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 years ended December 31, 2024 and 2023. 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 audited consolidated financial statements as at and for the years ended December 31, 2024 and 2023 (the "Financial Statements"). Additional information including that contained in Kiwetinohk's Annual Information Form ("AIF") is available on Kiwetinohk's website at www.kiwetinohk.com and 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 March 4, 2025.

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 from significant Duvernay and Montney resources with development upside as well as owned infrastructure for processing the majority of the Company's production and egress pipeline capacity for natural gas production to points in Alberta and Chicago, Illinois, United States.

Power

The power business unit is advancing pre-construction development plans of an Alberta-based power generation project portfolio that currently includes solar, and natural gas-fired power and carbon capture and storage ("CCS") facilities. The successful development of Kiwetinohk's power projects requires external capital, either from a project sale or through third-party financing, and would enable the future production of reliable, dispatchable, and affordable energy with lower emissions intensity relative to energy generated through Alberta's grid today.

Financial and operating highlights

	For the three months ended December 31,		For the year ended December 31,	
	2024	2023	**2024**	2023
Production				
Oil & condensate (bbl/d)	**8,627**	8,407	**8,396**	7,183
NGLs (bbl/d)	**4,132**	3,507	**3,936**	2,769
Natural gas (Mcf/d)	**89,385**	76,756	**87,260**	75,810
Total (boe/d)	**27,657**	24,707	**26,875**	22,587
Oil and condensate % of production	**31%**	34%	**31%**	32%
NGL % of production	**15%**	14%	**15%**	12%
Natural gas % of production	**54%**	52%	**54%**	56%
Realized prices				
Oil & condensate ($/bbl)	**95.38**	95.66	**95.76**	96.90
NGLs ($/bbl)	**44.96**	51.44	**43.86**	53.07
Natural gas ($/Mcf)	**3.39**	3.32	**3.04**	3.76
Total ($/boe)	**47.44**	50.17	**46.22**	49.95
Royalty expense ($/boe)	**(3.11)**	(4.84)	**(3.53)**	(4.72)
Operating expenses ($/boe)	**(7.74)**	(8.55)	**(7.04)**	(8.52)
Transportation expenses ($/boe)	**(5.21)**	(5.49)	**(5.44)**	(5.61)
Operating netback [1] ($/boe)	**31.38**	31.29	**30.21**	31.10
Realized (loss) gain on risk management ($/boe) [2]	**(0.18)**	0.23	**0.64**	1.50
Realized gain (loss) on risk management - purchases ($/boe) [2]	**0.11**	1.20	**0.31**	1.69
Net commodity sales from purchases (loss) ($/boe) [1]	**0.87**	(0.51)	**0.46**	(0.80)
Adjusted operating netback ($/boe) [1]	**32.18**	32.21	**31.62**	33.49
Financial results ($000s, except per share amounts)				
Commodity sales from production	**120,721**	114,038	**454,598**	411,826
Net commodity sales from purchases (loss) [1]	**2,239**	(1,152)	**4,519**	(6,642)
Cash flow from operating activities	**59,921**	58,946	**263,203**	240,760
Adjusted funds flow from operations [1]	**71,708**	63,697	**272,115**	241,311
Per share basic	**1.64**	1.46	**6.23**	5.49
Per share diluted	**1.61**	1.44	**6.11**	5.43
Net debt to adjusted funds flow from operations [1]	**1.00**	0.77	**1.00**	0.77
Free funds flow (deficiency from) operations (excluding acquisitions/ dispositions) [1]	**(27,767)**	(12,713)	**(64,632)**	(65,674)
Net (loss) income	**(16,024)**	48,302	**1,065**	111,896
Per share basic	**(0.37)**	1.11	**0.02**	2.54
Per share diluted	**(0.37)**	1.09	**0.02**	2.52
Capital expenditures prior to acquisitions (dispositions) [1]	**99,475**	76,410	**336,747**	306,985
Net acquisitions (dispositions) [1]	**—**	(18,000)	**(318)**	(19,995)
Capital expenditures and net acquisitions (dispositions) [1]	**99,475**	58,410	**336,429**	286,990

	2024	2023
Balance sheet ($000s, except share amounts)		
Total assets	**1,215,575**	1,085,615
Long-term liabilities	**388,452**	305,735
Net debt [1]	**272,764**	186,523
Adjusted working capital surplus (deficit) [1]	**(22,862)**	7,565
Weighted average shares outstanding		
Basic	**43,690,640**	43,971,108
Diluted	**44,571,772**	44,467,348
Shares outstanding end of period	**43,781,748**	43,662,644
Return on average capital employed ("ROACE") [1]	**3%**	21%
Reserves		
Proved reserves (MMboe) [3]	**130.7**	123.2
Proved reserves per share (boe) [3]	**3.0**	2.8
Proved plus probable reserves (MMboe) [3]	**246.4**	224.5
Proved plus probable reserves per share (boe) [3]	**5.6**	5.1

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 (loss) gain on risk management contracts includes settlement of financial hedges on production and foreign exchange, with gain (loss) on contracts associated with purchases presented separately.
3 – Oil and natural gas reserves are as determined by the Company's independent qualified reserve evaluator with an effective date of December 31 for the years shown in accordance with the Canadian Oil and Gas Evaluation Handbook and are shown as gross working interest reserves before royalties.

Guidance

The Company exited 2024 with strong performance when compared to its most recently disclosed full-year guidance. The Company achieved near the midpoint of guidance on production, capital expenditures and adjusted funds flow from operations while holding debt at the low end of guidance through strong performance on controllable cost categories which either beat or achieved the low end of guidance.

Kiwetinohk's 2024 actual results as compared to its most recent financial and operational guidance provided on November 5, 2024 are summarized below:

2024 operational & financial results vs guidance		2024 Guidance	2024 Actual	Variance vs Midpoint (%)
Sales volumes	Mboe/d	26.0 - 27.5	**26.9**	0.5%
Oil & liquids	%	45% - 49%	**46%**	(2.1)%
Natural gas	%	51% - 55%	**54%**	1.9%
Financial				
Royalty rate	%	7% - 10%	**7.6%**	(10.6)%
Operating costs	$/boe	$7.25 - $7.75	**$7.04**	(6.1)%
Transportation	$/boe	$5.50 - $6.00	**$5.44**	(5.4)%
Corporate G&A expense [1]	$MM	$23 - $25	**$23.3**	(2.9)%
Cash taxes [2]	$MM	$—	**—**	—%
Capital guidance [5]	$MM	$330 - $350	**$338.4**	(0.5)%
Upstream	$MM	$325 - $342	**$331.3**	(0.7)%
DCET [3]	$MM	$305 - $320	**$309.1**	(1.1)%
Infrastructure, production maintenance and other	$MM	$20 - $22	**$22.2**	5.7%
Power [4]	$MM	$5 - $8	**$7.1**	8.6%

2024 operational & financial results vs guidance		2024 Guidance	2024 Actual	Variance vs Midpoint (%)
2024 Adjusted Funds Flow from Operations commodity pricing sensitivities [5]				
US$70/bbl WTI & US$2.50/MMBtu HH	CAD$MM	$260 - $280	**$272.1**	0.8%
2024 Net debt to Adjusted Funds Flow from Operations sensitivities [5]				
US$70/bbl WTI & US$2.50/MMBtu HH	X	1.0x - 1.1x	**1.00x**	(4.8)%

1 – Includes G&A expenses for all divisions of the Company – Corporate, Upstream, Power and Business Development.
2 – The Company paid United States cash taxes of approximately $0.1 million reflecting taxes payable by its US subsidiary during 2024. The Company did not pay Canadian cash taxes in 2024.
3 – Includes drilling, completions, and equipping and associated pipelines and roads presented within facilities, pipelines, roads and optimization per the "Capital expenditures" section of this MD&A.
4 – The Company recognized an impairment on the power portfolio (excluding Homestead) as at June 30, 2024. Development costs related to impaired projects were expensed for the remainder of the year. Guidance and actual results for power development include capital expenditures, expensed project development costs, and the power connection process prepayment for the Company's Opal project.
5 – 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.

Management continues to execute on its development plans and is maintaining its 2025 guidance targets previously disclosed on December 16, 2024.

Kiwetinohk has updated its sensitivity analysis for expected adjusted funds flow from operations and the projected net debt-to-adjusted funds flow from operations ratio. These updates reflect actual year-to-date realized commodity pricing, a stronger forward strip for natural gas, the anticipated impact of U.S. import tariffs on gas volumes sold via the Alliance Pipeline to Chicago (estimated at approximately $15–$25 million if they remain in place), the $21 million Opal disposition in February 2025, and an expected $8.4 million payment related to the Homestead Solar power development project.

Despite the potential impact of U.S. import tariffs, these revisions have resulted in increased expected adjusted funds flow from operations and lower projected net debt-to-adjusted funds flow from operations ratio sensitivities. This reflects the strength of Kiwetinohk’s business, which benefits from strong production with low operating costs, high-liquids-content production, and critical access to the Chicago natural gas market for natural gas sales, which continues to offer premium pricing compared to Alberta.

