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 nine months ended September 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 nine months ended September 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 November 4, 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 centered on the Company's upstream assets and an orderly exit from its power business.

On October 28, 2025, the Company announced a plan of arrangement under which Cygnet Energy Ltd. will acquire all of the issued and outstanding common shares of Kiwetinohk for cash consideration of $24.75 per Share.

The Arrangement has been unanimously approved by Kiwetinohk's Board of Directors (with conflicted directors abstaining). A special meeting of shareholders will be held on or about December 16, 2025, to consider and vote on the Arrangement. Closing will occur thereafter upon satisfaction or waiver of all conditions, including required shareholder approvals, court approval and customary closing conditions. For further details on the arrangement, please refer to the news release dated October 28, 2025, available on the SEDAR+ website at www.sedarplus.ca or via the Company's website. Additional details will be provided through the Company's management information circular which will be mailed to shareholders in advance of the shareholder meeting.

A description of the Company's 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 previously involved in advancing pre-construction development plans for a portfolio of Alberta-based power generation projects that included solar, and natural gas-fired power generation as well as carbon capture and storage ("CCS") facilities. As of November 4, 2025, the Company has sold or cancelled six projects within its portfolio of projects and currently has one natural-gas fired development project remaining in its portfolio. This project remains for sale with management's intention to fully exit from all power development projects prior to year-end.

Financial and operating highlights

	For the three months ended September 30, 2025	2024	For the nine months ended September 30, 2025	2024
Production				
Oil & condensate (bbl/d)	**10,304**	8,898	**10,465**	8,318
NGLs (bbl/d)	**4,390**	3,766	**4,435**	3,870
Natural gas (Mcf/d)	**102,721**	79,992	**105,871**	86,546
Total (boe/d)	**31,814**	25,996	**32,545**	26,612
Oil & condensate % of production	**33%**	35%	**32%**	31%
NGL % of production	**14%**	14%	**14%**	15%
Natural gas % of production	**53%**	51%	**54%**	54%
Realized prices				
Oil & condensate ($/bbl)	**84.08**	93.47	**88.67**	95.89
NGLs ($/bbl)	**37.33**	41.36	**40.85**	43.47
Natural gas ($/Mcf)	**3.93**	2.49	**4.71**	2.92
Total ($/boe)	**45.09**	45.65	**49.39**	45.79
Royalty expense ($/boe)	**(2.08)**	(3.44)	**(2.57)**	(3.67)
Operating expenses ($/boe)	**(6.09)**	(7.19)	**(5.77)**	(6.80)
Transportation expenses ($/boe)	**(5.55)**	(6.04)	**(5.48)**	(5.52)
Operating netback ($/boe) [1]	**31.37**	28.98	**35.57**	29.80
Realized gain (loss) on risk management ($/boe) [2]	**1.35**	1.31	**0.14**	0.93
Realized gain (loss) on risk management - purchases ($/boe) [2]	**(1.12)**	(0.10)	**(0.85)**	0.38
Net commodity sales from purchases ($/boe) [1]	**1.96**	0.70	**1.59**	0.31
Adjusted operating netback ($/boe) [1]	**33.56**	30.89	**36.45**	31.42
Financial results ($000s, except per share amounts)				
Commodity sales from production	**131,972**	109,166	**438,783**	333,877
Net commodity sales from purchases [1]	**5,750**	1,683	**14,110**	2,280
Cash flow from operating activities	**83,872**	66,867	**274,028**	203,282
Adjusted funds flow from operations [1]	**98,782**	64,746	**303,042**	200,407
Per share basic	**2.25**	1.48	**6.91**	4.59
Per share diluted	**2.14**	1.46	**6.69**	4.54
Net debt to adjusted funds flow from operations [1]	**0.48**	0.91	**0.48**	0.91
Free funds flow (deficiency) from operations (excluding acquisitions/ dispositions) [1]	**27,967**	(26,298)	**94,623**	(36,865)
Net income	**18,106**	—	**132,325**	17,089
Per share basic	**0.41**	0.74	**3.01**	0.39
Per share diluted	**0.39**	0.73	**2.95**	0.39
Capital expenditures [1]	**70,815**	91,044	**208,419**	237,272
Net dispositions [1]	**(5,550)**	(297)	**(26,600)**	(318)
Capital expenditures and net dispositions [1]	**65,265**	90,747	**181,819**	236,954

	September 30, 2025	December 31, 2024
Balance sheet ($000s, except share amounts)		
Total assets	**1,244,359**	1,215,575
Long-term liabilities	**327,562**	388,452
Net debt [1]	**178,610**	272,764
Adjusted working capital surplus (deficit) [1]	**17,270**	(22,862)
Weighted average shares outstanding		
Basic	**43,827,848**	43,690,640
Diluted	**45,300,146**	44,571,772
Shares outstanding end of period	**43,788,097**	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 nine months of 2025, Kiwetinohk has made the following positive revisions to its annual guidance targets. Target ranges have been updated to reflect current strip pricing and revised outlooks for operating performance.

Updated guidance ranges are summarized and contrasted with the most recent previous targets in the table below. Notably,

- the low-end of production has been increased based on strong well results and successful completion of the infrastructure expansion;
- the high-end of royalty rates has been decreased, driven by reduced AECO pricing and new-well incentives;
- operating expenses have decreased due to strong production levels;
- transportation expenses have decreased due to lower NGL transportation charges and an expected reduction in Alliance Pipeline tolls effective November 2025;
- capital expenditures have decreased to reflect lower well costs achieved through efficient drilling and completion execution and improved cost certainty;
- adjusted funds from operations have increased as a result of factors noted above and a revision of the expected commodity prices for the remainder of the year to reflect current strip pricing.

Updated guidance is summarized in the table below.

