Management's discussion and analysis

The following is Management’s Discussion and Analysis (“MD&A”) of the financial performance and results of operations for Kiwetinohk Energy Corp. (“Kiwetinohk” or the “Company”) as at and for the three and six months ended June 30, 2025. Kiwetinohk’s common shares trade on the Toronto Stock Exchange under the symbol KEC.

This MD&A should be read in conjunction with the Company’s condensed consolidated interim financial statements as at and for the three and six months ended June 30, 2025 (the “Financial Statements”) and the audited financial statements as at and for the year ended December 31, 2024. Additional information is available on Kiwetinohk’s website at www.kiwetinohk.com and on the Company's profile on SEDAR+ at www.sedarplus.ca. The Financial Statements have been prepared in accordance with International Financial Reporting Standards (“IFRS”). This MD&A should also be read in conjunction with the Company’s disclosure under “Non-GAAP and Other Financial Measurements”, “Forward-Looking Statements”, “Future Oriented Financial Information”, “Abbreviations” and “Oil and Gas Advisories” below.

The reporting currency is the Canadian dollar, and all dollar amounts in this MD&A are stated in Canadian dollars unless otherwise indicated. This MD&A is dated July 29, 2025.

Overview of business

On June 23, 2025, the Company announced that it has launched a formal business strategy review to evaluate a range of potential value enhancing opportunities with a focus on the Company’s upstream assets and an orderly exit from its power business. A description of each business is provided below.

Upstream

The upstream business unit is involved in the development and production of petroleum and natural gas reserves in western Canada, with a focus on profitable early to mid-life liquids-rich natural gas properties that are expected to offer competitive economic resource potential. Upstream assets consist of high netback, liquids-rich natural gas production from significant Duvernay and Montney resources with development upside as well as owned infrastructure for processing the majority of the Company's production and egress pipeline capacity for natural gas production to points in Alberta and Chicago, Illinois, United States.

Power

The power business unit was advancing pre-construction development plans for an Alberta-based power generation project portfolio that includes solar, and natural gas-fired power generation as well as carbon capture and storage ("CCS") facilities.

Financial and operating highlights

	For the three months ended June 30, 2025	For the three months ended June 30, 2024	For the six months ended June 30, 2025	For the six months ended June 30, 2024
Production				
Oil & condensate (bbl/d)	**10,462**	7,598	**10,546**	8,025
NGLs (bbl/d)	**4,477**	3,817	**4,458**	3,922
Natural gas (Mcf/d)	**109,667**	89,259	**107,472**	89,859
Total (boe/d)	**33,217**	26,292	**32,916**	26,924
Oil and condensate % of production	**32%**	29%	**32%**	30%
NGL % of production	**13%**	15%	**14%**	15%
Natural gas % of production	**55%**	56%	**54%**	55%
Realized prices				
Oil & condensate ($/bbl)	**84.98**	102.71	**90.95**	97.25
NGLs ($/bbl)	**36.60**	42.21	**42.62**	44.49
Natural gas ($/Mcf)	**4.27**	2.39	**5.08**	3.11
Total ($/boe)	**45.79**	43.91	**51.50**	45.86
Royalty expense ($/boe)	**(2.10)**	(3.96)	**(2.81)**	(3.78)
Operating expenses ($/boe)	**(6.02)**	(6.17)	**(5.61)**	(6.61)
Transportation expenses ($/boe)	**(5.73)**	(5.97)	**(5.44)**	(5.27)
Operating netback ($/boe) [1]	**31.94**	27.81	**37.64**	30.20
Realized gain (loss) on risk management ($/boe) [2]	**0.59**	0.70	**(0.44)**	0.76
Realized gain (loss) on risk management - purchases ($/boe) [2]	**(0.28)**	0.79	**(0.73)**	0.61
Net commodity sales from purchases ($/boe) [1]	**0.67**	0.03	**1.40**	0.12
Adjusted operating netback ($/boe) [1]	**32.92**	29.33	**37.87**	31.69
Financial results ($000s, except per share amounts)				
Commodity sales from production	**138,419**	105,049	**306,811**	224,711
Net commodity sales from purchases [1]	**2,033**	87	**8,360**	597
Cash flow from operating activities	**79,839**	61,232	**190,156**	136,415
Adjusted funds flow from operations [1]	**88,378**	60,637	**204,260**	135,661
Per share basic	**2.02**	1.39	**4.66**	3.11
Per share diluted	**1.97**	1.37	**4.55**	3.08
Net debt to adjusted funds flow from operations [1]	**0.60**	0.81	**0.60**	0.81
Free funds flow (deficiency) from operations (excluding acquisitions/dispositions) [1]	**37,150**	(9,802)	**66,656**	(10,567)
Net income (loss)	**59,300**	(26,538)	**114,219**	(15,446)
Per share basic	**1.35**	(0.61)	**2.61**	(0.35)
Per share diluted	**1.32**	(0.61)	**2.55**	(0.35)
Capital expenditures [1]	**51,228**	70,439	**137,604**	146,228
Net acquisitions (dispositions) [1]	**—**	—	**(21,050)**	(21)
Capital expenditures and net acquisitions (dispositions) [1]	**51,228**	70,439	**116,554**	146,207

	June 30, 2025	December 31, 2024
Balance sheet ($000s, except share amounts)		
Total assets	**1,264,028**	1,215,575
Long-term liabilities	**353,325**	388,452
Net debt [1]	**205,142**	272,764
Adjusted working capital surplus (deficit) [1]	**(2,089)**	(22,862)
Weighted average shares outstanding		
Basic	**43,823,351**	43,690,640
Diluted	**44,861,678**	44,571,772
Shares outstanding end of period	**43,879,190**	43,781,748

1 – Non-GAAP and other financial measures that do not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. See "Non-GAAP and Other Financial Measures" section of this MD&A.
2 – Realized gain (loss) on risk management contracts includes settlement of financial hedges on production and foreign exchange, with gain (loss) on contracts associated with purchases presented separately.

Guidance

Following robust operational and financial results in the first half of 2025, Kiwetinohk has made the following positive revisions to its annual guidance:

- **The low-end of the annual production guidance range has been increased** to account for a strong first half of the year and the confidence we have in our remaining development program.
- **The projected royalty rate has been decreased,** in response to lower commodity prices than initially budgeted, particularly AECO natural gas prices. Kiwetinohk continues to benefit from higher Chicago pricing, while natural gas royalties are determined with reference to AECO.
- **Projected operating expenses have been decreased**, reflecting strong operational performance and continued asset reliability.
- **Projected transportation expenses have been decreased,** supported by lower costs to transport Placid NGLs in the second quarter of 2025 and an expected reduction in Alliance tolls effective November 2025.
- **The high-end of the annual upstream capital guidance range has been decreased,** driven by efficient drilling and completion execution and improved cost certainty.

Updated guidance is summarized in the table below. These updates reflect actual year-to-date realized commodity pricing, Kiwetinohk's hedging program and estimated forward strip pricing.

2025 Financial & Operational Guidance		**Current July 30, 2025**	Previous May 6, 2025 [8]
Production (2025 average)	Mboe/d	32.0 - 34.0	31.0 - 34.0
Oil & liquids	%	45% - 49%	
Natural gas [1]	%	51% - 55%	
Financial			
Royalty rate	%	5% - 7%	6% - 8%
Operating costs	$/boe	$6.25 - $6.75	$6.75 - $7.25
Transportation	$/boe	$5.50 - $5.75	$5.75 - $6.00
Corporate G&A expense [2]	$/boe	$1.95 - $2.15	
Cash taxes [3]	$MM	$—	
Upstream Capital [4]	$MM	$290 - $305	$290 - $315
DCET [5]	$MM	$270 - $285	$270 - $290
Plant expansion, production maintenance and other	$MM	$20	$20 - $25

2025 Guidance Sensitivities		Current July 30, 2025
2025 Adjusted Funds Flow from Operations commodity pricing [4, 6]		
Strip (July 28) US$66/bbl WTI & US$3.36/MMBtu HH	$MM	$380 - $405
US$60/bbl WTI & US$3.50/MMBtu HH & $0.73 USD/CAD	$MM	$365 - $395
US$70/bbl WTI & US$4.50/MMBtu HH & $0.73 USD/CAD	$MM	$405 - $435
US$ WTI +/- $1.00/bbl [7]	$MM	+/- $2.0
US$ Chicago +/- $0.10/MMBtu [7]	$MM	+/- $2.1
CAD$ AECO 5A +/- $0.10/GJ [7]	$MM	+/- $0.1
Exchange Rate (USD/CAD) +/- $0.01 [7]	$MM	+/- $1.8
2025 Net debt to Adjusted Funds Flow from Operations [4, 6]		
Strip (July 28) US$66/bbl WTI & US$3.36/MMBtu HH	X	0.4x - 0.5x
US$60/bbl WTI & US$3.50/MMBtu HH & $0.73 USD/CAD	X	0.5x - 0.6x
US$70/bbl WTI & US$4.50/MMBtu HH & $0.73 USD/CAD	X	0.4x - 0.5x

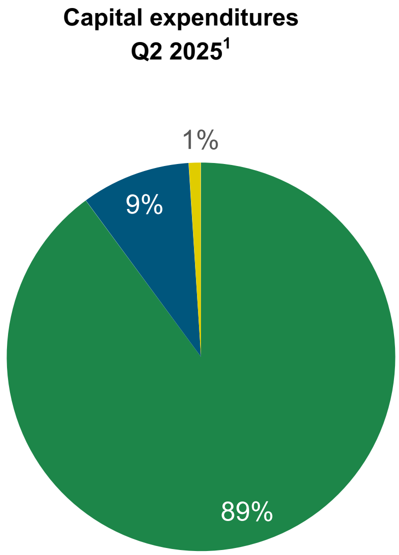
1 – ~90% is expected to be sold into the Chicago market in 2025.
2 – Includes G&A expenses for all divisions of Kiwetinohk – corporate, upstream, power and business development.
3 – Kiwetinohk expects to pay immaterial cash taxes on its U.S. subsidiary annually. No Canadian taxes are anticipated in 2025.
4 – Non-GAAP and other financial measures that do not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Please refer to the section "Non-GAAP Measures" herein.
5 – Approximately 5% of DCET relates to technology initiatives aimed at reducing per well capital costs and optimizing well design for improved productivity.
6 – Previously disclosed sensitivities utilized pricing levels prevailing at the time and have been revised to reflect current market data. As the previously disclosed sensitivities are no longer based on current information, they have been withdrawn.
7 – Assumes US$65/bbl WTI, US$4.00/mmbtu HH, US$2.50/mmbtu HH - AECO basis diff, 0.725 USD/CAD.
8 – Previously presented financial and operational guidance is shown only for balances that have been revised.

