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, 2024. 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, 2024 (the "Financial Statements") and the audited financial statements as at and for the year ended December 31, 2023. 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 5, 2024.

Overview of business

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 in significant Duvernay and Montney resources with development upside, 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 is pursuing the early stage, pre-construction development of an Alberta-based power generation project portfolio that currently includes solar, and natural gas-fired power and carbon capture and storage ("CCS") facilities. Successful development of Kiwetinohk's power projects would enable the future production of reliable, dispatchable, affordable energy with lower emissions intensity relative to energy generated through Alberta's grid today.

Financial and operating highlights

	For the three months ended September 30, 2024	2023	For the nine months ended September 30, 2024	2023
Production				
Oil & condensate (bbl/d)	**8,898**	6,367	**8,318**	6,770
NGLs (bbl/d)	**3,766**	2,765	**3,870**	2,520
Natural gas (Mcf/d)	**79,992**	72,518	**86,546**	75,492
Total (boe/d)	**25,996**	21,218	**26,612**	21,872
Oil and condensate % of production	**35%**	30%	**31%**	31%
NGL % of production	**14%**	13%	**15%**	11%
Natural gas % of production	**51%**	57%	**54%**	58%
Realized prices				
Oil & condensate ($/bbl)	**93.47**	100.05	**95.89**	97.43
NGLs ($/bbl)	**41.36**	48.21	**43.47**	53.84
Natural gas ($/Mcf)	**2.49**	3.53	**2.92**	3.92
Total ($/boe)	**45.65**	48.38	**45.79**	49.87
Royalty expense ($/boe)	**(3.44)**	(2.75)	**(3.67)**	(4.68)
Operating expenses ($/boe)	**(7.19)**	(9.17)	**(6.80)**	(8.51)
Transportation expenses ($/boe)	**(6.04)**	(5.59)	**(5.52)**	(5.65)
Operating netback [1] ($/boe)	**28.98**	30.87	**29.80**	31.03
Realized gain on risk management ($/boe) [2]	**1.31**	1.23	**0.93**	1.97
Realized (loss) gain on risk management - purchases ($/boe) [2]	**(0.10)**	1.59	**0.38**	1.88
Net commodity sales from purchases (loss) ($/boe) [1]	**0.70**	(1.22)	**0.31**	(0.92)
Adjusted operating netback ($/boe) [1]	**30.89**	32.47	**31.42**	33.96
Financial results ($000s, except per share amounts)				
Commodity sales from production	**109,166**	94,432	**333,877**	297,788
Net commodity sales from purchases (loss) [1]	**1,683**	(2,376)	**2,280**	(5,490)
Cash flow from operating activities	**66,867**	60,294	**203,282**	181,814
Adjusted funds flow from operations [1]	**64,746**	55,314	**200,407**	177,614
Per share basic	**1.48**	1.26	**4.59**	4.03
Per share diluted	**1.46**	1.25	**4.54**	3.99
Net debt to annualized adjusted funds flow from operations [1]	**0.91**	0.67	**0.91**	0.67
Free funds flow deficiency from operations (excluding acquisitions/ dispositions) [1]	**(26,298)**	(7,827)	**(36,865)**	(52,961)
Net income (loss)	**32,535**	(12,056)	**17,089**	63,594
Per share basic	**0.74**	(0.27)	**0.39**	1.44
Per share diluted	**0.73**	(0.27)	**0.39**	1.43
Capital expenditures prior to dispositions [1]	**91,044**	63,141	**237,272**	230,575
Net dispositions [1]	**(297)**	(1,645)	**(318)**	(1,995)
Capital expenditures and net dispositions [1]	**90,747**	61,496	**236,954**	228,580

	September 30, 2024	December 31, 2023
Balance sheet ($000s, except share amounts)		
Total assets	**1,155,263**	1,085,615
Long-term liabilities	**340,788**	305,735
Net debt [1]	**241,196**	186,523
Adjusted working capital (deficit) surplus [1]	**(22,490)**	7,565
Weighted average shares outstanding		
Basic	**43,667,312**	43,971,108
Diluted	**44,121,946**	44,467,348
Shares outstanding end of period	**43,713,404**	43,662,644

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

Guidance

Kiwetinohk plans to accelerate its 2025 drilling program by reoccupying the 1-27 pad in Simonette and commence drilling three Duvernay wells late in the fourth quarter. This acceleration is expected to enhance 2025 production growth while retaining flexibility to adapt to volatile commodity prices and to reduce capital expenditures in 2025, if needed. Kiwetinohk expects incremental capital spending of up to $10.0 million in 2024, with remaining capital to be included in its 2025 capital budget. Full-year capital guidance for 2024 is updated to a range of $330 - $350 million.

Kiwetinohk has also updated sensitivities for expected adjusted funds flow from operations and projected ratio of net debt to adjusted funds flow from operations to account for this capital acceleration assuming realized pricing for WTI Crude Oil and Henry Hub (HH) natural gas of US$70/MMBtu and US$2.50/MMBtu, respectively, for the remainder of the year.

All other financial and operational guidance remain as previously presented on July 30, 2024.

Kiwetinohk's revised 2024 annual guidance and related sensitivity provides information relevant to expectations for financial and operational results. This corporate guidance is based on commodity price assumptions and economic conditions and readers are cautioned that guidance estimates may fluctuate and are subject to numerous risks and uncertainties. Kiwetinohk will update guidance if and as required throughout the year. Details of current full year guidance are presented below.

2024 Financial & Operational Guidance		**Current November 5, 2024**	Previous July 30, 2024
Production (2024 average) [1]	Mboe/d	26.0 - 27.5	26.0 - 27.5
Oil & liquids	%	45% - 49%	45% - 49%
Natural gas [1]	%	55% - 51%	55% - 51%
Financial			
Royalty rate	%	7% - 10%	7% - 10%
Operating costs	$/boe	$7.25 - $7.75	$7.25 - $7.75
Transportation	$/boe	$5.50 - $6.00	$5.50 - $6.00
Corporate G&A expense [2]	$MM	$23 - $25	$23 - $25
Cash taxes[3]	$MM	$—	$—
Capital guidance	$MM	$330 - $350	$320 - $340
Upstream	$MM	$325 - $342	$315 - $332
DCET	$MM	$305 - $320	$295 - $310
Infrastructure, production maintenance and other	$MM	$20 - $22	$20 - $22
Power [6]	$MM	$5 - $8	$5 - $8
2024 Adjusted Funds Flow from Operations commodity pricing sensitivity [4, 5]			
US$70/bbl WTI & US$2.50/MMBtu HH	$MM	$260 - $280	Not previously provided [5]
2024 Net debt to Adjusted Funds Flow from Operations sensitivity [4, 5]			
US$70/bbl WTI & US$2.50/MMBtu HH	X	1.0x - 1.1x	Not previously provided [5]