2025 Financial & Operational Guidance		**Current November 4, 2025**	Previous July 30, 2025
Production (2025 average)	Mboe/d	33.0 - 34.0	32.0 - 34.0
Oil & liquids	%	45% - 49%	45% - 49%
Natural gas [1]	%	51% - 55%	51% - 55%
Financial			
Royalty rate	%	5% - 6%	5% - 7%
Operating costs	$/boe	$6.00 - $6.25	$6.25 - $6.75
Transportation	$/boe	$5.25 - $5.50	$5.50 - $5.75
Corporate G&A expense [2]	$/boe	$1.95 - $2.15	$1.95 - $2.15
Cash taxes [3]	$MM	$—	$—
Upstream Capital [4]	$MM	$280 - $288	$290 - $305
DCET [5]	$MM	$265 - $273	$270 - $285
Plant expansion, production maintenance and other	$MM	$15	$20

2025 Guidance Sensitivities		**Current November 4, 2025**
2025 Adjusted Funds Flow from Operations commodity pricing [4, 6]		
Strip (October 31) US$61/bbl WTI & US$3.75/MMBtu HH	$MM	$395 - $410
US$ WTI +/- $1.00/bbl [7]	$MM	+/- $0.8
US$ Chicago +/- $0.10/MMBtu [7]	$MM	+/- $1.0
CAD$ AECO 5A +/- $0.10/GJ [7]	$MM	+/- $0.1
Exchange Rate (USD/CAD) +/- $0.01 [7]	$MM	+/- $0.8
2025 Net debt to Adjusted Funds Flow from Operations [4, 6]		
Strip (October 31) US$61/bbl WTI & US$3.75/MMBtu HH	X	0.4x

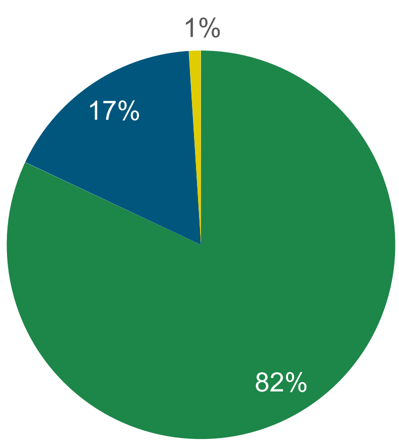
1 – ~90% is expected to be sold into the Chicago market in 2025.
2 – Includes G&A expenses for all divisions of Kiwetinohk – corporate, upstream, power and business development.
3 – Kiwetinohk's U.S. subsidiary expects to pay immaterial cash taxes annually. No Canadian taxes are anticipated to be paid 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. See "Non-GAAP and other financial measures" section 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 updated.
7 – Assumes US$61/bbl WTI, US$3.75/mmbtu HH, US$1.58/mmbtu HH - AECO basis diff, 0.71 USD/CAD.

Capital expenditures

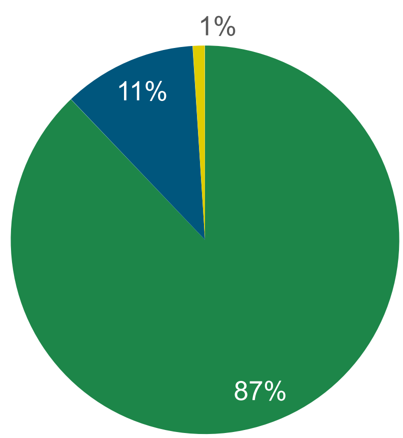
	For the three months ended September 30,		For the nine months ended September 30,	
$000s	**2025**	2024	**2025**	2024
Drilling, completions, and equipping	**58,018**	80,915	**182,355**	202,698
Facilities, pipelines, roads and optimization	**12,020**	7,425	**22,703**	26,271
Power projects	**21**	1,446	**383**	4,364
Land and other	**26**	133	**665**	1,003
Capitalized G&A - upstream	**730**	1,041	**2,313**	2,379
Capitalized G&A - power	**—**	84	**—**	557
Capital expenditures [1]	**70,815**	91,044	**208,419**	237,272
Upstream net dispositions [1]	**(30)**	(297)	**(80)**	(318)
Power net dispositions [1]	**(5,520)**	—	**(26,520)**	—
Capital and net dispositions [1]	**65,265**	90,747	**181,819**	236,954

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.

Capital expenditures Q3 2025[1]



Capital expenditures YTD 2025[1]



1 – Capital expenditures shown are before acquisitions/dispositions.

Drilling, completions and equipping · Facilities, pipelines, roads and optimization · Power projects · Land and other · Total capitalized G&A

Drilling, completions and equipping

For the three and nine months ended September 30, 2025, the Company invested $58.0 million and $182.4 million, respectively, to advance its development program through execution of a two-rig drilling program as outlined below:

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

1 - DUC refers to a drilled uncompleted well.

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 this development program with nine wells drilled during the nine months ended September 30, 2025, including one Placid Montney well which may be completed at a later date. Kiwetinohk's performance has benefited from a reduction in well costs during the year, achieved through efficient drilling and completion execution and supporting the positive revisions to annual upstream capital guidance previously discussed.

Facilities, pipelines, roads and optimization

For the three and nine months ended September 30, 2025, the Company invested $12.0 million and $22.7 million, respectively, to build facilities, pipelines, and roads required to grow production levels. During the three months ended September 30, 2025, the Company completed the expansion of the 5-31 gas plant in Simonette, which now has a capacity of 45 MMcf/d and brings the total owned and operated processing capacity in Simonette to 135 MMcf/d.

Kiwetinohk's 2025 capital program has continued to focus facility and other infrastructure spend on investments required to support base production and planned growth.

Power development projects

In the second quarter of 2025, the Company announced its plans to divest its power development portfolio to initiate an orderly exit from the power development business. During the nine months ended September 30, 2025, the Company invested $3.7 million, including a recovery of $0.6 million in the third quarter of 2025, in order to preserve existing projects' positions in the regulatory approval queue and retain project value within the power development portfolio during project sales negotiations.

During the nine months ended September 30, 2025, the Company sold or cancelled five of seven of its power projects, including its Homestead and Phoenix solar projects, and the Opal, Flipi and Little Flipi natural gas-fired power projects. All projects except for Homestead Solar were fully impaired in 2024, resulting in a net gain on disposition of $11.3 million through total aggregate gross proceeds of $26.5 million.

Subsequent to September 30, 2025, the Company sold its early stage Granum solar development project for immaterial proceeds.