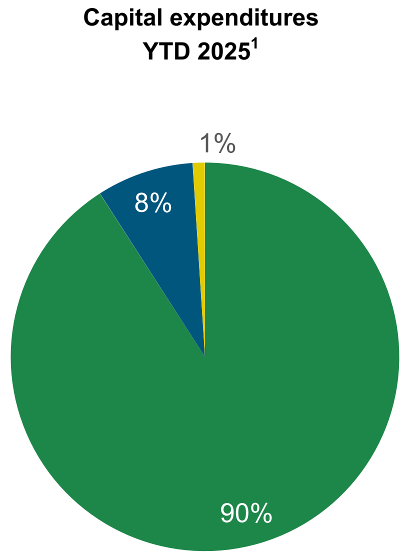
While U.S. trade policy changes may affect economic conditions, their impact on Kiwetinohk remains uncertain. Kiwetinohk's natural gas exports to the United States are CUSMA-compliant and currently exempt from tariffs. Given ongoing uncertainty, no tariff impacts are included in revised guidance. If future tariffs affect operations, guidance will be updated.

Capital expenditures

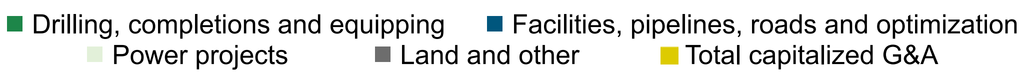
$000s	For the three months ended June 30, 2025	2024	For the six months ended June 30, 2025	2024
Drilling, completions, and equipping	**45,771**	61,956	**124,337**	121,783
Facilities, pipelines, roads and optimization	**4,677**	5,236	**10,683**	18,846
Power projects	**103**	1,958	**362**	2,918
Land and other	**120**	415	**639**	870
Capitalized G&A - upstream	**557**	636	**1,583**	1,338
Capitalized G&A - power	**—**	238	**—**	473
Capital expenditures [1]	**51,228**	70,439	**137,604**	146,228
Upstream net acquisitions (dispositions) [1]	**—**	—	**(50)**	(21)
Power net acquisitions (dispositions) [1]	**—**	—	**(21,000)**	—
Capital and net acquisitions (dispositions) [1]	**51,228**	70,439	**116,554**	146,207

1 – Non-GAAP and other financial measures that do not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. See "Non-GAAP and Other Financial Measures" section of this MD&A.





1 – Capital expenditures shown are before acquisitions/dispositions.



Drilling, completions and equipping

For the three and six months ended June 30, 2025, the Company invested $45.8 million and $124.3 million, respectively, to advance its development program through execution of a two-rig program as outlined below:

Pad	Spud	On-stream	# wells
09-11 (Simonette)	Q3/24	2 in Q4/24; 1 in Q1/25	3 Duvernay
14-29 (Simonette)	Q4/24	Q1/25	2 Duvernay, 1 Montney
09-33 (Simonette)	Q1/25	Q2/25	3 Duvernay
01-27 (Simonette)	Q4/24	Expected in Q3/25	2 Duvernay, 1 Montney
01-18 (Placid)	Q1/25	2 expected in Q3/25	2 Montney, 1 Montney DUC

The Company's upstream drilling program remains focused on optimization of its well design while developing its core Simonette Duvernay lands. A smaller portion of its development capital has been allocated to delineation of the Company's Montney acreage, with flexibility to manage the program in response to well results.

The Company continues to advance the development program with six wells drilled during the six months ended June 30, 2025, including one Placid Montney well to be completed at a later date, and has made positive revisions to annual upstream capital and production guidance as previously disclosed.

Facilities, pipelines, roads and optimization

For the three and six months ended June 30, 2025, the Company invested $4.7 million and $10.7 million, respectively, to build facilities, pipelines, roads and to optimize production. Kiwetinohk's 2025 capital program has continued to focus facility and other infrastructure spend on activity required to accommodate planned growth and base production.

Power development projects

For the three and six months ended June 30, 2025, power development portfolio spend of $3.7 million and $4.3 million, respectively, was incurred in order to preserve existing projects' positions in the regulatory approval queue.

During the first quarter of 2025, the Company sold its proposed Opal natural gas-fired power project, including all assets, material contracts, leases and permits, for gross proceeds of $21.0 million. The Opal project was previously fully impaired in the second quarter of 2024. The Company recorded a gain on disposition of $25.3 million, which included the removal of a $4.3 million provision for a gas transportation contract that was assumed by the purchaser.

The Homestead Solar project advanced to a fully permitted and licensed project in the first quarter of 2025, requiring a refundable $8.0 million payment to maintain the project in Alberta's regulatory queue. This payment has been recorded within long-term Prepaid Expenses and Deposits.

The Company remains focused on an orderly exit from its Power business.

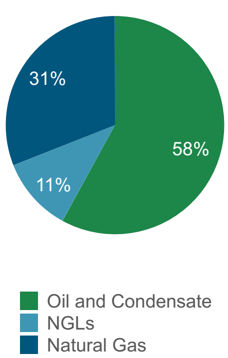
Results of operations

Production

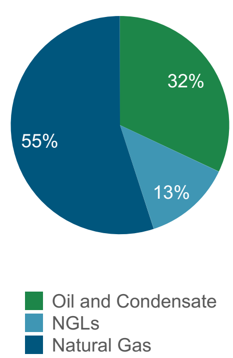
	For the three months ended June 30,		For the six months ended June 30,	
	2025	2024	**2025**	2024
Oil & condensate (bbl/d)	**10,462**	7,598	**10,546**	8,025
NGLs (bbl/d) [1]	**4,477**	3,817	**4,458**	3,922
Natural gas (Mcf/d)	**109,667**	89,259	**107,472**	89,859
Total production (boe/d)	**33,217**	26,292	**32,916**	26,924
Oil and condensate % of production	**32%**	29%	**32%**	30%
NGL % of production	**13%**	15%	**14%**	15%
Natural gas % of production	**55%**	56%	**54%**	55%
Total production volumes %	**100%**	100%	**100%**	100%

1 - NGL production includes production volumes for ethane (C2), propane (C3), butane (C4) and pentane (C5).

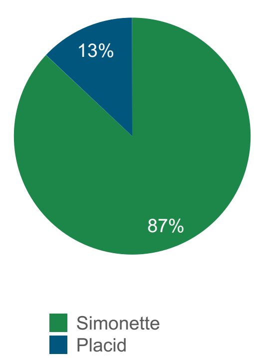
Revenue Mix ($)
Q2 2025



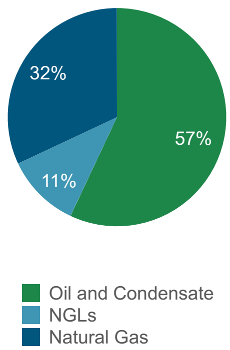
Production Mix (boe)
Q2 2025



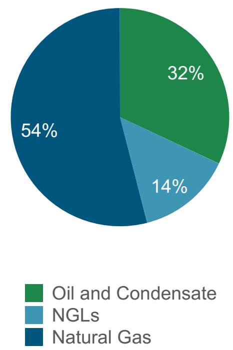
Production by Area (boe)
Q2 2025



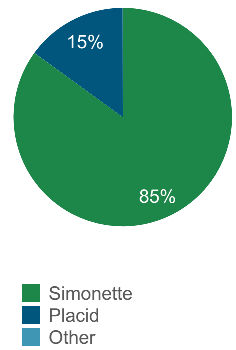
YTD 2025



YTD 2025



YTD 2025



Production for the three and six months ended June 30, 2025 increased by 26% to 33,217 boe/d and by 22% to 32,916 boe/d, respectively, compared to the same periods in 2024. The increase is attributable to the Company’s ongoing capital development program with a total of sixteen wells brought on-stream during the prior year, and an additional seven new wells placed into production during the first six months of 2025.

The composition of the Company's production during the three months ended June 30, 2025 was 32% oil and condensate, 13% NGLs, and 55% natural gas. For the six months ended June 30, 2025, the Company's production profile was 32% oil and condensate, 14% NGLs, and 54% natural gas. The production profile in both periods has a higher oil and condensate weighting relative to the comparative periods as the three wells brought on stream in the second quarter of 2025 were located in the liquids-rich Tony Creek area, and the two Tony Creek pads drilled in the prior year were brought on stream in the third quarter of 2024.

Benchmark and realized prices

	For the three months ended June 30,		For the six months ended June 30,	
	2025	2024	**2025**	2024
Liquid benchmark prices				
WTI (US$/bbl)	**63.74**	80.57	**67.58**	78.77
WTI (CDN$/bbl)	**88.20**	110.25	**95.34**	107.03
Edmonton Light (CDN$/bbl)	**84.25**	105.28	**89.79**	98.71
Natural gas benchmark prices				
Henry Hub (US$/MMBtu)	**3.44**	1.89	**3.55**	2.07
Chicago City Gate MI (US$/MMBtu)	**2.99**	1.60	**3.46**	2.05
Chicago City Gate DI (US$/MMBtu)	**2.86**	1.65	**3.43**	2.23
AECO 5A (CDN$/GJ)	**1.60**	1.12	**1.83**	1.74
AECO 7A (CDN$/GJ)	**1.96**	1.36	**1.94**	1.65
Foreign exchange rates (USD/CAD)	**0.72**	0.73	**0.71**	0.74

	For the three months ended June 30, 2025	2024	For the six months ended June 30, 2025	2024
Realized prices (before impact of hedging program)				
Oil & condensate ($/bbl)	**84.98**	102.71	**90.95**	97.25
NGLs ($/bbl)	**36.60**	42.21	**42.62**	44.49
Natural gas ($/Mcf)	**4.27**	2.39	**5.08**	3.11
Total ($/boe)	**45.79**	43.91	**51.50**	45.86

Crude oil prices for the three and six months ended June 30, 2025 decreased relative to the comparative periods in 2024, primarily due to increased global supply from OPEC and greater uncertainty related to U.S. trade policy which has triggered concerns with respect to overall demand from China and other developing nations.

NGL sales contracts are renewed annually in April each year, with pricing for the three and six months ended June 30, 2025 declining when compared to the prior periods of 2024 as a result of increased North American supply pressure and lower contract pricing.

Average Henry Hub natural gas prices increased to US $3.44 and US $3.55 per MMBtu in the three and six months ended June 30, 2025, respectively, when compared to US $1.89 and US $2.07 per MMBtu in the comparative periods of 2024. Increases in prices were due to an unseasonably cold winter that elevated North American demand, increased LNG export demand, and higher domestic industrial demand followed by increased storage injection requirements during the second quarter of 2025. The Chicago City Gate monthly index benchmark for natural gas also increased over both periods for the same reasons. During the second quarter of 2025, the Chicago to Henry Hub basis widened, reflecting the strength in Henry Hub pricing outlined above, while more seasonally normal temperatures in Chicago in the second quarter of 2025 and a muted late spring and early summer price response also contributed to the wider basis. On a relative basis, the Chicago basis as a percentage of Henry Hub remained largely consistent quarter-over-quarter.

