SECOND QUARTER REPORT

AS AT AND FOR THE THREE AND SIX MONTHS ENDED

JUNE 30, 2026

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FINANCIAL AND OPERATIONAL HIGHLIGHTS	Three months ended June 30			Six months ended June 30		
(CA$ thousands, except as otherwise indicated)	**2026**	2025	%	**2026**	2025	%
FINANCIAL						
Petroleum and natural gas sales	**222,166**	116,418	91	**390,272**	258,919	51
Cash provided by operating activities	**104,900**	60,696	73	**194,607**	147,625	32
Adjusted funds from operations [(1)]	**108,725**	61,846	76	**193,373**	140,060	38
Basic ($/ common share) [(1)]	**0.54**	0.31	74	**0.96**	0.71	35
Diluted ($/ common share) [(1)]	**0.53**	0.31	71	**0.94**	0.70	34
Net income and comprehensive net income	**44,679**	32,461	38	**45,365**	51,440	-12
Basic ($/ common share)	**0.22**	0.16	38	**0.22**	0.26	-15
Diluted ($/ common share)	**0.22**	0.16	38	**0.22**	0.26	-15
Capital expenditures, net of A&D [(1)]	**137,871**	90,952	52	**252,188**	195,698	29
Total assets	**1,754,609**	1,562,599	12	**1,754,609**	1,562,599	12
Bank debt	**187,000**	151,432	23	**187,000**	151,432	23
Net debt [(1)]	**242,141**	178,170	36	**242,141**	178,170	36
Shareholders' equity	**1,198,083**	1,121,679	7	**1,198,083**	1,121,679	7
Weighted average shares outstanding (000s)						
Basic	**202,675**	199,005	2	**201,652**	198,272	2
Diluted	**205,979**	201,749	2	**204,740**	201,150	2
OPERATIONS						
Average daily production						
Oil (bbls/d)	**11,812**	8,508	39	**11,221**	8,973	25
NGLs (bbls/d)	**7,669**	5,371	43	**7,445**	5,500	35
Gas (mcf/d)	**185,444**	149,128	24	**183,498**	149,381	23
Combined (BOE/d)	**50,388**	38,734	30	**49,249**	39,370	25
Production per million common shares (BOE/d) [(1)]	**249**	195	28	**244**	199	23
Net realized prices, before derivative financial instruments [(1)]						
Oil ($/bbl)	**131.65**	82.52	60	**113.33**	88.17	29
NGLs ($/bbl)	**57.75**	36.67	57	**50.51**	38.91	30
Gas ($/mcf)	**2.14**	2.32	-8	**2.54**	2.62	-3
Operating netbacks ($/BOE) [(1)]						
Petroleum and natural gas sales	**48.45**	33.03	47	**43.78**	36.33	21
Cost of purchases	**(0.93)**	(0.90)	3	**(0.86)**	(0.85)	1
Net realized price, before derivative financial instruments [(1)]	**47.52**	32.13	48	**42.92**	35.48	21
Realized gain (loss) on financial instruments	**(2.23)**	1.87	-219	**(1.40)**	1.82	-177
Net realized price, after derivative financial instruments [(1)]	**45.29**	34.00	33	**41.52**	37.30	11
Royalties	**(6.27)**	(2.69)	133	**(4.89)**	(3.47)	41
Production expense	**(10.03)**	(8.60)	17	**(10.16)**	(9.08)	12
Transportation expense	**(4.07)**	(3.21)	27	**(3.46)**	(3.36)	3
Operating netback [(1)]	**24.92**	19.50	28	**23.01**	21.39	8
Land holdings						
Gross acres	**802,921**	790,438	2	**802,921**	790,438	2
Net acres	**602,999**	590,892	2	**602,999**	590,892	2

(1) Refer to advisories regarding Non-GAAP and Other Financial Measures

MESSAGE TO SHAREHOLDERS

Kelt Exploration Ltd. ("Kelt" or the "Company") reports its financial and operating results to shareholders for the second quarter of 2026.

Kelt's average production for the three months ended June 30, 2026 reached a new Company record high quarterly production average of 50,388 BOE per day, up 30% from average production of 38,734 BOE per day during the corresponding period in 2025. Production for the three months ended June 30, 2026 was weighted 39% oil and NGLs and 61% gas.

Kelt's realized average oil price during the second quarter of 2026 was $131.65 per barrel, up 60% from $82.52 per barrel in the second quarter of 2025. Kelt's realized second quarter oil price in 2026 was 102% of the equivalent Canadian dollar WTI daily average index price for the same period. The realized average NGLs price was $57.75 per barrel, up 57% from $36.67 per barrel in the second quarter of 2025. Kelt's realized average gas price for the second quarter of 2026 was $2.14 per Mcf, down 8% from $2.32 per Mcf in the corresponding quarter of the previous year. Kelt's realized second quarter gas price in 2026 was 31% higher than the AECO daily average index price for the same period.

Kelt continues to generate robust returns from its sulphur production. The Company sold an average of 110 long tons per day at an average net price of $919.44 per long ton during the second quarter of 2026, which added $9.2 million to funds from operations. With significant shortages of sulphur supply globally, demand for the product remains resilient. As a result, sulphur prices have continued to trend upwards early in the third quarter of 2026.

For the three months ended June 30, 2026, petroleum and natural gas sales were $222.2 million and adjusted funds from operations was $108.7 million ($0.53 per common share, diluted), significantly higher than $116.4 million and $61.8 million ($0.31 per common share, diluted) respectively, in the second quarter of 2025. At June 30, 2026, the Company had net debt of $242.1 million, equating to 0.6 times forecasted 2026 adjusted funds from operations of $410.0 million.

Net capital expenditures incurred during the three months ended June 30, 2026 were $137.9 million. During the second quarter of 2026, the Company spent $109.1 million (79%) on drill and complete operations; $27.2 million (20%) on facilities, pipelines and equipment; and $1.6 million (1%) of other expenditures.

Operations Update

In its Wembley/Pipestone Division, year-to-date, Kelt has drilled and completed 12 Montney wells from three different pads (6-9, 11-34 and 16-26). These wells were all completed using the plug and perf method optimized with higher proppant and water intensities and are now on production. The Company has also drilled five Montney wells off the 7-8 pad which are currently being completed and are expected to commence production in late August 2026. During the remainder of the year, Kelt plans to drill and complete three additional Montney D3/D4 wells off the 14-26 pad and two Montney D2 wells off the 5-26 pad by La Glace.

The tables below summarize the results of the Wembley wells drilled off the 6-9 and 11-34 pads. These wells have now been on production for longer than 30 days. The Company is targeting both the Montney D3 and D4 zones off these pads that will result in eight Montney wells per section. Kelt has drilled a third lower zone, the Montney D1, off other pads in the Wembley/Pipestone area and expects that certain lands on its 190 section land block could be prospective for all three zones, resulting in the potential for twelve Montney wells per section on those lands.

Wembley 6-9 Pad (4 Wells)	IP30 Total Pad	Percent Mix	**IP30 Average per Well**	IP30 – Average per Well included in the Company's Third-party Independent Engineering Evaluation (Dec/31/25)	Difference	Percent
Oil & NGLs (bbls/d)	2,379	57%	**595**	451	144	32%
Gas (Mcf/d)	10,824	43%	**2,706**	2,125	581	27%
Combined (BOE/d)	**4,183**	**100%**	**1,046**	**805**	**241**	**30%**
Horizontal Lateral Length (m)			**3,185**	3,000	185	6%
Lateral Spacing in the same Zone (m)			**400**	300	100	33%
Cluster Spacing (m)			**8**	10	(2)	(20%)

Wembley 6-9 Pad (4 Wells)	**Actual Results (Average per Well)**	Previous Completion Design Parameters	Difference	Percent
Frac Sand Intensity (T/m)	**2.75**	2.25	0.50	22%
Frac Water Intensity (m3/T)	**3.91**	3.50	0.41	12%
Tubing Pressure (kPa)	**3,880**	2,300 – 2,900		

Wembley 11-34 Pad (4 Wells)	IP30 Total Pad	Percent Mix	**IP30 Average per Well**	IP30 – Average per Well included in the Company's Third-party Independent Engineering Evaluation (Dec/31/25)	Difference	Percent
Oil & NGLs (bbls/d)	2,778	67%	**695**	317	378	119%
Gas (Mcf/d)	8,348	33%	**2,087**	1,370	717	52%
Combined (BOE/d)	**4,169**	**100%**	**1,043**	**545**	**498**	**91%**
Horizontal Lateral Length (m)			**3,665**	3,000	665	22%
Lateral Spacing in the same zone (m)			**400**	300	100	33%
Cluster Spacing (m)			**8**	10	(2)	(20%)

Wembley 11-34 Pad (4 Wells)	**Actual Results (Average per Well)**	Previous Completion Design Parameters	Difference	Percent
Frac Sand Intensity (T/m)	**2.74**	2.25	0.49	22%
Frac Water Intensity (m3/T)	**3.94**	3.50	0.44	13%
Tubing Pressure (kPa)	**4,148**	2,300 – 2,900		

The Company is encouraged from the results of the Wembley wells drilled to date in 2026 and completed using the optimized fracture design that has resulted in higher IP30 rates and higher liquids ratios compared to those included for the same wells in last year's third-party independent engineering evaluation.

In the Pouce Coupe/Progress Division, Kelt has an active program in 2026 with 13 (11.5) drills and 14 (12.5) completions. Targets are predominantly the Montney and oily Charlie Lake formations. During the second half of 2026, the Company has four drills and six completions remaining in the capital program.

In its Oak/Flatrock Division, Kelt is less active where a four well pad located at 5-32 was drilled and these wells plus two DUCs on the same pad were completed.

2026 Outlook

The outlook for Kelt for the remainder of 2026 looks positive. Newly drilled wells are performing better than anticipated and forecasted adjusted funds from operations for the year has been revised upwards several times since the Company prepared its initial forecast in January 2026.

Production during 2026 is forecasted to average between 50,000 and 52,000 BOE per day, unchanged from the Company's previous guidance. Despite the following third-party facility downtime, production continues to be within its guidance range (primarily due to better than expected well performance to date from Kelt's 2026 drilling program):

- Progress Gas Plant – expected to be down for planned turnaround operations in September for approximately 17 days;
- MacMahon Gas Plant – expected to be down for planned turnaround operations in September/October for approximately 30 days; and
- Albright Gas Plant – has been down since July 25, 2026, for unplanned maintenance. Kelt has been diverting certain volumes previously dedicated to Albright to other gas plants in the area. The Company's gas production at Wembley/Pipestone is connected to five different gas processing plants.

Adjusted funds from operations for 2026 is forecasted to be $410.0 million or 3% higher than the Company's previous forecast of $400.0 million. The Company increased its forecasted 2026 estimated average WTI oil price by 3% from US$77.50 per barrel to US$79.50 per barrel. Kelt reduced its forecasted 2026 estimated average AECO gas price by 3% from CA$1.81 per GJ to CA$1.75 per GJ.

Kelt's 2026 capital expenditure budget remains unchanged at $375.0 million. However, if strong performance in production and commodity prices continue to boost cash flow, the Company may increase capital expenditures during the remainder of the year to get an earlier start to accelerate production growth in 2027.

On December 31, 2026, the Company expects to have net debt of $153.0 million, approximately 0.4 times forecasted 2026 adjusted funds from operations of $410.0 million.

Forecasted average commodity price assumptions for the remainder of 2026 are shown in the following table:

Commodity Index	Jan–Jun 2026 Actual	Jul–Dec 2026 Forecast	**2026 Forecast**
WTI Crude Oil (USD/bbl)	82.57	76.49	**79.50**
MSW Crude Oil (CAD/bbl)	113.00	103.09	**108.00**
NYMEX Natural Gas Daily Index (USD/MMBtu)	3.91	3.10	**3.50**
DAWN Gas Daily Index (USD/MMBtu)	3.49	2.91	**3.20**
AECO NIT 5A Gas Daily Index (CAD/GJ)	1.73	1.78	**1.75**
STATION 2 Gas Daily Index (CAD/GJ)	1.54	1.58	**1.56**
Exchange Rate (USD/CAD)	0.7258	0.7183	**0.7220**
Exchange Rate (CAD/USD)	1.3777	1.3922	**1.3850**

Financial and operating highlights for the Company's 2026 forecast compared to its 2025 results are highlighted in the table below:

Financial and Operating Highlights *($ MM, unless otherwise specified)*	2025	**2026 Forecast**	Change
Production *[2]*			
Oil & NGLs (bbls/d)	14,861	**19,600 – 20,600**	35%
Gas (MMcf/d)	153,214	**182,400 – 188,400**	21%
Combined (BOE/d)	40,397	**50,000 – 52,000**	26%
P&NG Sales *[1]*	513.1	**804.7**	57%
Adjusted Funds from Operations *[1]*	261.5	**410.0**	57%
AFFO per share, diluted ($/share) *[1]*	1.29	**1.99**	54%
Capital Expenditures, net of A&D *[1]*	328.3	**375.0**	14%
Net Debt, at year-end *[1]*	189.7	**153.0**	(19%)
Net Debt / AFFO ratio	0.7 x	**0.4 x**	
Notes: *[1] Refer to advisories regarding "Non-GAAP and Other Financial Measures".* *[2] Percent change for production is calculated using the mid-point of each production range.*			

With continued success in its drilling program and strong oil prices, Kelt expects to show significant production and cash flow growth in the second half of 2026. Management looks forward to updating shareholders with 2026 third quarter results on or about November 13, 2026.

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.

Management Update

Mr. Patrick Miles, the Company's Vice President, Exploration, will retire effective August 12, 2026. Mr. Miles has served as Vice President, Exploration since Kelt commenced operations in 2013 and has played a central role in building the Company's vast resource. We wish him well in this new chapter of his life. The Company has appointed Mr. David White, currently Kelt's Manager, Exploration, to succeed Mr. Miles as Vice President, Exploration. Mr. White joined Kelt in 2014 and has held progressively senior roles with the Company. David has been the lead geologist for the Company's Wembley/Pipestone Division and has extensive knowledge in various plays in both Alberta and British Columbia. Prior to joining Kelt, Mr. White was a geologist for a senior oil and gas exploration and production company based in Calgary, Alberta.

On behalf of the Board of Directors,

[signed]

David J. Wilson
President and Chief Executive Officer
August 6, 2026

MANAGEMENT'S DISCUSSION & ANALYSIS

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

The Company was incorporated under the *Business Corporations Act* (Alberta) on October 11, 2012. Kelt's assets are comprised of three core operating divisions, namely: (1) Wembley/Pipestone in Alberta; (2) Pouce Coupe/Progress/Spirit River in Alberta; and (3) Oak/Flatrock in British Columbia. The Company's British Columbia assets are operated by Kelt Exploration (LNG) Ltd. ("Kelt LNG"), a wholly owned subsidiary of Kelt. 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 are listed on the Toronto Stock Exchange ("TSX") under the symbol "KEL". Additional information relating to Kelt can be found on SEDAR+ at www.sedarplus.ca.