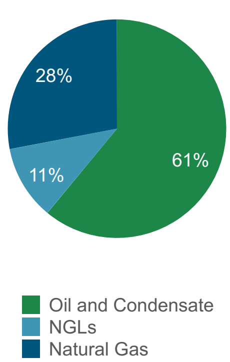
Results of operations

Production

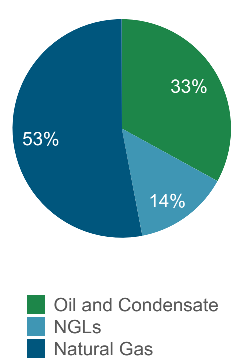
	For the three months ended September 30,		For the nine months ended September 30,	
	2025	2024	**2025**	2024
Oil & condensate (bbl/d)	**10,304**	8,898	**10,465**	8,318
NGLs (bbl/d) [1]	**4,390**	3,766	**4,435**	3,870
Natural gas (Mcf/d)	**102,721**	79,992	**105,871**	86,546
Total production (boe/d)	**31,814**	25,996	**32,545**	26,612
Oil & condensate % of production	**33%**	35%	**32%**	31%
NGL % of production	**14%**	14%	**14%**	15%
Natural gas % of production	**53%**	51%	**54%**	54%
Total production volumes %	**100%**	100%	**100%**	100%

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

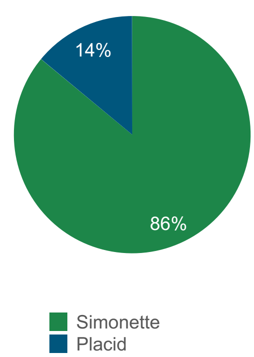
Revenue Mix ($)
Q3 2025



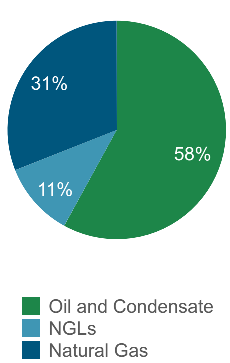
Production Mix (boe)
Q3 2025



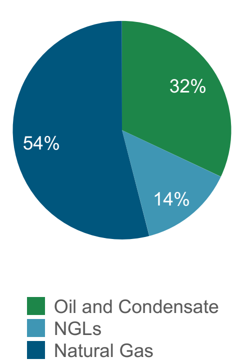
Production by Area (boe)
Q3 2025



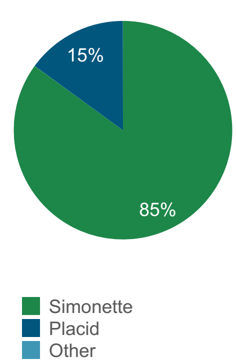
YTD 2025



YTD 2025



YTD 2025



Production for the three and nine months ended September 30, 2025 increased by 22% to 31,814 boe/d and 32,545 boe/d, respectively, relative to the 2024 comparative periods. The increase is attributable to the Company's ongoing capital development program, with a total of twelve new wells placed into production during the nine months ended September 30, 2025.

The composition of the Company's production during the three months ended September 30, 2025 was 33% oil and condensate, 14% NGLs, and 53% natural gas. For the nine months ended September 30, 2025, the Company's production profile was 32% oil and condensate, 14% NGLs, and 54% natural gas. The production profile in both periods was consistent with the comparative periods.

Benchmark and realized prices

	For the three months ended September 30,		For the nine months ended September 30,	
	2025	2024	**2025**	2024
Liquid benchmark prices				
WTI (US$/bbl)	**64.93**	75.09	**66.70**	77.54
WTI (CDN$/bbl)	**89.42**	102.42	**93.36**	105.50
Edmonton Light (CDN$/bbl)	**86.38**	99.06	**88.65**	98.83
Natural gas benchmark prices				
Henry Hub (US$/MMBtu)	**3.07**	2.16	**3.39**	2.10
Chicago City Gate MI (US$/MMBtu)	**2.70**	1.76	**3.20**	1.95
Chicago City Gate DI (US$/MMBtu)	**2.77**	1.78	**3.21**	2.08
AECO 5A (CDN$/GJ)	**0.60**	0.65	**1.42**	1.38
AECO 7A (CDN$/GJ)	**0.94**	0.77	**1.61**	1.36
Foreign exchange rates (USD/CAD)	**0.73**	0.73	**0.72**	0.74

	For the three months ended September 30,		For the nine months ended September 30,	
	2025	2024	**2025**	2024
Realized prices (before impact of hedging program)				
Oil & condensate ($/bbl)	**84.08**	93.47	**88.67**	95.89
NGLs ($/bbl)	**37.33**	41.36	**40.85**	43.47
Natural gas ($/Mcf)	**3.93**	2.49	**4.71**	2.92
Total ($/boe)	**45.09**	45.65	**49.39**	45.79

Crude oil prices for the three and nine months ended September 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 nine months ended September 30, 2025 declining relative to the comparative periods in 2024 as a result of increased North American supply pressure and lower contract pricing for the April 2025 - April 2026 contract year.

Average Henry Hub natural gas prices increased to US $3.07 and US $3.39 per MMBtu in the three and nine months ended September 30, 2025, respectively, when compared to US $2.16 and US $2.10 per MMBtu in the comparative periods of 2024. Higher prices on a three month basis were due to increased LNG export demand, and higher domestic industrial demand, while the impact of an abnormally cold winter on North American natural gas inventories also contributed to higher prices on a nine month basis. The Chicago City Gate monthly index benchmark for natural gas also increased over both periods for the same reasons, with the Chicago to Henry Hub basis consistent with the 2024 comparative periods.

