THIRD QUARTER REPORT

AS AT AND FOR THE THREE AND NINE MONTHS ENDED

SEPTEMBER 30, 2025

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FINANCIAL AND OPERATIONAL HIGHLIGHTS	Three months ended September 30			Nine months ended September 30		
(CA$ thousands, except as otherwise indicated)	**2025**	2024	%	**2025**	2024	%
FINANCIAL						
Petroleum and natural gas sales	**110,377**	107,884	2	**369,296**	343,368	8
Cash provided by operating activities	**53,827**	52,166	3	**201,452**	161,078	25
Adjusted funds from operations [(1)]	**44,648**	48,939	-9	**184,708**	152,572	21
Basic ($/ common share)	**0.22**	0.25	-12	**0.93**	0.78	19
Diluted ($/ common share)	**0.22**	0.24	-8	**0.92**	0.77	19
Net income (loss) and comprehensive net income (loss)	**(7,446)**	8,871	-184	**43,994**	31,623	39
Basic ($/ common share)	**(0.04)**	0.05	-180	**0.22**	0.16	38
Diluted ($/ common share)	**(0.04)**	0.04	-200	**0.22**	0.16	38
Capital expenditures, net of A&D [(1)]	**89,801**	82,110	9	**285,499**	236,101	21
Total assets	**1,594,538**	1,378,621	16	**1,594,538**	1,378,621	16
Bank debt	**186,000**	45,428	309	**186,000**	45,428	309
Net debt [(1)]	**223,684**	95,889	133	**223,684**	95,889	133
Shareholders' equity	**1,117,150**	1,046,142	7	**1,117,150**	1,046,142	7
Weighted average shares outstanding (000s)						
Basic	**199,274**	196,084	2	**198,610**	195,437	2
Diluted	**202,714**	200,015	1	**201,734**	199,257	1
OPERATIONS						
Average daily production						
Oil (bbls/d)	**8,281**	8,827	-6	**8,740**	8,396	4
NGLs (bbls/d)	**5,388**	3,075	75	**5,463**	3,213	70
Gas (Mcf/d)	**144,243**	122,857	17	**147,650**	122,314	21
Combined (BOE/d)	**37,710**	32,378	16	**38,811**	31,995	21
Production per million common shares (BOE/d)	**189**	165	15	**195**	164	19
Net realized prices, before derivative financial instruments [(1)]						
Oil ($/bbl)	**84.91**	93.88	-10	**87.13**	95.18	-8
NGLs ($/bbl)	**33.70**	49.06	-31	**37.18**	52.34	-29
Gas ($/Mcf)	**1.71**	1.25	37	**2.32**	1.95	19
Operating netbacks ($/BOE) [(1)]						
Petroleum and natural gas sales	**31.82**	36.22	-12	**34.85**	39.17	-11
Cost of purchases	**(1.81)**	(1.25)	45	**(1.17)**	(1.49)	-21
Combined net realized price, before derivative financial instruments [(1)]	**30.01**	34.97	-14	**33.68**	37.68	-11
Realized gain on derivative financial instruments	**2.11**	0.89	137	**1.92**	0.21	814
Combined net realized price, after derivative financial instruments [(1)]	**32.12**	35.86	-10	**35.60**	37.89	-6
Royalties	**(2.95)**	(4.33)	-32	**(3.30)**	(5.15)	-36
Production expense	**(10.70)**	(10.25)	4	**(9.61)**	(10.51)	-9
Transportation expense	**(3.78)**	(3.37)	12	**(3.50)**	(3.47)	1
Operating netback [(1)]	**14.69**	17.91	-18	**19.19**	18.76	2
Land holdings						
Gross acres	**801,798**	792,198	1	**801,798**	792,198	1
Net acres	**602,296**	580,343	4	**602,296**	580,343	4

(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 third quarter ended September 30, 2025.

Kelt's average production for the three months ended September 30, 2025 was 37,710 BOE per day, up 16% from average production of 32,378 BOE per day during the corresponding period in 2024. Production for the three months ended September 30, 2025 was weighted 36% oil and NGLs and 64% gas.

During the quarter, Kelt shut-in approximately 60 MMcf per day of relatively dry gas production in the Pouce Coupe and Grande Cache areas of Alberta for approximately 15 days due to low to negative AECO prices. In addition, the Company also shut-in oil and gas production in the Wembley area of Alberta for approximately 28 days when the Pipestone Deep-Cut Gas Plant was down for its periodic turnaround maintenance operations. All of the shut-in production has been brought back on-stream.

As previously reported, at Wembley, Kelt has commenced delivering gas to the newly constructed Albright Sulphur Recovery Gas Plant during the fourth quarter of 2025. As a result, Kelt expects to show significant production growth in the fourth quarter of 2025 when compared to third quarter 2025 results.

Kelt's realized average oil price during the third quarter of 2025 was $84.91 per barrel, down 10% from $93.88 per barrel in the third quarter of 2024. The realized average NGLs price during the third quarter of 2025 was $33.70 per barrel, down 31% from $49.06 per barrel in the same quarter of 2024. Kelt's realized average gas price for the third quarter of 2025 was $1.71 per Mcf, up 37% from $1.25 per Mcf in the corresponding quarter of the previous year.

For the three months ended September 30, 2025, petroleum and natural gas sales were $110.4 million and adjusted funds from operations was $44.6 million ($0.22 per common share, diluted), compared to $107.9 million and $48.9 million ($0.24 per common share, diluted) respectively, in the third quarter of 2024.

Net capital expenditures incurred during the three months ended September 30, 2025, were $89.8 million. During the quarter, the Company spent $56.6 million on drill and complete operations and $32.0 million on facilities, pipelines and equipment.

On September 30, 2025, the Company had net debt of $223.7 million. Capital expenditures during the fourth quarter of 2025 are expected to be lower than forecasted funds from operations for the quarter. As a result, Kelt expects to reduce its net debt to approximately $170.0 million by year-end or 0.6 times forecasted 2025 adjusted funds from operations.

2025 Outlook

The global economy is currently experiencing a slowdown in growth amid heightened uncertainty, driven primarily by escalating trade tensions, persistent inflationary pressures, and significant geopolitical risks. These factors contribute to an economic environment of uncertainty, which in turn results in volatile fluctuations in commodity prices. As a result, Kelt has been pro-active with commodity price risk management and has entered into certain future contracts to sell its oil and gas production at prices that provide the Company with an opportunity to protect its financial position as it conducts its planned capital expenditure program.

Production during 2025 is forecasted to average between 40,000 and 41,000 BOE per day, an increase of 22% from the mid-point of the range compared to average production of 33,115 BOE per day in 2024. The average production forecast for 2025 was reduced from the Company's previous guidance of 42,000 to 45,000 BOE per day to reflect the delayed start-up of the newly constructed Albright Sulphur Recovery Gas Plant, the shut-in of dry gas production due to low to negative AECO prices, and the longer than planned turnaround maintenance operations at the Pipestone Deep-Cut Gas Plant.

Adjusted funds from operations for 2025 is forecasted to be $280.0 million, down from the Company's previous forecast of $325.0 million. The lower production forecast and lower forecasted realized gas and NGL prices contributed to the majority of the reduction in the estimated adjusted funds from operations for the year. The Company has decreased its forecasted 2025 average WTI oil price from US$66.50 per barrel to US$66.00 per barrel. In addition, Kelt reduced its forecasted 2025 average AECO gas price by 22% from $2.23 per GJ to $1.73 per GJ. On December 31, 2025, the Company expects to have net debt of $170.0 million, representing 0.6 times forecasted 2025 adjusted funds from operations.

Forecasted average commodity price assumptions for the remainder of 2025 are shown in the following table:

Commodity Index	Jan–Sep 2025 Actual	Oct–Dec 2025 Forecast	**2025 Forecast**
WTI Crude Oil (USD/bbl)	67.38	61.93	**66.00**
MSW Crude Oil (CAD/bbl)	89.63	81.37	**87.54**
NYMEX Natural Gas Daily Index (USD/MMBtu)	3.48	3.55	**3.50**
DAWN Gas Daily Index (USD/MMBtu)	3.18	3.65	**3.30**
AECO NIT 5A Gas Daily Index (CAD/GJ)	1.41	2.67	**1.73**
STATION 2 Gas Daily Index (CAD/GJ)	0.68	2.71	**1.19**
Exchange Rate (USD/CAD)	0.7150	0.7194	**0.7161**
Exchange Rate (CAD/USD)	1.3987	1.3900	**1.3965**

Financial and operating highlights for the Company's 2025 forecast compared to its 2024 results are highlighted in the table below:

Financial and Operating Highlights ($ MM, unless otherwise specified)	**2025 Forecast**	2024	Change
Production *[2]*			
Oil & NGLs (bbls/d)	**14,600 – 15,400**	12,298	22%
Gas (MMcf/d)	**152,400 – 153,600**	124,902	22%
Combined (BOE/d)	**40,000 – 41,000**	33,115	22%
P&NG Sales *[1]*	**536.1**	468.4	14%
Adjusted Funds from Operations *[1]*	**280.0**	222.0	26%
AFFO per share, diluted ($/share) *[1]*	**1.38**	1.11	24%
Capital Expenditures, net of A&D *[1]*	**325.0**	333.1	(2%)
Net Debt, at year-end *[1]*	**170.0**	124.9	36%
Net Debt / AFFO ratio	**0.6 x**	0.6 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.

Operations Update

In its Wembley/Pipestone Division, Kelt continues to use the plug and perf * completion method on its pad development wells, however, the Company recently optimized the completion design on its 5-well Montney 6-9 pad:

(i) The Company engaged McDaniel & Associates Consultants Ltd. to create an analogue dataset model using machine learning that included approximately 3,000 wells from across the unconventional Montney horizon. The model focused on selecting plug and perf wells within a

relevant range of cumulative CGRs and initial reservoir pressures in the Alberta and British Columbia Montney fairway.

(ii) Inter-well spacing in the same zone was increased from a previously tested range of 300 to 330 metres up to approximately 390 metres on the 6-9 pad. Four of the wells were drilled with a lateral length of approximately 3,300 metres per well and the fifth well had a lateral length of approximately 3,000 metres.

(iii) Four of the wells were completed using 51 stages with 8 clusters per stage. The fifth and shorter well had 48 stages.

(iv) Proppant intensity was increased from 2.25 tonnes/metre to 2.75 tonnes/metre.

(v) Water intensity was increased from 3.5 cubic metres/tonne to 4.0 cubic metres/tonne.

(vi) Cluster spacing was tightened from 10 metres to 8 metres.

Kelt expects this optimized completion design to be better suited for reservoirs with higher liquids such as Kelt's development wells at Wembley. Initial indications from the 6-9 pad wells are oil and NGLs ranging from 62% to 68% of total production, significantly higher than the current field average.

** The plug and perf completion method: the horizontal well is stimulated by repeatedly setting a plug to isolate a section of the well, perforating the casing to access the formation, and then performing a hydraulic fracture treatment on that isolated zone; this process is repeated in stages, moving back up the wellbore towards the heel, and after all zones are treated, a milling operation removes all the plugs.*

In its Oak/Flatrock Division, Kelt drilled a four well pad located at 5-32. Two of these wells have now been completed and are expected to be put on production in December 2025. Completion of the remaining two wells has been deferred to 2026. Kelt plans to use this freed up capital for 2025 to commence its 2026 drilling program, leaving estimated capital expenditures for 2025 unchanged at $325 million.

With access to new gas processing capacity, Kelt expects to show significant production and cash flow growth leading into 2026. Management plans to release the Company's planned capital expenditure program for 2026 in early January, at which time the direction of commodity prices for 2026 will be better understood.