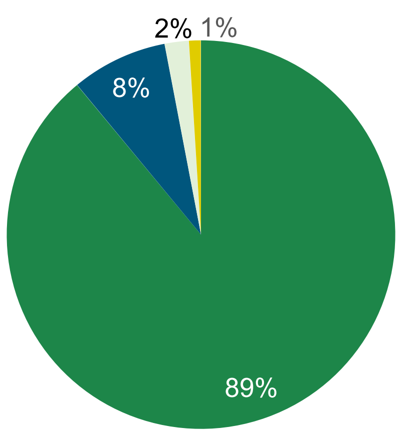
1 – Approximately 90% of natural gas sales are expected to be to the Chicago market in 2024.
2 – Includes G&A expenses for all divisions of the Company – corporate, upstream, power and business development.
3 – The Company expects to pay United States cash taxes of approximately $0.2 million reflecting taxes payable by its US marketing subsidiary during 2024. No Canadian cash taxes are anticipated in 2024.
4 – Non-GAAP and other financial measures that do not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Please refer to the section "Non-GAAP Measures" herein.
5 - Sensitivities for adjusted funds flow from operations and net debt to adjusted funds flow from operations were previously provided at US$70/bbl WTI & US$2.00/MMBtu HH and US$80/bbl WTI and US$3.00/MMBtu HH. Sensitivities have been revised to $US70/bbl WTI and US$2.50/MMBtu HH to approximate forward strip pricing for the remainder of the year. Assumes actual realized pricing to date and flat pricing for the remainder of the year.
6 – The company incurred $3.4 million of costs within the first six months of 2024 prior to recognizing an impairment on the power portfolio (excluding Homestead). Expenditures on impaired projects will be expensed for the remainder of the year. Guidance reflected includes capitalized costs and expensed project development costs.

Capital expenditures

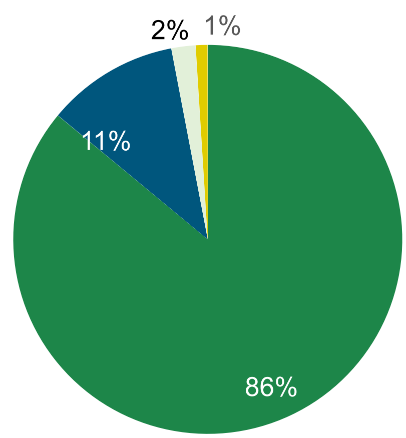
$000s	For the three months ended September 30, 2024	2023	For the nine months ended September 30, 2024	2023
Drilling, completions, and equipping	**80,915**	40,761	**202,698**	144,286
Facilities, pipelines, roads and optimization	**7,425**	18,360	**26,271**	73,953
Power projects	**1,446**	2,865	**4,364**	8,163
Land and other	**133**	398	**1,003**	1,355
Capitalized G&A - upstream	**1,041**	587	**2,379**	2,255
Capitalized G&A - power	**84**	170	**557**	563
Capital expenditures [1]	**91,044**	63,141	**237,272**	230,575
Upstream net dispositions [1]	**(297)**	(1,645)	**(318)**	(1,995)
Capital and net dispositions [1]	**90,747**	61,496	**236,954**	228,580

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 2024[1]



Capital expenditures YTD 2024[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, 2024, the Company invested $80.9 million and $202.7 million, respectively, to advance its development program with a focus on the Simonette Duvernay lands. During the nine months ended, September 30, 2024, the Company has executed a two-rig program, drilling a total of 13 Duvernay wells and one Montney well. Six Duvernay wells were drilled on two pads (three wells on each pad) during the third quarter of 2024. The Company anticipates bringing these two pads on-stream late in the fourth quarter of 2024.

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

Facilities, pipelines, roads and optimization

For the three and nine months ended September 30, 2024, the Company invested $7.4 million and $26.3 million, respectively, to build facilities, pipelines, roads and to optimize production. The 2024 upstream capital program benefits from upfront investment on infrastructure made in 2023 and requires less infrastructure spending, with a focusing primarily on the incremental infrastructure required to manage base production and develop or expand pipelines that are required to bring production from the 2024 development program on-stream.

Power development projects

The Company's power development portfolio includes gas-fired and solar projects with a total estimated nameplate capacity of approximately 2 GW. During the first nine months of 2024, the Company moderated its development expenditures across the entire portfolio to $4.9 million, inclusive of capitalized G&A.

At June 30, 2024, an accounting impairment indicator was identified on early-stage development projects, excluding the Homestead solar power project ("Homestead"), related to government policy and regulatory uncertainty. As a result, the Company has limited its capital allocation and an impairment expense of $29.2 million was recorded in the second quarter. This represented the carrying value for the Opal and Little Flipi gas-fired peaking projects, the Granum and Phoenix solar projects and the Black Bear and Flipi natural gas combined-cycle projects. Future development expenditures (excluding those on Homestead) are expected to be expensed going forward until the Company has a clear line of sight to financing and making a FID on projects under development.

The Company is still advancing Homestead towards a Final Investment Decision ("FID"). Kiwetinohk has engaged a financial advisor to assist in financing the project. During the third quarter, 100% of power development capital was incurred to advance the Homestead project with no investment made on other projects within the portfolio. There have been no power development expenses recognized in the quarter.

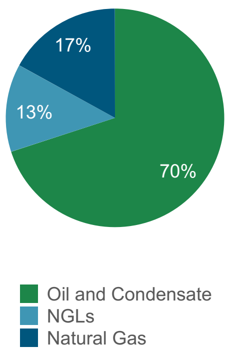
Results of operations

Production

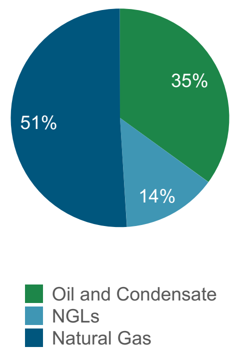
	For the three months ended September 30,		For the nine months ended September 30,	
	2024	2023	**2024**	2023
Oil & condensate (bbl/d)	**8,898**	6,367	**8,318**	6,770
NGLs (bbl/d) [1]	**3,766**	2,765	**3,870**	2,520
Natural gas (Mcf/d)	**79,992**	72,518	**86,546**	75,492
Total production (boe/d)	**25,996**	21,218	**26,612**	21,872
Oil and condensate % of production	**35%**	30%	**31%**	31%
NGL % of production	**14%**	13%	**15%**	11%
Natural gas % of production	**51%**	57%	**54%**	58%
Total production volumes %	**100%**	100%	**100%**	100%

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

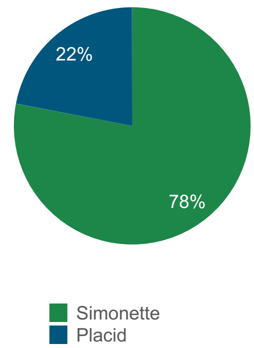
Revenue Mix ($)
Q3 2024



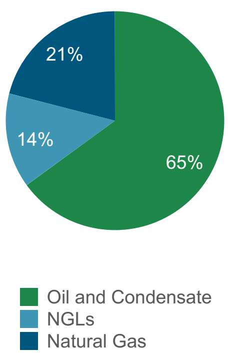
Production Mix (boe)
Q3 2024



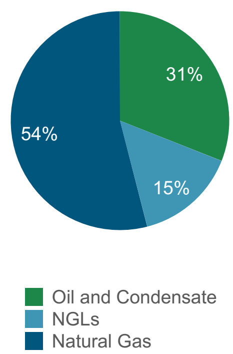
Production by Area (boe)
Q3 2024



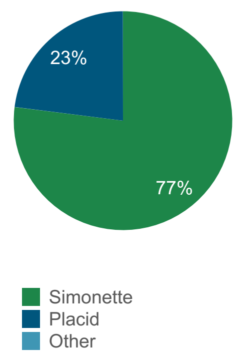
YTD 2024



YTD 2024



YTD 2024



Production for the three and nine months ended September 30, 2024 increased by 23% to 25,996 boe/d and by 22% to 26,612 boe/d, respectively, compared to the same periods in 2023. The increase in production volumes is attributable to the Company's upstream capital development program and continued focus on developing its core Simonette acreage. Ten incremental Duvernay wells, including 7 in the third quarter, and 1 Simonette Montney well have been brought on-stream in the first nine months of 2024.