Natural gas prices in Alberta at the AECO Hub increased alongside Henry Hub and Chicago pricing, supported by incremental LNG export demand, while storage levels in the basin remain elevated. On average, AECO Monthly 7A spot prices increased to $1.96/GJ and $1.94/GJ during the three and six months ended June 30, 2025, respectively, compared to $1.36/GJ and $1.65/GJ in the same periods in 2024.

Operating netback

	For the three months ended June 30, 2025	2024	For the six months ended June 30, 2025	2024
Realized price ($/boe)	**45.79**	43.91	**51.50**	45.86
Royalty expenses ($/boe)	**(2.10)**	(3.96)	**(2.81)**	(3.78)
Operating expenses ($/boe)	**(6.02)**	(6.17)	**(5.61)**	(6.61)
Transportation expenses ($/boe)	**(5.73)**	(5.97)	**(5.44)**	(5.27)
Operating netback ($/boe) [1]	**31.94**	27.81	**37.64**	30.20
Realized gain (loss) on risk management ($/boe) [2]	**0.59**	0.70	**(0.44)**	0.76
Realized gain (loss) on risk management - purchases ($/boe) [2]	**(0.28)**	0.79	**(0.73)**	0.61
Net commodity sales from purchases ($/boe) [1]	**0.67**	0.03	**1.40**	0.12
Adjusted operating netback ($/boe) [1]	**32.92**	29.33	**37.87**	31.69
Total production (boe/d)	**33,217**	26,292	**32,916**	26,924

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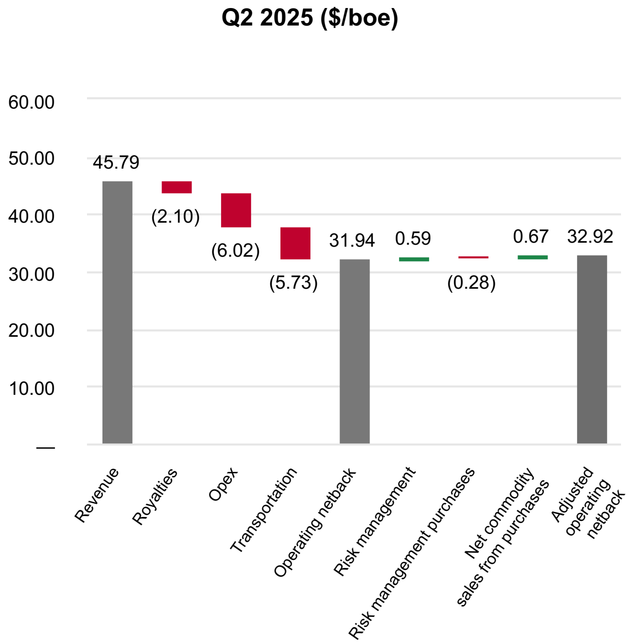

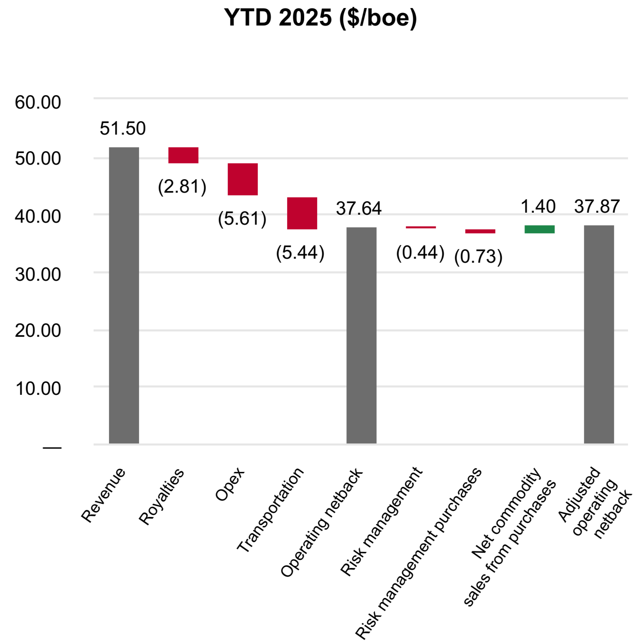

Operating netback for the three and six months ended June 30, 2025 was $31.94/boe and $37.64/boe, respectively, relative to the 2024 comparative periods of $27.81/boe and $30.20/boe. The increase in operating netback for both periods was attributable to higher realized prices and cost savings in royalties and operating expenses, while transportation expenses remained in line with prior periods, as described below.

Adjusted operating netback incorporates the impact of net commodity sales from purchases and the impact of the Company's risk management program and was $32.92/boe and $37.87/boe for the three and six months ended June 30, 2025, respectively. The Company was successful in managing excess transport commitments over the same periods, realizing gains of $0.39/boe and $0.67/boe, respectively, on its net commodity sales from purchases after hedging (described below). For the three and six months ended June 30, 2025, the Company realized gains of $0.59/boe and $0.44/boe, respectively, on risk management contracts on produced volumes and foreign exchange contracts, relative to gains of $0.70/boe and $0.76/boe in the comparative periods.

Commodity sales from production

	For the three months ended June 30,		For the six months ended June 30,	
$000s	**2025**	2024	**2025**	2024
Oil & condensate	**80,914**	71,012	**173,614**	142,031
NGLs	**14,910**	14,663	**34,383**	31,760
Natural gas	**42,595**	19,374	**98,814**	50,920
Total commodity sales from production	**138,419**	105,049	**306,811**	224,711

Revenue from production for the three and six months ended June 30, 2025 increased to $138.4 million and $306.8 million, respectively, compared to $105.0 million and $224.7 million in the same periods in 2024. Increases were driven by higher production levels in 2025 achieved through new well additions and higher average realized prices relative to the prior periods.

Net commodity sales from purchases

$000s	For the three months ended June 30, 2025	2024	For the six months ended June 30, 2025	2024
Commodity sales from purchases	**7,434**	7,353	**23,539**	23,336
Commodity purchases, transportation and other	**(5,401)**	(7,266)	**(15,179)**	(22,739)
Net commodity sales from purchases [1]	**2,033**	87	**8,360**	597
Realized hedging (loss) gain on purchases	**(861)**	1,882	**(4,322)**	2,999
Net commodity sales from purchases after hedging [1]	**1,172**	1,969	**4,038**	3,596
$/boe – before hedging	**0.67**	0.03	**1.40**	0.12
$/boe – after hedging	**0.39**	0.82	**0.67**	0.73

1 – Non-GAAP and other financial measures that do not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. See "Non-GAAP and Other Financial Measures" section of this MD&A.

In order to mitigate the cost of transportation service in excess of current production needs, the Company purchases available natural gas volumes in Alberta and/or British Columbia and resells these volumes in Chicago. The Company was able to successfully fill the balance of its Alliance firm transportation commitment during the six months ended June 30, 2025, not met through its own proprietary field production, through purchase and resale of natural gas and by temporarily assigning capacity.

As part of its broader risk management program, the Company enters into risk management contracts associated with purchased natural gas volumes for resale to secure the pricing difference between the Alberta and Chicago sales points. To date, this strategy has resulted in positive net commodity sales from purchases after hedging while allowing the Company to utilize its excess transportation commitments on the Alliance pipeline.

The Company does not seek to speculate on price movements for purchased natural gas volumes for resale and manages its excess pipeline commitments by securing third-party natural gas volumes. Price differentials between the Chicago and Alberta markets and the associated market risk is monitored on purchased volumes and managed by securing pricing through periodically entering into risk management contracts in accordance with risk management guidelines as approved by the Company's board of directors.

During the three and six months ended June 30, 2025, the Company realized a gain of $2.0 million and $8.4 million, respectively, on its marketing activities associated with purchasing natural gas to fulfill its transmission commitment on the Alliance pipeline system. Including the impact of related risk management contracts, the Company realized overall marketing income of $1.2 million and $4.0 million for the three and six months ended June 30, 2025, respectively, relative to $2.0 million and $3.6 million for the comparable periods in 2024.

Risk management contracts

In an effort to mitigate commodity price fluctuations for natural gas, crude oil and NGLs, the Company enters into financial commodity contracts as part of its risk management program which is designed to protect cash flows from its base production and help ensure sufficient capital and liquidity is available to execute its strategy and complete its planned capital development program.

Risk management contracts are entered into at prices that the Company believes enhance the probability of capital projects meeting or exceeding their targeted financial return hurdles. All risk management contracts are entered into in accordance with the Company's risk management policy, ensuring the Company retains its ability to cover all outstanding risk management liabilities when they arise. The Company also regularly reviews its credit exposure to the counterparties that it enters into risk management contracts with.

$000s	For the three months ended June 30, 2025	2024	For the six months ended June 30, 2025	2024
Risk management:				
Unrealized gain (loss)	**52,071**	(16,820)	**38,293**	(31,960)
Realized gain (loss)	**930**	3,542	**(7,028)**	6,677
Total gain (loss) on risk management	**53,001**	(13,278)	**31,265**	(25,283)
Unrealized gain (loss) ($/boe)	**17.23**	(7.03)	**6.43**	(6.52)
Realized gain (loss) ($/boe)	**0.31**	1.49	**(1.17)**	1.37

The following table reconciles the components of the realized gain (loss) on risk management contracts:

$000s	For the three months ended June 30, 2025	2024	For the six months ended June 30, 2025	2024
Realized gain on production	**3,082**	3,234	**2,602**	5,906
Realized (loss) gain on purchases	**(861)**	1,882	**(4,322)**	2,999
Realized loss on foreign exchange	**(1,291)**	(1,574)	**(5,308)**	(2,228)
Total realized gain (loss)	**930**	3,542	**(7,028)**	6,677
Realized gain on production ($/boe)	**1.02**	1.36	**0.44**	1.21
Realized (loss) gain on purchases ($/boe)	**(0.28)**	0.79	**(0.73)**	0.61
Realized loss on foreign exchange ($/boe)	**(0.43)**	(0.66)	**(0.88)**	(0.45)

For the three and six months ended June 30, 2025, the Company realized a gain on risk management contracts of $0.9 million and a loss of $7.0 million, respectively. This included the impact from production hedges (gains of $3.1 million and $2.6 million, respectively), foreign exchange contracts (losses of $1.3 million and $5.3 million, respectively) and natural gas volumes purchased for resale required to meet pipeline commitments in excess of the Company's production needs (losses of $0.9 million and $4.3 million, respectively). The Company hedges price differences between Chicago and Alberta markets at the time of contracting third-party natural gas purchases.

With respect to financial contracts, which are derivative financial instruments, management has elected not to use hedge accounting and consequently records the fair value of its natural gas, crude oil, and foreign exchange financial contracts on the balance sheet at each reporting period with the change in the fair value being classified as unrealized gains and losses in the condensed consolidated interim statement of net income (loss) and comprehensive income (loss).

