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, 2022 and 2021. The Company was formed as part of the amalgamation of Kiwetinohk Resources Corp. ("KRC") and Distinction Energy Corp. ("Distinction", previously known as Delphi Energy Corp.). Kiwetinohk's common shares commenced trading on the Toronto Stock Exchange under the symbol KEC on January 14, 2022.

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, 2022 and 2021 (the "Financial Statements"). Additional information including that contained in Kiwetinohk's 2022 Annual Information Form ("AIF"), is available on Kiwetinohk's website at www.kiwetinohk.com and SEDAR at www.sedar.com. 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 Measures", "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 7, 2023.

Overview of business

Kiwetinohk's mission is to build a profitable energy transition business which provides clean, reliable, dispatchable and affordable energy. The Company develops and produces liquids-rich natural gas and related products and is in the process of developing renewable and natural gas-fired power generation projects with a vision of also incorporating carbon capture technology and hydrogen production, all as part of a broader, integrated portfolio of clean energy assets that will support energy transition in the markets that it serves.

Upstream

The Upstream business unit is involved in the acquisition, exploration 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. In 2021, the Company completed acquisitions of upstream assets and associated infrastructure, with an additional working interest in a portion of these assets acquired during the third quarter of 2022. These assets consist of high-netback, liquids-rich natural gas production with development upside and spare processing capacity from owned infrastructure. These upstream assets provide a foundational base for the Company to pursue and develop energy transition opportunities.

Green Energy

The Green Energy business unit is pursuing greenfield and examining potential brownfield development opportunities across a diversified Alberta-based power generation project portfolio that currently includes renewable solar, natural gas-fired power with carbon capture, utilization and storage ("CCUS") and early stage hydrogen opportunities. Successful development of Kiwetinohk's Green Energy projects will enable the production of clean, reliable, dispatchable, affordable energy and provide downstream markets for integration of the Company's future natural gas production, allowing it to capture a larger portion of the energy value chain.

Financial and operating highlights

	Q4 2022	Q3 2022	Q4 2021	2022	2021
Production					
Oil & condensate (bbl/d)	**8,423**	5,558	3,949	**6,197**	3,130
NGLs (bbl/d)	**2,664**	1,944	1,572	**2,012**	1,180
Natural gas (Mcf/d)	**81,949**	53,912	41,410	**57,859**	32,942
Total (boe/d)	**24,745**	16,487	12,422	**17,852**	9,801
Oil and condensate % of production	**34%**	34%	32%	**35%**	32%
NGL % of production	**11%**	12%	13%	**11%**	12%
Natural gas % of production	**55%**	54%	55%	**54%**	56%
Realized prices					
Oil & condensate ($/bbl)	**104.96**	114.48	97.66	**115.82**	84.35
NGLs ($/bbl)	**68.82**	75.50	65.61	**74.06**	52.60
Natural gas ($/Mcf)	**8.12**	10.20	6.64	**8.69**	5.29
Total ($/boe)	**70.04**	80.86	61.48	**76.72**	51.06
Royalty expense ($/boe)	**(5.72)**	(12.51)	(6.80)	**(6.78)**	(5.46)
Operating expenses ($/boe)	**(7.20)**	(11.13)	(8.28)	**(9.70)**	(8.18)
Transportation expenses ($/boe)	**(5.27)**	(6.63)	(5.20)	**(5.31)**	(5.09)
Operating netback [1] ($/boe)	**51.85**	50.59	41.20	**54.93**	32.33
Realized loss on risk management ($/boe)	**(6.58)**	(19.41)	(12.55)	**(13.33)**	(8.77)
Realized loss on risk management – purchases ($/boe)	**(2.36)**	(16.92)	0.69	**(5.23)**	(1.38)
Net commodity sales from purchases ($/boe) [1]	**3.16**	21.64	2.50	**7.07**	1.91
Adjusted operating netback [1]	**46.07**	35.90	31.84	**43.44**	24.09
Financial results ($000s, except per share amounts)					
Commodity sales from production	**159,457**	122,644	70,267	**499,898**	182,668
Net commodity sales from purchases [1]	**7,174**	32,813	2,854	**46,069**	6,831
Cash flow from operating activities	**87,023**	91,710	25,509	**242,850**	35,820
Adjusted funds flow from operations [1]	**101,506**	49,342	30,763	**264,082**	69,829
Per share basic	**2.30**	1.12	0.71	**6.00**	2.20
Per share diluted	**2.26**	1.10	0.71	**5.92**	2.20
Net debt to annualized adjusted funds flow from operations [1]	**0.46**	0.65	0.74	**0.46**	0.74
Free funds flow (deficiency) from operations (excluding acquisitions/dispositions) [1]	**(1,202)**	(11,119)	(1,195)	**(5,647)**	18,929
Net income (loss)	**115,308**	55,379	44,306	**190,989**	(22,315)
Per share basic	**2.61**	1.26	1.02	**4.34**	(0.70)
Per share diluted	**2.57**	1.24	1.02	**4.28**	(0.70)
Capital expenditures [1]	**102,708**	60,461	31,958	**269,729**	50,900
Net acquisitions [1]	**-**	59,181	-	**57,323**	186,655
Capital expenditures and net acquisitions [1]	**102,708**	119,642	31,958	**327,052**	237,555
Balance sheet ($000s, except share amounts)					
Total assets	**932,650**	837,349	614,337	**932,650**	614,337
Long-term liabilities	**221,731**	214,536	124,587	**221,731**	124,587
Net debt [1]	**122,304**	125,263	51,512	**122,304**	51,512
Adjusted working capital surplus (deficit) [1]	**(3,105)**	(24,065)	18,644	**(3,105)**	18,644
Weighted average shares outstanding					
Basic	**44,168,157**	44,114,105	43,622,942	**44,045,613**	31,689,093
Diluted	**44,887,920**	44,795,079	43,622,942	**44,593,528**	31,689,093
Shares outstanding end of period	**44,176,710**	44,117,187	43,674,583	**44,176,710**	43,674,583
Return on average capital employed ("ROACE") [1]				**30%**	(10%)
Reserves					
Proved reserves (MMboe) [3]				**125.5**	106.1
Proved reserves per share (boe) [3]				**2.9**	2.4
Proved plus probable reserves (Mmboe) [3]				**214.5**	180.2
Proved plus probable reserves per share (boe) [3]				**4.9**	4.2

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

2 – Realized loss on risk management contracts includes settlement of financial hedges on production and foreign exchange, with losses 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 net working interest reserves before royalties.

Guidance

The Company exited 2022 with strong performance against previously disclosed guidance, meeting or exceeding corporate estimates in all categories. Strong production volumes achieved through new well production in the fourth quarter resulted in corporate production sales of 17.9 Mboe/d during 2022 exceeding the high end of guidance of 17.6 Mboe/d and positively contributed to all $/boe metrics. Capital spending was $10 million below the low end of guidance as a result of the timing of the capital program, with costs associated with the development of upstream and green energy assets that were assumed within the 2022 guidance being deferred into 2023.

Kiwetinohk's 2023 annual guidance and a review of 2022 actual results as compared to financial and operational guidance provided on November 16, 2022 are outlined below:

2022 financial & operational results vs guidance		Q4 2022 Guidance	Q4 2022 Actual	2022 Guidance	2022 Actual
Sales Volumes[1]	Mboe/d	23 - 24	**27.4**	17.4 – 17.6	**17.9**
Oil & liquids	Mbbl/d	11.0 – 11.5	**11.1**	8.2 – 8.3	**8.2**
Natural gas	MMcf/d	72 – 75	**81.9**	55 – 56	**57.9**
Sales Volumes by market					
Chicago	%	87 - 92	**88**	80 – 85	**82**
AECO	%	8 - 13	**12**	15 – 20	**18**
Financial					
Royalty rate[2]	%	9 – 11	**8.2**	10 – 12	**8.8**
Operating costs[1]	$/boe	8.00 – 9.00	**7.20**	10.00 – 11.00	**9.70**
Transportation	$/boe	5.75 – 6.25	**5.27**	5.50 – 6.00	**5.31**
Corporate G&A expense[3]	$MM	5 – 7	**4.5**	18 – 20	**17.5**
Cash taxes	$MM	-	**-**	-	**-**
Capital guidance	$MM	109 – 129	**103**	280 -300	**270**
Upstream	$MM	103 – 118	**95**	265 – 280	**256**
DCET	$MM	66 - 76	**60**	200 – 210	**193**
Other	$MM	37 – 42	**35**	65 – 70	**63**
Green Energy	$MM	6 – 11	**8**	15 – 20	**14**
Drilling – Fox Creek	wells	5	**5**	13	**13**
Duvernay	wells	3	**3**	11	**11**
Montney	wells	2	**2**	2	**2**
Adjusted funds flow from operations sensitivities[4]					
November 14 Strip	$MM	88 - 102	**101.5**	250 – 264	**264.1**
Net debt to adjusted funds flow from operations sensitivities[4]					
November 14 Strip	X	0.4x – 0.6x	**0.46**	0.4x – 0.6x	**0.46**

1 – Production and cash operating costs include Fox Creek plant turnarounds.
2 – Royalty rate in the table above calculated relative to corporate revenue, which for natural gas revenues is largely determined by US dollar denominated Chicago-based natural gas pricing.
3 – Includes G&A expenses for all divisions of the Company – Corporate, Upstream, Green Energy and Business Development.
4 – 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

The Company reiterates 2023 financial and operational guidance below with no updates.