The composition of the Company's production profile during the three months ended September 30, 2024 was 35% oil and condensate, 14% NGLs, and 51% natural gas, with a higher oil and condensate weighting compared to the comparable prior year period. This production profile resulted in a revenue mix of 70% oil and condensate, 13% NGLs, and 17% natural gas in the quarter. During the third quarter of 2024, 75% of new wells brought on stream were located in the Tony Creek area which are expected to provide significantly higher condensate levels and resulted in the change in the composition of the production mix compared to the third quarter of 2023.

For the nine months ended September 30, 2024, the Company's production profile was 31% oil and condensate, 15% NGLs, and 54% natural gas. This production profile resulted in a revenue mix of 65% oil and condensate, 14% NGLs, and 21% natural gas in the first nine months of the year. The production profile has become more liquids heavy compared to the comparative prior year period due to the composition of new wells and a marketing decision in the fourth quarter of 2023 to operate the Company's processing facilities at a colder temperature to extract NGLs in Alberta for sale to the Alberta market.

Benchmark and realized prices

	For the three months ended September 30, 2024	2023	For the nine months ended September 30, 2024	2023
Liquid benchmark prices				
WTI (US$/bbl)	**75.09**	82.26	**77.54**	77.39
WTI (CDN$/bbl)	**102.42**	110.38	**105.50**	104.13
Edmonton Light (CDN$/bbl)	**99.06**	107.89	**98.83**	100.62
Natural gas benchmark prices				
Henry Hub (US$/MMBtu)	**2.16**	2.55	**2.10**	2.69
Chicago City Gate MI (US$/MMBtu)	**1.76**	2.29	**1.95**	2.87
Chicago City Gate DI (US$/MMBtu)	**1.78**	2.31	**2.08**	2.31
AECO 5A (CDN$/GJ)	**0.65**	2.46	**1.38**	2.61
AECO 7A (CDN$/GJ)	**0.77**	2.26	**1.36**	2.87
Foreign exchange rates (USD/CAD)	**0.73**	0.75	**0.74**	0.74

	For the three months ended September 30, 2024	2023	For the nine months ended September 30, 2024	2023
Realized prices (before impact of hedging program)				
Oil & condensate ($/bbl)	**93.47**	100.05	**95.89**	97.43
NGLs ($/bbl)	**41.36**	48.21	**43.47**	53.84
Natural gas ($/Mcf)	**2.49**	3.53	**2.92**	3.92
Total ($/boe)	**45.65**	48.38	**45.79**	49.87

Crude oil prices for the nine months ended September 30, 2024 were consistent with the comparative period in 2023. Average benchmark prices for the three months ended September 30, 2024 declined from $110.38 to $102.42 per barrel, compared to the same period in 2023. This decrease was primarily driven by an increase in global supply and a reduction in demand from China and other developing nations.

Edmonton Light benchmark pricing has followed a similar pattern to WTI pricing in 2024 compared to 2023, generally driven by the same factors.

NGL sales contracts are negotiated annually in April each year, with pricing for the three and nine months ended September 30, 2024 declining when compared to the prior periods of 2023 primarily as a result of increased North American supply putting downward pressure on contract prices.

Average Henry Hub natural gas prices decreased to US $2.16 and US $2.10 per MMBtu in the three and nine months ended September 30, 2024, respectively, when compared to US $2.55 and US $2.69 per MMBtu in the comparative periods of 2023. The price declines were due to lower demand as a result of a relatively mild winter, coupled with increased North American supply and higher than average inventory levels. The Chicago City Gate monthly benchmark averaged US $1.76 and US $1.95 per MMBtu compared to US $2.29 and US $2.87 per MMBtu in the comparative periods of 2023, respectively. The Chicago City Gate monthly index benchmark for natural gas also declined in the three and nine months ended September 30, 2024, when compared to prior periods for the same reasons as Henry Hub.

Natural gas prices at AECO in Alberta also decreased as new supply outpaced demand and export capacity in the basin. On average, AECO 7A spot prices decreased to $0.77/GJ and $1.36/GJ during the three and nine months ended September 30, 2024, respectively, compared to 2.26/GJ and 2.87/GJ in the same periods in 2023.

The Company continues to benefit from its access to the Chicago market through firm transportation capacity held on the Alliance pipeline system selling approximately 90% of its natural gas production in Chicago at a premium relative to Alberta prices.

Operating netback

	For the three months ended September 30,		For the nine months ended September 30,	
	2024	2023	**2024**	2023
Realized price ($/boe)	**45.65**	48.38	**45.79**	49.87
Royalty expenses ($/boe)	**(3.44)**	(2.75)	**(3.67)**	(4.68)
Operating expenses ($/boe)	**(7.19)**	(9.17)	**(6.80)**	(8.51)
Transportation expenses ($/boe)	**(6.04)**	(5.59)	**(5.52)**	(5.65)
Operating netback ($/boe) [1]	**28.98**	30.87	**29.80**	31.03
Realized gain on risk management ($/boe) [2]	**1.31**	1.23	**0.93**	1.97
Realized (loss) gain on risk management - purchases ($/boe) [2]	**(0.10)**	1.59	**0.38**	1.88
Net commodity sales from purchases (loss) ($/boe) [1]	**0.70**	(1.22)	**0.31**	(0.92)
Adjusted operating netback ($/boe) [1]	**30.89**	32.47	**31.42**	33.96
Total production (boe/d)	**25,996**	21,218	**26,612**	21,872

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.
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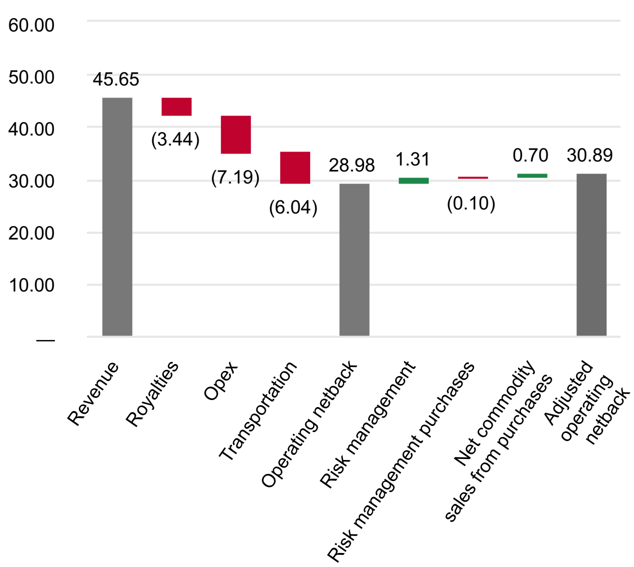
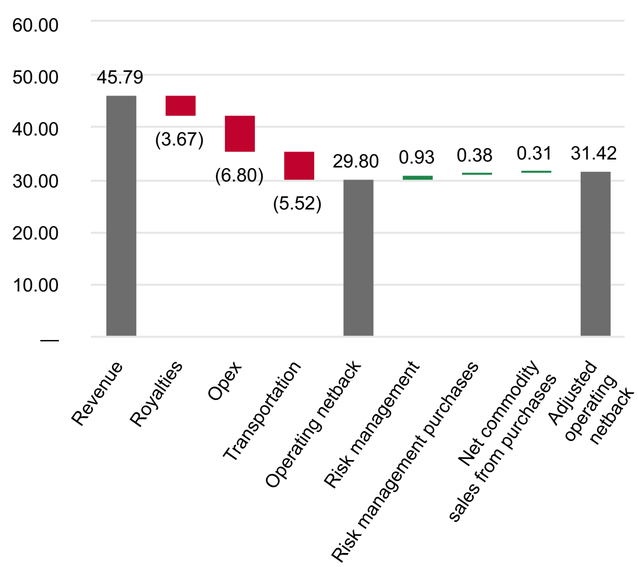
Q3 2024 ($/boe)