On behalf of the Board of Directors,

[signed]

David J. Wilson
President and Chief Executive Officer
November 12, 2025

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 November 12, 2025 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 nine months ended September 30, 2025 and its audited annual consolidated financial statements and MD&A as at and for the year ended December 31, 2024. 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. 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 September 30			Nine months ended September 30		
(CA$ thousands, except as otherwise indicated)	**2025**	2024	%	**2025**	2024	%
FINANCIAL PERFORMANCE						
Petroleum and natural gas sales	**110,377**	107,884	2	**369,296**	343,368	8
Cash provided by operating activities	**53,827**	52,166	3	**201,452**	161,078	25
Adjusted funds from operations [(1)]	**44,648**	48,939	-9	**184,708**	152,572	21
Diluted ($/ common share)	**0.22**	0.24	-8	**0.92**	0.77	19
Net income (loss) and comprehensive net income (loss)	**(7,446)**	8,871	-184	**43,994**	31,623	39
Diluted ($/ common share)	**(0.04)**	0.04	-200	**0.22**	0.16	38
Capital expenditures, net of A&D [(1)]	**89,801**	82,110	9	**285,499**	236,101	21
Bank debt	**186,000**	45,428	309	**186,000**	45,428	309
Net debt [(1)]	**223,684**	95,889	133	**223,684**	95,889	133
OPERATIONAL PERFORMANCE						
Average daily production (BOE/d)	**37,710**	32,378	16	**38,811**	31,995	21
Combined net realized price, before derivative financial instruments [(1)]	**30.01**	34.97	-14	**33.68**	37.68	-11
Combined net realized price, after derivative financial instruments [(1)]	**32.12**	35.86	-10	**35.60**	37.89	-6
Operating netback [(1)]	**14.69**	17.91	-18	**19.19**	18.76	2

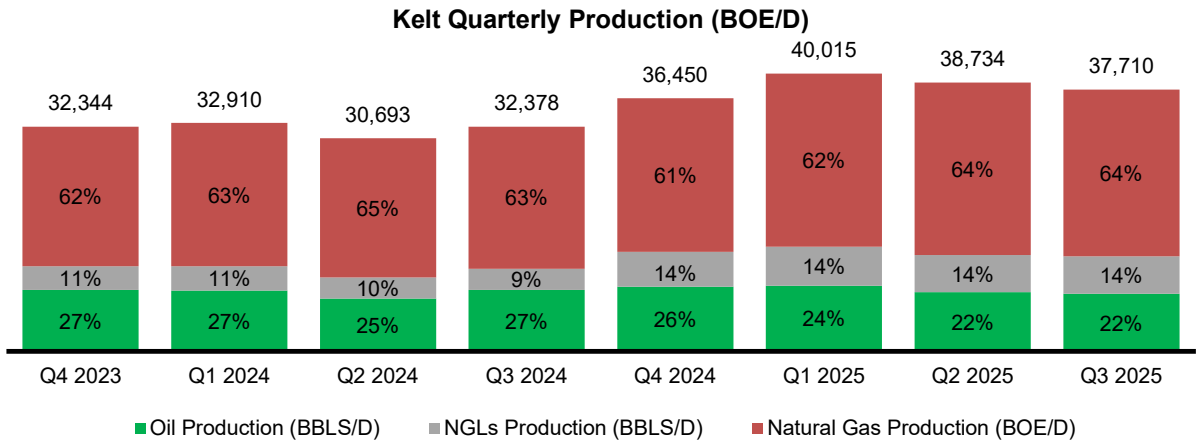
(1) Refer to advisories regarding Non-GAAP and Other Financial Measures

In the third quarter of 2025, Kelt's financial and operating results are highlighted by the following:

- **Production –** Average production of 37,710 BOE per day (36% liquids) increased 16% from 32,378 BOE per day (37% liquids) in the third quarter of 2024.
- **Petroleum and natural gas sales –** Petroleum and natural gas sales increased 2% in the third quarter of 2025 compared to the third quarter of 2024. Kelt's combined net realized price before derivative financial instruments of $30.01 per BOE decreased 14% from the third quarter of 2024, primarily due to lower oil and NGL prices.
- **Operating netback –** Kelt's operating netback was $14.69 per BOE for the quarter ended September 30, 2025, a decrease of 18% from $17.91 per BOE during the quarter ended September 30, 2024. This decrease was primarily driven by lower net realized oil and NGL prices relative to the prior period.
- **Cash provided by operating activities and adjusted funds from operations –** Cash provided by operating activities of $53.8 million increased 3% from the third quarter of 2024. Adjusted funds from operations of $44.6 million ($0.22 per common share, diluted) in the third quarter of 2025 decreased by 9% from $48.9 million ($0.24 per share, diluted) in the third quarter of 2024.
- **Net income (loss) –** Kelt reported a net loss of $7.4 million ($0.04 per common share, diluted) for the three months ended September 30, 2025, compared to net income of $8.9 million ($0.04 per common share, diluted) in the third quarter of 2024.
- **Capital investments –** Capital expenditures, net of A&D, of $89.8 million in the third quarter of 2025 included the drilling of 5.0 net wells and the completion of 10.0 net wells. Facilities, pipeline and well equipment expenditures were $32.0 million for the third quarter of 2025.
- **Net debt –** The Company ended the quarter with net debt of $223.7 million (0.9 times 12-month trailing adjusted funds from operations). Subsequent to the quarter ending September 30, 2025, the Company and its lenders increased the amount available under the credit facility to $300.0 million from a previous available amount of $250.0 million.

- **Third-party plant commissioning at Wembley/Pipestone –** Subsequent to the quarter ended September 30, 2025, Kelt has commenced delivering gas to the third-party Albright Sulphur Recovery Gas Plant at Wembley/Pipestone. As a result, Kelt expects to show significant production growth in the fourth quarter of 2025 when compared to third quarter 2025 results.

PRODUCTION



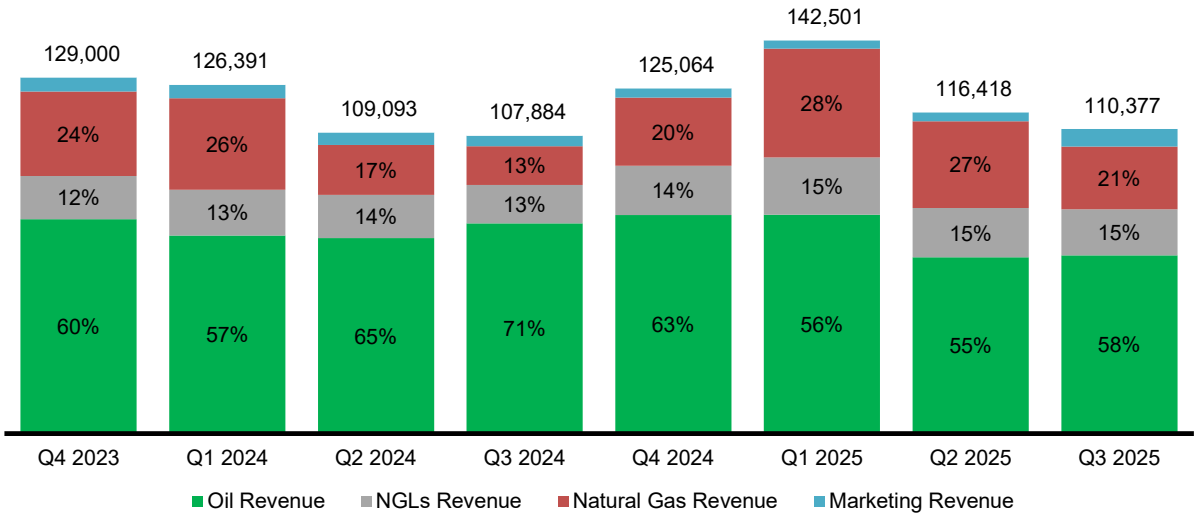
	Three months ended September 30			Nine months ended September 30		
	2025	2024	%	**2025**	2024	%
Average daily production:						
Oil (bbls/d)	**8,281**	8,827	-6	**8,740**	8,396	4
NGLs (bbls/d)	**5,388**	3,075	75	**5,463**	3,213	70
Gas (Mcf/d)	**144,243**	122,857	17	**147,650**	122,314	21
Combined (BOE/d)	**37,710**	32,378	16	**38,811**	31,995	21
Oil and NGLs weighting	**36%**	37%	-3	**37%**	36%	3

Average production for the three months ended September 30, 2025 of 37,710 BOE per day and for the nine months ended September 30, 2025 of 38,811 BOE per day increased 16% and 21%, respectively, from the comparable periods in 2024. The increase in 2025 was primarily due higher production at the Company's Pouce Coupe/Progress/Spirit River division as a result of the Company's drilling activities combined with obtaining additional third-party gas processing capacity. Production in the third quarter of 2025 was impacted by planned third party maintenance activities and the shut-in of gas weighted production in September 2025 due to low AECO and Station 2 prices.

The production liquids weight of 36% during the third quarter of 2025 and 37% in the nine months ending September 30, 2025 was relatively consistent compared to 37% and 36% in the comparable periods of 2024.

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

Kelt Quarterly Petroleum and Natural Gas Sales ($000)



	Three months ended September 30			Nine months ended September 30		
(CA$ thousands, except as otherwise indicated)	**2025**	2024	%	**2025**	2024	%
Oil	**64,533**	76,195	-15	**207,599**	218,811	-5
NGLs	**16,706**	13,877	20	**55,440**	46,077	20
Gas	**22,715**	14,043	62	**93,632**	65,245	44
Marketing revenue [1]	**6,423**	3,769	70	**12,625**	13,235	-5
P&NG Sales	**110,377**	107,884	2	**369,296**	343,368	8
Cost of purchases [2]	**(6,273)**	(3,728)	68	**(12,345)**	(13,060)	-5
P&NG Sales after cost of purchases [3][5]	**104,104**	104,156	-	**356,951**	330,308	8
Combined net realized price ($/BOE) [4][5]	**30.01**	34.97	-14	**33.68**	37.68	-11

(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.

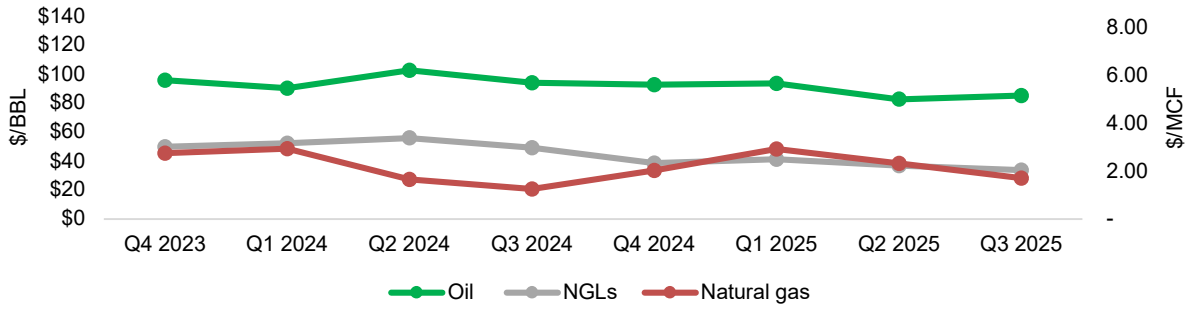
(3) P&NG sales after cost of purchases includes petroleum and natural gas sales, net of the cost of the third-party volumes purchased.

(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 for the third quarter of 2025 was $110.4 million, an increase of 2% from $107.9 million from the third quarter of 2024. Petroleum and natural gas sales for the nine months ending September 30, 2025 was $369.3 million, an increase of 8% from the comparable period in 2024. The increase in P&NG sales from 2024 was due to an increase in production, and an increase in realized natural gas prices, partially offset by lower oil and NGLs realized prices.

Kelt Quarterly Realized Prices (1)



(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 risk management contracts. Refer to additional information under the heading of "Non-GAAP and Other Financial Measures".

