SECOND QUARTER REPORT

AS AT AND FOR THE THREE AND SIX MONTHS ENDED

JUNE 30, 2019

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FINANCIAL AND OPERATIONAL HIGHLIGHTS	Three months ended June 30			Six months ended June 30		
(CA$ thousands, except as otherwise indicated)	**2019**	2018	%	**2019**	2018	%
FINANCIAL						
Petroleum and natural gas revenue, before royalties	**100,734**	98,715	2	**203,319**	188,708	8
Cash provided by operating activities	**58,639**	39,183	50	**112,452**	92,846	21
Adjusted funds from operations [1]	**45,455**	47,099	-3	**96,896**	92,823	4
Basic ($/ common share) [1]	**0.25**	0.26	-4	**0.53**	0.51	4
Diluted ($/ common share) [1]	**0.25**	0.25	-	**0.53**	0.51	4
Profit and comprehensive income	**2,740**	1,702	61	**12,109**	1,679	621
Basic ($/ common share)	**0.01**	0.01	-	**0.07**	0.01	600
Diluted ($/ common share)	**0.01**	0.01	-	**0.07**	0.01	600
Total capital expenditures, net of dispositions	**91,022**	54,702	66	**198,984**	146,739	36
Total assets	**1,577,824**	1,346,701	17	**1,577,824**	1,346,701	17
Net bank debt [1]	**308,636**	157,058	97	**308,636**	157,058	97
Convertible debentures	**80,512**	76,348	5	**80,512**	76,348	5
Shareholders' equity	**909,373**	882,916	3	**909,373**	882,916	3
Weighted average shares outstanding (000s)						
Basic	**184,151**	182,708	1	**184,085**	181,423	1
Diluted	**184,532**	184,825	-	**184,513**	183,210	1
OPERATIONS						
Average daily production						
Oil (bbls/d)	**9,727**	8,300	17	**8,772**	8,396	4
NGLs (bbls/d)	**4,679**	2,700	73	**4,293**	3,067	40
Gas (mcf/d)	**95,450**	90,723	5	**93,779**	90,498	4
Combined (BOE/d)	**30,314**	26,120	16	**28,695**	26,546	8
Production per million common shares (BOE/d)[1]	**165**	143	15	**156**	146	7
Average realized prices, before financial instruments[1]						
Oil ($/bbl)	**72.17**	80.56	-10	**69.95**	74.33	-6
NGLs ($/bbl)	**20.28**	38.67	-48	**22.51**	34.15	-34
Gas ($/mcf)	**2.75**	2.56	7	**3.95**	2.87	38
Operating netbacks ($/BOE) [1]						
Petroleum and natural gas revenue	**36.52**	41.54	-12	**39.14**	39.28	-
Cost of purchases	**(1.56)**	(3.03)	-49	**(1.52)**	(2.00)	-24
Average realized price, before financial instruments[1]	**34.96**	38.51	-9	**37.62**	37.28	1
Realized gain (loss) on financial instruments	**0.05**	-	-	**(0.13)**	-	-
Average realized price, after financial instruments[1]	**35.01**	38.51	-9	**37.49**	37.28	1
Royalties	**(2.25)**	(3.97)	-43	**(2.14)**	(3.35)	-36
Production expense	**(8.73)**	(9.14)	-4	**(9.39)**	(9.30)	1
Transportation expense	**(5.53)**	(3.83)	44	**(5.17)**	(3.61)	43
Operating netback [1]	**18.50**	21.57	-14	**20.79**	21.02	-1
Undeveloped land						
Gross acres	**679,904**	761,429	-11	**679,904**	761,429	-11
Net acres	**585,075**	644,986	-9	**585,075**	644,986	-9

(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 second quarter ended June 30, 2019.

Average production for the three months ended June 30, 2019 was 30,314 BOE per day, up 16% compared to average production of 26,120 BOE per day during the second quarter of 2018. Quarter-over-quarter, daily average production in the second quarter of 2019 was 12% higher than average production of 27,057 BOE per day in the first quarter of 2019. Higher quarter-over-quarter production reflects on-going new production additions from the Company's successful development pad drilling operations at Inga/Fireweed. Production for the three months ended June 30, 2019 was weighted 48% oil and NGLs and 52% gas. However, operating income was weighted 90% oil and NGLs and 10% gas.

Kelt's realized average oil price during the second quarter of 2019 was $72.17 per barrel, down 10% from $80.56 per barrel in the second quarter of 2018. The realized average NGLs price during the second quarter of 2019 was $20.28 per barrel, down 48% from $38.67 per barrel in the same quarter of 2018. The significant decrease in NGL prices were due to much weaker propane and butane prices at Edmonton. In British Columbia, where the Company has oil blending operations that result in premium liquids pricing, Kelt's direct oil sales were impacted during the Husky Prince George Refinery turnaround operations that occurred from April 8, 2019 to June 16, 2019, resulting in lower liquids pricing and higher oil transportation expenses.

Kelt's realized average gas price for the second quarter of 2019 was $2.75 per Mcf, up 7% from $2.56 per Mcf in the corresponding quarter of the previous year. Kelt benefits with premium natural gas price realizations compared to AECO as a result of its gas market diversification portfolio and high heat content gas. During the second quarter of 2019, the Company's realized average gas price per Mcf was 167% higher than the average AECO 5A price of $1.03 per MMBtu.

For the three months ended June 30, 2019, revenue was $100.7 million and adjusted funds from operations was $45.5 million ($0.25 per share, diluted), compared to $98.7 million and $47.1 million ($0.25 per share, diluted) respectively, in the second quarter of 2018.

Net capital expenditures incurred during the three months ended June 30, 2019 were $91.0 million. During the second quarter of 2019, the Company spent $57.1 million on drill and complete operations, $36.2 million on equipment, facilities and pipelines and $1.4 million on land and seismic. Property dispositions, net of property acquisitions were $3.7 million during the quarter.

During the second quarter of 2019, Kelt's production was negatively impacted by firm gas transportation service restrictions on TC Energy's NGTL system, temporary shut-ins from producing Inga wells during completion operations on the Inga 24-well pad and intermittent downtime at the Encana Sexsmith Gas Plant where the Company processes gas from its La Glace field. In order to mitigate the impact of production disruptions resulting from these events, Kelt elected to advance its 2019 capital expenditure program. In doing so, the Company was also able to take advantage of significant cost savings on its continuing drilling and completion operations. Approximately $30.0 million in capital expenditures relating to capital projects that were originally budgeted for the third quarter of 2019 were completed during the second quarter of 2019, including the following:

- completion operations for six wells from the Inga 24-well pad (wells #7 to #12);
- drilling operations for six wells from the Inga 24-well pad (wells #13 to #18); and
- drilling operations for one well at Oak.

At June 30, 2019, bank debt, net of working capital was $308.6 million. During the second half of 2019, Kelt is forecasting higher funds from operations compared to estimated capital expenditures, resulting in bank debt, net of working capital of approximately $258.0 million at December 31, 2019.

OPERATIONS UPDATE

Inga/Fireweed Core Area

At Inga, Kelt completed six wells (wells #7 to #12) on its 24-well pad Montney cube development program. Four of the six wells have been put on production and the remaining two wells are expected to be put on production this week. Initial production rates from these wells have exceeded the Company's expectations. The average drill and complete cost per well was $4.8 million, a 4% reduction from the average drill and complete cost of $5.0 million per well for the first six wells and 11% lower than the original budgeted average drill and complete cost of $5.4 million per well. The Company is pleased with the higher capital efficiencies on the second batch of six wells considering that the total amount of proppant pumped into the wells averaged 3,528 tonnes per well, a 15% increase from an average 3,074 tonnes per well of proppant pumped into the first six wells drilled from the pad. Kelt has been able to improve costs through drilling efficiencies resulting in lower drill times and completion efficiencies resulting from the use of the Company's newly installed water handling facilities. Additional savings are being realized by using bi-fuel (natural gas capable) frac pumpers and on-site fuel gas further reducing costs and at the same time, improving the Company's carbon footprint. A summary of the drill and complete operations for these wells is shown in the table below:

Well	Montney Zone	Completion Technology	Drill & Complete (MM)	Total Proppant (tonnes)	Proppant per Metre (tonnes)	Total Frac Fluid (m3)	Avg. Frac Intensity (m3/min)
00/16-17 (H4-9)	Upper	Open Hole Ball-Drop	$ 4.6	3,398	1.25	23,657	11.0
02/15-17 (J4-9)	Upper	Open Hole Ball Drop	$ 4.7	3,406	1.21	22,153	11.0
03/16-17 (F4-9)	IBZ	Plug and Perf	$ 4.4	3,288	1.33	26,730	11.2
03/15-17 (I4-9)	IBZ	Plug and Perf	$ 5.0	3,516	1.33	27,891	10.7
02/16-17 (G4-9)	Middle	Open Hole Ball-Drop	$ 4.3	3,440	1.27	22,158	11.2
00/15-17 (K4-9)	Middle	Plug and Perf	$ 5.9	4,120	1.56	27,268	11.2

The next six wells (wells #13 to #18) on the 24-well pad were also drilled in the second quarter and are expected to be completed during the third quarter of 2019. Included in these six wells is one well targeting the Lower Middle Montney horizon. This will be the Company's first Lower Middle Montney test on its Inga/Fireweed land acreage. The first six wells (wells #1 to #6) were put on production during the second quarter and were temporarily shut-in for a short period while the Company was completing the second batch of six wells. Production volumes from each of these first six wells for the respective initial 30 days (approximately 720 operating hours) in aggregate were 6,569 BOE per day (77% oil and NGLs), exceeding the Company's expected range of 5,800 to 6,200 BOE per day (60% to 65% oil and NGLs).

At Fireweed, the Company was ahead of schedule putting five Upper and Middle Montney single pad wells on production during the second quarter. These wells that were previously drilled in 2018 and which were expected to be put on production in the third quarter of 2019, were tied-in ahead of schedule with production commencing in the second quarter of 2019. Production volumes from each of these five wells for the respective initial 30 days (approximately 720 operating hours) in aggregate were 5,281 BOE per day (72% oil and NGLs), within the Company's expected range of 5,200 to 5,500 BOE per day (60% to 65% oil and NGLs).

Kelt has entered into an agreement with AltaGas Ltd. ("AltaGas") whereby the Company will construct a 16-inch gas pipeline from its Inga 2-10 facility to the AltaGas Townsend Deep-Cut Gas Plant. The total cost to build the pipeline is estimated to be approximately $39.0 million and ownership of the pipeline will be two-thirds Kelt and one-third AltaGas. The pipeline will have a capacity to transport up to approximately 300 MMcf per day of natural gas. AltaGas will reimburse Kelt the full amount of $39.0 million ($13 million during construction and $26 million after construction) and in return Kelt has agreed to make annual payments over 10 years as repayment for its share of the cost of the pipeline (approximately $26.0 million). The annual payments to AltaGas over ten years are representative of payments that would have been required if Kelt did not take an ownership interest in the pipeline but instead entered into a take-or-pay arrangement to deliver gas through the pipeline as a third party. Under such an arrangement, Kelt would not have an ownership interest in the pipeline after 10 years and would have to re-negotiate transportation terms thereafter. Under the current agreement, Kelt retains its two-thirds ownership in the pipeline after the ten year term is complete, with no further financial obligation to AltaGas.

The Government of British Columbia offers an Infrastructure Royalty Credit Program that encourages new capital investment in oil and natural gas infrastructure. The program is designed to create and sustain good paying jobs for British Columbians and stimulate new royalty revenue for the Province. Through the Infrastructure Royalty Credit Program, oil and gas companies such as Kelt can apply for a reduction to the royalties they would otherwise pay to the Province under a competitive Request for Applications process. This reduction can be applied to future royalties that would otherwise be payable and is determined based on an approved percentage of the costs to build roads, pipelines and gas facilities that are approved under the program.

In 2017, Kelt made an application to the Infrastructure Royalty Credit Program and was approved for its planned infrastructure build in certain parts of its Inga/Fireweed property relating to expenditures totaling approximately $38.6 million. This infrastructure build includes the following:

- construction of a pipeline route comprised of a sour gas line, a sweet gas line, a sour emulsion line, a disposal water line, a frac water line and a fuel gas line;
- building and upgrading of roads and installation of a bridge; and

- installation of centralized dehydration and compression facilities.

The Government of British Columbia approved a recovery of approximately 39% of Kelt's infrastructure expenditures or $15.0 million through the program. The amount is expected to be recovered from reduced future royalties payable relating to 20 horizontal Montney wells associated with this project. To date, Kelt has incurred over 80% of the infrastructure capital committed to under the program and has drilled 10 of the 20 horizontal Montney wells. The Company has commenced sales from these wells and expects to apply for royalty credits imminently, however, the future benefit of credits from the program are not currently reflected in the Company's 2019 financial guidance.

Wembley/Pipestone Core Area

At Wembley/Pipestone, the Company has now drilled and completed three Upper Middle Montney (D3/D4) wells from the 1-14 pad offsetting the original discovery well located at 00/04-01-072-08W6 which had an IP30 production rate of 1,337 BOE per day (83% oil and NGLs). The average drill & complete cost per well was $5.4 million per well, 8% lower than the budgeted average cost of $5.9 million per well. Kelt has also drilled three additional Upper Middle Montney (D3/D4) wells from the 12-3 pad offsetting the 2018 well drilled from the same pad located at 00/12-05-073-08W6 which when tested, over the last three days of the test, produced average sales volumes of approximately 1,497 BOE per day (74% oil and NGLs). In August 2019, the Company expects to commence completion operations on these three wells that were drilled from the 12-3 pad. During the second quarter, the Company also drilled a single well on its main Wembley/Pipestone land block located at (03/16-08) 02/16-10-72-7W6.