2023 financial & operational guidance		Low		High
Sales Volumes[1]	Mboe/d	24.5		28.5
Oil & liquids	Mbbl/d	12.1		14.0
Natural gas	MMcf/d	74.4		87.0
Sales Volumes by market	%	100		100
Chicago	%		90	
AECO	%		10	
Financial				
Royalty rate[2]	%	10		12
Operating costs[1]	$/boe	8.25		9.25
Transportation	$/boe	6.25		7.25
Corporate G&A expense[3]	$MM	24		27
Cash taxes	$MM	-		-

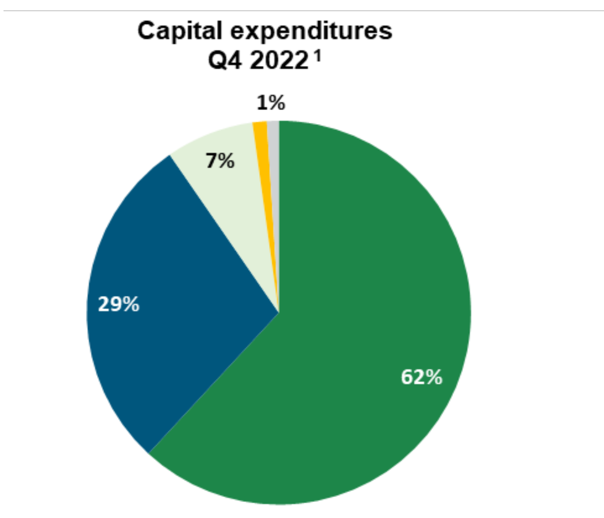
Capital guidance	$MM	378	402
Upstream	$MM	360	380
DCET	$MM	270	285
Other	$MM	90	95
Green Energy	$MM	18	22
Drilling – Fox Creek	wells	19	
Duvernay	wells	14	
Montney	wells	5	
Adjusted funds flow from operations sensitivities[4]			
US$70 WTI; US$4.50 HH; US$0.73/CAD	$MM	355	410
US$80 WTI; US$5.00 HH; US$0.75/CAD	$MM	390	450
Net debt to adjusted funds flow from operations sensitivities[4]			
US$70 WTI; US$4.50 HH; US$0.73/CAD	X	0.3x	0.5x
US$80 WTI; US$5.00 HH; US$0.75/CAD	X	0.1x	0.4x

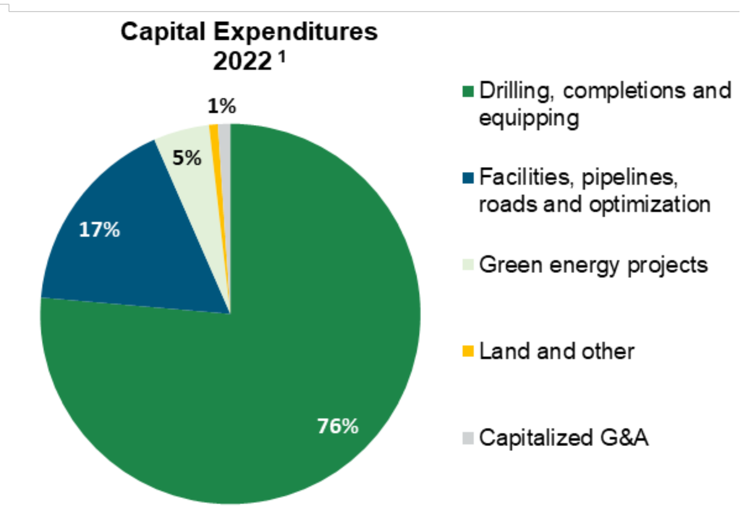
1 – No plant turnarounds scheduled for 2023; includes two week shutdown of facilities to accommodate plant expansion work in the third quarter.
2 – Royalty rate in the table above calculated relative to corporate revenue, which for natural gas revenues is largely determined by US dollar denominated Chicago-based natural gas pricing.
3 – Includes G&A expenses for all divisions of the Company – Corporate, Upstream, Green Energy and Business Development.
4 – 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

Capital expenditures

$000s	Q4 2022	Q4 2021	2022	2021
Drilling, completions, and equipping	**55,316**	28,742	**197,761**	42,617
Drilling, completions, and equipping – prepayment	**8,236**	-	**8,236**	-
Facilities, pipelines, roads, and optimization	**29,276**	1,184	**46,055**	3,105
Green energy projects	**7,624**	867	**12,834**	2,193
Land and other	**1,218**	638	**2,017**	1,280
Capitalized G&A	**1,038**	527	**2,826**	1,705
Capital expenditures [1]	**102,708**	31,958	**269,729**	50,900
Upstream net acquisitions [2]	**-**	-	**54,823**	186,655
Green Energy net acquisitions [2]	**-**	-	**2,500**	-
Capital expenditures and net acquisitions [1]	**102,708**	31,958	**327,052**	237,555

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
2 – Represents cash consideration on acquisitions net of proceeds from dispositions





1 – Capital expenditures shown are before Acquisitions.

Drilling, completions and equipping

For the three months and year ended December 31, 2022, the Company spent $63.5 million and $206.0 million, respectively, in order to spud 13 new development wells during the year and bring production on-stream from 12 new wells which contributed to average fourth quarter production rates of 24,745 boe/d. In the fourth quarter of 2022, the Company commenced drilling three additional Duvernay wells on Pad 04-34, where the four wells drilled earlier in the year demonstrated strong results since commencing production and made an $8.2 million prepayment to secure casing for the 2023 development program with delivery expected in early 2023. The new Pad 04-34 wells are projected to come on-stream before the end of the first quarter of 2023 and the Company is currently drilling two Montney wells in Placid West expected on-stream before the end of the second quarter of 2023.

The Company remains focused on developing both the Duverney and Montney assets, with a 2023 drilling program focused on high rate of return oil and gas production and strong production per share growth. The program aims to delineate and prove the assets while retaining land in both Simonette and Placid.

Facilities, pipelines, roads and optimization

For the three months and year ended December 31, 2022, the Company spent $30.2 million and $47.0 million, respectively, on construction, facilities, pipelines and production optimization required to complete the Company's drilling and completions program and maximize production during the year.

The Company is currently expanding its owned processing capacity in Simonette by ~37 MMcf/d and electrifying the 5-31 Simonette gas plant, with completion expected by the end of the third quarter of 2023.

Acquisitions

On September 15, 2022, the Company acquired an incremental working interest in its Placid Montney asset for cash consideration of $59.2 million ("Placid Acquisition"). The Placid Acquisition increases Kiwetinohk's Placid area natural gas processing and condensate handling capacity to 100 MMcf/d and 5,000 bbl/d respectively (an increase of 30 MMcf/d and 1,750 bbl/d). Through this acquisition, Kiwetinohk also obtained an incremental 14.12% ownership in the 14-28 Bigstone sweet natural gas processing facility, bringing its total working interest to 39.31%. Total owned processing capacity at the Bigstone sweet natural gas processing facility increased from 20 MMcf/d to 31 MMcf/d. As substantially all of the fair value of the assets acquired was concentrated in a single identifiable asset or group of similar identifiable assets the optional concentration test was met and as a result the purchase was accounted for as an asset acquisition.

The Placid Acquisition increased Kiwetinohk's working interest to 100% in 53,000 Montney acres (in the area where all its new Montney drilling has occurred in the past two years) and consolidates the Company's position in the Placid Montney area, increasing its average working interest over 79,000 acres in the region to 88.2%. It also added 12.6 MMboe of total proved plus probable reserves, based on the independent reserves report of McDaniel & Associates Consultants Ltd. effective as of December 31, 2022.

In the second quarter of 2022, the Company disposed of assets in non-core exploration and evaluation assets resulting in proceeds from disposition of $4.4 million.

In 2021, the Company completed a business combination with a purchase price after adjustments of $296.4 million and completed the amalgamation of Distinction energy whereby Kiwetinohk inherited the reporting issuer status of Distinction.

Green energy development projects

During 2022, the Company advanced and expanded its power development portfolio to seven projects, which now includes four gas-fired and three solar projects, with a total estimated nameplate capacity of approximately 2,150 MW. The acquisition of the Phoenix solar project, development of a second natural gas-fired Firm Renewable peaking project, and project optimization on resulted in an increased total nameplate capacity during 2022.

During 2022, the Company invested $13.8 million, excluding acquisitions, to advance the power portfolio through the Alberta Electric System Operator ("AESO") queue, with the Homestead Solar, Phoenix Solar, Opal Firm Renewable and Natural Gas Combined Cycle ("NGCC") 1 power projects now all in AESO Stage 3 and the remaining three projects in AESO Stage 2 as of December 31, 2022. In addition, the Company obtained Alberta Utilities Commission ("AUC") power plant approval for the Opal Firm Renewable Project and Homestead Solar project in August and September 2022, respectively. The Opal project received Environmental Protection and Enhancement Act ("EPEA") approval in December of 2022 which leaves AUC transmission line approvals as the final key regulatory approval still remaining for the Homestead and Opal projects. Transmission approvals are currently expected to be obtained by the fourth quarter of 2023 which allows the Homestead and Opal projects to continue to advance towards a potential final investment decision ("FID") in the fourth quarter of 2023.

During the fourth quarter of 2022, the Company invested $8.1 million in Green Energy capital across the seven major projects noted below with predominately on Opal which incurred $4.9 million of engineering costs in the quarter. The remaining costs were invested in engineering, procurement and construction ("EPC") bid evaluation for Homestead, pre-front end engineering and design ("FEED"), advancing permitting, environmental studies and consultation, and AESO review and engineering analysis to progress all seven projects in the power portfolio towards FID.

On May 18, 2022, the Company entered into an agreement to purchase the Phoenix Solar project, an early-stage 170 – 300 MW solar development project for cash consideration of up to $9.0 million, of which $2.5 million was paid upon closing, $1.5 million was paid in August of 2022, with all remaining contingent payments subject to regulatory milestones being achieved.