	Three months ended September 30			Nine months ended September 30		
	2025	2024	%	**2025**	2024	%
Net realized prices (9)						
Oil ($/bbl)	**84.91**	93.88	-10	**87.13**	95.18	-8
NGLs ($/bbl)	**33.70**	49.06	-31	**37.18**	52.34	-29
Gas ($/Mcf)	**1.71**	1.25	37	**2.32**	1.95	19
Combined ($/BOE)	**30.01**	34.97	-14	**33.68**	37.68	-11
Average benchmark prices						
Oil and NGLs						
WTI Cushing Oklahoma (US$/bbl) (1)	**65.76**	76.31	-14	**67.38**	78.53	-14
Mixed Sweet Blend Edmonton ("MSW") ($/bbl) (2)	**87.53**	99.50	-12	**89.63**	99.78	-10
Edmonton Pentane ($/bbl) (3)	**86.91**	99.75	-13	**91.34**	101.12	-10
Edmonton Butane ($/bbl) (3)	**40.34**	50.01	-19	**41.93**	45.94	-9
Conway Propane ($/bbl) (3)	**26.52**	29.05	-9	**32.00**	29.03	10
Edmonton Ethane ($/bbl) (3)	**1.69**	1.96	-14	**4.11**	3.75	10
Natural Gas						
NYMEX Henry Hub (US$/MMBtu) (6)	**3.03**	2.08	46	**3.48**	2.19	59
AECO 5A (CA$/MMBtu) (4)	**0.63**	0.69	-9	**1.49**	1.46	2
Chicago Alliance, into Interstates (CA$/MMBtu) (5)	**3.82**	2.28	68	**4.50**	2.73	65
Dawn (CA$/MMBtu) (5)	**3.85**	2.32	66	**4.46**	2.56	74
Sumas (CA$/MMBtu) (5)	**1.29**	2.03	-36	**2.06**	2.64	-22
Station 2 (CA$/MMBtu) (7)	**0.47**	0.50	-6	**0.72**	1.29	-44
Marcellus (TZ4 L300) (CA$/MMBtu) (5)	**2.87**	1.88	53	**3.81**	2.07	84
Average exchange rate (CA$/US$) (8)	**1.3775**	1.3637	1	**1.3988**	1.3603	3

(1) Source: U.S Energy Information Administration, Canadian dollar equivalent price WTI price ("CA$WTI") is calculated based on the monthly average US dollar WTI price and the monthly average CA$/US$ exchange rate (8).

(2) Source: Tidal Energy Marketing.

(3) Source: Sproule Associates Limited.

(4) Source: Canadian Gas Price Reporter converted to CA$/MMBtu using monthly average CA$/US$ exchange rate (8).

(5) Source: S&P Global Platts (US$/MMBtu) Daily Midpoint Average converted to CA$/MMBtu using monthly average CA$/US$ exchange rate (8).

(6) Source: S&P Global Platts (US$/MMBtu) Daily Midpoint Average.

(7) Source: S&P Global Platts (CA$/GJ) Daily Midpoint Average converted to CA$/MMBtu.

(8) Source: Bank of Canada.

(9) 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 decreased 14% to $30.01 per BOE in the third quarter of 2025 and decreased 11% to $33.68 per BOE in the nine months ending September 30, 2025 versus the comparable periods in 2024. The decrease in the average realized price was due to a decrease in realized oil and NGLs prices partially offset by a higher realized natural gas price.

Oil prices

The mixed sweet blend benchmark crude oil price decreased 12% for the quarter ended September 30, 2025 and decreased 10% for the nine months ended September 30, 2025 versus the comparable periods in 2024. Benchmark crude oil prices decreased in 2025 primarily due to OPEC+ announcing its phasing out of its supply cuts in 2025 and into 2026.

NGL prices

For the three months and nine months ended September 30, 2025, Kelt's realized NGLs price decreased 31% and 29%, respectively, as compared to the same period in 2024.

In the fourth quarter of 2024 Kelt added third-party natural gas processing resulting in higher overall NGLs recoverability, primarily lower value propane and ethane, which resulted in an overall reduction in Kelt's average NGLs realized price. Kelt's realized NGLs price also decreased in 2025 due to lower pentane and butane benchmark prices, which are generally closely related to crude oil prices. Benchmark propane and ethane were also lower in the third quarter of 2025 compared to the third quarter of 2024, however the benchmark prices were higher for the nine months ending September 30, 2025 compared to the nine months ending September 30, 2024.

Natural gas prices

US natural gas prices increased in 2025 compared to 2024 due to higher LNG exports and increased domestic demand offsetting higher supply. However, the Canadian AECO and Station 2 benchmark prices decreased in 2025 due to higher Canadian natural gas production and pipeline maintenance activities that occurred in the summer of 2025 and a slower than anticipated start-up of LNG Canada.

Kelt's net realized natural gas price increased by 37% to $1.71 per MCF in the third quarter of 2025 compared to the third quarter of 2024 and increased 19% to $2.32 per MCF for the nine months ended September 30, 2025. The increase in the Company's net realized natural gas price was due to Kelt's exposure to the US natural gas markets obtained through its diversified natural gas marketing portfolio.

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 had a loss of $0.2 million on derivative financial instruments for the third quarter of 2025 and a gain of $33.3 million for the nine months ended September 30, 2025. The unrealized loss on derivative financial instruments for the third quarter of 2025 was primarily due to unrealized gains moving over to realized gains during the quarter and an increase in the forward forecasted oil price as of September 30, 2025 compared to June 30, 2025. The unrealized gains on derivative financial instruments for the nine months ending September 30, 2025 was primarily due to a decrease in the crude oil and natural gas strip price at September 30, 2025 compared to December 31, 2024.

The realized gains on derivative financial instruments for both the three and nine months ending September 30, 2025 was due to a lower benchmark natural gas and crude oil price in 2025 compared to the derivative financial instrument contractual price.

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

	Three months ended September 30			Nine months ended September 30		
(CA$ thousands, except as otherwise indicated)	**2025**	2024	%	**2025**	2024	%
Realized gains						
Derivative financial instruments - Oil	**1,630**	482	238	**4,227**	379	1,015
Derivative financial instruments - Gas	**4,941**	1,957	152	**15,274**	1,314	1,062
Derivative financial instruments - NGLs	**226**	207	9	**81**	207	-61
Natural gas embedded derivative	**522**	-	-	**709**	-	-
Total realized gain	**7,319**	2,646	177	**20,291**	1,900	968
Unrealized gains (losses)						
Derivative financial instruments - Oil	**(6,107)**	1,221	-600	**7,405**	(891)	-931
Derivative financial instruments - Gas	**(1,760)**	(200)	780	**4,841**	2,383	103
Derivative financial instruments - NGLs	**250**	156	60	**224**	156	44
Natural gas embedded derivative	**62**	75	-17	**532**	75	609
Total unrealized gain (loss)	**(7,555)**	1,252	-703	**13,002**	1,723	655
Gain (loss) on derivative financial instruments	**(236)**	3,898	-106	**33,293**	3,623	819
$ per BOE	**(0.07)**	1.31	-105	**3.14**	0.41	666

Commodity price risk

Commodity price risk is the risk that future cash flows will fluctuate as a result of changes in commodity prices and is inherent in the business of producing oil and gas. 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 at September 30, 2025, 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 option [2]	500 bbl/d	Settles monthly if WTI price > USD$70.50/bbl	Oct 25 – Dec 25
WTI fixed price swap	2,000 bbl/d	USD$69.6575/bbl	Oct 25 – Dec 25
WTI fixed price swap [3]	2,500 bbl/d	CAD $89.68/bbl	Oct 25 – Dec 25
WTI fixed price swap [4,5,6,7]	4,500 bbl/d	CAD $90.49/bbl	Jan 26 – Mar 26
WTI fixed price swap [5,6,7]	4,000 bbl/d	CAD $90.20/bbl	Apr 26 – Jun 26

(1) West Texas Intermediate ("WTI")

(2) The WTI option is settled monthly at USD$70.50/bbl if the average WTI price is above USD$70.50/bbl.

(3) Includes a fixed price WTI oil swap option to sell 500 bbl/d for Jan-Mar 2026 at CAD$94.30/bbl exercisable on December 31, 2025.

(4) Includes a fixed price WTI oil swap option to sell 500 bbl/d for Apr-Jun 2026 at CAD$92.85/bbl exercisable on March 31, 2026.

(5) Includes a fixed price WTI oil swap option to sell 500 bbl/d for Jul-Dec 2026 at CAD$91.90/bbl exercisable on June 30, 2026.

(6) Includes a fixed price WTI oil swap option to sell 500 bbl/d for Jul-Dec 2026 at CAD$90.50/bbl exercisable on June 30, 2026.

(7) Includes a fixed price WTI oil swap option to sell 500 bbl/d for Jul-Dec 2026 at CAD$90.63/bbl exercisable on June 30, 2026.

NGL derivative financial instrument swap

Contract Type	Notional Volume	Contract Price	Remaining Term
OPIS-Conway propane fixed price swap	250 bbl/d	USD$33.60/bbl	Oct 25 – Mar 26
OPIS-Conway propane basis swap	250 bbl/d	Monthly OPIS-Conway basis calculated at 46% of the floating monthly WTI price	Oct 25 – Mar 26

Natural gas derivative financial instrument

Contract Type [1]	Notional Volume	Contract Price $/MMBtu	Remaining Term
NYMEX swap	20,000 MMBtu/d	CAD$6.405/MMBtu	Oct 25 – Dec 25
NYMEX costless collar	10,000 MMBtu/d	Floor: CAD$5.00/MMBtu Ceiling: CAD$10.00/MMBtu	Oct 25 – Dec 25
NYMEX call	20,000 MMBtu/d	USD$5.50/MMBtu	Jan 26 – Dec 26
AECO 7A put	21,000 GJ/d	CAD$2.80/GJ	Jan 26 – Dec 26

(1) NYMEX Henry Hub ("NYMEX")

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 [1]	Remaining Term
Physical delivery	2,513 GJ/d	Floating AESO power pool price (CAD/MWh) divided by the Fixed Heat Rate of 17.95 GJ/MWh	Oct 25 – Dec 25
Physical delivery	7,349 GJ/d	Floating AESO power pool price (CAD/MWh) divided by the Fixed Heat Rate of 16.75 GJ/MWh	Jan 26 – Dec 26

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

In addition to the derivative contracts above, the Company has the following fixed price sales contracts for physical delivery at September 30, 2025:

Natural gas physical delivery contracts

Contract Type	Notional Volume	Contract Price	Remaining Term
Fixed price	5,000 GJ/d	CAD$1.91/GJ	Oct 2025

Subsequent to September 30, 2025 Kelt entered into the following fixed price physical delivery sales contract:

Natural gas physical delivery contracts

Contract Type	Notional Volume	Contract Price	Remaining Term
Fixed price	2,500 GJ/d	CAD$3.05/GJ	Nov 25 – Mar 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 bank debt balance as of September 30, 2025 of $186.0 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 September 30, 2025, 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 September 30, 2025, the following foreign exchange derivative financial instrument contracts are outstanding:

Foreign exchange derivative financial instrument swap			
Contract Type	Notional Volume	Contract/Exercise Price	Remaining Term
CAD/USD swap	USD$6.0 million/month	$1.3795 CAD/USD	Oct 25 – Dec 25

Foreign exchange derivative financial instrument option				
Contract Type	Notional Volume	Contract/Exercise Price	Exercise/ expiration date	Term if exercised
Sold call option	USD$2.0 million/month	$1.3820 CAD/USD	Dec 31, 2025	Jan 26 – Dec 26
Sold call option	USD$2.0 million/month	$1.3800 CAD/USD	Dec 31, 2025	Jan 26 – Dec 26

Foreign exchange derivative financial instrument fade-in forward				
Contract Type	Notional Volume	Strike Rate	Fade-in Rate	Remaining Term
Average rate fade-in forward	USD$2.0 million/month	$1.3910 CAD/USD	$1.3295 CAD/USD	Jan 26 – Dec 26

Subsequent to September 30, 2025 the Company entered into the following foreign exchange derivative financial instrument contracts:

Foreign exchange derivative financial instrument average rate forward			
Contract Type	Notional Volume	Strike Rate	Remaining Term
Average rate forward (1)	USD$2.0 million/month	$1.4025 CAD/USD	Jan 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.