Details of current full year guidance are presented below.

2025 Financial & Operational Guidance		**Current March 4, 2025**	Previous December 16, 2024
Production (2025 average)	Mboe/d	31.0 - 34.0	31.0 - 34.0
Oil & liquids	%	45% - 49%	45% - 49%
Natural gas [1]	%	51% - 55%	51% - 55%
Financial			
Royalty rate	%	6% - 8%	6% - 8%
Operating costs	$/boe	$7.25 - $7.75	$7.25 - $7.75
Transportation	$/boe	$6.00 - $6.25	$6.00 - $6.25
Corporate G&A expense [2]	$/boe	$1.95 - $2.15	$1.95 - $2.15
Cash taxes [3]	$MM	$—	$—
Upstream Capital [4]	$MM	$290 - $315	$290 - $315
DCET [5]	$MM	$270 - $290	$270 - $290
Plant expansion, production maintenance and other	$MM	$20 - $25	$20 - $25

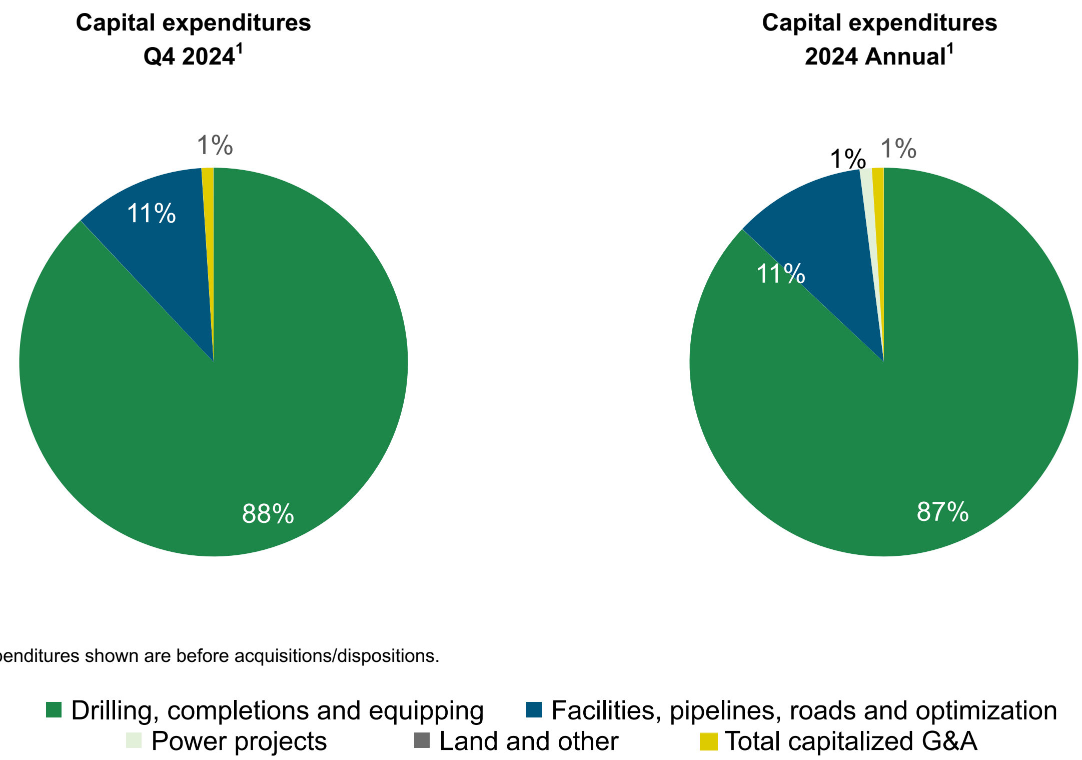
2025 Financial & Operational Guidance		Current March 4, 2025	Previous December 16, 2024
2025 Adjusted Funds Flow from Operations commodity pricing sensitivity [4, 6]			
US$60/bbl WTI & US$3.50/MMBtu HH & $0.70 USD/CAD	CAD$MM	$335 - $375	
US$70/bbl WTI & US$5.00/MMBtu HH & $0.70 USD/CAD	CAD$MM	$405 - $450	
US$ WTI +/- $1.00/bbl [7]	CAD$MM	+/- $4.3	
US$ Chicago +/- $0.10/MMBtu [7]	CAD$MM	+/- $4.7	
CAD$ AECO 5A +/- $0.10/GJ [7]	CAD$MM	+/- $0.1	
Exchange Rate (USD/CAD) +/- $0.01 [7]	CAD$MM	+/- $3.6	
2025 Net debt to Adjusted Funds Flow from Operations sensitivity [4, 6]			
US$60/bbl WTI & US$3.50/MMBtu HH & $0.70 USD/CAD	X	0.5x - 0.7x	
US$70/bbl WTI & US$5.00/MMBtu HH & $0.70 USD/CAD	X	0.3x - 0.4x	

1 – ~90% is expected to be sold into the Chicago market in 2025.
2 – Includes G&A expenses for all divisions of the Company – corporate, upstream, power and business development.
3 – The Company expects to pay immaterial cash taxes on its US subsidiary annually. No Canadian taxes are anticipated in 2025.
4 – Non-GAAP and other financial measures that do not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Please refer to the section "Non-GAAP Measures" herein.
5 – Approximately 5% of DCET relates to technology initiatives aimed at reducing per well capital costs and optimizing well design for improved productivity.
6 - Previously disclosed sensitivities utilized pricing levels at such time and have been revised to reflect current market data. As the sensitivities are no longer based on current information, prior values have been withdrawn.
7 – Assumes US$65/bbl WTI, US$3.25/mmbtu HH, US$2.60/mmbtu HH - AECO basis diff, 0.70 USD/CAD.

Capital expenditures

$000s	For the three months ended December 31, 2024	2023	For the year ended December 31, 2024	2023
Drilling, completions, and equipping	**86,983**	59,589	**289,681**	203,875
Facilities, pipelines, roads and optimization	**11,006**	11,541	**37,277**	85,494
Power projects	**443**	4,245	**4,807**	12,408
Land and other	**—**	—	**1,003**	1,355
Capitalized G&A - upstream	**959**	831	**3,338**	3,087
Capitalized G&A - power	**84**	204	**641**	766
Capital expenditures [1]	**99,475**	76,410	**336,747**	306,985
Upstream net acquisitions (dispositions) [1]	**—**	(18,000)	**(318)**	(19,995)
Capital and net acquisitions (dispositions) [1]	**99,475**	58,410	**336,429**	286,990

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



1 – Capital expenditures shown are before acquisitions/dispositions.

Drilling, completions and equipping

For the three months and year ended December 31, 2024, the Company invested $87.0 million and $289.7 million, respectively, to advance its development program with a focus on the Simonette Duvernay lands. During the year ended, December 31, 2024, the Company executed a two-rig program as outlined below:

Pad	Spud	On-stream	# wells
01-27 (Simonette)	Q1/24	Q3/24	1 Duvernay, 1 Montney
11-24 (Tony Creek)	Q1/24	Q3/24	3 Duvernay
10-29 (Tony Creek)	Q1/24	Q3/24	3 Duvernay
08-23 (Simonette)	Q3/24	Q4/24	2 Duvernay, 1 Montney
09-11 (Simonette)	Q3/24	2 in Q4/24; 1 in Q1/25	3 Duvernay
14-29 (Simonette)	Q4/24	Q1/25	2 Duvernay, 1 Montney
01-27 (Simonette)	Q4/24	Expected in Q3/25	2 Duvernay, 1 Montney

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

Facilities, pipelines, roads and optimization

For the three months and year ended December 31, 2024, the Company invested $11.0 million and $37.3 million, respectively, to build facilities, pipelines, roads and to optimize production. The 2024 upstream capital program benefited from upfront investment on infrastructure made in 2023 and required less infrastructure spending. Spending in 2024 was focused on building 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. For the year ended December 31, 2024, the Company moderated its development expenditures across the entire portfolio. Total costs to support the power development business included $5.4 million in capitalized expenditures (including capitalized G&A), $0.6 million in expensed project development costs and a $1.0 million deposit to the AESO for the Opal project power connection process.

In the second quarter of 2024, an accounting impairment indicator related to government policy and regulatory uncertainty was identified on six out of seven early-stage development projects. Given its advanced stage of development and ongoing investment to bring the project to a final investment decision ("FID"), there was no impairment indicator for the Homestead solar power project ("Homestead"). The Company has limited capital allocated to developing the power portfolio and as such, 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 not expected to meet capitalization criteria outlined in Note 5 of the Company's consolidated financial statements and 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 remain's focused on the sale and financing of the projects within its power development portfolio.