This Management's Discussion and Analysis ("MD&A") is dated August 5, 2026 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, 2026 and its audited annual consolidated financial statements and MD&A as at and for the year ended December 31, 2025. The accompanying condensed consolidated interim financial statements have been prepared in accordance with International Financial Reporting Standards, as issued by the International Accounting Standards Board ("IFRS Accounting Standards").

GENERAL ADVISORY

This MD&A contains certain specified financial measures consisting of non-GAAP measures, capital management measures, and supplementary financial measures. These non-GAAP and other financial measures include "funds from operations", "adjusted funds from operations", "adjusted funds from operations per common share", "petroleum and natural gas sales after cost of purchases", "operating income", "operating netback", "capital expenditures, before A&D", "capital expenditures, net of A&D", "net debt (surplus)", "net realized prices", "combined net realized prices", and "net debt (surplus) to adjusted funds from operations ratio" which do not have standardized meanings prescribed by generally accepted accounting principles ("GAAP") and therefore may not be comparable to similar measures presented by other companies where similar terminology is used. For further information and reconciliation to Canadian generally accepted accounting principles "GAAP" measures, see "Non-GAAP and Other Financial Measures" in this MD&A.

This MD&A contains forward-looking information within the meaning of applicable Canadian securities laws. The use 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. As of January 1, 2026 sulphur volumes and sales are included in NGLs volumes and sales. Prior to January 1, 2026 sulphur volumes and sales were included in natural gas volumes and sales. The term BOE may be misleading, particularly if used in isolation. A BOE conversion ratio of six thousand cubic feet per barrel is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead and is significantly different than the value ratio based on the current price of crude oil and natural gas. This conversion factor is an industry accepted norm and is not based on either energy content or current prices. Such abbreviation may be misleading, particularly if used in isolation.

FINANCIAL AND OPERATING SUMMARY

	Three months ended June 30			Six months ended June 30		
(CA$ thousands, except as otherwise indicated)	**2026**	2025	%	**2026**	2025	%
FINANCIAL PERFORMANCE						
Petroleum and natural gas sales	**222,166**	116,418	91	**390,272**	258,919	51
Cash provided by operating activities	**104,900**	60,696	73	**194,607**	147,625	32
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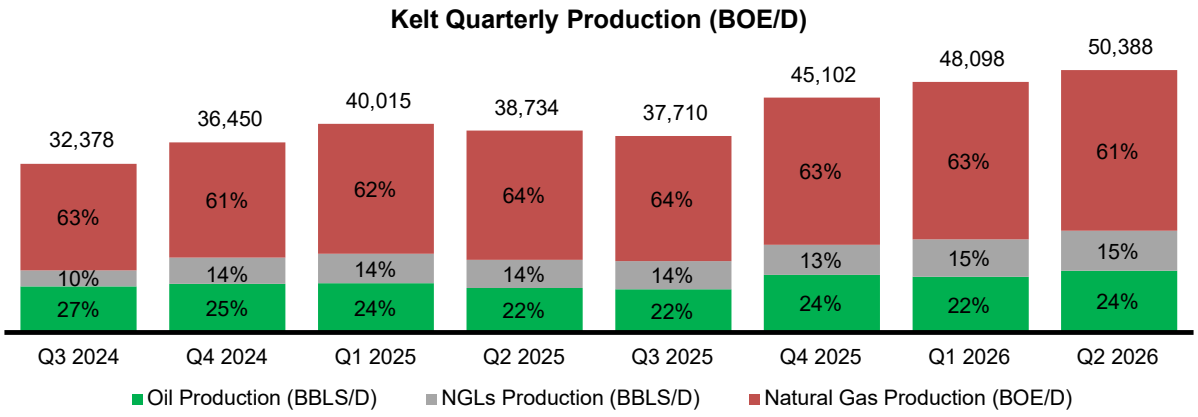
Net income and comprehensive net income	**44,679**	32,461	38	**45,365**	51,440	-12
Diluted ($/ common share)	**0.22**	0.16	38	**0.22**	0.26	-15
Capital expenditures, net of A&D [(1)]	**137,871**	90,952	52	**252,188**	195,698	29
Bank debt	**187,000**	151,432	23	**187,000**	151,432	23
Net debt [(1)]	**242,141**	178,170	36	**242,141**	178,170	36
OPERATIONAL PERFORMANCE						
Average daily production (BOE/d)	**50,388**	38,734	30	**49,249**	39,370	25
Net realized price, before derivative financial instruments [(1)]	**47.52**	32.13	48	**42.92**	35.48	21
Net realized price, after derivative financial instruments [(1)]	**45.29**	34.00	33	**41.52**	37.30	11
Operating netback [(1)]	**24.92**	19.50	28	**23.01**	21.39	8

(1) Refer to advisories regarding Non-GAAP and Other Financial Measures.

In the second quarter of 2026, Kelt's financial and operating results are highlighted by the following:

- **Production –** Average production of 50,388 BOE per day (39% liquids) during the second quarter of 2026, an increase of 30% from 38,734 BOE per day (36% liquids) in the second quarter of 2025 and increased by 5% from 48,098 BOE per day (37% liquids) in the first quarter of 2026.
- **Petroleum and natural gas sales –** For the three months ended June 30, 2026, petroleum and natural gas sales increased by 91% compared to the second quarter of 2025. Kelt's net realized price before derivative financial instruments of $47.52 per BOE increased by 48% from the second quarter of 2025 primarily due to higher benchmark oil and NGLs prices.
- **Operating netback –** Kelt's operating netback was $24.92 per BOE for the three months ended June 30, 2026, a 28% increase from $19.50 per BOE for the three months ended June 30, 2025. The increase in the operating netback was primarily due to higher petroleum and natural gas sales which was partially offset by higher royalties and a realized loss on derivative financial instruments of $2.23 per BOE for the quarter ended June 30, 2026 compared to a gain of $1.87 for the quarter ended June 30, 2025.
- **Cash provided by operating activities and adjusted funds from operations –** Cash provided by operating activities increased to $104.9 million in the second quarter of 2026 compared to $60.7 million in the second quarter of 2025. Adjusted funds from operations of $108.7 million ($0.53 per common share, diluted) for the three months ended June 30, 2026 increased 76% from the second quarter of 2025 primarily due to higher production volumes and a higher operating netback.
- **Net income –** Kelt reported net income of $44.7 million ($0.22 per common share, diluted) for the three months ended June 30, 2026, compared to net income of $32.5 million ($0.16 per common share, diluted) in the second quarter of 2025.
- **Capital investments –** Capital expenditures, net of A&D, were $137.9 million in the second quarter of 2026 which included the drilling of 13.0 net wells and the completion of 15.0 net wells.
- **Net debt –** The Company ended the quarter with net debt of $242.1 million (0.8 times trailing 12-month adjusted funds from operations).

PRODUCTION

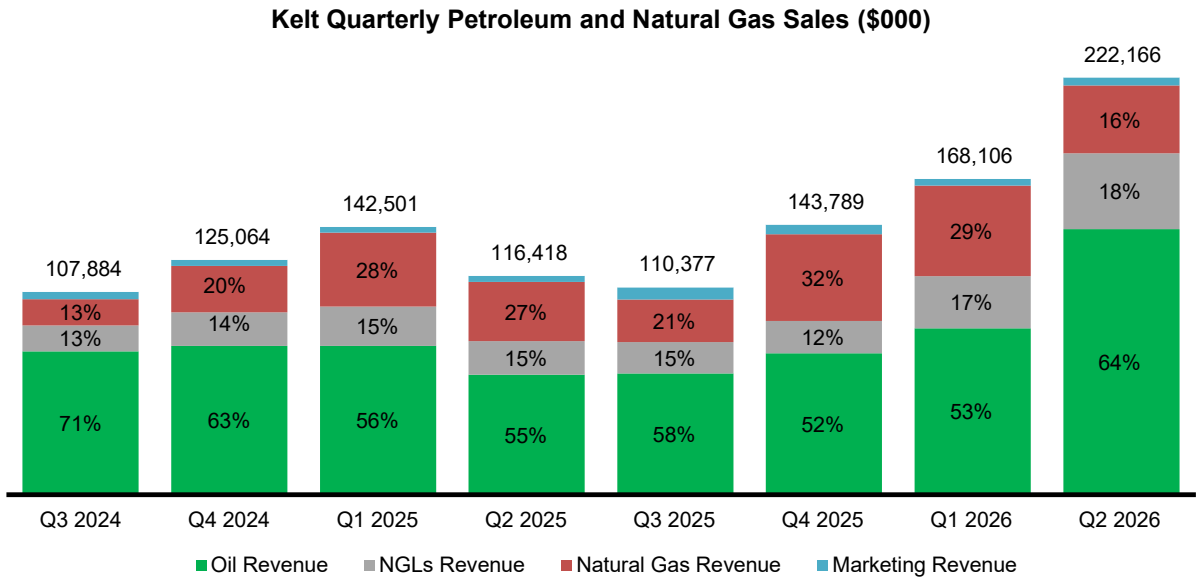


	Three months ended June 30			Six months ended June 30		
	2026	2025	%	**2026**	2025	%
Average daily production:						
Oil (bbls/d)	**11,812**	8,508	39	**11,221**	8,973	25
NGLs (bbls/d)	**7,669**	5,371	43	**7,445**	5,500	35
Gas (mcf/d)	**185,444**	149,128	24	**183,498**	149,381	23
Combined (BOE/d)	**50,388**	38,734	30	**49,249**	39,370	25
Oil and NGLs weighting	**39%**	36%	8	**38%**	37%	3

Production averaged 50,388 BOE per day for the three months ended June 30, 2026 and 49,249 BOE per day for the six months ended June 30, 2026, an increase of 30% and 25%, respectively, from the comparable periods in 2025. The increase in production in 2026 was driven by the Company's drilling activities combined with higher available processing capacity at Wembley/Pipestone.

Oil and NGLs weighting increased to 39% for the second quarter of 2026 compared to 36% in the comparable period of 2025.

PETROLEUM AND NATURAL GAS SALES ("P&NG SALES")



	Three months ended June 30			Six months ended June 30		
(CA$ thousands, except as otherwise indicated)	**2026**	2025	%	**2026**	2025	%
Oil	**141,426**	63,836	122	**229,952**	143,066	61
NGLs	**40,300**	17,921	125	**68,070**	38,734	76
Gas	**36,105**	31,448	15	**84,358**	70,917	19
Marketing revenue [(1)]	**4,335**	3,213	35	**7,892**	6,202	27
P&NG Sales	**222,166**	116,418	91	**390,272**	258,919	51
Cost of purchases [(2)]	**(4,253)**	(3,168)	34	**(7,667)**	(6,072)	26
P&NG Sales after cost of purchases [(3)(5)]	**217,913**	113,250	92	**382,605**	252,847	51
Net realized price ($/BOE) [(4)(5)]	**47.52**	32.13	48	**42.92**	35.48	21

(1) Marketing revenue includes the sale of third-party volumes related to the Company's marketing of third party oil production.

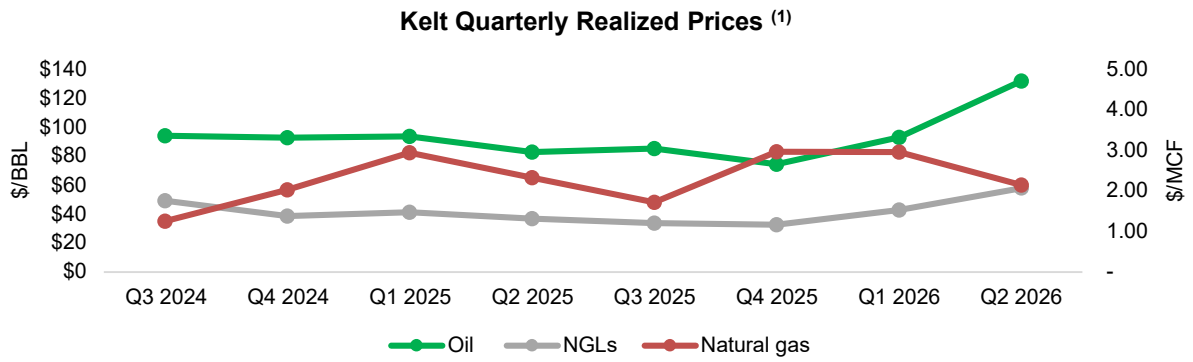
(2) Cost of purchases includes costs for the purchase of third-party volumes related to the Company's marketing of third party oil production.

(3) P&NG sales after cost of purchases includes petroleum and natural gas sales, net of the cost of the third-party volumes purchased.

(4) Combined net realized price ($/BOE) equals P&NG sales after cost of purchases divided by total production.

(5) Refer to advisories regarding Non-GAAP and Other Financial Measures.

Petroleum and natural gas sales totaled $222.2 million for the three months ended June 30, 2026, an increase of 91% from $116.4 million in the second quarter of 2025. For the six months ended June 30, 2026, petroleum and natural gas sales were $390.3 million, an increase of 51% from the comparable period in 2025. The increase in petroleum and natural gas sales during both periods was primarily due to higher production volumes and higher realized oil and NGL prices, partially offset by lower realized natural gas prices.



(1) Net realized prices are calculated based on P&NG Sales, less the cost of purchases of third-party volumes and reflect Kelt's realized commodity prices plus the net benefit of oil blending and natural gas marketing activities. Net realized prices exclude both realized and unrealized gains and losses on risk management contracts. Refer to additional information under the heading of "Non-GAAP and Other Financial Measures".

	Three months ended June 30			Six months ended June 30		
	2026	2025	%	**2026**	2025	%
Net realized prices (1)						
Oil ($/bbl)	**131.65**	82.52	60	**113.33**	88.17	29
NGLs ($/bbl)	**57.75**	36.67	57	**50.51**	38.91	30
Gas ($/Mcf)	**2.14**	2.32	-8	**2.54**	2.62	-3
Combined ($/BOE)	**47.52**	32.13	48	**42.92**	35.48	21
Average benchmark prices						
Oil, NGLs and Sulphur						
WTI Cushing Oklahoma (US$/bbl)	**92.85**	64.60	44	**82.57**	68.20	21
Mixed Sweet Blend Edmonton ("MSW") ($/bbl)	**131.94**	85.45	54	**113.00**	90.69	25
Edmonton Pentane ($/bbl)	**128.55**	88.28	46	**113.33**	93.59	21
Edmonton Butane ($/bbl)	**56.86**	37.68	51	**50.29**	42.73	18
Edmonton Propane ($/bbl)	**29.03**	30.08	-3	**26.34**	33.32	-21
Edmonton Ethane ($/bbl)	**4.43**	4.82	-8	**4.99**	5.35	-7
Sulphur realized price ($/LT)	**919.44**	258.92	255	**709.55**	138.51	412
Natural Gas						
NYMEX Henry Hub (US$/MMBtu)	**2.93**	3.16	-7	**3.91**	3.71	5
AECO 5A (CA$/MMBtu)	**1.63**	1.69	-4	**1.82**	1.92	-5
Chicago Alliance, into Interstates (CA$/MMBtu)	**3.40**	3.95	-14	**5.43**	4.84	12
Dawn (CA$/MMBtu)	**3.53**	4.00	-12	**4.80**	4.77	1
Sumas (CA$/MMBtu)	**1.58**	1.28	23	**1.94**	2.45	-21
Station 2 (CA$/MMBtu)	**1.37**	0.43	219	**1.63**	0.84	94
Marcellus (TZ4 L300) (CA$/MMBtu)	**2.80**	3.09	-9	**4.87**	4.28	14
Average exchange rate (CA$/US$)	**1.3837**	1.3841	-	**1.3777**	1.4097	-2

(1) Net realized prices are calculated based on Petroleum and Natural Gas Sales, less the cost of purchases of third-party volumes and reflect Kelt's realized commodity prices plus the net benefit of oil blending and natural gas marketing activities. Net realized prices exclude both realized and unrealized gains and losses on derivative financial instruments. Refer to additional information under the heading of "Non-GAAP and Other Financial Measures".