YTD 2024 ($/boe)



Operating netback for the three months ended September 30, 2024 was $28.98/boe compared to $30.87/boe in the same period in 2023. The decrease was attributable to a reduction in average realized prices and higher royalty and transportation expenses, offset by lower operating expenses as described below. Operating netback for the nine months ended September 30, 2024 was $29.80/boe compared to $31.03/boe in the same period in 2023, with the decrease attributable to a reduction in average realized prices, partially offset by period over period cost savings across royalty, operating and transportation expenses as described below.

Adjusted operating netback incorporates the impact of net commodity sales from purchases and the impact of the Company's risk management program and was $30.89/boe and $31.42/boe for the three and nine months ended

September 30, 2024, respectively. The Company realized gains of 0.60/boe and 0.69/boe on its net commodity sales from purchases after hedging (described below), with incremental gains of 1.31/boe and 0.93/boe generated through risk management contracts on produced volumes during the three and nine month periods, respectively.

Commodity sales from production

$000s	For the three months ended September 30, 2024	2023	For the nine months ended September 30, 2024	2023
Oil & condensate	**76,507**	58,608	**218,538**	180,064
NGLs	**14,331**	12,261	**46,091**	37,033
Natural gas	**18,328**	23,563	**69,248**	80,691
Total commodity sales from production	**109,166**	94,432	**333,877**	297,788

Revenue from production increased to $109.2 million and $333.9 million, respectively, for the three and nine months ended September 30, 2024, representing 16% and 12% growth over the comparative periods in 2023. Increases were driven by higher production levels in 2024 achieved through new well additions, partially offset by lower average realized prices relative to 2023, with NGL and gas pricing experiencing the largest price declines.

Net commodity sales from purchases

$000s	For the three months ended September 30, 2024	2023	For the nine months ended September 30, 2024	2023
Commodity sales from purchases	**15,773**	19,464	**39,109**	57,437
Commodity purchases, transportation and other	**(14,090)**	(21,840)	**(36,829)**	(62,927)
Net commodity sales from purchases (loss) [1]	**1,683**	(2,376)	**2,280**	(5,490)
Realized hedging (loss) gain on purchases	**(240)**	3,113	**2,759**	11,216
Net commodity sales from purchases after hedging[1]	**1,443**	737	**5,039**	5,726
$/boe – before hedging	**0.70**	(1.22)	**0.31**	(0.92)
$/boe – after hedging	**0.60**	0.37	**0.69**	0.96

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

In order to mitigate the cost of transportation service in excess of current production needs, the Company purchases available natural gas volumes in Alberta and/or British Columbia and resells these volumes in Chicago. The Company was able to successfully purchase and fill the balance of its Alliance firm transportation commitment during the nine months ended September 30, 2024, not met through proprietary field production and temporarily assigned volumes.

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

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

In the three and nine months ended September 30, 2024, the Company realized a gain of $1.7 million and $2.3 million, respectively, on its marketing activities associated with purchasing natural gas to fulfill its transmission commitment on the Alliance pipeline system. Including the impact of related risk management contracts, the Company realized overall marketing income of $1.4 million and $5.0 million for the three and nine months ended September 30, 2024, respectively, relative to $0.7 million and $5.7 million for the comparable periods in 2023.

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,	
$000s	**2024**	2023	**2024**	2023
Risk management:				
Unrealized gain (loss)	**21,570**	(38,802)	**(10,390)**	(1,104)
Realized gain	**2,884**	5,514	**9,561**	23,016
Total gain (loss) on risk management	**24,454**	(33,288)	**(829)**	21,912
Unrealized gain (loss) ($/boe)	**9.02**	(19.88)	**(1.42)**	(0.18)
Realized gain ($/boe)	**1.21**	2.82	**1.31**	3.85

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

	For the three months ended September 30,		For the nine months ended September 30,	
$000s	**2024**	2023	**2024**	2023
Realized gain on production	**4,590**	2,511	**10,496**	13,341
Realized (loss) gain on purchases	**(240)**	3,113	**2,759**	11,216
Realized loss on foreign exchange	**(1,466)**	(110)	**(3,694)**	(1,541)
Total realized gain	**2,884**	5,514	**9,561**	23,016
Realized gain on production ($/boe)	**1.92**	1.29	**1.44**	2.23
Realized (loss) gain on purchases ($/boe)	**(0.10)**	1.59	**0.38**	1.88
Realized loss on foreign exchange ($/boe)	**(0.61)**	(0.06)	**(0.51)**	(0.26)

For the three and nine months ended September 30, 2024, the Company realized gains on risk management contracts of $2.9 million and $9.6 million, respectively. This included the impact from production hedges (gains of $4.6 million and $10.5 million, respectively), foreign exchange contracts (losses of $1.5 million and $3.7 million, respectively) and natural gas volumes purchased for resale required to meet pipeline commitments in excess of the Company's production needs. The Company hedges price differences between Chicago and Alberta markets at the time of contracting third party natural gas purchases (loss of $0.2 million and gain of $2.8 million for the three and nine months ended September 30, 2024, respectively).

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

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

The Company has recognized an unrealized gain on risk management of $21.6 million, during the three months ended September 30, 2024 and an unrealized loss of $10.4 million during the nine months ended September 30, 2024, representing the changes in the fair value of risk management contracts outstanding at the end of those periods. As of September 30, 2024 the Company's risk management portfolio was in a net asset position of $9.2 million (net receivable) as compared to a net asset of $19.5 million as at December 31, 2023.

The Company has the following commodity risk management contracts outstanding as of September 30, 2024:

Type		Q4 2024	2025	2026	2027
Crude oil [1]					
WTI swap	bbl/d	2,000	563	—	—
WTI buy put	bbl/d	3,833	2,333	500	42
WTI sell call	bbl/d	3,333	2,333	500	42
WTI swap average	US$/bbl	$73.91	$74.17	$—	$—
WTI buy put average	US$/bbl	$69.35	$69.34	$70.00	$70.00
WTI sell call average	US$/bbl	$78.25	$77.07	$73.18	$73.18
Natural gas [1]					
NYMEX Henry Hub swap	MMBtu/d	2,500	—	—	—
NYMEX Henry Hub buy put	MMBtu/d	40,833	33,958	20,833	863
NYMEX Henry Hub sell call	MMBtu/d	32,500	33,958	20,833	863
NYMEX Henry Hub swap average	US$/MMBtu	$3.23	$—	$—	$—
NYMEX Henry Hub buy put average	US$/MMBtu	$3.19	$3.20	$3.11	$3.00
NYMEX Henry Hub sell call average	US$/MMBtu	$4.14	$4.52	$4.40	$3.90
Natural gas transportation [1,2]					
Purchase AECO 5A basis (to NYMEX Henry Hub)	MMBtu/d	30,000	22,083	—	—
Sell GDD Chicago basis (to NYMEX Henry Hub) [3]	MMBtu/d	(30,000)	(22,083)	—	—
AECO 5A basis (to NYMEX Henry Hub) average	US$/MMBtu	$(1.33)	$(1.36)	$—	$—
GDD Chicago basis (to NYMEX Henry Hub) average [3]	US$/MMBtu	$(0.03)	$(0.06)	$—	$—