Subsequent events

Subsequent to December 31, 2024, the Company closed the sale of its proposed 101-MW Opal natural gas-fired power project for gross proceeds of $21.0 million. The sale included all Opal assets, material contracts, leases and permits relating to the project, including the assignment of the transportation service required to offload natural gas from the Nova Gas Transmission Ltd. pipeline system to the Opal project. This contract was recognized as an onerous contract when the Opal project was impaired in the second quarter of 2024, and resulted in a $4.4 million provision recorded as at December 31, 2024. Upon closing, the Company has unrecognized this provision with no further liability held by the Company as of March 4, 2025.

Subsequent to December 31, 2024, the Homestead Solar project advanced to AESO Stage 5, thereby becoming a fully permitted and licensed project which will require a $8.4 million Generating Unit Owner’s Contribution ("GUOC") payment to the Alberta Electric System Operator ("AESO") in March of 2025 to maintain the project in Alberta's regulatory queue. Without this payment, which cannot be deferred, the Homestead project would have been cancelled by the regulator and would be relegated to the start of the regulatory process as part of the AESO's third cluster study. The Company is pursuing a sale of Homestead and has approved this payment in the expectation of a future transaction.

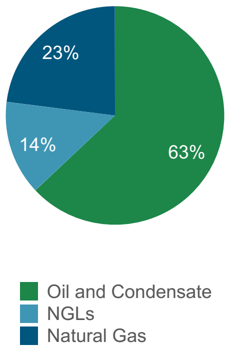
Results of operations

Production

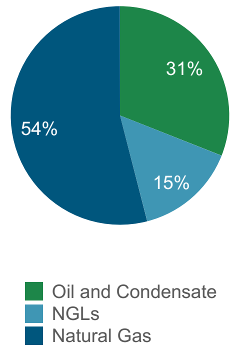
	For the three months ended December 31,		For the year ended December 31,	
	2024	2023	**2024**	2023
Oil & condensate (bbl/d)	**8,627**	8,407	**8,396**	7,183
NGLs (bbl/d) [1]	**4,132**	3,507	**3,936**	2,769
Natural gas (Mcf/d)	**89,385**	76,756	**87,260**	75,810
Total production (boe/d)	**27,657**	24,707	**26,875**	22,587
Oil and condensate % of production	**31%**	34%	**31%**	32%
NGL % of production	**15%**	14%	**15%**	12%
Natural gas % of production	**54%**	52%	**54%**	56%
Total production volumes %	**100%**	100%	**100%**	100%

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

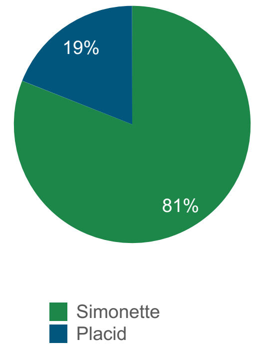
Revenue Mix ($)
Q4 2024



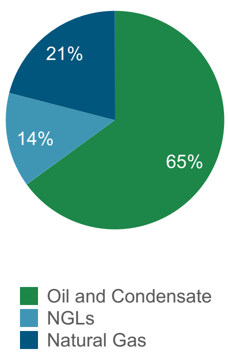
Production Mix (boe)
Q4 2024



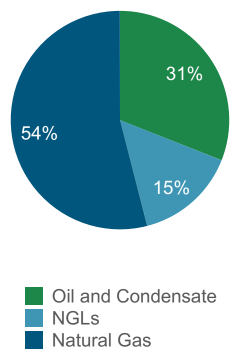
Production by Area (boe)
Q4 2024



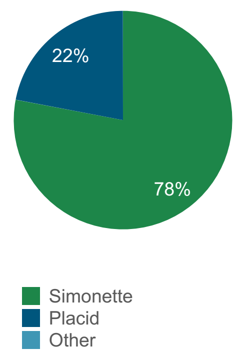
2024



2024



2024



Production for the three months and year ended December 31, 2024 increased by 12% to 27,657 boe/d and by 19% to 26,875 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. Six pads totaling 14 Duvernay wells and 2 Simonette Montney well have been brought on-stream during the year ended December 31, 2024, including five wells in the fourth quarter of 2024.

The composition of the Company's production during the three months ended December 31, 2024 was 31% oil and condensate, 15% NGLs, and 54% natural gas. The production profile has a lower oil and condensate weighting compared to the same period in the prior year as new well production was more gas weighted, with strong initial gas rates on the five wells brought on-stream during the fourth quarter of 2024. This production profile resulted in a revenue mix of 63% oil and condensate, 14% NGLs, and 23% natural gas in the quarter.

For the year ended December 31, 2024, the Company's production profile was 31% oil and condensate, 15% NGLs, and 54% natural gas. The 2024 production profile has a higher NGL weighting, offset by a lower natural gas weighting, compared to the prior year as a result of 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. This production profile resulted in a revenue mix of 65% oil and condensate, 14% NGLs, and 21% natural gas in 2024.

Benchmark and realized prices

	For the three months ended December 31,		For the year ended December 31,	
	2024	2023	**2024**	2023
Liquid benchmark prices				
WTI (US$/bbl)	**70.27**	78.32	**75.72**	77.62
WTI (CDN$/bbl)	**98.30**	106.72	**103.70**	104.78
Edmonton Light (CDN$/bbl)	**94.90**	99.69	**97.54**	100.39
Natural gas benchmark prices				
Henry Hub (US$/MMBtu)	**2.79**	2.88	**2.27**	2.74
Chicago City Gate MI (US$/MMBtu)	**2.71**	2.63	**2.14**	2.81
Chicago City Gate DI (US$/MMBtu)	**2.21**	2.28	**2.12**	2.30
AECO 5A (CDN$/GJ)	**1.40**	2.18	**1.38**	2.50
AECO 7A (CDN$/GJ)	**1.38**	2.52	**1.37**	2.78
Foreign exchange rates (USD/CAD)	**0.71**	0.73	**0.73**	0.74

	For the three months ended December 31,		For the year ended December 31,	
	2024	2023	**2024**	2023
Realized prices (before impact of hedging program)				
Oil & condensate ($/bbl)	**95.38**	95.66	**95.76**	96.90
NGLs ($/bbl)	**44.96**	51.44	**43.86**	53.07
Natural gas ($/Mcf)	**3.39**	3.32	**3.04**	3.76
Total ($/boe)	**47.44**	50.17	**46.22**	49.95

Crude oil prices for the three months and year ended December 31, 2024 decreased relative to the comparative periods in 2023. This decrease was primarily driven by an increase in global supply and a reduction in demand from China and other developing nations.

NGL sales contracts are negotiated annually in April each year, with pricing for the three months and year ended December 31, 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 $2.79 and US $2.27 per MMBtu in the three months and year ended December 31, 2024, respectively, when compared to US $2.88 and US $2.74 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 index benchmark averaged US $2.71 for the three months ended December 31, 2024, consistent with the same period in the prior year (US $2.63 per MMBtu). On an annual basis, the Chicago City Gate monthly index benchmark averaged US $2.14 per MMBtu for the year ended December 31, 2024, declining when compared to prior year (US $2.81 per MMBtu) primarily due to the same factors causing declines in Henry Hub prices.

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 $1.38/GJ and $1.37/GJ during the three months and year ended December 31, 2024, respectively, compared to $2.52/GJ and $2.78/GJ in the same periods in 2023.

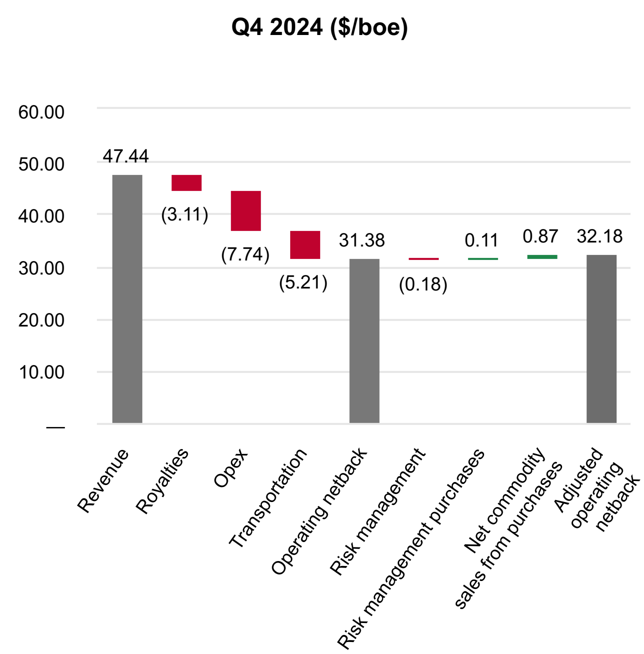
The Company continues to benefit from its access to the Chicago market through firm transportation capacity held on the Alliance pipeline system, selling approximately 95% of its natural gas production for the year ended December 31, 2024 in Chicago at a premium relative to Alberta prices. For the three months and year ended

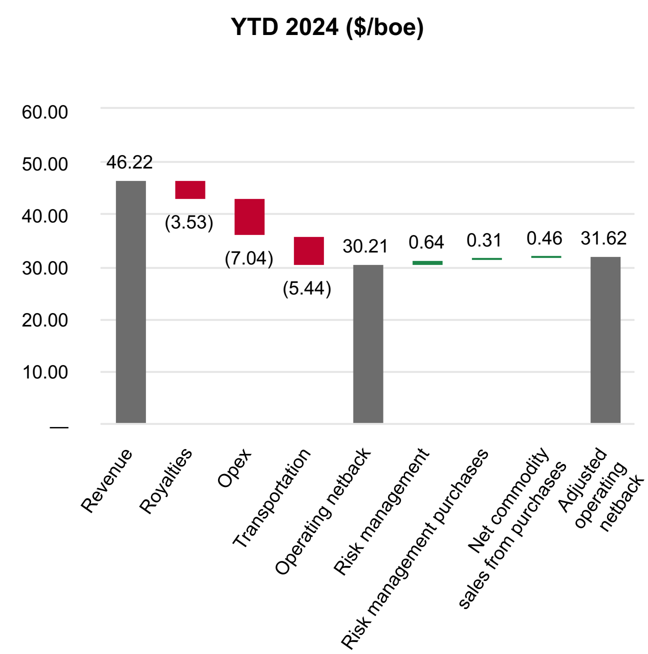
December 31, 2024, this premium was approximately 99% and 109%, respectively taking into account commodity price and currency differences.

