	**2019**	**2020**	**2021**	**2022**	**2023(1)**
WTI Cushing Oklahoma (US$/bbl)	**58.44**	**63.75**	**67.28**	**70.50**	**73.54**
Canadian Light Sweet 40 API ($/bbl)	**66.93**	**74.99**	**79.71**	**82.90**	**86.33**
NYMEX Henry Hub (US$/MMBtu)	**3.00**	**3.14**	**3.36**	**3.53**	**3.68**
AECO-C Spot ($/MMBtu)	**1.85**	**2.28**	**2.68**	**2.99**	**3.21**
Exchange rate (CA$/US$)	**1.2987**	**1.2500**	**1.2500**	**1.2500**	**1.2500**

(1) Prices escalate at 2% after 2025 and between 2.0%-5.0% in years 2024 and 2025

As at December 31, 2017	2018	2019	2020	2021	2022[(1)]
WTI Cushing Oklahoma (US$/bbl)	55.00	65.00	70.00	73.00	74.46
Canadian Light Sweet 40 API ($/bbl)	65.44	74.51	78.24	82.45	84.10
NYMEX Henry Hub (US$/MMBtu)	3.25	3.50	4.00	4.08	4.16
AECO-C Spot ($/MMBtu)	2.65	3.08	3.35	3.56	3.67
Exchange rate (CA$/US$)	1.2658	1.2195	1.1765	1.1765	1.1765

(1) Prices escalate at 2.0% thereafter

7. BANK DEBT

	December 31, 2018	December 31, 2017
Bank loan	**-**	17,000
Bankers' acceptances	**170,000**	75,000
Prepaid interest and unamortized financing fees	**(1,119)**	(535)
Bank debt	**168,881**	91,465

The Company has a revolving committed term credit facility ("the Credit Facility") with a syndicate of financial institutions. As of December 31, 2018, the authorized borrowing amount available under the Credit Facility was $250 million, an increase of $65 million from $185 million in the prior year. The Credit Facility may be extended annually at Kelt's option and subject to lender approval, with a 364 day term-out period if not renewed.

The Credit Facility is subject to semi-annual borrowing base reviews, occurring approximately in April and October of each year. In the event that the lenders reduce the borrowing base below the amount drawn at the time of the redetermination, the Company would have 60 days to eliminate any borrowing base shortfall by repaying the amount drawn in excess of the re-determined borrowing base or by providing additional security or other consideration satisfactory to the lenders. Repayments of principal are not required provided that the borrowings under the facility do not exceed the authorized borrowing amount and the Company is in compliance with all covenants, representations and warranties.

There are no financial covenants under the Credit Facility and Kelt is in compliance with all other covenants. Covenants include industry standard positive and negative covenants including reporting requirements, permitted indebtedness, permitted dispositions (to a maximum in each calendar year which are in the aggregate not more than 5% of the borrowing base then in effect), permitted risk management activities (as more particularly described in note 11), permitted encumbrances and other standard business operating covenants. Security is provided for by a first fixed and floating charge debenture over all assets in the amount of $800.0 million and general assignment of book debts.

Interest is payable monthly for borrowings through direct advances. Interest rates fluctuate based on a pricing grid and range from bank prime plus 0.5% to bank prime plus 2.5%, depending upon the Company's then current debt to cash flow ratio of between less than 0.5 times to greater than three times. Under the Credit Facility, borrowings through the use of bankers' acceptances are also available. Stamping fees fluctuate based on a pricing grid and range from 1.5% to 3.5%, depending upon the Company's then current debt to earning before interest, taxes, depreciation and amortization ("EBITDA") ratio of between less than 0.5 times to greater than three times.

The following table reconciles movements in the balance of bank debt during the year:

	December 31, 2018
Bank debt balance, beginning of year	**91,465**
Net debt drawdown	**78,000**
Decrease in unamortized financing fees	**151**
Increase in prepaid interest on BAs	**(735)**
Net bank debt movement	**77,416**
Bank debt balance, end of year	**168,881**

8. CONVERTIBLE DEBENTURES

	Number of convertible debentures	Liability component ($ thousands)	Equity component ($ thousands)
Balance at December 31, 2016	90,000	70,978	12,856
Accretion of discount	-	3,539	-
Balance at December 31, 2017	**90,000**	**74,517**	**12,856**
Conversion of convertible debentures to equity	**(90)**	**(76)**	**(13)**
Accretion of discount	**-**	**3,949**	**-**
Balance at December 31, 2018	**89,910**	**78,390**	**12,843**

On May 3, 2016, the Company issued $90.0 million principal amount of convertible unsecured subordinated debentures for net proceeds of $86.4 million. The Debentures mature on May 31, 2021 (the "Maturity Date") and bear interest at 5.0% per annum payable semi-annually on May 31st and November 30th. At the holder's option, the Debentures may be converted into common shares of the Company at any time prior to the close of business on the earlier of the business day immediately preceding (i) the Maturity Date, (ii) if called for redemption, the date fixed for redemption by the Company, or (iii) if called for repurchase in the event of a change of control, the payment date, at a conversion price of $5.50 per share (the "Conversion Price").