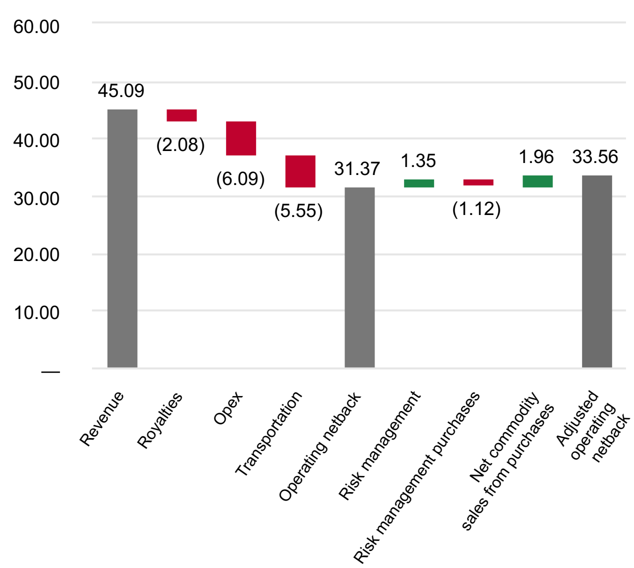
Natural gas prices in Alberta at AECO Hub increased alongside Henry Hub and Chicago pricing, supported by incremental LNG export demand and increasing demand for power generation, even while storage levels in the basin remained elevated compared to prior years. On average, AECO Monthly 7A spot prices increased to $0.94/GJ and $1.61/GJ during the three and nine months ended September 30, 2025, respectively, compared to $0.77/GJ and $1.36/GJ in the same periods in 2024.

Operating netback

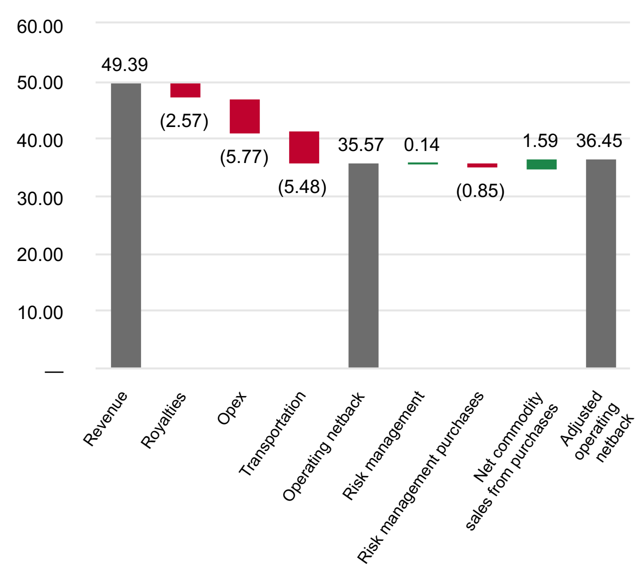
	For the three months ended September 30,		For the nine months ended September 30,	
	2025	2024	**2025**	2024
Realized price ($/boe)	**45.09**	45.65	**49.39**	45.79
Royalty expenses ($/boe)	**(2.08)**	(3.44)	**(2.57)**	(3.67)
Operating expenses ($/boe)	**(6.09)**	(7.19)	**(5.77)**	(6.80)
Transportation expenses ($/boe)	**(5.55)**	(6.04)	**(5.48)**	(5.52)
Operating netback ($/boe) [1]	**31.37**	28.98	**35.57**	29.80
Realized gain (loss) on risk management ($/boe) [2]	**1.35**	1.31	**0.14**	0.93
Realized gain (loss) on risk management - purchases ($/boe) [2]	**(1.12)**	(0.10)	**(0.85)**	0.38
Net commodity sales from purchases ($/boe) [1]	**1.96**	0.70	**1.59**	0.31
Adjusted operating netback ($/boe) [1]	**33.56**	30.89	**36.45**	31.42
Total production (boe/d)	**31,814**	25,996	**32,545**	26,612

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 includes settlement of financial hedges on production and foreign exchange, with gain (loss) on contracts associated with purchases presented separately.

Q3 2025 ($/boe)



YTD 2025 ($/boe)



Operating netback for the three and nine months ended September 30, 2025 was $31.37/boe and $35.57/boe, respectively, relative to the 2024 comparative periods of $28.98/boe and $29.80/boe. The increases in operating netback reflected higher realized pricing over the nine month period and cost savings in royalties, operating expenses and transportation expenses in both periods, as described further 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 $33.56/boe and $36.45/boe for the three and nine months ended September 30, 2025, respectively. The Company was successful in managing its exposure to excess transport commitments, realizing net commodity sales from purchases after hedging of $0.84/boe and $0.74/boe, respectively, during the three and nine month periods (described further below).

The Company's risk management program on produced volumes and foreign exchange contracts delivered gains of $1.35/boe and $0.14/boe, respectively, during the three and nine months ended September 30, 2025, relative to gains of $1.31/boe and $0.93/boe in the comparative periods.

Commodity sales from production

$000s	For the three months ended September 30, 2025	2024	For the nine months ended September 30, 2025	2024
Oil & condensate	**79,717**	76,507	**253,331**	218,538
NGLs	**15,075**	14,331	**49,458**	46,091
Natural gas	**37,180**	18,328	**135,994**	69,248
Total commodity sales from production	**131,972**	109,166	**438,783**	333,877

Revenue from production for the three and nine months ended September 30, 2025 increased to $132.0 million and $438.8 million, respectively, compared to $109.2 million and $333.9 million in the 2024 comparative periods. Increases in both periods were driven by higher production levels in 2025 as a result of new well additions with higher average realized pricing also contributing to the increase in revenue for the nine month period relative to the comparative period in 2024.

Net commodity sales from purchases

$000s	For the three months ended September 30, 2025	2024	For the nine months ended September 30, 2025	2024
Commodity sales from purchases	**17,924**	15,773	**41,463**	39,109
Commodity purchases, transportation and other	**(12,174)**	(14,090)	**(27,353)**	(36,829)
Net commodity sales from purchases [1]	**5,750**	1,683	**14,110**	2,280
Realized hedging (loss) gain on purchases	**(3,266)**	(240)	**(7,588)**	2,759
Net commodity sales from purchases after hedging [1]	**2,484**	1,443	**6,522**	5,039
$/boe – before hedging	**1.96**	0.70	**1.59**	0.31
$/boe – after hedging	**0.84**	0.60	**0.74**	0.69

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. During the nine months ended September 30, 2025, the Company was able to successfully fill the balance of its Alliance Pipeline firm transportation commitment 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 by periodically entering into risk management contracts to protect against movements in price differentials in accordance with risk management guidelines as approved by the Company's board of directors.