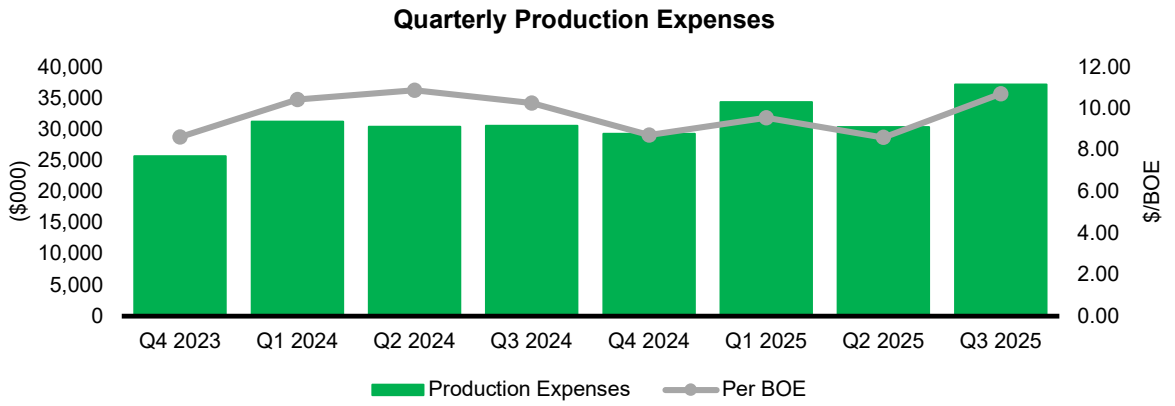
ROYALTIES

	Three months ended September 30			Nine months ended September 30		
(CA$ thousands, except as otherwise indicated)	**2025**	2024	%	**2025**	2024	%
Royalties	**10,235**	12,899	-21	**34,946**	45,185	-23
Average royalty rate (1)	**9.8%**	12.4%	-21	**9.8%**	13.7%	-28
$ per BOE	**2.95**	4.33	-32	**3.30**	5.15	-36

(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 9.8% for the three months and nine months ended September 30, 2025 compared to 12.4% and 13.7% in the comparable periods of 2024, respectively. The decrease in the royalty rate in the three and nine months ended September 30, 2025 was primarily due to a higher percentage of producing wells that were eligible under the Alberta government's initial 5% royalty rate.

PRODUCTION EXPENSES

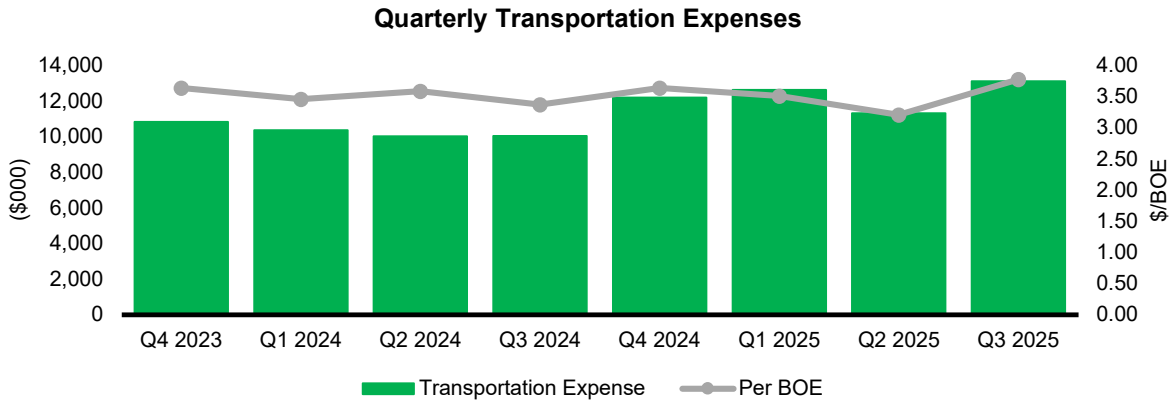


	Three months ended September 30			Nine months ended September 30		
(CA$ thousands, except as otherwise indicated)	**2025**	2024	%	**2025**	2024	%
Production expense	**37,135**	30,533	22	**101,806**	92,120	11
$ per BOE	**10.70**	10.25	4	**9.61**	10.51	-9

Production expense was $37.1 million during the third quarter of 2025 compared to $30.5 million in the comparative quarter. Production expenses averaged $10.70 per BOE during the third quarter of 2025, compared to $10.25 per BOE in the same period in 2024. Production expenses per BOE increased in the third quarter of 2025 primarily due to an increase in the downhole workovers and field maintenance costs in the quarter.

Production expense was $101.8 million during the first nine months of 2025, an increase of 11% from the nine months ended September 30, 2024. On a BOE basis, production expenses averaged $9.61 per BOE during the first nine months of 2025, compared to $10.51 per BOE in the same period in 2024. Production expenses per BOE decreased in 2025 year to date due to a decrease in utility, carbon taxes and trucking costs.

TRANSPORTATION EXPENSES



	Three months ended September 30			Nine months ended September 30		
(CA$ thousands, except as otherwise indicated)	**2025**	2024	%	**2025**	2024	%
Transportation expense [1]	**13,123**	10,046	31	**37,081**	30,427	22
$ per BOE	**3.78**	3.37	12	**3.50**	3.47	1

(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 $3.78 per BOE during the third quarter of 2025, and $3.50 per BOE for the nine months ended September 30, 2025 compared to $3.37 per BOE during the third quarter of 2024 and $3.47 per BOE for the nine months ended September 30, 2024. Kelt's per BOE transportation costs increased during the third quarter of 2025 due to additional gas volumes sent to Chicago under a short term agreement for the month of September 2025.

FINANCING EXPENSES

	Three months ended September 30			Nine months ended September 30		
(CA$ thousands, except as otherwise indicated)	**2025**	2024	%	**2025**	2024	%
Interest expense	**3,280**	1,078	204	**7,982**	2,217	260
Accretion of decommissioning obligations	**824**	817	1	**2,431**	2,273	7
Total financing expense	**4,104**	1,895	117	**10,413**	4,490	132
Interest expense per BOE [1]	**0.95**	0.36	164	**0.75**	0.25	200

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

Interest expense was $3.3 million for the third quarter of 2025 and $8.0 million for the nine months ending September 30, 2025. As at September 30, 2025, $186.0 million was drawn under the credit facility, with outstanding letters of credit of $2.4 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 September 30			Nine months ended September 30		
(CA$ thousands, except as otherwise indicated)	**2025**	2024	%	**2025**	2024	%
Salaries and benefits	**4,137**	3,716	11	**12,395**	11,092	12
Other G&A expenses	**1,179**	1,640	-28	**4,787**	5,031	-5
Gross G&A expenses	**5,316**	5,356	-1	**17,182**	16,123	7
Overhead recoveries	**(2,197)**	(2,111)	4	**(6,679)**	(6,337)	5
Net G&A expenses	**3,119**	3,245	-4	**10,503**	9,786	7
Gross G&A ($ per BOE)	**1.53**	1.80	-15	**1.62**	1.84	-12
Net G&A ($ per BOE)	**0.90**	1.09	-17	**0.99**	1.12	-12

Net G&A expenses per BOE decreased 17% in the third quarter of 2025 and decreased 12% during the nine months ended September 30, 2025, respectively, compared to the same periods in 2024. 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.

SHARE BASED COMPENSATION ("SBC")

	Three months ended September 30			Nine months ended September 30		
(CA$ thousands, except as otherwise indicated)	**2025**	2024	%	**2025**	2024	%
Stock options	**616**	1,367	-55	**2,526**	3,890	-35
Restricted share units ("RSUs")	**968**	954	1	**2,571**	2,607	-1
Performance share units ("PSUs")	**468**	-	-	**699**	-	-
Total SBC expense	**2,052**	2,321	-12	**5,796**	6,497	-11
$ per BOE	**0.59**	0.78	-24	**0.55**	0.74	-26

In April 2025, the Company's shareholders approved a PSU plan, as a component of its long-term incentive compensation strategy, designed to align the interests of executives and employees with those of shareholders. The approval of the PSU plan, was made in combination with discontinuing the Company's Stock Option Plan, after which no future stock options will be issued.

The decrease in SBC expense during the three and nine months ended September 30, 2025 was primarily due to a lower monthly PSU expense amount in 2025 compared to the reduction of the monthly stock option expense as a result of the discontinuation of granting additional stock options in 2025.

As at September 30, 2025, stock options, RSUs, and PSUs outstanding represent 5.2% of total shares outstanding (December 31, 2024 – 6.0%).

DEPLETION AND DEPRECIATION

	Three months ended September 30			Nine months ended September 30		
(CA$ thousands, except as otherwise indicated)	**2025**	2024	%	**2025**	2024	%
Depletion and depreciation	**43,309**	35,187	23	**130,506**	100,955	29
$ per BOE	**12.48**	11.81	6	**12.32**	11.52	7

Depletion and depreciation expense increased by 23% and 29% for the three and nine months ended September 30, 2025, respectively, as compared to the same periods in 2024. The increase was primarily due to an increase in production. For the three and nine months ended September 30, 2025, on a per BOE basis, the depletion and depreciation expense increased by 6% and 7% compared to the three and nine months ended September 30, 2024.

Based on its assessment as of September 30, 2025, the Company determined that there were no indicators of impairment for the Alberta CGU and BC CGU and there are no previous impairments available for reversals.

INCOME TAXES

	Three months ended September 30			Nine months ended September 30		
(CA$ thousands, except as otherwise indicated)	**2025**	2024	%	**2025**	2024	%
Deferred income tax expense (recovery)	**(1,782)**	2,995	-159	**14,798**	12,802	16
Net income (loss) before taxes	**(9,228)**	11,866	-178	**58,792**	44,425	32
Effective tax recovery rate	**19.3%**	25.2%	-23	**25.2%**	28.8%	-13

Kelt's consolidated combined federal and provincial statutory tax rate averaged 23% during the nine months ended September 30, 2025 and 2024. The Company is not expected to have any cash income taxes payable in 2025.

The Company's consolidated tax pools are estimated to be approximately $999.3 million as of September 30, 2025 as summarized in the table below.

(CA$ thousands, except otherwise indicated)	Rate	**September 30 2025**
Canadian oil and gas property expenses (COGPE)	10%	**55,396**
Canadian development expenses (CDE)	30%	**349,901**
Canadian exploration expenses (CEE)	100%	**14,587**
Undepreciated capital cost [1] (UCC)	25%	**305,240**
Non-capital losses [2] (NCL)	100%	**274,129**
Estimated tax deductions available, end of period		**999,253**

(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 2033 to 2044.

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 nine month periods ended September 30, 2025 and 2024, respectively.

	Three months ended September 30			Nine months ended September 30		
(CA$ thousands, except as otherwise indicated)	**2025**	2024	%	**2025**	2024	%
Petroleum and natural gas sales	**110,377**	107,884	2	**369,296**	343,368	8
Cost of purchases	**(6,273)**	(3,728)	68	**(12,345)**	(13,060)	-5
Realized gain on derivative financial instruments [1]	**7,319**	2,646	177	**20,291**	1,900	968
Royalties	**(10,235)**	(12,899)	-21	**(34,946)**	(45,185)	-23
Production expense	**(37,135)**	(30,533)	22	**(101,806)**	(92,120)	11
Transportation expense	**(13,123)**	(10,046)	31	**(37,081)**	(30,427)	22
Operating Income [2]	**50,930**	53,324	-4	**203,409**	164,476	24
Financing expense [3]	**(3,280)**	(1,078)	204	**(7,982)**	(2,217)	260
G&A expense	**(3,119)**	(3,245)	-4	**(10,503)**	(9,786)	7
Gain (loss) on foreign exchange	**111**	(67)	-266	**(244)**	(15)	1,527
Other income	**6**	5	20	**28**	114	-75
Adjusted funds from operations [2]	**44,648**	48,939	-9	**184,708**	152,572	21
Basic ($ per common share) [4]	**0.22**	0.25	-12	**0.93**	0.78	19
Diluted ($ per common share) [4]	**0.22**	0.24	-8	**0.92**	0.77	19

	Three months ended September 30			Nine months ended September 30		
($ per BOE)	**2025**	2024	%	**2025**	2024	%
Petroleum and natural gas sales	**31.82**	36.22	-12	**34.85**	39.17	-11
Cost of purchases	**(1.81)**	(1.25)	45	**(1.17)**	(1.49)	-21
Realized gain on derivative financial instruments [1]	**2.11**	0.89	137	**1.92**	0.21	814
Royalties	**(2.95)**	(4.33)	-32	**(3.30)**	(5.15)	-36
Production expense	**(10.70)**	(10.25)	4	**(9.61)**	(10.51)	-9
Transportation expense	**(3.78)**	(3.37)	12	**(3.50)**	(3.47)	1
Operating Netback [2]	**14.69**	17.91	-18	**19.19**	18.76	2
Financing expense [3]	**(0.95)**	(0.36)	164	**(0.75)**	(0.25)	200
G&A expense	**(0.90)**	(1.09)	-17	**(0.99)**	(1.12)	-12
Gain (loss) on foreign exchange	**0.03**	(0.02)	-250	**(0.02)**	-	-
Other income	**-**	-	-	**-**	0.01	-100
Adjusted funds from operations [2]	**12.87**	16.44	-22	**17.43**	17.40	-