The Debentures are redeemable by the Company after May 31, 2019 and prior to May 31, 2020, in whole or in part, on not more than 60 days and not less than 40 days prior notice at a redemption price equal to their principal amount plus accrued and unpaid interest provided that the volume weighted average trading price of the common shares on the TSX for the 20 consecutive trading days ending five trading days (the "Current Market Price") prior to the date on which notice of redemption is provided is at least 125% of the Conversion Price. On or after May 31, 2020 and prior to the Maturity Date, the Debentures may be redeemed by the Company, in whole or in part on not more than 60 days and not less than 40 days prior notice at a redemption price equal to their principal amount plus accrued and unpaid interest.

The Company may elect to satisfy its obligation to repay all or any portion of the principal amount of the Debentures upon redemption or due at maturity, by issuing common shares instead of cash (subject to the receipt of any required regulatory approvals and provided that no event of default has occurred). The number of common shares to be issued would be obtained by dividing the principal amount of the Debentures by 95% of the Current Market Price on the date fixed for redemption or maturity.

Accretion of the liability component and accrued interest payable on the Debentures are included in financing expenses in the Consolidated Statement of Profit (Loss) and Comprehensive Income (Loss) (note 14). As at December 31, 2018, the Debentures are not "in-the-money" based on the closing price of Kelt common shares on the TSX of $4.64 on December 31, 2018, being the last trading day in the year. To date, $0.09 million of the face value has been converted to $0.02 million shares and $89.9 million principal amount is outstanding. The fair value of the Debentures at the year-end date was $99.6 million (note 11).

9. DECOMMISSIONING OBLIGATIONS

Decommissioning obligations arise as a result of the Company's net ownership interests in petroleum and natural gas assets including well sites, processing facilities and infrastructure. The following table provides a reconciliation of the carrying amount of the obligation associated with the retirement of oil and gas properties:

	December 31, 2018	December 31, 2017
Balance, beginning of period	**136,928**	128,047
Obligations incurred	**8,244**	6,624
Obligations acquired	**612**	-
Reclassification (to) from held for sale [note 4]	**-**	2,532
Obligations disposed [note 4]	**(2,528)**	(4,408)
Obligations settled	**(1,122)**	(1,512)
Changes in discount rate	**4,786**	2,221
Revisions to estimates	**(5,446)**	443
Accretion expense	**3,193**	2,981
Balance, end of period	**144,667**	136,928
Decommissioning obligations – current	**904**	1,585
Decommissioning obligations – non-current	**143,763**	135,343
Key assumptions		
Risk free rate	**2.18%**	2.26%
Inflation rate	**2.0%**	2.0%

The underlying cost estimates are derived from a combination of published industry benchmarks as well as site specific information. As at December 31, 2018, the undiscounted amount of the estimated cash flows required to settle the obligation is $153.4 million (December 31, 2017 – $148.3 million), and is expected to be incurred over the next 50 years. Based on an inflation rate of 2.0%, the undiscounted amount of the estimated future cash flows required to settle the obligation is $303.1 million at December 31, 2018 (December 31, 2017 – $282.0 million). The inflated future cost estimates are discounted based on a risk-free rate to determine the carrying amounts presented in the table above.

Accretion of the decommissioning obligation due to the passage of time is presented within financing expenses in the Consolidated Statement of Profit (Loss) and Comprehensive Income (Loss) (note 14).

10. SHARE CAPITAL

Authorized

The Company is authorized to issue an unlimited number of common shares and an unlimited number of preferred shares, each without par value.

Issued and outstanding

The following table summarizes the change in common shares issued and outstanding. There are no preferred shares issued or outstanding as of December 31, 2018 (December 31, 2017 – nil).

	Number of Shares (000s)	Amount ($ thousands)
Balance at December 31, 2016	175,672	1,055,959
Issued for cash through common share offerings	2,585	20,605
Deferred premium on flow-through shares	-	(2,553)
Issued for cash on exercise of stock options	415	2,299
Transfer from contributed surplus on exercise of stock options	-	935
Released upon vesting of restricted share units	186	1,740
Share issue costs, net of deferred taxes ($103)	-	(212)
Balance at December 31, 2017	**178,858**	**1,078,773**
Issued for cash through common share offerings	**2,758**	**24,776**
Deferred premium on flow-through shares	**-**	**(3,099)**
Conversion of convertible debentures to common shares	**16**	**76**
Transfer from equity component of convertible debentures on conversion of convertible debentures to common shares	**-**	**13**
Issued for cash on exercise of stock options	**2,081**	**12,687**
Transfer from contributed surplus on exercise of stock options	**-**	**5,007**
Released upon vesting of restricted share units	**290**	**1,606**
Share issue costs, net of deferred taxes ($224)	**-**	**(607)**
Balance at December 31, 2018	**184,003**	**1,119,232**

Flow-through common shares

Canadian tax legislation permits entities meeting specified criteria to issue securities to investors whereby the deductions for tax purposes related to eligible expenditures may be claimed by the investors rather than by the entity. The table below summarizes flow-through common shares ("FTS") issued during the year ended December 31, 2018 and the year ended December 31, 2017. As of December 31, 2018 all eligible expenditures for the Company's flow through shares issued in 2018 and 2017 have been incurred.