At Wembley/Pipestone, Kelt is currently building a battery that will be capable of processing all of the gas, oil and water associated with the Company's firm service commitment at the Pipestone Sour Deep-Cut Gas Processing Plant which is also currently under construction by Tidewater Midstream and Infrastructure Ltd. ("Tidewater"). The Kelt battery, consisting of dehydration, separation, treating, storage and water injection facilities, is expected to be commissioned in September coinciding with the expected start-up of the Tidewater facility. Kelt's water injection well, which was completed earlier this year, has already been tested and used for water disposal.

OUTLOOK/GUIDANCE

As the Company prepares to ramp up production in the second half of 2019 with significant production additions from its Inga/Fireweed and Wembley/Pipestone core areas, Kelt has not changed its 2019 average production estimate that was forecasted to be in a range of 33,500 to 34,500 BOE per day. However, in light of recent third party gas plant interruptions, the Company expects its 2019 average production to be at the low end of its forecasted range. Subsequent to the end of the second quarter, the Enbridge McMahon Gas Plant, which accounts for approximately one-third of Kelt's B.C. production, was shut down on July 30, 2019 and has indicated that it will resume operations on August 13, 2019. At La Glace, where the Company produces approximately 2,800 BOE per day through the Encana Sexsmith Gas Plant, Kelt has been experiencing interruptions in its production resulting from restrictions to the plant due to heat caused by high ambient temperatures and increased NGTL pipeline pressures.

With the recent volatility in oil and gas prices, Kelt is reducing its forecasted commodity price assumptions for 2019.

Kelt's 2019 capital expenditure program, excluding the Company's share of costs relating to the proposed 16-inch gas pipeline from its Inga 2-10 facility to the Townsend Deep-Cut Gas Plant, remains unchanged at $270.0 million. The cost of the pipeline of approximately $26.0 million will be incurred by Kelt during the year, however, Kelt will be reimbursed by AltaGas and in return Kelt will re-pay AltaGas based on a pre-determined fee basis over 10 years.

In addition, Kelt's 2019 capital expenditures includes approximately $18.0 million of drilling expenditures for wells (DUCs) that are not expected to be completed until 2020:

- 6 wells at Inga/Fireweed – wells #19 to #24 from the Inga 24-well pad; and
- 2 wells at Wembley/Pipestone – 02/16-10 (sfc 03/16-08) and 00/04-24 (sfc 16-26).

Production from these eight wells (DUCs) plus an additional two wells at Oak (to be drilled and completed in 2019) is not included in the Company's 2019 production forecast and will provide the Company with momentum for continued production growth in early 2020.

The table below summarizes Kelt's revised financial guidance for 2019:

Commodity Prices:	**2019 Forecast**	**Previous Forecast**	**Change**
WTI Crude Oil (USD/bbl)	58.00	60.00	− 3%
MSW Edmonton Oil (CAD/bbl)	69.32	73.17	− 5%
NYMEX Natural Gas (USD/MMBtu)	2.80	2.85	− 2%
DAWN Gas Daily Index (USD/MMBtu)	2.70	2.75	− 2%
CHICAGO City Gate Gas Daily Index (USD/MMBtu)	2.70	2.70	N/C
MALIN Gas Monthly Index (USD/MMBtu)	2.75	2.80	− 2%
SUMAS Gas Monthly Index (USD/MMBtu)	3.50	3.50	N/C
AECO 5A Gas Daily Index (USD/MMBtu)	1.25	1.30	− 4%
Station 2 Gas NGX Daily Index (USD/MMBtu)	0.85	0.90	− 6%
Exchange Rate (USD/CAD)	1.320	1.340	− 1%
Capital expenditures, net of dispositions [1] ($ MM)	296.0	270.0	+ 10%
Adjusted funds from operations ("AFFO") ($ MM)	220.0	240.0	− 8%
Per common share, diluted ($)	1.19	1.24	− 4%
Bank debt, net of working capital, at year-end [2] ($ MM)	258.0	235.0	+ 10%
Net bank debt to trailing AFFO ratio	1.2 x	0.9 x	

[1] Capital expenditures include $26.0 million for the 16-inch gas pipeline from Kelt's Inga 2-10 facility to AltaGas's Townsend Gas Plant.
[2] In addition to forecasted net bank debt at December 31, 2019, Kelt estimates 2019 year-end financial liabilities of approximately $26.0 million primarily relating to the Inga 16-inch gas pipeline (AltaGas).

During this period of volatile commodity price swings responding to headlines regarding political uncertainty and global trade wars, Kelt continues to remain disciplined financially.

Management looks forward to updating shareholders with 2019 third quarter results on or about November 8, 2019.

On behalf of the Board of Directors,

[signed]

David J. Wilson
President and Chief Executive Officer
August 8, 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, primarily in northwestern Alberta and northeastern British Columbia (“BC”). The Company was incorporated under the *Business Corporations Act* (Alberta) on October 11, 2012 and was inactive until February 26, 2013. Kelt’s land holdings are located in two core areas: (a) Grande Prairie, Alberta (including Pouce Coupe, Wembley, Progress and La Glace), 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 August 8, 2019 and should be read in conjunction with the Company’s unaudited condensed consolidated interim financial statements and related notes as at and for the three and six months ended June 30, 2019 and its audited consolidated annual financial statements and MD&A 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 interim financial statements on August 7, 2019 for issue on August 8, 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 bank debt”, “total revenue”, “average realized prices”, “net bank debt to annualized quarterly adjusted funds from operations ratio” and “debt to EBITDA” 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 reconciliations 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. 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 June 30			Six months ended June 30		
(CA$ thousands, except as otherwise indicated)	**2019**	2018	%	**2019**	2018	%
FINANCIAL PERFORMANCE						
Petroleum and natural gas revenue, before royalties	**100,734**	98,715	2	**203,319**	188,708	8
Cash provided by operating activities	**58,639**	39,183	50	**112,452**	92,846	21
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Profit and comprehensive income	**2,740**	1,702	61	**12,109**	1,679	621
Diluted ($/ common share)	**0.01**	0.01	-	**0.07**	0.01	600
Total capital expenditures, net of dispositions	**91,022**	54,702	66	**198,984**	146,739	36
Net bank debt (1)	**308,636**	157,058	97	**308,636**	157,058	97
OPERATIONAL PERFORMANCE						
Average daily production (BOE/d)	**30,314**	26,120	16	**28,695**	26,546	8
Average realized price, before financial instruments (1)	**34.96**	38.51	-9	**37.62**	37.28	1
Average realized price, after financial instruments (1)	**35.01**	38.51	-9	**37.49**	37.28	1
Operating netback (1)	**18.50**	21.57	-14	**20.79**	21.02	-1

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

In the second quarter of 2019 Kelt delivered strong financial and operating results highlighted by the following:

- Achieved record average production of 30,314 BOE per day, an increase of 16% from 26,120 BOE per day in the second quarter of 2018 and an increase of 12% from 27,057 BOE per day in the first quarter of 2019.
- Kelt's oil and NGLs production increased to 48% of total production in the second quarter of 2019, up 14% from the second quarter of 2018 and up 12% from the first quarter of 2019.
- Total revenue for the three months ended June 30, 2019 was $100.7 million, up 2% from $98.7 million in the same quarter of 2018. The increase is primarily due an increase in Kelt's average production which was partially offset by lower benchmark oil and natural gas prices.
- Kelt's operating netback was $18.50 per BOE for the quarter ended June 30, 2019, down 11% from $23.39 per BOE from the quarter ended March 31, 2019. The decrease in operating netback is primarily caused by lower benchmark oil and natural gas prices and higher transportation costs; however this was partially offset by lower production costs which averaged $8.73 per BOE during the second quarter of 2019 compared to $10.14 per BOE in the first quarter of 2019.
- Capital expenditures, before minor acquisitions and dispositions activity, of $94.7 million in the second quarter of 2019 focused on the development drilling of 14 net wells and the completion of 10 net wells at the Company's Montney acreage at Inga/Fireweed and Wembley. At Wembley the Company has seven drilled and completed wells and four drilled wells which are expected to come on-stream in the third and fourth quarter of 2019 once the Tidewater Facility commences operations. The Company's 2-10 facility at Inga was brought on-stream in the second quarter of 2019 which Kelt expects will result in future operational savings at its Inga/Fireweed development drilling program.
- Kelt's net bank debt was $308.6 million representing 1.7 times annualized quarterly adjusted funds from operations as at June 30, 2019 (December 31, 2018 – 1.1 times).
- The Company achieved quarterly funds from operations of $45.5 million ($0.25 per share, diluted) during the second quarter of 2019 and $96.9 million ($0.52 per share, diluted) for the six months ending June 30, 2019.

PRODUCTION

(CA$ thousands, except as otherwise indicated)	Three months ended June 30 2019	2018	%	Six months ended June 30 2019	2018	%
Average daily production:						
Oil (bbls/d)	**9,727**	8,300	17	**8,772**	8,396	4
NGLs (bbls/d)	**4,679**	2,700	73	**4,293**	3,067	40
Gas (mcf/d)	**95,450**	90,723	5	**93,779**	90,498	4
Combined (BOE/d)	**30,314**	26,120	16	**28,695**	26,546	8
Oil and NGLs weighting	**48%**	42%	14	**46%**	43%	7

Average production for the three months ended June 30, 2019 increased by 16% as compared to the same period in 2018 and increased 12% compared to the average production during the first quarter of 2019. Kelt's average production reported for the first six months of 2019 of 28,695 BOE per day is 8% higher than the comparative period in 2018. Average oil production during the six months ending June 30, 2019, increased by 4% compared to average oil production for the same period in 2018.

The increase in production in 2019 from the comparable periods in 2018 was driven by strong results from the Company's drilling program targeting multiple zones of its oil and condensate rich Montney acreage. The Company's ongoing development program involves drilling, completing and equipping pad sites of multiple wells prior to bringing new production on-stream. Kelt continues to expect significant production additions in the second half of 2019 and at the beginning of 2020 as it brings these pad sites on production. In addition, the Company awaits the commencement of commercial operations at the Townsend Deep-cut Gas Plant ("AltaGas Facility") in BC and the Pipestone Sour Deep-cut Gas Plant ("Tidewater Facility") at Wembley. At Wembley the Company has seven wells drilled and completed and four wells drilled which are expected to come on-stream in the third and fourth quarter of 2019 once the Tidewater Facility commences operations.

Kelt's oil and NGLs production increased to 48% of total production in the second quarter of 2019, up 14% from the second quarter of 2018 and up 12% from the first quarter of 2019. Kelt expects to further increase its oil and liquids production ratio as it continues its drilling program on its oil and condensate rich Montney acreage.

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".

(CA$ thousands, except as otherwise indicated)	Three months ended June 30 2019	2018	%	Six months ended June 30 2019	2018	%
Revenue, before royalties and financial instruments:						
Oil	**63,518**	60,630	5	**109,617**	112,640	-3
NGLs	**8,635**	9,501	-9	**17,489**	18,960	-8
Gas	**22,724**	21,226	7	**62,193**	47,240	32
Revenue, before marketing	**94,877**	91,357	4	**189,299**	178,840	6
Marketing revenue (2)	**5,857**	7,358	-20	**14,020**	9,868	42
Total revenue (1)	**100,734**	98,715	2	**203,319**	188,708	8
Cost of purchases (3)	**(4,312)**	(7,209)	-40	**(7,920)**	(9,616)	-18
Kelt Revenue (4)	**96,422**	91,506	5	**195,399**	179,092	9

(CA$ thousands, except as otherwise indicated)	Three months ended June 30 2019	2018	%	Six months ended June 30 2019	2018	%
Average realized prices [5]						
Oil ($/bbl)	**72.17**	80.56	-10	**69.95**	74.33	-6
NGLs ($/bbl)	**20.28**	38.67	-48	**22.51**	34.15	-34
Gas ($/mcf)	**2.75**	2.56	7	**3.95**	2.87	38
Combined ($/BOE)	**34.96**	38.51	-9	**37.62**	37.28	1

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

(2) Marketing revenue relates to the Company's sale of third party volumes in its oil blending operations and the resale of third party gas volumes.

(3) Cost of purchases relates to third party volumes purchased for resale in the Company's oil blending operations and the purchase of third party gas volumes.

(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 before financial instruments and reflect Kelt's realized commodity prices plus the net benefit of oil blending and natural gas marketing activities. Refer to additional information under the heading of *"Non-GAAP Financial Measures and Other Key Performance Indicators"*.

Revenue before marketing for the second quarter of 2019 was $94.9 million, up 4% from $91.4 million from the second quarter of 2018. Revenue before marketing for the six months ending June 30, 2019 was $189.3 million, up 6% from the comparable period in 2018. The increase in revenue is primarily from a 16% increase in production in the second quarter of 2019 compared the second quarter in the prior year. The decrease in Kelt's average realized price is driven by lower oil and NGL commodity prices which were offset by higher natural gas benchmark prices.

OIL REVENUE

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

(CA$ thousands, except as otherwise indicated)	Three months ended June 30 2019	2018	%	Six months ended June 30 2019	2018	%
Oil production (average bbls per day)	**9,727**	8,300	17	**8,772**	8,396	4
Oil revenue, before marketing	**63,518**	60,630	5	**109,617**	112,640	-3
Marketing revenue, net of cost of purchases [1]	**360**	214	68	**1,448**	317	357
Kelt Revenue - Oil	**63,878**	60,844	5	**111,065**	112,957	-2
Average realized oil prices ($/bbl) [2][3]						
Before financial instruments	**72.17**	80.56	-10	**69.95**	74.33	-6
Average realized price, percentage of MSW	**98%**	104%		**100%**	101%	
Benchmark oil prices:						
WTI Cushing Oklahoma (US$/bbl) [5]	**59.78**	67.88	-12	**57.31**	65.38	-12
WTI Cushing Oklahoma (CA$/bbl) [5]	**79.98**	87.86	-9	**76.43**	83.69	-9
Mixed Sweet Blend Edmonton ("MSW") ($/bbl) [4]	**73.84**	77.82	-8	**70.18**	73.96	-5
MSW % of CA$WTI	**92%**	89%	1	**92%**	88%	4
Average exchange rate (CA$/US$) [6]	**1.3375**	1.2940	4	**1.3333**	1.2791	4

(1) Net 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 Revenue - Oil and reflects Kelt's realized oil price plus the net benefit of oil blending/marketing activities.