The fair values of these contracts are based on an approximation of the amounts that would have been paid to or received from counterparties to settle the contracts outstanding at the end of the period having regard to forward prices and market values provided by independent sources. Due to the inherent volatility in commodity prices, foreign exchange and interest rates, actual amounts realized may differ from these estimates.

The Company has recognized an unrealized gain on risk management of $52.1 million, during the three months ended June 30, 2025 and an unrealized gain of $38.3 million during the six months ended June 30, 2025, representing the changes in the fair value of risk management contracts outstanding at the end of those periods. As of June 30, 2025 the Company's risk management portfolio was in a net asset position of $6.1 million as compared to a net liability of $32.2 million as at December 31, 2024.

The Company has the following commodity risk management contracts outstanding as of June 30, 2025:

Type		Q3 2025	Q4 2025	2026	2027	2028
Crude oil [1]						
WTI swap	bbl/d	1,167	1,000	750	188	—
WTI buy put	bbl/d	5,083	4,833	3,083	1,188	83
WTI sell call	bbl/d	4,083	3,833	2,333	688	—
WTI swap average	US$/bbl	$70.47	$70.04	$68.72	$66.05	$—
WTI buy put average	US$/bbl	$63.31	$62.96	$61.28	$53.01	$55.00
WTI sell call average	US$/bbl	$74.52	$74.29	$72.19	$74.08	$—
Natural gas [1]						
NYMEX Henry Hub buy put	MMBtu/d	75,000	68,333	53,958	24,167	1,667
NYMEX Henry Hub sell call	MMBtu/d	72,500	65,833	53,333	24,167	1,667
NYMEX Henry Hub buy put average	US$/MMBtu	$3.37	$3.33	$3.25	$3.45	$3.52
NYMEX Henry Hub sell call average	US$/MMBtu	$4.56	$4.62	$4.49	$4.80	$4.89
Natural gas transportation [1,2]						
Purchase AECO 5A basis (to NYMEX Henry Hub)	MMBtu/d	25,000	15,000	8,333	—	—
Sell GDD Chicago basis (to NYMEX Henry Hub) [3]	MMBtu/d	(25,000)	(15,000)	(8,333)	—	—
AECO 5A basis (to NYMEX Henry Hub) average	US$/MMBtu	$(1.36)	$(1.91)	$(2.19)	$—	$—
GDD Chicago basis (to NYMEX Henry Hub) average [3]	US$/MMBtu	$(0.08)	$(0.14)	$(0.18)	$—	$—

1 – Prices per unit and volumes per day are represented at the average amounts for the period.
2 – Natural gas transportation hedges relate to exposure to basis pricing differentials between AECO and Chicago arising from firm transportation commitments.
3 – Gas Daily Daily ("GDD") pricing represents the daily natural gas settlement price in Chicago.

The Company has the following foreign exchange risk management contracts outstanding at June 30, 2025:

Type		Q3 2025	Q4 2025	2026	2027	2028
Foreign exchange [1]						
Sell USD CAD (monthly average)	US$	$12.5 MM	$12.5 MM	$— MM	$— MM	$— MM
USD CAD buy put	US$	$10.5 MM	$10.5 MM	$15.0 MM	$10.0 MM	$— MM
USD CAD sell call [2]	US$	$10.5 MM	$10.5 MM	$19.0 MM	$10.0 MM	$— MM
USD CAD fixed sell rate		$1.35	$1.35	$—	$—	$—
USD CAD buy put rate		$1.36	$1.36	$1.32	$1.34	$—
USD CAD sell call rate [2]		$1.42	$1.42	$1.40	$1.40	$—

1 – Prices per unit and volumes per day are represented at the average amounts for the period.
2 – The Company entered into a collar effective for the 2026 calendar year, included in the above table at $8.0 million per month at a rate of 1.37 USD/CAD. Should the WM/Reuters monthly average drop below 1.405, the notional amount will drop to $4.0 million at a call rate of 1.405.

The components of the Company's total risk management contract asset (liability) outstanding are as follows:

$000s	June 30, 2025	December 31, 2024
Short term risk management asset	**6,896**	—
Long term risk management asset	**2,733**	—
Short term risk management liability	**(2,931)**	(20,900)
Long term risk management liability	**(631)**	(11,326)
Total risk management contracts asset (liability)	**6,067**	(32,226)

$000s	June 30, 2025	December 31, 2024
Asset on produced volumes	**5,242**	1,023
Liability on purchased volumes	**(1,869)**	(9,748)
Asset (liability) on foreign exchange contracts	**2,694**	(23,501)
Total risk management contracts asset (liability)	**6,067**	(32,226)

Royalty expense

	For the three months ended June 30,		For the six months ended June 30,	
$000s	**2025**	2024	**2025**	2024
Royalty expense	**6,353**	9,470	**16,716**	18,537
As a % of revenue	**4.6 %**	9.0 %	**5.4 %**	8.2 %
$/boe	**2.10**	3.96	**2.81**	3.78

The Company pays Crown, freehold, and overriding royalties on production volumes. Royalties for the three and six months ended June 30, 2025 were $6.4 million and $16.7 million, respectively, as compared to $9.5 million and $18.5 million in the comparative periods of 2024.

Royalties as a percentage of revenue for the three and six months ended June 30, 2025 decreased to 4.6% and 5.4%, respectively, compared to 9.0% and 8.2% in the prior year periods as a result of lower oil pricing and an increased proportion of production from new wells which benefit from provincial incentive programs. Alberta's drilling and completion cost allowance program provides a 5% royalty rate on a well's initial production until the well's cumulative revenue, from all hydrocarbon products, equals a maximum threshold.

Operating expenses

	For the three months ended June 30,		For the six months ended June 30,	
$000s	**2025**	2024	**2025**	2024
Operating expenses	**18,190**	14,758	**33,438**	32,383
$/boe	**6.02**	6.17	**5.61**	6.61

Operating costs include amounts incurred to extract commodities to the surface including expenditures for field operators, gas and liquids processing, gathering and compression, utilities, chemicals and maintenance related costs. Operating costs for the three and six months ended June 30, 2025 increased to $18.2 million and $33.4 million, respectively, as compared to $14.8 million and $32.4 million in the comparable periods of 2024. The increase was attributable to higher production levels over the same periods.

On a per barrel basis, operating expenses for the three and six months ended June 30, 2025 decreased by 2% to $6.02/boe and 15% to $5.61/boe, respectively, due to continued strong asset performance and reduced expenditures in the first half of the year aimed at optimizing planned project spending and aligning certain expenditures with scheduled facility downtime, now planned for the third quarter of 2025. Higher production during the period also led to per barrel efficiencies gained through the Company's owned and operated infrastructure within Simonette.

Transportation expenses

$000s	For the three months ended June 30, 2025	2024	For the six months ended June 30, 2025	2024
Transportation expenses	**17,336**	14,280	**32,395**	25,819
$/boe	**5.73**	5.97	**5.44**	5.27

Transportation expenses are incurred to deliver oil and natural gas commodities from the Company's production sites to the delivery point of sale. The Company has contracted for firm transportation service on the Alliance pipeline system from Alberta to Chicago and on the NGTL system in Alberta. The balance of costs pertains to trucking charges and pipeline fees related to oil, NGL and condensate transportation charges.

Transportation expenses for the three and six months ended June 30, 2025 were $17.3 million and $32.4 million, respectively, as compared to $14.3 million and $25.8 million in the same periods in 2024, with the increase attributable to higher production.

On a per barrel basis, transportation expenses for the three months ended June 30, 2025 of $5.73/boe were consistent with the same period in 2024. For the six months ended June 30, 2025, transportation expenses increased to $5.44/boe relative to $5.27/boe in the comparative period due to a smaller credit received during the current year upon reconciling actual versus expected annual volumes of condensate shipped during the previous year.

Adjusted funds flow from operations

$000s	For the three months ended June 30, 2025	2024	For the six months ended June 30, 2025	2024
Cash flows from operating activities	**79,839**	61,232	**190,156**	136,415
Net change in non-cash working capital from operating activities	**8,217**	(969)	**11,139**	(1,673)
Asset retirement obligation expenditures	**322**	374	**2,845**	919
Adjusted funds flow from operations [1]	**88,378**	60,637	**204,260**	135,661
$/boe	**29.24**	25.34	**34.28**	27.69

1 – Non-GAAP and other financial measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. See "Non-GAAP and Other Financial Measures" section of this MD&A.

Adjusted funds flow from operations for the three and six months ended June 30, 2025 increased to $88.4 million and $204.3 million, respectively, relative to $60.6 million and $135.7 million in the comparative periods in 2024. On a per barrel basis, adjusted flow from operations for the three and six months ended June 30, 2025 increased by 15% to $29.24/boe and by 23% to $34.28/boe, respectively, relative to the comparative periods.

Increases on a total and per barrel basis were attributable to greater production levels, a stronger netback per barrel (as described above) and lower financing costs resulting from lower average borrowing rates during the period.

Free funds flow from operations

$000s	For the three months ended June 30, 2025	2024	For the six months ended June 30, 2025	2024
Adjusted funds flow from operations [1]	**88,378**	60,637	**204,260**	135,661
Capital expenditures [1]	**(51,228)**	(70,439)	**(137,604)**	(146,228)
Free funds flow (deficiency) from operations [1]	**37,150**	(9,802)	**66,656**	(10,567)
$/boe	**12.29**	(4.10)	**11.19**	(2.16)

1 – Non-GAAP and other financial measures that do not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. See "Non-GAAP and Other Financial Measures" section of this MD&A.

During the three and six months ended June 30, 2025, the Company had a free funds flow of $37.2 million and $66.7 million relative to a deficiency of $9.8 million and $10.6 million in the comparative periods of 2024. The Company achieved its first quarter of positive free funds flow generation in the first quarter of 2025, representing an inflection point for the Company which continued into the three months ended June 30, 2025. The Company plans to utilize free funds flow from operations to reduce debt levels, repurchase shares under its normal course issuer bid (NCIB) program subject to market conditions, while continuing to execute a capital program aimed at generating short and long-term production and cash-flow growth.

The Company was able to fund capital spending and reduce balances drawn on its credit facilities during the six months ended June 30, 2025 using cash flow from operations. The Company continuously monitors its liquidity position and financial performance to ensure ongoing financial flexibility and has the ability to adjust future capital spending plans if required to manage liquidity and/or balance sheet constraints.