(CA$ thousands, except as otherwise indicated)					Eligible Expenditures [1]			Expenditure Period End / Effective date of Renunciation
						As at December 31, 2018		
Closing Dates	# of FTS	Price per FTS	Gross Proceeds	Deferred Premium	Type	**Incurred**	**Remaining**	
October 11, 2017	**1.263 million**	**$7.75**	**9,785**	**896**	**CDE**	**9,785**	**-**	**December 31, 2017 December 31, 2017**
October 27, 2017	**0.75 million**	**$7.75**	**5,811**	**615**	**CDE**	**5,811**	**-**	**December 31, 2017 December 31, 2017**
October 27, 2017	**0.572 million**	**$8.75**	**5,009**	**1,042**	**CEE**	**5,009**	**-**	**December 31, 2018 December 31, 2017**
April 27, 2018, April 30, 2018	**2.348 million**	**$8.85**	**20,778**	**2,324**	**CDE**	**20,778**	**-**	**December 31, 2018 December 31, 2018**
April 27, 2018, April 30, 2018	**0.410 million**	**$9.75**	**3,998**	**775**	**CEE**	**3,998**	**-**	**December 31, 2018 December 31, 2018**

(1) Pursuant to the provisions of the *Income Tax Act* (Canada), the Company has incurred eligible Canadian development expenses ("CDE") or Canadian exploration expenses ("CEE") as required under the respective subscription agreements.

Stock options

Kelt has an Incentive Stock Option Plan (the “Option Plan”) that provides for granting of stock options to directors, officers, employees and certain consultants. The stock options granted pursuant to the Option Plan are to be settled through the issuance of new common shares of the Company, typically vest in equal tranches over a three year period and have a maximum term of five years to expiry.

The following table summarizes the change in stock options outstanding:

	Number of Options (000s)	Average Exercise Price ($/share)
Balance at December 31, 2016	8,376	6.57
Granted	2,347	6.25
Exercised (1)	(415)	5.54
Forfeited	(414)	7.03
Balance at December 31, 2017	**9,894**	**6.51**
Granted	**2,590**	**5.29**
Exercised (1)	**(2,081)**	**6.10**
Forfeited	**(247)**	**6.94**
Expired	**(353)**	**8.42**
Balance at December 31, 2018	**9,803**	**6.20**

(1) The weighted average share price on the date stock options were exercised during the period ended December 31, 2018 was $7.74 per common share ($6.96 per common share on average during the year ended December 31, 2017).

The total fair value of each option granted is estimated on the date of grant using the Black-Scholes option pricing model with weighted average assumptions as follows:

	Year ended December 31	
	2018	2017
Risk free interest rate	**2.2%**	1.3%
Expected life (years)	**3.4**	3.5
Expected volatility (1)	**48.2%**	53.8%
Expected dividend yield	**0.0%**	0.0%
Expected forfeiture rate	**4.9%**	2.5%
Fair value of options granted during the year ($/share)	**1.94**	2.44

(1) The expected volatility for options granted is estimated based on Kelt’s historical volatility over the expected life.

The following table summarizes information regarding stock options outstanding at December 31, 2018:

Range of exercise prices per common share	Number of options outstanding (000s)	Weighted average remaining term (years)	Weighted average exercise price for options outstanding ($/share)	Number of options exercisable (000s)	Weighted average exercise price for options exercisable ($/share)
$0.00 to $5.00	5,057	3.3	4.63	2,272	4.50
$5.01 to $10.00	3,813	2.9	6.73	1,906	6.85
$10.01 to $15.00	873	0.3	12.40	873	12.40
$15.01 to $20.00	60	0.5	15.40	60	15.40
Total	**9,803**	**2.9**	**6.20**	**5,111**	**6.86**

Restricted share units

Kelt has a restricted share unit plan that provides for granting of restricted share units (“RSUs”) to officers, employees and certain consultants. The RSUs granted under the RSU Plan are to be settled through the issuance of new common shares upon vesting. RSUs typically vest in two equal tranches with the first half vesting after two years and the second half after three years.

The following table summarizes the change in RSUs outstanding:

	Number of RSUs (000s)
Balance at December 31, 2016	720
Granted	325
Released upon vesting	(186)
Forfeited	(66)
Balance at December 31, 2017	**793**
Granted	**625**
Released upon vesting	**(290)**
Forfeited	**(31)**
Balance at December 31, 2018	**1,097**

Share based compensation expense

The total fair value associated with stock options and RSUs is recognized over the service period using graded vesting, resulting in share based compensation expense as follows:

	Year ended December 31	
	2018	2017
Stock options	**3,964**	3,867
Restricted share units	**2,144**	1,572
Total share based compensation expense	**6,108**	5,439

Per share amounts

The table below summarizes the weighted average number of common shares outstanding used in the calculation of basic and diluted profit (loss) per common share:

	Year ended December 31	
(000s of common shares)	**2018**	2017
Weighted average common shares outstanding, basic	**182,576**	176,466
Effect of stock options and RSUs	**1,817**	1,454
Effect of convertible debentures	**-**	-
Weighted average common shares outstanding, diluted	**184,393**	177,920

The Company uses the treasury stock method to determine the dilutive effect of stock options and RSUs. Under this method, only “in-the-money” dilutive instruments impact the calculation of diluted profit per common share. Accordingly, in computing the diluted profit or loss per common share for the periods ended December 31, 2018 and 2017, the Company excluded the effect of the conversion of the Debentures as they are anti-dilutive. In computing the diluted loss per common share for the period ended December 31, 2017, the Company excluded the effect of stock options and RSUs as they were anti-dilutive.

11. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Financial instruments of the Company include cash and cash equivalents, accounts receivable and accrued revenue, deposits, accounts payable and accrued liabilities, derivative financial instruments, convertible debentures, and bank debt. The Company is exposed to financial risks arising from its financial assets and liabilities that include credit and liquidity risk in addition to the market risks associated with commodity prices, and interest and foreign exchange rates. Profit (loss), cash flows and the fair value of financial assets and liabilities may fluctuate due to movement in market prices or as a result of the Company's exposure to credit and liquidity risks.

The Company uses derivative financial instruments from time to time in order to manage market risks. The objective of risk management is to manage and control market risk exposures within acceptable limits, while maximizing long-term returns. All such transactions are conducted in accordance with the Company's established risk management policies that permit management to enter into commodity price agreements, provided that:

i) the contracts are not entered into for speculative purposes;
ii) the total notional quantity hedged, at the time of entering into the contract, does not exceed 65% of average daily production; and
iii) the contracted term does not exceed 36 months.

Commodity price risk

Inherent to the business of producing oil and gas, the Company's cash provided by operating activities is subject to commodity price risk. Commodity price risk is the risk that future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices are impacted by world economic events that dictate the levels of supply and demand as well as the currency exchange rate relationship between the Canadian and U.S. dollar.

As at December 31, 2018, the following commodity price risk management contracts outstanding:

Contract Type	Notional Volume	Reference Prices	Fixed Contract Price	Term
Financial Swap Natural Gas	10,000 MMBtu/d	NYMEX to Chicago Citygate Basis Differential	NYMEX Henry Hub less USD$0.14 per MMBtu	January 2019 to October 2019
Financial Swap Natural Gas	10,000 MMBtu/d	NYMEX to Union Dawn Basis Differential	NYMEX Henry Hub less USD$0.0975 per MMBtu	January 2019 to December 2019
Financial Swap Natural Gas	7,500 MMBtu/d	Sumas	USD$5.97 per MMBtu	November 2018 to March 2019
Financial Swap Natural Gas	5,000 MMBtu/d	Malin	USD$4.55 per MMBtu	January 2019 to March 2019

Interest rate risk

The Company is exposed to interest rate risk to the extent that changes in market interest rates will impact the Company's Credit Facility which is subject to a floating interest rate. Based on average bank debt outstanding of $127.4 million during 2018, an increase (decrease) in the market rate of interest by 25 basis points would have increased (decreased) annualized interest expense by $0.3 million.

As at December 31, 2018, there are no interest rate risk management contracts outstanding.

Foreign exchange risk

Kelt is exposed to fluctuations of the Canadian to U.S. dollar exchange rate given realized pricing is directly influenced by U.S. dollar denominated benchmark pricing. In addition, the Company has natural gas marketing arrangements in place whereby Kelt receives revenue in U.S. dollars. The Company also has commitments for firm gas transportation service under contracts denominated in U.S. dollars as outlined in note 15. The Company may enter into derivative contracts to mitigate the impact of foreign currency fluctuations. As at December 31, 2017, there were no foreign exchange risk management contracts outstanding.

As at December 31, 2018, the following foreign exchange risk management contracts outstanding:

Contract Type	Notional Amount per month	Fixed Contract Price	Term
FX swap	US$1,000,000	CA$/US$ 1.3050	January 2019 to December 2019

Gains and losses on risk management contracts

The table below summarizes realized and unrealized gains (losses) on risk management contracts:

	Year ended December 31	
	2018	2017
Realized loss	**(5,900)**	(1,050)
Unrealized gain	**2,596**	599
Loss on derivative financial instruments	**(3,304)**	(451)

Fair value measurements

The Company classifies fair value measurements using a fair value hierarchy that reflects the significance of the inputs used in making the measurements. The Company maximizes the use of observable inputs when preparing calculations of fair value, where possible. The fair value hierarchy has the following levels:

- Level 1 - Values are based on unadjusted quoted prices available in active markets for identical assets or liabilities as of the reporting date.
- Level 2 - Values are based on inputs, including quoted forward prices for commodities, time value and volatility factors, which can be substantially observed or corroborated in the marketplace. Prices in Level 2 are either directly or indirectly observable as of the reporting date.
- Level 3 - Values are based on prices or valuation techniques that are not based on observable market data.

Assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement within the fair value hierarchy.

The fair value of cash and cash equivalents, accounts receivable and accrued revenue, deposits, accounts payable and accrued liabilities approximate their carrying value due to the short term to maturity of these instruments. Bank debt bears interest at a floating market rate and accordingly the fair market value of bank debt approximates the carrying amount. The fair value of the convertible debentures is estimated using quoted market prices on the TSX as of the Consolidated Statement of Financial Position date.

The fair value of financial assets and liabilities, excluding working capital, is attributable to the following fair value hierarchy levels at December 31, 2018:

	Carrying Value ("CV")			Fair Value		
	Gross	Netting(1)	Net CV	Level 1	Level 2	Level 3
Financial assets						
Derivative financial instrument	3,247	-	-	-	3,247	-
Investment in securities	1,000	-	-	-	-	1,000
Financial liabilities						
Derivative financial instrument	651	-	-	-	651	-
Convertible debentures (note 8)	78,390	-	-	99,601	-	-

(1) Financial assets and liabilities are only offset if the Company has the current legal right to offset and intends to settle on a net basis or settle the asset and liability simultaneously. Kelt offsets derivative contracts assets and liabilities when the counterparty, commodity, currency and timing of settlement are the same.