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, 2024:

Type		Q4 2024	2025	2026	2027
Foreign exchange [1]					
Sell USD CAD (monthly average)	US$	$9.0 MM	$16.5 MM	$— MM	$— MM
USD CAD buy put	US$	$5.0 MM	$2.5 MM	$5.0 MM	$— MM
USD CAD sell call	US$	$5.0 MM	$2.5 MM	$5.0 MM	$— MM
USD CAD fixed sell rate		$1.33	$1.34	$—	$—
USD CAD put rate		$1.32	$1.33	$1.28	$—
USD CAD call rate		$1.34	$1.38	$1.35	$—

1 – Prices per unit and volumes per day are represented at the average amounts for the period.

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

$000s	September 30, 2024	December 31, 2023
Short term risk management asset	**7,967**	10,708
Long term risk management asset	**2,015**	8,838
Short term risk management liability	**(826)**	—
Total risk management contracts asset	**9,156**	19,546

$000s	September 30, 2024	December 31, 2023
Asset on produced volumes	**15,659**	9,186
(Liability) asset on purchased volumes	**(4,337)**	3,616
(Liability) asset on foreign exchange contracts	**(2,166)**	6,744
Total risk management contracts asset	**9,156**	19,546

Subsequent to September 30, 2024, the Company entered into the following risk management contracts:

Type		Q4 2024	2025	2026	2027
Crude oil contracts [1,2]					
WTI fixed price	bbl/d	—	500	500	—
WTI buy put	bbl/d	—	500	500	—
WTI sell call	bbl/d	—	500	500	—
WTI swap average	US$/bbl	$—	$70.05	$70.05	$—
WTI buy put average	US$/bbl	$—	$65.00	$65.00	$—
WTI sell call average	US$/bbl	$—	$74.15	$74.15	$—
Natural gas [1,2]					
NYMEX Henry Hub buy put	MMBtu/d	—	5,000	5,000	—
NYMEX Henry Hub sell call	MMBtu/d	—	5,000	5,000	—
NYMEX Henry Hub buy put average	US$/MMBtu	$—	$3.00	$3.00	$—
NYMEX Henry Hub sell call average	US$/MMBtu	$—	$4.05	$4.05	$—

1 – Prices per unit and volumes per day are represented at the average amounts for the period.
2 – Additional contracts were layered into the Company's existing risk management portfolio in accordance with the Company's risk management policy. The Company does not seek to speculate on commodity price movements through the hedging program.

Royalty expense

$000s	For the three months ended September 30, 2024	2023	For the nine months ended September 30, 2024	2023
Royalty expense	**8,233**	5,360	**26,770**	27,919
As a % of revenue	**7.5 %**	5.7 %	**8.0 %**	9.4 %
$/boe	**3.44**	2.75	**3.67**	4.68

The Company pays Crown, freehold, and overriding royalties on production volumes. Royalties for the three and nine months ended September 30, 2024 were $8.2 million and $26.8 million, respectively, as compared to $5.4 million and $27.9 million in the comparative periods of 2023.

Royalties as a percentage of revenue for the three months ended September 30, 2024 increased to 7.5% compared to 5.7% in the comparable prior year period due to an adjustment to estimated gas cost allowances recognized in the third quarter of 2023.

On a year to date basis, royalties as a percentage of revenue decreased to 8.0% compared to 9.4% in 2023 as a result of declines in benchmark pricing and an increased proportion of production from new wells which benefit from provincial incentive programs. Alberta's drilling and completion cost allowance program provides a 5% royalty rate on a well's initial production until the well's cumulative revenue, from all hydrocarbon products, equals a maximum threshold.

Operating expenses

$000s	For the three months ended September 30, 2024	2023	For the nine months ended September 30, 2024	2023
Operating expenses	**17,206**	17,895	**49,589**	50,822
$/boe	**7.19**	9.17	**6.80**	8.51

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, 2024 were $17.2 million and $49.6 million, as compared to $17.9 million and $50.8 million, respectively, in the comparable periods of 2023.

On a per barrel basis, operating expenses for the three and nine months ended September 30, 2024 decreased by 22% to $7.19/boe and 20% to $6.80/boe, respectively, as higher production led to operating efficiencies gained through the Company's owned and operated infrastructure within Simonette.

Transportation expenses

$000s	For the three months ended September 30, 2024	2023	For the nine months ended September 30, 2024	2023
Transportation expenses	**14,417**	10,913	**40,236**	33,735
$/boe	**6.04**	5.59	**5.52**	5.65

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, 2024 were $14.4 million and $40.2 million, respectively, as compared to $10.9 million and $33.7 million in the same periods in 2023, with the increase attributable to higher production. On a per barrel basis, transportation expenses for the three months ended September 30, 2024 were $6.04/boe compared to $5.59/boe in the prior period due to higher condensate production levels and unplanned third party outages during the quarter. Transportation per barrel on a year to date basis decreased from $5.65/boe to $5.52/boe as a result of a 13 month adjustment credit received in the first quarter of 2024. Excluding this credit, transportation expenses per barrel for the nine months ended are consistent with the comparable prior year period.

Adjusted funds flow from operations

$000s	For the three months ended September 30, 2024	2023	For the nine months ended September 30, 2024	2023
Cash flows from operating activities	**66,867**	60,294	**203,282**	181,814
Net change in non-cash working capital from operating activities	**(3,670)**	(5,454)	**(5,343)**	(8,076)
Asset retirement obligation expenditures	**1,549**	474	**2,468**	3,876
Adjusted funds flow from operations [1]	**64,746**	55,314	**200,407**	177,614
$/boe	**27.07**	28.34	**27.48**	29.75

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 during the three and nine months ended September 30, 2024 increased to $64.7 million and $200.4 million relative to $55.3 million and $177.6 million during the comparative periods in 2023, respectively. Increases on a total basis were attributable to growth in the business driven by increased production levels as described above (see operating netback), partially offset by increased financing costs resulting from higher average debt levels outstanding and interest on lease obligations.

On a per barrel basis, adjusted funds flow from operations during the three and nine months ended September 30, 2024 decreased by 5% to $27.07/boe and by 8% to $27.48/boe, respectively, relative to the comparable periods of 2023. Per barrel reductions relative to the prior periods reflect higher production levels and are consistent with the changes in adjusted operating netback and adjusted funds flow from operations described above.

Free funds flow from operations

$000s	For the three months ended September 30, 2024	2023	For the nine months ended September 30, 2024	2023
Adjusted funds flow from operations [1]	**64,746**	55,314	**200,407**	177,614
Capital expenditures [1]	**(91,044)**	(63,141)	**(237,272)**	(230,575)
Free funds flow deficiency from operations [1]	**(26,298)**	(7,827)	**(36,865)**	(52,961)
$/boe	**(11.00)**	(4.01)	**(5.06)**	(8.87)

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, 2024, the Company had a free funds flow deficiency of $26.3 million and $36.9 million relative to a deficiency of $7.8 million and $53.0 million in the comparative periods of 2023. The Company continues to execute a capital program aimed at generating short and longer-term production and cash-flow growth through development of its existing reserve base and investment in the infrastructure required to grow production in future periods.