Operating netback

	For the three months ended December 31,		For the year ended December 31,	
	2024	2023	**2024**	2023
Realized price ($/boe)	**47.44**	50.17	**46.22**	49.95
Royalty expenses ($/boe)	**(3.11)**	(4.84)	**(3.53)**	(4.72)
Operating expenses ($/boe)	**(7.74)**	(8.55)	**(7.04)**	(8.52)
Transportation expenses ($/boe)	**(5.21)**	(5.49)	**(5.44)**	(5.61)
Operating netback ($/boe) [1]	**31.38**	31.29	**30.21**	31.10
Realized (loss) gain on risk management ($/boe) [2]	**(0.18)**	0.23	**0.64**	1.50
Realized gain on risk management - purchases ($/boe) [2]	**0.11**	1.20	**0.31**	1.69
Net commodity sales from purchases (loss) ($/boe) [1]	**0.87**	(0.51)	**0.46**	(0.80)
Adjusted operating netback ($/boe) [1]	**32.18**	32.21	**31.62**	33.49
Total production (boe/d)	**27,657**	24,707	**26,875**	22,587

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





Operating netback for the three months and year ended December 31, 2024 was $31.38/boe and $30.21/boe, respectively, consistent with the 2023 comparative periods of $31.29/boe and $31.10/boe. Changes in operating netback for both periods were attributable to lower realized prices, offset by cost savings in royalties, 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 $32.18/boe and $31.62/boe for the three months and year ended December 31, 2024, respectively. The Company was successful in managing excess transport commitments and realized gains of $0.98/boe and $0.77/boe on its net commodity sales from purchases after hedging (described below). For the three months and year ended December 31, 2024, the Company realized a loss of $0.18/boe and gain of $0.64/boe, respectively, on risk management contracts on produced volumes and foreign exchange contracts, relative to gains of $0.23/boe and $1.50/boe in the prior periods, with the declines primarily resulting from losses on foreign exchange contracts arising from a weaker Canadian dollar.

Commodity sales from production

$000s	For the three months ended December 31, 2024	2023	For the year ended December 31, 2024	2023
Oil & condensate	**75,708**	73,989	**294,246**	254,053
NGLs	**17,095**	16,596	**63,186**	53,629
Natural gas	**27,918**	23,453	**97,166**	104,144
Total commodity sales from production	**120,721**	114,038	**454,598**	411,826

Revenue from production increased to $120.7 million and $454.6 million, respectively, for the three months and year ended December 31, 2024, representing 6% and 10% 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 the prior periods.

Net commodity sales from purchases

$000s	For the three months ended December 31, 2024	2023	For the year ended December 31, 2024	2023
Commodity sales from purchases	**16,417**	18,136	**55,526**	75,573
Commodity purchases, transportation and other	**(14,178)**	(19,288)	**(51,007)**	(82,215)
Net commodity sales from purchases (loss) [1]	**2,239**	(1,152)	**4,519**	(6,642)
Realized hedging gain on purchases	**275**	2,718	**3,034**	13,934
Net commodity sales from purchases after hedging[1]	**2,514**	1,566	**7,553**	7,292
$/boe – before hedging	**0.87**	(0.51)	**0.46**	(0.80)
$/boe – after hedging	**0.98**	0.69	**0.77**	0.89

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, and if required, will purchase condensate volumes required to meet firm commitments for resale in the Alberta market. The Company was able to successfully purchase and fill the balance of its Alliance firm transportation commitment during the year ended December 31, 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 months and year ended December 31, 2024, the Company realized a gain of $2.2 million and $4.5 million, respectively, on its marketing activities associated with purchasing natural gas to fulfill its transmission commitment on the Alliance pipeline system. Including the impact of related risk management contracts, the Company realized overall marketing income of $2.5 million and $7.6 million for the three months and year ended December 31, 2024, respectively, relative to $1.6 million and $7.3 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 December 31,		For the year ended December 31,	
$000s	**2024**	2023	**2024**	2023
Risk management:				
Unrealized (loss) gain	**(41,382)**	38,417	**(51,772)**	37,313
Realized (loss) gain	**(208)**	3,241	**9,353**	26,257
Total (loss) gain on risk management	**(41,590)**	41,658	**(42,419)**	63,570
Unrealized (loss) gain ($/boe)	**(16.26)**	16.90	**(5.26)**	4.53
Realized (loss) gain ($/boe)	**(0.07)**	1.43	**0.95**	3.19

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

	For the three months ended December 31,		For the year ended December 31,	
$000s	**2024**	2023	**2024**	2023
Realized gain on production	**2,448**	1,702	**12,944**	15,043
Realized gain on purchases	**275**	2,718	**3,034**	13,934
Realized loss on foreign exchange	**(2,931)**	(1,179)	**(6,625)**	(2,720)
Total realized (loss) gain	**(208)**	3,241	**9,353**	26,257
Realized gain on production ($/boe)	**0.96**	0.75	**1.31**	1.83
Realized gain on purchases ($/boe)	**0.11**	1.20	**0.31**	1.69
Realized loss on foreign exchange ($/boe)	**(1.14)**	(0.52)	**(0.67)**	(0.33)

For the three months and year ended December 31, 2024, the Company realized a loss on risk management contracts of $0.2 million and gain of $9.4 million, respectively. This included the impact from production hedges (gains of $2.4 million and $12.9 million, respectively), foreign exchange contracts (losses of $2.9 million and $6.6 million, respectively) and natural gas volumes purchased for resale required to meet pipeline commitments in excess of the Company's production needs (gains of $0.3 million and $3.0 million, respectively). The Company hedges price differences between Chicago and Alberta markets at the time of contracting third party natural gas purchases.

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

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

The Company has recognized an unrealized loss on risk management of $41.4 million, during the three months ended December 31, 2024 and an unrealized loss of $51.8 million during the year ended December 31, 2024, representing the changes in the fair value of risk management contracts outstanding at the end of those periods. As of December 31, 2024 the Company's risk management portfolio was in a net liability position of $32.2 million 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 December 31, 2024:

Type		Q1 2025	Q2 2025	Q3 2025	Q4 2025	2026	2027
Crude oil [1]							
WTI swap	bbl/d	1,833	1,250	1,167	1,000	750	225
WTI buy put	bbl/d	3,833	3,583	3,083	2,833	1,500	50
WTI sell call	bbl/d	3,833	3,583	3,083	2,833	1,500	50
WTI swap average	US$/bbl	$72.57	$70.69	$70.47	$70.04	$68.72	$67.57
WTI buy put average	US$/bbl	$67.98	$67.83	$67.48	$67.26	$65.83	$70.00
WTI sell call average	US$/bbl	$76.38	$76.12	$75.59	$75.38	$73.11	$73.18
Natural gas [1]							
NYMEX Henry Hub buy put	MMBtu/d	57,500	47,500	45,833	45,000	35,833	3,587
NYMEX Henry Hub sell call	MMBtu/d	57,500	47,500	45,833	45,000	36,042	3,337
NYMEX Henry Hub buy put average	US$/MMBtu	$3.13	$3.15	$3.15	$3.17	$3.08	$3.21
NYMEX Henry Hub sell call average	US$/MMBtu	$4.32	$4.33	$4.35	$4.45	$4.24	$3.69
Natural gas transportation [1,2]							
Purchase AECO 5A basis (to NYMEX Henry Hub)	MMBtu/d	30,000	25,000	25,000	8,333	—	—
Sell GDD Chicago basis (to NYMEX Henry Hub) [3]	MMBtu/d	(30,000)	(25,000)	(25,000)	(8,333)	—	—
AECO 5A basis (to NYMEX Henry Hub) average	US$/MMBtu	$(1.35)	$(1.36)	$(1.36)	$(1.36)	$—	$—
GDD Chicago basis (to NYMEX Henry Hub) average [3]	US$/MMBtu	$(0.01)	$(0.08)	$(0.08)	$(0.08)	$—	$—