Combined Net Realized Price

Kelt's combined net realized price increased by 48% to $47.52 per BOE for the three months ended June 30, 2026 and increased by 21% to $42.92 per BOE for the six months ended June 30, 2026, as compared to the same periods in 2025. The increase in the average realized price during both periods was driven by higher realized oil and NGL prices, partially offset by lower realized natural gas prices.

Oil prices

For the three months and six months ended June 30, 2026, Kelt's realized crude oil price increased by 60% and 29%, respectively, as compared to the same periods in 2025. The increase in realized crude oil price is consistent with the increase in the sweet blend Edmonton benchmark crude oil price which increased 54% for the three months ended June 30, 2026 and increased by 25% for the six months ended June 30, 2026 as compared to the same periods in 2025. Benchmark crude oil prices increased in March 2026 and remained elevated throughout the second quarter, driven by the Middle East conflict and a significant reduction of crude oil tanker traffic through the Strait of Hormuz.

NGL prices

For the three months and six months ended June 30, 2026, Kelt's realized NGLs price increased by 57% and 30%, respectively, as compared to the same periods in 2025. The increase in the realized NGLs price was primarily due to higher pentane and butane prices which are correlated to the price of crude oil. This was partially offset by lower propane and ethane prices, with propane prices in western Canada impacted from overall higher inventory levels in 2026 than in 2025 and ethane prices impacted from lower natural gas prices which they are generally correlated to.

Sulphur

The start-up of a new third-party sour gas processing facility at Wembley/Pipestone at the end of 2025 has resulted in Kelt increasing its sulphur production volumes. The Company sold an average of 112 long tons per day during the first six months of 2026, which contributed $14.4 million to funds from operations. Canadian sulphur prices remained elevated in 2026 due to the global supply being impacted by the conflict in the Middle East.

Natural gas prices

Kelt manages its natural gas marketing portfolio in order to maximize its netback, with 21% of its natural gas sold at indices outside of Alberta and British Columbia for the six months ending June 30, 2026. Kelt's realized natural gas price decreased by 8% to $2.14 per Mcf in the second quarter of 2026 compared to the second quarter of 2025 and decreased by 3% to $2.54 per Mcf for the six months ended June 30, 2026 as compared to the same period in 2025. For the three months ended June 30, 2026, AECO 5A, Chicago Alliance, and Dawn benchmark prices were lower while Sumas and Station 2 benchmark prices were higher compared to the second quarter of 2025. Natural gas inventory levels in the US went from slightly below the 5-year average in the first quarter of 2026 to above average in the second quarter of 2026, resulting in an overall downward pressure on prices. Western Canadian natural gas storage levels have remained above the 5-year average storage levels throughout 2026, however Station 2 prices in 2026 increased relative to the AECO 5A benchmark price with additional demand in British Columbia from LNG Canada commencing operations in the second half of 2025.

RISK MANAGEMENT AND HEDGING ACTIVITIES

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.

Kelt recognized a gain of $3.3 million on derivative financial instruments in the second quarter of 2026, consisting of a realized loss of $10.2 million and an unrealized gain of $13.5 million. The realized loss on derivative financial instruments in 2026, and the unrealized loss for the six months ending June 30, 2026 was driven by higher realized oil prices during the period. This was partially offset by realized and unrealized gains in the JKM and TTF contracts in 2026.

The unrealized gain on derivative financial instruments for the three months ended June 30, 2026 was primarily due to oil financial derivative contracts being settled in the quarter and the unrealized loss moving into a realized loss position.

The table below summarizes realized and unrealized gains (losses) on derivative financial instrument contracts:

	Three months ended June 30			Six months ended June 30		
(CA$ thousands, except as otherwise indicated)	**2026**	2025	%	**2026**	2025	%
Realized gain (loss)						
Derivative financial instruments - Oil	**(16,708)**	3,029	-652	**(20,147)**	2,597	-876
Derivative financial instruments - Gas	**2,662**	3,323	-20	**2,335**	10,333	-77
Derivative financial instruments - NGLs	**467**	99	372	**887**	(145)	-712
Embedded derivative - Gas	**3,357**	149	2,153	**4,445**	187	2,277
Total realized gain (loss)	**(10,222)**	6,600	-255	**(12,480)**	12,972	-196
Unrealized gain (loss)						
Derivative financial instruments - Oil	**21,001**	11,760	79	**(13,527)**	13,513	-200
Derivative financial instruments - Gas	**(3,183)**	11,712	-127	**(1,104)**	6,600	-117
Derivative financial instruments - NGLs	**658**	583	13	**1,285**	(26)	-5,042
Embedded derivative - Gas	**(5,006)**	2,828	-277	**3,272**	470	596
Total unrealized gain (loss)	**13,470**	26,883	-50	**(10,074)**	20,557	-149
Gain (loss) on derivative financial instruments	**3,248**	33,483	-90	**(22,554)**	33,529	-167
$ per BOE	**0.71**	9.50	-93	**(2.53)**	4.71	-154

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 from changes in commodity prices. Commodity prices are impacted by world economic events that dictate the levels of supply and demand as well as the currency exchange rate relationship between the Canadian and US dollar.

As at August 5, 2026, the following commodity price derivative financial instrument contracts are outstanding:

Crude oil derivative financial instrument swap

Contract Type [1]	Notional Volume	Contract Price	Remaining Term
WTI fixed price	500 bbl/d	CAD$87.65/bbl	Jul 26 – Sept 26
WTI fixed price	2,000 bbl/d	CAD$93.08/bbl	Jul 26 – Dec 26
WTI fixed price [2]	500 bbl/d	CAD$85.00/bbl	Jul 26 – Dec 26
WTI fixed price	500 bbl/d	CAD$85.65/bbl	Oct 26 – Dec 26

(1) West Texas Intermediate ("WTI").

(2) Includes a fixed price WTI oil swap option to sell 500 bbl/d for Jan-Jun 2027 at CAD$85.00/bbl exercisable on December 31, 2026.

Crude oil derivative financial instrument differential

Contract Type [1]	Notional Volume	Contract Price	Remaining Term
MSW-WTI basis differential	1,500 bbl/d	(USD$1.95/bbl)	Jul 26 – Sept 26

(1) Mountain sweet blend crude oil ("MSW").

NGL derivative financial instrument swap

Contract Type	Notional Volume	Contract Price	Remaining Term
OPIS-Conway propane	800 bbl/d	Floating WTI USD$/bbl x 50.5%	Jul 26 – Mar 27

Natural gas derivative financial instruments

Contract Type	Notional Volume	Contract Price $/MMBtu	Remaining Term
NYMEX [(1)] call	20,000 MMBtu/d	USD$5.50/MMBtu	Jul 26 – Dec 26
AECO [(2)] 7A put	21,000 GJ/d	CAD$2.80/GJ	Jul 26 – Dec 26

(1) New York Mercantile Exchange ("NYMEX").

(2) Alberta Energy Company "C" Meter Station of the NOVA Pipeline System ("AECO").

Electricity derivative financial instrument swap

Contract Type [(1)]	Notional Volume	Contract Price	Remaining Term
AESO fixed price	24 MW/d	50.25 CAD per MWh	Jul 26 – Dec 26
AESO fixed price	24 MW/d	45.25 CAD per MWh	Jul 26 – Dec 26

(1) Alberta Electric System Operator ("AESO").

Natural Gas Embedded Derivatives: AESO

The Company has the following natural gas physical supply agreements for delivery to the Nova Inventory Transfer point, where the Company receives a price equal to the Floating AESO Power Pool Price divided by the fixed heat rate. These supply agreements contain an embedded derivative where the fair value of the embedded derivative is calculated as the difference between the forecasted Floating AESO Power Pool Price divided by the fixed heat rate, less the forecasted AECO 5A price.

Natural gas embedded derivative

Contract Type	Notional Volume	Contract Price	Remaining Term
Physical delivery	7,349 GJ/d	Floating AESO power pool price (CAD/MWh) divided by the Fixed Heat Rate of 16.75 GJ/MWh	Jul 26 – Dec 26

Natural Gas Embedded Derivatives: JKM and TTF

The Company has the following natural gas physical supply agreements for delivery to the Nova Inventory Transfer point. These supply agreements contain an embedded derivative where the fair value of the embedded derivative is based upon the future price in each respective market.

Natural gas embedded derivative

Contract Type	Notional Volume	Contract Price	Remaining Term
Physical delivery	5,000 MMBtu/d	Floating JKM (Japan/Korea Marker) Price (USD/MMBtu) multiplied by 22.0%	Jul 26 – Dec 26
Physical delivery	5,000 MMBtu/d	Floating TTF (Title Transfer Facility Netherlands) Price (USD/MMBtu) multiplied by 22.0%	Jul 26 – Dec 26

Interest rate risk

The Company is exposed to interest rate risk as changes in market interest rates will impact the Credit Facility which is subject to a floating interest rate. Based on the bank debt balance as of June 30, 2026 of $187.0 million, an increase (decrease) in the market rate of interest by 25 basis points would have an increased (decreased) annualized interest expense by $0.5 million. As of June 30, 2026, 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 marketing

arrangements.

As of August 5, 2026, the following foreign exchange risk management contracts are outstanding:

Foreign exchange derivative financial instrument

Contract Type	Notional Volume	Strike Rate	Remaining Term
Average rate forward (1)	USD$2.0 million/month	$1.4025 CAD/USD	Jul 26 – Dec 26
Average rate forward	USD$1.0 million/month	$1.3800 CAD/USD	Jul 26 – Dec 26
Average rate forward	USD$4.0 million/month	$1.4015 CAD/USD	Jul 26 – Dec 26

(1) Contract includes an option that extends the contract into the 2027 calendar year at a strike price of $1.4025 CAD/USD if the spot CAD/USD is $1.4025 CAD/USD or higher on December 31, 2026. The contract also includes a knock out provision that if the spot CAD/USD trades at or below $1.3250 CAD/USD anytime between the trade date of November 3, 2025 to December 31, 2026, the option to extend into 2027 is cancelled.

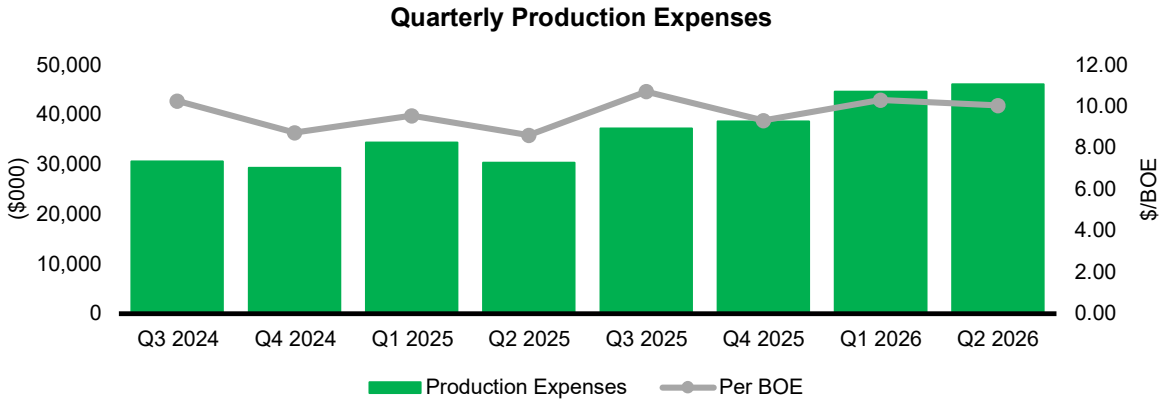
ROYALTIES

	Three months ended June 30			Six months ended June 30		
(CA$ thousands, except as otherwise indicated)	**2026**	2025	%	**2026**	2025	%
Royalties	**28,742**	9,472	203	**43,590**	24,711	76
Average royalty rate (1)	**13.2%**	8.4%	57	**11.4%**	9.8%	16
$ per BOE	**6.27**	2.69	133	**4.89**	3.47	41

(1) The average royalty rate is calculated based on total royalties as a percentage of "P&NG Sales, before marketing revenue" which excludes sales related to the sale of third-party production volumes used in oil blending operations (see table under the heading of *"Petroleum and Natural Gas Sales"*).

Kelt's average royalty rate was 13.2% for the three months ended June 30, 2026, compared to 8.4% for the comparable period in 2025. For the six months ended June 30, 2026, the average royalty rate was 11.4%, compared to 9.8% for the comparable period in 2025. The increase in the royalty rate in both periods of 2026 is primarily due to higher oil and NGL benchmark prices and lower GCA.

PRODUCTION EXPENSES



	Three months ended June 30			Six months ended June 30		
(CA$ thousands, except as otherwise indicated)	**2026**	2025	%	**2026**	2025	%
Production expense	**45,994**	30,319	52	**90,544**	64,671	40
$ per BOE	**10.03**	8.60	17	**10.16**	9.08	12

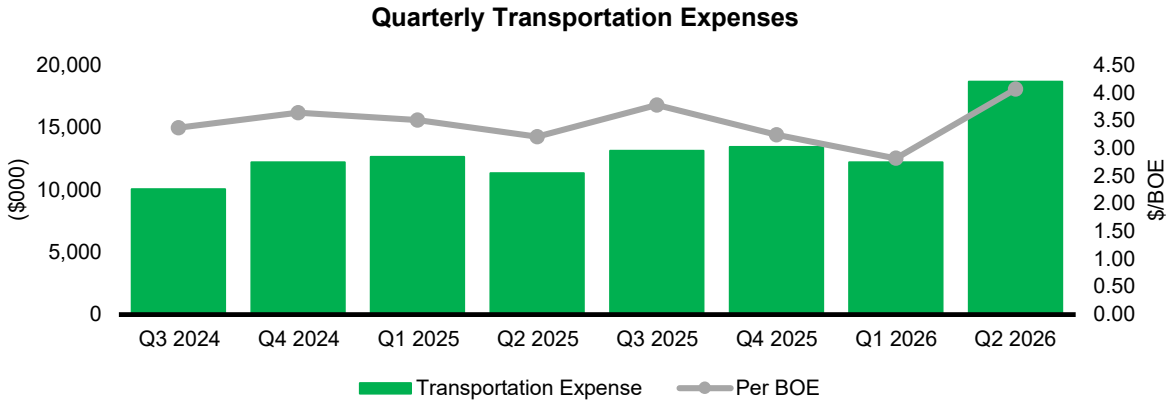
The company incurred production expenses of $46.0 million for the three months ended June 30, 2026 compared to $30.3 million for the same period in 2025. Production expenses per BOE increased by 17% to $10.03 for the three months ended June 30, 2026 compared to $8.60 per BOE for the same period in 2025.