Kelt's investment in securities includes an investment in a private corporation entered into during the first quarter of 2018. The estimated fair value of the Company's investments in the shares of private companies is based on equity issuances and other indications of value from time-to-time (level three fair value hierarchy inputs).

The fair value of the convertible debentures of $99.6 million as at December 31, 2018, is based on the closing market price of $110.73 per Debenture, being the price at which the Debentures last traded on the year ended December 31, 2018, and represents the market value of the entire instrument. As at December 31, 2017, the fair value was $135.0 million based on the closing market price of $150.00 per Debenture at the end of the year.

Credit risk

As at December 31, 2018, the carrying amount of cash and cash equivalents, accounts receivable and accrued revenue, and deposits, represent the Company's maximum credit exposure. Cash and cash equivalents are held on deposit with a Canadian chartered bank. The Company's credit risk exposure arises primarily from receivables from oil and gas marketers and joint venture partners.

The composition of the Company's accounts receivable is set out in the following table:

Accounts receivable and accrued revenue	**December 31, 2018**	December 31, 2017
Oil and gas marketers	**35,129**	30,996
Joint venture partners	**3,672**	3,654
GST input tax credits	**4,559**	4,419
Other	**2,820**	377
Accounts receivable and accrued revenue	**46,180**	39,446

During the year ended December 31, 2018, sales to three oil and gas marketers each individually represented more than 10% of total revenue. Sales to these marketers account for approximately 40%, 18%, and 11% of total revenue, respectively. During the comparative period ended December 31, 2017, sales to three oil and gas marketers accounted for approximately 38%, 17%, and 11% of total revenue, respectively. Kelt's oil and gas marketers have either provided parental guarantees (with terms ranging from two to five years), or have been rated investment-grade by a reputable ratings agency for substantially all of the Company's monthly credit exposure.

The oil and gas industry has a pre-arranged monthly clearing day for payment of revenues from all buyers of oil and natural gas; this occurs on the 25th day following the month of sale. As a result, the Company's production revenues are current. All other accounts receivable are generally contractually due within 30-90 days.

The balance of accounts receivable outstanding for more than 90 days relates primarily to receivables from the Company's joint venture partners. Credit risk related to joint venture receivables is mitigated by obtaining partner approval of significant capital expenditures prior to expenditure and in certain circumstances may require cash deposits in advance of incurring financial obligations on behalf of joint venture partners. The Company has the ability to withhold production from joint venture partners in the event of non-payment or may be able to register security on the assets of joint venture partners.

The aging of the Company's accounts receivable and the loss allowance provision is determined as follows:

Accounts receivable and accrued revenue	Current	30-60 days	60-90 days	Over 90 days	Total
Gross accounts receivable	43,704	968	607	1,439	46,718
Estimated credit loss rate	0.4%	3.7%	3.6%	21.7%	
Loss allowance provision	(167)	(36)	(22)	(313)	(538)
Balance at December 31, 2018	**43,537**	**932**	**585**	**1,126**	**46,180**
Balance at December 31, 2017	37,889	325	189	1,043	39,446

The allowance for doubtful accounts provision as at December 31, 2018 reconciles to the opening loss allowance provision as at January 1, 2017 in the following table:

	Amount ($ thousands)
Allowance for doubtful accounts at January 1, 2017	789
Direct write-off of amounts included in provision	(123)
Allowance for doubtful accounts at December 31, 2017	**666**
Provisions for potential credit losses through profit or loss	(128)
Loss allowance balance at December 31, 2018	**538**

During the year ended December 31, 2018, the Company's recognized a decrease in the loss allowance provision resulting in a recovery in the statement of Consolidated Statement of Profit (Loss) and Comprehensive Income of $0.1 million (December 31, 2017 – nil).

Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they are due. The Company's financial liabilities include accounts payable, derivative financial instruments, bank debt and convertible debentures. The Company manages liquidity risk through prudent use of bank debt and an actively managed production and capital expenditure budgeting process. In addition, risk management contracts such as derivative financial instruments may be used from time to time. As discussed further under the *Capital Management* section to follow, Kelt targets a relatively low debt to trailing adjusted funds from operations ratio. To manage this, the Board of Directors approves an annual capital expenditure budget, which is regularly monitored and updated as necessary in response to changing capital requirements.

The capital intensive nature of Kelt's operations may create a working capital deficiency position during periods with high levels of capital investment. However, during such periods, the Company targets to maintain sufficient unused bank credit lines to satisfy such working capital deficiencies. As at December 31, 2018, the Company's working capital deficit of $28.0 million combined with outstanding bank debt of $168.9 million, represented 79% of the authorized borrowing amount available under the Credit Facility of $250.0 million (up from 74% at December 31, 2017). The Credit Facility is available for a revolving period of 364 days, maturing on April 28, 2019, and may be extended annually at Kelt's option and subject to lender approval, with a 364 day term-out period if not renewed.

On April 18, 2018 the facility was amended and the revolving period was extended to April 28, 2019. On November 8, 2018 the authorized borrowing amount available under the Credit Facility was increased to $250.0 million. In 2018. The pricing grid range was amended to bank prime plus 0.5% to bank prime plus 2.5% (from 1.0% to 2.5% previously), and the stamping fee range was changed to 1.5% to 3.5% (from 2.0% to 3.5% previously) depending upon the Company's then current debt to EBITDA ratio of between less than one half times to greater than three times.