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 December 31, 2024:

Type		Q1 2025	Q2 2025	Q3 2025	Q4 2025	2026	2027
Foreign exchange [1]							
Sell USD CAD (monthly average)	US$	$12.5 MM	$12.5 MM	$12.5 MM	$12.5 MM	$— MM	$— MM
USD CAD buy put	US$	$6.5 MM	$6.5 MM	$6.5 MM	$6.5 MM	$13.0 MM	$— MM
USD CAD sell call [2]	US$	$6.5 MM	$6.5 MM	$6.5 MM	$6.5 MM	$17.0 MM	$— MM
USD CAD fixed sell rate		$1.35	$1.35	$1.35	$1.35	$—	$—
USD CAD buy put rate		$1.33	$1.33	$1.33	$1.33	$1.33	$—
USD CAD sell call rate [2]		$1.39	$1.39	$1.39	$1.39	$1.39	$—

1 – Prices per unit and volumes per day are represented at the average amounts for the period.
2 – The Company entered into a collar effective for the 2026 calendar year. As at December 31, 2024, $8.0 million per month at a rate of 1.37 USD/CAD has been included in the above table. Should the WM/Reuters monthly average drop below 1.4050, the notional amount will drop to $4.0 million at a call rate of 1.405.

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

$000s	2024	2023
Short term risk management asset	—	10,708
Long term risk management asset	—	8,838
Short term risk management liability	**(20,900)**	—
Long term risk management liability	**(11,326)**	—
Total risk management contracts (liability) asset	**(32,226)**	19,546

$000s	2024	2023
Asset on produced volumes	**1,023**	9,186
(Liability) asset on purchased volumes	**(9,748)**	3,616
(Liability) asset on foreign exchange contracts	**(23,501)**	6,744
Total risk management contracts (liability) asset	**(32,226)**	19,546

Subsequent to December 31, 2024, the Company entered into the following risk management contracts:

Type		Q1 2025	Q2 2025	Q3 2025	Q4 2025	2026	2027	2028
Crude oil contracts [1,2]								
WTI buy put	bbl/d	167	250	250	250	250	—	—
WTI sell call	bbl/d	167	250	250	250	250	—	—
Sell Ft Sask C5 differential (to WTI)	bbl/d	833	1,667	—	—	—	—	—
WTI buy put average	US$/bbl	$65.00	$65.00	$65.00	$65.00	$65.00	$—	$—
WTI sell call average	US$/bbl	$72.50	$72.50	$72.50	$72.50	$72.50	$—	$—
Ft Sask C5 differential (to WTI) average	US$/bbl	$(0.57)	$(0.57)	$—	$—	$—	$—	$—
Natural gas [1,2]								
NYMEX Henry Hub buy put	MMBtu/d	7,500	18,333	20,000	13,333	8,125	7,500	208
NYMEX Henry Hub sell call	MMBtu/d	7,500	15,833	17,500	10,833	7,500	7,500	208
NYMEX Henry Hub buy put average	US$/MMBtu	$3.53	$3.65	$3.69	$3.56	$3.44	$3.42	$3.50
NYMEX Henry Hub sell call average	US$/MMBtu	$4.47	$4.53	$4.71	$4.52	$4.48	$4.48	$4.28

Type		Q1 2025	Q2 2025	Q3 2025	Q4 2025	2026	2027	2028
Foreign exchange								
Buy USD CAD put (monthly average)	US$	$— MM	$— MM	$4.0 MM	$4.0 MM	$2.0 MM	$2.0 MM	$— MM
Sell USD CAD call (monthly average)	US$	$— MM	$— MM	$4.0 MM	$4.0 MM	$2.0 MM	$2.0 MM	$— MM
Buy USD/CAD put rate		$—	$—	$1.40	$1.40	$1.38	$1.36	$—
Sell USD/CAD call rate		$—	$—	$1.47	$1.47	$1.46	$1.42	$—

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 December 31, 2024	2023	For the year ended December 31, 2024	2023
Royalty expense	**7,920**	11,000	**34,690**	38,919
As a % of revenue	**6.6 %**	9.6 %	**7.6 %**	9.5 %
$/boe	**3.11**	4.84	**3.53**	4.72

The Company pays Crown, freehold, and overriding royalties on production volumes. Royalties for the three months and year ended December 31, 2024 were $7.9 million and $34.7 million, respectively, as compared to $11.0 million and $38.9 million in the comparative periods of 2023.

Royalties as a percentage of revenue for the three months and year ended December 31, 2024 decreased to 6.6% and 7.6%, respectively, compared to 9.6% and 9.5% in the prior year periods 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 December 31, 2024	2023	For the year ended December 31, 2024	2023
Operating expenses	**19,688**	19,428	**69,277**	70,250
$/boe	**7.74**	8.55	**7.04**	8.52

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 months and year ended December 31, 2024 were $19.7 million and $69.3 million, as compared to $19.4 million and $70.3 million, respectively, in the comparable periods of 2023.

On a per barrel basis, operating expenses for the three months and year ended December 31, 2024 decreased by 9% to $7.74/boe and 17% to $7.04/boe, respectively, as higher production led to operating efficiencies gained through the Company's owned and operated infrastructure within Simonette. Fourth quarter operating expenses increased over prior quarters in 2024 as a result of planned maintenance and workovers.

Transportation expenses

$000s	For the three months ended December 31, 2024	2023	For the year ended December 31, 2024	2023
Transportation expenses	**13,274**	12,479	**53,510**	46,214
$/boe	**5.21**	5.49	**5.44**	5.61

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 months and year ended December 31, 2024 were $13.3 million and $53.5 million, respectively, as compared to $12.5 million and $46.2 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 and year ended December 31, 2024 decreased to $5.21/boe and $5.44/boe, respectively, relative to $5.49/boe and $5.61/boe in the prior periods with annual increases in tolling offset by a credit to previously paid condensate transportation as actual volumes were reconciled to the Company's committed transportation obligations.

Adjusted funds flow from operations

$000s	For the three months ended December 31, 2024	2023	For the year ended December 31, 2024	2023
Cash flows from operating activities	**59,921**	58,946	**263,203**	240,760
Net change in non-cash working capital from operating activities	**9,508**	3,786	**4,165**	(4,290)
Asset retirement obligation expenditures	**2,279**	198	**4,747**	4,074
Adjusted funds flow from operations [1]	**71,708**	63,697	**272,115**	241,311
$/boe	**28.18**	28.02	**27.66**	29.27

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

Adjusted funds flow from operations for the three months and year ended December 31, 2024 increased to $71.7 million and $272.1 million, respectively, relative to $63.7 million and $241.3 million in the comparative periods in 2023. Increases on a total basis were attributable to growth in the business driven by increased production levels and cost savings as described above (see operating netback), partially offset by increased financing costs resulting from higher average debt levels outstanding and interest on lease obligations.

For the three months ended December 31, 2024, adjusted funds flow from operations per barrel of $28.18/boe was consistent with the comparative period in 2023 ($28.02/boe). On an annual basis, adjusted flow from operations decreased by 6% to $27.66/boe due to the movements in operating netback and adjusted funds flow from operations described above, which were driven by lower commodity pricing.

Free funds flow from operations

$000s	For the three months ended December 31, 2024	2023	For the year ended December 31, 2024	2023
Adjusted funds flow from operations [1]	**71,708**	63,697	**272,115**	241,311
Capital expenditures [1]	**(99,475)**	(76,410)	**(336,747)**	(306,985)
Free funds flow (deficiency) from operations [1]	**(27,767)**	(12,713)	**(64,632)**	(65,674)
$/boe	**(10.91)**	(5.59)	**(6.57)**	(7.97)

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 months and year ended December 31, 2024, the Company had a free funds flow deficiency of $27.8 million and $64.6 million relative to a deficiency of $12.7 million and $65.7 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 December 31, 2024	2023	For the year ended December 31, 2024	2023
Gross G&A expenses	**7,374**	7,209	**27,277**	24,561
Less capitalized G&A	**(1,042)**	(1,035)	**(3,979)**	(3,853)
G&A Expenses	**6,332**	6,174	**23,298**	20,708
$/boe	**2.49**	2.72	**2.37**	2.51

For the three months and year ended December 31, 2024, the Company incurred gross G&A expenses of $7.4 million and $27.3 million, respectively, relative to $7.2 million and $24.6 million in the comparable periods in 2023 with the increase being primarily attributable to company growth. On a per barrel basis, G&A of $2.49/boe and $2.37/boe for the three months and year ended December 31, 2024 decreased relative to the prior periods primarily due to higher production levels.