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

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

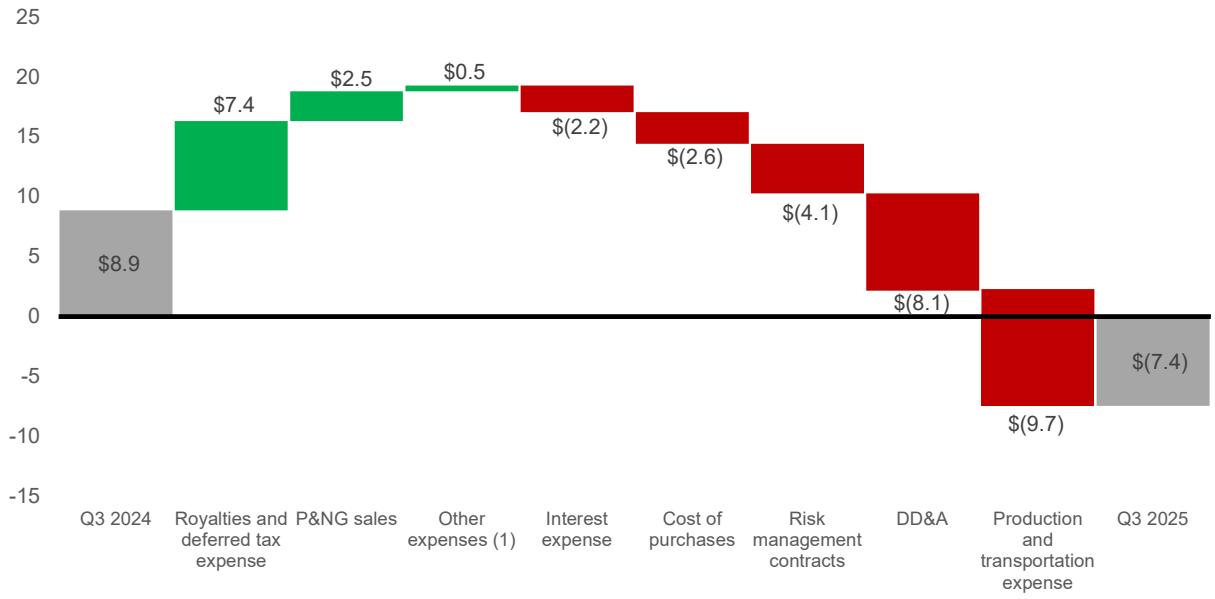
(3) Excludes non-cash accretion of decommissioning obligations.

(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.

During the three months ended September 30, 2025, adjusted funds from operations of $44.6 million ($0.22 per common share, diluted) decreased by 9% from $48.9 million ($0.24 per share, diluted) during the third quarter ended September 30, 2024. The decrease in adjusted funds from operations is primarily attributed to an increase in cost of production, transportation, and financing expenses; offset by lower royalties and a realized gain on financial instruments.

During the nine months ended September 30, 2025, adjusted funds from operations of $184.7 million ($0.92 per common share, diluted) increased by 21% from $152.6 million ($0.77 per share, diluted) compared to the nine months ended September 30, 2024. The increase in adjusted funds from operations is primarily attributed to an increase in petroleum and natural gas sales, a realized gain on financial instruments, and lower royalties partially offset by higher production, transportation, and financing expenses.

NET INCOME (LOSS) AND COMPREHENSIVE NET INCOME (LOSS)



(1) The change net income due to other expenses includes general and administrative expenses, share based compensation expense, foreign exchange gain (loss), and other income (expenses).

	Three months ended September 30			Nine months ended September 30		
(CA$ thousands, except as otherwise indicated)	**2025**	2024	%	**2025**	2024	%
Net income (loss) and comprehensive net income (loss)	**(7,446)**	8,871	-184	**43,994**	31,623	39
$ per common share, basic	**(0.04)**	0.05	-180	**0.22**	0.16	38
$ per common share, diluted (1)	**(0.04)**	0.04	-200	**0.22**	0.16	38
$ per BOE	**(2.15)**	2.99	-172	**4.15**	3.60	15
Wtd avg. shares outstanding, basic (000s)	**199,274**	196,084	2	**198,610**	195,437	2
Wtd avg. shares outstanding, diluted (000s) (1)	**202,714**	200,015	1	**201,734**	199,257	1

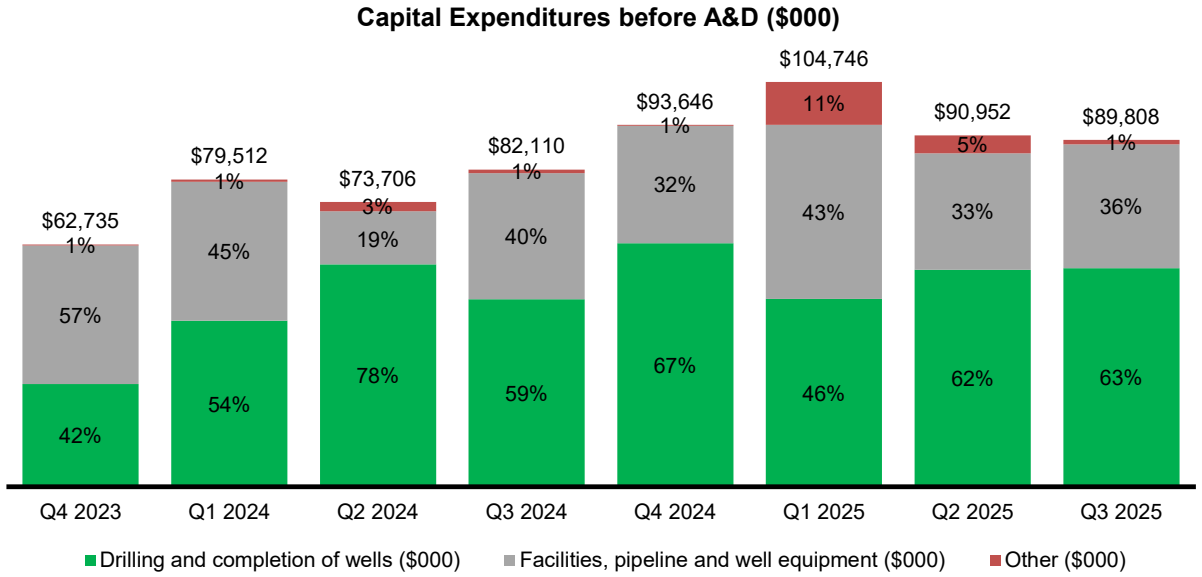
(1) The Company uses the treasury stock method to determine the dilutive effect of stock options, RSUs, and PSUs. Under this method, only "in-the-money" dilutive instruments impact the calculation of diluted net income per common share.

Kelt reported a net loss of $7.4 million ($0.04 per common share, diluted) for the three months ended September 30,

2025, compared to net income of $8.9 million ($0.04 per common share, diluted) in the comparative period of 2024. Kelt reported a net income of $44.0 million ($0.22 per common share, diluted) for the nine months ended September 30, 2025, compared to a net income of $31.6 million ($0.16 per common share, diluted) in the same period of 2024.

The decrease in net income for the three months ended September 30, 2025 was primarily driven by a lower adjusted funds from operations in 2025 plus a higher depletion and depreciation expense in 2025. The increase in net income for the nine months ended September 30, 2025 was primarily driven by a higher adjusted funds from operations in 2025 which was partially offset by higher depletion and depreciation expense 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 September 30			Nine months ended September 30		
(CA$ thousands)	**2025**	2024	%	**2025**	2024	%
Capital expenditures:						
Lease acquisition and retention	**977**	115	750	**2,032**	2,252	-10
Geological and geophysical	**(3)**	85	-104	**13,905**	587	2,269
Drilling and completion of wells	**56,572**	48,529	17	**161,397**	149,080	8
Facilities, pipeline and well equipment	**32,028**	32,630	-2	**107,248**	82,344	30
Corporate assets	**234**	751	-69	**924**	1,065	-13
Capital expenditures, before A&D [(1)]	**89,808**	82,110	9	**285,506**	235,328	21
Property acquisitions	**312**	161	94	**312**	1,316	-76
Property dispositions	**(319)**	(161)	98	**(319)**	(543)	-41
Capital expenditures, net of A&D [(1)]	**89,801**	82,110	9	**285,499**	236,101	21

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

Capital expenditures, before A&D, increased 9% in the third quarter of 2025 compared to the third quarter in 2024 and increased 21% from the nine months ending September 30, 2025 versus the comparable period in 2024.

In the third quarter of 2025, drilling and completion costs of $56.6 million included the drilling of 5.0 net wells and the

completion of 10.0 net wells. Kelt's facility, pipeline and well equipment expenditures were $32.0 million in the third quarter of 2025.

For the nine months ended September 30, 2025 drilling and completion costs of $161.4 million included the drilling of 25.6 net wells and the completion of 24.6 net wells in Alberta. Kelt's facility, pipeline and well equipment expenditures was $107.3 million in the nine months ended September 30, 2025. The Company also incurred $14.0 million in 2025 on a 3-D seismic program at its Oak property.

DRILLING

	Three months ended September 30			Nine months ended September 30		
Gross wells	**2025**	2024	%	**2025**	2024	%
Drilling	**5**	11	-55	**30**	31	-3
Completion	**10**	8	25	**29**	22	32
Service	**-**	-	-	**1**	1	-
Net wells						
Drilling	**5.0**	10.2	-51	**25.6**	28.3	-10
Completion	**10.0**	7.2	39	**24.6**	19.3	27
Service	**-**	-	-	**1.0**	1.0	-

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.

At September, 30, 2025 $186.0 million was drawn under the Company's credit facility, with outstanding letters of credit of $2.4 million. 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.

Subsequent to the third quarter of 2025, the Company and its lenders increased the amount available under the credit facility to $300.0 million from a previous available amount of $250.0 million.

Repayments of principal are not required provided that the borrowings under the facility do not exceed the authorized borrowing amount. The borrowing base is subject to semi-annual reviews with the next scheduled review to take place prior to November 30, 2025. 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 as otherwise indicated)	**September 30, 2025**	December 31, 2024
Bank debt	**186,000**	108,993
Accounts payable and accrued liabilities	**89,308**	80,463
Cash and cash equivalents	**(1,336)**	(228)
Accounts receivable and accrued sales	**(46,198)**	(60,236)
Prepaid expenses and deposits	**(4,090)**	(4,109)
Net debt [(1)]	**223,684**	124,883
Adjusted funds from operations [(1)(2)]	**254,114**	221,978
Net debt to adjusted funds from operations ratio [(1)]	**0.9**	0.6

(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 September 30, 2025:

(CA$ thousands)	Within 1 Year	1 to 5 Years	More than 5 Years	**Total**
Accounts payable and accrued liabilities	89,308	-	-	**89,308**
Derivative financial instruments	4,470	83	-	**4,553**
Lease liability	633	424	-	**1,057**
Bank debt and estimated interest [(1)]	11,346	186,000	-	**197,346**
Total	**105,757**	**186,507**	**-**	**292,264**

(1) Estimated interest for future years related to the credit facility was calculated using the weighted average interest rate of 6.1% for the nine months ended September 30, 2025, applied to the principal balance outstanding as at that date.

COMMITMENTS

As of September 30, 2025, the Company is committed to future payments under the following agreements:

(CA$ thousands)	2025	2026	2027	2028	2029	Thereafter
Firm processing commitments	13,527	72,132	73,553	75,558	74,467	416,270
Firm transportation commitments	10,862	47,682	47,733	52,671	41,954	151,719
Total annual commitments	**24,389**	**119,814**	**121,286**	**128,229**	**116,421**	**567,989**

SHARE INFORMATION

The Company is authorized to issue an unlimited number of common shares and an unlimited number of preferred shares. As at September 30, 2025 there were 199.4 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 third quarter of 2025, 23.3 million common shares traded on the TSX at a weighted average price of $7.05 per common share compared to 24.3 million common shares traded on the TSX at a weighted average price of $6.12 per common share in the third quarter of 2024. Kelt's closing share price was $6.88 per common share on September 30, 2025, compared to the volume weighted average trading price of $6.14 per common share during the year ended December 31, 2024.

As at September 30, 2025, officers, directors, and employees have been granted options to purchase 8.0 million common shares of the Company at an average exercise price of $4.93 per common share. In addition, there are 1.7

million RSUs and 0.7 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 September 30, 2025 and 2024.