(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 $72.17 per barrel during the three months ended June 30, 2019, down 10% from $80.56 per barrel during the comparative period of 2018. Kelt realized an average oil price of $69.95 per barrel during the six months ended June 30, 2019, down from $74.33 per barrel during the comparative period of 2018. Benchmark oil prices decreased in the second quarter of 2019 as oil demand forecasts were revised down as global trade tensions continue to impact international economies. The downward pressure on oil prices was partially offset by a reduction of oil supply as the US tightened sanctions on Iran and geopolitical tensions in the Middle East increased.

The average discount on Kelt's realized oil price relative to the MSW reference price was $1.67 per barrel (98% of MSW) during the second quarter of 2019 compared to an average premium of $2.74 per barrel (104% of MSW) during the second quarter of 2018.

NGL REVENUE

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

	Three months ended June 30			Six months ended June 30		
(CA$ thousands, except as otherwise indicated)	**2019**	2018	%	**2019**	2018	%
NGLs production (average bbls per day)	**4,679**	2,700	73	**4,293**	3,067	40
NGLs barrels per mmcf of natural gas sales	**49**	30	63	**46**	34	35
NGLs revenue	**8,635**	9,501	-9	**17,489**	18,960	-8
Average realized NGLs prices ($/bbl)	**20.28**	38.67	-48	**22.51**	34.15	-34
Average realized price, percentage of CA$WTI [1]	**25%**	44%		**29%**	41%	
Benchmark NGLs prices [2] ($/bbl):						
Edmonton Pentane	**73.73**	86.44	15	**71.18**	83.37	-15
% of CA$WTI	**92%**	98%	-6	**93%**	100%	-7
Edmonton Butane	**24.43**	41.16	-41	**15.17**	44.78	-66
% of CA$WTI	**31%**	47%	-34	**20%**	54%	-63
Edmonton Propane	**12.31**	24.67	-50	**14.35**	28.84	-50
% of CA$WTI	**15%**	28%	-46	**19%**	34%	-44
Edmonton Ethane	**5.73**	3.31	73	**7.81**	4.51	73
% of CA$WTI	**7%**	4%	75	**10%**	5%	100

(1) Average realized NGLs price, before financial instruments, divided by the Canadian dollar equivalent WTI reference price for the period.

(2) Source: Sproule Associates Limited.

Kelt's NGLs revenue decreased by 9% in the second quarter of 2019, and decreased 8% in the six months ending June 30, 2019 compared to the same periods in 2018. The decrease in revenues resulted from a decrease in benchmark WTI and NGLs prices, partially offset by increased production.

The Company's NGLs production increased by 73% in the second quarter of 2019, and 40% in the six months ending June 30, 2019 as compared to the same periods in 2018. The increase in production in 2019 was driven by strong results from the Company's development drilling program in its oil and condensate rich Montney acreage.

Kelt realized an average price before financial instruments for its NGL sales of $20.28 per barrel (25% of CA$WTI) during the second quarter of 2019, down 48% from $38.67 per barrel (44% of CA$WTI) during the second quarter of 2018. Kelt realized an average price before financial instruments for its NGL sales of $22.51 per barrel (29% of CA$WTI) during the six months ending June 30 2019, down from $34.15 per barrel (41% of CA$WTI) during the comparable period in 2018. The decrease in NGLs prices in 2019 was driven by a disconnect in propane and butane prices from WTI benchmark prices due to an oversupply in Western Canada and constrained takeaway capacity.

GAS REVENUE

References to "gas" in this discussion includes natural gas and sulphur (see "Basis of Presentation" for additional references). All references to "gas revenue" are before gas royalties.

	Three months ended June 30			Six months ended June 30		
(CA$ thousands, except as otherwise indicated)	**2019**	2018	%	**2019**	2018	%
Gas production (MCF per day)	**95,450**	90,723	5	**93,779**	90,498	4
Gas revenue, before marketing	**22,724**	21,226	7	**62,193**	47,240	32
Marketing revenue, net of cost of purchases (10)	**1,185**	(65)	-1,923	**4,652**	(65)	-7,257
Kelt Revenue - Gas	**23,909**	21,161	13	**66,845**	47,175	42
Average realized gas price ($/MCF)						
Before financial instruments	**2.75**	2.56	7	**3.95**	2.87	38
Realized gain (loss) on financial instruments	**0.02**	-	-	**(0.04)**	-	-
After financial instruments	**2.77**	2.56	8	**3.91**	2.87	36
Kelt average premium to AECO 5A (1)	**167%**	117%		**116%**	76%	
Benchmark gas prices:						
NYMEX Henry Hub (US$/MMBtu) (2)	**2.62**	2.78	-6	**2.87**	2.87	-
Average exchange rate (CA$/US$) (3)	**1.3375**	1.2911	4	**1.3333**	1.2780	4
NYMEX Henry Hub (CA$/MMBtu) (2)	**3.50**	3.59	-3	**3.83**	3.66	5
AECO 5A (CA$/MMBtu) (4)	**1.03**	1.18	-13	**1.83**	1.63	12
Chicago-City Gate (CA$/MMBtu) (5)	**3.09**	3.44	-10	**3.59**	3.58	-
Dawn (CA$/MMBtu) (6)	**3.14**	3.57	-12	**3.50**	3.69	-5
Malin (CA$/MMBtu) (7)	**2.91**	2.55	14	**4.03**	2.86	41
Sumas (CA$/MMBtu) (8)	**2.81**	2.11	33	**5.94**	2.62	127
Station 2 (CA$/MMBtu) (9)	**0.60**	1.05	-43	**0.95**	1.43	-37

(1) Kelt's average premium, 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) Marketing revenue, net of cost of purchases, relates to the purchase and resale of third party volumes.

Natural gas revenue before marketing increased 7% to $22.7 million in the second quarter of 2019 and increased 32% to $62.2 million for the six months ending June 30, 2019 as compared to the same periods in 2018. In 2019 the AECO 5A gas reference price averaged $1.03 per MMBtu for the second quarter of 2019 and $1.83 per MMBtu for the six months ending June 30, 2019, compared to Kelt's realized price of $2.75 per MMBtu and $3.95 per MMBtu, respectively. Kelt's premium to the AECO 5A is due to its gas marketing arrangements which exposes Kelt to markets outside of BC and Alberta, and due to the higher heat content of its gas production. US markets experienced higher natural gas prices in the first quarter of 2019 and into the second quarter of 2019 due to a cold winter heating season, constrained supply in Western US, and lower than historical storage volumes resulting in increased upward price volatility. 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.

The Company estimates that approximately 15% of its natural gas production was sold at AECO and Station 2 in second quarter of 2019. Based on current estimates, the Company anticipates selling less than 20% of its 2019 production at AECO and Station 2.

ROYALTIES

	Three months ended June 30			Six months ended June 30		
(CA$ thousands, except as otherwise indicated)	**2019**	2018	%	**2019**	2018	%
Royalties	**6,203**	9,441	-34	**11,110**	16,108	-31
Average royalty rate (1)	**6.5%**	9.6%	-37	**5.9%**	8.5%	-34
$ per BOE	**2.25**	3.97	-43	**2.14**	3.35	-36

(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 (see table under the heading of *"Revenue"*).

Kelt's average royalty rate was 6.5% during the second quarter of 2019, compared to 9.6% during the second quarter of 2018 and 5.9% for the six months ending June 30, 2019 versus 8.5% in the comparable periods in 2018. Oil and NGLs royalties decreased by $1.1 million in the second quarter of 2019 and $3.9 million in the six months ending June 30, 2019 as compared to the same periods in 2018. Alberta oil royalties are calculated based on crown par reference prices, which are on a one to two month lag against benchmark commodity prices. The steep drop in Canadian benchmark crude oil prices in December 2018 and into 2019 resulted in a drop in royalty expense in 2019 as compared to 2018. In addition, Kelt's BC montney wells brought on-stream in 2019 qualify for the provinces deep-well royalty program which allows for favorable royalty treatment at the beginning of the life of the well.

PRODUCTION EXPENSES

	Three months ended June 30			Six months ended June 30		
(CA$ thousands, except as otherwise indicated)	**2019**	2018	%	**2019**	2018	%
Production expense (1)	**24,095**	21,726	11	**48,793**	44,675	9
$ per BOE	**8.73**	9.14	-4	**9.39**	9.30	1

(1) As at June 30, 2019, production expenses exclude $0.8 million of lease payments which would have been included in production expenses for prior periods.

The Company incurred total production expenses of $24.1 million during the second quarter of 2019, up 11% from the comparative quarter. Production expenses averaged $8.73 per BOE during the second quarter of 2019, compared to $9.14 per BOE in the same period in 2018. On a per BOE basis, operating expenses decreased by 4%, primarily due to lower maintenance and repair work in the second quarter of 2019.

The Company incurred total production expenses of $48.8 million during the first six months of 2019, up 9% from $44.7 million during the six months ending June 30, 2018. Production expenses averaged $9.39 per BOE during the six months ending June 30, 2019, relatively unchanged from $9.30 per BOE for the six months ending June 30, 2018. On a BOE basis, higher optimization and maintenance and repairs in the first quarter of 2019 was offset by lower maintenance and repair work in the second quarter of 2019 versus the comparable periods in 2018.

TRANSPORTATION EXPENSES

	Three months ended June 30			Six months ended June 30		
(CA$ thousands, except as otherwise indicated)	**2019**	2018	%	**2019**	2018	%
Transportation expense (1)	**15,259**	9,100	68	**26,878**	17,347	55
$ per BOE	**5.53**	3.83	44	**5.17**	3.61	43

(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 absence of a firm contractual obligation on the pipeline, and where Kelt does not maintain control of the product delivered, the pipeline tariffs are presented as a reduction of revenue rather than as transportation expense.

Transportation expenses averaged $5.53 per BOE during the second quarter of 2019, an increase of 44% from $3.83 per BOE in the second quarter of 2018 and averaged $5.17 per BOE in the six months ending June 30, 2019, an increase of 43% from $3.61 per BOE in the same period in 2018. The increase in average per unit transportation expense was due to higher pipeline tolls under marketing arrangements entered into in the fourth quarter of 2018 to deliver additional natural gas on the Alliance pipeline to Chicago, and additional trucking expense in BC during 2019 in order to circumvent third party facility outages.

FINANCING EXPENSES

	Three months ended June 30			Six months ended June 30		
(CA$ thousands, except as otherwise indicated)	**2019**	2018	%	**2019**	2018	%
Interest and fees on bank debt	**2,511**	1,181	113	**4,509**	2,411	87
Interest on convertible debentures	**1,121**	1,121	-	**2,229**	2,231	-
Interest on finance lease	**59**	-	-	**100**	-	-
Interest on financing liability	**35**	-	-	**35**	-	-
Total interest expense	**3,726**	2,302	62	**6,873**	4,642	48
Accretion of convertible debentures	**1,086**	981	11	**2,122**	1,907	11
Accretion of decommissioning obligations	**759**	786	-3	**1,543**	1,555	-1
Total financing expense	**5,571**	4,069	37	**10,538**	8,104	30
Interest expense per BOE (1)	**1.35**	0.97	39	**1.32**	0.97	36
Average principal amount outstanding during period:						
Bank debt	**231,105**	118,431	95	**207,749**	113,391	83
Convertible debentures	**89,910**	89,978	-	**89,910**	89,989	-
Average total principal amount of debt outstanding	**321,015**	208,409	54	**297,659**	203,380	46
Average interest rates:						
Bank debt (2)	**3.9**	3.3	18	**4.0**	3.6	11
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, accrued interest on convertible debentures, and interest on finance leases and financing liabilities.

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

The Company's total interest expense of $5.6 million ($1.35 per BOE) for the second quarter of 2019 is up 37% from the comparative quarter and increased 30% for the six months ending June 30, 2019 versus the comparable periods in 2018. The increase in interest expense was due to the increase in average total debt outstanding in 2019.

Additional information regarding the credit facility and debentures is provided under the heading of *"Capital Resources and Liquidity"*.

GENERAL AND ADMINISTRATIVE ("G&A") EXPENSES

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

	Three months ended June 30			Six months ended June 30		
(CA$ thousands, except as otherwise indicated)	**2019**	2018	%	**2019**	2018	%
Salaries and benefits	**2,464**	2,352	5	**5,298**	4,676	13
Other G&A expenses	**1,176**	874	35	**2,672**	2,116	26
Gross G&A expenses	**3,640**	3,226	13	**7,970**	6,792	17
Overhead recoveries	**(1,768)**	(1,260)	40	**(3,507)**	(2,983)	18
G&A expense, net of recoveries	**1,872**	1,966	-5	**4,463**	3,809	17
Gross G&A ($ per BOE)	**1.32**	1.36	-3	**1.53**	1.41	9
Net G&A ($ per BOE)	**0.68**	0.83	-18	**0.86**	0.79	9

Kelt continues to incur below industry average G&A expenses as a result of management's continued efforts to maintain a low cost structure. G&A expense, net of recoveries, averaged $0.68 per BOE during the second quarter of 2019, a decrease of 18% compared to $0.83 per BOE during the second quarter of 2018. The per BOE costs have decreased over 2018 as production ramps up from the Company's development drilling program.

G&A expenses are reported net of overhead recoveries; however, Kelt does not capitalize any direct G&A expenses.