The company incurred production expenses of $90.5 million for the six months ended June 30, 2026 compared to $64.7

million for the same period in 2025. Production expenses per BOE increased by 12% to $10.16 for the six months ended June 30, 2026 compared to $9.08 for the same period in 2025.

This increase in production expenses per BOE for the three months and six months ended June 30, 2026 was primarily due to higher gas processing costs, which were partially offset by lower carbon taxes.

TRANSPORTATION EXPENSES



	Three months ended June 30			Six months ended June 30		
(CA$ thousands, except as otherwise indicated)	**2026**	2025	%	**2026**	2025	%
Transportation expense [1]	**18,679**	11,326	65	**30,886**	23,958	29
$ per BOE	**4.07**	3.21	27	**3.46**	3.36	3

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

Transportation expense averaged $4.07 per BOE for the three months ended June 30, 2026 and $3.46 per BOE for the six months ended June 30, 2026, compared to $3.21 per BOE and $3.36 per BOE, respectively, for the comparable periods in 2025. The increase in transportation costs per BOE for the three months ended June 30, 2026 was primarily due to additional natural gas volumes sold at Dawn during the second quarter of 2026, resulting in higher natural gas transportation costs.

FINANCING EXPENSES

	Three months ended June 30			Six months ended June 30		
(CA$ thousands, except as otherwise indicated)	**2026**	2025	%	**2026**	2025	%
Total interest expense	**2,993**	2,685	11	**5,833**	4,702	24
Accretion of decommissioning obligations	**844**	807	5	**1,670**	1,607	4
Total financing expense	**3,837**	3,492	10	**7,503**	6,309	19
Interest expense per BOE [1]	**0.65**	0.76	-14	**0.65**	0.66	-2

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

Interest expense was $3.0 million and $5.8 million for the three and six months ended June 30, 2026, respectively. As at June 30, 2026, $187.0 million was drawn under the credit facility, with outstanding letters of credit of $4.0 million.

Additional information regarding the credit facility 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)	**2026**	2025	%	**2026**	2025	%
Salaries and benefits	**4,374**	3,903	12	**8,962**	8,258	9
Other G&A expenses	**1,482**	1,923	-23	**3,187**	3,608	-12
Gross G&A expenses	**5,856**	5,826	1	**12,149**	11,866	2
Overhead recoveries	**(2,810)**	(2,044)	37	**(5,721)**	(4,482)	28
Net G&A expenses	**3,046**	3,782	-19	**6,428**	7,384	-13
Gross G&A ($ per BOE)	**1.28**	1.65	-22	**1.36**	1.67	-19
Net G&A ($ per BOE)	**0.66**	1.07	-38	**0.72**	1.04	-31

Net G&A expenses per BOE decreased by 38% for the three months ended June 30, 2026 and decreased by 31% for the six months ended June 30, 2026, compared to the same periods in 2025. The decrease in net G&A expenses per BOE was primarily due to higher production volumes which increased at a greater rate than the increase in G&A expenses, as well as higher overhead recoveries as a result of an increase in capital expenditures in 2026.

SHARE BASED COMPENSATION

	Three months ended June 30			Six months ended June 30		
(CA$ thousands, except as otherwise indicated)	**2026**	2025	%	**2026**	2025	%
Stock options	**249**	644	-61	**825**	1,909	-57
Restricted share units ("RSUs")	**737**	721	2	**1,682**	1,604	5
Performance share units ("PSUs")	**730**	231	216	**1,200**	231	419
Total share based compensation expense	**1,716**	1,596	8	**3,707**	3,744	-1
$ per BOE	**0.37**	0.45	-18	**0.42**	0.53	-21

Total share based compensation expense increased by 8% for the three months ended June 30, 2026 and decreased by 1% for the six months ended June 30, 2026, compared to the same periods in 2025. The increase in share based compensation expense for the three months ended June 30, 2026 was due to RSUs and PSUs granted in May 2026.

Total share based compensation expense on a per BOE basis decreased by 18% and 21% for the three and six months ended June 30, 2026, respectively, compared to the same periods in 2025. The decrease was primarily due to higher production volumes in both periods of 2026 compared to 2025.

As at June 30, 2026, stock options, RSUs, and PSUs outstanding represent 3.8% of total shares outstanding (December 31, 2025 – 5.0%).

DEPLETION AND DEPRECIATION

	Three months ended June 30			Six months ended June 30		
(CA$ thousands, except as otherwise indicated)	**2026**	2025	%	**2026**	2025	%
Depletion and depreciation expense	**60,931**	43,428	40	**117,568**	87,197	35
$ per BOE	**13.29**	12.32	8	**13.19**	12.24	8

Depletion and depreciation expense increased by 40% and 35% for the three and six months ended June 30, 2026, respectively, as compared to the same periods in 2025. The increase in both periods was primarily due to an increase in production.

On a per BOE basis, depletion and depreciation expense increased by 8% for both the three and six months ended June 30, 2026, compared to the same periods in 2025.

Based on its assessment as of June 30, 2026 and December 31, 2025, the Company determined that there were no indicators of impairment.

INCOME TAXES

	Three months ended June 30			Six months ended June 30		
(CA$ thousands, except as otherwise indicated)	**2026**	2025	%	**2026**	2025	%
Deferred income tax expense	**14,015**	10,388	35	**14,979**	16,580	-10
Net income before taxes	**58,694**	42,849	37	**60,344**	68,020	-11
Effective tax recovery rate	**23.9%**	24.2%	-1	**24.8%**	24.4%	2

Kelt's consolidated combined federal and provincial statutory tax rate averaged 23% during the three months ended June 30, 2026 and 2025. The Company is not expected to have any cash income taxes payable in 2026.

The Company's consolidated tax pools are estimated to be approximately $1,028.4 million as of June 30, 2026 as summarized in the table below:

(CA$ thousands, except otherwise indicated)	Rate	**June 30 2026**
Canadian oil and gas property expenses (COGPE)	10%	**52,186**
Canadian development expenses (CDE)	30%	**418,510**
Canadian exploration expenses (CEE)	100%	**14,715**
Undepreciated capital cost [(1)] (UCC)	25%	**294,337**
Non-capital losses [(2)] (NCL)	100%	**248,680**
Estimated tax deductions available, end of period		**1,028,428**

(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 2035 to 2045.

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, 2026 and 2025, respectively.

	Three months ended June 30			Six months ended June 30		
(CA$ thousands, except as otherwise indicated)	**2026**	2025	%	**2026**	2025	%
Petroleum and natural gas sales	**222,166**	116,418	91	**390,272**	258,919	51
Cost of purchases	**(4,253)**	(3,168)	34	**(7,667)**	(6,072)	26
Realized gain (loss) on derivative financial instruments [(1)]	**(10,222)**	6,600	-255	**(12,480)**	12,972	-196
Royalties	**(28,742)**	(9,472)	203	**(43,590)**	(24,711)	76
Production expense	**(45,994)**	(30,319)	52	**(90,544)**	(64,671)	40
Transportation expense	**(18,679)**	(11,326)	65	**(30,886)**	(23,958)	29
Operating Income [(2)]	**114,276**	68,733	66	**205,105**	152,479	35
Financing expense [(3)]	**(2,993)**	(2,685)	11	**(5,833)**	(4,702)	24
G&A expense	**(3,046)**	(3,782)	-19	**(6,428)**	(7,384)	-13
Gain (loss) on foreign exchange	**478**	(428)	-212	**499**	(355)	-241
Other income	**10**	8	25	**30**	22	36
Adjusted funds from operations [(2)]	**108,725**	61,846	76	**193,373**	140,060	38
Basic ($ per common share) [(4)]	**0.54**	0.31	74	**0.96**	0.71	35
Diluted ($ per common share) [(4)]	**0.53**	0.31	71	**0.94**	0.70	34

	Three months ended June 30			Six months ended June 30		
($ per BOE)	**2026**	2025	**%**	**2026**	2025	%
Petroleum and natural gas sales	**48.45**	33.03	47	**43.78**	36.33	21
Cost of purchases	**(0.93)**	(0.90)	3	**(0.86)**	(0.85)	1
Realized gain (loss) on derivative financial instruments [1]	**(2.23)**	1.87	-219	**(1.40)**	1.82	-177
Royalties	**(6.27)**	(2.69)	133	**(4.89)**	(3.47)	41
Production expense	**(10.03)**	(8.60)	17	**(10.16)**	(9.08)	12
Transportation expense	**(4.07)**	(3.21)	27	**(3.46)**	(3.36)	3
Operating Netback [2]	**24.92**	19.50	28	**23.01**	21.39	8
Financing expense [3]	**(0.65)**	(0.76)	-14	**(0.65)**	(0.66)	-2
G&A expense	**(0.66)**	(1.07)	-38	**(0.72)**	(1.04)	-31
Gain (loss) on foreign exchange	**0.10**	(0.12)	-183	**0.05**	(0.05)	-200
Adjusted funds from operations [2]	**23.71**	17.55	35	**21.69**	19.64	10

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

(2) Refer to advisories regarding *"Non-GAAP and Other Financial Measures"*.

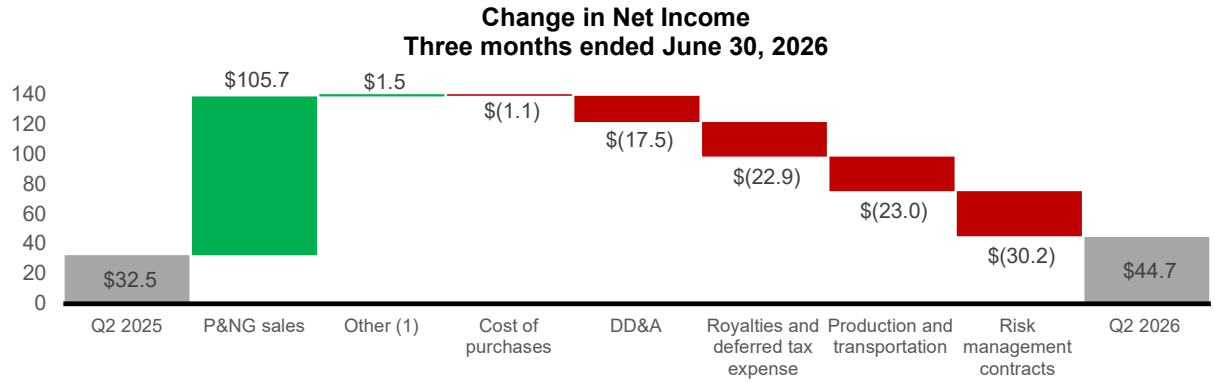
(3) Excludes non-cash accretion of decommissioning obligations.

(4) Adjusted funds from operations (2) per common share is calculated on a consistent basis with net income per common share, using basic and diluted weighted average common shares as determined in accordance with GAAP.

For the three months ended June 30, 2026, adjusted funds from operations of $108.7 million ($0.53 per common share, diluted) increased by 76% from $61.8 million ($0.31 per common share, diluted) for the second quarter of 2025. The increase in adjusted funds from operations is a result of higher petroleum and natural gas sales, partially offset by a realized loss on derivative financial instruments and higher royalties, production and transportation expenses.

For the six months ended June 30, 2026, adjusted funds from operations of $193.4 million ($0.94 per common share, diluted) increased by 38% from $140.0 million ($0.70 per common share, diluted) for the six months ended June 30, 2025. The increase in adjusted funds from operations is a result of higher petroleum and natural gas sales and a decrease in G&A expenses, partially offset by a realized loss on derivative financial instruments and higher royalties, financing, production and transportation expenses.

NET INCOME AND COMPREHENSIVE NET INCOME



(1) Other includes G&A expenses, share based compensation expenses, and foreign exchange gains (losses).

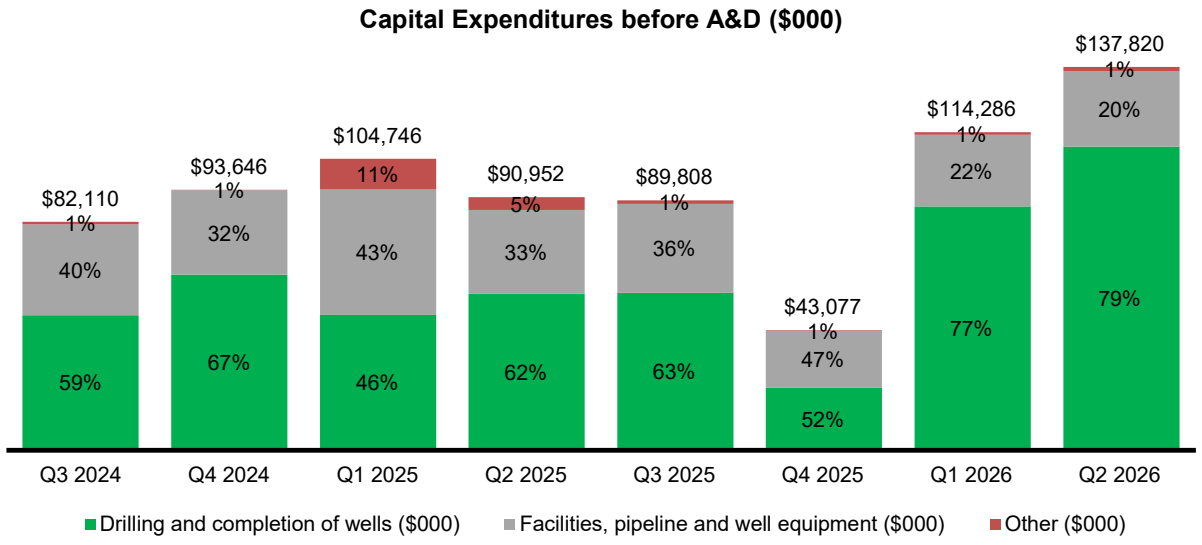
	Three months ended June 30			Six months ended June 30		
(CA$ thousands, except as otherwise indicated)	**2026**	2025	%	**2026**	2025	%
Net income and comprehensive net income	**44,679**	32,461	38	**45,365**	51,440	-12
$ per common share, basic	**0.22**	0.16	38	**0.22**	0.26	-15
$ per common share, diluted [(1)]	**0.22**	0.16	38	**0.22**	0.26	-15
$ per BOE	**9.74**	9.22	6	**5.09**	7.18	-29
Wtd avg. shares outstanding, basic (000s)	**202,675**	199,005	2	**201,652**	198,272	2
Wtd avg. shares outstanding, diluted (000s) [(1)]	**205,979**	201,749	2	**204,740**	201,150	2

(1) The Company uses the treasury stock method to determine the dilutive effect of stock options, RSUs, and PSUs. Under this method, only "in-the-money" dilutive instruments impact the calculation of diluted net income per common share.