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)	**Q3 2025**	Q2 2025	Q1 2025	Q4 2024	Q3 2024	Q2 2024	Q1 2024	Q4 2023
Revenue	**110,377**	106,946	127,262	115,512	94,985	91,849	111,349	111,062
Cash provided by operating activities	**53,827**	60,696	86,929	48,067	52,166	46,419	62,493	62,477
Adjusted funds from operations [(1)]	**44,648**	61,846	78,214	69,406	48,939	42,457	61,176	66,618
Per share – basic ($/common share) [(1)]	**0.22**	0.31	0.40	0.35	0.25	0.22	0.31	0.34
Per share – diluted ($/common share) [(1)]	**0.22**	0.31	0.39	0.35	0.24	0.21	0.31	0.33
Net income (loss) and comprehensive income (loss)	**(7,446)**	32,461	18,979	13,800	8,871	10,905	11,847	23,729
Per share – basic ($/common share)	**(0.04)**	0.16	0.10	0.07	0.05	0.06	0.06	0.12
Per share – diluted ($/common share)	**(0.04)**	0.16	0.09	0.07	0.04	0.05	0.06	0.12
Capital expenditures, net of A&D [(1)]	**89,801**	90,952	104,746	97,046	82,110	73,810	80,181	62,695
Total assets	**1,594,538**	1,562,599	1,512,752	1,450,679	1,378,621	1,328,148	1,282,456	1,260,292
Bank debt	**186,000**	151,432	102,766	108,993	45,428	12,611	-	-
Net debt [(1)]	**223,684**	178,170	150,024	124,883	95,889	63,084	31,961	12,997
Shareholders' equity	**1,117,150**	1,121,679	1,086,264	1,063,004	1,046,142	1,033,204	1,018,604	1,003,663
Average daily production (BOE/d)	**37,710**	38,734	40,015	36,450	32,378	30,693	32,910	32,344
Combined net realized price ($/BOE) [(1)(2)]	**32.12**	34.00	40.53	37.01	35.86	37.18	40.59	41.78
Operating netback ($/BOE) [(1)]	**14.69**	19.50	23.25	21.80	17.91	16.55	21.69	23.49
Operating netback % of combined net realized price [(2)]	**46%**	57%	57%	59%	50%	45%	53%	56%

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

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

In 2024, crude oil demand and supply remained relatively balanced, resulting in a range bound crude oil benchmark price.

North American benchmark natural gas prices at the start of 2024 were impacted by higher than historical average inventory levels due to a warmer than average 2023/2024 winter and high North American natural gas production. A colder than average 2024/2025 winter, which, combined with additional LNG export capacity in the US coming on-stream in 2025, resulted in rising US natural gas prices at the beginning of 2025. However the rising prices were tempered due to an increase in US natural gas production in 2025 which resulted in inventory levels rising to above the 5-year average by Q3 2025.

Canadian benchmark natural gas prices in 2024 were lower than historical norms due to elevated natural gas inventory levels. In the first half of 2025, AECO prices rose due to a colder than average 2024/2025 winter, however prices for both AECO and Station 2 decreased in the third quarter of 2025 due to a continued lack of egress to other markets, an increase in Canadian natural gas production and pipeline maintenance activities that occurred in the summer of 2025.

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 2025 guidance from August 7, 2025 to incorporate revised commodity price assumptions and first quarter results.

(CA$ millions, except as otherwise indicated)	Current 2025 Budget	Previous 2025 Guidance (August 7, 2025)	% Change to Current 2025 Budget
Average Production [2]			
Oil and NGLs (bbls/d)	14,600 – 15,400	15,700 – 17,200	-9
Gas (MMcf/d)	152.4 – 153.6	157.8 – 166.8	-6
Combined (BOE/d)	40,000 – 41,000	42,000 – 45,000	-7
Forecasted Average Commodity Prices			
WTI oil price (US$/bbl)	66.00	66.50	-1
Canadian Light Sweet ($/bbl)	87.54	87.58	-
NYMEX natural gas price (US$/MMBtu)	3.50	3.80	-8
AECO natural gas price ($/GJ)	1.73	2.23	-22
Station 2 natural gas price ($/GJ)	1.19	1.57	-24
Average Exchange Rate (US$/CA$)	0.716	0.722	-1
Capital Expenditures, net of A&D [1]	325.0	325.0	-
Petroleum and natural gas sales	536.1	596.9	-10
Adjusted funds from operations [1]	280.0	325.0	-14
Per common share, diluted [1]	1.38	1.60	-14
Net debt [1]	170.0	126.0	35
Weighted average common shares outstanding (millions) [1]	198.8	198.8	-

(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 2025 is estimated to be approximately 40,000 to 41,000 BOE per day, a decrease of 7% from the previous 2025 forecasted production. The decrease in forecasted production is primarily a result of a delay in the start-up of the third-party Albright Sulphur Recovery Gas Plant at Wembley/Pipestone. Kelt has commenced delivering gas to the Albright Sulphur Recovery Gas Plant during the fourth quarter of 2025. As a result, Kelt expects to show significant production growth in the fourth quarter of 2025 when compared to third quarter 2025 results.

WTI crude oil prices are forecasted to average US$66.00 per barrel, a decrease of 1% from the Company's previous guidance. Forecasted AECO natural gas prices decreased by 22% to average $1.73 per GJ and forecasted Station 2 natural gas prices decreased by 24% to average $1.19 per GJ in 2025.

After giving effect to the changes in production and commodity price assumptions, Kelt is forecasting 2025 adjusted funds from operations to be $280.0 million, a decrease of 14% from the previous guidance, capital expenditures of $325.0 million, consistent with the previous guidance, and net debt as of December 31, 2025 of $170.0 million, an increase of 35% from the previous guidance.

A 10% increase/decrease in the Company's forecasted average oil/NGLs price for the three months remaining in 2025 would increase/decrease forecasted adjusted funds from operations in 2025 by approximately $4.6 million. A 10% increase/decrease in the Company's average natural gas price forecasted for the three months remaining in 2025 would increase/decrease adjusted funds from operations in 2025 by approximately $4.0 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, 2024 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 July 1, 2025 to September 30, 2025 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 September 30		Nine months ended September 30	
(CA$ thousands)	**2025**	2024	**2025**	2024
Cash used in investing activities	**87,954**	86,896	**281,290**	224,507
Change in non-cash investing working capital	**1,847**	(4,786)	**4,209**	11,594
Capital expenditures, net of A&D	**89,801**	82,110	**285,499**	236,101
Property acquisitions	**(40)**	-	**(40)**	(773)
Property dispositions	**47**	-	**47**	-
Capital expenditures, before A&D	**89,808**	82,110	**285,506**	235,328

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 September 30		Nine months ended September 30	
(CA$ thousands)	**2025**	2024	**2025**	2024
Cash provided by operating activities	**53,827**	52,166	**201,452**	161,078
Change in non-cash working capital	**(10,365)**	(4,407)	**(18,693)**	(11,674)
Funds from operations	**43,462**	47,759	**182,759**	149,404
Settlement of decommissioning obligations	**1,186**	1,180	**1,949**	3,168
Adjusted funds from operations	**44,648**	48,939	**184,708**	152,572

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 FINANICAL 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, 2024, dated March 12, 2025.

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 12, 2025 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 2025. 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 12, 2025 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.
CONSOLIDATED STATEMENTS OF FINANCIAL POSITION
[UNAUDITED]

(CA$ thousands)	[Notes]	**September 30, 2025**	December 31, 2024
ASSETS			
Current assets			
Cash and cash equivalents		**1,336**	228
Accounts receivable and accrued sales	[9]	**46,198**	60,236
Prepaid expenses and deposits		**4,090**	4,109
Derivative financial instruments	[9]	**16,328**	6,709
Total current assets		**67,952**	71,282
Exploration and evaluation assets	[4]	**32,176**	18,092
Property, plant and equipment	[5]	**1,494,410**	1,361,305
Total assets		**1,594,538**	1,450,679
LIABILITIES			
Current liabilities			
Accounts payable and accrued liabilities	[9]	**89,308**	80,463
Derivative financial instruments	[9]	**4,470**	7,936
Decommissioning obligations	[7]	**4,203**	3,552
Lease liability		**633**	1,655
Total current liabilities		**98,614**	93,606
Bank debt	[6]	**186,000**	108,993
Derivative financial instruments	[9]	**83**	-
Decommissioning obligations	[7]	**90,235**	97,423
Lease liability		**424**	419
Deferred income tax liability		**102,032**	87,234
Total liabilities		**477,388**	387,675
SHAREHOLDERS' EQUITY			
Shareholders' capital	[8]	**1,193,685**	1,184,065
Contributed surplus and reserve		**(6,160)**	(6,692)
Deficit		**(70,375)**	(114,369)
Total shareholders' equity		**1,117,150**	1,063,004
Total liabilities and shareholders' equity		**1,594,538**	1,450,679

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.
CONSOLIDATED STATEMENTS OF NET INCOME (LOSS) AND COMPREHENSIVE NET INCOME (LOSS)
[UNAUDITED]

		Three months ended September 30		Nine months ended September 30	
(CA$ thousands, except per share amounts)	[Notes]	**2025**	2024	**2025**	2024
Revenue					
Petroleum and natural gas sales	[10]	**110,377**	107,884	**369,296**	343,368
Royalties		**(10,235)**	(12,899)	**(34,946)**	(45,185)
		100,142	94,985	**334,350**	298,183
Expenses					
Production		**37,135**	30,533	**101,806**	92,120
Transportation		**13,123**	10,046	**37,081**	30,427
Cost of purchases		**6,273**	3,728	**12,345**	13,060
Financing	[11]	**4,104**	1,895	**10,413**	4,490
General and administrative		**3,119**	3,245	**10,503**	9,786
Share based compensation	[8]	**2,052**	2,321	**5,796**	6,497
Exploration and evaluation	[4]	**-**	-	**49**	145
Depletion and depreciation	[5]	**43,309**	35,187	**130,506**	100,955
		109,115	86,955	**308,499**	257,480
Gain (loss) on derivative financial instruments	[9]	**(236)**	3,898	**33,293**	3,623
Gain (loss) on foreign exchange		**111**	(67)	**(244)**	(15)
Other income (expenses)		**(130)**	5	**(108)**	114
Net income (loss) before taxes		**(9,228)**	11,866	**58,792**	44,425
Deferred income tax recovery (expense)		**1,782**	(2,995)	**(14,798)**	(12,802)
Net income (loss) and comprehensive net income (loss)		**(7,446)**	8,871	**43,994**	31,623
Net income (loss) per common share					
Basic		**(0.04)**	0.05	**0.22**	0.16
Diluted		**(0.04)**	0.04	**0.22**	0.16

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

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

(CA$ thousands)	[Notes]	Shareholders' capital: Number of Shares (000s)	Shareholders' capital: Amount ($ thousands)	Contributed surplus and reserve	Retained earnings (deficit)	Total shareholders' equity
Balance at December 31, 2024		196,756	1,184,065	(6,692)	(114,369)	1,063,004
Net income and comprehensive net income		-	-	-	43,994	43,994
Exercise of stock options	[8]	1,931	6,442	(2,086)	-	4,356
Vesting of restricted share units	[8]	671	3,178	(3,178)	-	-
Share based compensation	[8]	-	-	5,796	-	5,796
Balance at September 30, 2025		**199,358**	**1,193,685**	**(6,160)**	**(70,375)**	**1,117,150**

(CA$ thousands)	[Notes]	Shareholders' capital: Number of Shares (000s)	Shareholders' capital: Amount ($ thousands)	Contributed surplus and reserve	Retained earnings (deficit)	Total shareholders' equity
Balance at December 31, 2023		194,506	1,175,465	(12,010)	(159,792)	1,003,663
Net income and comprehensive net income		-	-	-	31,623	31,623
Exercise of stock options	[8]	1,463	6,127	(1,768)	-	4,359
Vesting of restricted share units	[8]	408	1,393	(1,393)	-	-
Share based compensation	[8]	-	-	6,497	-	6,497
Balance at September 30, 2024		196,377	1,182,985	(8,674)	(128,169)	1,046,142