SHARE BASED COMPENSATION ("SBC")

	Three months ended June 30			Six months ended June 30		
(CA$ thousands, except as otherwise indicated)	**2019**	2018	%	**2019**	2018	%
Stock options	**1,087**	978	11	**2,203**	2,120	4
Restricted share units ("RSUs")	**711**	382	86	**1,473**	828	78
Total SBC expense	**1,798**	1,360	32	**3,676**	2,948	25
$ per BOE	**0.65**	0.57	14	**0.71**	0.61	16

The increase in SBC expense during the quarter ended June 30, 2019 and during the six months ending June 30, 2019 versus the comparable periods in 2018 is primarily a result an increase in the number of RSUs outstanding.

As at June 30, 2019, stock options and RSUs outstanding represent 5.3% of total shares outstanding (December 31, 2018 – 6%).

EXPLORATION AND EVALUATION ("E&E") EXPENSES

	Three months ended June 30			Six months ended June 30		
(CA$ thousands, except as otherwise indicated)	**2019**	2018	%	**2019**	2018	%
Expired mineral leases	**300**	607	-51	**573**	2,097	-73
$ per BOE	**0.11**	0.26	-58	**0.11**	0.44	-75

The Company expensed $0.3 million of costs related to the expiry of non-core land holdings during the second quarter of 2019, and $0.6 million during the six months ending June 30, 2019 compared to lease expiries of $0.6 million expensed in second quarter of 2018 and $2.1 million for the six months ending June 30, 2018. The lease expiries relate to non-core land holdings as the Company continues to focus on the development of its core areas.

DEPLETION, DEPRECIATION AND IMPAIRMENT

	Three months ended June 30			Six months ended June 30		
(CA$ thousands, except as otherwise indicated)	**2019**	2018	%	**2019**	2018	%
Depletion of D&P assets	**40,440**	34,481	17	**73,764**	73,007	1
Depreciation of right-of-use assets	**384**	-	-	**788**	-	-
Depreciation of corporate assets	**202**	114	77	**390**	317	23
Depletion and depreciation	**41,026**	34,595	19	**74,942**	73,324	2
Impairment	**-**	3,000	-100	**-**	3,000	-100
Total depletion and depreciation	**41,026**	37,595	9	**74,942**	76,324	-2
Depletion and depreciation ($/BOE)	**14.87**	14.56	2	**14.43**	15.26	-5
Impairment ($/BOE)	**-**	1.26	-100	**-**	0.62	-100

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 expense of $41.0 million for the quarter ended June 30, 2019 increased by 19% from $34.6 million in the comparable period in 2018. The increase was primarily attributed to higher production in the second quarter of 2019, partially offset by a $3.0 million impairment taken in the second quarter of 2018.

Depletion and depreciation of $74.9 million for the six months ended June 30, 2019 decreased by 2% from comparable period in 2018, with the decrease attributed to a significant increase in proved reserves at December 31, 2018, partially offset by an increase in production.

GAIN (LOSS) ON SALE OF ASSETS

	Three months ended June 30			Six months ended June 30		
(CA$ thousands, except as otherwise indicated)	**2019**	2018	%	**2019**	2018	%
Gain (loss) on sale of assets	**3,525**	31	11,271	**4,900**	159	2,982

During the six months ended June 30, 2019 the Company completed minor dispositions of non-core properties with a fair value of $6.0 million and a gain on sale of $4.9 million.

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 June 30			Six months ended June 30		
(CA$ thousands, except as otherwise indicated)	**2019**	2018	%	**2019**	2018	%
Realized gain (loss)	**145**	-	-	**(667)**	-	-
Unrealized loss	**(501)**	-	-	**(3,130)**	-	-
Loss on derivative financial instruments	**(356)**	-	-	**(3,797)**	-	-
$ per BOE	**(0.13)**	-	-	**(0.73)**	-	-

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 June 30, 2019, 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 Crude Oil	4,000 bbl/d	Mixed Sweet Blend Edmonton	WTI less USD$10.95 per bbl	October 2019 to December 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 $207.7 million during the first half of 2019, an increase (decrease) in the market rate of interest by 25 basis points would have increased (decreased) annualized interest expense by $0.5 million.

As at June 30, 2019, 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 June 30, 2019, 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 June 30			Six months ended June 30		
(CA$ thousands, except as otherwise indicated)	**2019**	2018	%	**2019**	2018	%
Premium on flow-through shares	**-**	1,723	-	**-**	2,765	-

Canadian tax legislation permits entities meeting specified criteria to issue flow-through common shares securities ("FTS") to investors whereby the deductions for tax purposes related to eligible expenditures may be claimed by the investors rather than by the entity. As of December 31, 2018 all eligible expenditures for the Company's flow through shares issued in 2018 and in prior years have been incurred, and no FTS were issued in the first half of 2019.

INCOME TAXES

	Three months ended June 30			Six months ended June 30		
(CA$ thousands, except as otherwise indicated)	**2019**	2018	%	**2019**	2018	%
Deferred income tax expense	**548**	5,816	-91	**4,135**	9,237	-55
Profit before taxes	**3,288**	7,518	-56	**16,244**	10,916	49
Effective tax recovery rate	**16.7%**	77.4%	-78	**25.5%**	84.6%	-70

Kelt's consolidated combined federal and provincial statutory tax rate averaged 27.0% during the three months ended June 30, 2019 and 2018, respectively. In the second quarter of 2019, the Government of Alberta substantively enacted legislation to reduce the corporate income tax rate in stages from 12% to 8% over the next four years, with the average statutory tax rate for 2019 in Alberta being 26.5%. As a result of the tax rate change in Alberta, Kelt recognized a deferred income tax recovery of $0.6 million in the second quarter of 2019.

Kelt's effective tax rate for the second quarter of 2019 is lower than the statutory rate due to the Alberta statutory tax rate change which resulted in a deferred income tax recovery of $0.6 million. For 2018, the effective rate was 77.4%, primarily due to qualifying expenditures incurred and renounced in respect of the Company's CEE flow-through share commitments.

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. The Company's consolidated tax pools are estimated to be approximately $1,153 million as of June 30, 2019 as summarized in the table below.

(CA$ thousands, unless otherwise indicated)	Rate	**June 30 2019**	December 31 2018	% Change
Canadian oil and gas property expenses (COGPE)	10%	**122,108**	128,254	-5
Canadian development expenses (CDE)	30%	**288,331**	216,975	33
Canadian exploration expenses (CEE)	100%	**101,710**	105,921	-4
Undepreciated capital cost (1) (UCC)	25%	**279,108**	254,430	10
Share and debt issue costs (SIC/DIC)	5 years	**2,899**	4,010	-28
Non-capital losses (2) (NCL)	100%	**358,447**	339,031	6
Estimated tax deductions available, end of period		**1,152,603**	1,048,621	10

(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 (LOSS)

	Three months ended June 30			Six months ended June 30		
(CA$ thousands, except as otherwise indicated)	**2019**	2018	%	**2019**	2018	%
Profit and comprehensive income	**2,740**	1,702	61	**12,109**	1,679	621
Wtd avg. shares outstanding, basic (000s)	**184,151**	182,708	1	**184,085**	181,423	1
Wtd avg. shares outstanding, diluted (000s) (1)(2)	**184,532**	184,825	-	**184,513**	183,210	1
$ per common share, basic	**0.01**	0.01	-	**0.07**	0.01	600
$ per common share, diluted (1)(2)	**0.01**	0.01	-	**0.07**	0.01	600
$ per BOE	**1.01**	0.72	40	**2.32**	0.36	544

(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 second quarter ended June 30, 2018 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 second quarter ended June 30, 2019 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 $2.7 million ($0.01 per common share, diluted) for the three months ended June 30, 2019, compared to a profit of $1.7 million ($0.01 per common share, diluted) in the same three month period of 2018. The increase to profit is primarily due to an increase in the gains on sales of assets of $3.5 million, and a decrease in deferred tax expense of $5.3 million partially offset by an increase in depletion and depreciation of $3.4 million, a decrease in the premium from flow through shares of $1.7 million and a decrease of $1.6 million in adjusted funds from operations.

Kelt reported a profit of $12.1 million ($0.07 per common share, diluted) for the six months ended June 30, 2019, compared to a profit of $1.7 million ($0.01 per common share, diluted) in the same period of 2018. The increase in profit is primarily due to an increase of $4.1 million in adjusted funds from operations, an increase in the gains on sales of assets of $4.7 million, a decrease in deferred tax expense of $5.1 million partially offset by a decrease in the premium from flow through shares of $2.8 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 and six month periods ended June 30, 2019 and 2018, respectively. Adjusted funds from operations and operating income or netbacks ($ per BOE) are non-GAAP measures 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.

THREE MONTHS ENDED JUNE 30TH	**2019**		2018		% change	
(CA$ thousands, unless otherwise indicated)	**Amount**	**$/BOE**	Amount	$/BOE	Amount	$/BOE
Petroleum and natural gas revenue	**100,734**	**36.52**	98,715	41.54	2	-12
Cost of purchases	**(4,312)**	**(1.56)**	(7,209)	(3.03)	-40	-49
Realized gain on financial instruments (1)	**145**	**0.05**	-	-	-	-
Royalties	**(6,203)**	**(2.25)**	(9,441)	(3.97)	-34	-43
Revenue, after royalties and financial instruments	**90,364**	**32.76**	82,065	34.54	10	-5
Production expense	**(24,095)**	**(8.73)**	(21,726)	(9.14)	11	-4
Transportation expense	**(15,259)**	**(5.53)**	(9,100)	(3.83)	68	44
Operating income (2)	**51,010**	**18.50**	51,239	21.57	-	-14
Financing expense (3)	**(3,726)**	**(1.35)**	(2,302)	(0.97)	62	39
G&A expense	**(1,872)**	**(0.68)**	(1,966)	(0.83)	-5	-18
Realized gain on foreign exchange	**43**	**0.01**	128	0.05	-66	-80
Adjusted funds from operations (4)	**45,455**	**16.48**	47,099	19.82	-3	-17
Basic ($ per common share) (5)	**0.25**		0.26		-4	
Diluted ($ per common share) (5)	**0.25**		0.25		-	
Common shares outstanding (000s):						
Basic, weighted average	**184,151**		182,708		1	
Diluted, weighted average	**184,532**		184,825		-	

SIX MONTHS ENDED JUNE 30TH	2019		2018		% change	
(CA$ thousands, unless otherwise indicated)	**Amount**	**$/BOE**	Amount	$/BOE	Amount	$/BOE
Petroleum and natural gas revenue	**203,319**	**39.14**	188,708	39.28	8	-
Cost of purchases	**(7,920)**	**(1.52)**	(9,616)	(2.00)	-18	-24
Realized loss on financial instruments (1)	**(667)**	**(0.13)**	-	-	-	-
Royalties	**(11,110)**	**(2.14)**	(16,108)	(3.35)	-31	-36
Revenue, after royalties and financial instruments	**183,622**	**35.35**	162,984	33.93	13	4
Production expense	**(48,793)**	**(9.39)**	(44,675)	(9.30)	9	1
Transportation expense	**(26,878)**	**(5.17)**	(17,347)	(3.61)	55	43
Operating income (2)	**107,951**	**20.79**	100,962	21.02	7	-1
Financing expense (3)	**(6,873)**	**(1.32)**	(4,642)	(0.97)	48	36
G&A expense	**(4,463)**	**(0.86)**	(3,809)	(0.79)	17	9
Other income	**495**	**0.10**	-	-	-	-
Realized gain (loss) on foreign exchange	**(214)**	**(0.05)**	312	0.06	-169	-183
Adjusted funds from operations (4)	**96,896**	**18.66**	92,823	19.32	4	-3
Basic ($ per common share) (5)	**0.53**		0.51		4	
Diluted ($ per common share) (5)	**0.53**		0.51		4	
Common shares outstanding (000s):						
Basic, weighted average	**184,085**		181,423		1	
Diluted, weighted average	**184,513**		183,210		1	

(1) Includes realized gains (losses) on commodity price and foreign exchange derivatives.

(2) "Operating income" is a non-GAAP financial measure which is calculated by deducting cost of purchases, 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 June 30, 2019, adjusted funds from operations of $45.5 million ($0.25 per share, diluted) decreased by 3% from $47.1 million ($0.25 per share, diluted) during the second quarter ended June 30, 2018. The decrease in adjusted funds from operations is primarily attributed an increase in financing expense, as operating income was relatively consistent compared to the prior year's second quarter.

During the six months ended June 30, 2019, adjusted funds from operations of $96.9 million ($0.53 per share, diluted) increased by 4% from $92.8 million ($0.51 per share, diluted) during the six months ended June 30, 2018. The increase in adjusted funds from operations is primarily attributed to the increase in Kelt's operating income which is up 7% to $108.0 million compared to $101.0 million in the six months ending June 30, 2018. The increase is driven by an 8% increase in average production, partially offset by a 9% decrease in the benchmark WTI (CA$/bbl) oil price.

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 June 30			Six months ended June 30		
(CA$ thousands, except as otherwise indicated)	**2019**	2018	%	**2019**	2018	%
Capital expenditures:						
Lease acquisition and retention	**453**	772	-41	**793**	3,571	-78
Geological and geophysical	**964**	(151)	-738	**1,101**	57	1,832
Drilling and completion of wells	**57,055**	29,813	91	**124,466**	94,313	32
Facilities, pipeline and well equipment	**36,115**	24,328	48	**73,040**	47,026	55
Corporate assets	**87**	(43)	-302	**200**	129	55
Capital expenditures, before A&D	**94,674**	54,719	73	**199,600**	145,096	38
Property acquisitions (1)	**1,000**	20	4,900	**5,408**	1,927	181
Property dispositions (1)	**(4,652)**	(37)	12,473	**(6,024)**	(284)	2,021
Total capital expenditures, net of dispositions	**91,022**	54,702	66	**198,984**	146,739	36

(1) Includes the impact of non-cash asset swap transactions in which $2.4 million of exploration and evaluation assets were exchanged for assets with a net book value of $328k.