General and administrative ("G&A") expenses

$000s	For the three months ended June 30, 2025	2024	For the six months ended June 30, 2025	2024
Gross G&A expenses	**6,446**	6,629	**14,737**	13,656
Less capitalized G&A	**(557)**	(874)	**(1,583)**	(1,811)
G&A Expenses	**5,889**	5,755	**13,154**	11,845
$/boe	**1.95**	2.41	**2.21**	2.42

For the three and six months ended June 30, 2025, the Company incurred gross G&A expenses of $6.4 million and $14.7 million, respectively, relative to $6.6 million and $13.7 million in the comparable periods in 2024 with the increase on a year to date basis primarily attributable to company growth. On a per barrel basis, G&A of $1.95/boe and $2.21/boe for the three and six months ended June 30, 2025 decreased relative to the prior periods due to higher production levels.

A portion of G&A expense continues to be directly related to business development initiatives in the power segment including the advancement of development plans for solar and natural gas-fired power generation projects as well as early stage investigation of opportunities to develop carbon capture hubs within Alberta.

Share-based compensation expenses

$000s	For the three months ended June 30, 2025	2024	For the six months ended June 30, 2025	2024
Equity-settled awards	**1,439**	801	**1,814**	1,610
Cash-settled awards	**7,597**	1,867	**10,907**	3,137
Total share-based compensation expenses	**9,036**	2,668	**12,721**	4,747
$/boe	**2.99**	1.12	**2.14**	0.97

Share-based compensation is the compensation expense recognized for non-cash, equity-settled incentive plans including stock options and performance warrants and cash-settled incentive plans including deferred share units, performance share units and restricted share units.

The compensation expense for equity-settled awards is based on an estimated grant date fair value of the stock options and warrants, recognized over a graded vesting period by tranche, which results in a higher upfront expense recorded in the earlier years of the vesting periods. The compensation expense related to cash-settled awards is calculated using the fair value method based on the trading price of the Company's shares at the end of each reporting period after adjusting for an estimated forfeiture rate and any applicable performance criteria, with changes in fair value recognized over the vesting period as share-based compensation expense.

Total share-based compensation of $9.0 million and $12.7 million for the three and six months ended June 30, 2025 increased relative to $2.7 million and $4.7 million in the respective prior year periods, attributable to increases in both cash-settled and equity-settled award compensation. Greater cash-settled compensation is due to more awards outstanding, a higher share price at the end of the 2025 period and strong performance relative to peers resulting in the application of a higher performance multiplier for applicable awards. Greater equity-settled award compensation is due to the Company extending certain performance warrants during the second quarter of 2025.

Finance costs

$000s	For the three months ended June 30, 2025	2024	For the six months ended June 30, 2025	2024
Interest and bank charges	**3,851**	4,677	**8,150**	9,339
Accretion expense	**919**	925	**1,838**	1,784
Interest on lease obligations	**719**	548	**1,434**	1,085
Deferred financing amortization	**197**	183	**391**	344
Unrealized loss (gain) on foreign exchange	**2,030**	(119)	**2,278**	(673)
Total finance costs	**7,716**	6,214	**14,091**	11,879
$/boe	**2.55**	2.60	**2.37**	2.42

The Company has a $400 million senior secured extendible revolving facility (the "Credit Facility") with a syndicate of banks. As at June 30, 2025 the Company had drawn $204.6 million on the facility (June 30, 2024 - $139.9 million).

Interest and bank charges for the three and six months ended June 30, 2025 decreased by 18% to $3.9 million and 13% to $8.2 million, respectively, compared to the same periods in the prior year. Decreases in both periods were attributable to lower average interest rates, offset by higher average debt levels, relative to the comparative periods.

Depletion and Depreciation

$000s	For the three months ended June 30, 2025	2024	For the six months ended June 30, 2025	2024
Depletion	**52,215**	39,555	**103,082**	81,266
Depreciation	**548**	511	**1,089**	1,026
Total depletion and depreciation	**52,763**	40,066	**104,171**	82,292
$/boe	**17.46**	16.75	**17.48**	16.79

The Company recognized depletion of $52.2 million and $103.1 million during the three and six months ended June 30, 2025 compared to $39.6 million and $81.3 million during the comparative periods of 2024.

Increases in depletion were attributable to higher production levels and a greater depletion rate. Depletion per barrel increased due to a larger depletable base, resulting from the Company's continued upstream development activity and an increase in future development costs assigned in accordance with the Company's 2024 reserve report, partially offset by an increase in proved and probable reserves assigned.

Income taxes

During the six months ended June 30, 2025, the Company incurred approximately $13.0 thousand in income taxes relating to the Company’s United States subsidiary. The Company did not pay any Canadian income taxes in 2025 (2024: $nil) and does not expect to be taxable in Canada in 2025.

As of June 30, 2025, the Company recognized a net deferred tax liability of $41.8 million. The Company’s estimated tax pools as at June 30, 2025, were $855.0 million comprised of the following:

Category	Deductibility	$000s
Canadian oil and gas property expense ("COGPE")	10%	161,321
Successored COGPE	10%	906
Canadian development expense ("CDE")	30%	369,651
Successored CDE	30%	33,322
Canadian exploration expense ("CEE")	100%	202
Successored CEE	100%	—
Undepreciated capital cost ("UCC")	Primarily 25%, declining balance	160,946
Non-capital losses	100%	123,287
Share/Debt issue costs	5-year straight line	2,579
Other	Various	2,762
Total estimated tax pools		854,976

Asset retirement obligations

The Company’s asset retirement obligations ("ARO") pertain to the Company’s wells and related infrastructure. The estimated ARO includes assumptions with respect to actual costs to abandon wells or reclaim the property, the time frame in which such costs will be incurred, and annual inflation factors. The Company estimates the total undiscounted, uninflated, future cash flows to settle its ARO is $106.6 million, or $173.7 million inflated at 1.91% and undiscounted. These cash flows have been discounted using a risk-free interest rate of 3.56% to arrive at the present value estimate of $75.4 million.

There is approximately $13.8 million (December 31, 2024 - $28.0 million) of abandonment and reclamation costs associated with inactive wells or facilities where there are no active operations or attributed reserves.

Provision for onerous contract

In the prior year, the Company recognized a provision related to an onerous contract to transport and offload natural gas from the Nova Gas Transmission Ltd. pipeline system for use at its Opal gas-fired peaking project. On February 4, 2025, the Company sold its Opal project and assigned all future tolling obligations under the contract and removed the provision. No liability remains as at June 30, 2025 (December 31, 2024 - $4.4 million).

Select quarterly information

($000s except per share and production)	2025	2025	2024	2024	2024	2024	2023	2023
	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Production (average boe/d)	**33,217**	32,611	27,657	25,996	26,292	27,556	24,707	21,218
Commodity sales from production	**138,419**	168,392	120,721	109,166	105,049	119,662	114,038	94,432
Commodity sales from purchases	**7,434**	16,105	16,417	15,773	7,353	15,983	18,136	19,464
Cash flow from operating activities	**79,839**	110,317	59,921	66,867	61,232	75,183	58,946	60,294
Per share (basic)	**1.82**	2.52	1.37	1.53	1.40	1.72	1.35	1.37
Per share (diluted)	**1.78**	2.46	1.35	1.51	1.39	1.71	1.33	1.36
Net income (loss)	**59,300**	54,919	(16,024)	32,535	(26,538)	11,092	48,302	(12,056)
Per share (basic)	**1.35**	1.25	(0.37)	0.74	(0.61)	0.25	1.11	(0.27)
Per share (diluted)	**1.32**	1.23	(0.37)	0.73	(0.61)	0.25	1.09	(0.27)

Capital resources and liquidity

The Company's objective when managing its balance sheet is to maintain a conservative capital structure that provides financial flexibility to address contingencies and execute on strategic business opportunities. It relies on cash flow from operating activities, available funding capacity on its Credit Facility and future equity or debt issuances to fund its capital requirements and any potential acquisitions. The Company anticipates that cash flow from operating activities and availability on its Credit Facility will be sufficient to meet working capital requirements and fund Kiwetinohk's 2025 capital program.

Credit Facility

On May 30, 2025 the Company completed the annual borrowing base review of the consolidated Credit Facility and confirmed no changes to the borrowing base of $400.0 million. The borrowing base is comprised of an operating facility of $65.0 million and a syndicated facility of $335.0 million.

At June 30, 2025, $204.6 million was drawn on the Credit Facility (December 31, 2024 - $251.0 million). In addition, $59.2 million in letters of credit issued to support transportation and other commitments were outstanding (December 31, 2024 - $70.0 million). Of the $59.2 million letters of credit, $39.6 million were provided for through the EDC facility (see below), and the remaining $19.6 million were issued under the Credit Facility and reduce the available operating facility capacity.

$000s	Borrowing capacity	Drawn	Letters of credit	Available Capacity
Credit Facility	400,000	204,573	19,611	**175,816**
EDC Facility	100,000	—	39,636	**60,364**
Total				**236,180**

$000s	June 30, 2025	December 31, 2024
Credit facility drawn	**204,573**	251,002
Deferred financing costs	**(1,520)**	(1,100)
Loans and borrowings	**203,053**	249,902
Adjusted working capital deficit [1]	**2,089**	22,862
Net debt [1]	**205,142**	272,764
Trailing 12-month adjusted funds flow from operations [1]	**340,714**	272,115
Net debt to trailing 12-month adjusted funds flow from operations [1]	**0.60**	1.00

1 – Non-GAAP and other financial measures that do not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. See "Non-GAAP and Other Financial Measures" section of this MD&A.

The Credit Facility is a 364-day committed facility available on a revolving basis which was extended until May 31, 2026, at which time it may be extended at the lenders' option. If the revolving period is not extended, the undrawn portion of the Credit Facility will be cancelled and the amount outstanding would be required to be repaid at the end of the non-revolving term, being May 31, 2027. The borrowing base is determined based on the lenders' evaluation of the Company's petroleum and natural gas reserves at the time and commodity prices.

Interest payable on amounts drawn under the Credit Facility is charged at the prevailing bankers' acceptance rate plus the applicable stamping fees, lenders' prime rate or U.S. base rate plus the applicable margins, depending on the form of borrowing by the Company. The applicable margins and stamping fees are based on a sliding scale pricing grid tied to the ratio of the Company's debt to earnings before interest, taxes, depreciation and amortization ("bank EBITDA ratio"). Applicable margins over the bank's prime rate or U.S. base rate range from 1.75 percent to 5.25 percent and stamping fees applicable to the relevant Canadian Overnight Repo Rate Average ("CORRA") rate range from 2.75 percent to 6.25 percent. The undrawn portion of the Credit Facility is subject to standby fees ranging from 0.6875 percent to 1.5625 percent based on the Company's bank EBITDA ratio.

The Credit Facility is secured by a $1.0 billion demand floating charge debenture and a general security agreement over all recourse assets of the Company.

The Company plans to utilize its funds from operations to fund its current working capital and planned capital program during 2025. Free funds from operations are expected to be utilized to reduce the balance drawn on the Credit Facility. This preserves and is expected to increase the available Credit Facility capacity, providing flexibility to adapt plans to the market environment while maintaining a target ratio of net debt to last-twelve months of adjusted funds flow from operations of no more than 1.0 times (June 30, 2025 - 0.60 times).