Kelt reported net income of $44.7 million ($0.22 per common share, diluted) for the three months ended June 30, 2026, compared to net income of $32.5 million ($0.16 per common share, diluted) in the comparative period of 2025. The increase in net income was primarily driven by an increase in petroleum and natural gas sales and a gain on derivative financial instruments, which were partially offset by an increase in royalties, production and transportation expenses, and depletion and depreciation.

Kelt reported net income of $45.4 million ($0.22 per common share, diluted) for the six months ended June 30, 2026, compared to net income of $51.4 million ($0.26 per common share, diluted) in the comparative period of 2025. The decrease in net income was primarily driven by a $10.1 million unrealized loss on derivative financial instruments and depletion and depreciation expense of $117.6 million for the six months ending June 30, 2026 compared to a $20.6 million unrealized gain on derivative financial instruments and depletion and depreciation expense of $87.2 million for the six months ending June 30, 2025. This was partially offset by higher operating income in 2026 than in 2025.

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)	**2026**	2025	%	**2026**	2025	%
Capital expenditures:						
Lease acquisition and retention	**832**	787	6	**1,630**	1,054	55
Geological and geophysical	**25**	3,178	-99	**28**	13,908	-100
Drilling and completion of wells	**109,121**	56,182	94	**196,802**	104,826	88
Facilities, pipeline and well equipment	**27,190**	30,147	-10	**52,930**	75,220	-30
Corporate assets	**652**	658	-1	**716**	690	4
Capital expenditures, before A&D [(1)]	**137,820**	90,952	52	**252,106**	195,698	29
Property acquisitions	**141**	-	-	**539**	-	-
Property dispositions	**(90)**	-	-	**(457)**	-	-
Capital expenditures, net of A&D [(1)]	**137,871**	90,952	52	**252,188**	195,698	29

(1) Refer to advisories regarding "Non-GAAP and Other Financial Measures".

Capital expenditures, before A&D, increased by 52% for the three months ended June 30, 2026 and by 29% for the six months ended June 30, 2026 compared to the same periods in 2025.

In the second quarter of 2026, drilling and completion costs of $109.1 million included the drilling of 13.0 net wells and the completion of 15.0 net wells. Kelt's facility, pipeline and well equipment expenditures were $27.2 million in the second quarter of 2026.

For the six months ended June 30, 2026 drilling and completion costs of $196.8 million included the drilling of 29.0 net wells and the completion of 25.2 net wells. Kelt's facility, pipeline and well equipment expenditures were $52.9 million in the six months ended June 30, 2026.

	Three months ended June 30			Six months ended June 30		
Gross wells	**2026**	2025	%	**2026**	2025	**%**
Drilling	**13**	10	30	**29**	25	16
Completion	**15**	10	50	**26**	19	37
Service	**-**	1	-100	**-**	1	-100

	Three months ended June 30			Six months ended June 30		
Net wells	**2026**	2025	%	**2026**	2025	**%**
Drilling	**13.0**	10.0	30	**29.0**	20.6	41
Completion	**15.0**	8.0	88	**25.2**	14.6	73
Service	**-**	1.0	-100	**-**	1.0	-100

CAPITAL RESOURCES AND LIQUIDITY

Kelt's objective is to maintain a flexible capital structure that provides sufficient liquidity for the Company to meet its obligations when due and to execute on its capital investment program. The Company manages its capital structure in response to changes in economic conditions and the risk characteristics of its underlying oil and natural gas assets.

The Company has a $300.0 million credit facility from a syndicate of financial institutions. At June 30, 2026, $187.0 million was drawn under the Credit Facility. In addition to the amounts drawn, the Company had $4.0 million in letters of credit. 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.

Repayments of principal are not required provided that the borrowings under the facility do not exceed the authorized borrowing amount. The credit facility is subject to semi-annual redeterminations on or before June 30 and November 30 of each year, with the next redetermination prior to November 30, 2026. There are no financial covenants under the Credit Facility and Kelt is in compliance with all other covenants. Covenants include industry standard positive and negative covenants including reporting requirements, permitted indebtedness, permitted risk management activities, permitted encumbrances and other standard business operating covenants. Security is provided for by a demand debenture with a floating charge over all assets in the amount of $800.0 million.

Interest is payable monthly for borrowings through direct advances. Interest rates fluctuate based on the prime rate plus the applicable margin. The applicable margin ranges from 175 basis points to 375 basis points depending upon the Net Debt to Cash Flow ratio of between less than 0.5 times and three times. Under the Credit Facility, borrowings through the use of CORRA term loans are also available. Stamping fees fluctuate based on a pricing grid and range from 2.75% to 4.75%, depending upon the Net Debt to Cash Flow ratio of between less than 0.5 times and three times.

(CA$ thousands, except otherwise indicated)	**June 30, 2026**	December 31, 2025
Bank debt	**187,000**	179,861
Accounts payable and accrued liabilities	**142,673**	78,046
Cash and cash equivalents	**(2,527)**	(90)
Accounts receivable and accrued sales	**(78,071)**	(64,195)
Prepaid expenses and deposits	**(6,934)**	(3,919)
Net debt [(1)]	**242,141**	189,703
Adjusted funds from operations [(1)(2)]	**314,838**	261,525
Net debt to adjusted funds from operations ratio [(1)]	**0.8**	0.7

(1) Refer to advisories regarding Capital Management Measures.

(2) 12-month trailing adjusted funds from operations.

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

The Company may adjust its future capital structure and capital expenditures according to market conditions to maintain flexibility to achieve its objectives. In doing so, the Company may increase or decrease capital expenditures including acquisitions and dispositions, issue new shares, issue new debt or repay existing debt.

The table below outlines a contractual maturity analysis for Kelt's financial liabilities as at June 30, 2026:

(CA$ thousands)	Within 1 Year	1 to 5 Years	More than 5 Years	**Total**
Accounts payable and accrued liabilities	142,673	-	-	**142,673**
Derivative financial instruments	5,876	-	-	**5,876**
Lease liability	637	303	-	**940**
Bank debt and estimated interest [(1)]	10,659	187,000	-	**197,659**
Total	**159,845**	**187,303**	**-**	**347,148**

(1) Estimated interest for future years related to the Credit Facility was calculated using the weighted average interest rate of 5.7% for the six months ended June 30, 2026, applied to the principal balance outstanding as at that date.

COMMITMENTS

As of June 30, 2026, the Company is committed to future payments under the following agreements:

(CA$ thousands)	2026	2027	2028	2029	2030	Thereafter
Firm processing commitments	34,000	72,067	78,513	79,285	80,519	400,808
Firm transportation commitments	23,772	47,559	49,030	39,029	31,275	97,725
Total annual commitments	**57,772**	**119,626**	**127,543**	**118,314**	**111,794**	**498,533**

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, 2026 there were 203.0 million common shares issued and outstanding; there are no preferred shares issued or outstanding.

The Company's common shares trade on the TSX under the symbol "KEL". During the second quarter of 2026, 40.9 million common shares traded on the TSX at a weighted average price of $9.40 per common share compared to 23.5 million common shares traded on the TSX at a weighted average price of $6.40 per common share in the second quarter of 2025. Kelt's closing share price was $8.75 per common share on June 30, 2026, compared to the volume weighted average trading price of $6.86 per common share during the year ended December 31, 2025.

As at June 30, 2026, officers, directors, and employees have been granted options to purchase 5.2 million common shares of the Company at an average exercise price of $5.50 per common share. In addition, there are 1.3 million RSUs and 1.2 million PSUs outstanding. Additional information regarding the Company's stock options, RSUs, and PSUs is included in note 8 of the interim financial statements.

OFF-BALANCE SHEET TRANSACTIONS

The Company did not engage in any off-balance sheet transactions during the periods ended June 30, 2026 and 2025.

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 2026**	Q1 2026	Q4 2025	Q3 2025	Q2 2025	Q1 2025	Q4 2024	Q3 2024
Revenue	**193,424**	153,258	132,638	100,142	106,946	127,262	115,512	94,985
Cash provided by operating activities	**104,900**	89,707	62,804	53,827	60,696	86,929	48,067	52,166
Adjusted funds from operations [(1)]	**108,725**	84,648	76,817	44,648	61,846	78,214	69,406	48,939
Per share – basic ($/common share) [(1)]	**0.54**	0.42	0.39	0.22	0.31	0.40	0.35	0.25
Per share – diluted ($/common share) [(1)]	**0.53**	0.42	0.38	0.22	0.31	0.39	0.35	0.24
Net income (loss) and comprehensive income (loss)	**44,679**	686	19,064	(7,446)	32,461	18,979	13,800	8,871
Per share – basic ($/common share)	**0.22**	0.00	0.10	(0.04)	0.16	0.10	0.07	0.05
Per share – diluted ($/common share)	**0.22**	0.00	0.09	(0.04)	0.16	0.09	0.07	0.04
Capital expenditures, net of A&D [(1)]	**137,871**	114,317	42,806	89,801	90,952	104,746	97,046	82,110
Total assets	**1,754,609**	1,665,894	1,600,515	1,594,538	1,562,599	1,512,752	1,450,679	1,378,621
Bank debt	**187,000**	146,757	179,861	186,000	151,432	102,766	108,993	45,428
Net debt [(1)]	**242,141**	215,114	189,703	223,684	178,170	150,024	124,883	95,889
Shareholders' equity	**1,198,083**	1,148,796	1,139,639	1,117,150	1,121,679	1,086,264	1,063,004	1,046,142
Average daily production (BOE/d)	**50,388**	48,098	45,102	37,710	38,734	40,015	36,450	32,378
Net realized price ($/BOE) [(1)(2)]	**45.29**	37.52	35.27	32.12	34.00	40.53	37.01	35.86
Operating netback ($/BOE) [(1)]	**24.92**	20.98	20.04	14.69	19.50	23.25	21.80	17.91
Operating netback % of combined net realized price [(2)]	**55%**	56%	57%	46%	57%	57%	59%	50%

(1) Refer to advisories regarding *"*Non-GAAP and Other Financial Measures*"*.

(2) In this table, combined net realized prices are after derivative financial instruments.

Kelt's business objective is for long-term profitable growth by implementing a full cycle exploration and development program. Over the past eight quarters, Kelt has focused its cash provided from operating activities on its development capital program which has resulted in higher average daily production and adjusted funds from operations.

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.sedarplus.ca.

OUTLOOK AND GUIDANCE

As of the date of this MD&A, management has updated its 2026 guidance from May 8, 2026 to incorporate revised commodity price assumptions and second quarter results.

(CA$ millions, except as otherwise indicated)	**Current 2026 Budget**	**Previous 2026 Guidance (May 8, 2026)**	**% Change to Previous Guidance**
Average Production [2]			
Oil and NGLs (bbls/d)	19,600 – 20,600	19,600 – 20,600	-
Gas (MMcf/d)	182.4 – 188.4	182.4 – 188.4	-
Combined (BOE/d)	50,000 – 52,000	50,000 – 52,000	-
Forecasted Average Commodity Prices			
WTI oil price (US$/bbl)	79.50	77.50	3
Canadian Light Sweet ($/bbl)	108.00	102.81	5
NYMEX (US$/MMBtu)	3.50	3.60	-3
Dawn (US$/MMBtu)	3.20	3.40	-6
AECO ($/GJ)	1.75	1.81	-3
Station 2 ($/GJ)	1.56	1.69	-8
Average Exchange Rate (US$/CA$)	0.7220	0.7315	-1
Capital Expenditures, net of A&D [1]	375.0	375.0	-
Petroleum and natural gas sales	804.7	767.7	5
Adjusted funds from operations [1]	410.0	400.0	3
Per common share, diluted [1]	1.99	1.94	3
Net debt [1]	153.0	165.0	-7
Weighted average common shares outstanding (millions) [1]	202.5	202.0	-

(1) Refer to advisories regarding "Non-GAAP and Other Financial Measures".

(2) Percent change for production is calculated on the mid-point of each production range.

Forecasted average production for 2026 remains at approximately 50,000 to 52,000 BOE per day. WTI crude oil prices are forecasted to average US $79.50 per barrel, an increase of 3% from the Company's previous guidance. Forecasted AECO natural gas prices decreased by 3% to average $1.75 per GJ and forecasted Station 2 natural gas prices decreased by 8% to average $1.56 per GJ.

After giving effect to the changes in commodity price assumptions, Kelt is forecasting 2026 petroleum and natural gas sales of $804.7 million and adjusted funds from operations of $410.0 million, an increase of 5% and 3%, respectively, from the previous forecast. Capital expenditures, net of A&D is consistent with Company's previous guidance at $375.0 million. Net debt at December 31, 2026 is estimated to be $153.0 million, a decrease from $165.0 million in the previous guidance.

A 10% increase/decrease in the Company's forecasted average oil/NGLs price for the six months remaining in 2026

would increase/decrease forecasted adjusted funds from operations in 2026 by approximately $18.2 million. A 10% increase/decrease in the Company's average natural gas price forecasted for the six months remaining in 2026 would increase/decrease adjusted funds from operations in 2026 by approximately $6.7 million.

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, 2025 audited annual consolidated financial statements.

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, 2026 to June 30, 2026 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 AND OTHER FINANCIAL MEASURES

This MD&A contains certain non-GAAP financial measures and other specified financial measures, as described below, which do not have standardized meanings prescribed by GAAP and do not have standardized meanings under the applicable securities legislation. As these non-GAAP, and other specified financial measures 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

P&NG sales after cost of purchases

Throughout this MD&A, reference is made to "P&NG sales" and "P&NG sales after cost of purchases". P&NG sales is as reported in the consolidated financial statements in accordance with GAAP and is before realized gains or losses on derivative financial instruments. P&NG sales after cost of purchases includes P&NG sales (in accordance with GAAP), net of the cost of third-party volumes purchases. P&NG sales after cost of purchases are used by management to assess the Company's sales from its core operations, which the Company believes may be a better indicator of

historical and future performance.

See the "Petroleum and Natural Gas Sales" section of this MD&A which provides a reconciliation of "P&NG sales after cost of purchases to P&NG sales.