The Company has been able to fund capital spending using cash flow from operations and available credit facilities and continuously monitors its liquidity position and financial performance to ensure ongoing financial flexibility and has the ability to adjust future capital spending plans if required to manage liquidity and/or balance sheet constraints.

General and administrative ("G&A") expenses

$000s	For the three months ended September 30, 2024	2023	For the nine months ended September 30, 2024	2023
Gross G&A expenses	**6,247**	4,958	**19,903**	17,352
Less capitalized G&A	**(1,126)**	(757)	**(2,937)**	(2,818)
G&A Expenses	**5,121**	4,201	**16,966**	14,534
$/boe	**2.14**	2.15	**2.33**	2.43

For the three and nine months ended September 30, 2024, the Company incurred gross G&A expenses of $6.2 million and $19.9 million, respectively, relative to $5.0 million and $17.4 million in the comparable periods in 2023. Increases resulted from growth in the business, with per barrel G&A expenses of $2.14/boe and $2.33/boe for the three and nine months ended September 30, 2024 decreasing slightly from the same periods in 2023, reflecting higher production levels.

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

Share-based compensation expenses

$000s	For the three months ended September 30, 2024	2023	For the nine months ended September 30, 2024	2023
Equity-settled awards	**513**	(14)	**2,123**	3,353
Cash-settled awards	**1,262**	1,041	**4,399**	1,723
Total share-based compensation expenses	**1,775**	1,027	**6,522**	5,076
$/boe	**0.74**	0.53	**0.89**	0.85

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, vesting period, and any applicable performance criteria with changes in fair value recognized as share-based compensation expense.

Total share-based compensation was $1.8 million and $6.5 million for the three and nine months ended September 30, 2024 compared to $1.0 million and $5.1 million, in the respective prior year periods, with increases driven by cash-settled awards with more awards outstanding, stronger relative performance to peers during 2024, and a higher share price at the end of the 2024 reporting period.

Finance costs

$000s	For the three months ended September 30, 2024	2023	For the nine months ended September 30, 2024	2023
Interest and bank charges	**4,774**	4,511	**14,113**	11,992
Accretion expense	**977**	956	**2,761**	2,676
Interest on lease obligations	**527**	428	**1,612**	872
Deferred financing amortization	**194**	161	**538**	754
Unrealized loss (gain) on foreign exchange	**395**	(307)	**(278)**	(139)
Total finance costs	**6,867**	5,749	**18,746**	16,155
$/boe	**2.87**	2.95	**2.57**	2.71

The Company has a $400 million senior secured extendible revolving facility (the “Credit Facility”) with a syndicate of banks. As at September 30, 2024 the Company had drawn $220.0 million on the facility (September 30, 2023 - $139.9 million).

Interest and bank charges for the three and nine months ended September 30, 2024 increased by 6% to $4.8 million and 18% to $14.1 million, respectively, compared to the same periods in the prior year. On a three month basis, the increase is attributable to higher average debt levels (2024 - $203.9 million; 2023 - $180.4 million), partially offset by a lower average interest rate (2024 - 7.69%; 2023 - 8.13%). On a nine month basis, the increase is attributable to higher average debt levels (2024 - $206.4 million; 2023 - $149.2 million) while average interest rates were consistent period over period (2024 - 8.07%; 2023 - 8.05%).

Depletion and Depreciation

$000s	For the three months ended September 30, 2024	2023	For the nine months ended September 30, 2024	2023
Depletion	**39,515**	30,026	**120,781**	88,699
Depreciation	**518**	525	**1,544**	1,407
Total depletion and depreciation	**40,033**	30,551	**122,325**	90,106
$/boe	**16.74**	15.65	**16.78**	15.09

The Company recognized depletion of $39.5 million and $120.8 million during the three and nine months ended September 30, 2024 compared to $30.0 million and $88.7 million during the comparative periods of 2023.

Increases in depletion was driven by higher production levels and increases in the depletion rate. Per barrel depletion rates have increased as a result of an increase in the depletable base, resulting from the Company's continued upstream development activity and greater future development costs assigned in accordance with the Company's 2023 reserve report. On a per barrel basis, increases in future development costs arose from inflationary pressures and the reallocation of capital to more liquids-rich development along with changes to other assumptions utilized by independent external reserve evaluators, offset by an increase in proved and probable reserves assigned.

Income taxes

During the nine months ended September 30, 2024, the Company incurred approximately $29.0 thousand in income taxes relating to the Company’s United States subsidiary. The Company did not pay any Canadian income taxes in 2024 (2023: $nil) and does not expect to be taxable in Canada in the near future.

As of September 30, 2024, the Company recognized a net deferred tax liability of $15.6 million. The Company’s estimated tax pools as at September 30, 2024, are as follows:

Category	Deductibility	$000s
Canadian oil and gas property expense (“COGPE”)	10%	174,149
Successored COGPE	10%	979
Canadian development expense (“CDE”)	30%	303,356
Successored CDE	30%	43,363
Canadian exploration expense (“CEE”)	100%	1,241
Undepreciated capital cost (“UCC”)	Primarily 25%, declining balance	173,591
Non-capital losses	100%	198,030
Share/Debt issue costs	5-year straight line	2,669
Other	Various	362
Total estimated tax pools		897,740

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 $115.2 million, or $169.3 million inflated at 1.64% and undiscounted. These cash flows have been discounted using a risk-free interest rate of 3.13% to arrive at the present value estimate of $84.8 million.

There is approximately $27.1 million (December 31, 2023: $26.7 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

During the second quarter of 2024, 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. The provision represents the future tolling obligations that the Company is presently obligated to make under the contract. As at September 30, 2024, the Company estimates the total undiscounted future tolling obligations under this contract to be $5.0 million. These payments have been discounted using a seven-year risk-free interest rate of 2.81% to arrive at a present value estimate of $4.6 million (December 31, 2023 – nil). The Company expects to reduce the provision by $0.8 million over the next twelve months as obligations become due. The estimate may vary as a result of changes in future discount rates and revisions in published tolls over the contract period.

Select quarterly information

($000s except per share and production)	2024			2023				2022
	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Production (average boe/d)	**25,996**	26,292	27,556	24,707	21,218	20,432	23,996	24,745
Commodity sales from production	**109,166**	105,049	119,662	114,038	94,432	83,935	119,421	159,457
Commodity sales from purchases	**15,773**	7,353	15,983	18,136	19,464	17,475	20,498	47,902
Cash flow from operating activities	**66,867**	61,232	75,183	58,946	60,294	41,360	80,160	87,028
Per share (basic)	**1.53**	1.40	1.72	1.35	1.37	0.94	1.81	1.97
Per share (diluted)	**1.51**	1.39	1.71	1.33	1.36	0.93	1.79	1.94
Net income (loss)	**32,535**	(26,538)	11,092	48,302	(12,056)	21,701	53,949	115,308
Per share (basic)	**0.74**	(0.61)	0.25	1.11	(0.27)	0.49	1.22	2.61
Per share (diluted)	**0.73**	(0.61)	0.25	1.09	(0.27)	0.49	1.21	2.57

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 2024 capital program.