In the second quarter of 2019, Kelt's 2-10 facility at Inga was brought on-stream which the Company expects will result in future operational savings at its Inga/Fireweed development drilling program. Kelt's capital expenditures for the three and six months ended June 30, 2019 also includes initial costs related to the construction of a pipeline from the 2-10 facility to the AltaGas Facility, with $6.7 million (net to Kelt) incurred as of June 30, 2019.

DRILLING

Drilling and completion expenditures for the three month period ended June 30, 2019 were focused on Montney wells in the Company's core Alberta and BC areas. During the quarter, the Company drilled 14.0 net wells and completed 10.0 net wells compared to 5.0 net wells drilled and 3.0 net wells completed in the second quarter of 2018. The Company has seven wells drilled and completed and four wells drilled at Wembley which are expected to come on-stream in the third quarter of 2019 once the Tidewater Facility commences operations.

	Three months ended June 30		Six months ended June 30	
Net Wells	**2019**	2018	**2019**	2018
Drilling	**14.0**	5.0	**24.0**	14.1
Completion	**10.0**	3.0	**25.0**	15.1
Tied-in	**14.0**	-	**14.0**	11.1

PROPERTY ACQUISITIONS AND DISPOSITIONS

During the six months ended June 30, 2019, the Company acquired certain oil and gas assets which included undeveloped land of $5.2 million, developed land of $0.8 million, and decommissioning obligations of $0.6 million. The net assets acquired and the liabilities assumed were recorded at fair value of $5.4 million, and included cash consideration of $3.0 million and non-cash swap transactions of $2.4 million.

During the six months ended June 30, 2019, the Company disposed of certain non-core oil and gas assets which included undeveloped land of $1.5 million, and decommissioning obligations of $0.4 million. Consideration received was measured at fair value and included cash consideration of $3.6 million and non-cash swap transactions of $2.4

million, resulting in a gain on sale of $4.9 million.

CAPITAL RESOURCES AND LIQUIDITY

Kelt's objective is to maintain a flexible capital structure and sufficient liquidity 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 June 30, 2019, 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 bank debt to annualized quarterly adjusted funds from operations ratio, which is a non-GAAP financial measure. Kelt targets a net bank debt to annualized quarterly adjusted funds from operations ratio of less than 2.0 times.

The capital intensive nature of Kelt's operations results in increases to bank debt or working capital deficiency during periods with high levels of capital investment. In the second quarter of 2019 the Company's capital expenditures of $94.7 million (before minor property acquisitions and dispositions) versus its funds from operations of $45.5 million resulted in an increase of net bank debt to $308.6 million at June 30, 2019 from $196.4 million at December 31, 2018. At June 30, 2019, the Company's net bank debt to annualized quarterly adjusted funds from operations ratio increased to 1.7 times from 1.1 times as at December 31, 2018 as Kelt incurred $199.6 million of its $296.0 million 2019 budget in the first half of 2019. The net bank debt to annualized quarterly adjusted funds from operations ratio is expected to decrease to 1.2 times by the end of 2019 as the Company's funds from operations increases as a result of production adds during the second half of 2019.

	June 30, 2019	December 31, 2018
Bank debt	**250,993**	168,881
Working capital deficiency	**57,643**	27,535
Net bank debt (1)	**308,636**	196,416
Annualized quarterly adjusted funds from operations (2)(3)	**181,820**	186,839
Net bank debt to annualized quarterly adjusted funds from operations ratio (1)	**1.7**	1.1

(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) Annualized adjusted funds from operations are 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 over the long term. As at June 30, 2019, the Company's working capital deficit of $57.6 million combined with outstanding bank debt of $251.0 million, represented 98% of the authorized borrowing amount available under the credit facility of $315.0 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.

FINANCING LIABILITY

During the second quarter of 2019, Kelt entered into a sale and financing arrangement of a compressor with a third party for $0.8 million under an 18 month financing term where Kelt retains an option to re-purchase the compressor at the end of the lease term.

Kelt has also entered into an agreement with AltaGas Ltd. ("AltaGas") whereby the Company will construct a 16-inch gas pipeline from its Inga 2-10 facility to the AltaGas Facility. The total cost to build the pipeline is estimated to be approximately $39.0 million and ownership of the pipeline will be two-thirds Kelt and one-third AltaGas, with the completion date expected by the end of 2019. Once the pipeline is built, AltaGas will reimburse Kelt the full amount of $39.0 million ($13.0 million during construction and $26.0 million after construction) and in return Kelt has agreed to make annual payments over 10 years as repayment for its share of the cost of the pipeline (approximately $26.0 million). The annual payments to AltaGas over ten years are representative of payments that would have been required if Kelt did not take an ownership interest in the pipeline but instead entered into a take-or-pay arrangement to deliver gas through the pipeline as a third party. Under such an arrangement, Kelt would not have an ownership interest in the pipeline after 10 years and would have to re-negotiate transportation terms thereafter. Under the agreement, Kelt retains its two-thirds ownership in the pipeline after the ten year term is complete, with no further financial obligation to AltaGas.

CREDIT FACILITY

On March 29, 2019, the Company's revolving committed term credit facility million ("the Credit Facility") was amended with the revolving period extended to April 28, 2020 and the lenders commitments under the Credit Facility increased to \$315.0 million from \$250.0 million. The pricing grid and stamping fees remained the same, which currently ranges from bank prime plus 0.5% to bank prime plus 2.5% and the stamping fee ranges from 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.

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

The Company has \$89.9 million principal amount of convertible unsecured subordinated debentures outstanding as at June 30, 2019. 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 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 at a redemption price equal to their principal amount plus accrued and unpaid interest.

The Company may elect 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 Debentures trade on the TSX under the symbol "KEL.DB".

SHARE INFORMATION

The Company is authorized to issue an unlimited number of common shares and an unlimited number of preferred shares. As at June 30, 2019 there were 184.2 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 second quarter of 2019, 59.6 million common shares traded on the TSX at a weighted average price of \$4.83 per common share, down from the volume weighted average trading price of \$7.10 per common share during the year ended December 31, 2018.

As at June 30, 2019, officers, directors, and employees have been granted options to purchase 8.8 million common shares of the Company at an average exercise price of \$5.51 per common share. In addition, there are 0.9 million RSUs outstanding. Options and RSUs outstanding at June 30, 2019 represented 5.3% of total common shares issued and outstanding. Additional information regarding the Company's stock options and RSUs is included in note 11 of the interim financial statements.

COMMITMENTS AND CONTRACTUAL OBLIGATIONS

As of June 30, 2019, the Company is committed to future payments under the following agreements:

(CA$ thousands)	2019	2020	2021	2022	2023	Thereafter
Firm processing commitments (1)	4,485	13,386	17,041	20,429	19,073	111,438
Firm transportation commitments (2)	22,025	29,787	24,954	23,914	21,053	181,763
Total annual commitments	**26,510**	**43,173**	**41,995**	**44,343**	**40,126**	**293,201**

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

(2) A portion of Kelt's commitments on the Alliance pipeline is 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 June 28, 2019 of CA$/US$1.3087.

On January 1, 2019, the Company adopted IFRS 16 which resulted in the recognition of lease liabilities related to operating leases on the balance sheet some of which were previously reported as commitments. Refer to note 3 of the interim financial statements for a reconciliation of the commitments as at December 31, 2018 to Kelt's lease liabilities as at January 1, 2019.

RELATED PARTY TRANSACTIONS

The Company has engaged a law firm where a director of Kelt is a partner at the law firm, and Kelt has engaged the services of a registrar and transfer agent where an officer of Kelt is a director of the company. During the six months ended June 30, 2019, the Company incurred $0.4 million (2018 – $0.3 million) in disbursements to related parties.

OFF-BALANCE SHEET TRANSACTIONS

The Company did not engage in any off-balance sheet transactions during the periods ended June 30, 2019 and 2018.

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)	**Q2 2019**	Q1 2019	Q4 2018	Q3 2018
Petroleum and natural gas revenue, before royalties	**100,734**	102,585	100,350	100,219
Cash provided by operating activities	**58,639**	53,813	63,656	29,881
Adjusted funds from operations (1)	**45,455**	51,441	47,140	46,876
Per share – basic ($/common share) (1)	**0.25**	0.28	0.26	0.25
Per share – diluted ($/common share) (1)	**0.25**	0.28	0.26	0.25
Profit and comprehensive income	**2,740**	9,369	2,843	3,246
Per share – basic ($/common share)	**0.01**	0.05	0.02	0.02
Per share – diluted ($/common share)	**0.01**	0.05	0.02	0.02
Total capital expenditures, net of dispositions	**91,022**	107,962	70,332	68,427
Total assets	**1,577,824**	1,515,227	1,423,521	1,378,114
Net bank debt (1)	**308,636**	258,351	196,416	176,046
Convertible debentures	**80,512**	79,426	78,390	77,350
Shareholders' equity	**909,373**	904,835	893,796	889,275
Average daily production (BOE/d)	**30,314**	27,057	28,711	26,204
Average realized price ($/BOE) (1)(2)	**35.01**	40.31	34.71	37.74
Operating netback ($/BOE) (1)	**18.50**	23.39	19.39	20.93
Operating netback % of average realized price (2)	**53%**	58%	56%	55%

	Q2 2018	Q1 2018	Q4 2017	Q3 2017
Petroleum and natural gas revenue, before royalties	98,715	89,993	80,838	56,422
Cash provided (used in) by operating activities	39,183	53,663	36,458	24,394
Adjusted funds from operations (1)	47,099	45,724	32,898	22,957
Per share – basic ($/common share) (1)	0.26	0.25	0.18	0.13
Per share – diluted ($/common share) (1)	0.25	0.25	0.18	0.13
Profit (loss) and comprehensive income (loss)	1,702	(23)	(5,389)	(10,653)
Per share – basic ($/common share)	0.01	-	(0.03)	(0.06)
Per share – diluted ($/common share))	0.01	-	(0.03)	(0.06)
Total capital expenditures, net of dispositions	54,702	92,037	55,778	75,933
Total assets	1,346,701	1,337,688	1,276,567	1,227,962
Net bank debt (1)	157,058	173,587	136,729	134,759
Convertible debentures	76,348	75,443	74,517	73,584
Shareholders' equity	882,916	857,019	845,701	830,344
Average daily production (BOE/d)	26,120	26,978	25,063	22,510
Average realized price ($/BOE) (1)(2)	38.51	36.07	33.42	27.26
Operating netback ($/BOE) (1)	21.57	20.47	16.18	12.86
Operating netback as a % of average realized price (2)	56%	57%	48%	47%

(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 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. The 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. 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. During 2019, benchmark WTI oil prices have increased and have settled in a range between US$50-60/barrel from the last quarter of 2018. In the second quarter of 2019, a weakening of benchmark oil prices occurred compared to the first quarter of 2019, as oil demand forecasts were lowered due to an increase in global trade tensions. The reduction of global demand forecasts were partially offset by a reduction of global oil supply as the US tightened economic sanctions on Iran and an increase in geopolitical tensions occurring in the Middle East as a result of those increased sanctions.

The recovery of oil prices in 2019 and the increase in the Company's average oil production weighting, taken together with higher average production, drove the increase in revenues, cash provided by operating activities, and operating netbacks during the first quarter of 2019. In the second quarter of 2019, benchmark oil prices and US natural gas prices decreased resulting in a reduction of second quarter netbacks.

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.

CHANGES IN ACCOUNTING POLICIES

The Company adopted IFRS 16 *Leases* ("IFRS 16") with a date of initial application of January 1, 2019. IFRS 16 replaces IAS 17 *Leases* ("IAS 17") and other related interpretations. Under IFRS 16, lessees must recognize a lease liability and a right-of-use asset for most lease arrangements previously recognized as an operating lease under IAS 17. On adoption, the Company's lease liabilities were measured at the present value of the remaining lease payments discounted using the Company's incremental borrowing rate on January 1, 2019 of 5.9%. Right-of-use assets were measured at an amount equal to the lease liability or, if IFRS 16 had been applied from the lease commencement date, using the Company's incremental borrowing rate on January 1, 2019.

The Company used the modified retrospective approach to adopt the new standard, which does not require restatement of prior period financial information as it recognizes any cumulative effect as an adjustment to opening retained earnings and applies the standard prospectively. The recognition of the present value of minimum lease payments for certain contracts previously classified as operating leases resulted in increases to assets, liabilities, depletion depreciation and amortization, and finance expense, and decreases to production and general and administrative expenses.

Refer to note 3 of the interim financial statements for additional information on the adoption of IFRS 16.

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. The significant judgments, estimates and assumptions made by management in the interim financial statements are outlined in note 2 of the December 31, 2018 annual financial statements. There have been no significant changes in the Company's judgments and estimates applied during the interim period ended June 30, 2019 relative to those described in the most recent annual financial statements as at and for the year ended December 31, 2018.

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.

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 April 1, 2019 to June 30, 2019 that have materially affected, or are reasonably likely to materially affect the Company's internal controls over financial reporting.

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.

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 ($ per BOE) are Non-GAAP measures used by management to measure operating performance. Adjusted funds from operations and operating income or netbacks is useful to the Company's stakeholders as it provides better ability to analyze performance and to compare with information that is 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 June 30			Six months ended June 30		
(CA$ thousands, except as otherwise indicated)	**2019**	2018	%	**2019**	2018	%
Cash provided by operating activities	**58,639**	39,183	50	**112,452**	92,846	21
Change in non-cash working capital	**(14,033)**	7,740	-281	**(17,483)**	(786)	2,124
Funds from operations	**44,606**	46,923	-5	**94,969**	92,060	3
Provision for potential credit losses	**221**	-	-	**203**	-	-
Settlement of decommissioning obligations	**628**	176	257	**1,724**	763	126
Adjusted funds from operations	**45,455**	47,099	-3	**96,896**	92,823	4

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, and the net benefit of the purchase and resale of third party natural gas volumes. In addition to using its own production, the Company may purchase butane and crude oil from third 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 bank debt” is used synonymously with, and is equal to, “bank debt, net of working capital”. “Net bank 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 bank debt to annualized 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 bank debt to annualized quarterly adjusted funds from operations ratio” is also indicative of the “debt to EBITDA” 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.