Early-stage development and design factors and the status of each project as at March 7, 2023 are summarized in the following table:

Early-stage Green Energy development, design factors & status	Homestead (Solar 1)	Opal (Firm Renewable 1) [9]	Granum (Solar 2)	Phoenix (Solar 3)	NGCC 2	NGCC 1	Firm Renewable 2 [9]
Approximate Capacity (nameplate, AC)	400 MW	101 MW	350 MW	170 MW	500 MW	500 MW	124 MW
Approximate Capacity (net to grid, AC)	400 MW	97 MW	350 MW	170 MW	460 MW	460 MW	120 MW
Capacity factor	27% [6]	50% [7]	27% [6]	27% [6]	90%	90%	50% [7]
Heat rate [8] (MJ/KWH: +/-5%)	-	7.6	-	-	6.0	6.0	TBD
AESO stage	3	3	2	3	2	3	2
Earliest FID date	Q4 2023	Q4 2023	Q2 2024	Q1 2024	2H 2024	1H 2025	TBD [10]
Earliest COD date[4]	Q4 2025	Q4 2025	Q2 2026	Q3 2025	2H 2027	1H 2028	TBD [10]
Total estimated installed capital cost ($ million) [1, 2, 3, 5]	$750 (Class 2)	$156 (Class 3)	$660 (Class 3)	$320 (Class 4)	$875 (Class 4)	$875 (Class 4)	Preliminary estimate underway

1 – Total installed cost estimates are classified in a manner consistent with American Association of Cost Engineering ("AACE") standards.
2 – Total installed cost numbers exclude carbon capture and sequestration for gas-fired projects ("CCUS"). Preliminary carbon capture capital cost for an NGCC power plant is estimated to be an incremental 60 to 80% of the total installed power plant cost based on a third party engineering study (March 2022), and for Opal, an incremental 70 to 100% of the total installed power plant cost based on an independent engineering study (January 2023).
3 – None of the Company's planned power generation projects have a final design, performance projection or cost estimate, or full regulatory approval or internal or external funding. There is no assurance that the power generation projects will proceed as described or at all.
4 – If an FID decision is reached, the Company will advance the project towards an estimated Commercial Operations Date ("COD").
5 – Capital costs may increase due to, among other things, the state of the current economic environment and related inflation and supply chain challenges; specific capital cost adjustments will be applied as projects progress through engineering review stages. Homestead Solar capital cost estimate updated with completion of Class 2 estimate on June 8, 2022. Pre-Feed studies by a third party engineering firm on NGCC plants (January 2023) validate previous estimates.
6 – First year capacity factor based on DC/AC ratio of 1.35, and bifacial, single axis solar panel tracking design.
7 – Designed for intermittent operation. The actual dispatch will be based on market conditions and contracting.
8 –Gas-fired generation simple cycle heat rates averaged 9.5 and NGCC heat rates averaged 7 on existing projects within the AESO grid as per publicly available data.
9 - The term "Firm Renewable" is a Kiwetinohk-originated term that describes efficient, flexible-output, fast-responding, gas-fired, internal reciprocating engine-driven power generation.
10 - Kiwetinohk has advanced development of the project including progressing AESO stage reviews, securing a project site, initiating a preliminary capital cost estimate, and reviewing project schedule.

Carbon storage hubs

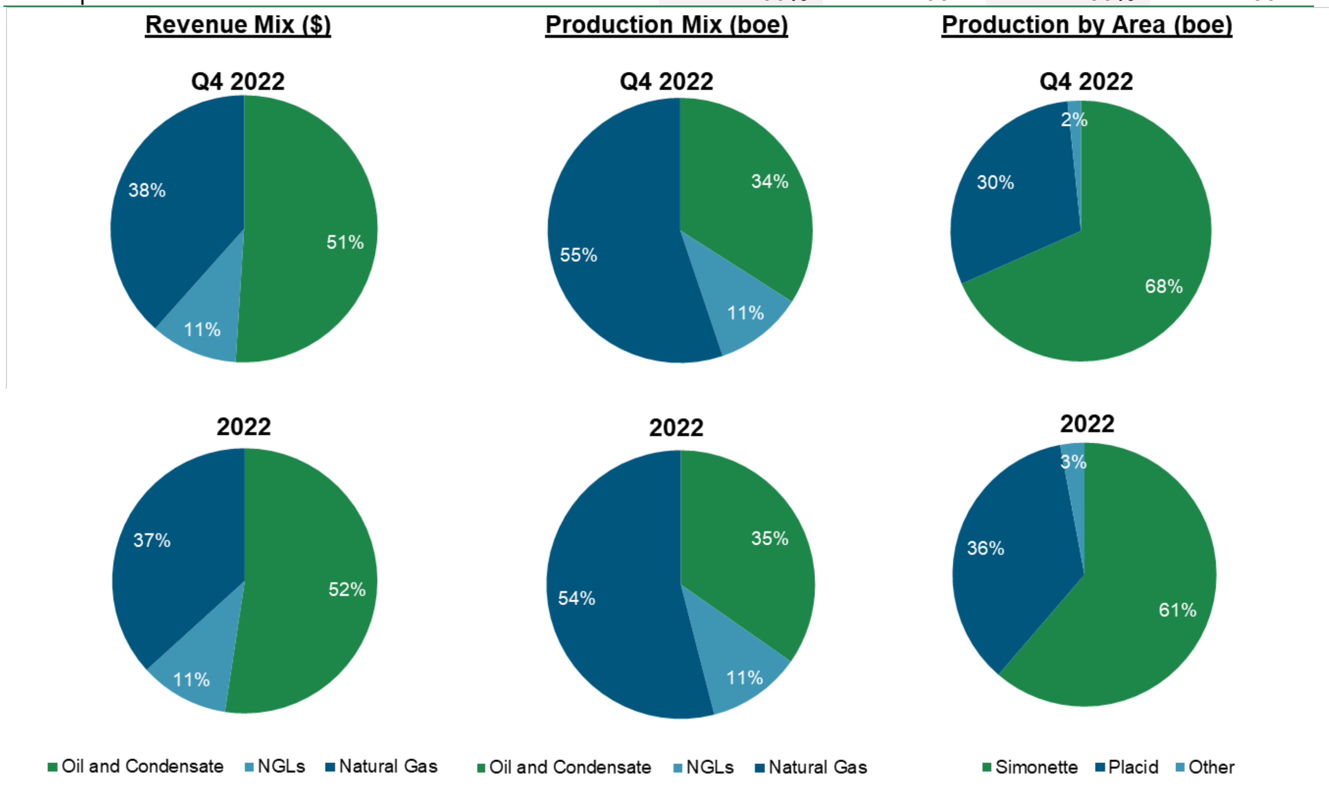
On October 4, 2022, the Government of Alberta awarded Kiwetinohk the right to advance planning on the Opal Carbon Hub and NGCC 2 Carbon Hub projects, which together would provide up to an estimated 4 million tonnes/year of sequestration capacity. Kiwetinohk incurred approximately $0.1 million of costs during the fourth quarter of 2022 to execute evaluation agreements with the Province of Alberta, under which Kiwetinohk was granted the right to conduct evaluations and testing of deep subsurface reservoirs, over a term not to exceed five years, for the purpose of determining their suitability for use for the sequestration of captured carbon dioxide.

As a primary user of its awarded carbon hubs through the Company's associated power projects in development and potential future CCUS projects, Kiwetinohk believes it will be well positioned in a sustainable market. The development of the carbon hubs will also provide an opportunity for third party revenue streams, through sales of processing and sequestration capacity, to other regional players seeking to reduce their carbon emissions footprint.

Results of operations

Production

	Q4 2022	Q4 2021	2022	2021
Oil & condensate (bbl/d)	**8,423**	3,949	**6,197**	3,130
NGLs (bbl/d)	**2,664**	1,572	**2,012**	1,180
Natural gas (Mcf/d)	**81,949**	41,410	**57,859**	32,942
Total production (boe/d)	**24,745**	12,422	**17,852**	9,801
Oil and condensate % of production	**34%**	32%	**35%**	32%
NGL % of production	**11%**	13%	**11%**	12%
Natural gas % of production	**55%**	55%	**54%**	56%
Total production volumes %	**100%**	100%	**100%**	100%



Production during the fourth quarter of 2022 averaged 24,745 boe/d compared to 12,422 boe/d in the fourth quarter of 2021. The Company was able to double production levels over the 2021 comparative quarter through strong results from the Company's development program with an additional six wells brought on production during the fourth quarter. In addition, the Company's Placid acquisition which was completed on September 15, 2022, contributed an estimated 1,200 boe/d of incremental production during the fourth quarter of 2022. The Company's production portfolio during the fourth quarter of 2022 was 34% oil and condensate, 11% NGLs, and 55% natural gas, with a slight increase in condensate production as compared to 2021 resulting from new wells being more liquids weighted compared to historical production.

Production during the year ended December 31, 2022 averaged 17,852 boe/d and increased by 82% compared to 9,801 boe/d in 2021. The significant increase results from a full year of production from Kiwetinohk's Fox Creek upstream assets and strong results from the 2022 development program which saw an additional 12 wells brought on production over the course of the year. During 2022, the Simonette and Placid areas contributed 61% and 36% of company upstream production, respectively. The Simonette and Placid assets both deliver high-liquids content natural gas with overall production having an average total liquids yield of approximately 142 bbls/MMcf during the year.

Benchmark and realized prices

	Q4 2022	Q4 2021	2022	2021
Liquid benchmark prices				
WTI (US$/bbl)	**82.65**	77.19	**94.23**	67.91
WTI (CDN$/bbl)	**112.17**	97.20	**122.37**	85.13
Edmonton Light (CDN$/bbl)	**109.84**	92.14	**120.02**	80.28
Natural gas benchmark prices				
Henry Hub (US$/MMBtu)	**6.26**	5.83	**6.64**	3.84
Chicago City Gate MI (US$/MMBtu)	**5.86**	5.87	**6.61**	3.77
Chicago City Gate DI (US$/MMBtu)	**5.37**	4.59	**5.19**	5.19
AECO 5A (CDN$/GJ)	**4.85**	4.41	**5.04**	3.44
AECO 7A (CDN$/GJ)	**5.29**	4.69	**5.27**	3.38
Foreign exchange rates (CAD/USD)	**0.74**	0.79	**0.77**	0.80

	Q4 2022	Q4 2021	2022	2021
Realized prices				
Oil & condensate ($/bbl)	**104.96**	97.66	**115.82**	84.35
NGLs ($/bbl)	**68.82**	65.61	**74.06**	52.60
Natural gas ($/Mcf)	**8.12**	6.64	**8.69**	5.29
Total ($/boe)	**70.04**	61.48	**76.72**	51.06

WTI benchmark prices increased significantly in the three months and year ended December 31, 2022, over the comparative periods of 2021. The increase is a result of Russia's invasion of Ukraine and related supply sanctions which have continued to limit Russian supply into the market, the return of energy demand as jurisdictions around the world opened-up following the easing of restrictions related to the COVID-19 pandemic as well as restricted supply from the Organization of Petroleum Exporting Countries. This, along with increased capital discipline amongst producers, has resulted in global crude oil demand outpacing supply during 2022. For the three months and year ended December 31, 2022, WTI benchmark prices averaged $112.17 and $122.02 per barrel compared to $97.20 and $85.13 per barrel in the comparative periods of 2021, respectively.