Credit Facility

On May 27, 2024 the Company completed the annual borrowing base review of the consolidated Credit Facility and increased the borrowing base from $375.0 million to $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, 2024, $220.0 million was drawn on the Credit Facility (December 31, 2023 - $195.0 million). In addition, $72.9 million (December 31, 2023 - $89.4 million) in letters of credit issued to support transportation and other commitments were outstanding. Of the $72.9 million letters of credit, $48.0 million were provided for through the EDC facility (see below), and the remaining $24.9 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	220,000	24,864	**155,136**
EDC Facility	125,000	—	48,036	**76,964**
Total				**232,100**

$000s	September 30, 2024	December 31, 2023
Credit facility drawn	**220,000**	195,000
Deferred financing costs	**(1,294)**	(912)
Loans and borrowings	**218,706**	194,088
Adjusted working capital deficit (surplus) [1]	**22,490**	(7,565)
Net debt [1]	**241,196**	186,523
Annualized adjusted funds flow from operations [1]	**264,104**	241,311
Net debt to annualized adjusted funds flow from operations [1]	**0.91**	0.77

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, 2025, 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, 2026. The borrowing base is determined based on the lenders' evaluation of the Company's petroleum and natural gas reserves at the time and commodity prices.

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

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

The Company plans to continue using the Credit Facility to fund working capital and planned capital expenditures in advance of cash flow from new investments while targeting to maintain the ratio of net debt to last-twelve-months of adjusted funds flow from operations at no more than 1.0 times (September 30, 2024 - 0.91 times).

EDC letter of credit facility

On May 27, 2024, Kiwetinohk amended and increased the unsecured demand revolving letter of credit facility (the "LC Facility") with Export Development Canada ("EDC") from $75.0 million to $125.0 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, 2025 and may be extended from time-to-time at the option of Kiwetinohk and with the agreement of EDC. The Company expects to renew the PSG in May 2025 concurrently with its annual borrowing base review of the consolidated Credit Facility. At September 30, 2024, the Company has $77.0 million of capacity remaining under the LC Facility (December 31, 2023 - $8.9 million).

Base shelf prospectus

The Company filed a final short-form base shelf prospectus ("Prospectus") on May 27, 2024. The Prospectus provides financing flexibility and additional options for quicker access to public equity and/or debt markets as Kiwetinohk continues to pursue potential acquisition and other opportunities. It provides Kiwetinohk with the ability to issue up to $500 million of securities over a period of 25 months, if and when desirable. There are no immediate plans to raise equity, debt or other forms of financing and net proceeds from the sale of any securities issued under the Prospectus could have a wide range of uses including to complete asset or corporate acquisitions, to finance potential future growth opportunities, to repay indebtedness, to 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, 2023, the Company renewed its normal course issuer bid ("NCIB"), allowing the Company to purchase and cancel up to 2.2 million Common Shares prior to December 22, 2024. The Company has not purchased any shares under the NCIB program during the nine months ended September 30, 2024.

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 throughout the remainder of 2024 with the amount and timing of any purchases depending, among other things, on the share price, commodity prices and overall budget projections.

(000s)	For the three months ended September 30, 2024	2023	For the nine months ended September 30, 2024	2023
Weighted average shares outstanding				
Basic	**43,673**	43,885	**43,667**	44,059
Diluted	**44,289**	44,390	**44,122**	44,555
Outstanding securities				
Common shares	**43,713**	43,786	**43,713**	43,786
Stock options[1]	**2,891**	2,730	**2,891**	2,730
Performance warrants[1]	**6,703**	6,779	**6,703**	6,779
Total diluted outstanding securities	**53,307**	53,295	**53,307**	53,295

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 5, 2024, the Company has 43,758,615 Common Shares and no preferred shares outstanding.

Commitments, contractual obligations, and contingencies

$ millions	2024	2025	2026	2027	2028	Thereafter
Accounts payable	70.1	—	—	—	—	—
Cash-settled compensation liability [1]	—	2.3	0.7	0.1	—	1.8
Loans and borrowings [2]	—	—	220.0	—	—	—
Gathering, processing and transport [3]	18.9	75.5	62.0	37.8	37.9	107.2
Natural gas purchases	5.3	19.4	—	—	—	—
Upstream and corporate lease liabilities	0.4	2.2	2.2	2.2	2.2	6.3
Power lease liabilities [4]	—	2.0	1.3	1.3	1.3	27.2
Other	—	0.4	0.4	0.4	0.4	0.4
Total	94.7	101.8	286.6	41.8	41.8	142.9

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, 2024 is repaid on the facility's maturity date.
3 - The Company has extended its commitment on the US segment of the Alliance pipeline until October 2032, with evergreen renewals on the Canadian segment of the Alliance pipeline for one-year terms starting November 2025.
4 – The Company has not reached a FID on power projects as of the date hereof. The Company has the ability to terminate the lease and remove this financial obligation if FID is not achieved.

The Company currently has natural gas transportation commitments on the Nova Gas Transmission Ltd. and Alliance pipelines, with a commitment to deliver approximately 120.0 MMcf per day of gas to Chicago on Alliance which was extended by seven years through October 2032.

The Company currently has secured 35,100 GJ per day of gas supply (approximately 30.7 MMcf per day) from natural gas producers through September 2025, preparing the Company to fully utilize its remaining Alliance pipeline capacity after taking into account deliveries of its own production.

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

The Company is involved in litigation and disputes arising in the normal course of operations. Management is of the opinion that any potential litigation will not have a material adverse impact on the Company's financial position or results of operations as at September 30, 2024.

Related party information

For the three and nine months ended September 30, 2024, the Company incurred a total of $0.2 million and $0.9 million, respectively (September 30, 2023 – $0.2 million and $0.5 million), in the following related party transactions:

- The Company has retained a law firm to provide legal services on corporate matters. 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. A director of the Company is the Chairman of the Board of Directors of this company.

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

Risk factors and risk management

The Company's management team is focused on long-term strategic planning and has identified key material risks, uncertainties and opportunities associated with the Company's business that can impact the financial position, operations, cash flows and future prospects of the business. There were no significant changes in key risks identified during the three and nine months ended September 30, 2024. For additional information on risk factors, refer to the Company's audited financial statements as at and for the year ended December 31, 2023 and the Company's Annual Information Form ("AIF") dated March 5, 2024 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. Other risks are discussed under "Risk Factors" as presented in the AIF.

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, 2024, and ending on September 30, 2024, 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
There were no changes in accounting policies that had a material effect on the Company's financial statements during the three and nine months ended September 30, 2024.

Critical accounting estimates
The significant accounting judgements and estimates used by the Company are discussed in the notes to the December 31, 2023 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, 2024.

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 cash, 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.

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 forward looking capital expenditures to manage liquidity risk as required.

Market risk

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

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

Off-balance sheet arrangements

Except as disclosed in the Financial Statements, the Company has not entered into any guarantee or off-balance sheet arrangements that would materially impact the financial position or results of operations as at September 30, 2024.

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" and "capital management measures", as defined in National Instrument 52-112 *Non-GAAP and Other Financial Measures Disclosure* and explained in further detail below. These 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.