Net realized price

Net realized price is a non-GAAP measure and is calculated by dividing the Company's P&NG sales after cost of purchases by the Company's production and reflects Kelt's realized selling prices plus the net benefit of oil blending and third-party natural gas sales. 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 P&NG sales as reported in the Consolidated Statement of Net Income and Comprehensive Net Income 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, and excludes the sale of third-party marketing volumes, management believes that disclosing its net realized prices based on P&NG sales after cost of purchases is more appropriate and useful, because the cost of third-party volumes purchased to generate the incremental marketing revenue has been deducted.

Combined net realized prices referenced throughout this MD&A are before derivative financial instruments, except as otherwise indicated as being after derivative financial instruments.

See the "Petroleum and Natural Gas Sales" section of this MD&A which provides a reconciliation of the net realized price to P&NG sales, which is a GAAP measure.

Operating income and operating netback

Operating income is a non-GAAP measure calculated by deducting royalties, production expenses and transportation expenses from petroleum and natural gas sales, net of the cost of purchases and after realized gains or losses on derivative financial instruments. The Company also presents operating income on a per BOE basis, referred to as "operating netback" or "operating income per BOE", which allows management to better analyze performance against prior periods, on a comparable basis, and is a key industry performance measure of operational efficiency.

See the "Adjusted Funds from Operations" section of this MD&A which provides a reconciliation of the operating income and operating netback from P&NG sales, which is a GAAP measure.

Capital expenditures

"Capital expenditures, before A&D" and "Capital expenditures, net of A&D" are measures the Company uses to monitor its investment in exploration and evaluation, investment in property plant and equipment, and net investment in acquisition and disposition activities. The most directly comparable GAAP measure is "Cash used in investing activities", and is calculated as follows:

	Three months ended June 30		Six months ended June 30	
(CA$ thousands)	**2026**	2025	**2026**	2025
Cash used in investing activities	**146,101**	110,578	**208,603**	193,336
Change in non-cash investing working capital	**(8,230)**	(19,626)	**43,585**	2,362
Capital expenditures, net of A&D	**137,871**	90,952	**252,188**	195,698
Property acquisitions	**(141)**	-	**(172)**	-
Property dispositions	**90**	-	**90**	-
Capital expenditures, before A&D	**137,820**	90,952	**252,106**	195,698

CAPITAL MANAGEMENT MEASURES

Funds from operations and adjusted funds from operations

Management considers funds from operations and adjusted funds from operations as a key capital management measure as it demonstrates the Company's ability to meet its financial obligations and cash flow available to fund its capital program. Funds from operations and adjusted funds from operations are not standardized measures and

therefore may not be comparable with the calculation of similar measures by other entities. The most comparable GAAP measure is “Cash provided by operating activities”. Funds from operations and adjusted funds from operations are calculated as follows:

	Three months ended June 30		Six months ended June 30	
(CA$ thousands)	**2026**	2025	**2026**	2025
Cash provided by operating activities	**104,900**	60,696	**194,607**	147,625
Change in non-cash working capital	**3,091**	913	**(4,151)**	(8,328)
Funds from operations	**107,991**	61,609	**190,456**	139,297
Settlement of decommissioning obligations	**734**	237	**2,917**	763
Adjusted funds from operations	**108,725**	61,846	**193,373**	140,060

Net debt (surplus) and net debt (surplus) to adjusted funds from operations ratio

Management considers net debt (surplus) and net debt (surplus) to adjusted funds from operations ratio as key capital management measures to assess the Company’s liquidity at a point in time and to monitor its capital structure and short-term financing requirements. The “net debt (surplus) to adjusted funds from operations ratio” is also indicative of the “net debt to cash flow ratio” 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).

“Net debt (surplus)” is equal to bank debt, accounts payable and accrued liabilities, net of cash and cash equivalents, accounts receivables and accrued sales and prepaid expenses and deposits. The Company believes that using a “Net debt (surplus)” non-GAAP measure, which excludes non-cash derivative financial instruments, non-cash lease liabilities, and non-cash decommissioning obligations, provides investors with more useful information to understand the Company’s cash liquidity risk.

See the “Capital Resources and Liquidity” section of this MD&A for calculation of the Net debt and net debt to adjusted funds from operations ratio.

SUPPLEMENTARY FINANCIAL MEASURES

“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.

P&NG sales, cost of purchases, gain (loss) on financial instruments, royalties, production expenses, transportation expenses, financing expenses, gross and net G&A expenses, realized loss (gain) on foreign exchange, other income (expense), share based compensation expense, and depletion and depreciation expense on a $/BOE basis is calculated by dividing the amounts by the Company’s total production over the period.

Adjusted funds from operations per share (basic and diluted), and net income and comprehensive net income per share (basic and diluted) is calculated by dividing the amounts by the basic weighted average common shares outstanding.

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, 2025, dated March 11, 2026.

Since January 2025, the United States has implemented, suspended or threatened to impose, tariffs on goods imported from various countries, including Canada. In turn, several governments around the world have either imposed or threatened retaliatory tariffs on U.S. goods. The introduction of new tariffs, or the reactivation of those currently suspended, could significantly harm the Canadian economy and the oil and natural gas industry. Additionally, the introduction of tariffs, combined with retaliatory measures from other countries, may escalate into a broader global trade conflict. Such an escalation could have a material adverse impact on the Canadian, U.S., and global economies, as well as on the Canadian oil and natural gas industry through lower demand for oil and natural gas and potentially higher

costs.

Additional information is included in Kelt's Annual Information Form dated March 11, 2026 which can be found at www.sedarplus.ca.

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 2026. 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, the scope and duration of export tariffs, export restrictions, or import tariffs on commodities that Kelt sells, or products that Kelt uses in its supply chains, 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.

Any forward-looking information or financial outlook set out herein does not include any potential impact of tariffs or trade-related regulations that have been announced by the U.S. and Canada.

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.

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and NGL reserves, and the future net revenue attributed to such reserves, including many factors beyond the control of Kelt. The reserves and associated future net revenue information set forth in this MD&A are estimates only. In general, estimates of economically recoverable oil, natural gas and NGLs reserves and the future net revenue therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserves recovery, the timing and amount of capital expenditures, marketability of oil, natural gas and NGLs, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. For these reasons, estimates of the economically recoverable oil, natural gas and NGLs reserves attributable to any particular group of properties, the classification of such reserves based on risk of recovery and estimates of future net revenue associated with reserves prepared by different engineers, or by the same engineer at different times, may vary.

Kelt's actual production, revenue, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material. It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to the Corporation's reserves estimated by the Corporation's independent qualified reserves evaluators represent the fair market value of those reserves. There is no assurance that the forecast prices and costs assumptions will be attained, and variances could be material. Actual oil, natural gas and NGLs reserves may be greater than or less than the estimates provided herein, and variances could be material.

With respect to the disclosure of reserves contained herein relating to portions of Kelt's properties, the estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation. Unless otherwise stated all references to "reserves" are to Kelt's gross company reserves before deduction of royalties and without including and royalty interests of Kelt. It should not be assumed that the undiscounted or discounted net present value of the

Company's reserves, as determined by McDaniel, represents the fair value of those reserve estimates.

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; its expected oil and NGLs weighting; the start-up date of the postponed wells; the cost and timing of future capital expenditures and expected results; the expected timing of wells bring brought on-production; the expected timing of production additions from capital expenditures; the ability to show significant production growth; the expected reductions in drill and complete costs; the expected timing and processing capacity from the start-up of a third party facility; the expected timing of when the Company shoots its 3-D seismic program; and the Company's expected future financial position and operating results.

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; the ability to access sufficient water or other fluids needed for completion operations; and the ability to access sufficient capital. We caution that the foregoing list of risks and uncertainties is not exhaustive.

ADDITIONAL INFORMATION

Additional information relating to Kelt, including the Company's Annual Information Form ("AIF") dated March 11, 2026 is filed on SEDAR+ and can be viewed on their website at www.sedarplus.ca. 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.
CONDENSED CONSOLIDATED STATEMENTS OF FINANCIAL POSITION
[UNAUDITED]

(CA$ thousands)	[Notes]	**June 30, 2026**	December 31, 2025
ASSETS			
Current assets			
Cash and cash equivalents		**2,527**	90
Accounts receivable and accrued sales	[9]	**78,071**	64,195
Prepaid expenses and deposits		**6,934**	3,919
Derivative financial instruments	[9]	**11,817**	17,048
Total current assets		**99,349**	85,252
Exploration and evaluation assets	[4]	**18,873**	18,140
Property, plant and equipment	[5]	**1,636,387**	1,497,123
Total assets		**1,754,609**	1,600,515
LIABILITIES			
Current liabilities			
Accounts payable and accrued liabilities	[9]	**142,673**	78,046
Derivative financial instruments	[9]	**5,876**	1,033
Decommissioning obligations	[7]	**6,363**	5,463
Lease liability		**637**	633
Total current liabilities		**155,549**	85,175
Bank debt	[6]	**187,000**	179,861
Decommissioning obligations	[7]	**90,528**	87,288
Lease liability		**303**	385
Deferred income tax liability		**123,146**	108,167
Total liabilities		**556,526**	460,876
SHAREHOLDERS' EQUITY			
Shareholders' capital	[8]	**1,213,989**	1,195,874
Contributed surplus and reserve		**(9,960)**	(4,924)
Deficit		**(5,946)**	(51,311)
Total shareholders' equity		**1,198,083**	1,139,639
Total liabilities and shareholders' equity		**1,754,609**	1,600,515

Commitments [12]

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

On behalf of the Board of Directors:

[signed] *[signed]*

David J. Wilson, Director Ray Kwan, Director

KELT EXPLORATION LTD.
CONDENSED CONSOLIDATED STATEMENTS OF NET INCOME AND COMPREHENSIVE NET INCOME
[UNAUDITED]

		Three months ended June 30		Six months ended June 30	
(CA$ thousands, except per share amounts)	[Notes]	**2026**	2025	**2026**	2025
Revenue					
Petroleum and natural gas sales	[10]	**222,166**	116,418	**390,272**	258,919
Royalties		**(28,742)**	(9,472)	**(43,590)**	(24,711)
		193,424	106,946	**346,682**	234,208
Expenses					
Production		**45,994**	30,319	**90,544**	64,671
Transportation		**18,679**	11,326	**30,886**	23,958
Cost of purchases		**4,253**	3,168	**7,667**	6,072
Financing	[11]	**3,837**	3,492	**7,503**	6,309
General and administrative		**3,046**	3,782	**6,428**	7,384
Share based compensation	[8]	**1,716**	1,596	**3,707**	3,744
Exploration and evaluation	[4]	**10**	49	**10**	49
Depletion and depreciation	[5]	**60,931**	43,428	**117,568**	87,197
		138,466	97,160	**264,313**	199,384
Gain (loss) on derivative financial instruments	[9]	**3,248**	33,483	**(22,554)**	33,529
Gain (loss) on foreign exchange		**478**	(428)	**499**	(355)
Other income		**10**	8	**30**	22
Net income before taxes		**58,694**	42,849	**60,344**	68,020
Deferred income tax expense		**(14,015)**	(10,388)	**(14,979)**	(16,580)
Net income and comprehensive net income		**44,679**	32,461	**45,365**	51,440
Net income per common share					
Basic		**0.22**	0.16	**0.22**	0.26
Diluted		**0.22**	0.16	**0.22**	0.26

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

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

		Shareholders' capital				
(CA$ thousands)	[Notes]	Number of Shares (000s)	Amount ($ thousands)	Contributed surplus and reserve	Retained earnings (deficit)	Total shareholders' equity
Balance at December 31, 2025		199,805	1,195,874	(4,924)	(51,311)	1,139,639
Net income and comprehensive income		-	-	-	45,365	45,365
Exercise of stock options	[8]	2,354	14,038	(4,666)	-	9,372
Vesting of restricted share units	[8]	810	4,077	(4,077)	-	-
Share based compensation	[8]	-	-	3,707	-	3,707
Balance at June 30, 2026		**202,969**	**1,213,989**	**(9,960)**	**(5,946)**	**1,198,083**
Balance at December 31, 2024		196,756	1,184,065	(6,692)	(114,369)	1,063,004
Net income and comprehensive income		-	-	-	51,440	51,440
Exercise of stock options	[8]	1,726	5,175	(1,684)	-	3,491
Vesting of restricted share units	[8]	654	3,057	(3,057)	-	-
Share based compensation	[8]	-	-	3,744	-	3,744
Balance at June 30, 2025		199,136	1,192,297	(7,689)	(62,929)	1,121,679

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

KELT EXPLORATION LTD.
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
[UNAUDITED]

		Three months ended June 30		Six months ended June 30	
(CA$ thousands)	[Notes]	**2026**	2025	**2026**	2025
Operating activities					
Net income and comprehensive income		**44,679**	32,461	**45,365**	51,440
Items not affecting cash:					
Accretion of decommissioning obligations	[11]	**844**	807	**1,670**	1,607
Share based compensation		**1,716**	1,596	**3,707**	3,744
Exploration and evaluation		**10**	49	**10**	49
Depletion and depreciation		**60,931**	43,428	**117,568**	87,197
Unrealized (gain) loss on derivative financial instruments	[9]	**(13,470)**	(26,883)	**10,074**	(20,557)
Deferred income tax expense		**14,015**	10,388	**14,979**	16,580
Settlement of decommissioning obligations	[7]	**(734)**	(237)	**(2,917)**	(763)
Change in non-cash operating working capital	[13]	**(3,091)**	(913)	**4,151**	8,328
Cash provided by operating activities		**104,900**	60,696	**194,607**	147,625
Financing activities					
Advances and repayments of bank debt		**40,243**	48,666	**7,139**	42,439
Proceeds on exercise of stock options	[8]	**2,892**	1,358	**9,372**	3,491
Repayment of lease liability principal		**(39)**	(161)	**(78)**	(377)
Cash provided by financing activities		**43,096**	49,863	**16,433**	45,553
Investing activities					
Exploration and evaluation assets	[4]	**(464)**	(3,966)	**(770)**	(14,963)
Property, plant and equipment	[5]	**(137,356)**	(86,986)	**(251,336)**	(180,735)
Property acquisitions		**(141)**	-	**(172)**	-
Property dispositions		**90**	-	**90**	-
Change in non-cash investing working capital	[13]	**(8,230)**	(19,626)	**43,585**	2,362
Cash used in investing activities		**(146,101)**	(110,578)	**(208,603)**	(193,336)
Net change in cash and cash equivalents		**1,895**	(19)	**2,437**	(158)
Cash and cash equivalents, beginning of period		**632**	89	**90**	228
Cash and cash equivalents, end of period		**2,527**	70	**2,527**	70

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

KELT EXPLORATION LTD.
NOTES TO THE CONDENSED CONSOLIDATED INTERIM FINANCIAL STATEMENTS
AS AT AND FOR THE THREE AND SIX MONTHS ENDED JUNE 30, 2026
[UNAUDITED]

(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. The Company's British Columbia assets are operated by Kelt Exploration (LNG) Ltd. ("Kelt LNG"), a wholly owned subsidiary of Kelt. The Company's common shares are listed on the Toronto Stock Exchange ("TSX") under the symbol "KEL".