Edmonton Light benchmark pricing experienced significant increases in 2022 compared to 2021, generally driven by the same factors as WTI prices. For the three months and year ended December 31, 2022, Edmonton Light benchmark prices averaged $109.84 and $120.02 per barrel compared to $92.14 and $80.28 per barrel in the comparative periods of 2021, respectively.

Henry Hub natural gas prices increased in the three months and year ended December 31, 2022, versus the prior year periods due to lower storage levels, relatively flat production levels and decreased Russian supplies into Europe due to sanctions, all of which continued to drive an increase in both domestic and worldwide pricing. The Chicago City Gate monthly index for natural gas of $5.86 US/MMBtu for the three months ended December 31, 2022, was consistent with the fourth quarter of 2021, but on an annual basis increased an average $2.84 US/MMBtu to $6.61 US/MMBtu, in 2022. However, by year-end 2022, natural gas prices had fallen significantly from their mid-summer highs due to mild early winter weather, the continued Freeport LNG terminal outage, Lower-48 storage levels recovering closer to five-year averages and high European storage levels.

The AECO market in Alberta experienced continued volatility during the three months ended December 31, 2022 due to ongoing maintenance on the NGTL system and a growing storage inventory in the face of early cold weather. However on average, AECO monthly prices increased significantly during the three months and year ended December 31, 2022, when compared to the same periods in 2021, increasing by $0.60 CDN/GJ to $5.29 for the fourth quarter of 2022, and by $1.89 CDN/GJ to $5.27 CDN/GJ for the year.

To date, natural gas prices across the Chicago and AECO markets have continued to decline during the first quarter of 2023 from levels realized during the fourth quarter of 2022 as a result of warmer than expected temperatures. The Company has re-assessed the 2023 guidance and determined no change is required at this time.

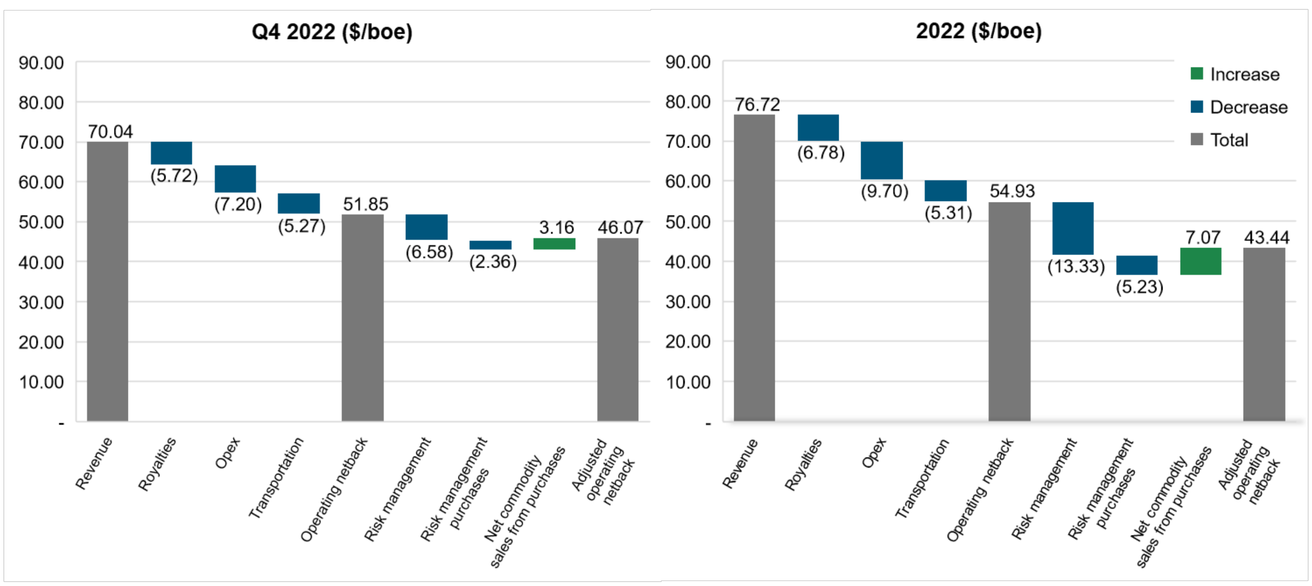
The Company has a total of 120 MMcf/d of firm Alliance Pipeline transportation service to Chicago contracted through October 31, 2025. Kiwetinohk is currently the fourth largest shipper on Alliance Pipeline and is uniquely positioned with respect to the optionality of its transportation capacity. Approximately 82% of its natural gas production (including purchased volumes) was sold into the Chicago market during 2022 and approximately 90% is expected to be sold into Chicago throughout 2023.

Kiwetinohk currently holds 20.5 mmcf/d of firm receipt service on Nova Gas Transmission where it also sells some of its natural gas production into the AECO market. Some of this natural gas is sweetened (through the removal of hydrogen sulfide) at the Company's 7-11 amine facility and is further processed at its approximately 40%-owned, non-operated, sweet natural gas plant ("Bigstone Sweet Plant") which is currently connected to both the Alliance and NGTL pipeline systems.

Operating netback

	Q4 2022	Q4 2021	2022	2021
Realized price ($/boe)	**70.04**	61.48	**76.72**	51.06
Royalty expenses ($/boe)	**(5.72)**	(6.80)	**(6.78)**	(5.46)
Operating expenses ($/boe)	**(7.20)**	(8.28)	**(9.70)**	(8.18)
Transportation expenses ($/boe)	**(5.27)**	(5.20)	**(5.31)**	(5.09)
Operating netback [1]($/boe)	**51.85**	41.20	**54.93**	32.33
Realized loss on risk management ($/boe) [2]	**(6.58)**	(12.55)	**(13.33)**	(8.77)
Realized loss on risk management – purchases ($/boe)	**(2.36)**	0.69	**(5.23)**	(1.38)
Net commodity sales from purchases ($/boe)[1]	**3.16**	2.50	**7.07**	1.91
Adjusted operating netback[1]	**46.07**	31.84	**43.44**	24.09
Total production (boe/d)	**24,745**	12,422	**17,852**	9,801

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.
2 – Realized loss on risk management contracts includes settlement of financial hedges on production and foreign exchange, with losses on contracts associated with purchases presented separately.



Operating netback for the year ended December 31, 2022, was $54.93/boe compared to $32.33/boe during 2021. The significant increase in netback was driven by a $25.66/boe improvement in average realized pricing. The increase in realized pricing led to higher royalty expenses per boe for the year ended December 31, 2022. Operating expense per boe for the year ended December 31, 2022, increased relative to 2021 due to workovers completed on older wells, facility turnaround costs, required road maintenance and a decision to use temporary flowback equipment ahead of permanent tie-in operations to accelerate profitable new well production. Transportation costs per boe for the year ended December 31, 2022, were consistent with 2021.

Operating netback for the three months ended December 31, 2022, was $51.85/boe compared to $41.20/boe during the same period in 2021. The increase in netback was largely attributable to higher average realized prices, equivalent to $8.56/boe. Royalty expenses per boe decreased over the comparable period in 2021 due to strong production from new wells in the fourth quarter which benefited from a lower rate through Alberta's royalty program. The 13% reduction in quarter over comparative quarter per barrel operating costs were achieved through higher production levels in the fourth quarter of 2022, and are a reflection of more normalized operating activity during the fourth quarter of 2022. Transportation costs per boe for the three months ended December 31, 2022, were consistent with the same period in 2021.

Adjusted operating netback incorporates the impact of risk management contracts and marketing activities. Adjusted operating netback for the three months and year ended December 31, 2022, increased compared to 2021, with $46.07/boe realized during the fourth quarter and $43.44/boe during the year. The Company incurred realized losses on risk management contracts associated with production during 2022, as a portion of volumes are hedged, in accordance with established risk management guidelines as approved by the Company's Board of Directors, to manage price volatility and ensure predictable cash flows during a period of significant capital expenditures and growth. The Company also manages cash flows associated with commodity sales from purchases through hedging with income generated through purchases offset by losses on hedging, as further described below (see Net commodity sales from purchases).

Revenue

$000s	Q4 2022	Q4 2021	2022	2021
Oil & condensate	**81,338**	35,481	**261,941**	96,367
NGLs	**16,865**	9,488	**54,393**	22,659
Natural gas	**61,254**	25,298	**183,564**	63,642
Total commodity sales from production	**159,457**	70,267	**499,898**	182,668

Revenue increased significantly to $159.5 million and $499.9 million, respectively, for the quarter and year ended December 31, 2022, representing 127% and 174% respective increases over the comparative periods in 2021. Increases for the three months and year ended December 31, 2022 were due to greater production levels in combination with a sustained increase in benchmark pricing.

Net commodity sales from purchases

$000s	Q4 2022	Q4 2021	2022	2021
Commodity sales from purchases	**47,902**	58,398	**268,552**	114,517
Commodity purchases, transportation and other	**(40,728)**	(55,544)	**(222,483)**	(107,686)
Net commodity sales from purchases [1]	**7,174**	2,854	**46,069**	6,831
Realized hedging gain (loss) on purchases	**(5,380)**	785	**(34,079)**	(4,935)
Net commodity sales from purchases after hedging[1]	**1,794**	3,639	**11,990**	1,896
$/boe – before hedging	**3.16**	2.50	**7.07**	1.91
$/boe – after hedging	**0.80**	3.19	**1.84**	0.53

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.