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

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

		Three months ended September 30		Nine months ended September 30	
(CA$ thousands)	[Notes]	**2025**	2024	**2025**	2024
Operating activities					
Net income (loss) and comprehensive net income (loss)		**(7,446)**	8,871	**43,994**	31,623
Items not affecting cash:					
Accretion of decommissioning obligations	[11]	**824**	817	**2,431**	2,273
Share based compensation		**2,052**	2,321	**5,796**	6,497
Exploration and evaluation		**-**	-	**49**	145
Depletion and depreciation		**43,309**	35,187	**130,506**	100,955
Unrealized (gain) loss on derivative financial instruments	[9]	**7,555**	(1,252)	**(13,002)**	(1,723)
Other expenses		**136**	-	**136**	-
Deferred income tax expense (recovery)		**(1,782)**	2,995	**14,798**	12,802
Settlement of decommissioning obligations	[7]	**(1,186)**	(1,180)	**(1,949)**	(3,168)
Change in non-cash operating working capital	[13]	**10,365**	4,407	**18,693**	11,674
Cash provided by operating activities		**53,827**	52,166	**201,452**	161,078
Financing activities					
Increase in bank debt		**34,568**	32,817	**77,007**	45,428
Proceeds on exercise of stock options	[8]	**865**	1,746	**4,356**	4,359
Repayment of lease liability principal		**(40)**	(200)	**(417)**	(554)
Cash provided by financing activities		**35,393**	34,363	**80,946**	49,233
Investing activities					
Exploration and evaluation assets	[4]	**(133)**	(200)	**(15,096)**	(2,844)
Property, plant and equipment	[5]	**(89,675)**	(81,910)	**(270,410)**	(232,484)
Property acquisitions		**(40)**	-	**(40)**	(773)
Property dispositions		**47**	-	**47**	-
Change in non-cash investing working capital	[13]	**1,847**	(4,786)	**4,209**	11,594
Cash used in investing activities		**(87,954)**	(86,896)	**(281,290)**	(224,507)
Net change in cash and cash equivalents		**1,266**	(367)	**1,108**	(14,196)
Cash and cash equivalents, beginning of period		**70**	511	**228**	14,340
Cash and cash equivalents, end of period		**1,336**	144	**1,336**	144

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

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

1. DESCRIPTION OF THE BUSINESS

Kelt Exploration Ltd. ("Kelt" or the "Company") is an oil and gas company based in Calgary, Alberta, focused on the exploration, development and production of crude oil and natural gas resources, primarily in northwestern Alberta and northeastern British Columbia. 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 November 12, 2025.

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, 2024.

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, 2024 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.

In April 2025, the Company approved a Performance Share Unit ("PSU") plan, as a new component of its long-term incentive compensation strategy. The fair value method of accounting is used for its PSU Plan, with the fair value estimated on the date of grant using the Black-Scholes option pricing model based on the prevailing Kelt share price at the date granted.

PSU's are granted with a performance multiplier. This multiplier, ranging from zero to two, will be applied at vesting and is dependent on the performance of the Company relative to pre-defined corporate performance measures for a particular period and the Board of Directors' discretion. Judgment is required to estimate the multiplier, the rate of forfeiture, and the number of performance share units that will ultimately vest.

3. MATERIAL ACCOUNTING POLICIES

The material accounting policies applied by the Company are described in note 3 of the December 31, 2024 audited annual consolidated financial statements. These condensed consolidated interim financial statements as at September 30, 2025 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, 2024.

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. 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 are required to be adopted retrospectively with early adoption permitted. The Company is assessing the impact of IFRS 18 on the Company's consolidated financial statements.

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 does not anticipate significant impacts to the Company's consolidated financial statements.

4. EXPLORATION AND EVALUATION ASSETS

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

	September 30, 2025	December 31, 2024
Balance, beginning of period	**18,092**	17,162
Additions	**15,096**	2,961
Transfers to property, plant and equipment	**(963)**	(1,817)
Exploration and evaluation expense	**(49)**	(214)
Balance, end of period	**32,176**	18,092

5. PROPERTY, PLANT AND EQUIPMENT

Net carrying value	**September 30, 2025**	December 31, 2024
Development and production ("D&P") assets	**1,492,618**	1,358,231
Right-of-use ("ROU") assets	**1,027**	2,227
Corporate assets	**765**	847
Total net carrying value of property, plant and equipment	**1,494,410**	1,361,305

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

Property, plant and equipment, at cost	D&P Assets	Corporate Assets	ROU Assets	Total PP&E
Balance at December 31, 2023	2,057,993	7,908	4,617	2,070,518
Additions	324,190	1,140	1,967	327,297
Transfers from ROU assets	683	-	(683)	-
Property acquisitions	5,115	-	-	5,115
Property dispositions	(705)	-	-	(705)
Change in decommissioning obligations	2,777	-	-	2,777
Transfers from E&E	1,817	-	-	1,817
Balance at December 31, 2024	**2,391,870**	**9,048**	**5,901**	**2,406,819**
Additions	**268,198**	**924**	**1,210**	**270,332**
Transfers from ROU assets	**1,288**	**-**	**(1,288)**	**-**
Property acquisitions	**573**	**-**	**-**	**573**
Property disposition and derecognition (1)	**(460)**	**-**	**(4,544)**	**(5,004)**
Change in decommissioning obligations	**(7,139)**	**-**	**-**	**(7,139)**
Transfers from E&E	**963**	**-**	**-**	**963**
Balance at September 30, 2025	**2,655,293**	**9,972**	**1,279**	**2,666,544**

Accumulated depletion and depreciation	D&P Assets	Corporate Assets	ROU Assets	Total PP&E
Balance at December 31, 2023	893,745	7,333	3,028	904,106
Depletion and depreciation expense	139,894	868	732	141,494
Property disposition and derecognition	-	-	(86)	(86)
Balance at December 31, 2024	**1,033,639**	**8,201**	**3,674**	**1,045,514**
Depletion and depreciation expense	**129,036**	**1,006**	**464**	**130,506**
Property disposition and derecognition (1)	**-**	**-**	**(3,886)**	**(3,886)**
Balance at September 30, 2025	**1,162,675**	**9,207**	**252**	**1,172,134**

(1) In the third quarter of 2025 the Company derecognized $3.1 million of cost and accumulated depreciation related to ROU Assets where the lease term had ended.

Future capital costs required to develop proved reserves in the amount of $1,747.9 million (December 31, 2024 – $1,839.9 million) are included in the depletion calculation for development and production assets.

Based on its assessment as of September 30, 2025, the Company determined that there were no indicators of impairment.

6. BANK DEBT

At September, 30, 2025 $186.0 million was drawn under the Company's credit facility, with outstanding letters of credit of $2.4 million. Subsequent to the third quarter of 2025, the Company and its lenders increased the amount available under the credit facility to $300.0 million from a previous available amount of $250.0 million.

Repayments of principal are not required provided that the borrowings under the credit facility do not exceed the authorized borrowing amount. The borrowing base is subject to semi-annual reviews with the next scheduled review to take place prior to November 30, 2025. 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:

	September 30, 2025	December 31, 2024
Balance, beginning of period	**100,975**	99,915
Obligations incurred	**1,523**	3,247
Obligations acquired	**261**	299
Obligations disposed	**(141)**	(62)
Obligations settled	**(1,949)**	(5,036)
Changes in discount rate	**(7,815)**	(6,954)
Revisions to estimates	**(847)**	6,484
Accretion expense	**2,431**	3,082
Balance, end of period	**94,438**	100,975
Decommissioning obligations – current	**4,203**	3,552
Decommissioning obligations – non-current	**90,235**	97,423
Key assumptions		
Risk free rate	**3.7%**	3.3%
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 September 30, 2025 the undiscounted amount of the estimated cash flows required to settle the obligation is $146.3 million (December 31, 2024 – $144.3 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 $263.9 million at September 30, 2025 (December 31, 2024 – $274.4 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 (Loss) and Comprehensive Net Income (Loss) (note 11).

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 September 30, 2025 (December 31, 2024 – nil).

	Number of Shares (000s)	Amount ($ thousands)
Balance at December 31, 2023	194,506	1,175,465
Issued on exercise of stock options	1,836	5,072
Transfer from contributed surplus on exercise of stock options	-	2,103
Released upon vesting of restricted share units	414	1,425
Balance at December 31, 2024	**196,756**	**1,184,065**
Issued on exercise of stock options	**1,931**	**4,356**
Transfer from contributed surplus on exercise of stock options	**-**	**2,086**
Released upon vesting of restricted share units	**671**	**3,178**
Balance at September 30, 2025	**199,358**	**1,193,685**

Stock options

The Incentive Stock Option Plan (the "Option Plan") includes stock options which may be granted to directors, officers, employees and certain consultants. The stock options granted pursuant to the Option Plan are to be settled through the issuance of new common shares of the Company which vest in equal tranches over a three year period and have a maximum term of five years to expiry. In April 2025 the Company discontinued the Option Plan, after which no further stock options will be granted.

The following table summarizes the change in stock options outstanding:

	Number of Options (000s)	Average Exercise Price ($/share)
Balance at December 31, 2023	9,697	3.74
Granted	2,315	6.09
Exercised [(1)]	(1,836)	2.76
Forfeited	(205)	6.19
Balance at December 31, 2024	**9,971**	**4.41**
Granted	**35**	**5.78**
Exercised [(1)]	**(1,931)**	**2.26**
Forfeited	**(96)**	**5.64**
Balance at September 30, 2025	**7,979**	**4.93**

(1) The weighted average share price on the date stock options were exercised during the nine months ended September 30, 2025 was $7.10 per common share ($6.19 per common share on average during the year ended December 31, 2024).

The following table summarizes information regarding stock options outstanding at September 30, 2025:

Range of exercise prices per common share	Number of options outstanding (000s)	Weighted average remaining term (years)	Weighted average exercise price for options outstanding ($/share)	Number of options exercisable (000s)	Weighted average exercise price for options exercisable ($/share)
$0.00 to $2.00	15	0.1	1.59	15	1.59
$2.01 to $4.00	1,614	0.5	2.75	1,614	2.75
$4.01 to $6.00	4,002	1.9	5.08	3,413	5.14
$6.01 to $8.00	2,348	3.5	6.19	781	6.20
Total	**7,979**	**2.0**	**4.93**	**5,823**	**4.61**

Restricted share units

The restricted share unit plan includes restricted share units ("RSUs") that may be granted to officers 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, 2023	1,742
Granted	558
Released upon vesting	(414)
Forfeited	(58)
Balance at December 31, 2024	**1,828**
Granted	**610**
Released upon vesting	**(671)**
Forfeited	**(45)**
Balance at September 30, 2025	**1,722**

Performance share units

In April 2025, the Company's shareholders approved a PSU plan, as a component of its long-term incentive compensation strategy, designed to align the interests of executives and employees with those of shareholders. The approval of the PSU plan, was made in combination with discontinuing the Company's Stock Option Plan.

The 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	**751**
Released upon vesting	**-**
Forfeited	**(4)**
Balance at September 30, 2025	**747**

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 September 30		Nine months ended September 30	
	2025	2024	**2025**	2024
Stock options	**616**	1,367	**2,526**	3,890
Restricted share units	**968**	954	**2,571**	2,607
Performance share units	**468**	-	**699**	-
Total share based compensation expense	**2,052**	2,321	**5,796**	6,497

Weighted average number of common shares

The table below summarizes the weighted average number of common shares outstanding:

	Three months ended September 30		Nine months ended September 30	
(000s of common shares)	**2025**	2024	**2025**	2024
Weighted average common shares outstanding, basic	**199,274**	196,084	**198,610**	195,437
Effect of stock options, RSUs, and PSUs	**3,440**	3,931	**3,124**	3,820
Weighted average common shares outstanding, diluted	**202,714**	200,015	**201,734**	199,257

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. Accordingly, in computing the diluted loss per common share for the three months ended September 30, 2025, the Company excluded the effect of stock options, RSUs, and PSUs as they were antidilutive.

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 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 September 30, 2025, 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 option [2]	500 bbl/d	Settles monthly if WTI price > USD$70.50/bbl	Oct 25 – Dec 25
WTI fixed price swap	2,000 bbl/d	USD$69.6575/bbl	Oct 25 – Dec 25
WTI fixed price swap [3]	2,500 bbl/d	CAD $89.68/bbl	Oct 25 – Dec 25
WTI fixed price swap [4,5,6,7]	4,500 bbl/d	CAD $90.49/bbl	Jan 26 – Mar 26
WTI fixed price swap [5,6,7]	4,000 bbl/d	CAD $90.20/bbl	Apr 26 – Jun 26

(1) West Texas Intermediate ("WTI")

(2) The WTI option is settled monthly at USD$70.50/bbl if the average WTI price is above USD$70.50/bbl.