During the three and nine months ended September 30, 2025, the Company realized a gain of $5.8 million and $14.1 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 $2.5 million and $6.5 million for the three and nine months ended September 30, 2025, respectively, compared to $1.4 million and $5.0 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.

	For the three months ended September 30,		For the nine months ended September 30,	
$000s	**2025**	2024	**2025**	2024
Risk management:				
Unrealized gain (loss)	**933**	21,570	**39,226**	(10,390)
Realized gain (loss)	**679**	2,884	**(6,349)**	9,561
Total gain (loss) on risk management	**1,612**	24,454	**32,877**	(829)
Unrealized gain (loss) ($/boe)	**0.32**	9.02	**4.41**	(1.42)
Realized gain (loss) ($/boe)	**0.23**	1.21	**(0.71)**	1.31

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

	For the three months ended September 30,		For the nine months ended September 30,	
$000s	**2025**	2024	**2025**	2024
Realized gain (loss) on production	**4,864**	4,590	**7,466**	10,496
Realized gain (loss) on purchases	**(3,266)**	(240)	**(7,588)**	2,759
Realized gain (loss) on foreign exchange	**(919)**	(1,466)	**(6,227)**	(3,694)
Total realized gain (loss)	**679**	2,884	**(6,349)**	9,561
Realized gain (loss) on production ($/boe)	**1.66**	1.92	**0.84**	1.44
Realized gain (loss) on purchases ($/boe)	**(1.12)**	(0.10)	**(0.85)**	0.38
Realized gain (loss) on foreign exchange ($/boe)	**(0.31)**	(0.61)	**(0.70)**	(0.51)

For the three and nine months ended September 30, 2025, the Company realized a gain on risk management contracts of $0.7 million and a loss of $6.3 million, respectively. This included the impact from production hedges (gains of $4.9 million and $7.5 million, respectively), foreign exchange contracts (losses of $0.9 million and $6.2 million, respectively) and natural gas volumes purchased for resale required to meet pipeline commitments in excess of the Company’s production needs (losses of $3.3 million and $7.6 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 and comprehensive income.

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 $0.9 million and $39.2 million, respectively, for the three and nine months ended September 30, 2025, representing the changes in the fair value of risk management contracts outstanding at the end of those periods. As of September 30, 2025 the Company's risk management portfolio was in a net asset position of $7.0 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 September 30, 2025:

Type		Q4 2025	2026	2027	2028
Crude oil [1]					
WTI swap	bbl/d	1,000	750	188	—
WTI buy put	bbl/d	4,833	3,333	1,438	83
WTI sell call	bbl/d	3,833	2,333	688	—
WTI swap average	US$/bbl	$70.04	$68.72	$66.05	$—
WTI buy put average	US$/bbl	$62.96	$60.80	$53.41	$55.00
WTI sell call average	US$/bbl	$74.29	$72.19	$74.08	$—
Natural gas [1]					
NYMEX Henry Hub buy put	MMBtu/d	68,333	53,958	24,167	1,667
NYMEX Henry Hub sell call	MMBtu/d	65,833	53,333	24,167	1,667
NYMEX Henry Hub buy put average	US$/MMBtu	$3.33	$3.25	$3.45	$3.52
NYMEX Henry Hub sell call average	US$/MMBtu	$4.62	$4.49	$4.80	$4.89
Natural gas transportation [1,2]					
Purchase AECO 5A basis (to NYMEX Henry Hub)	MMBtu/d	15,000	8,333	—	—
Sell GDD Chicago basis (to NYMEX Henry Hub) [3]	MMBtu/d	(15,000)	(8,333)	—	—
AECO 5A basis (to NYMEX Henry Hub) average	US$/MMBtu	$(1.91)	$(2.19)	$—	$—
GDD Chicago basis (to NYMEX Henry Hub) average [3]	US$/MMBtu	$(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 September 30, 2025:

Type		Q4 2025	2026	2027	2028
Foreign exchange [1]					
Sell USD CAD (monthly average)	US$	$12.5 MM	$— MM	$3.0 MM	$— MM
USD CAD buy put	US$	$10.5 MM	$15.0 MM	$10.0 MM	$— MM
USD CAD sell call [2]	US$	$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	$1.32	$1.34	$—
USD CAD sell call rate [2]		$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	September 30, 2025	December 31, 2024
Short term risk management asset	**8,133**	—
Long term risk management asset	**1,544**	—
Short term risk management liability	**(1,105)**	(20,900)
Long term risk management liability	**(1,572)**	(11,326)
Total risk management contracts asset (liability)	**7,000**	(32,226)

$000s	September 30, 2025	December 31, 2024
Asset on produced volumes	**10,072**	1,023
Asset (liability) on purchased volumes	**761**	(9,748)
Liability on foreign exchange contracts	**(3,833)**	(23,501)
Total risk management contracts asset (liability)	**7,000**	(32,226)

Royalty expense

	For the three months ended September 30,		For the nine months ended September 30,	
$000s	2025	2024	2025	2024
Royalty expense	**6,084**	8,233	**22,800**	26,770
As a % of revenue	**4.6 %**	7.5 %	**5.2 %**	8.0 %
$/boe	**2.08**	3.44	**2.57**	3.67

The Company pays Crown, freehold, and overriding royalties on production volumes. Royalties for the three and nine months ended September 30, 2025 were $6.1 million and $22.8 million, respectively, as compared to $8.2 million and $26.8 million in the comparative periods of 2024.

Royalties as a percentage of revenue for the three and nine months ended September 30, 2025 decreased to 4.6% and 5.2%, respectively, compared to 7.5% and 8.0% 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.

In addition, royalties as a percent of revenue continue to benefit from the Company selling the majority of its natural gas production at the historically higher priced Chicago market while natural gas royalties in Alberta are calculated and paid based on AECO benchmark pricing.

Operating expenses

$000s	For the three months ended September 30, 2025	2024	For the nine months ended September 30, 2025	2024
Operating expenses	**17,821**	17,206	**51,259**	49,589
$/boe	**6.09**	7.19	**5.77**	6.80

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 nine months ended September 30, 2025 increased to $17.8 million and $51.3 million, respectively, as compared to $17.2 million and $49.6 million in the comparable periods of 2024, with the increase attributable to higher production levels over the same periods.