In order to mitigate the cost of transportation service in excess of current production needs, the Company purchases available natural gas volumes in Alberta and/or British Columbia and resells these volumes in Chicago. The Company was able to successfully purchase and fill the balance of the Alliance firm transportation commitment during 2022, after proprietary field production and temporarily assigned volumes. The Company also 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 meet 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 periodic 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, 2022, the Company realized net commodity sales from purchases of $7.1 million and $46.1 million, respectively, on its marketing activities associated with purchasing natural gas to fulfill its transmission commitment on the Alliance pipeline system. Including the offsetting impact of risk management contracts, the Company realized overall marketing income of $1.8 million and $12.0 million for the three months and year ended December 31, 2022, respectively (2021: $3.6 million and $1.9 million, respectively).

Risk management contracts

In an effort to mitigate commodity price fluctuations for natural gas, crude oil and natural gas liquids, the Company enters into financial commodity contracts as part of its risk management program designed to protect cash flows from its base production and help ensure sufficient capital and liquidity is available to pursue its ongoing growth plans and complete a significant capital development program.

The Company may be exposed to the risk of financial loss in certain circumstances, including instances in which: production falls short of the hedged volumes or prices fall significantly lower than projected; there is a widening of price-basis differentials between delivery points for production and the delivery point assumed in the hedge arrangement; the counterparties to the hedging arrangements or other price risk management contracts fail to perform under those arrangements; and/or a sudden unexpected material event impacts crude oil and natural gas prices. 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 according to the Company's risk management policy, ensuring the Company retains its ability to cover all outstanding risk management liabilities when they arise. Additionally, the Company regularly reviews its credit exposure to financial counterparties that volumes are purchased from or sold to.

$000s	Q4 2022	Q4 2021	2022	2021
Risk management:				
Unrealized gain (loss)	**29,475**	33,916	**11,036**	(28,588)
Realized loss	**(20,341)**	(13,547)	**(120,938)**	(36,306)
Total gain (loss) on risk management	**9,134**	20,369	**(109,902)**	(64,894)
Unrealized gain (loss) ($/boe)	**12.95**	29.68	**1.69**	(7.99)
Realized loss ($/boe)	**(8.94)**	(11.86)	**(18.56)**	(10.15)

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

$000s	Q4 2022	Q4 2021	2022	2021
Realized gain (loss) on production	**(13,768)**	(14,240)	**(86,107)**	(30,766)
Realized gain (loss) on purchases	**(5,380)**	785	**(34,079)**	(4,935)
Realized gain (loss) on foreign exchange	**(1,193)**	(92)	**(752)**	(605)
Total realized gain (loss)	**(20,341)**	(13,547)	**(120,938)**	(36,306)
Realized gain (loss) on production ($/boe)	**(6.06)**	(12.47)	**(13.21)**	(8.60)
Realized gain (loss) on purchases ($/boe)	**(2.36)**	0.69	**(5.23)**	(1.38)
Realized gain (loss) on foreign exchange ($/boe)	**(0.52)**	(0.08)	**(0.12)**	(0.17)

For the three months and year ended December 31, 2022, the Company recorded realized losses on risk management contracts of $20.3 million and $120.9 million, respectively. Approximately 26% of fourth quarter and 28% of full-year losses were related to natural gas volumes purchased for resale required to meet pipeline commitments in excess of the Company's production needs, where the Company hedges price differences between Chicago and Alberta markets at the time of contracting third party natural gas purchases.

Losses on production hedges in the three months and year ended December 31, 2022 have increased relative to 2021 as a result of higher benchmark pricing relative to hedged levels.

The unrealized gain on risk management of $29.5 million and $11.0 million during the three months and year ended December 31, 2022, represent changes in the fair value of risk management contracts outstanding at the end of those periods.

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 and crude oil financial contracts on the balance sheet at each reporting period with the change in the fair value being classified as unrealized gains and losses in the condensed consolidated interim statement of net loss and comprehensive loss.

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

The Company has the following risk management contracts outstanding as of December 31, 2022:

Type		Q1 2023	Q2 2023	Q3 2023	Q4 2023	2024
Crude oil						
WTI fixed price	bbl/d	1,700	1,700	1,950	1,100	500
WTI buy put	bbl/d	3,250	2,750	1,750	1,750	1,000
WTI sell call	bbl/d	2,500	2,250	1,750	1,750	500
WTI swap average	US$/bbl	$69.25	$68.59	$67.94	$70.41	$70.62
WTI buy put average	US$/bbl	$80.08	$77.73	$74.14	$74.14	$66.50
WTI sell call average	US$/bbl	$93.85	$91.49	$89.05	$89.05	$77.90
Natural gas [2]						
NYMEX Henry Hub fixed price	MMBtu/d	12,500	12,500	12,500	8,000	2,500
NYMEX Henry Hub buy put	MMBtu/d	26,500	24,500	23,667	17,000	7,500
NYMEX Henry Hub sell call	MMBtu/d	14,000	9,500	11,167	9,500	2,500
NYMEX Henry Hub buy call	MMBtu/d	5,000	5,000	-	-	-
NGI Chicago basis to NYMEX Henry Hub	MMBtu/d	17,500	12,500	12,500	-	-
NYMEX Henry Hub fixed price average	US$/MMBtu	$3.35	$3.35	$3.35	$3.34	$3.23
NYMEX Henry Hub buy put average	US$/MMBtu	$5.37	$4.84	$4.87	$4.91	$4.00
NYMEX Henry Hub sell call average	US$/MMBtu	$11.00	$5.41	$5.59	$5.70	$5.40
NYMEX Henry Hub buy call average	US$/MMBtu	$8.00	$8.00	-	-	-
NGI Chicago basis to NYMEX Henry Hub average	US$/MMBtu	$0.14	$0.01	$0.01	-	-
Natural gas transportation [2,3]						
Purchase AECO 5A basis (to NYMEX Henry Hub)	MMBtu/d	25,000	25,000	25,000	8,333	-
Sell GDD Chicago basis (to NYMEX Henry Hub)	MMBtu/d	(25,000)	(25,000)	(25,000)	(8,333)	-
AECO 5A basis (to NYMEX Henry Hub) average	US$/MMBtu	$(1.28)	$(1.28)	$(1.28)	$(0.43)	-
GDD Chicago basis (to NYMEX Henry Hub) average	US$/MMBtu	$0.10	$0.10	$0.10	$0.03	-

1 – Prices per unit and volumes per day are represented at the average amounts for the period.
2 – All basis swap pricing is in $USD / unit relative to NYMEX Henry Hub benchmark pricing.
3 – Natural gas transportation hedges relate to basis pricing differentials between AECO and Chicago on firm transportation commitments.

The Company has the following foreign exchange risk management contracts outstanding at December 31, 2022:

Type		Q1 2023	Q2 2023	Q3 2023	Q4 2023	2024
Crude oil						
Sell USD CAD (monthly average)	US$	-	-	-	-	-
USD CAD buy put	US$	$2.5 MM	-	-	-	-
USD CAD sell call	US$	$2.5 MM	-	-	-	-
USD CAD fixed sell rate		-	-	-	-	-
USD CAD put rate		1.26	-	-	-	-
USD CAD call rate		1.30	-	-	-	-

The Company's total risk management contract liability outstanding is as follows:

$000's	2022	2021
Short term risk management asset (liability)	**2,554**	-
Short term risk management asset (liability)	**(13,687)**	(26,115)
Long term risk management asset (liability)	**(6,634)**	(2,688)
Total risk management contracts asset (liability)	**(17,767)**	(28,803)

$000's	2022	2021
Asset (liability) on produced volumes	**(17,466)**	(28,529)
Asset (liability) on purchased volumes	**131**	(1,936)
Asset (liability) on foreign exchange contracts	**(432)**	1,662
Total risk management asset (liability)	**(17,767)**	(28,803)

Subsequent to December 31, 2022, the Company entered into the following risk management contracts:

Type	Unit	2023	2024	2025
Crude oil contracts				
WTI buy call [2]	bbl/d	250	-	-
WTI sell call [2]	bbl/d	104	250	-
WTI buy put [2]	bbl/d	104	250	-
WTI buy call average	US$/bbl	$85.00	-	-
WTI sell call average	US$/bbl	$80.00	$77.05	-
WTI buy put average	US$/bbl	$75.00	$70.00	-
Natural gas				
NYMEX Henry Hub buy call [2]	MMBtu/d	2,500	-	-
NYMEX Henry Hub buy call average	US$/MMBtu	$7.00	-	-
Foreign exchange				
Buy USD CAD put (monthly average)	US$	$15.0 MM	$10.0 MM	-
Sell USD CAD call (monthly average)	US$	$15.0 MM	$10.0 MM	-
USD/CAD swap	US$	$11.5MM	$9.0 MM	$4.0 MM
USD/CAD swap rate		$1.34	$1.33	$1.32
Buy USD/CAD put rate		$1.32	$1.32	-
Sell USD/CAD call rate		$1.36	$1.35	-

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 as part of the Company's risk management policy. The Company does not seek to speculate on commodity price movements through the hedging program.

Royalty expense

$000s	Q4 2022	Q4 2021	2022	2021
Royalty expense	**13,023**	7,766	**44,154**	19,526
As a % of revenue	**8.2%**	11.1%	**8.8%**	10.7%
$/boe	**5.72**	6.80	**6.78**	5.46

The Company pays Crown, freehold, and overriding royalties on production volumes. Royalties for the three months and year ended December 31, 2022 increased to $13.0 million and $44.2 million, respectively, as compared to $7.8 million and $19.5 million in the comparative periods of 2021. The Company continues to benefit from Alberta's drilling and completion cost allowance program ("C*"), which 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. Royalties as a percentage of revenue decreased during the three months and year ended December 31, 2022 to 8.2% and 8.8%, respectively, as the wells brought on-production in the year benefited from the C* program discussed above and natural gas revenues increasing through Chicago sales with associated royalties based on AECO benchmarks.

Operating expenses

$000s	Q4 2022	Q4 2021	2022	2021
Operating expenses	**16,399**	9,460	**63,204**	29,272
$/boe	**7.20**	8.28	**9.70**	8.18

Operating costs include amounts incurred to extract commodities to the surface such as field operators, gas and liquids processing, gathering and compression, utilities, chemicals and maintenance related costs. Operating costs during the three months and year ended December 31, 2022, increased to $16.4 million and $63.2 million, respectively, due to increased production volumes and higher levels of activity.