(3) Includes a fixed price WTI oil swap option to sell 500 bbl/d for Jan-Mar 2026 at CAD$94.30/bbl exercisable on December 31, 2025.

(4) Includes a fixed price WTI oil swap option to sell 500 bbl/d for Apr-Jun 2026 at CAD$92.85/bbl exercisable on March 31, 2026.

(5) Includes a fixed price WTI oil swap option to sell 500 bbl/d for Jul-Dec 2026 at CAD$91.90/bbl exercisable on June 30, 2026.
(6) Includes a fixed price WTI oil swap option to sell 500 bbl/d for Jul-Dec 2026 at CAD$90.50/bbl exercisable on June 30, 2026.
(7) Includes a fixed price WTI oil swap option to sell 500 bbl/d for Jul-Dec 2026 at CAD$90.63/bbl exercisable on June 30, 2026.

NGL derivative financial instrument swap

Contract Type	Notional Volume	Contract Price	Remaining Term
OPIS-Conway propane fixed price swap	250 bbl/d	USD$33.60/bbl	Oct 25 – Mar 26
OPIS-Conway propane basis swap	250 bbl/d	Monthly OPIS-Conway basis calculated at 46% of the floating monthly WTI price	Oct 25 – Mar 26

Natural gas derivative financial instrument

Contract Type (1)	Notional Volume	Contract Price $/MMBtu	Remaining Term
NYMEX swap	20,000 MMBtu/d	CAD$6.405/MMBtu	Oct 25 – Dec 25
NYMEX costless collar	10,000 MMBtu/d	Floor: CAD$5.00/MMBtu Ceiling: CAD$10.00/MMBtu	Oct 25 – Dec 25
NYMEX call	20,000 MMBtu/d	USD$5.50/MMBtu	Jan 26 – Dec 26
AECO 7A put	21,000 GJ/d	CAD$2.80/GJ	Jan 26 – Dec 26

(1) NYMEX Henry Hub ("NYMEX")

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 (1)	Remaining Term
Physical delivery	2,513 GJ/d	Floating AESO power pool price (CAD/MWh) divided by the Fixed Heat Rate of 17.95 GJ/MWh	Oct 25 – Dec 25
Physical delivery	7,349 GJ/d	Floating AESO power pool price (CAD/MWh) divided by the Fixed Heat Rate of 16.75 GJ/MWh	Jan 26 – Dec 26

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

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 bank debt balance as of September 30, 2025 of $186.0 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 September 30, 2025, 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 September 30, 2025, the following foreign exchange risk management contracts are outstanding:

Foreign exchange derivative financial instrument swap			
Contract Type	Notional Volume	Contract/Exercise Price	Remaining Term
CAD/USD swap	USD$6.0 million/month	$1.3795 CAD/USD	Oct 25 – Dec 25

Foreign exchange derivative financial instrument option				
Contract Type	Notional Volume	Contract/Exercise Price	Exercise/ expiration date	Term if exercised
Sold call option	USD$2.0 million/month	$1.3820 CAD/USD	Dec 31, 2025	Jan 26 – Dec 26
Sold call option	USD$2.0 million/month	$1.3800 CAD/USD	Dec 31, 2025	Jan 26 – Dec 26

Foreign exchange derivative financial instrument fade-in forward				
Contract Type	Notional Volume	Strike Rate	Fade-in Rate	Remaining Term
Average rate fade-in forward	USD$2.0 million/month	$1.3910 CAD/USD	$1.3295 CAD/USD	Jan 26 – Dec 26

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 September 30		Nine months ended September 30	
	2025	2024	**2025**	2024
Realized gain				
Derivative financial instrument contracts	**6,797**	2,646	**19,582**	1,900
Natural gas embedded derivative	**522**	-	**709**	-
Total realized gain	**7,319**	2,646	**20,291**	1,900
Unrealized gain (loss)				
Derivative financial instrument contracts	**(7,617)**	1,177	**12,470**	1,648
Natural gas embedded derivative	**62**	75	**532**	75
Total unrealized gain (loss)	**(7,555)**	1,252	**13,002**	1,723
Gain (loss) on derivative financial instruments	**(236)**	3,898	**33,293**	3,623

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 September 30, 2025, 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	**September 30, 2025**	December 31, 2024
Joint venture partners	**8,340**	5,893
Oil and gas marketers	**31,586**	45,708
GST input tax credits	**2,835**	4,036
Derivative financial instrument contracts	**2,919**	1,314
Other	**966**	3,638
Expected credit loss provision	**(448)**	(353)
Accounts receivable and accrued sales	**46,198**	60,236

During the quarter ended September 30, 2025, sales to three oil and gas marketers accounted for approximately 28% and 22% and 16% of total sales. During the year ended December 31, 2024, sales to two oil and gas marketers accounted for approximately 29% and 31% 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 sales.

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.

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. As of September 30, 2025, the collection risk on outstanding accounts receivable balances is considered low as 1.0% of the accounts receivable balance are outstanding for more than 90 days (December 31, 2024 – 1.0%).

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 September 30, 2025:

	Within 1 Year	1 to 5 Years	More than 5 Years	**Total**
Accounts payable and accrued liabilities	89,308	-	-	**89,308**
Derivative financial instruments	4,470	83	-	**4,553**
Lease liability	633	424	-	**1,057**
Bank debt and estimated interest [(1)]	11,346	186,000	-	**197,346**
Total	**105,757**	**186,507**	**-**	**292,264**

(1) Estimated interest for future years related to the credit facility was calculated using the weighted average interest rate of 6.1% for the nine months ended September 30, 2025, 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 increase or decrease capital expenditures including acquisitions and dispositions, issue new shares, issue new debt or repay existing debt, if any, according to market conditions in order to maintain 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 a standardized measure 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 September 30		Nine months ended September 30	
	2025	2024	**2025**	2024
Cash provided by operating activities	**53,827**	52,166	**201,452**	161,078
Change in non-cash working capital	**(10,365)**	(4,407)	**(18,693)**	(11,674)
Settlement of decommissioning obligations	**1,186**	1,180	**1,949**	3,168
Adjusted funds from operations	**44,648**	48,939	**184,708**	152,572

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

	September 30, 2025	December 31, 2024
Bank debt	**186,000**	108,993
Accounts payable and accrued liabilities	**89,308**	80,463
Cash and cash equivalents	**(1,336)**	(228)
Accounts receivable and accrued sales	**(46,198)**	(60,236)
Prepaid expenses and deposits	**(4,090)**	(4,109)
Net debt	**223,684**	124,883
Adjusted funds from operations [(1)]	**254,114**	221,978
Net debt to adjusted funds from operations ratio	**0.9**	0.6

(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 and 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 nine months ended September 30, 2025, natural gas sales in relation to these contracts was $10.2 million (September 30, 2024 – $11.3 million).

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

	Three months ended September 30		Nine months ended September 30	
	2025	2024	**2025**	2024
Oil production	**64,291**	75,953	**206,935**	218,093
Oil treating and other	**242**	242	**664**	718
NGLs production	**16,706**	13,877	**55,440**	46,077
Gas production	**21,899**	13,417	**91,948**	63,248
Gas processing and other	**816**	626	**1,684**	1,997
Marketing revenue	**6,423**	3,769	**12,625**	13,235
Total petroleum and natural gas sales	**110,377**	107,884	**369,296**	343,368

Included in accounts receivable at September 30, 2025 is $31.6 million (December 31, 2024 – $45.7 million) of accrued oil and gas sales related to September 2025 production.

11. FINANCING EXPENSES

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

	Three months ended September 30		Nine months ended September 30	
	2025	2024	**2025**	2024
Total interest expense	**3,280**	1,078	**7,982**	2,217
Accretion of decommissioning obligations	**824**	817	**2,431**	2,273
Total financing expense	**4,104**	1,895	**10,413**	4,490

12. COMMITMENTS

As of September 30, 2025, the Company is committed to future payments under the following agreements:

	2025	2026	2027	2028	2029	Thereafter
Firm processing commitments	13,527	72,132	73,553	75,558	74,467	416,270
Firm transportation commitment	10,862	47,682	47,733	52,671	41,954	151,719
Total annual commitments	**24,389**	**119,814**	**121,286**	**128,229**	**116,421**	**567,989**

13. SUPPLEMENTAL CASH FLOW INFORMATION

	Three months ended September 30		Nine months ended September 30	
Changes in non-cash working capital	**2025**	2024	**2025**	2024
Accounts receivable and accrued sales	**3,054**	1,725	**14,038**	12,121
Prepaid expenses and deposits	**2,113**	1,294	**19**	1,065
Accounts payable and accrued liabilities	**7,045**	(3,398)	**8,845**	10,082
Change in non-cash working capital	**12,212**	(379)	**22,902**	23,268
Relating to:				
Operating activities	**10,365**	4,407	**18,693**	11,674
Investing activities	**1,847**	(4,786)	**4,209**	11,594
Change in non-cash working capital	**12,212**	(379)	**22,902**	23,268

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

	Three months ended September 30		Nine months ended September 30	
Cash outlays in respect of interest and taxes	**2025**	2024	**2025**	2024
Interest and standby fees on bank debt	**2,936**	969	**7,335**	1,732
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
AECO	Alberta Energy Company "C" Meter Station of the NOVA Pipeline System
AT	After income taxes
bbls	barrels
bbls/d	barrels per day
bcf	billion cubic feet
BOE	barrels of oil equivalent
BOE/d	barrels of oil equivalent per day
BT	Before income taxes
CA$/CAD	Canadian Dollar
CGU	Cash Generating Unit
CORRA	Canadian Overnight Repo Rate Average
Dawn	Gas traded at Union Gas' Dawn Hub in Dawn Township, Ontario
E&E	Exploration and Evaluation
FDC	Future Development Capital
G&A	General and Administration
GJ	gigajoules
LNG	Liquefied Natural Gas
Mbbls	thousand barrels
MBOE	thousand barrels of oil equivalent
Mcf	thousand cubic feet
MD&A	Management's Discussion and Analysis
MMBtu	million British Thermal Units
MMcf	million cubic feet
MMcf/d	million cubic feet per day
MSW	Mountain sweet blend crude oil
NGLs	Natural Gas Liquids
NGX	Natural Gas Exchange Inc. (Canada)
NGTL	Nova Gas Transmission Line
NIT	NOVA Inventory Transfer ("AB-NIT"), being the reference price at the AECO Hub
NYMEX	New York Mercantile Exchange
Oil	Oil includes crude oil and field condensate
OPEC+	The Organization of Petroleum Exporting Countries along with 10 additional oil-producing countries
P&NG	Petroleum and Natural Gas
Q1	First quarter ended March 31st
Q2	Second quarter ended June 30th
Q3	Third quarter ended September 30th
Q4	Fourth quarter ended December 31st
SBC	Share Based Compensation
SEDAR+	System for Electronic Document Analysis and Retrieval
Station 2	Spectra Energy receipt location
TSX	Toronto Stock Exchange
US$/USD	United States dollar
WTI	West Texas Intermediate
YTD	Year to date
1P	Proved reserves
2P	Proved plus probable reserves

CONVERSION OF UNITS

Imperial = Metric

1 acre = 0.4 hectares

2.5 acres = 1 hectare

1 bbl = 0.159 cubic metres

6.29 bbls = 1 cubic metre

1 foot = 0.3048 metres

3.281 feet = 1 metre

1 Mcf = 28.2 cubic metres

0.035 Mcf = 1 cubic metre

1 mile = 1.61 kilometres

0.62 miles = 1 kilometre

1 MMBtu = 1.054 GJ

0.949 MMBtu = 1 GJ

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

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

CORPORATE INFORMATION

BOARD OF DIRECTORS

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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Vice President & Chief Financial Officer

Douglas J. Errico
Senior Vice President, Land and Corporate Development

Alan G. Franks
Vice President, Production

Bruce D. Gigg
Vice President, Engineering

David A. Gillis
Vice President, Finance

Douglas O. MacArthur
Vice President, Operations

Patrick W.G. Miles
Vice President, Exploration

Louise K. Lee
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