The table below outlines a contractual maturity analysis for Kelt's financial liabilities as at December 31, 2018:

	Within 1 Year	1 to 5 Years	More than 5 Years	**Total**
Accounts payable and accrued liabilities	83,530	-	-	**83,530**
Derivative financial liabilities	651	-	-	**651**
Bank debt and estimated interest(1)	7,600	168,881	-	**176,481**
Convertible debentures(2)	4,496	96,278	-	**100,774**
Total	**96,277**	**265,159**	**-**	**361,436**

(1) Estimated interest for future periods related to the Credit Facility was calculated using the weighted average interest rate of 4.5% for the quarter ended December 31, 2018, applied to the principal balance outstanding as at that date. For purposes of this analysis, principal repayment of the Company's revolving Credit Facility is assumed to occur on April 28, 2019.

(2) The contractual maturity analysis includes semi-annual cash interest payments at the fixed coupon rate of 5.0%, assuming that the $89.9 million principal amount of the Debentures is outstanding for the full term to maturity on May 31, 2021, provided that: the equity conversion option is not first exercised by the holder; and that the Company does not elect to settle its financial obligation by issuing common shares instead of cash at redemption or maturity. Refer to additional information regarding the Debentures in note 8.

Capital management

The Company's capital structure is comprised of shareholders' capital, convertible debentures, bank debt and working capital. Kelt's objectives when managing its capital structure is to maintain financial flexibility in order to meet financial obligations, as well as to finance future growth through capital expenditures relating to exploration, development and acquisition activities.

The Company monitors its capital structure and short-term financing requirements using a net debt to trailing adjusted funds from operations ratio, which is a non-GAAP financial measure.

	December 31, 2018	December 31, 2017
Bank debt	**168,881**	91,465
Working capital deficiency	**27,535**	45,264
Net debt (1)	**196,416**	136,729
Trailing annualized adjusted funds from operations (2)(3)	**186,839**	131,592
Net debt to trailing adjusted funds from operations ratio (1)	**1.1**	1.0

(1) "Net debt" is equal to "Bank debt, net of working capital" determined in accordance with GAAP.

(2) Adjusted funds from operations is a non-GAAP financial measure which is calculated as cash provided by operating activities before changes in non-cash operating working capital, and adding back (if applicable): transaction costs, provisions for potential credit losses, and settlement of decommissioning obligations.

(3) Trailing adjusted funds from operations is annualized based on the most recent quarter's adjusted funds from operations.

Kelt targets a net debt to trailing adjusted funds from operations ratio of less than 2.0 times. The Company manages its capital structure and makes adjustments according to market conditions in order to maintain flexibility to achieve its objectives stated above. To adjust its capital structure, the Company may increase or decrease capital expenditures, issue new shares, issue new debt or repay existing debt.

The Company's net debt to trailing adjusted funds from operations ratio of 1.1 times increased as at December 31, 2018 from 1.0 times at December 31, 2017.

As more particularly described in note 7, Kelt is subject to certain non-financial covenants under the Credit Facility agreement. As at December 31, 2018, the Company is in compliance with all covenants. The Company is not subject to any other externally imposed capital requirements.

The Company also has $90.0 million principal amount of convertible unsecured subordinated debentures which mature on May 31, 2021 as described in note 8.

12. INCOME TAXES

Kelt was not required to pay income taxes in the current or prior year as the Company had sufficient income tax deductions available to shelter taxable income. Tax deductions available as of December 31, 2018 are estimated to be approximately $1,048.6 million (December 31, 2017 – $977.8 million).

The following table reconciles income taxes calculated at the weighted average Canadian statutory rate with the actual provision for deferred income taxes per the Consolidated Statement of Profit (Loss) and Comprehensive Income (Loss):

	Year ended December 31	
	2018	2017
Profit (Loss) before income taxes	**22,853**	(26,320)
Canadian statutory tax rate	**27.0%**	26.7%
Expected income tax expense (recovery)	**6,170**	(7,033)
Increase (decrease) resulting from:		
Non-deductible expenses (1)	**1,659**	1,473
Recognition deferred tax asset	**(1,569)**	(2,052)
Qualifying expenditures on flow-through shares	**8,042**	5,094
Premium on flow-through shares	**(1,118)**	(624)
Change in tax rates	**1,515**	-
Deferred income tax expense (recovery)	**14,699**	(3,142)

(1) Non-deductible expenses primarily include share based compensation.

The Canadian statutory tax rate per the rate reconciliation above represents the weighted average combined federal and provincial corporate tax rate. The federal corporate tax rate is 15.0% and the provincial tax rate is 12.0% in both British Columbia and Alberta.