On a per boe basis, operating costs increased to $9.70/boe for the year ended December 31, 2022 compared to $8.18/boe in the comparative period as a result of workovers completed on older wells, facility turnaround costs, required road maintenance and a decision to use temporary flowback equipment ahead of permanent tie-in operations to accelerate profitable new well production.

The Company was able to demonstrate the value of owning the majority of the Company's infrastructure during the fourth quarter as incremental production was brought on stream without a corresponding increase in gross operating costs as operating activity normalized in the quarter. Increases in production resulted in a decrease on a per barrel basis to $7.20/boe, a 13% decrease relative to fourth quarter of 2021.

Transportation expenses

$000s	Q4 2022	Q4 2021	2022	2021
Transportation expenses	**12,000**	5,939	**34,628**	18,193
$/boe	**5.27**	5.20	**5.31**	5.09

Transportation expenses are incurred to deliver oil and natural gas commodities from the Company's production to the delivery point of sale. The Company has firm transportation service on the Alliance pipeline system from Alberta to Chicago. The balance of costs pertains to trucking charges and pipeline fees related to oil, NGL and condensate transportation charges. Per barrel transportation expenses were relatively consistent with the comparative periods in 2021 with increases as a result of flowing a larger proportion of natural gas to the higher cost Chicago market and incremental costs as a result of NGL production exceeding firm commitments with additional volumes transported at the higher-cost posted rate.

Adjusted funds flow from operations

$000s	Q4 2022	Q4 2021	2022	2021
Cash flow from operating activities	**87,028**	25,518	**242,850**	35,820
Net change in non-cash working capital from operating activities	**11,238**	2,168	**16,280**	11,977
Asset retirement obligation expenditures	**3,184**	671	**4,771**	671
Restructuring costs	**-**	9	**-**	2,458
Acquisition costs	**56**	2,397	**181**	8,903
Settlement costs	**-**	-	**-**	10,000
Adjusted funds flow from operations [1]	**101,506**	30,763	**264,082**	69,829
$/boe	**44.59**	26.92	**40.53**	19.52

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 increased significantly to $101.5 million and $264.1 million for the three months and year ended December 31, 2022, respectively. The Company's cash flow from operating activities was $87.0 million and $242.9 million for the three months and year ended December 31, 2022. Cash flow from operating activities has been adjusted for the net change in non-cash working capital from operating activities, asset retirement obligation expenditures, restructuring costs associated with Distinction's *Companies' Creditors Arrangement Act* process, costs to complete acquisitions and one-time settlement costs to terminate certain carried interest rights and obligations.

Free funds flow (deficiency) from operations

$000s	Q4 2022	Q4 2021	2022	2021
Adjusted funds flow from operations[1]	**101,506**	30,763	**264,082**	69,829
Capital expenditures [1]	**(102,708)**	(31,958)	**(269,729)**	(50,900)
Free funds flow (deficiency) from operations[1]	**(1,202)**	(1,195)	**(5,647)**	18,929
$/boe	**(0.53)**	(1.05)	**(0.87)**	5.29

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.

Free funds flow (deficiency) from operations during the three months and year ended December 31, 2022 was ($1.2) million and ($5.6) million relative to ($1.2) million and $18.9 million in the comparative periods of 2021. The Company had significantly higher capital expenditures during 2022 given the continued development of the Fox Creek core area. The Company has been able to finance capital spending through funds flow from operations as a result of continued strength in the commodity price environment and utilization of available credit facilities.

General and administrative ("G&A") expenses

$000s	Q4 2022	Q4 2021	2022	2021
Gross G&A expenses	**5,521**	5,589	**20,327**	14,381
Less capitalized G&A	**(1,038)**	(527)	**(2,826)**	(1,705)
G&A Expenses	**4,483**	5,062	**17,501**	12,676
$/boe	**1.97**	4.43	**2.69**	3.54

For the three months and year ended December 31, 2022, the Company incurred gross G&A expenses of $5.5 million and $20.3 million, respectively, as compared to $5.6 million and $14.4 million in the comparable periods of 2021. The increase in year over year costs and consistent quarter over quarter costs are primarily attributable to the significant growth in the Company that occurred in the second half of 2021 and into 2022. This included additional employees to support and execute on the Company's integrated Upstream and Green Energy strategy and additional costs associated with operating as a public company. On a per boe basis, both the three months and year ended December 31, 2022 decreased significantly by 56% and 24%, respectively, with the Company's production growth during the quarter and year.

Share-based compensation expenses

$000s	Q4 2022	Q4 2021	2022	2021
Share-based compensation expenses	**2,995**	4,316	**11,270**	14,472
$/boe	**1.32**	3.78	**1.73**	4.05

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.

Share-based compensation was $3.0 million and $11.3 million for the three months and year ended December 31, 2022, respectively, compared to $4.3 million and $14.5 million in the comparable prior year periods.

Finance costs

$000s	Q4 2022	Q4 2021	2022	2021
Interest and bank charges	**2,633**	1,408	**7,424**	2,959
Accretion of asset retirement obligations	**841**	442	**2,411**	654
Interest on lease obligations	**216**	20	**446**	71
Deferred financing amortization	**323**	294	**1,292**	901
Unrealized gain on foreign exchange	**(209)**	-	**(2,080)**	-
Total finance costs	**3,804**	2,164	**9,493**	4,585
$/boe	**1.67**	1.89	**1.46**	1.28

The Company has a $375 million senior secured extendible revolving facility (the "Credit Facility") with a syndicate of banks. As at December 31, 2022 the Company had drawn $119.7 million on the facility (December 31, 2021 - $34.7 million). The increase in financing costs for the three months and year ended December 31, 2022 is associated with higher average debt levels outstanding and higher interest rates during the periods.

Depletion and Depreciation

$000s	Q4 2022	Q4 2021	2022	2021
Depletion	**34,717**	11,846	**81,717**	29,064
Depreciation	**430**	296	**1,497**	1,139
Total depletion and depreciation	**35,147**	12,142	**83,214**	30,203
$/boe	**15.44**	10.62	**12.77**	8.44

Increases in depletion per barrel for the three months and year ended December 31, 2022 are attributable to a greater depletable base due to a significant capital development plan and an increase in future development costs offset by an increase in reserves assigned through the Company's 2022 reserve report. The Company recognized depletion of $34.7 million and $81.7 million for the three months and year ended December 31, 2022 (2021 - $11.8 million and $29.1 million respectively). On a per barrel basis, depletion and depreciation costs of $12.77 were incurred during 2022 (2021 - $8.44) which is consistent with the Company's two-year finding and development costs of $13.00 on a total proved and probable basis as calculated per the Company's 2022 reserve report.

Exploration and evaluation ("E&E") expenses

$000s	Q4 2022	Q4 2021	2022	2021
Depletion	**-**	881	**1,216**	5,427
Impairment	**-**	-	**6,367**	47,415
Other	**(75)**	269	**672**	3,396
Total E&E expenses	**(75)**	1,150	**8,255**	56,238
$/boe	**(0.03)**	1.01	**1.27**	15.72

The Company continuously evaluates various projects and upstream business opportunities, which are expensed as incurred until the Company has purchased the related land and has a legal right to explore. The Company will engage various consultants, advisors, and reservoir engineering specialists in completing evaluation and due diligence procedures.

Following the Simonette Acquisition the Company re-prioritized its development and drilling plans to higher return undeveloped land locations in the Fox Creek Area and as a result, the Company recognized impairment in the West Central Alberta cash generating unit relating to near-term land expiries of $6.4 million in 2022 (2021 - $47.4 million). No additional impairment recognized in the fourth quarter of 2022.

E&E depletion expense was previously recorded on a unit of production basis for properties that have production but have not yet been transferred to property, plant and equipment. All E&E assets were transferred to property plant and equipment during the second quarter of 2022, resulting in no depletion recognized during the three months ended December 31, 2022. The Company performed an impairment assessment at the time of transfer with no impairment recognized.

Income taxes

During 2022, the Company paid approximately $0.1 million in income taxes to the Internal Revenue Service relating to the Company's United States subsidiary. The Company did not pay any Canadian income taxes in 2022 and does not expect to be taxable in Canada in the near future. As of December 31, 2022, the Company recognized a deferred tax asset of $23.7 million as the Company expects to have sufficient taxable profits in the future in order to utilize its non-capital losses with the earliest expiries occurring in 2038. Deferred tax assets have been recognized net of deferred tax liabilities. The Company's estimated tax pools as at December 31, 2022, are as follows:

Category	Deductibility	$000's
Canadian oil and gas property expense ("COGPE")	10%	191,932
Successored COGPE	10%	1,176
Canadian development expense ("CDE")	30%	155,774
Successored CDE	30%	79,889
Canadian exploration expense ("CEE")	100%	-
Successored CEE	100%	10,032
Undepreciated capital cost ("UCC")	Primarily 25%, declining balance	121,099
Non-capital losses	100%	216,126
Share/Debt issue costs	5-year straight line	3,205
Other	Various	(1,797)
Total estimated tax pools		777,436

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 future cash flows to settle its ARO is $117.5 million, or $202.6 million inflated at 2.09% and undiscounted. These cash flows have been discounted using a risk-free interest rate of 3.28% to arrive at the present value estimate of $89.8 million.

There is approximately $31.7 million of abandonment and reclamation costs associated with inactive wells or facilities where there is no active operations or attributed reserves. Kiwetinohk is currently working on an abandonment program to proactively manage and reduce the inactive decommissioning liabilities over the next five to seven years which exceeds the minimum regulatory requirements.

Environmental sustainability is a key focus area of the Company where all development activities are reviewed to ensure that they are done in the most responsible and prudent manner and in accordance with the Alberta government's liability management framework.