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

Share-based compensation expenses

$000s	For the three months ended December 31, 2024	2023	For the year ended December 31, 2024	2023
Equity-settled awards	**488**	1,141	**2,611**	4,494
Cash-settled awards	**3,632**	484	**8,031**	2,207
Total share-based compensation expenses	**4,120**	1,625	**10,642**	6,701
$/boe	**1.62**	0.71	**1.08**	0.81

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 $4.1 million and $10.6 million for the three months and year ended December 31, 2024 compared to $1.6 million and $6.7 million, in the respective prior year periods. Increases in both periods are attributable to higher cash-settled award compensation due to more awards outstanding, stronger relative performance to peers during 2024 and therefore a higher performance multiplier, and a higher share price at the end of the 2024 reporting period. Equity-settled award compensation award compensation declined over the comparative periods of 2023 as a result of units vesting over time, with a portion of equity-settled awards fully vested in 2024.

Finance costs

	For the three months ended December 31,		For the year ended December 31,	
$000s	**2024**	2023	**2024**	2023
Interest and bank charges	**5,029**	4,400	**19,142**	16,392
Accretion expense	**945**	1,001	**3,706**	3,677
Interest on lease obligations	**628**	533	**2,240**	1,405
Deferred financing amortization	**194**	160	**732**	914
Unrealized loss (gain) on foreign exchange	**(182)**	822	**(460)**	683
Total finance costs	**6,614**	6,916	**25,360**	23,071
$/boe	**2.60**	3.04	**2.58**	2.80

The Company has a $400 million senior secured extendible revolving facility (the "Credit Facility") with a syndicate of banks. As at December 31, 2024 the Company had drawn $251.0 million on the facility (December 31, 2023 - $139.9 million).

Interest and bank charges for the three months and year ended December 31, 2024 increased by 14% to $5.0 million and 17% to $19.1 million, respectively, compared to the same periods in the prior year. Increases were attributable to higher average debt levels (2024 - $222.0 million; 2023 - $156.6 million) offset by a lower average interest rate (2024 - 7.72%; 2023 - 8.17%).

Depletion and Depreciation

	For the three months ended December 31,		For the year ended December 31,	
$000s	**2024**	2023	**2024**	2023
Depletion	**44,694**	37,501	**165,475**	126,200
Depreciation	**531**	543	**2,075**	1,950
Total depletion and depreciation	**45,225**	38,044	**167,550**	128,150
$/boe	**17.77**	16.74	**17.03**	15.54

The Company recognized depletion of $44.7 million and $165.5 million during the three months and year ended December 31, 2024 compared to $37.5 million and $126.2 million during the comparative periods of 2023.

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

On a per barrel basis, depletion and depreciation costs of $17.03 were incurred during 2024 (2023 - $15.54) with the year-over-year increase in line with the increase the Company’s long term finding and development costs on a total proved and probable basis as calculated based on the Company’s 2024 reserve report.

Income taxes

During the year ended December 31, 2024, the Company incurred approximately $53.0 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 December 31, 2024, the Company recognized a net deferred tax liability of $11.1 million. The Company’s estimated tax pools as at December 31, 2024, were $927.8 million comprised of the following:

Category	Deductibility	$000s
Canadian oil and gas property expense ("COGPE")	10%	169,381
Successored COGPE	10%	953
Canadian development expense ("CDE")	30%	323,227
Successored CDE	30%	39,146
Canadian exploration expense ("CEE")	100%	—
Undepreciated capital cost ("UCC")	Primarily 25%, declining balance	171,923
Non-capital losses	100%	220,502
Share/Debt issue costs	5-year straight line	2,302
Other	Various	373
Total estimated tax pools		927,807

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 $114.9 million, or $176.6 million inflated at 1.82% and undiscounted. These cash flows have been discounted using a risk-free interest rate of 3.33% to arrive at the present value estimate of $84.2 million.

There is approximately $28.0 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 obligated to make under the contract. As at December 31, 2024, the Company estimates the total undiscounted future tolling obligations under this contract to be $4.8 million. These payments have been discounted using a seven-year risk-free interest rate of 3.07% to arrive at a present value estimate of $4.4 million (December 31, 2023 – nil).

Subsequent to December 31, 2024, the Company sold its Opal gas-fired peaking project and assigned all future tolling obligations under the contract and unrecognized the provision. As such, the Company has unrecognized this provision in the first quarter of 2025 with no further liability held by the Company as of March 4, 2025.

Select annual information

($000s except per share and production)	2024	2023	2022
Production (average boe/d)	**26,875**	22,587	17,852
Commodity sales from production ($000)	**454,598**	411,826	499,898
Commodity sales from purchases ($000)	**55,526**	75,573	268,552
Cash flow from operating activities	**263,203**	240,760	242,850
Per share (basic)	**6.02**	5.48	5.51
Per share (diluted)	**5.91**	5.41	5.45
Net income	**1,065**	111,896	190,989
Per share (basic)	**0.02**	2.54	4.34
Per share (diluted)	**0.02**	2.52	4.28
Total assets	**1,215,575**	1,085,615	932,650
Long-term liabilities	**388,452**	305,735	221,731
Net debt [1]	**272,764**	186,523	122,304
Adjusted working capital (deficit) surplus [1]	**(22,862)**	7,565	(3,105)

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.

Select quarterly information

	2024				2023			
($000s except per share and production)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Production (average boe/d)	**27,657**	25,996	26,292	27,556	24,707	21,218	20,432	23,996
Commodity sales from production	**120,721**	109,166	105,049	119,662	114,038	94,432	83,935	119,421
Commodity sales from purchases	**16,417**	15,773	7,353	15,983	18,136	19,464	17,475	20,498
Cash flow from operating activities	**59,921**	66,867	61,232	75,183	58,946	60,294	41,360	80,160
Per share (basic)	**1.37**	1.53	1.40	1.72	1.35	1.37	0.94	1.81
Per share (diluted)	**1.35**	1.51	1.39	1.71	1.33	1.36	0.93	1.79
Net (loss) income	**(16,024)**	32,535	(26,538)	11,092	48,302	(12,056)	21,701	53,949
Per share (basic)	**(0.37)**	0.74	(0.61)	0.25	1.11	(0.27)	0.49	1.22
Per share (diluted)	**(0.37)**	0.73	(0.61)	0.25	1.09	(0.27)	0.49	1.21

Capital resources and liquidity

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

Credit Facility

On May 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 December 31, 2024, $251.0 million was drawn on the Credit Facility (December 31, 2023 - $195.0 million). In addition, $70.0 million (December 31, 2023 - $89.4 million) in letters of credit issued to support transportation and other commitments were outstanding. Of the $70.0 million letters of credit, $48.0 million were provided for through the EDC facility (see below), and the remaining $22.0 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	251,002	22,015	**126,983**
EDC Facility	125,000	—	48,036	**76,964**
Total				**203,947**

$000s	2024	2023
Credit facility drawn	**251,002**	195,000
Deferred financing costs	**(1,100)**	(912)
Loans and borrowings	**249,902**	194,088
Adjusted working capital deficit (surplus) [1]	**22,862**	(7,565)
Net debt [1]	**272,764**	186,523
Adjusted funds flow from operations [1]	**272,115**	241,311
Net debt to adjusted funds flow from operations [1]	**1.00**	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 (2024 - 1.00 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 December 31, 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, 2024, the Company renewed its normal course issuer bid ("NCIB"), allowing the Company to purchase and cancel up to 2,188,237 Common Shares prior to December 22, 2025. The Company did not purchase any shares under the NCIB program for the year ended December 31, 2024. In 2023, the Company purchased 598,776 Common Shares at a total cost of $7.6 million, an average of $12.71 per share.

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

	For the three months ended December 31,		For the year ended December 31,	
(000s)	**2024**	2023	**2024**	2023
Weighted average shares outstanding				
Basic	**43,760**	43,711	**43,691**	43,971
Diluted	**44,548**	44,172	**44,572**	44,467
Outstanding securities				
Common shares	**43,782**	43,663	**43,782**	43,663
Stock options[1]	**2,827**	2,768	**2,827**	2,768
Performance warrants[1]	**6,583**	6,779	**6,583**	6,779
Total diluted outstanding securities	**53,192**	53,210	**53,192**	53,210

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 13 of the Consolidated Financial Statements for further information regarding share based compensation plans.

At March 4, 2025, the Company has 43,784,452 Common Shares and no preferred shares outstanding.

Commitments, contractual obligations, and contingencies

$ millions	2025	2026	2027	2028	2029	Thereafter
Accounts payable	75.9	—	—	—	—	—
Cash-settled compensation liability [1]	4.3	1.4	0.3	—	—	2.4
Loans and borrowings [2]	—	251.0		—	—	—
Risk management contracts	20.9	10.9	0.4	—	—	—
Gathering, processing and transport [3]	76.8	63.6	39.9	39.9	39.9	72.0
Natural gas purchases	31.0	—	—	—	—	—
Upstream and corporate lease liabilities	2.2	2.2	2.2	2.2	2.2	3.9
Power lease liabilities [4]	2.0	1.9	1.5	1.7	1.8	75.8
Other	0.4	0.4	0.4	0.4	0.4	—
Total	213.5	331.4	44.7	44.2	44.3	154.1

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 December 31, 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 29.3 MMcf/d of natural gas transportation commitments on the Nova Gas Transmission Ltd. to March 2026. In addition, the Company holds a commitment to deliver approximately 120.0 MMcf/d of gas to Chicago on Alliance. The Company has extended its commitment on the US segment of the Alliance Pipeline until October 31, 2032, with anticipated toll renewals on the Canadian segment of the Alliance Pipeline for evergreen one-year terms starting November 1, 2025, with a longer term expectation of renewing for the full-term committed to on the US segment pending a review of tolls on the Canadian segment by the Canadian Energy Regulator.