The movement in deferred income tax assets and liabilities, without taking into consideration the offsetting balances within the same tax jurisdiction are as follows:

Deferred income tax asset (liability)	Balance at December 31, 2017	Recognized in profit and CI(1)	Recognized in balance sheet	**Balance at December 31, 2018**
Derivative financial instruments	-	(701)	-	(701)
PP&E and E&E	(158,566)	(19,468)	-	(178,034)
Decommissioning obligations	36,505	2,556	-	39,061
Convertible debentures	(3,604)	878	-	(2,726)
Share and debt issue costs	1,333	(924)	224	633
Reserve from common control transaction	(5,058)	1,557	-	(3,501)
Non-capital losses (2)	90,259	1,403	-	91,662
	(39,131)	(14,699)	224	**(53,606)**

Deferred income tax asset (liability)	Balance at December 31, 2016	Recognized in profit and CI(1)	Recognized in balance sheet	**Balance at December 31, 2017**
Derivative financial instruments	162	(162)	-	**-**
PP&E and E&E	(144,335)	(14,231)	-	**(158,566)**
Decommissioning obligations	34,144	2,361	-	**36,505**
Convertible debentures	(4,368)	764	-	**(3,604)**
Share and debt issue costs	2,847	(1,592)	78	**1,333**
Reserve from common control transaction	(7,113)	2,055	-	**(5,058)**
Non-capital losses (2)	76,312	13,947	-	**90,259**
	(42,351)	3,142	78	**(39,131)**

(1) Comprehensive income has been abbreviated as “CI”.

(2) The Company’s non-capital losses expire in years 2023 to 2037.

The amount and timing of reversals of temporary differences will be dependent upon a number of factors, including the nature and timing of future capital expenditures and the Company’s future operating results.

13. REVENUE

Kelt sells its oil, natural gas, and NGLs production pursuant to variable price contracts. The transaction price is based on a benchmark commodity price, adjusted for quality, location or other factors, whereby each component of the pricing formula (apart from the benchmark commodity price) can be either fixed or variable, depending on the contract terms. Revenues are typically collected on the 25th day of the month following the prior month's production, with revenue being recorded once the product is delivered to a contractually agreed upon delivery point.

Kelt generates oil treating, gas processing, and other services income from fees charged to third parties provided at facilities where Kelt has an ownership interest. Kelt generates marketing revenue from the sales of third party volumes related to the Company's oil blending operations, with the production being sold under the same terms of the Company's variable oil price contracts discussed above.

Gas production sales includes revenue related to transportation for contracts where pricing is based on a market index at a location different from the sales delivery point where Kelt is the principal to transportation arrangements after the point where title is transferred to a third party. Transportation costs incurred in the year in relation to these contracts was $17 million.

Kelt has certain index based long term commodity sales contracts where the volumes under these contracts for future periods have not yet been fulfilled resulting in unsatisfied or partially unsatisfied performance obligations as at the reporting date. These contracts have varying durations, with the longest individual commodity sales contract ending in October 2020.

In the first quarter of 2018, Kelt adopted IFRS 15 Revenue from contracts with customers as detailed in note 3, using modified retrospective approach. There was no change or adjustment to the Company's consolidated financial statements as a result of the adoption of IFRS 15.

The following table presents Kelt's production disaggregated by revenue source:

Revenue, before royalties and financial instruments:	**December 31, 2018**	December 31, 2017
Oil production	**198,117**	140,840
Oil treating and other	**3,170**	2,159
NGLs production	**39,310**	26,382
Gas production	**120,018**	81,934
Gas processing and other	**1,734**	3,091
Marketing revenue	**26,928**	3,151
Total revenue	**389,277**	257,557

Included in accounts receivable at December 31, 2018 is $35.1 million (December 31, 2017 - $31.0 million) of accrued oil and gas sales related to December 2018 production.

14. FINANCING EXPENSES

The following table summarizes significant components of the Company's financing expenses:

	Year ended December 31	
	2018	2017
Interest on bank debt	**5,556**	3,310
Interest on convertible debentures	**4,497**	4,500
Accretion of convertible debentures	**3,949**	3,539
Accretion of decommissioning obligations [note 9]	**3,193**	2,981
Financing expense	**17,195**	14,330

15. COMMITMENTS

As of December 31, 2018, the Company is committed to future payments under the following agreements:

(CA$ thousands)	2019	2020	2021	2022	2023	Thereafter
Operating lease - office buildings	973	1,043	1,064	1,085	379	-
Operating lease - vehicles	470	322	154	-	-	-
Firm processing commitments (1)	13,278	13,386	19,481	20,429	19,073	106,952
Firm transportation commitments (2)	43,922	27,332	23,246	22,717	19,784	161,863
Total annual commitments	**58,643**	**42,083**	**43,945**	**44,231**	**39,236**	**268,815**

(1) Includes gas gathering related to the Company's firm processing commitments

(2) A portion of Kelt's commitments on the Alliance pipeline are denominated in US dollars. The volumes committed vary over the term of the contract, which is effective until October 31, 2020, respectively. Amounts are translated to Canadian dollars at the spot rate on December 31, 2018 of CA$/US$1.3642.

Payments under the office building operating leases relate to the Company's head office in Calgary, Alberta, and field offices in Grande Prairie, Alberta and Fort St. John, British Columbia. The leases expire on April 30, 2023, February 28, 2020, and July 31, 2023, respectively, if not extended.

During 2018 firm transportation and processing commitments increased by $357 million primarily due to take or pay commitments on the North Montney Mainline, a firm processing agreement for 30 mmcf per day of raw gas over a 10 year term, and a firm processing agreement of 75 mmcf per day over a 10 year term.

16. GENERAL AND ADMINISTRATIVE ("G&A") EXPENSES

The following table summarizes significant components of the Company's G&A expenses:

	Year ended December 31	
	2018	2017
Salaries and benefits (1)	**9,383**	8,247
Other G&A expenses	**4,664**	4,323
G&A expenses before recoveries	**14,047**	12,570
Overhead recoveries	**(5,695)**	(5,006)
General and administrative expense	**8,352**	7,564

(1) Refer to additional information regarding salaries and benefits paid to key management personnel in note 18 of these financial statements.