<u>Non-GAAP Financial Measures</u>

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:

$000s	For the three months ended September 30, 2024	2023	For the nine months ended September 30, 2024	2023
Commodity sales from production	**109,166**	94,432	**333,877**	297,788
Royalty expenses	**(8,233)**	(5,360)	**(26,770)**	(27,919)
Operating expenses	**(17,206)**	(17,895)	**(49,589)**	(50,822)
Transportation expenses	**(14,417)**	(10,913)	**(40,236)**	(33,735)
Operating netback	**69,310**	60,264	**217,282**	185,312
Realized gain on risk management	**3,124**	2,401	**6,802**	11,800
Realized (loss) gain on risk management - purchases	**(240)**	3,113	**2,759**	11,216
Net commodity sales from purchases (loss)	**1,683**	(2,376)	**2,280**	(5,490)
Adjusted operating netback	**73,877**	63,402	**229,123**	202,838

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:

$000s	For the three months ended September 30, 2024	2023	For the nine months ended September 30, 2024	2023
Cash flow used in investing activities	**91,766**	53,715	**227,101**	235,987
Net change in non-cash investing working capital	**(1,019)**	7,781	**10,838**	2,843
Power connection process payment	**—**	—	**(985)**	—
Settlement of contingent consideration	**—**	—	**—**	(10,250)
Capital expenditures and net acquisitions (dispositions)	**90,747**	61,496	**236,954**	228,580
Cash used in acquisitions	**—**	(855)	**—**	(1,286)
Proceeds from disposition	**297**	2,500	**318**	3,281
Net dispositions	**297**	1,645	**318**	1,995
Capital expenditures	**91,044**	63,141	**237,272**	230,575

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 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, in this MD&A within the Results of Operations section.

Non-GAAP Financial Ratios

Operating netback per boe & adjusted operating netback per boe

"Operating netback per boe" and "adjusted operating netback per boe" is calculated as operating netback and adjusted operating netback, respectively, divided by total production for the period as measured by boe. Operating netback per boe and adjusted operating netback per boe are key industry benchmarks and assist management with evaluating operating performance and efficiency on a comparable basis. The Company has disclosed the calculations of operating netback per boe & adjusted operating netback per boe 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 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 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 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).

$000s	September 30, 2024	December 31, 2023
Current assets	**69,247**	87,951
Current liabilities	**(84,596)**	(69,678)
Working capital (deficit) surplus	**(15,349)**	18,273
Remove short term risk management contracts net liability (asset)	**(7,141)**	(10,708)
Adjusted working capital (deficit) surplus	**(22,490)**	7,565

Net debt and net debt to annualized 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 annualized 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 annualized adjusted funds flow is calculated as net debt divided by the trailing four quarter adjusted funds flow from operations. The composition of Net debt and net debt to annualized adjusted funds flow from operations 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 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 from operating activities, adjusted funds flow and free cash flow on a per share – basic and diluted basis are calculated by dividing the cash 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", "expect", "plan", "intend", "estimate", "propose", "project", "potential", "may" 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 Power business unit's development strategy to enable the production of reliable, dispatchable, affordable and cleaner energy than what is available through Alberta's grid today;
- the Company's detailed 2024 financial and operational guidance and adjustments to the previously communicated 2024 guidance, including expected increase in capital spending, and revised sensitivity for adjusted funds flow from operations and related ratio of net debt to adjusted funds flow from operations;
- 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 Company's ability to continue to access the Chicago market;
- the continuing costs of engineering and procurement;
- the upside potential and significant potential inventory in the Company's Montney acreage;
- the expectation of being able to develop the Simonette Montney at a lower cost structure when compared to Simonette Duvernay lands;
- the timing and amount of cash taxes for the Company's US subsidiary and the Company's expectations regarding being taxable in Canada and the timing thereof;
- the Company's continued advancement of the Homestead solar project towards an FID decision;
- receipt of further clarity from provincial and federal governments regarding pending electricity regulations;
- the anticipated outcomes of successful execution of the Company's investment and financing strategies for its power project portfolio;
- the anticipated outcomes of the Company's capital program;
- expectations regarding the Company's working capital requirements and funding of the Company's capital program;
- asset retirement obligations and the estimated future cash flows to settle such obligations;
- operating and capital costs in 2024;
- sufficiency of funds to meet the Company's working capital requirements and anticipated drilling through 2024;
- the Company's ability to reduce the provision under its contract to transport and offload natural gas from the Nova Gas Transmission Ltd. pipeline system for use at its Opal gas-fired peaking project.
- timing for the next scheduled redetermination of the borrowing base on the Company's consolidated Credit Facility and EDC letter of credit facility and the borrowing base extended to the Company under such facilities at such time;
- use of the Credit Facility for working capital purposes to fund go forward capital plans;
- 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 and greenhouse gas regulations and related abandonment and reclamation obligations;
- the Company's expectations on timing and use of the NCIB program during 2024;
- 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 2024;
- the timing and costs of the Company's capital projects, including drilling and completion of certain wells;
- costs to abandon wells or reclaim property;

- the expectation of adding value through delineating the Duvernay and Montney assets and retaining core land;
- the impact of the Federal Government's draft CER and the REM
- 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;
- 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 (including COVID-19), instability and political and economic conditions (including the ongoing Russian-Ukrainian conflict and conflict in the Middle East) on the Company;
- the ability of the Company to successfully market its products;
- power project debt will be held at the project level;
- power projects will be funded by third parties, as currently anticipated; and
- the Company's operational success and results being consistent with current expectations.

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

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

- those risks set out in the AIF under “Risk Factors”;
- the ability of management to execute its business plan;
- general economic and business conditions;
- the ability of the Company to proceed with the power generation projects as described or at all;
- risks of natural disaster, war, hostilities, civil insurrection, pandemics (including COVID-19), 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 annualized adjusted funds flow from operations. Readers are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise or inaccurate and, as such, undue reliance should not be placed on FOFI. The Company's actual results, performance and achievements could differ materially from those expressed in, or implied by, FOFI. The Company has included FOFI in order to provide readers with a more complete perspective on the Company's future operations and management's current expectations relating to the Company's future performance. Readers are cautioned that such information may not be appropriate for other purposes. FOFI contained herein was made as of the date of this MD&A. Unless required by applicable laws, the Company does not undertake any obligation to publicly update or revise any FOFI statements, whether as a result of new information, future events or otherwise.

Abbreviations

$/bbl	dollars per barrel
$/boe	dollars per barrel equivalent
$/GJ	dollars per gigajoule
$/Mcf	dollars per thousand cubic feet
AECO	the daily average benchmark price for natural gas at the physical storage and trading hub for natural gas on the TransCanada Alberta transmission system which is the delivery point for various benchmark Alberta index prices
AESO	Alberta Electric Systems Operator
AIF	Annual Information Form
bbl/d	barrels per day
boe	barrel of oil equivalent, including crude oil, condensate, natural gas liquids, and natural gas (converted on the basis of one boe per six Mcf of natural gas)
boe/d	barrel of oil equivalent per day
CCS	Carbon Capture and Storage
CER	Clean Electricity Regulation
DI	daily index

FID	Final Investment Decision
GJ	gigajoule
GW	one billion watts
Mcf	thousand cubic feet
Mcf/d	thousand cubic standard feet per day
MI	monthly index
MMcf/d	million cubic feet per day
MMBtu	one million British Thermal Units is a measure of the energy content in gas
MMBtu/d	one million British thermal units per day
NGLs	natural gas liquids, which includes butane, propane, and ethane
REM	Restructured Energy Market
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. The Company 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 the Company 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. 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

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

Kaush Rakhit
Director

Steve Sinclair
Director

John Whelen
Director

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

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