The Company currently has secured 10,100 GJ per day of gas supply (approximately 8.9 MMcf per day) from natural gas producers through October 2025, preparing the Company to fully utilize its remaining Alliance pipeline capacity after taking into account deliveries of its own production.

Lease liabilities represent the undiscounted payments required under lease obligations as described in Note 6 of the consolidated 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 December 31, 2024.

Related party information

For the quarter and year ended December 31, 2024, the Company incurred a total of $0.3 million and $1.2 million, respectively (December 31, 2023 – $0.1 million and $0.7 million), in the following related party transactions:

- The Company has retained a law firm to provide legal services on corporate matters. 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.

Environment, social and governance

Kiwetinohk regularly reviews its environmental, social and governance ("ESG") risks and management strategies, and published its 2024 ESG report (for the 2023 reporting year) in May, 2024 guided by the Sustainability Accounting Standards Board ("SASB") data standards for Oil & Gas – Exploration and Production and the Financial Stability Board's Task Force on Climate-related Financial Disclosures ("TCFD") framework.

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. The following information is a summary of only certain risk factors, and is not an exhaustive list, nor should it be taken as a complete summary or description of all risks relating to the Company or its securities and should be read in conjunction with the "Risk Factors" as presented in the Company's AIF dated March 5, 2025 available on the SEDAR+ website at www.sedarplus.ca.

• risks associated with global economic and financial conditions and commodity prices;	• restrictions on development activities to protect wildlife;
• risks associated with the capital required to conduct future operations and acquire and develop reserves;	• maintaining access to credit facilities to fund working capital and capital projects;
• exploration, development and production risks;	• competition in the crude oil and natural gas industry;
• risks associated with exploration, development and production of crude oil and natural gas, and drilling for unconventional oil, NGL and natural gas;	• risks associated with developing the power generation portfolio;
• risks related to impacts of hydraulic fracturing and seismic activity;	• the risks and limitations of forecasting reserves data;
• risks associated with political uncertainty and legal or regulatory developments in Canada and globally;	• health, safety and environmental risks
• risks associated with drilling in the high pressure Duvernay formation and loss of control of a well;	• market constraints, including processing and transportation, and access to services and equipment;
• risks associated with tariffs and trade barriers including United States tariffs;	• risks associated with changes in capital markets and industry conditions impacting access to capital;
• adverse changes to interest, currency and inflation rates;	• technology and cybersecurity risks;
• failure to obtain necessary licenses and permits;	• the other factors discussed under "Risk Factors" within the Company's AIF.

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 properties and projects that it invests in, utilizes proven technologies and pursues new technologies where appropriate.

Control environment

Disclosure controls and procedures

Disclosure controls and procedures ("DC&P"), as defined in National Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings ("NI 52-109"), are designed to provide reasonable assurance that information required to be disclosed in the Company's annual filings, interim filings or other reports filed, or submitted by the Company under securities legislation is recorded, processed, summarized and reported within the time periods specified under securities legislation and include controls and procedures designed to ensure that information required to be so disclosed is accumulated and communicated to management, including the Chief Executive Officer and the Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

Kiwetinohk's Chief Executive Officer and the Chief Financial Officer evaluated the effectiveness of the design and operation of the Company's DC&P. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded the Company's DC&P were effective as at December 31, 2024.

It should be noted that while the Company's DC&P are intended to provide a reasonable level of assurance that information required to be disclosed is recorded, processed, summarized and reported within the time periods specified in securities legislation, DC&P cannot be expected to prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

Internal controls over financial reporting

Internal controls over financial reporting ("ICFR"), as defined in NI 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings, is a set of processes designed to provide reasonable assurance that all assets are safeguarded, transactions are appropriately authorized, and facilitate the preparation of relevant, reliable, and timely information. 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.

Kiwetinohk's Chief Executive Officer and the Chief Financial Officer evaluated the effectiveness of the Company's ICFR as defined in Canada by NI 52-109. The assessment was based on the framework in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded the Company's ICFR was effective as of December 31, 2024. No changes were made to the Company's ICFR during the year ended December 31, 2024 that have materially affected, or are reasonably likely to materially affect, the ICFR.

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 months and year ended December 31, 2024.

The significant accounting judgements and estimates used by the Company are discussed in the notes to the December 31, 2024 audited financial statements. Certain accounting policies require that management make appropriate decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, and expenses. Management reviews its estimates on a regular basis. The emergence of new information and changed circumstances may result in actual results or changes to estimate amounts that differ materially from current estimates.

The critical accounting estimates that may impact the Company's financial and operating results include:

- estimated depletion and impairment which is based on estimates of oil and natural gas reserves;
- estimates of economically recoverable oil and natural gas reserves which are impacted by production rates, commodity prices, royalties, operating costs, and other relevant assumptions;
- estimated asset retirement obligations based on current legal and constructive requirements, technology, price levels, cost inflation, the risk-free interest rate, timing and expected plans for remediation;
- equity-settled share-based compensation expense based on Black-Scholes option pricing model inputs including fair value of shares, issue date, expected volatility, dividend yield, forfeiture, and discount rates;
- cash-settled share-based compensation expense based on fair value of shares, forfeiture, and expected payout multipliers, as applicable;
- estimated deferred tax liabilities; and

- estimated fair value of risk management contracts based on forecast commodity prices and foreign exchange rates.

Future Accounting Pronouncements

The following are future accounting pronouncements issued and not yet effective as at December 31, 2024. The Company intends to adopt these standards as they become effective and is in the process of evaluating the impacts, if any, on the consolidated financial statements.

IAS 21 The Effects of Changes in Foreign Exchange Rates
Effective January 1, 2025, amendments require entities to apply a consistent approach in assessing whether a currency can be exchanged into another currency and, when it cannot, in determining the exchange rate to use and the disclosures to provide. This is not expected to have a material impact on the Company's financial statements.

IFRS 18 Presentation and Disclosure in Financial Statements
Effective January 1, 2027, IFRS 18 will replace IAS 1, carrying forward many of the requirements in IAS 1 unchanged and complementing them with new requirements. IFRS 18 will introduce new requirements to present specific categories and defined subtotals in the statement of profit and loss, provide disclosures on management-defined performance measures in the notes to the financial statements and improve aggregation and disaggregation. The Company expects IFRS 18 to impact future consolidated financial statements and disclosures.

IFRS 19 Subsidiaries without Public Accountability Disclosures
Effective January 1, 2027, amendments permit eligible subsidiaries to provide reduced disclosures if it does not have public accountability and its ultimate or any intermediate parent produces consolidated financial statements available for public use that comply with IFRS. This is not expected to be applied for purposes of the consolidated financial statements.

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 planned capital expenditures to manage liquidity risk as required.

Market risk

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

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

Off-balance sheet arrangements

Except as disclosed in the Financial Statements, the Company has not entered into any guarantee or off-balance sheet arrangements that would materially impact the financial position or results of operations as at December 31, 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.

Non-GAAP Financial Measures

Operating netback & adjusted operating netback

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

$000s	For the three months ended December 31, 2024	2023	For the year ended December 31, 2024	2023
Commodity sales from production	**120,721**	114,038	**454,598**	411,826
Royalty expenses	**(7,920)**	(11,000)	**(34,690)**	(38,919)
Operating expenses	**(19,688)**	(19,428)	**(69,277)**	(70,250)
Transportation expenses	**(13,274)**	(12,479)	**(53,510)**	(46,214)
Operating netback	**79,839**	71,131	**297,121**	256,443
Realized (loss) gain on risk management	**(483)**	523	**6,319**	12,323
Realized gain on risk management - purchases	**275**	2,718	**3,034**	13,934
Net commodity sales from purchases (loss)	**2,239**	(1,152)	**4,519**	(6,642)
Adjusted operating netback	**81,870**	73,220	**310,993**	276,058

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 December 31, 2024	2023	For the year ended December 31, 2024	2023
Cash flow used in investing activities	**91,314**	67,044	**318,415**	303,031
Net change in non-cash investing working capital	**8,161**	(8,634)	**18,999**	(5,791)
Power connection process payment	**—**	—	**(985)**	—
Settlement of contingent consideration	**—**	—	**—**	(10,250)
Capital expenditures and net acquisitions (dispositions)	**99,475**	58,410	**336,429**	286,990
Cash used in acquisitions	**—**	—	**—**	(1,286)
Proceeds from disposition	**—**	18,000	**318**	21,281
Net acquisitions (dispositions)	**—**	18,000	**318**	19,995
Capital expenditures	**99,475**	76,410	**336,747**	306,985