BUSINESS RISKS

The business of exploration, development, production and acquisition of oil and gas reserves involves a number of uncertainties. As a result, the Company is exposed to certain business risks inherent in the oil and gas industry which may impact the Company’s operations or financial results. A discussion of business risks, as well as economic and industry factors affecting the Company is included in Kelt’s annual MD&A for the year ended December 31, 2018, dated March 6, 2019. Additional information is included in Kelt’s Annual Information Form dated March 6, 2019 which can be found at www.sedar.com

BUSINESS OUTLOOK

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 commencing 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.

CURRENT ECONOMIC ENVIRONMENT

The current economic environment in the energy industry remains volatile; however economic indicators suggest a balanced supply and demand for oil and natural gas with the potential for higher oil prices at the end of 2019 if political risk increases:

- US crude oil production continues to break monthly production records however U.S. crude oil inventories continue to remain within the 5-year band as both exports and domestic consumption increase;
- Global trade tensions increase resulting in a reduction in forecasted crude oil demand expectations;
- Additional Iranian sanctions by the US in the second quarter of 2019 have lowered global crude oil supply and increased geopolitical risk;
- Political instability in Venezuela continues throughout 2019;
- U.S. natural gas exports (to Mexico and LNG) continue to grow supporting North American natural gas prices; and
- U.S. natural gas storage continues to remain below the five-year average.

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.

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.

2019 OUTLOOK AND GUIDANCE

As of the date of this MD&A, management has updated its guidance from May 8, 2019 to incorporate revised commodity price assumptions and second quarter results.

The 2019 capital expenditure guidance was increased to $296 million from an initial budget of $270 million, primarily due to an agreement with AltaGas whereby Kelt will construct a 16-inch gas pipeline from its Inga 2-10 facility to the AltaGas Facility. The pipeline is expected to cost $39 million with Kelt owning a 67% working interest and AltaGas 33%. Once the pipeline is built, AltaGas will reimburse Kelt for its interest in the pipeline of $26 million in exchange for annual payments over 10 years.

Forecasted average production in 2019 is unchanged and estimated to be in the range from 33,500 BOE per day to 34,500 BOE per day, representing a 24% to 28% increase from average production of 27,006 BOE per day in 2018. Average production is estimated to be weighted 47%-49% to oil/NGLs and 51%-53% to gas compared to 47% to oil/NGLs and 53% to gas in the previous guidance.

WTI crude oil prices are forecasted to average US$58.00 per barrel, down 3% from the average forecasted price of US$60.00 per barrel in the Company's previous guidance. Forecasted NYMEX natural gas prices have been revised downwards by 2% to average $2.80 per $US/mmbtu. The average exchange rate has increased by 2% to US$/CA$ 0.7576. After giving effect to the changes in commodity price assumptions and estimated expenses, funds from operations for 2019 was revised down by 8% to $220.0 million.

Net bank debt at December 31, 2019 is estimated to be $258 million which is an increase of $23 million from lower forecasted commodity prices and higher capital investment. The Company expects to exit 2019 with an annual net bank debt to quarterly annualized funds from operations ratio of 1.2 times. The Company is well positioned financially to execute its capital program during the remainder of 2019 based on the assumptions currently contained in the budget.

The following table outlines the Company's revised financial and operating guidance for 2019 compared to its 2019 guidance included in Kelt's Q1 2019 MD&A dated May 7, 2019:

(CA$ millions, except as otherwise indicated)	**Current 2019 Guidance**	Previous 2019 Guidance (May 7, 2019)	%
Average Production			
Oil & NGLs (bbls/d)	**15,800 – 16,900**	15,500 – 16,400	2 to 3
Gas (mmcf/d)	**102.0 – 109.0**	105.0 – 112.0	-3
Combined (BOE/d)	**33,500 – 34,500**	33,500 – 34,500	-
Production per million common shares (BOE/d)	**181 - 187**	174 - 179	4
Forecasted Average Commodity Prices			
WTI oil price (US$/bbl)	**58.00**	60.00	-3
Mixed Sweet Blend Edmonton (CA$/bbl)	**69.32**	73.17	-5
NYMEX natural gas price (US$/MMBTU)	**2.80**	2.85	- 2
AECO natural gas price (US$/MMBTU)	**1.25**	1.30	-4
Average Exchange Rate (US$/CA$)	**0.758**	0.746	2
Net Capital Expenditures	**296.0**	270.0	10
Funds from operations (1)	**220.0**	240.0	-8
Per common share, diluted	**1.19**	1.24	-4

(CA$ millions, except as otherwise indicated)	**Current 2019 Guidance**	Previous 2019 Guidance (May 7, 2019)	%
Net bank debt, at year-end (1) (2)	**258.0**	235.0	10
Net bank debt to annualized quarterly adjusted funds from operations ratio	**1.2 x**	0.9 x	33
Weighted average common shares outstanding (millions)	**184.1**	191.0	-4

(1) Refer to advisories regarding non-GAAP financial measures and other key performance indicators.
(2) In addition to net bank debt, the Company has $89.9 million principal amount of 5% convertible subordinated unsecured debentures outstanding, maturing on May 31, 2021 and convertible to common equity at a price of $5.50 per share. Also, in addition to net bank debt, Kelt estimates 2019 year-end financial liabilities of $26.0 million primarily relating to the Inga 16-inch gas pipeline (AltaGas).

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)	**Current 2019 Guidance**	2018 Actuals	%
Average Production			
Oil & NGLs (bbls/d)	**15,800 – 16,900**	11,589	36 to 46
Gas (mmcf/d)	**102.0 – 109.0**	92.5	10 to 18
Combined (BOE/d)	**33,500 – 34,500**	27,006	24 to 28
Production per million common shares (BOE/d)	**181 - 187**	148	22 to 26
Forecasted Average Commodity Prices			
WTI oil price (US$/bbl)	**58.00**	65.03	-11
Mixed Sweet Blend Edmonton (CA$/bbl)	**69.32**	69.29	-
NYMEX natural gas price (US$/MMBTU)	**2.80**	3.04	-8
AECO natural gas price (US$/MMBTU)	**1.25**	1.40	-11
Average Exchange Rate (US$/CA$)	**0.758**	0.772	-2
Net Capital Expenditures	**296.0**	285.5	4
Funds from operations (1)	**220.0**	186.8	18
Per common share, diluted	**1.19**	1.01	18
Net bank debt, at year-end (1) (2)	**258.0**	196.4	31
Net bank debt to annualized quarterly adjusted funds from operations ratio	**1.2 x**	1.1 x	9
Weighted average common shares outstanding (millions)	**184.1**	182.6	1

(1) Refer to advisories regarding non-GAAP financial measures and other key performance indicators.
(2) In addition to net bank debt, the Company has $89.9 million principal amount of 5% convertible subordinated unsecured debentures outstanding, maturing on May 31, 2021 and convertible to common equity at a price of $5.50 per share. Also, in addition to net bank debt, Kelt estimates 2019 year-end financial liabilities of $26.0 million primarily relating to the Inga 16-inch gas pipeline (AltaGas).

A 10% increase (decrease) in the Company's forecasted average oil/NGLs price for 2019 would increase (decrease) forecasted funds from operations by approximately $28.1 million ($28.1 million). A 10% increase (decrease) in the Company's average gas price forecasted for 2019 would increase (decrease) funds from operations by approximately $13.0 million ($13.0 million). A 5% increase (decrease) in the forecasted average exchange rate would increase (decrease) funds from operations by approximately $17.5 million ($17.5 million).

Changes in forecasted commodity prices and variances in production estimates can have a significant impact on estimated funds from operations and profit. Please refer to the advisories regarding forward-looking statements and to the cautionary statement below.

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.

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.

KELT EXPLORATION LTD.
CONSOLIDATED STATEMENT OF FINANCIAL POSITION
[UNAUDITED]

(CA$ thousands)	[Notes]	**June 30, 2019**	December 31, 2018
ASSETS			
Current assets			
Cash and cash equivalents		**113**	6,455
Accounts receivable and accrued revenue	[13]	**43,640**	46,180
Prepaid expenses and deposits		**1,501**	1,668
Derivative financial instruments	[13]	**411**	3,247
Total current assets		**45,665**	57,550
Investment in securities	[13]	**5,600**	1,000
Exploration and evaluation assets	[5]	**120,320**	119,282
Property, plant and equipment	[6]	**1,406,239**	1,245,689
Total assets		**1,577,824**	1,423,521
LIABILITIES			
Current liabilities			
Accounts payable and accrued liabilities		**100,204**	83,530
Derivative financial instruments	[13]	**945**	651
Decommissioning obligations	[9]	**1,340**	904
Lease liability	[11]	**819**	-
Total current liabilities		**103,308**	85,085
Bank debt	[7]	**250,993**	168,881
Convertible debentures	[8]	**80,512**	78,390
Decommissioning obligations	[9]	**173,235**	143,763
Deferred income tax liability		**57,740**	53,606
Financing liability	[10]	**810**	-
Lease liability	[11]	**1,853**	-
Total liabilities		**668,451**	529,725
SHAREHOLDERS' EQUITY			
Shareholders' capital	[12]	**1,120,481**	1,119,232
Reserve from common control transaction		**(57,668)**	(57,668)
Equity component of convertible debentures	[8]	**12,843**	12,843
Contributed surplus		**22,153**	19,713
Retained earnings (deficit)		**(188,436)**	(200,324)
Total shareholders' equity		**909,373**	893,796
Total liabilities and shareholders' equity		**1,577,824**	1,423,521
Commitments	[16]		

The accompanying notes form an integral part of these consolidated condensed interim 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)
[UNAUDITED]

		Three months ended June 30		Six months ended June 30	
(CA$ thousands, except per share amounts)	[Notes]	**2019**	2018	**2019**	2018
Revenue					
Petroleum and natural gas revenue	[14]	**100,734**	98,715	**203,319**	188,708
Royalties		**(6,203)**	(9,441)	**(11,110)**	(16,108)
		94,531	89,274	**192,209**	172,600
Expenses					
Production		**24,095**	21,726	**48,793**	44,675
Transportation		**15,259**	9,100	**26,878**	17,347
Cost of purchases		**4,312**	7,209	**7,920**	9,616
Financing	[15]	**5,571**	4,069	**10,538**	8,104
General and administrative		**1,872**	1,966	**4,463**	3,809
Provision for potential credit losses		**221**	-	**203**	-
Share based compensation	[12]	**1,798**	1,360	**3,676**	2,948
Exploration and evaluation	[5]	**300**	607	**573**	2,097
Depletion and depreciation	[6]	**41,026**	37,595	**74,942**	76,324
		94,454	83,632	**177,986**	164,920
(Loss) on derivative financial instruments	[13]	**(356)**	-	**(3,797)**	-
Foreign exchange gain (loss)		**42**	122	**(177)**	312
Unrealized gain on investment	[13]	**-**	-	**600**	-
Premium on flow-through shares		**-**	1,723	**-**	2,765
Gain on sale of assets	[4]	**3,525**	31	**4,900**	159
Other income		**-**	-	**495**	-
Profit before taxes		**3,288**	7,518	**16,244**	10,916
Deferred income tax expense		**(548)**	(5,816)	**(4,135)**	(9,237)
Profit and comprehensive income		**2,740**	1,702	**12,109**	1,679
Profit per common share					
Basic	[12]	**0.01**	0.01	**0.07**	0.01
Diluted	[12]	**0.01**	0.01	**0.07**	0.01

KELT EXPLORATION LTD.
CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS' EQUITY
[UNAUDITED]

(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, 2018		184,003	1,119,232	(57,668)	12,843	19,713	(200,324)	893,796
Initial adoption of IFRS 16	[3]	-	-	-	-	-	(221)	(221)
Profit and comprehensive income		-	-	-	-	-	12,109	12,109
Exercise of stock options	[12]	4	18	-	-	(5)	-	13
Vesting of restricted share units	[12]	228	1,231	-	-	(1,231)	-	-
Share based compensation	[12]	-	-	-	-	3,676	-	3,676
Balance at June 30, 2019		**184,235**	**1,120,481**	**(57,668)**	**12,843**	**22,153**	**(188,436)**	**909,373**

Balance at December 31, 2017		178,858	1,078,773	(57,668)	12,856	20,218	(208,478)	845,701
Profit and comprehensive income		-	-	-	-	-	1,679	1,679
Common shares issued, net of costs:								
Private placements		2,758	24,776	-	-	-	-	24,776
Premium on flow-through shares		-	(3,099)	-	-	-	-	(3,099)
Share issue costs, net of tax		-	(541)	-	-	-	-	(541)
Conversion of convertible debentures		16	89		(13)			76
Exercise of stock options	[12]	1,854	15,917	-	-	(4,541)	-	11,376
Vesting of restricted share units	[12]	223	1,232	-	-	(1,232)	-	-
Share based compensation	[12]	-	-	-	-	2,948	-	2,948
Balance at June 30, 2018		183,709	1,117,147	(57,668)	12,843	17,393	(206,799)	882,916

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

KELT EXPLORATION LTD.
CONSOLIDATED STATEMENT OF CASH FLOWS
[UNAUDITED]