On a per barrel basis, operating expenses for the three and nine months ended September 30, 2025 decreased by 15% to $6.09/boe and $5.77/boe, respectively, relative to the comparative periods due to continued strong asset performance and higher production leading to per barrel efficiencies gained through the Company's owned and operated infrastructure within Simonette.

Transportation expenses

$000s	For the three months ended September 30, 2025	2024	For the nine months ended September 30, 2025	2024
Transportation expenses	**16,260**	14,417	**48,655**	40,236
$/boe	**5.55**	6.04	**5.48**	5.52

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 nine months ended September 30, 2025 were $16.3 million and $48.7 million, respectively, relative to $14.4 million and $40.2 million in the comparative periods, with the increase attributable to higher production.

On a per barrel basis, transportation expenses for the three months ended September 30, 2025 decreased to $5.55/boe, relative to $6.04/boe in the comparative period, driven by lower NGL transportation charges. For the nine months ended September 30, 2025, transportation expenses of $5.48/boe were consistent with the comparative period.

Adjusted funds flow from operations

$000s	For the three months ended September 30, 2025	2024	For the nine months ended September 30, 2025	2024
Cash flows from operating activities	**83,872**	66,867	**274,028**	203,282
Net change in non-cash working capital from operating activities	**11,862**	(3,670)	**23,001**	(5,343)
Asset retirement obligation expenditures	**551**	1,549	**3,396**	2,468
Adjusted funds flow from operations [1]	**98,782**	64,746	**303,042**	200,407
$/boe	**33.75**	27.07	**34.11**	27.48

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 nine months ended September 30, 2025 increased to $98.8 million and $303.0 million, respectively, relative to $64.7 million and $200.4 million in the comparative periods in 2024. On a per barrel basis, adjusted flow from operations for the three and nine months ended September 30, 2025 increased by 25% to $33.75/boe and by 24% to $34.11/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 September 30, 2025	2024	For the nine months ended September 30, 2025	2024
Adjusted funds flow from operations [1]	**98,782**	64,746	**303,042**	200,407
Capital expenditures [1]	**(70,815)**	(91,044)	**(208,419)**	(237,272)
Free funds flow (deficiency) from operations [1]	**27,967**	(26,298)	**94,623**	(36,865)
$/boe	**9.55**	(11.00)	**10.65**	(5.06)

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 nine months ended September 30, 2025, the Company generated free funds flow of $28.0 million and $94.6 million relative to a deficiency of $26.3 million and $36.9 million in the comparative periods of 2024. The Company has profitably grown its production to a level where it is now generating more adjusted funds flow from operations than required to fund its upstream capital program. Free funds flow from operations was positive in each of the first three quarters of 2025 which has been utilized to reduce debt levels, repurchase shares under its normal course issuer bid ("NCIB") program subject to market conditions, and continues 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 nine months ended September 30, 2025 using available 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.

Other income

$000s	For the three months ended September 30, 2025	2024	For the nine months ended September 30, 2025	2024
Processing, road use and other activities	**1,731**	963	**3,561**	2,748
Pipeline settlement refund receivable	**7,870**	—	**7,870**	—
Power sale process non-refundable deposit	**—**	—	**2,500**	—
Other income	**9,601**	963	**13,931**	2,748
$/boe	**3.28**	0.39	**1.57**	0.38

For the three and nine months ended September 30, 2025, the Company earned other income of $9.6 million and $13.9 million, respectively, relative to $1.0 million and $2.7 million in the comparable periods in 2024. The Company generates income from third-party processing at its gas plants, road use fees, and other ancillary infrastructure activities.

During the three months ended September 30, 2025, the Canadian Energy Regulator approved a settlement between Alliance Pipeline and its shippers, including Kiwetinohk, on a new tolling structure for the Canadian portion of the pipeline that will apply for the next ten years. As part of the settlement, the Company recognized a $7.8 million receivable related to a one-time refund from Alliance for recoverable cost variance, which is expected to be collected in the first quarter of 2026 and was recognized in Other Income in the third quarter of 2025.

During the nine months ended September 30, 2025, the Company also recognized $2.5 million in Other Income for a non-refundable deposit received from a counterparty evaluating the Homestead Solar project, who ultimately elected not to proceed with their purchase of the project. The Homestead Solar project was later sold in the third quarter of 2025 (see "Power development project" section of this MD&A).

General and administrative ("G&A") expenses

$000s	For the three months ended September 30, 2025	2024	For the nine months ended September 30, 2025	2024
Gross G&A expenses	**6,497**	6,247	**21,234**	19,903
Less capitalized G&A	**(730)**	(1,126)	**(2,313)**	(2,937)
G&A Expenses	**5,767**	5,121	**18,921**	16,966
$/boe	**1.97**	2.14	**2.13**	2.33

For the three and nine months ended September 30, 2025, the Company incurred gross G&A expenses of $6.5 million and $21.2 million, respectively, relative to $6.2 million and $19.9 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 $1.97/boe and $2.13/boe for the three and nine months ended September 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 the business strategy review process and other business development initiatives, including maintaining power development projects within the regulatory queue and facilitating an orderly exit from the power business.

Share-based compensation expenses

$000s	For the three months ended September 30, 2025	2024	For the nine months ended September 30, 2025	2024
Equity-settled awards	**551**	513	**2,365**	2,123
Cash-settled awards	**3,737**	1,262	**14,644**	4,399
Total share-based compensation expenses	**4,288**	1,775	**17,009**	6,522
$/boe	**1.46**	0.74	**1.91**	0.89

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.

During the three and nine months ended September 30, 2025, total share-based compensation of $4.3 million and $17.0 million, respectively, increased relative to $1.8 million and $6.5 million in the comparative periods, attributable to increases in both cash-settled and equity-settled award compensation. Greater cash-settled compensation in both periods 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 in both periods is due to the vesting of higher priced awards relative to the comparative period, and the increase for the nine months ended September 30, 2025 is also attributable to the extension of certain performance warrants during the second quarter of 2025.