EDC letter of credit facility

On June 12, 2025, the Company amended and decreased the unsecured demand revolving letter of credit facility (the "LC Facility") with Export Development Canada ("EDC") in response to lower anticipated utilization, from $125.0 million to $100.0 million. Kiwetinohk's obligations under the LC Facility are supported by a performance security guarantee ("PSG") granted by EDC to the Credit Facility lender to guarantee the payment of certain amounts in respect of letters of credit. The PSG is valid to May 31, 2026 and may be extended from time-to-time at the option of Kiwetinohk and with the agreement of EDC. The Company expects to renew the PSG in May 2026 concurrently with its annual borrowing base review of the consolidated Credit Facility. At June 30, 2025, the Company has $60.4 million of capacity remaining under the LC Facility (December 31, 2024 - $77.0 million).

Base shelf prospectus

The Company filed a final short-form base shelf prospectus ("Prospectus") on May 27, 2024. The Prospectus provides financing flexibility and additional options for quicker access to public equity and/or debt markets as Kiwetinohk continues to pursue potential acquisition and other opportunities. It provides Kiwetinohk with the ability to issue up to $500 million of securities over a period of 25 months, if and when desirable.

There are no immediate plans to raise equity, debt or other forms of financing and net proceeds from the sale of any securities issued under the Prospectus could have a wide range of uses including to complete asset or corporate acquisitions, finance potential future growth opportunities, repay indebtedness, finance the Company’s ongoing capital program, or for other general corporate purposes.

Share capital

The Company is authorized to issue an unlimited number of voting common shares and an unlimited number of preferred shares, issuable in series.

On December 19, 2024, the Company renewed its normal course issuer bid ("NCIB"), allowing the Company to purchase and cancel up to 2,188,237 Common Shares prior to December 22, 2025. During the six months ended June 30, 2025, the Company purchased 8,848 Common Shares under the NCIB program at a total cost of $0.2 million (an average of $20.24 per share). No shares were repurchased during the 2024 year.

The Company weighs the benefits to shareholders of allocating funds to new capital expenditures versus utilizing the NCIB program and will continue to monitor the use of the NCIB program with the amount and timing of any purchases depending, among other things, on the share price, commodity prices and overall budget projections.

	For the three months ended June 30,		For the six months ended June 30,	
(000s)	**2025**	2024	**2025**	2024
Weighted average shares outstanding				
Basic	**43,823**	43,667	**43,823**	43,665
Diluted	**44,868**	44,149	**44,862**	44,029
Outstanding securities				
Common shares	**43,879**	43,668	**43,879**	43,668
Stock options[1]	**2,860**	2,740	**2,860**	2,740
Performance warrants[1]	**6,583**	6,708	**6,583**	6,708
Total diluted outstanding securities	**53,322**	53,116	**53,322**	53,116

1 - Balance presented includes all potentially dilutive stock options and performance warrants issued and outstanding and is not limited to those currently available for exercise. Refer to Note 12 of the Condensed Consolidated Interim Financial Statements for further information regarding share-based compensation plans.

At July 29, 2025, the Company has 43,857,794 Common Shares and no preferred shares outstanding.

Commitments, contractual obligations, and contingencies

$ millions	**2025**	**2026**	**2027**	**2028**	**2029**	**Thereafter**
Accounts payable	54.3	—	—	—	—	—
Cash-settled compensation liability [1]	10.8	3.6	1.2	—	—	3.7
Loans and borrowings [2]	—	—	204.6	—	—	—
Gathering, processing and transport	37.1	62.7	39.0	39.1	39.0	71.2
Natural gas purchases	3.8	—	—	—	—	—
Upstream and corporate lease liabilities	1.0	2.2	2.2	2.2	2.2	3.9
Power lease liabilities [3]	2.5	1.5	1.5	1.8	1.8	75.6
Other	—	0.4	0.4	0.4	0.4	—
Total	109.5	70.4	248.9	43.5	43.4	154.4

1 – Cash outflows relating to the DSU cash-settled compensation liability will be paid when each director retires. The Company has no available information to estimate the year of cash outflow and therefore the entirety of the DSU expected outflow has been assigned to "Thereafter".
2 – Assumes the outstanding debt on the Credit Facility as of June 30, 2025 is repaid on the facility's maturity date.
3 – The Company has not reached a FID on power projects as of the date hereof. The Company has the ability to terminate the lease and remove this financial obligation if FID is not achieved.

The Company currently has 29.7 MMcf/d of natural gas transportation commitments on the Nova Gas Transmission Ltd. to July 31, 2031. In addition, the Company holds a commitment to deliver approximately 120.0 MMcf/d of gas to Chicago on Alliance. The Company has extended its commitment on the US segment of the Alliance Pipeline until October 31, 2032, and the Canadian segment until October 31, 2026. The Company anticipates a toll extension on the Canadian segment of the Alliance Pipeline for a longer term starting November 1, 2025, with the expectation of aligning with the term committed to on the US segment pending a review and approval of tolls on the Canadian segment by the Canadian Energy Regulator.

The Company currently has secured 15,000 GJ per day of gas supply (approximately 13.1 MMcf per day) from natural gas producers through October 2025, preparing the Company to fully utilize its remaining Alliance pipeline capacity after taking into account deliveries of its own production.

Lease liabilities represent the undiscounted payments required under lease obligations as described in Note 5 of the condensed consolidated interim financial statements.

The Company is involved in litigation and disputes arising in the normal course of operations. Management is of the opinion that any potential litigation will not have a material adverse impact on the Company's financial position or results of operations as at June 30, 2025.

Related party information

For the three and six months ended June 30, 2025, the Company incurred a total of $0.7 million and $1.3 million, respectively (June 30, 2024 – $0.5 million and $0.7 million), in the following related party transactions:

- the Company has retained a law firm to provide legal services on corporate matters and a director of the Company is a partner of this law firm; and
- the Company has engaged an energy information services company to assist in the evaluation of prospective upstream oil and gas properties and a director of the Company is the Chairman of the Board of Directors of this company.

All related party transactions are incurred in the normal course of operations and recorded at the exchange amount which approximates the fair value of the services provided. There are no contractual commitments associated with related parties.

Risk factors and risk management

The Company's management team is focused on long-term strategic planning and has identified key material risks, uncertainties and opportunities associated with the Company's business that can impact the financial position, operations, cash flows and future prospects of the business. There were no significant changes in key risks identified during the three and six months ended June 30, 2025. For additional information on risk factors, refer to the Company's audited financial statements as at and for the year ended December 31, 2024 and the Company's Annual Information Form ("AIF") dated March 4, 2025 available on the SEDAR+ website at www.sedarplus.ca.

In order to reduce risk the Company employs subject matter experts that are highly qualified professionals with clearly defined roles and responsibilities, seeks to operate and control the majority of its properties and projects, utilizes proven technologies and will pursue new technologies where appropriate.

Control environment

Internal control over financial reporting is a process designed to provide reasonable assurance regarding the preparation of relevant, reliable, and timely financial information and that all the Company's assets are safeguarded, and daily transactions are appropriately authorized.

The Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") are responsible for internal controls over financial reporting to be designed under their supervision. Given the size of the Company and high involvement of the CEO and CFO in the day-to-day operating activities of the Company, there are appropriate disclosure controls and procedures in place to provide reasonable assurance that (i) material information relating to the Company is made known to the Company's CEO and CFO by others, 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 and reported within the time periods specified in securities legislation.

There were no changes in the Company's internal controls during the period beginning on April 1, 2025, and ending on June 30, 2025, that have materially affected, or are reasonably likely to materially affect, the Company's internal controls over financial reporting. It should be noted that a control system, including the Company's disclosure and internal controls and procedures, no matter how well conceived can provide only reasonable, but not absolute assurance that the objectives of the control system will be met, and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud.

Financial reporting

Changes in accounting policies including initial adoption
Effective January 1, 2025, the Company adopted the amendments to IAS 21 The Effect of Changes in Foreign Exchange Rates. It did not have a material impact on the Company's financial statements.

Critical accounting estimates
The significant accounting judgements and estimates used by the Company are discussed in the notes to the December 31, 2024 audited financial statements. Certain accounting policies require that management make appropriate decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, and expenses. Management reviews its estimates on a regular basis. The emergence of new information and changed circumstances may result in actual results or changes to estimate amounts that differ materially from current estimates. There were no material changes to how the Company evaluates critical accounting estimates and judgments during the three and six months ended June 30, 2025.

Financial instruments and risk management

The Company's financial instruments are classified and measured at amortized cost or fair value through profit or loss ("FVTPL").

Financial assets are measured at amortized cost if the financial asset is held within a business model whose objective is to hold financial assets in order to collect contractual cash flows, and the contractual cash flows give rise on specified dates to cash flows that are solely payments of principal and interest on the principal amount outstanding. All other financial assets are measured at FVTPL.

Financial instruments carried at fair value include share-based compensation liability and risk management contracts. Share-based compensation liability and risk management contracts are classified as a Level 2 measurement in the fair value measurement hierarchy. All other financial instruments are measured at amortized cost.

See "Risk management contracts" section of this MD&A for further information with respect to the Company's financial instruments, the risks associated therewith and the Company's efforts to manage such risks.

Credit risk

Credit risk is the risk of financial loss to the Company if a counterparty to a financial instrument fails to meet its contractual obligation. The Company is exposed to credit risk with respect to its accounts receivable and risk management contracts.

The Company's risk management contracts are held with large established financial institutions. The Company manages credit risk by ensuring transactions are only entered into with counterparties with strong credit worthiness and regular internal reviews are performed on the Company's exposure to these counterparties, the majority of which is short-term.

Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they are due. The Company operates in a capital-intensive industry with medium to long-term cash cycles. The Company may face lengthy development lead times, as well as risks associated with rising capital costs and timing of project completion because of the availability of resources, permits and other factors beyond its control. The Company regularly monitors its cash requirements by assessing its ability to generate cash flow from operations, access to external financing, debt obligations as they become due, and its expected future operating and capital expenditure requirements. The Company may adjust planned capital expenditures to manage liquidity risk as required.

Market risk

Market risk is the risk that fluctuations in market prices, such as foreign exchange rates, commodity prices, and interest rates will affect the Company's condensed consolidated interim statement of net income (loss) and comprehensive income (loss) to the extent the Company has outstanding financial instruments.

The Company uses financial risk management contracts to mitigate its exposure to the potential adverse impact of commodity price and exchange rate volatility. The primary objective of the risk management program is to protect cash flows from base production and ensure sufficient capital and liquidity is available to pursue Kiwetinohk's ongoing growth plans and significant capital development program.

Off-balance sheet arrangements

Except as disclosed in the Financial Statements, the Company has not entered into any guarantee or off-balance sheet arrangements that would materially impact the financial position or results of operations as at June 30, 2025.