Earnings before interest and taxes

"Earnings before interest and taxes" or "EBIT" is calculated as net income (loss) plus financing costs and total income taxes (recovery). The Company uses EBIT as a measure of operating performance and as an input in the calculation for the non-GAAP financial ratio, "Return on average capital employed". The table below reconciles EBIT to the most directly comparable GAAP measure, net income (loss):

$000s	Q4 2024	Q4 2023	2024	2023
Net (loss) income	**(16,024)**	48,302	**1,065**	111,896
Finance costs	**6,614**	6,916	**25,360**	23,071
Total income taxes (recovery)	**(4,521)**	18,793	**1,105**	33,961
EBIT	**(13,931)**	74,011	**27,530**	168,928

Average capital employed

"Average capital employed" is the average of the total of net debt and shareholders' equity at the beginning of the period and at the end of the period. The Company uses average capital employed as a measure of capital management and as an input in the calculation for the non-GAAP financial ratio, ROACE. The table below reconciles average capital employed to the most directly comparable GAAP measure, shareholders' equity:

$000s	2024	2023
Beginning of year		
Shareholders' equity	**710,202**	600,619
Net debt	**186,523**	122,304
Capital employed	**896,725**	722,923
End of year		
Shareholders' equity	**715,038**	710,202
Net debt	**272,764**	186,523
Capital employed	**987,802**	896,725
Average capital employed	**942,264**	809,824

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.

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

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 per boe is disclosed in this MD&A within the Results of operations section.

Return on average capital employed

"Return on average capital employed" or "ROACE" is calculated as EBIT divided by the average capital employed. ROACE is used by management to measure the effectiveness of its capital management and its ability to generate returns for shareholders. The following table includes the updated calculation of ROACE for the years ended December 31, 2024 and 2023.

$000s	2024	2023	2022	3-Year Average
Earnings before interest and taxes	**27,530**	168,928	176,811	124,423
Average capital employed	**942,264**	809,824	585,935	779,341
ROACE	**3%**	21%	30%	16%

During 2024, the Company saw a decline in its ROACE, primarily as a result of the impact of non-cash losses within the Consolidated Statement of Net Income and Comprehensive Income. These included, unrealized losses on the Company's hedging program as well as impairments recognized on the power portfolio during the year. The Company's capital management priorities are managed with a longer term focus, and believes these non-cash impacts are normalized over time with a three year average ROACE of 16%.

Capital Management Measures

Adjusted funds flow from operations

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

Free funds flow (deficiency) from operations

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

Adjusted working capital surplus (deficit)

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

$000s	2024	2023
Current assets	**68,323**	87,951
Current liabilities	**(112,085)**	(69,678)
Working capital (deficit) surplus	**(43,762)**	18,273
Remove short term risk management contracts net liability (asset)	**20,900**	(10,708)
Adjusted working capital (deficit) surplus	**(22,862)**	7,565

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

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

Supplementary Financial Measures

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

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

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

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

Forward-Looking Statements

Certain information set forth in this MD&A contains forward-looking information and statements. Such forward-looking statements or information are provided for the purpose of providing, without limitation, information about management's current expectations of business strategy, and management's assessment of future plans and operations. Forward-looking statements or information typically contain statements with words such as "anticipate", "believe", "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 Upstream business unit's properties that are expected to offer competitive economic resource potential and development upside;
- the Power business unit's development strategy to enable the production of reliable, dispatchable, affordable and cleaner energy than what is available through Alberta's grid today;
- the Company’s detailed 2025 financial and operational guidance and adjustments to the previously communicated 2025 guidance, including revised sensitivity for adjusted funds flow from operations and related ratio of net debt to adjusted funds flow from operations;
- expectations of continued premiums in the Chicago natural gas benchmark pricing when compared to Alberta markets;
- estimated impact of United States import tariffs;
- anticipated well production;

- the timing and costs of the Company's capital projects, including, but not limited to, drilling, production and completion of certain wells, the delineation of the Company's Montney acreage and technology initiatives;
- the Company's ability to continue to access the Chicago market and its expectation to renew the Canadian segment of the Alliance pipeline to a similar term as the US segment, as well as any impact of potential tolling reviews by the Canadian Energy Regulator;
- the timing and amount of cash taxes for the Company's US subsidiary and the Company's expectations regarding being taxable in Canada and the timing thereof;
- the Company's continued advancement of the Homestead solar project towards an FID decision;
- the Company's expectation of a future transaction on its Homestead solar project;
- the anticipated outcomes of successful execution of the Company's investment and financing strategies for its power project portfolio, including the Homestead project;
- future Power development expenditures not expected to meet capitalization criteria
- the anticipated outcomes of the Company's capital program;
- expectations regarding the Company's working capital requirements and funding of the Company's capital program;
- provision liabilities and the estimated future cash flows to settle such obligations;
- operating and capital costs in 2025;
- sufficiency of funds to meet the Company's working capital requirements and anticipated drilling through 2025;
- estimates of the total undiscounted future tolling obligations under the contract to transport and offload natural gas from the Nova Gas Transmission Ltd. pipeline system for use at the Opal gas-fired peaking project;
- timing for the next scheduled redetermination of the borrowing base on the Company's consolidated Credit Facility and EDC LC Facility, including the PSG, and the borrowing base extended to the Company under such facilities at such time;
- use of the Credit Facility 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 2025;
- the Company's expectations regarding the impact of future accounting pronouncements on the consolidated financial statements;
- expectations regarding the Company's ability to continue to manage risk through hedging contracts and risk management contracts;
- the Company's ability to continue to meet its pipeline transportation commitments;
- expectations regarding the future risk associated with take or pay pipeline obligations;
- the Company's ability to continue to benefit from Alberta's drilling and completion cost allowance program;
- the expected demand for, and prices and inventory levels of, petroleum products, including NGL;
- the Company's expectations regarding material adverse litigation; and
- the impact of current market conditions on the Company;

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

- the expectation of ~90% of natural gas sales being directed to the Chicago market during 2025;
- the timing and costs of the Company's capital projects, including drilling, production and completion of certain wells and the delineation of the Company's Montney acreage;
- costs to abandon wells or reclaim property;
- the ability of the Company to mitigate the cost of transportation services in excess of current production needs;
- the impact of increasing competition;
- general business, economic and market conditions
- the general stability of the economic and political environment in which the Company operates;
- the ability of the Company to obtain qualified staff, equipment and services in a timely and cost efficient manner;

- the ability of the operator of the projects that the Company has an interest in to operate in a safe, efficient and effective manner;
- future commodity and power prices;
- currency, exchange and interest rates;
- near and long-term impacts of tariffs or other changes in trade policies in North America, as well as globally;
- the Company's unique position to deliver additional value to shareholders;
- the regulatory framework regarding royalties, taxes, power, renewable and environmental matters in the jurisdictions in which the Company operates;
- the ability of the Company to obtain the required capital to finance its exploration, development and other operations and meet its commitments and financial obligations;
- the ability of the Company to extend the PSG under the EDC LC Facility;
- the ability of the Company to secure adequate product processing, transportation, fractionation and storage capacity on acceptable terms and the capacity and reliability of facilities;
- anticipated timelines and budgets being met in respect of drilling and completions programs and other operations;
- the impact of natural disaster, war, hostilities, civil insurrection, pandemics (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;
- global economic, financial and political conditions, including the results of ongoing trade negotiations in North America, as well as globally;
- risks of natural disaster, war, hostilities, civil insurrection, pandemics (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 adjusted funds flow from operations. Readers are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise or inaccurate and, as such, undue reliance should not be placed on FOFI. The Company's actual results, performance and achievements could differ materially from those expressed in, or implied by, FOFI. The Company has included FOFI in order to provide readers with a more complete perspective on the Company's future operations and management's current expectations relating to the Company's future performance. Readers are cautioned that such information may not be appropriate for other purposes. FOFI contained herein was made as of the date of this MD&A. Unless required by applicable laws, the Company does not undertake any obligation to publicly update or revise any FOFI statements, whether as a result of new information, future events or otherwise.

Abbreviations

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

Oil and gas advisories

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

This MD&A includes references to sales volumes of "crude oil" "oil and condensate", "NGLs" and "natural gas" and revenues therefrom. National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities, includes condensate within the NGLs product type. 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

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Chief Sustainability Officer

Mike Backus
Chief Operating Officer, Upstream

Jakub Brogowski
Chief Financial Officer

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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
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Lisa Wong
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ATB Financial
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Bank of Nova Scotia
Business Development Bank of Canada

Auditor

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Board of Directors

Kevin Brown
Board Chair

Beth Reimer-Heck
Lead Director

Judith Athaide
Director

Colin Bergman
Director

Pat Carlson
Director and Chief Executive Officer

Leland Corbett
Director

Alicia Kilmer
Director

Kaush Rakhit
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Steve Sinclair
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John Whelen
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