Select annual information

($000s except per share and production)	2022	2021	2020
Production (average boe/d)	**17,852**	9,801	771
Commodity sales from production	**499,898**	182,668	9,758
Commodity sales from purchases	**268,552**	114,517	-
Cash flow from (used in) operating activities	**242,850**	35,820	(1,661)
Per share - basic	**5.51**	$1.13	(0.12)
Per share - diluted	**5.45**	$1.13	(0.12)
Net income (loss)	**190,989**	(22,315)	(4,869)
Per share - basic	**4.34**	(0.70)	(0.36)
Per share - diluted	**4.28**	(0.70)	(0.36)
Total assets	**932,650**	614,337	172,993
Long-term liabilities	**221,731**	124,587	3,448
Net debt (surplus) [1]	**122,304**	51,512	(54,401)
Adjusted working capital surplus (deficit) [1]	**(3,105)**	18,644	(54,401)

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

($000s except per share and production)	2022				2021			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Production (average boe/d)	**24,745**	16,487	16,810	13,253	12,422	15,058	10,797	741
Commodity sales from production	**159,457**	122,644	137,931	79,866	70,267	66,898	42,261	3,242
Commodity sales from purchases	**47,902**	77,623	82,429	60,598	58,398	38,349	17,770	-
Cash flow from (used in) operating activities	**87,028**	91,710	38,780	25,332	25,509	29,643	(15,753)	(3,579)
Per share - basic	**1.97**	2.08	0.88	0.58	0.58	0.86	(0.53)	(0.19)
Per share - diluted	**1.94**	2.05	0.87	0.58	0.58	0.86	(0.53)	(0.19)
Net income (loss)	**115,308**	55,379	44,854	(24,552)	44,306	(34,080)	13,726	(46,267)
Per share - basic	**2.61**	1.26	1.02	(0.56)	1.02	(0.99)	0.47	(2.43)
Per share - diluted	**2.57**	1.24	1.01	(0.56)	1.02	(0.99)	0.47	(2.43)

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 execute on strategic and new business opportunities. The Company relies on cash flow from operating activities, available funding capacity on the 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 the Company's anticipated capital program in 2023.

Credit Facility

On June 13, 2022, the Company increased the consolidated Credit facility by $60.0 million to $375.0 million. The Credit Facility is comprised of an operating facility of $65.0 million and a syndicated facility of $310.0 million.

At December 31, 2022, $119.7 million before deferred financing costs (December 31, 2021- $34.7 million) was outstanding on the Credit Facility along with $40.8 million (December 31, 2021 - $52.3 million) in letters of credit issue to support transportation and other commitments, of which, $14.4 million has been provided for through the Export Development Canada ("EDC") facility, resulting in $26.4 million in letters of credit which reduce the available operating facility capacity.

The aggregate commitment under the Credit Facility was confirmed at $375.0 million on November 2, 2022 through the lender's semi-annual redetermination process with no changes in terms.

$000	Credit Facility	EDC Facility	Drawn	Letters of credit	Capacity [1]
Credit Facility	375,000	15,000	119,737	40,752	**229,511**

$000s	2022	2021
Credit facility drawn	**119,737**	34,698
Deferred financing costs	**(538)**	(1,830)
Loans and borrowings	**119,199**	32,868
Adjusted working capital deficit[1]	**3,105**	18,644
Net debt [1]	**122,304**	51,512
Adjusted funds flow from operations [1]	**264,082**	69,829
Net debt to annualized adjusted funds flow from operations [1]	**0.46**	0.74

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.

The Credit Facility is a 364-day committed facility available on a revolving basis until May 31, 2023, 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, 2024. 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 at the prevailing bankers' acceptance plus 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 Company's debt to earnings before interest, taxes, depreciation and amortization ("bank EBITDA" ratio): from a minimum of the bank's prime rate or U.S. base rate plus an applicable margin ranging from 1.75 percent to 5.25 percent or from a minimum of bankers' acceptances rate plus a stamping fee ranging from 2.75 percent to 6.25 percent. The undrawn portion of the Credit Facility is subject to standby fees ranging from 0.6875% to 1.5625% based on the Company's bank EBITDA.

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

The Company plans to continue using the Credit Facility for working capital purposes to fund go forward capital plans in advance of cash flow from new investments and target a net debt to last-twelve-months of adjusted funds flow from operations ratio of no more than 1.0 times.

EDC Credit Facilities

On February 10, 2022, Kiwetinohk entered into a $15.0 million unsecured demand revolving letter of credit facility (the "LC Facility") with a Canadian bank. Kiwetinohk's obligations under the LC Facility are supported by a performance security guarantee ("PSG") from EDC. The PSG is valid to May 31, 2024 and may be extended from time-to-time at the option of Kiwetinohk and with the agreement of EDC. As at December 31, 2022, the Company had $0.6 million of capacity remaining under the LC Facility.

Base shelf prospectus

The Company filed a short-form base shelf prospectus ("Prospectus") in April 2022 to provide financing flexibility and additional options for quicker access to public equity and/or debt markets as it continues to pursue potential acquisition opportunities. The Prospectus provides Kiwetinohk with the ability to issue up to $500 million of securities over a period of 25 months. 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 20, 2022, the Company announced the approval of a normal course issuer bid to purchase and cancel up to 2.2 million Common Shares over a 12-month period, commencing December 22, 2022. During the year ended December 31, 2022, the Company purchased 6,471 common shares at a total cost of $0.1 million ($14.69 per share).

(000s)	Q4 2022	Q4 2021	2022	2021
Weighted average shares outstanding				
Basic	**44,168**	43,623	**44,046**	31,689
Diluted	**44,888**	43,623	**44,594**	31,689
Outstanding securities				
Common shares	**44,177**	43,675	**44,177**	43,675
Stock options	**2,717**	3,228	**2,717**	3,228
Performance warrants	**7,555**	7,922	**7,555**	7,922
Total diluted outstanding securities	**54,815**	54,825	**54,815**	54,825

At March 7, 2023, the Company has 44,252,924 common shares and no preferred shares outstanding.

Commitments, contractual obligations, and provisions

$000s	2023	2024	2025	2026	2027	Thereafter
Gathering, processing and transport	74.2	76.8	67.6	15.3	16.8	40.6
Natural gas purchases	49.7	-	-	-	-	-
Cash-settled compensation liability[1]	0.7	0.4	0.3	-	-	0.7
Accounts payable	77.0	-	-	-	-	-
Contingent payment consideration	12.0	-	-	-	-	-
Lease liabilities	0.5	1.8	2.1	2.2	2.2	7.8
Other	0.4	0.4	0.4	0.4	0.4	0.7
Loans and borrowings	-	119.7	-	-	-	-
Risk management contracts	11.1	6.6	-	-	-	-
Total	225.6	205.7	70.4	17.9	19.4	49.8

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 been assigned to "Thereafter".

As part of the Simonette Acquisition and Distinction business combination, the Company assumed natural gas transportation commitments of approximately 120.0 MMcf per day to deliver gas to Chicago on the Alliance pipeline through October 2025.

The Company currently has secured 34,000 GJ per day of gas supply (approximately 29.7 MMcf per day) from natural gas producers through 2023, allowing the Company to fully utilize its Alliance pipeline capacity. As a result, the Company is able to use proceeds from purchased gas volumes sold to meet all of its transportation and purchase commitments.

Related party information

For the quarter and year ended December 31, 2022, the Company incurred a total of $0.1 million and $1.4 million, respectively (2021 - $0.6 million and $2.5 million), in the following related party transactions:

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

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.

Health, safety and environmental

As part of the integration of the Simonette assets and Distinction, Kiwetinohk is implementing a new health and safety program that applies best practices across all operations.

Kiwetinohk is completing a thorough review of its environmental, social and governance ("ESG") risks and management strategies, and published its first ESG report on November 10, 2022 in alignment with the Sustainability Accounting Standards Board ("SASB") data standards for Oil & Gas – Exploration and Production and with the 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 and should be read in conjunction with the "Risk Factors" as presented in the Company's AIF dated March 7, 2023 available on the SEDAR website at www.sedar.com.

• risks associated with developing and operating the power generation and renewable energy business;	• health, safety and environmental risks;
• natural gas, oil and electricity prices;	• competition in the crude oil and natural gas industry;
• the ability of the Company to achieve its investment and development objectives;	• greenhouse gas emissions regulations, carbon taxes and environmental compliance costs;
• the ability of the Company to successfully execute its energy transition strategy	• regulatory and voluntary emissions offset regulations and markets;
• risks associated with exploration, development and production of crude oil and natural gas, and drilling for unconventional oil, NGL and natural gas;	• coronavirus, variants or derivations of it and other pandemics;
• the risks and limitations of forecasting reserves data;	• market constraints and access to services and equipment;
• global economic and financial conditions;	• talent, recruitment and retention of key personnel;

• inflation and supply chain issues;	• technology risks;
• capital market conditions;	• seasonality;
• licenses and permits;	• environmental, health and safety requirements; and
• government regulations;	• 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, utilizes proven technologies and will pursue 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, 2022.

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, 2022. No changes were made to the Company's ICFR during the year ended December 31, 2022 that have materially affected, or are reasonably likely to materially affect, the ICFR.

Financial reporting

Critical accounting estimates

The significant accounting judgements and estimates used by the Company are discussed in the notes of the December 31, 2022 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:

- acquisition date fair value of identifiable assets in business combinations;
- 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;
- recognition of deferred tax assets based on probability of future taxable profits; 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, 2022. 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 and does not expect a significant impact.

IAS 1 – Presentation of Financial Statements

Effective January 1, 2024, amendments to the classification of liabilities as non-current include the requirement that a right to defer settlement must have substance and exist at the end of the reporting period.

IAS 8 – Accounting Policies, Changes in Accounting Estimates and Errors

Effective January 1, 2023, amendments to IAS 8 include additional clarification on the determination of changes in accounting policies from changes in accounting estimates. The development of accounting estimates includes selecting a measurement technique and choosing the inputs to be used when applying the chosen measurement technique.

IAS 12 – Income Taxes

Effective January 1, 2023, amendments to IAS 12 narrow the scope of the recognition exemption so that it no longer applies to transactions that, on initial recognition, give rise to equal taxable and deductible temporary differences.

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, contingent payment consideration, share based compensation liability, and risk management contracts. 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 cash, accounts receivable and risk management contracts.

The Company's cash balances and 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.

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 its 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, 2022.