		Three months ended June 30		Six months ended June 30	
(CA$ thousands)	[Notes]	**2019**	2018	**2019**	2018
Operating activities					
Profit and comprehensive income		**2,740**	1,702	**12,109**	1,679
Items not affecting cash:					
Accretion of convertible debentures	[8,15]	**1,086**	981	**2,122**	1,907
Accretion of decommissioning obligations	[9,15]	**759**	786	**1,543**	1,555
Share based compensation		**1,798**	1,360	**3,676**	2,948
Exploration and evaluation		**300**	607	**573**	2,097
Depletion and depreciation		**41,026**	37,595	**74,942**	76,324
Unrealized loss on derivative financial instruments	[13]	**501**	-	**3,130**	-
Unrealized gain on investment in securities		**-**	-	**(600)**	-
Unrealized (gain) loss on foreign exchange		**1**	6	**(37)**	-
Premium on flow-through shares		**-**	(1,723)	**-**	(2,765)
Gain on sale of assets		**(3,525)**	(31)	**(4,900)**	(159)
Deferred income tax expense		**548**	5,816	**4,135**	9,237
Settlement of decommissioning obligations	[9]	**(628)**	(176)	**(1,724)**	(763)
Change in non-cash operating working capital	[17]	**14,033**	(7,740)	**17,483**	786
Cash provided by operating activities		**58,639**	39,183	**112,452**	92,846
Financing activities					
Increase (decrease) in bank debt		**57,671**	(15,766)	**82,112**	15,528
Increase (decrease) in financing		**810**	-	**810**	-
Issue of common shares, net of costs	[12]	**-**	24,072	**-**	24,037
Proceeds on exercise of stock options	[12]	**-**	1,598	**13**	11,376
Payments on lease liability		**(360)**	-	**(680)**	-
Cash provided by financing activities		**58,121**	9,904	**82,255**	50,941
Investing activities					
Exploration and evaluation assets		**(1,428)**	(6,358)	**(1,896)**	(40,102)
Property, plant and equipment		**(93,246)**	(48,361)	**(197,704)**	(104,994)
Property acquisitions		**-**	(20)	**(3,002)**	(1,927)
Property dispositions	[4]	**3,652**	37	**3,618**	284
Investment in securities	[13]	**(4,000)**	-	**(4,000)**	(1,000)
Change in non-cash investing working capital	[17]	**(24,796)**	2,169	**1,898**	286
Cash provided by (used in) investing activities		**(119,818)**	(52,533)	**(201,086)**	(147,453)
Foreign exchange on cash and cash equivalents		**(1)**	(6)	**37**	-
Net change in cash and cash equivalents		**(3,059)**	(3,452)	**(6,342)**	(3,666)
Cash and cash equivalents, beginning of period		**3,172**	3,481	**6,455**	3,695
Cash and cash equivalents, end of period		**113**	29	**113**	29

The accompanying notes form an integral part of these consolidated condensed interim 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 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 condensed interim financial statements on August 7, 2019 for issue on August 8, 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 condensed consolidated interim 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 interim financial statements, including IAS 34 *Interim Financial Reporting*. Certain disclosures included in the notes to the annual financial statements have been condensed in the following note disclosures or have been disclosed on an annual basis only. Accordingly, these condensed consolidated interim financial statements should be read in conjunction with the audited consolidated annual financial statements as at and for the year ended December 31, 2018.

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 13 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 outlined in note 2 of the December 31, 2018 consolidated annual financial statements. There have been no significant changes in the Company's judgments and estimates applied during the interim period ended June 30, 2019 relative to those described in the most recent annual financial statements as at and for the year ended December 31, 2018.

3. SIGNIFICANT ACCOUNTING POLICIES

The significant accounting policies applied by the Company are described in note 3 of the December 31, 2018 consolidated annual financial statements. Except as outlined below, these condensed consolidated interim financial statements as at June 30, 2019 have been prepared following the same accounting policies and methods of computation as the most recent consolidated annual financial statements as at and for the year ended December 31, 2018.

Income tax expense for an interim period is based on an estimated average annual effective income tax rate.

New Accounting Policies

The Company adopted IFRS 16 *Leases* (“IFRS 16”) with a date of initial application of January 1, 2019. IFRS 16 replaces IAS 17 *Leases* (“IAS 17”) and other related interpretations. Under IFRS 16, lessees must recognize a lease liability and a right-of-use asset for most lease arrangements previously recognized as an operating lease under IAS 17. On adoption, the Company’s lease liabilities were measured at the present value of the remaining lease payments discounted using the Company’s incremental borrowing rate on January 1, 2019 of 5.9%. Right-of-use assets were measured at an amount equal to the lease liability or, if IFRS 16 had been applied from the lease commencement date, using the Company’s incremental borrowing rate on January 1, 2019.

The Company used the modified retrospective approach to adopt the new standard, which does not require restatement of prior period financial information as it recognizes any cumulative effect as an adjustment to opening retained earnings and applies the standard prospectively. The recognition of the present value of minimum lease payments for certain contracts previously classified as operating leases resulted in increases to assets, liabilities, depletion depreciation and amortization, and finance expense, and decreases to production and general and administrative expenses.

The financial impact of initially applying the standard resulted in an increase of $2.7 million in right-of-use assets (included in property, plant and equipment, note 6), an increase of $2.9 million in lease liability (note 11) and a $0.2 million adjustment to retained earnings.

On adoption, the Company elected to use the following practical expedients:

- Apply a single discount rate to a portfolio of leases with similar characteristics;
- Use of hindsight in determining lease terms; and
- Apply the short term lease exemption for leases with lease terms less than one year

The following table provides a reconciliation of the commitments as at December 31, 2018 to the Company’s lease liabilities as at January 1, 2019:

	Total
Operating lease - office buildings	**4,544**
Operating lease - vehicles	**946**
Total operating leases included in commitments as at December 31, 2018	**5,490**
Less:	
Non-Lease components	**(2,646)**
Add:	
Finance lease liabilities not previously recognized in future commitments	**348**
Undiscounted lease liability as at January 1, 2019	**3,192**
Impact of discounting	**(304)**
Present value of lease liability as at January 1, 2019	**2,888**

4. PROPERTY ACQUISITIONS AND DISPOSITIONS

The following table summarizes the fair value of net assets acquired pursuant to property acquisitions during the six months ended June 30, 2019 and the year ended December 31, 2018.

Net assets acquired (1)	June 30, 2019	December 31, 2018
Exploration and evaluation assets	**5,194**	2,976
Property, plant and equipment	**828**	496
Decommissioning obligations	**(614)**	(612)
Total assets acquired	**5,408**	2,860

Consideration (1)	June 30, 2019	December 31, 2018
Cash consideration	**3,002**	2,860
Non-cash consideration	**2,406**	-
Total consideration	**5,408**	2,860

(1) Net assets acquired include the impact of non-cash asset swap transactions in which $2.4 million of exploration and evaluation assets were exchanged for assets with a net book value of $328k.

During the six months ended June 30, 2019, the Company acquired certain oil and gas assets which included undeveloped land of $5.2 million, developed land of $0.8 million, and decommissioning obligations of $0.6 million. The net assets acquired and the liabilities assumed were recorded at fair value on the acquisition date of $5.4 million, and included cash consideration of $3.0 million and non-cash swap transactions of $2.4 million.

During the six months ended June 30, 2019, the Company disposed of certain non-core oil and gas assets which included undeveloped land of $1.5 million, and decommissioning obligations of $0.4 million. Consideration received was measured at fair value and included cash consideration of $3.6 million and non-cash swap transactions of $2.4 million, resulting in a gain on sale of $4.9 million.

The table below summarizes the aggregate proceeds received and carrying values of the assets and associated decommissioning obligations disposed during the first six months of 2019 and year ended December 31, 2018:

	June 30, 2019	December 31, 2018
Exploration and evaluation assets	**(1,543)**	(122)
Property, plant and equipment (1)	**31**	(8,914)
Decommissioning obligations	**388**	2,528
Carrying value of net (assets) liabilities disposed	**(1,124)**	(6,508)
Cash consideration, after closing adjustments	**3,618**	10,070
Non-cash consideration	**2,406**	-
Total consideration	**6,024**	10,070
Gain on sale of assets	**4,900**	3,562

(1) The adjustment to property plant and equipment in 2019 relates to the final closing adjustments for the Leduc disposition.

5. EXPLORATION AND EVALUATION ASSETS

Exploration and evaluation ("E&E") 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 ("PP&E") or charged to exploration and evaluation expense.

The following table reconciles movements of exploration and evaluation assets:

	June 30, 2019	December 31, 2018
Balance, beginning of period	**119,282**	123,349
Additions	**1,896**	44,283
Property acquisitions [note 4]	**5,194**	2,976
Property dispositions [note 4]	**(1,543)**	(122)
Transfers to property, plant and equipment	**(3,936)**	(45,993)
Expired mineral leases	**(573)**	(5,211)
Balance, end of period	**120,320**	119,282

The Company concluded that there are no indicators of potential impairment of its E&E assets at June 30, 2019.

6. PROPERTY, PLANT AND EQUIPMENT

Net carrying value	June 30, 2019	December 31, 2018
Development and production ("D&P") assets	**1,403,576**	1,245,178
Right-of-use ("ROU") assets	**2,342**	-
Corporate assets	**321**	511
Total net carrying value of property, plant and equipment	**1,406,239**	1,245,689

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	ROU Assets	Total PP&E
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**
Initial adoption of IFRS 16 [note 3]	**-**	**-**	**2,666**	**2,666**
Additions	**197,504**	**200**	**523**	**198,227**
Property acquisitions [note 4]	**828**	-	**-**	**828**
Property dispositions [note 4]	**31**	**-**	**(118)**	**(87)**
Decommissioning costs	**29,863**	**-**	**-**	**29,863**
Transfers from E&E	**3,936**	**-**	**-**	**3,936**
Balance at June 30, 2019	**2,110,805**	**4,229**	**3,071**	**2,118,105**

Accumulated depletion, depreciation and impairment	D&P Assets	Corporate Assets	ROU Assets	Total PP&E
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**
Depletion and depreciation expense	**73,764**	**390**	**788**	**74,942**
Dispositions	**-**	**-**	**(59)**	**(59)**
Balance at June 30, 2019	**707,229**	**3,908**	**729**	**711,866**

Future capital costs required to develop proved reserves in the amount of $816.1 million (December 31, 2018 – $871.5 million) are included in the depletion calculation for development and production assets.

As at June 30, 2019, Kelt's net asset value was greater than its market capitalization therefore an impairment test was conducted over all Kelt's CGUs and as a result, no impairment was recognized.

The following table discloses depreciation expense for the six months ending June 30, 2019 and the carrying amount for right-of-use assets by class of underlying asset as at June 30, 2019:

	Depreciation expense	**Carrying amount**
Office leases	**203**	1,283
Vehicle leases	**267**	741
Field equipment leases	**283**	-
Surface leases	**35**	318
Total	**788**	2,342

7. BANK DEBT

	June 30, 2019	December 31, 2018
Bank loan	**7,400**	-
Bankers' acceptances	**245,000**	170,000
Unamortized financing fees	**(1,407)**	(1,119)
Bank debt	**250,993**	168,881

The Company has a revolving committed term credit facility ("the Credit Facility") with a syndicate of financial institutions. At the end of the first quarter of 2019, the Company and its lenders completed the semi-annual review and amended the Credit Facility to extend the current revolving period to April 30, 2020, and authorized an increase to the borrowing base to $315 million, up $65 million from December 31, 2018. 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.

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 debt to earnings before interest, taxes, depreciation and amortization ("EBITDA") 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 debt to 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:

	June 30, 2019
Bank debt balance, beginning of year	**168,881**
Bank debt drawdown	**82,400**
Decrease in unamortized financing fees	**95**
Increase in prepaid interest on bankers acceptances	**(383)**
Bank debt movement	**82,112**
Bank debt balance, end of period	**250,993**

8. CONVERTIBLE DEBENTURES

	Number of convertible debentures	Liability component ($ thousands)	Equity Component ($ thousands)
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**
Accretion of discount	**-**	**2,122**	**-**
Balance at June 30, 2019	**89,910**	**80,512**	**12,843**

The Company has $89.9 million principal amount of convertible unsecured subordinated debentures outstanding as at June 30, 2019. 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 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 at a redemption price equal to their principal amount plus accrued and unpaid interest.

The Company may elect 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 is obtained by dividing the principal amount of the Debentures by 95% of the Current Market Price on the redemption or maturity date.

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 15). At June 30, 2019, the fair value of the Debentures was $90.9 million (note 13).

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:

	June 30, 2019	December 31, 2018
Balance, beginning of period	**144,667**	136,928
Obligations incurred	**3,252**	8,244
Obligations acquired [note 4]	**614**	612
Obligations disposed [note 4]	**(388)**	(2,528)
Obligations settled	**(1,724)**	(1,122)
Changes in discount rate	**25,463**	4,786
Revisions to estimates	**1,148**	(5,446)
Accretion expense	**1,543**	3,193
Balance, end of period	**174,575**	144,667
Decommissioning obligations – current	**1,340**	904
Decommissioning obligations – non-current	**173,235**	143,763
Key assumptions		
Risk free rate	**1.68%**	2.18%
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 June 30, 2019, the undiscounted amount of the estimated cash flows required to settle the obligation is $155.9 million (December 31, 2018 – $153.4 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 $308.1 million at June 30, 2019 (December 31, 2018 – $303.1 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 15).

10. FINANCING LIABILITY

Balance at December 31, 2018	**-**
Additions	**810**
Balance at June 30, 2019	**810**

During the second quarter of 2019, Kelt entered into a sale and financing arrangement of a compressor with a third party for $0.8 million under a 18 month financing term where Kelt retains an option to re-purchase the compressor at the end of the lease term.

Kelt has entered into an agreement with AltaGas Ltd. ("AltaGas") whereby the Company will construct a 16-inch gas pipeline from its Inga 2-10 facility to the AltaGas Townsend Deep-Cut Gas Plant, with ownership of the pipeline being two-thirds Kelt and one-third AltaGas. Once the construction is complete, which is expected by the end of 2019, AltaGas will reimburse Kelt the full amount of pipeline. In return Kelt has agreed to make annual payments over 10 years as repayment for its share of the cost of the pipeline. The annual payments to AltaGas over ten years are representative of payments that would have been required if Kelt did not take an ownership interest in the pipeline but instead entered into a take-or-pay arrangement to deliver gas through the pipeline as a third party.