Other

Non-GAAP and other financial measures

Throughout this MD&A and in other materials disclosed by the Company, the Company uses various specified financial measures including "non-GAAP financial measures", "non-GAAP financial ratios", "capital management measures" and "supplementary financial measures", in each case, as defined in National Instrument 52-112 *Non-GAAP and Other Financial Measures Disclosure* and explained in further detail below. The non-GAAP and other financial measures presented in this MD&A should not be considered in isolation or as a substitute for performance measures prepared in accordance with IFRS and should be read in conjunction with the Financial Statements. Readers are cautioned that these non-GAAP measures do not have any standardized meanings and should not be used to make comparisons between Kiwetinohk and other companies without also taking into account any differences in the method by which the calculations are prepared.

Non-GAAP Financial Measures

Operating netback & adjusted operating netback

"Operating netback" is calculated as commodity sales from production less royalty, operating, and transportation expenses. The Company also discloses "adjusted operating netback" which includes realized gain or loss on risk management contracts that settled in cash during the respective period and marketing income. Disclosing the impact of the realized gain or loss on risk management contracts and marketing income provides management and investors with a measure that reflects how the Company's risk management program and marketing income impacts its netback. The table below reconciles operating netback and adjusted operating netback to the most directly comparable GAAP measure, commodity sales from production:

	For the three months ended June 30,		For the six months ended June 30,	
$000s	**2025**	2024	**2025**	2024
Commodity sales from production	**138,419**	105,049	**306,811**	224,711
Royalty expenses	**(6,353)**	(9,470)	**(16,716)**	(18,537)
Operating expenses	**(18,190)**	(14,758)	**(33,438)**	(32,383)
Transportation expenses	**(17,336)**	(14,280)	**(32,395)**	(25,819)
Operating netback	**96,540**	66,541	**224,262**	147,972
Realized gain (loss) on risk management	**1,791**	1,660	**(2,706)**	3,678
Realized gain (loss) on risk management - purchases	**(861)**	1,882	**(4,322)**	2,999
Net commodity sales from purchases	**2,033**	87	**8,360**	597
Adjusted operating netback	**99,503**	70,170	**225,594**	155,246

Capital expenditures, net acquisitions (dispositions) & capital expenditures and net acquisitions (dispositions)

"Capital expenditures" is calculated as cash used in investing activities, excluding changes in non-cash working capital, settlements of contingent consideration, acquisitions and dispositions, and refundable payments made under the AESO connection process. The Company uses capital expenditures to monitor its investment in property, plant and equipment, exploration and evaluation and projects in development. "Net acquisitions (dispositions)" is calculated as cash used in acquisitions and proceeds from disposition. "Capital expenditures and net acquisitions (dispositions)" is equal to the sum of capital expenditures and net acquisitions (dispositions).
The table below reconciles capital expenditures, net acquisitions (dispositions) and capital expenditures and net acquisitions (dispositions) to the most directly comparable GAAP measure, cash flow used in investing activities:

	For the three months ended June 30,		For the six months ended June 30,	
$000s	**2025**	2024	**2025**	2024
Cash flow used in investing activities	**58,853**	66,052	**142,236**	135,335
Net change in non-cash investing working capital	**(7,625)**	4,387	**(17,682)**	11,857
Power connection process payment	**—**	—	**(8,000)**	(985)
Capital expenditures and net acquisitions (dispositions)	**51,228**	70,439	**116,554**	146,207
Proceeds from disposition	**—**	—	**21,050**	21
Net acquisitions (dispositions)	**—**	—	**21,050**	21
Capital expenditures	**51,228**	70,439	**137,604**	146,228

Net commodity sales from purchases & Net commodity sales from purchases after hedging

Commodity sales from purchases and commodity purchases, transportation and other is revenue from the sale of purchased natural gas or condensate less associated commodity purchases, transportation expense and related marketing fees. "Net commodity sales from purchases" is used as a key measure of how the Company is managing its take or pay pipeline commitments. The Company also enters into risk management contracts associated with marketing activities to protect the basis differential between the Alberta and Chicago sales points related to net commodity sales from purchase. "Net commodity sales from purchases after hedging" includes the impact of these basis differential contracts. The Company has disclosed the reconciliation of net commodity sales from purchases & net commodity sales from purchases after hedging to the most directly comparable GAAP measure, commodity sales from purchases, as well as its comparison to prior periods in this MD&A within the "Results of operations" section.

Non-GAAP Financial Ratios

Operating netback per boe & adjusted operating netback per boe

"Operating netback per boe" and "adjusted operating netback per boe" is calculated as operating netback and adjusted operating netback, respectively, divided by total production for the period as measured by boe. Operating netback per boe and adjusted operating netback per boe are key industry benchmarks and assist management with evaluating operating performance and efficiency on a comparable basis. The Company has disclosed the calculations of operating netback per boe & adjusted operating netback per boe, as well as its comparison to prior periods in this MD&A within the "Results of operations" section.

Adjusted funds flow from operations per boe

"Adjusted funds flow from operations per boe" is cash flow from operating activities before changes in net change in non-cash working capital from operating activities, asset retirement obligations, and transaction costs divided by total production for the period. Management considers adjusted funds flow from operations per boe as a key measure to analyze performance as it demonstrates the Company’s ability to generate the cash necessary to fund future capital investments, asset retirement obligations and to repay debt. The composition of adjusted funds flow from operations per boe is disclosed in this MD&A within the Results of operations section.

Capital Management Measures

Adjusted funds flow from operations

"Adjusted funds flow from operations" is cash flow from operating activities before changes in net change in non-cash working capital from operating activities, asset retirement obligations, and transaction costs. Management considers adjusted funds flow from operations as a key measure to analyze performance as it demonstrates the Company’s ability to generate the cash necessary to fund future capital investments, asset retirement obligations and to repay debt. The composition of adjusted funds flow from operations, as well as its comparison to prior periods, is disclosed in this MD&A within the "Results of operations" section.

Free funds flow (deficiency) from operations

"Free funds flow (deficiency) from operations" is adjusted funds flow from operations less capital expenditures prior to property acquisitions. Management uses free funds flow as a key measure to analyze the Company’s ability to generate returns for investors and repay debt. The composition of Free funds flow (deficiency) from operations, as well as its comparison to prior periods, is disclosed in this MD&A within the "Results of operations" section.

Adjusted working capital surplus (deficit)

"Adjusted working capital surplus (deficit)" is comprised of current assets less current liabilities excluding risk management contracts. Adjusted working capital is used by management to provide a more complete understanding of the Company's liquidity. The current portion of risk management contracts has been excluded as there is no intention to realize these financial instruments and they are also subject to a high degree of volatility prior to ultimate settlement. The following table includes the composition of adjusted working capital surplus (deficit), as well as its comparison to prior period.

$000s	**June 30, 2025**	December 31, 2024
Current assets	**80,583**	68,323
Current liabilities	**(78,707)**	(112,085)
Working capital surplus (deficit)	**1,876**	(43,762)
Remove short term risk management contracts net liability (asset)	**(3,965)**	20,900
Adjusted working capital deficit	**(2,089)**	(22,862)

Net debt and net debt to adjusted funds flow from operations or adjusted funds flow from operations

"Net debt" is comprised of loans and borrowings plus adjusted working capital surplus (deficit) and represents the Company's net financing obligations. Net debt is used by management to provide a more complete understanding of the Company's capital structure and provides a key measure to assess the Company's liquidity. "Net debt to adjusted funds flow from operations" is a liquidity ratio that represents the Company's ability to cover its net debt with its adjusted funds flow from operations. Net debt to adjusted funds flow is calculated as net debt divided by the trailing 12-month adjusted funds flow from operations. The composition of Net debt and net debt to adjusted funds flow from operations, as well as its comparison to prior periods, is disclosed in this MD&A within the "Capital resources and liquidity" section.

Supplementary Financial Measures

This MD&A contains supplementary financial measures expressed as: (i) cash flow from operating activities, adjusted funds flow on a per share – basic and per share – diluted basis, (ii) realized prices, petroleum and natural gas sales, adjusted funds flow, revenue, royalties, operating expenses, transportation, realized loss on risk management, and net commodity sales from purchases on a $/bbl, $/Mcf or $/boe basis and (iii) royalty rate.

Cash flow from operating activities, adjusted funds flow and free cash flow on a per share – basic and diluted basis are calculated by dividing the cash flow from operating activities, adjusted funds flow or free cash flow, as applicable, over the referenced period by the weighted average basic or diluted shares outstanding during the period determined under IFRS.

Metrics presented on a $/bbl, $/Mcf or $/boe basis are calculated by dividing the respective measure, as applicable, over the referenced period by the aggregate applicable units of production (bbl, Mcf or boe) during such period.

Royalty rate is calculated by dividing royalties by petroleum and natural gas sales less royalty and other revenue.

Forward-Looking Statements

Certain information set forth in this MD&A contains forward-looking information and statements. Such forward-looking statements or information are provided for the purpose of providing, without limitation, information about management's current expectations of business strategy, and management's assessment of future plans and operations. Forward-looking statements or information typically contain statements with words such as "anticipate", "believe", "continue", "expect", "plan", "estimate", "project", "potential", "may", “ongoing”, “seek”, “should”, “will”, "would" or similar words suggesting future outcomes or statements regarding future performance and outlook. Readers are cautioned that assumptions used in the preparation of such information may prove to be incorrect. Events or circumstances may cause actual results to differ materially from those predicted as a result of numerous known and unknown risks, uncertainties and other factors, many of which are beyond the control of the Company.