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	Q4 2022	Q4 2021	2022	2021
Commodity sales from production	**159,457**	70,267	**499,898**	182,668
Royalty expenses	**(13,023)**	(7,766)	**(44,154)**	(19,526)
Operating expenses	**(16,399)**	(9,460)	**(63,204)**	(29,272)
Transportation expenses	**(12,000)**	(5,939)	**(34,628)**	(18,193)
Operating netback	**118,035**	47,102	**357,912**	115,677
Realized gain (loss) on risk management	**(14,961)**	(14,332)	**(86,859)**	(31,371)
Realized gain (loss) on risk management contracts – purchases	**(5,380)**	785	**(34,079)**	(4,935)
Net commodity sales from purchases	**7,174**	2,854	**46,069**	6,831
Adjusted operating netback	**104,868**	36,409	**283,043**	86,202

Capital expenditures & capital expenditures and net acquisitions

"Capital expenditures" is calculated as cash used in investing activities, excluding changes in non-cash working capital, settlements of contingent consideration and acquisition, disposition, and investment in associate cash flows. The Company uses capital expenditures to monitor its investment in property, plant and equipment, exploration and evaluation and projects in development. "Capital expenditures and net acquisitions" includes the impact of acquisitions and dispositions. The table below reconciles capital expenditures and capital expenditures and net acquisitions to the most directly comparable GAAP measure, cash flow used in investing activities:

$000s	Q4 2022	Q4 2021	2022	2021
Cash flow used in investing activities	**103,343**	27,070	**330,152**	265,390
Net change in non-cash investing working capital	**(635)**	4,888	**3,400**	12,278
Settlement of contingent consideration	**-**	-	**(6,500)**	-
Investment in associate	**-**	-	**-**	(40,113)
Capital expenditures and net acquisitions	**102,708**	31,958	**327,052**	237,555
Cash used in acquisition	**-**	-	**(61,681)**	(186,655)
Proceeds from disposition	**-**	-	**4,358**	-
Net acquisitions	**-**	-	**57,323**	(186,655)
Capital expenditures	**102,708**	31,958	**269,729**	50,900

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, ROACE. The table below reconciles EBIT to the most directly comparable GAAP measure, net income (loss):

$000s	Q4 2022	Q4 2021	2022	2021
Net income (loss)	**115,308**	44,306	**190,989**	(22,315)
Finance costs	**3,804**	2,164	**9,493**	4,585
Total income taxes (recovery)	**(23,671)**	-	**(23,671)**	(9,811)
EBIT	**95,441**	46,470	**176,811**	(27,541)

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	2022	2021
Beginning of period		
Shareholder's equity	**397,434**	166,254
Net debt (surplus)	**51,512**	(54,401)
Capital employed	**448,946**	111,853
End of period		
Shareholder's equity	**600,619**	397,434
Net debt	**122,304**	51,512
Capital employed	**722,923**	448,946
Average capital employed	**585,935**	280,400

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

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

Non-GAAP Financial Ratios

Operating netback per boe & adjusted operating netback per boe

"Operating netback per boe" and "adjusted operating netback per boe" is calculated as operating netback and adjusted operating netback, respectively, divided by total production for the period. 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.

Return on average capital employed

"Return on average capital invested" 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. During the year ended December, 31, 2022, in order to be more comparable with the Company's peer group, the methodology for calculating the ROACE was adjusted from what was previously. The following table includes the updated calculation of ROACE for the years ended December 31, 2022 and 2021.

$000s	2022	2021
Earnings before interest and taxes	**176,811**	(27,541)
Average capital employed	**585,935**	280,400
ROACE	**30%**	(10%)

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, restructuring costs, acquisition costs and settlement agreement costs. Management considers adjusted funds flow from operations as a key measure to analyze performance as it demonstrates the Company's ability to generate the cash necessary to fund future capital investments, asset retirement obligations and to repay debt. The composition of adjusted funds flow from operations is disclosed in this MD&A within the Results of Operations section.

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

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

$000s	2022	2021
Current assets	**96,062**	47,557
Current liabilities	**(110,300)**	(92,316)
Working capital deficit	**(14,238)**	(44,759)
Short term risk management contracts net liability	**11,133**	26,115
Adjusted working capital surplus (deficit)	**(3,105)**	(18,644)

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

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

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

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

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

Forward-Looking Statements

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

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

- the impact of low-cost natural gas produced from Kiwetinohk's upstream resources on the Company's gross margin;
- the Company’s growth strategy, including its focus on consolidation of strategic upstream assets, identification and development of natural gas-fired power generation and renewable projects and the Company’s plans for integration of its upstream and power portfolios;
- successful execution of the Company’s Green Energy projects and the impacts thereof;
- the expansion of the processing capacity in Simonette and electrification of the 5-31 Simonette gas plant;
- the Company’s plans for developing a low emission power generation business as a source of power for Alberta's electrical grid, including development of its natural gas-fired and solar and wind power generation projects and expectations with respect to future opportunities for other renewable energy projects;
- the amount of the Company’s natural gas to be sold on the Chicago market and the timing thereof;
- anticipated North American natural gas prices;
- the particulars for a potential financing including the timing, occurrence and potential financial partners;
- timing for the Company’s Homestead Solar, Opal Firm Renewable and Solar 3 projects to reach FID and COD;
- submission of applications and receipt of certain regulatory approvals, including AUC power plant approvals and EPEA industrial approval thereof;
- anticipated grid capacity for green energy projects;
- the expected payment of contingent payments in respect of the Phoenix project;
- the Company’s use and development of carbon hubs
- expected length of third party pipeline outages;
- development, evaluation and permitting of the Company’s solar and gas-fired power portfolio;
- the Company’s goal to capture 90% of carbon associated with its gas-fired power projects;
- anticipated production increases into the first quarter of 2023;
- perceived benefits of the Company’s hub projects;
- future investigations by the Company of CCUS and application for grants related thereto;
- industry volatility and uncertainty around the timing and extent of a COVID-19 recovery;
- future taxes payable by the Company;
- anticipated contingent payments from acquisitions and the timing thereof;

- the timing and costs of the Company's capital projects, including, but not limited to, drilling, production and completion of certain wells;
- 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;
- anticipated well production;
- asset retirement obligations;
- the Company's 2023 financial and operational guidance
- operating and capital costs in 2023;
- sufficiency of funds to meet the Company's working capital requirements and anticipated drilling through 2023;
- the anticipated outcomes of successful execution of the Company's investment and financing strategies for its power project portfolio;
- use of the Credit Facility for working capital purposes to fund go forward capital plans;
- treatment under governmental regulatory regimes, including taxes and tax regimes, environmental and greenhouse gas regulations and related abandonment and reclamation obligations, and Indigenous, landowner and other stakeholder consultation requirements;
- the Company's adoption of accounting standards in the future
- the expected demand for, and prices and inventory levels of, petroleum products, including NGL;
- the anticipated staffing levels required to achieve the Company's current plans;
- the Company's operational, financial and capital guidance; 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 timing and costs of the Company's capital projects, including drilling and completion of certain wells;
- costs to abandon wells or reclaim property;
- the impact of increasing competition;
- general business, economic and market conditions
- the general stability of the economic and political environment in which the Company operates;
- the ability of the Company to obtain qualified staff, equipment and services in a timely and cost efficient manner;
- the ability of the operator of the projects that the Company has an interest in to operate in a safe, efficient and effective manner;
- future commodity and power prices;
- currency, exchange and interest rates;
- the 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 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 war, hostilities, civil insurrection, pandemics (including COVID-19), instability and political and economic conditions (including the ongoing Russian-Ukrainian conflict) on the Company; and
- the ability of the Company to successfully market its products.

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;
- risks of war, hostilities, civil insurrection, pandemics (including COVID-19), instability and political and economic conditions (including the ongoing Russian-Ukranian conflict) 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 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 Company’s information technology systems, including in the event of cyberattacks
- global economy risk
- the Company’s inability to meet regulatory requirements and/or stakeholders’ expectations of disclusre management and implementation of ESG initiatives and standards
- interest rate fluctuations; 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 adjusted funds flow from operations, free funds flow (deficiency) from operations, adjusted working capital surplus (deficit), net debt and 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 and was approved by management as of the date hereof. 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.

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.

This MD&A includes references to sales volumes of "Oils 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.

Abbreviations

$M	thousand dollars
$MM	million dollars
$/bbl	dollars per barrel
$/boe	dollars per barrel equivalent
$/GJ	dollars per gigajoule
$/Mcf	dollars per thousand cubic feet
AECO	the daily average benchmark price for natural gas at the physical storage and trading hub for natural gas on the TransCanada Alberta transmission system which is the delivery point for various benchmark Alberta index prices
AESO	Alberta Electric Systems Operator
EPEA	Environmental Protection and Enhancement Act
AIF	Annual Information Form
AUC	Alberta Utilities Commission
bbl(s)	barrel(s)
bbl/d	barrels per day
boe	barrel of oil equivalent, including crude oil, condensate, natural gas liquids, and natural gas (converted on the basis of one boe per six Mcf of natural gas)
boe/d	barrel of oil equivalent per day
CCUS	Carbon Capture Utilization and Storage
COD	Commercial Operations Date
DI	daily index
EBITDA	earnings before interest, income taxes, depreciation, depletion, and amortization
E&E	exploration and evaluation
FEED	Front End Engineering and Design
FID	Final Investment Decision
GJ	gigajoule
GJ/d	gigajoule per day
Henry Hub	the daily average benchmark price for natural gas at the distribution hub on the natural gas pipeline system in Erath, Louisiana
LNG	Liquified natural gas
mbbls	thousand barrels
MMboe	million barrels of oil equivalent
Mcf	thousand cubic feet
Mcf/d	thousand cubic standard feet per day
MI	monthly index
MMcf/d	million cubic feet per day
MMBtu	one million British Thermal Units is a measure of the energy content in gas
MMBtu/d	one million British thermal units per day
MW	one million watts
MW.h	electrical energy of one million watts acting for one hour
NGCC	Natural Gas Combined Cycle
NGLs	natural gas liquids, which includes butane, propane, and ethane
US$/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

CORPORATE INFORMATION

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President, Green Energy Division

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Sue Kuethe
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