11. LEASE LIABILITY

	June 30, 2019
Balance, beginning of period [note 3]	**2,888**
Additions	**523**
Disposals	**(59)**
Interest expense	**100**
Lease payments	**(780)**
Balance, end of period	**2,672**
Lease liability – current	**819**
Lease liability – non-current	**1,853**

The Company has lease liabilities for contracts related to drilling rigs, office space, field equipment, surface leases, and vehicle leases. The weighted average discount rate for the six months ended June 30, 2019 was 5.9 percent. Payments under the Company's short term leases were $6.1 million in the first half of 2019.

12. 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 June 30, 2019 (December 31, 2018 – nil).

	Number of Shares (000s)	Amount ($ thousands)
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**
Issued for cash on exercise of stock options	**4**	**13**
Transfer from contributed surplus on exercise of stock options	**-**	**5**
Released upon vesting of restricted share units	**228**	**1,231**
Balance at June 30, 2019	**184,235**	**1,120,481**

Flow-through common shares

Canadian tax legislation permits entities meeting specified criteria to issue flow-through common shares securities ("FTS") to investors whereby the deductions for tax purposes related to eligible expenditures may be claimed by the investors rather than by the entity. As of December 31, 2018 all eligible expenditures for the Company's flow through shares issued in 2018 and in prior years have been incurred, and no FTS were issued in the first half of 2019.

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 which 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, 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**
Granted	**76**	**5.25**
Exercised (1)	**(4)**	**3.25**
Forfeited	**(58)**	**5.52**
Expired	**(988)**	**12.35**
Balance at June 30, 2019	**8,829**	**5.51**

(1) The weighted average share price on the date stock options were exercised during the period ended June 30, 2019 was $5.72 per common share ($7.74 per common share on average during the year ended December 31, 2018).

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:

	Six months ended June 30	
	2019	2018
Risk free interest rate	**1.7%**	1.9%
Expected life (years)	**3.9**	3.2
Expected volatility (1)	**46.0%**	48.1%
Expected dividend yield	**0.0%**	0.0%
Expected forfeiture rate	**4.7%**	4.2%
Fair value of options granted during the year ($/share)	**1.93**	2.60

(1) The expected volatility for options granted is estimated based on Kelt’s historical share price volatility.

The following table summarizes information regarding stock options outstanding at June 30, 2019:

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	5,050	2.9	4.63	2,833	4.52
$5.01 to $10.00	3,754	2.5	6.65	1,973	6.78
$10.01 to $15.00	25	0.1	12.66	25	12.66
Total	**8,829**	**2.7**	**5.51**	**4,831**	**5.49**

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, 2017	793
Granted	625
Released upon vesting	(290)
Forfeited	(31)
Balance at December 31, 2018	**1,097**
Granted	**13**
Released upon vesting	**(228)**
Forfeited	**(15)**
Balance at June 30, 2019	**867**

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:

	Three months ended June 30		Six months ended June 30	
	2019	2018	**2019**	2018
Stock options	**1,087**	978	**2,203**	2,120
Restricted share units	**711**	382	**1,473**	828
Total share based compensation expense	**1,798**	1,360	**3,676**	2,948

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:

	Three months ended June 30		Six months ended June 30	
(000s of common shares)	**2019**	2018	**2019**	2018
Weighted average common shares outstanding, basic	**184,151**	182,708	**184,085**	181,423
Effect of stock options and RSUs	**381**	2,117	**428**	1,787
Weighted average common shares outstanding, diluted	**184,532**	184,825	**184,513**	183,210

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 June 30, 2019 and 2018, the Company excluded the effect of stock options and RSUs as they were anti-dilutive. The common shares potentially issuable on conversion of the Debentures are also excluded as they were determined to be anti-dilutive for the quarter ended June 30, 2019.

13. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Financial instruments of the Company include cash and cash equivalents, accounts receivable and accrued revenue, deposits, investments in securities, 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 market 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 many factors including regional and world economic events that dictate the levels of supply and demand, local and international market access issues, and the currency exchange rate relationship between the Canadian and U.S. dollar.

As at June 30, 2019, 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 Crude Oil	4,000 bbl/d	Mixed Sweet Blend Edmonton	WTI less USD$10.95 per bbl	October 2019 to December 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 $207.7 million at the end of the second quarter of 2019, an increase (decrease) in the market rate of interest by 25 basis points would have increased (decreased) interest expense by $0.5 million.

As at June 30, 2019, 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 and from exposure from certain U.S. dollar denominated natural gas marketing arrangements.

As at June 30, 2019, 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:

	Three months ended June 30		Six months ended June 30	
	2019	2018	**2019**	2018
Realized gain (loss)	**145**	-	**(667)**	-
Unrealized loss	**(501)**	-	**(3,130)**	-
Loss on derivative financial instruments	**(356)**	-	**(3,797)**	-

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 June 30, 2019:

	Carrying Value ("CV")			Fair Value		
	Gross	Netting(1)	Net CV	Level 1	Level 2	Level 3
Financial assets						
Investment in securities	5,600	-	-	-	-	5,600
Derivative financial instrument	411	-	-	-	411	-
Financial liabilities						
Derivative financial instrument	945	-	-	-	945	-
Convertible debentures [note 8]	80,512	-	-	98,901	-	-

(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 securities is based on equity issuances and other indications of value (level three fair value hierarchy inputs). During the six months ended June 30, 2019, the Company recognized an unrealized gain of its investment in securities of $0.6 million based on the fair value implied by an equity issuance.

The fair value of the convertible debentures of $98.9 million as at June 30, 2019, is based on the closing market price of $110.00 per Debenture, being the price at which the Debentures last traded in the year, and represents the market value of the entire instrument. As at December 31, 2018, the fair value was $99.6 million based on the closing market price of $110.73 per Debenture.

Credit Risk

As at June 30, 2019, 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	**June 30, 2019**	December 31, 2018
Joint venture partners	**6,574**	3,672
Oil and gas marketers	**30,551**	35,129
GST input tax credits	**6,293**	4,559
Risk management contracts	**168**	-
Other	**54**	2,820
Accounts receivable and accrued revenue	**43,640**	46,180

During the six months ended June 30, 2019, sales to three oil and gas marketers each individually represented more than 10% of total revenue. Sales to these marketers account for approximately 10%, 24%, and 38%, of total revenue, respectively. During the comparative period ended December 31, 2018, sales to three oil and gas marketers accounted for approximately 40%, 18%, and 11% of total revenue, respectively. Kelt's oil and gas marketers have 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 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	41,381	658	629	1,620	44,288
Estimated credit loss rate	0.4%	3.8%	3.9%	26.6%	
Loss allowance provision	(167)	(25)	(25)	(431)	(648)
Balance at June 30, 2019	**41,214**	**633**	**604**	**1,189**	**43,640**
Balance at December 31, 2018	43,537	932	585	1,126	46,180

The allowance provision as at June 30, 2019 reconciles to the opening loss allowance as at January 1, 2019 in the following table:

	Total
Allowance for doubtful accounts at January 1, 2018	666
Direct write-off (recovery) of amounts included in provision	(128)
Allowance for doubtful accounts at December 31, 2018	**538**
Direct write-off of amounts included in provision	**(93)**
Provisions for potential credit losses through profit or loss	**203**
Loss allowance balance at June 30, 2019	**648**

During the six months ended June 30, 2019, the Company's recognized an increase in the loss allowance provision resulting in a expense in the statement of Consolidated Statement of Profit (Loss) and Comprehensive Income of $0.2 million (December 31, 2018 – recovery $0.1 million).

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 annualized quarterly 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, the Company targets to maintain sufficient unused bank credit lines over the long term to satisfy such working capital deficiencies. As at June 30, 2019, the Company's working capital deficit of $57.6 million combined with outstanding bank debt of $251.0 million, represented 98% of the authorized borrowing amount available under the Credit Facility of $315.0 million (up from 79% at December 31, 2018). The Credit Facility is available for a revolving period of 364 days, maturing on April 30, 2020, and may be extended annually at Kelt's option and subject to lender approval, with a 364 day term-out period if not renewed.

The table below outlines a contractual maturity analysis for Kelt's financial liabilities as at June 30, 2019:

	Within 1 Year	1 to 5 Years	More than 5 Years	**Total**
Accounts payable and accrued liabilities	100,204	-	-	**100,204**
Derivative financial instruments	945	-	-	**945**
Bank debt and estimated interest[(1)]	10,040	250,993	-	**261,033**
Convertible debentures[(2)]	4,508	94,036	-	**98,544**
Lease liability	820	1,723	129	**2,672**
Financing liability	-	810	-	**810**
Total	**116,517**	**347,562**	**129**	**464,208**

(1) Estimated interest for future periods related to the Credit Facility was calculated using the weighted average interest rate of 4.0% for the quarter ended June 30, 2019, 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 30, 2020.

(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 bank debt to annualized quarterly adjusted funds from operations ratio, which is a non-GAAP financial measure.

	June 30, 2019	December 31, 2018
Bank debt	**250,993**	168,881
Working capital deficiency	**57,643**	27,535
Net bank debt (1)	**308,636**	196,416
Annualized quarterly adjusted funds from operations (2)(3)	**181,820**	186,839
Net bank debt to annualized quarterly adjusted funds from operations ratio (1)	**1.7**	1.1

(1) "Net bank 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) Adjusted funds from operations are annualized based on the most recent quarter's adjusted funds from operations.

Kelt targets a net bank debt to annualized quarterly 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 bank debt to annualized quarterly adjusted funds from operations ratio of 1.7 times increased as at June 30, 2019 from 1.1 times at December 31, 2018.

As more particularly described in note 7, Kelt is subject to certain non-financial covenants under the Credit Facility agreement. As at June 30, 2019, the Company is in compliance with all covenants. The Company is not subject to any other externally imposed capital requirements.

14. 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.

Where Kelt is the principal to transportation arrangements, gas production sales includes revenue for variable priced contracts after the point where title is transferred to a third party. The transaction price for these contracts is based on benchmark commodity prices at a location that is different from the price at which title transfer takes place. For the six months ended June 30, 2019, transportation costs incurred in relation to these contracts was $6 million.

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

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

	Three months ended June 30		Six months ended June 30	
	2019	2018	**2019**	2018
Revenue, before royalties and financial instruments:				
Oil production	**63,424**	59,697	**109,333**	111,115
Oil treating and other	**94**	933	**284**	1,525
NGLs production	**8,635**	9,501	**17,489**	18,960
Gas production	**22,389**	20,785	**61,577**	46,194
Gas processing and other	**335**	441	**616**	1,046
Marketing revenue	**5,857**	7,358	**14,020**	9,868
Total revenue	**100,734**	98,715	**203,319**	188,708

Included in accounts receivable at June 30, 2019 is $30.6 million (December 31, 2018 - $35.1 million) of accrued oil and gas sales related to June 2019 production.

15. FINANCING EXPENSES

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

	Three months ended June 30		Six months ended June 30	
	2019	2018	**2019**	2018
Interest on bank debt [note 7]	**2,511**	1,181	**4,509**	2,411
Interest on convertible debentures [note 8]	**1,121**	1,121	**2,229**	2,231
Interest on finance leases [note 11]	**59**	-	**100**	-
Interest on financing liability [note 10]	**35**	-	**35**	-
Accretion of convertible debentures [note 8]	**1,086**	981	**2,122**	1,907
Accretion of decommissioning obligations [note 9]	**759**	786	**1,543**	1,555
Financing expense	**5,571**	4,069	**10,538**	8,104

16. COMMITMENTS

As of June 30, 2019, the Company is committed to future payments under the following agreements:

	2019	2020	2021	2022	2023	Thereafter
Firm processing commitments	4,485	13,386	17,041	20,429	19,073	111,438
Firm transportation commitments (1)	22,025	29,787	24,954	23,914	21,053	181,763
Total annual commitments	**26,510**	**43,173**	**41,995**	**44,343**	**40,126**	**293,201**

(1) A portion of Kelt's commitments on the Alliance pipeline is 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 June 28, 2019 of CA$/US$1.3087.

On January 1, 2019, the Company adopted IFRS 16 which resulted in the recognition of lease liabilities related to operating leases on the balance sheet some of which were previously reported as commitments. See note 3 for a reconciliation from the commitments as at December 31, 2018 to Kelt's lease liabilities as at January 1, 2019.

17. SUPPLEMENTAL CASH FLOW INFORMATION

	Three months ended June 30		Six months ended June 30	
Changes in non-cash working capital	**2019**	2018	**2019**	2018
Accounts receivable and accrued revenue	**4,935**	7,405	**2,540**	4,580
Prepaid expenses and deposits	**(235)**	(1,257)	**167**	(1,238)
Accounts payable and accrued liabilities	**(15,463)**	(11,719)	**16,674**	(2,270)
Change in non-cash working capital	**(10,763)**	(5,571)	**19,381**	1,072
Relating to:				
Operating activities	**14,033**	(7,740)	**17,483**	786
Investing activities	**(24,796)**	2,169	**1,898**	286
Change in non-cash working capital	**(10,763)**	(5,571)	**19,381**	1,072

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

	Three months ended June 30		Six months ended June 30	
Cash outlays in respect of interest and taxes	**2019**	2018	**2019**	2018
Interest and standby fees on bank debt	**1,098**	2,280	**4,711**	2,923
Interest on convertible debentures (1)	**2,242**	2,244	**2,242**	2,244
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.

18. RELATED PARTY TRANSACTIONS

The Company has engaged a law firm where a director of Kelt is a partner at the law firm, and Kelt has engaged the services of a registrar and transfer agent where an officer of Kelt is a director of the company. During the six months ended June 30, 2019, the Company incurred $0.4 million (2018 – $0.3 million) in disbursements to related parties.

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]
Chief Financial Officer, Chief Compliance Officer, & Portfolio Manager, Camber Capital Corp.

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

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Vice President, Marketing

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Convertible Debentures “KEL.DB”

kelt exploration

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