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 condensed consolidated interim financial statements on August 5, 2026.

a) Statement of compliance

These condensed consolidated interim financial statements have been prepared in accordance with International Financial Reporting Standards, as issued by the International Accounting Standards Board ("IFRS Accounting Standards"), applicable to the preparation of interim financial statements, including IAS 34 *Interim Financial Reporting*. Certain disclosures included in the notes to the 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 annual consolidated financial statements as at and for the year ended December 31, 2025.

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 9 of these financial statements.

c) Significant Judgements 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, 2025 audited annual consolidated financial statements.

These estimates require assumptions for future commodity prices, exchange rates, interest rates, future oil and natural gas production, and other economic issues that have a high degree of uncertainty.

3. MATERIAL ACCOUNTING POLICIES

The material accounting policies applied by the Company are described in note 3 of the December 31, 2025 audited annual consolidated financial statements. These condensed consolidated interim financial statements as at June 30, 2026 have been prepared following the same accounting policies and methods of computation as the most recent

audited annual consolidated financial statements as at and for the year ended December 31, 2025.

In April 2024, the IASB issued IFRS 18 'Presentation and Disclosure in Financial Statements' which will replace IAS 1 'Presentation of Financial Statements'. The standard introduces a new defined structure to the Consolidated Statements of Net Income and Comprehensive Net Income with new categories for income and expenses and new totals and subtotals. The standard will also will impact the presentation in the Condensed Consolidated Statements of Cash Flows. In addition, there are additional disclosures around management defined performance measures and additional requirements regarding the aggregation and disaggregation of certain information. IFRS 18 is effective January 1, 2027, and is required to be adopted retrospectively with early adoption permitted. The Company is currently assessing the impact of IFRS 18 on the Company's Condensed Consolidated Statements of Net Income and Comprehensive Net Income, the Condensed Consolidated Statements of Cash Flows, and related disclosures.

In May 2024, the IASB issued amendments IFRS 9 'Financial Instruments' and IFRS 7 'Financial Instruments: Disclosures' to clarify the date of recognition and derecognition of financial assets and liabilities including the settling of financial liabilities using an electronic payment system and assessing contractual cash flow characteristics of financial assets. These amendments are effective January 1, 2026, and are required to be adopted retrospectively with early adoption permitted. The company elected to apply the exemption for qualifying electronic payment systems to account for payments made through such systems when initiated. There are no material impacts to the Company's consolidated financial statements as a result of these amendments.

4. EXPLORATION AND EVALUATION ASSETS

The following table reconciles movements of exploration and evaluation (“E&E”) assets:

	June 30, 2026	December 31, 2025
Balance, beginning of period	**18,140**	18,092
Additions	**770**	15,176
Transfers to property, plant and equipment	**(27)**	(14,971)
Exploration and evaluation expense	**(10)**	(157)
Balance, end of period	**18,873**	18,140

5. PROPERTY, PLANT AND EQUIPMENT

The Company's property, plant and equipment ("PP&E") includes development and production ("D&P") assets, corporate assets, and right-of-use ("ROU") assets.

The following table reconciles movements of property, plant and equipment during the year:

Property, plant and equipment, at cost	D&P Assets	Corporate Assets	ROU Assets	Total PP&E
Balance at December 31, 2024	2,391,870	9,048	5,901	2,406,819
Additions	311,138	981	1,210	313,329
Transfers from ROU assets	1,288	-	(1,288)	-
Property acquisitions	477	-	-	477
Property dispositions and derecognition	(470)	-	(4,544)	(5,014)
Change in decommissioning obligations	(8,260)	-	-	(8,260)
Transfers from E&E	14,971	-	-	14,971
Balance at December 31, 2025	**2,711,014**	**10,029**	**1,279**	**2,722,322**
Additions	**250,620**	**716**	**-**	**251,336**
Property acquisitions	**539**	**-**	**-**	**539**
Property dispositions and derecognition [(1)]	**(457)**	**(7,362)**	**-**	**(7,819)**
Change in decommissioning obligations	**5,387**	**-**	**-**	**5,387**
Transfers from E&E	**27**	**-**	**-**	**27**
Balance at June 30, 2026	**2,967,130**	**3,383**	**1,279**	**2,971,792**

Accumulated depletion, depreciation and impairment	D&P Assets	Corporate Assets	ROU Assets	Total PP&E
Balance at December 31, 2024	1,033,639	8,201	3,674	1,045,514
Depletion and depreciation expense	181,858	1,207	506	183,571
Property dispositions and derecognition	-	-	(3,886)	(3,886)
Balance at December 31, 2025	**1,215,497**	**9,408**	**294**	**1,225,199**
Depletion and depreciation expense	**117,160**	**325**	**83**	**117,568**
Property dispositions and derecognition [(1)]	**-**	**(7,362)**	**-**	**(7,362)**
Balance at June 30, 2026	**1,332,657**	**2,371**	**377**	**1,335,405**

Net carrying amount	D&P Assets	Corporate Assets	ROU Assets	Total PP&E
Balance, December 31, 2025	1,495,517	621	985	1,497,123
Balance, June 30, 2026	**1,634,473**	**1,012**	**902**	**1,636,387**

(1) In the first quarter of 2026 the Company de-recognized $7.4 million of cost and accumulated depreciation related to fully amortized corporate assets.

Future capital costs required to develop proved reserves in the amount of $1,773.4 million (December 31, 2025 – $1,928.3 million) are included in the depletion calculation for development and production assets.

Based on its assessment as of June 30, 2026 and December 31, 2025, the Company determined that there were no indicators of impairment.

6. BANK DEBT

At June 30, 2026, the Company has a $300.0 million credit facility ("Credit Facility") from a syndicate of financial institutions. As at June 30, 2026, $187.0 million was drawn under the Credit Facility. In addition to the amounts drawn, the Company had $4.0 million in letters of credit. 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.

Repayments of principal are not required provided that the borrowings under the facility do not exceed the authorized borrowing amount. The credit facility is subject to semi-annual redeterminations on or before June 30 and November 30 of each year. There are no financial covenants under the Credit Facility and Kelt is in compliance with all other covenants. Covenants include industry standard positive and negative covenants including reporting requirements, permitted indebtedness, permitted risk management activities, permitted encumbrances and other standard business operating covenants. Security is provided for by a demand debenture with a floating charge over all assets in the amount of $800.0 million.

Interest is payable monthly for borrowings through direct advances. Interest rates fluctuate based on the prime rate plus the applicable margin. The applicable margin ranges from 175 basis points to 375 basis points depending upon the Net Debt to Cash Flow ratio of between less than 0.5 times and three times. Under the Credit Facility, borrowings through the use of benchmark loans are also available. Stamping fees fluctuate based on a pricing grid and range from 2.75% to 4.75%, depending upon the Net Debt to Cash Flow ratio of between less than 0.5 times and three times.

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.

7. 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, 2026	December 31, 2025
Balance, beginning of period	**92,751**	100,975
Obligations incurred	**1,632**	1,770
Obligations acquired	**-**	261
Obligations disposed	**-**	(141)
Obligations settled	**(2,917)**	(3,348)
Changes in discount rate	**1,623**	(11,492)
Revisions to estimates	**2,132**	1,462
Accretion expense	**1,670**	3,264
Balance, end of period	**96,891**	92,751
Decommissioning obligations – current	**6,363**	5,463
Decommissioning obligations – non-current	**90,528**	87,288
Key assumptions		
Risk-free rate	**3.8%**	3.9%
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, 2026 the undiscounted amount of the estimated cash flows required to settle the obligation is $148.8 million (December 31, 2025 – $144.7 million) and is expected to be incurred over the next 50 years. The undiscounted amount of the estimated future cash flows required to settle the obligation is $249.1 million at June 30, 2026 (December 31, 2025 – $243.0 million). The inflated future cost estimates are discounted based on a risk-free rate to determine the carrying amounts presented in the table above. Accretion of the decommissioning obligation due to the passage of time is presented within financing expenses in the Consolidated Statement of Net Income and

Comprehensive Net Income (note 11).

The table below shows the impact of a 1% increase/decrease in the risk-free rate, and of a 1% increase/decrease in the inflation rate on the Company's decommissioning obligation.

	Change in rate	Positive movement	Negative movement
Risk-free rate	+/- 1%	(17,122)	24,834
Inflation rate	+/- 1%	25,058	(17,509)

8. 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, 2026 (December 31, 2025 – nil).

	Number of Shares (000s)	Amount ($ thousands)
Balance at December 31, 2024	196,756	1,184,065
Issued on exercise of stock options	2,366	5,764
Transfer from contributed surplus on exercise of stock options	-	2,788
Issued and transferred from contributed surplus on vesting of restricted share units	683	3,257
Balance at December 31, 2025	**199,805**	**1,195,874**
Issued on exercise of stock options	**2,354**	**9,372**
Transferred from contributed surplus on exercise of stock options	**-**	**4,666**
Issued and transferred from contributed surplus on vesting of restricted share units	**810**	**4,077**
Balance at June 30, 2026	**202,969**	**1,213,989**

Stock options

The Company discontinued its stock option plan in April 2025. However, all previously allocated options remain outstanding and subject to their original terms. The stock options granted prior to April 2025 will be settled through the issuance of common shares of the Company which 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, 2024	9,971	4.41
Granted	35	5.78
Exercised (1)	(2,366)	2.44
Forfeited	(110)	5.74
Balance at December 31, 2025	**7,530**	**5.02**
Exercised (1)	**(2,354)**	**3.98**
Forfeited	**(1)**	**6.06**
Balance at June 30, 2026	**5,175**	**5.50**

(1) The weighted average share price on the date stock options were exercised during the six months ended June 30, 2026 was $8.86 per common share ($7.22 per common share on average during the year ended December 31, 2025).

The following table summarizes information regarding stock options outstanding at June 30, 2026:

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)
$4.00 to $5.25	1,227	1.7	4.60	1,227	4.60
$5.26 to $6.50	3,760	1.7	5.71	3,020	5.62
$6.51 to $7.75	188	2.5	7.14	88	7.21
Total	**5,175**	**1.7**	**5.50**	**4,335**	**5.36**

Restricted share units

The restricted share unit plan includes restricted share units (“RSUs”) that may be granted to officers, directors and employees. The RSUs granted under the RSU Plan are to be settled through the issuance of new common shares upon vesting. RSUs 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, 2024	1,828
Granted	610
Released upon vesting	(683)
Forfeited	(54)
Balance at December 31, 2025	**1,701**
Granted	**383**
Released upon vesting	**(810)**
Forfeited	**(11)**
Balance at June 30, 2026	**1,263**

Performance share units

The performance share unit ("PSU") plan provides for the issuance of equity-settled awards that vest based on the achievement of defined performance criteria over a rolling three-year period.

Each PSU entitles the holder to receive common shares upon vesting, with the number of shares issued ranging from 0% to 200% of the target award. The final number of shares delivered is determined by a Payout Multiplier, which is calculated based on the Company's performance against pre-established targets over the vesting period.

The following table summarizes the change in PSUs outstanding:

	Number of PSUs (000s)
Balance at December 31, 2024	-
Granted	752
Released upon vesting	-
Forfeited	(11)
Balance at December 31, 2025	**741**
Granted	**495**
Released upon vesting	**-**
Forfeited	**(6)**
Balance at June 30, 2026	**1,230**

The total fair value associated with stock options, RSUs, and PSUs 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	
	2026	2025	**2026**	2025
Stock options	**249**	644	**825**	1,909
Restricted share units	**737**	721	**1,682**	1,604
Performance share units	**730**	231	**1,200**	231
Total share based compensation expense	**1,716**	1,596	**3,707**	3,744

Weighted average number of common shares

The table below summarizes the weighted average number of common shares outstanding used in the calculation of basic and diluted net income per common share:

	Three months ended June 30		Six months ended June 30	
(000s of common shares)	**2026**	2025	**2026**	2025
Weighted average common shares outstanding, basic	**202,675**	199,005	**201,652**	198,272
Effect of stock options, RSUs, and PSUs	**3,304**	2,744	**3,088**	2,878
Weighted average common shares outstanding, diluted	**205,979**	201,749	**204,740**	201,150

The treasury stock method is used to determine the dilutive effect of stock options, RSUs, and PSUs. Under this method, only "in-the-money" dilutive instruments impact the calculation of diluted net income per common share.

9. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Financial instruments of the Company include cash and cash equivalents, accounts receivable and accrued sales, deposits, accounts payable and accrued liabilities, derivative financial instruments, lease liabilities 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. Net income, 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 objective of the Company's 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 risk management policy that permits 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, 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 economic events that dictate the levels of supply and demand as well as the currency exchange rate relationship between the Canadian and U.S. dollar.

As of June 30, 2026, the following commodity price derivative financial instrument contracts are outstanding:

Crude oil derivative financial instrument swap

Contract Type (1)	Notional Volume	Contract Price	Remaining Term
WTI fixed price	500 bbl/d	CAD$87.65/bbl	Jul 26 – Sept 26
WTI fixed price	2,000 bbl/d	CAD$93.08/bbl	Jul 26 – Dec 26
WTI fixed price (2)	500 bbl/d	CAD$85.00/bbl	Jul 26 – Dec 26
WTI fixed price	500 bbl/d	CAD$85.65/bbl	Oct 26 – Dec 26

(1) West Texas Intermediate ("WTI").

(2) Includes a fixed price WTI oil swap option to sell 500 bbl/d for Jan-Jun 2027 at CAD$85.00/bbl exercisable on December 31, 2026.

Crude oil derivative financial instrument differential

Contract Type (1)	Notional Volume	Contract Price	Remaining Term
MSW-WTI basis differential	1,500 bbl/d	(USD$1.95/bbl)	Jul 26 – Sept 26

(1) Mountain sweet blend crude oil ("MSW").

NGL derivative financial instrument swap

Contract Type	Notional Volume	Contract Price	Remaining Term
OPIS-Conway propane	800 bbl/d	Floating WTI USD$/bbl x 50.5%	Jul 26 – Mar 27

Natural gas derivative financial instrument

Contract Type	Notional Volume	Contract Price	Remaining Term
NYMEX (1) call	20,000 MMBtu/d	USD$5.50/MMBtu	Jul 26 – Dec 26
AECO (2) 7A put	21,000 GJ/d	CAD$2.80/GJ	Jul 26 – Dec 26

(1) New York Mercantile Exchange ("NYMEX").

(2) Alberta Energy Company "C" Meter Station of the NOVA Pipeline System ("AECO").

Electricity derivative financial instrument swap

Contract Type (1)	Notional Volume	Contract Price	Remaining Term
AESO fixed price	24 MW/d	50.25 CAD per MWh	Jul 26 – Dec 26
AESO fixed price	24 MW/d	45.25 CAD per MWh	Jul 26 – Dec 26

(1) Alberta Electric System Operator ("AESO").