Finance costs

$000s	For the three months ended September 30, 2025	2024	For the nine months ended September 30, 2025	2024
Interest and bank charges	**3,742**	4,774	**11,892**	14,113
Accretion expense	**930**	977	**2,768**	2,761
Interest on lease obligations	**200**	527	**1,634**	1,612
Deferred financing amortization	**198**	194	**589**	538
Unrealized (gain) loss on foreign exchange	**(494)**	395	**1,784**	(278)
Total finance costs	**4,576**	6,867	**18,667**	18,746
$/boe	**1.56**	2.87	**2.10**	2.57

The Company has a $400 million senior secured extendible revolving facility (the "Credit Facility") with a syndicate of banks. As at September 30, 2025 the Company had drawn $197.2 million on the facility (September 30, 2024 - $220.0 million).

Interest and bank charges for the three and nine months ended September 30, 2025 decreased by 22% to $3.7 million and 16% to $11.9 million, respectively, relative to the prior year comparative periods. Decreases in both periods were attributable to lower average interest rates, with the three month period also benefiting from lower average debt levels relative to the comparative periods.

Depletion and Depreciation

$000s	For the three months ended September 30, 2025	2024	For the nine months ended September 30, 2025	2024
Depletion	**50,841**	39,515	**153,923**	120,781
Depreciation	**384**	518	**1,473**	1,544
Total depletion and depreciation	**51,225**	40,033	**155,396**	122,325
$/boe	**17.50**	16.74	**17.49**	16.78

The Company recognized depletion of $50.8 million and $153.9 million during the three and nine months ended September 30, 2025 compared to $39.5 million and $120.8 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 nine months ended September 30, 2025, the Company incurred approximately $31.0 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 September 30, 2025, the Company recognized a net deferred tax liability of $50.6 million. The Company's estimated tax pools as at September 30, 2025, were $836.7 million comprised of the following:

Category	Deductibility	$000s
Canadian oil and gas property expense ("COGPE")	10%	157,063
Successored COGPE	10%	882
Canadian development expense ("CDE")	30%	372,789
Successored CDE	30%	30,362
Canadian exploration expense ("CEE")	100%	3,980
Successored CEE	100%	—
Undepreciated capital cost ("UCC")	Primarily 25%, declining balance	153,301
Non-capital losses	100%	110,184
Share/Debt issue costs	5-year straight line	2,071
Other	Various	6,027
Total estimated tax pools		836,659

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 $101.6 million, or $164.8 million inflated at 1.95% and undiscounted. These cash flows have been discounted using a risk-free interest rate of 3.61% to arrive at the present value estimate of $72.4 million.

There is approximately $22.7 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 September 30, 2025 (December 31, 2024 - $4.4 million).

Select quarterly information

($000s except per share and production)	2025			2024				2023
	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Production (average boe/d)	**31,814**	33,217	32,611	27,657	25,996	26,292	27,556	24,707
Commodity sales from production	**131,972**	138,419	168,392	120,721	109,166	105,049	119,662	114,038
Commodity sales from purchases	**17,924**	7,434	16,105	16,417	15,773	7,353	15,983	18,136
Cash flow from operating activities	**83,872**	79,839	110,317	59,921	66,867	61,232	75,183	58,946
Per share (basic)	**1.91**	1.82	2.52	1.37	1.53	1.40	1.72	1.35
Per share (diluted)	**1.81**	1.78	2.46	1.35	1.51	1.39	1.71	1.33
Net income (loss)	**18,106**	59,300	54,919	(16,024)	32,535	(26,538)	11,092	48,302
Per share (basic)	**0.41**	1.35	1.25	(0.37)	0.74	(0.61)	0.25	1.11
Per share (diluted)	**0.39**	1.32	1.23	(0.37)	0.73	(0.61)	0.25	1.09

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 September 30, 2025, $197.2 million was drawn on the Credit Facility (December 31, 2024 - $251.0 million). In addition, $56.8 million in letters of credit issued to support transportation and other commitments were outstanding (December 31, 2024 - $70.0 million). Of the $56.8 million letters of credit, $37.2 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	197,201	19,611	**183,188**
EDC Facility	100,000	—	37,179	**62,821**
Total				**246,009**

$000s	September 30, 2025	December 31, 2024
Credit facility drawn	**197,201**	251,002
Deferred financing costs	**(1,321)**	(1,100)
Loans and borrowings	**195,880**	249,902
Adjusted working capital (surplus) deficit [1]	**(17,270)**	22,862
Net debt [1]	**178,610**	272,764
Trailing 12-month adjusted funds flow from operations [1]	**374,750**	272,115
Net debt to trailing 12-month adjusted funds flow from operations [1]	**0.48**	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 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 (September 30, 2025 - 0.48 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. At September 30, 2025, the Company has $62.8 million of capacity remaining under the LC Facility (December 31, 2024 - $77.0 million). Subsequent to September 30, 2025, the Company extinguished $21.0 million of letters of credit that were related to securing capacity for a power project that was sold.

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 nine months ended September 30, 2025, the Company purchased 99,941 Common Shares under the NCIB program at a total cost of $2.3 million (an average of $23.18 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. The Company will not make any further purchase under the NCIB program as a result of the plan of arrangement announced on October 28, 2025.

	For the three months ended September 30,		For the nine months ended September 30,	
(000s)	**2025**	2024	**2025**	2024
Weighted average shares outstanding				
Basic	**43,837**	43,673	**43,828**	43,667
Diluted	**46,256**	44,289	**45,300**	44,122
Outstanding securities				
Common shares	**43,788**	43,713	**43,788**	43,713
Stock options[1]	**2,859**	2,891	**2,859**	2,891
Performance warrants[1]	**6,583**	6,703	**6,583**	6,703
Total diluted outstanding securities	**53,230**	53,307	**53,230**	53,307

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 November 4, 2025, the Company has 43,760,466 Common Shares and no preferred shares outstanding.