17. SUPPLEMENTAL CASH FLOW INFORMATION

	Year ended December 31	
Changes in non-cash working capital	**2018**	2017
Accounts receivable and accrued revenue	**(6,734)**	(9,040)
Prepaid expenses and deposits	**337**	(814)
Accounts payable and accrued liabilities	**(4,253)**	32,124
Change in non-cash working capital	**(10,650)**	22,270
Relating to:		
Operating activities	**538**	8,723
Investing activities	**(11,188)**	13,547
Change in non-cash working capital	**(10,650)**	22,270

During the reporting period, the Company made the following cash outlays in respect of interest and taxes:

	Year ended December 31	
Cash outlays in respect of interest and taxes	**2018**	2017
Interest and standby fees on bank debt	**6,140**	3,193
Interest on convertible debentures (1)	**4,498**	4,500
Taxes (2)	**-**	-

(1) Interest on the Debentures is payable semi-annually on May 31st and November 30th (note 8).

(2) Kelt was not required to pay cash income taxes as the Company had sufficient income tax deductions available to shelter taxable income (note 12).

18. RELATED PARTY TRANSACTIONS

A director of the Company is also a partner at a law firm which Kelt has engaged to provide legal services. During the year ended December 31, 2018, the Company incurred $0.4 million (2017 – $0.3 million) in legal fees and disbursements.

Key management personnel are those persons having authority and responsibility for planning, directing and controlling the activities of the Company. The following table summarizes compensation paid or payable to officers and directors of the Company:

	Year ended December 31	
	2018	2017
Salaries, bonuses and other benefits	**2,116**	1,752
Share based compensation	**4,135**	2,185
Total compensation	**6,251**	3,937

During the year ended December 31, 2018, key management personnel were granted 194,000 RSUs and 1,187,000 stock options with an exercise price of $5.43 per share. During the previous year ended December 31, 2017, key management personnel were granted 89,000 RSUs and 984,000 stock options with an exercise price of $6.09 per share.

ABBREVIATIONS

bbls	barrels
mbbls	thousand barrels
bbls/d	barrels per day
BOE	barrels of oil equivalent
mBOE	thousand barrels of oil equivalent
BOE/d	barrels of oil equivalent per day
mcf	thousand cubic feet
mmcf	million cubic feet
bcf	billion cubic feet
mmcf/d	million cubic feet per day
MMBtu	million British Thermal Units
GJ	gigajoules
AECO	Alberta Energy Company "C" Meter Station of the NOVA Pipeline System
NIT	NOVA Inventory Transfer ("AB-NIT"), being the reference price at the AECO Hub
WTI	West Texas Intermediate
NYMEX	New York Mercantile Exchange
Station 2	Spectra Energy receipt location
NGX	Natural Gas Exchange Inc. (Canada)
API	American Petroleum Institute
MD&A	Management's Discussion and Analysis
Q1	First quarter ended March 31st
Q2	Second quarter ended June 30th
Q3	Third quarter ended September 30th
Q4	Fourth quarter ended December 31st
YTD	Year to date
BT	Before income taxes
AT	After income taxes
1P	Proved reserves
2P	Proved plus probable reserves

CONVERSION OF UNITS

Imperial = Metric

1 acre = 0.4 hectares

2.5 acres = 1 hectare

1 bbl = 0.159 cubic metres

6.29 bbls = 1 cubic metre

1 foot = 0.3048 metres

3.281 feet = 1 metre

1 mcf = 28.2 cubic metres

0.035 mcf = 1 cubic metre

1 mile = 1.61 kilometres

0.62 miles = 1 kilometre

1 MMBtu = 1.054 GJ

0.949 MMBtu = 1 GJ

Natural gas is equated to oil on the basis of 6 mcf = 1 BOE

Sulphur is equated to gas on the basis of 1LT = 10 mcf (1 BOE = 0.6 LT)

CORPORATE INFORMATION

BOARD OF DIRECTORS

Robert J. Dales [2, 3, 4, 7]
President, Valhalla Ventures Inc.

Geri L. Greenall [2, 3, 6]
Vice President, Portfolio Manager & Chief Operating Officer, Kyklopes Capital Management Ltd.

William C. Guinan [1, 5]
Partner, Borden Ladner Gervais LLP

Michael R. Shea [3, 4, 6]
Independent Businessman

Neil G. Sinclair [2, 4, 5, 6]
President, Sinson Investments Ltd.

David J. Wilson [5]
President & Chief Executive Officer,
Kelt Exploration Ltd.

1 chairman of the board
2 member of the audit committee
3 member of the reserves committee
4 member of the compensation committee
5 member of the health, safety and environment committee
6 member of the nominating committee
7 lead director

OFFICERS

David J. Wilson
President & Chief Executive Officer

Sadiq H. Lalani
Vice President & Chief Financial Officer

Douglas J. Errico
Vice President, Land

Alan G. Franks
Vice President, Production

Bruce D. Gigg
Vice President, Engineering

David A. Gillis
Vice President, Finance

Douglas O. MacArthur
Vice President, Operations

Patrick W.G. Miles
Vice President, Exploration

Carol Van Brunschot
Vice President, Marketing

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Convertible Debentures “KEL.DB”

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