The Company has the following natural gas physical supply agreements for delivery to the Nova Inventory Transfer point, where the Company receives a price equal to the Floating AESO Power Pool Price divided by the fixed heat rate. These supply agreements contain an embedded derivative where the fair value of the embedded derivative is calculated as the difference between the forecasted Floating AESO Power Pool Price divided by the fixed heat rate, less the forecasted AECO 5A price.

Natural gas embedded derivative

Contract Type	Notional Volume	Contract Price	Remaining Term
Physical delivery	7,349 GJ/d	Floating AESO power pool price (CAD/MWh) divided by the Fixed Heat Rate of 16.75 GJ/MWh	Jul 26 – Dec 26

The Company has the following natural gas physical supply agreements for delivery to the Nova Inventory Transfer point. These supply agreements contain an embedded derivative where the fair value of the embedded derivative is based upon the future price in each respective market.

Natural gas embedded derivative

Contract Type	Notional Volume	Contract Price	Remaining Term
Physical delivery	5,000 MMBtu/d	Floating JKM (Japan/Korea Marker) Price (USD/MMBtu) multiplied by 22.0%	Jul 26 – Dec 26
Physical delivery	5,000 MMBtu/d	Floating TTF (Title Transfer Facility Netherlands) Price (USD/MMBtu) multiplied by 22.0%	Jul 26 – Dec 26

Interest rate risk

The Company is exposed to interest rate risk as changes in market interest rates will impact the Credit Facility which is subject to a floating interest rate. Based on the bank debt balance as of June 30, 2026 of $187.0 million, an increase (decrease) in the market rate of interest by 25 basis points would have an increased (decreased) annualized interest expense of $0.5 million. As of June 30, 2026, 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 marketing arrangements.

As at June 30, 2026, the following foreign exchange risk management contracts are outstanding:

Foreign exchange derivative financial instrument			
Contract Type	Notional Volume	Strike Rate	Remaining Term
Average rate forward [(1)]	USD$2.0 million/month	$1.4025 CAD/USD	Jul 26 – Dec 26
Average rate forward	USD$1.0 million/month	$1.3800 CAD/USD	Jul 26 – Dec 26
Average rate forward	USD$4.0 million/month	$1.4015 CAD/USD	Jul 26 – Dec 26

(1) Contract includes an option that extends the contract into the 2027 calendar year at a strike price of $1.4025 CAD/USD if the spot CAD/USD is $1.4025 CAD/USD or higher on December 31, 2026. The contract also includes a knock out provision that if the spot CAD/USD trades at or below $1.3250 CAD/USD anytime between the trade date of November 3, 2025 to December 31, 2026, the option to extend into 2027 is cancelled.

Gains and losses on derivative financial instrument contracts

The table below summarizes realized and unrealized gains (losses) on derivative financial instrument contracts:

	Three months ended June 30		Six months ended June 30	
	2026	2025	**2026**	2025
Realized gain (loss)				
Derivative financial instrument contracts	**(13,579)**	6,451	**(16,925)**	12,785
Natural gas embedded derivative	**3,357**	149	**4,445**	187
Total realized gain (loss)	**(10,222)**	6,600	**(12,480)**	12,972
Unrealized gain				
Derivative financial instrument contracts	**18,476**	24,055	**(13,346)**	20,087
Natural gas embedded derivative	**(5,006)**	2,828	**3,272**	470
Total unrealized gain (loss)	**13,470**	26,883	**(10,074)**	20,557
Gain (loss) on derivative financial instruments	**3,248**	33,483	**(22,554)**	33,529

Fair value measurements

The Company classifies fair value measurements using a 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. 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 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.

The fair value of cash and cash equivalents, accounts receivable and accrued sales, 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. Derivative financial instruments are classified as Level 2.

Credit Risk

As at June 30, 2026, the carrying amount of cash and cash equivalents, accounts receivable and accrued sales, deposits, and derivative financial instruments represent the Company's maximum credit exposure. Potential losses are mitigated from this credit exposure by holding cash and cash equivalents with a Canadian chartered bank, and restricting derivative financial instrument transactions to counterparties that are all investment grade. The remaining 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 sales	**June 30, 2026**	December 31, 2025
Joint venture partners	**2,961**	6,076
Oil and gas marketers	**70,972**	53,572
GST input tax credits	**3,222**	2,664
Derivative financial instrument contracts	**1,274**	1,951
Other	**-**	270
Expected credit loss provision	**(358)**	(338)
Accounts receivable and accrued sales	**78,071**	64,195

For the quarter ended June 30, 2026, market concentration risk was limited to three oil and gas marketers that represented more than 10% of total sales, comprising approximately 11%, 14%, and 14% of total sales. For the year ended December 31, 2025, sales to three oil and gas marketers accounted for approximately 15%, 16%, and 22% of total sales. Credit risk from oil and gas marketers is mitigated through transacting with investment grade rating counterparties for the majority of its oil and gas marketing.

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, oil and gas marketers revenues are current. All other accounts receivable are generally contractually due within 30-90 days.

As of June 30, 2026, the collection risk on outstanding accounts receivable balances is considered low as less than 1.0% of the accounts receivable balance are outstanding for more than 90 days (December 31, 2025 – less than 1.0%). The balance of accounts receivable outstanding for more than 90 days relates primarily to receivables from 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.

Liquidity Risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they are due. Financial obligations include accounts payable, derivative financial instruments, lease liabilities and bank debt. Liquidity risk is managed through the budgeting process, which sets out expected debt levels, capital expenditures and funds from operations. In addition, derivative financial instrument contracts may be used to protect future sales. The Board of Directors approves an annual capital expenditure budget, which is regularly monitored and updated as necessary in response to changing capital requirements and expected sales.

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 or other liquidity to satisfy such working capital deficiencies.

The table below outlines a contractual maturity analysis for Kelt's financial liabilities as at June 30, 2026:

	Within 1 Year	1 to 5 Years	More than 5 Years	**Total**
Accounts payable and accrued liabilities	142,673	-	-	**142,673**
Derivative financial instruments	5,876	-	-	**5,876**
Lease liability	637	303	-	**940**
Bank debt and estimated interest [(1)]	10,659	187,000	-	**197,659**
Total	**159,845**	**187,303**	**-**	**347,148**

(1) Estimated interest for future years related to the Credit Facility was calculated using the weighted average interest rate of 5.7% for the six months ended June 30, 2026, applied to the principal balance outstanding as at that date.

Capital Management

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

The Company may adjust capital expenditures, issue new shares, issue new debt or repay existing debt, if any, according to market conditions in order to maintain and manage its financial flexibility.

Adjusted funds from operations, net debt and net debt to adjusted funds from operations ratio

Management considers adjusted funds from operations, net debt and net debt to adjusted funds from operations ratio as key capital management measures that demonstrate the Company's ability to meet its financial obligations and cash flow available to fund its capital program, and to assess the Company's liquidity at a point in time while monitoring its capital structure and short-term financing requirements. The Company targets a net debt to adjusted funds from operations ratio of less than 2.0 times.

Adjusted funds from operations, net debt and net debt to adjusted funds are not standardized measures and therefore may not be comparable with the calculation of similar measures by other entities.

Adjusted funds from operations are calculated as follows:

	Three months ended June 30		Six months ended June 30	
	2026	2025	**2026**	2025
Cash provided by operating activities	**104,900**	60,696	**194,607**	147,625
Change in non-cash working capital	**3,091**	913	**(4,151)**	(8,328)
Settlement of decommissioning obligations	**734**	237	**2,917**	763
Adjusted funds from operations	**108,725**	61,846	**193,373**	140,060

Net debt and net debt to adjusted funds from operations ratio is calculated as follows:

	June 30, 2026	December 31, 2025
Bank debt	**187,000**	179,861
Accounts payable and accrued liabilities	**142,673**	78,046
Cash and cash equivalents	**(2,527)**	(90)
Accounts receivable and accrued sales	**(78,071)**	(64,195)
Prepaid expenses and deposits	**(6,934)**	(3,919)
Net debt	**242,141**	189,703
Adjusted funds from operations [(1)]	**314,838**	261,525
Net debt to adjusted funds from operations ratio	**0.8**	0.7

(1) 12-month trailing adjusted funds from operations.

As described in note 6, there are no financial covenants under the Credit Facility agreement and Kelt is in compliance with all other covenants.

10. PETROLEUM AND NATURAL GAS SALES

Kelt sells its oil, natural gas, and NGLs production under fixed or variable price contracts. The transaction price for fixed price contracts represents the stand-alone selling price per the contract terms. The transaction price for variable priced contracts 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. Sales are typically collected on the 25th day of the month following the prior month's production, with sales 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. Marketing revenue is generated from the sales of third-party volumes related to its oil blending and natural gas operations, with the production being sold under the same terms as the variable price contracts discussed above.

Kelt sells some of its natural gas outside of Alberta and British Columbia where title transfer occurs prior to the market location where the benchmark commodity price is determined. For the six months ended June 30, 2026, natural gas sales in relation to these contracts was $10.5 million (June 30, 2025 – $7.6 million).

The following table presents Kelt's sales disaggregated by source:

	Three months ended June 30		Six months ended June 30	
	2026	2025	**2026**	2025
Oil production	**141,278**	63,599	**229,562**	142,644
Oil treating and other	**148**	237	**390**	422
NGLs production	**40,300**	17,921	**68,070**	38,734
Gas production	**35,685**	31,019	**83,326**	70,049
Gas processing and other	**420**	429	**1,032**	868
Marketing revenue	**4,335**	3,213	**7,892**	6,202
Total petroleum and natural gas sales	**222,166**	116,418	**390,272**	258,919

Included in accounts receivable at June 30, 2026 is $71.0 million (December 31, 2025 – $53.6 million) of accrued oil and gas sales related to June 2026 production.

11. FINANCING EXPENSES

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

	Three months ended June 30		Six months ended June 30	
	2026	2025	**2026**	2025
Total interest expense	**2,993**	2,685	**5,833**	4,702
Accretion of decommissioning obligations	**844**	807	**1,670**	1,607
Total financing expense	**3,837**	3,492	**7,503**	6,309

12. COMMITMENTS

As of June 30, 2026, the Company is committed to future payments under the following agreements:

	2026	2027	2028	2029	2030	Thereafter
Firm processing commitments	34,000	72,067	78,513	79,285	80,519	400,808
Firm transportation commitments	23,772	47,559	49,030	39,029	31,275	97,725
Total annual commitments	**57,772**	**119,626**	**127,543**	**118,314**	**111,794**	**498,533**

13. SUPPLEMENTAL CASH FLOW INFORMATION

	Three months ended June 30		Six months ended June 30	
Changes in non-cash working capital	**2026**	2025	**2026**	2025
Accounts receivable and accrued sales	**(9,606)**	14,907	**(13,876)**	10,984
Prepaid expenses and deposits	**(4,088)**	(2,991)	**(3,015)**	(2,094)
Accounts payable and accrued liabilities	**2,373**	(32,455)	**64,627**	1,800
Change in non-cash working capital	**(11,321)**	(20,539)	**47,736**	10,690
Relating to:				
Operating activities	**(3,091)**	(913)	**4,151**	8,328
Investing activities	**(8,230)**	(19,626)	**43,585**	2,362
Change in non-cash working capital	**(11,321)**	(20,539)	**47,736**	10,690

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	**2026**	2025	**2026**	2025
Interest and standby fees on bank debt	**2,354**	2,520	**5,457**	4,399
Taxes [(1)]	**-**	-	**-**	-

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

ABBREVIATIONS

A&D	Acquisitions and dispositions	MMcf	million cubic feet
AECO	Alberta Energy Company “C” Meter Station of the NOVA Pipeline System	MMcf/d	million cubic feet per day
AESO	Alberta Electric System Operator	MSW	Mountain sweet blend crude oil
AT	After income taxes	NGLs	Natural Gas Liquids
bbls	barrels	NGX	Natural Gas Exchange Inc. (Canada)
bbls/d	barrels per day	NGTL	Nova Gas Transmission Line
bcf	billion cubic feet	NIT	NOVA Inventory Transfer (“AB-NIT”), being the reference price at the AECO Hub
BOE	barrels of oil equivalent	NYMEX	New York Mercantile Exchange
BOE/d	barrels of oil equivalent per day	Oil	Oil includes crude oil and field condensate
BT	Before income taxes	OPEC+	The Organization of Petroleum Exporting Countries along with 10 additional oil-producing countries
CA$/CAD	Canadian Dollar	P&NG	Petroleum and Natural Gas
CGU	Cash Generating Unit	Q1	First quarter ended March 31st
CORRA	Canadian Overnight Repo Rate Average	Q2	Second quarter ended June 30th
Dawn	Gas traded at Union Gas' Dawn Hub in Dawn Township, Ontario	Q3	Third quarter ended September 30th
E&E	Exploration and Evaluation	Q4	Fourth quarter ended December 31st
FDC	Future Development Capital	SEDAR+	System for Electronic Document Analysis and Retrieval
G&A	General and Administration	Station 2	Spectra Energy receipt location
GJ	gigajoules	TSX	Toronto Stock Exchange
LNG	Liquefied Natural Gas	US$/USD	United States dollar
LT	Long ton	WTI	West Texas Intermediate
Mbbls	thousand barrels	YTD	Year to date
MBOE	thousand barrels of oil equivalent	1P	Proved reserves
Mcf	thousand cubic feet	2P	Proved plus probable reserves
MD&A	Management’s Discussion and Analysis		
MMBtu	million British Thermal Units		

CONVERSION OF UNITS

Imperial = Metric	1 Mcf = 28.2 cubic metres	Natural gas is equated to oil on the basis of 6 Mcf = 1 BOE
1 acre = 0.4 hectares	0.035 Mcf = 1 cubic metre	
2.5 acres = 1 hectare	1 mile = 1.61 kilometres	Sulphur is equated to NGLs on the basis of 0.6 LT = 1 BOE
1 bbl = 0.159 cubic metres	0.62 miles = 1 kilometre	
6.29 bbls = 1 cubic metre	1 MMBtu = 1.054 GJ	3.281 feet = 1 metre
1 foot = 0.3048 metres	0.949 MMBtu = 1 GJ	

CORPORATE INFORMATION

BOARD OF DIRECTORS

William C. Guinan [5, 8, 9]
Board Chair, Independent

Jennifer Haskey [2, 6, 10]
Director, Independent

Ray Kwan [1, 7]
Director, Independent

Neil G. Sinclair [4, 8, 10]
Director, Independent

Janet E. Vellutini [3, 6, 7]
Director, Independent

David J. Wilson [9]
President & Chief Executive Officer,
Kelt Exploration Ltd.

1 chair, audit committee
2 chair, reserves committee
3 chair, compensation and corporate governance committee
4 chair, health, safety, environment and sustainability committee
5 chair, nominating committee
6 member, audit committee
7 member, reserves committee
8 member, compensation and corporate governance committee
9 member, health, safety and environment and sustainability committee
10 member, nominating committee

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Bruce D. Gigg
Vice President, Engineering

David A. Gillis
Vice President, Finance

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