Commitments, contractual obligations, and contingencies

$ millions	**2025**	**2026**	**2027**	**2028**	**2029**	**Thereafter**
Accounts payable	55.7	—	—	—	—	—
Cash-settled compensation liability [1]	—	5.7	2.0	0.2	—	4.4
Loans and borrowings [2]	—	—	197.2	—	—	—
Gathering, processing and transport	15.2	56.9	56.9	56.9	56.9	192.5
Natural gas purchases	0.6	—	—	—	—	—
Upstream and corporate lease liabilities	0.4	2.2	2.2	2.3	—	—
Other	—	0.4	0.4	0.4	0.4	—
Total [3]	71.9	65.2	258.7	59.8	57.3	196.9

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 September 30, 2025 is repaid on the facility's maturity date.
3 – The details disclosed above do not reflect any potential changes that may arise through the proposed plan of arrangement, announced on October 28, 2025.

The Company holds a commitment to deliver approximately 120.0 MMcf/d of gas to Chicago on the Alliance Pipeline. The commitment on the US segment of Alliance Pipeline extends until October 31, 2032 and the Company has extended its commitment on the Canadian segment until October 31, 2035. In addition, the Company currently has 29.7 MMcf/d of natural gas transportation commitments on the Nova Gas Transmission Ltd. to July 31, 2031.

Subsequent to September 30, 2025, the Company extended its commitment on the US segment of Alliance Pipeline to October 31, 2035, to align with the term on the Canadian segment. This three-year extension represents an incremental $50.2 million transportation commitment.

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 September 30, 2025.

Related party information

For the three and nine months ended September 30, 2025, the Company incurred a total of $0.9 million and $2.2 million, respectively (September 30, 2024 – $0.2 million and $0.9 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.

Environment, social and governance

Kiwetinohk regularly reviews its environmental, social and governance ("ESG") risks and management strategies, and published its 2025 ESG report (for the 2024 reporting year) guided by the Sustainability Accounting Standards Board ("SASB") data standards for Oil & Gas – Exploration and Production and the Financial Stability Board's Task Force on Climate-related Financial Disclosures ("TCFD") framework.

In the third quarter of 2025, Kiwetinohk became the first Canadian company to achieve Gold Standard Level 5 reporting under the United Nations Environment Programme's Oil and Gas Methane Partnership.

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 nine months ended September 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 July 1, 2025, and ending on September 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 nine months ended September 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 and comprehensive income 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 September 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 September 30,		For the nine months ended September 30,	
$000s	**2025**	2024	**2025**	2024
Commodity sales from production	**131,972**	109,166	**438,783**	333,877
Royalty expenses	**(6,084)**	(8,233)	**(22,800)**	(26,770)
Operating expenses	**(17,821)**	(17,206)	**(51,259)**	(49,589)
Transportation expenses	**(16,260)**	(14,417)	**(48,655)**	(40,236)
Operating netback	**91,807**	69,310	**316,069**	217,282
Realized gain on risk management	**3,945**	3,124	**1,239**	6,802
Realized gain (loss) on risk management - purchases	**(3,266)**	(240)	**(7,588)**	2,759
Net commodity sales from purchases	**5,750**	1,683	**14,110**	2,280
Adjusted operating netback	**98,236**	73,877	**323,830**	229,123

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 September 30,		For the nine months ended September 30,	
$000s	**2025**	2024	**2025**	2024
Cash flow used in investing activities	**62,370**	91,766	**204,606**	227,101
Net change in non-cash investing working capital	**2,895**	(1,019)	**(14,787)**	10,838
Power connection process payment	**—**	—	**(8,000)**	(985)
Capital expenditures and net dispositions	**65,265**	90,747	**181,819**	236,954
Proceeds from disposition	**5,550**	297	**26,600**	318
Net dispositions	**5,550**	297	**26,600**	318
Capital expenditures	**70,815**	91,044	**208,419**	237,272

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" are 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	September 30, 2025	December 31, 2024
Current assets	**92,580**	68,323
Current liabilities	**(68,282)**	(112,085)
Working capital surplus (deficit)	**24,298**	(43,762)
Remove short term risk management contracts net (asset) liability	**(7,028)**	20,900
Adjusted working capital surplus (deficit)	**17,270**	(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 expected timing for holding the Special Meeting of shareholders;
- the expected timing for closing the Arrangement;
- the consideration and expected benefits to be received by Kiwetinohk Shareholders pursuant to Arrangement;
- the expectation of satisfying all conditions of closing;
- the Upstream business unit's properties that are expected to offer competitive economic resource potential and development upside;
- the Company's plans for an orderly exit from its power business and intention to have fully exited the power development business prior to year-end;
- 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 annual production range, reduced royalty rate, reduced operating costs, decreased transportation expenses, revised upstream capital spend range, and revised operations sensitivities;
- expectations of continued premiums in the Chicago natural gas benchmark pricing when compared to Alberta markets;
- expectations of a reduction in Alliance Pipeline tolls to take effect in November 2025;
- 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, as well as any impact of potential tolling reviews by the Canadian Energy Regulator;
- the Company's development program, including the anticipated completion of a Placid Montney well;
- 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;
- 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 the fourth quarter of 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; 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
$/Mcf	dollars per thousand cubic feet
AECO	the daily average benchmark price for natural gas at the physical storage and trading hub for natural gas on the TransCanada Alberta transmission system which is the delivery point for various benchmark Alberta index prices
AESO	Alberta Electric Systems Operator
bbl/d	barrels per day
boe	barrel of oil equivalent, including crude oil, condensate, natural gas liquids, and natural gas (converted on the basis of one boe per six Mcf of natural gas)
boe/d	barrel of oil equivalent per day
DI	daily index
GJ	gigajoule
Mcf	thousand cubic feet
Mcf/d	thousand cubic standard feet per day
MI	monthly index
MMcf/d	million cubic feet per day
MMBtu	one million British Thermal Units is a measure of the energy content in gas
MMBtu/d	one million British thermal units per day
NGLs	natural gas liquids, which includes butane, propane, and ethane
US$/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
Senior Vice President, Business Systems

Corporate Head Office

Kiwetinohk Energy Corp.
1700, 250 2 St SW
Calgary, AB
T2P 0C1

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
Director

Reserve Engineers

McDaniel & Associates Consultants Ltd.
Calgary, AB

Legal Counsel

Stikeman Elliot LLP
Norton Rose Fulbright Canada LLP
Calgary, AB

Transfer Agent

Computershare
Calgary, AB

Stock Symbol

KEC
Toronto Stock Exchange