In particular, this MD&A contains forward-looking statements pertaining to the following:

- the Upstream business unit's properties that are expected to offer competitive economic resource potential and development upside;
- the Power business unit's development strategy to enable the future production of reliable, dispatchable, and affordable energy with lower emissions intensity relative to energy generated through Alberta’s electric grid today.;
- expectations regarding the Company's formal business strategy review and the associated timelines to complete such process;
- the Company’s detailed 2025 financial and operational guidance and adjustments to the previously communicated 2025 guidance, including revised sensitivity for adjusted funds flow from operations and related ratio of net debt to adjusted funds flow from operations;
- expectations of continued premiums in the Chicago natural gas benchmark pricing when compared to Alberta markets;
- anticipated well production;
- the timing and costs of the Company's capital projects, including, but not limited to, drilling, production and completion of certain wells, the delineation of the Company's Montney acreage and technology initiatives;
- the Company's ability to continue to access the Chicago market and its expectation to renew the Canadian segment of the Alliance pipeline to a similar term as the US segment, as well as any impact of potential tolling reviews by the Canadian Energy Regulator;
- the timing and amount of cash taxes for the Company's US subsidiary and the Company's expectations regarding being taxable in Canada and the timing thereof;
- the Company's expectation of a future transaction on its Homestead solar project;
- the anticipated outcomes of successful execution of the Company's investment and financing strategies for its power project portfolio, including the Homestead project;
- future Power development expenditures not expected to meet capitalization criteria;
- the anticipated outcomes of the Company’s capital program;
- expectations regarding the Company’s plan to utilize its funds from operations to fund its working capital requirements and capital program, and free funds from operations to reduce the balance drawn on the Credit Facility;
- provision liabilities and the estimated future cash flows to settle such obligations;
- operating and capital costs in 2025;
- sufficiency of funds to meet the Company's working capital requirements and anticipated drilling through 2025;
- timing for the next scheduled redetermination of the borrowing base on the Company's consolidated Credit Facility and EDC LC Facility, including the PSG, and the borrowing base extended to the Company under such facilities at such time;
- use of the Credit Facility capacity to adapt plans to market environment;
- the Company's future plans to potentially issue securities under the Prospectus and the possible use of proceeds therefrom;
- treatment under governmental regulatory regimes, including taxes and tax regimes, environmental regulations and related abandonment and reclamation obligations;

- the Company's expectations on timing and use of the NCIB program during 2025;
- the Company's expectations regarding the impact of future accounting pronouncements on the consolidated financial statements;
- expectations regarding the Company’s ability to continue to manage risk through hedging contracts and risk management contracts;
- the Company’s ability to continue to meet its pipeline transportation commitments;
- expectations regarding the future risk associated with take or pay pipeline obligations;
- the Company’s ability to continue to benefit from Alberta’s drilling and completion cost allowance program;
- the expected demand for, and prices and inventory levels of, petroleum products, including NGL;
- the Company's expectations regarding material adverse litigation; and
- the impact of current market conditions on the Company.

In addition to other factors and assumptions that may be identified in this MD&A, assumptions have been made regarding, among other things:

- the expectation of ~90% of natural gas sales being directed to the Chicago market during 2025;
- the timing and costs of the Company's capital projects, including drilling, production and completion of certain wells and the delineation of the Company's Montney acreage;
- costs to abandon wells or reclaim property;
- the ability of the Company to mitigate the cost of transportation services in excess of current production needs;
- the impact of increasing competition;
- general business, economic and market conditions
- the general stability of the economic and political environment in which the Company operates;
- the ability of the Company to obtain qualified staff, equipment and services in a timely and cost efficient manner;
- the ability of the operator of the projects that the Company has an interest in to operate in a safe, efficient and effective manner;
- future commodity and power prices;
- currency, exchange and interest rates;
- near and long-term impacts of tariffs or other changes in trade policies in North America, as well as globally;
- the Company's unique position to deliver additional value to shareholders;
- the regulatory framework regarding royalties, taxes, power, renewable and environmental matters in the jurisdictions in which the Company operates;
- the ability of the Company to obtain the required capital to finance its exploration, development and other operations and meet its commitments and financial obligations;
- the ability of the Company to extend the PSG under the EDC LC Facility;
- the ability of the Company to secure adequate product processing, transportation, fractionation and storage capacity on acceptable terms and the capacity and reliability of facilities;
- anticipated timelines and budgets being met in respect of drilling and completions programs and other operations;
- the impact of natural disaster, war, hostilities, civil insurrection, pandemics, instability and political and economic conditions (including the ongoing Russian-Ukrainian conflict and conflict in the Middle East) on the Company;
- the ability of the Company to successfully market its products;
- power project debt will be held at the project level;
- power projects will be funded by third parties, as currently anticipated; and
- the Company's operational success and results being consistent with current expectations.

Readers are cautioned that the foregoing list is not exhaustive of all factors and assumptions that have been used. Although the Company believes that the expectations reflected in such forward-looking statements or information are reasonable, undue reliance should not be placed on forward-looking statements as the Company can give no assurance that such expectations will prove to be correct.

Forward-looking statements or information involve a number of risks and uncertainties that could cause actual results to differ materially from those anticipated by the Company and described in the forward-looking statements or information. These risks and uncertainties include, among other things:

- those risks set out in the AIF under "Risk Factors";
- the ability of management to execute its business plan;
- general economic and business conditions;
- the ability of the Company to proceed with the power generation projects as described or at all;
- global economic, financial and political conditions, including the results of ongoing trade negotiations in North America, as well as globally;
- risks of natural disaster, war, hostilities, civil insurrection, pandemics, instability and political and economic conditions (including the ongoing Russian-Ukrainian conflict and conflict in the Middle East) in or affecting jurisdictions in which the Company operates;
- the risks of the power and renewable industries;
- operational and construction risks associated with certain projects;
- the possibility that government policies or laws may change or governmental approvals may be delayed or withheld;
- risks relating to regulatory approvals and financing;
- uncertainty regarding provincial and federal government electricity regulations and policies;
- uncertainty involving the forces that power certain renewable projects;
- the Company's ability to enter into or renew leases;
- potential delays or changes in plans with respect to power and solar projects or capital expenditures;
- risks associated with rising capital costs and timing of project completion;
- fluctuations in commodity and power prices, foreign currency exchange rates and interest rates;
- inflation and increased pricing and costs for services, personnel and other items;
- risks inherent in the Company's marketing operations, including credit risk;
- health, safety, environmental and construction risks;
- risks associated with existing and potential future lawsuits and regulatory actions against the Company;
- uncertainties as to the availability and cost of financing;
- the ability to secure adequate product processing, transportation, fractionation and storage capacity on acceptable terms;
- processing, pipeline and fractionation infrastructure outages, disruptions and constraints;
- financial risks affecting the value of the Company's investments;
- risks related to the interpretation of, and/or potential claims made pursuant to, the Government of Canada amendments to the deceptive marketing practices provisions of the Competition Act (Canada) regarding greenwashing; and
- other risks and uncertainties described elsewhere in this document and in Kiwetinohk's other filings with Canadian securities authorities.

Readers are cautioned that the foregoing list is not exhaustive of all possible risks and uncertainties.

The forward-looking statements and information contained in this MD&A speak only as of the date of this MD&A and the Company undertakes no obligation to publicly update or revise any forward-looking statements or information, except as expressly required by applicable securities laws.

Future Oriented Financial Information

This MD&A contains information that may constitute future-orientated financial information or financial outlook information (collectively, "FOFI") about the Company's prospective financial performance, financial position or cash flows, all of which is subject to the same assumptions, risk factors, limitations and qualifications as set forth above. In particular, this MD&A contains information concerning expectations for adjusted funds flow from operations and the ratio of net debt to adjusted funds flow from operations. Readers are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise or inaccurate and, as such, undue reliance should not be placed on FOFI. The Company's actual results, performance and achievements could differ materially from those expressed in, or implied by, FOFI. The Company has included FOFI in order to provide readers with a more complete perspective on the Company's future operations and management's current expectations relating to the Company's future performance. Readers are cautioned that such information may not be appropriate for other purposes. FOFI contained herein was made as of the date of this MD&A. Unless required by applicable laws, the Company does not undertake any obligation to publicly update or revise any FOFI statements, whether as a result of new information, future events or otherwise.

Abbreviations

$/bbl	dollars per barrel
$/boe	dollars per barrel equivalent
$/GJ	dollars per gigajoule
$/Mcf	dollars per thousand cubic feet
AECO	the daily average benchmark price for natural gas at the physical storage and trading hub for natural gas on the TransCanada Alberta transmission system which is the delivery point for various benchmark Alberta index prices
AESO	Alberta Electric Systems Operator
AIF	Annual Information Form
bbl/d	barrels per day
boe	barrel of oil equivalent, including crude oil, condensate, natural gas liquids, and natural gas (converted on the basis of one boe per six Mcf of natural gas)
boe/d	barrel of oil equivalent per day
CCS	Carbon Capture and Storage
DI	daily index
FID	Final Investment Decision
GJ	gigajoule
GW	one billion watts
Mcf	thousand cubic feet
Mcf/d	thousand cubic standard feet per day
MI	monthly index
MMcf/d	million cubic feet per day
MMBtu	one million British Thermal Units is a measure of the energy content in gas
MMBtu/d	one million British thermal units per day
NGLs	natural gas liquids, which includes butane, propane, and ethane
US$/bbl	US Dollars per barrel
US$/MMbtu	US Dollars per million British thermal units
WTI	West Texas Intermediate, the reference price paid for crude oil of standard grade in US dollars at Cushing, Oklahoma

Oil and gas advisories

For the purpose of calculating unit costs, natural gas is converted to a barrel of oil equivalent using six thousand cubic feet of natural gas equal to one barrel of oil unless otherwise stated. The term barrel of oil equivalent (boe) may be misleading, particularly if used in isolation. A boe conversion ratio for gas of 6 Mcf:1 boe is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from an energy equivalency of 6:1, utilizing a conversion ratio of 6:1 may be misleading as an indication of value.

This MD&A includes references to sales volumes of "crude oil", "oil and condensate", "NGLs" and "natural gas" and revenues therefrom. National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities, includes condensate within the NGLs product type. Kiwetinohk has disclosed condensate as combined with crude oil and separately from other NGLs since the price of condensate as compared to other NGLs is currently significantly higher, and Kiwetinohk believes that this crude oil and condensate presentation provides a more accurate description of its operations and results therefrom. Crude oil therefore refers to light oil, medium oil, tight oil, and condensate. Notwithstanding the foregoing, the Company's amount of crude oil that constitutes light oil, medium oil and tight oil is immaterial, and the majority of KEC's crude oil is comprised of condensate. NGLs refers to ethane, propane, butane, and pentane combined. Natural gas refers to conventional natural gas and shale gas combined.

CORPORATE INFORMATION

Management

Pat Carlson
Chief Executive Officer

Janet Annesley
Chief Sustainability Officer

Mike Backus
Chief Operating Officer, Upstream

Jakub Brogowski
Chief Financial Officer

Mike Hantzsch
Senior Vice President, Midstream and Market Development

Sue Kuethe
Executive VP, Land and Community Inclusion

Chris Lina
Senior Vice President, Projects

Craig Parsons
Vice President, Finance, Power Division

Fareen Sunderji
President, Power

Lisa Wong
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Corporate Head Office

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Bankers

Bank of Montreal
ATB Financial
National Bank of Canada
Royal Bank of Canada
Bank of Nova Scotia
Business Development Bank of Canada

Auditor

Deloitte LLP
Calgary, AB

Board of Directors

Kevin Brown
Board Chair

Beth Reimer-Heck
Lead Director

Judith Athaide
Director

Colin Bergman
Director

Pat Carlson
Director and Chief Executive Officer

Leland Corbett
Director

Alicia Kilmer
Director

Kaush Rakhit
Director

Steve Sinclair
Director

John Whelen
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Reserve Engineers

McDaniel & Associates Consultants Ltd.
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Transfer Agent

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Stock Symbol

KEC
Toronto Stock Exchange