Management's discussion and analysis

The following is Management's Discussion and Analysis ("MD&A") of the financial performance and results of operations for Kiwetinohk Energy Corp. ("Kiwetinohk" or the "Company") as at and for the three months ended March 31, 2023. 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 condensed consolidated interim financial statements as at and for the three months ended March 31, 2023 (the "Financial Statements") and the audited financial statements as at and for the year ended December 31, 2022. Additional information 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 Measurements", "Forward-Looking Statements", "Future Oriented Financial Information", "Abbreviations" and "Oil and Gas Advisories" below.

The reporting currency is the Canadian dollar, and all dollar amounts in this MD&A are stated in Canadian dollars unless otherwise indicated. This MD&A is dated May 2, 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, development and production of petroleum and natural gas reserves in Western Canada, with a focus on profitable early to mid-life liquids-rich natural gas properties that are expected to offer competitive economic resource potential. Upstream assets consist of high-netback, liquids-rich natural gas production 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, and natural gas-fired power with carbon capture, utilization and storage ("CCUS"). Successful development of Kiwetinohk's Green Energy projects will enable the production of clean, reliable, dispatchable, affordable energy and provide downstream markets for potential future integration of the Company's natural gas production, allowing it to capture a larger portion of the energy value chain.

Financial and operating highlights

	Q1 2023	Q1 2022
Production		
Oil & condensate (bbl/d)	**7,558**	4,364
NGLs (bbl/d)	**2,517**	1,561
Natural gas (Mcf/d)	**83,526**	43,970
Total (boe/d)	**23,996**	13,253
Oil and condensate % of production	**31%**	33%
NGL % of production	**10%**	12%
Natural gas % of production	**59%**	55%
Realized prices		
Oil & condensate ($/bbl)	**100.25**	115.70
NGLs ($/bbl)	**65.55**	66.03
Natural gas ($/Mcf)	**4.84**	6.35
Total ($/boe)	**55.30**	66.96
Royalty expense ($/boe)	**(5.89)**	(6.74)
Operating expenses ($/boe)	**(7.66)**	(9.56)
Transportation expenses ($/boe)	**(5.35)**	(4.55)
Operating netback [1] ($/boe)	**36.40**	46.11
Realized gain (loss) on risk management ($/boe) [2]	**0.41**	(15.05)
Realized gain (loss) on risk management - purchases ($/boe) [2]	**1.98**	3.96
Net commodity sales from purchases (loss) ($/boe) [1]	**(0.05)**	0.50
Adjusted operating netback [1]	**38.74**	35.52
Financial results ($000s, except per share amounts)		
Commodity sales from production	**119,421**	79,866
Net commodity sales from purchases (loss) [1]	**(110)**	596
Cash flow from operating activities	**80,160**	25,332
Adjusted funds flow from operations [1]	**75,981**	37,002
Per share basic	**1.72**	0.84
Per share diluted	**1.70**	0.84
Net debt to annualized adjusted funds flow from operations [1]	**0.52**	0.66
Free funds flow deficiency from operations (excluding acquisitions/dispositions) [1]	**(32,648)**	(17,210)
Net income (loss)	**53,949**	(24,552)
Per share basic	**1.22**	(0.56)
Per share diluted	**1.21**	(0.56)
Capital expenditures prior to dispositions [1]	**108,629**	54,212
Net dispositions [1]	**(781)**	(238)
Capital expenditures and net dispositions [1]	**107,848**	53,974
Balance sheet ($000s, except share amounts)		
Total assets	**984,214**	662,245
Long-term liabilities	**234,853**	145,549
Net debt [1]	**157,540**	73,521
Adjusted working capital (deficit) surplus [1]	**(17,808)**	21,466
Weighted average shares outstanding		
Basic	**44,218,711**	43,815,340
Diluted	**44,748,871**	43,815,340
Shares outstanding end of period	**44,184,985**	44,042,515

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

Guidance update

Management remains committed to capital discipline as the Company executes its upstream and Green Energy development plans. As a result of anticipated ongoing weakness and volatility in natural gas prices, Kiwetinohk is moderating its pace of production growth for the remainder of 2023 and is making the following adjustments to the previously communicated 2023 guidance.

- **Drill, complete, equip and tie-in ("DCET") spending** is expected to decrease by approximately $30 million to a revised range of $240 million to $255 million.The Company now expects to drill or commence drilling 14 gross/net wells in 2023, five gross (3.5 net) fewer than originally budgeted. The updated plan reflects management's desire to selectively defer drilling activity during a period of relative natural gas price weakness and accounts for suspension of drilling activity in the second quarter in certain regions to accommodate spring breakup and caribou calving. The updated drill plan includes spudding two new wells in the north part of the Simonette lands in the Tony Creek area in the second quarter. These two oil window Duvernay wells are expected to enhance the Company's liquids weighting at a time when liquids pricing is expected to remain strong.

- **Gas plant processing facility expansion capital** deferral of approximately $8 million. The gas plant expansion projects are progressing well. With the pull back in activity for 2023, the entire expansion capacity will not be required within the next 12 months, therefore Kiwetinohk will defer construction and commissioning activities, including electrification, at the 5-31 plant, the smaller of two wholly-owned Simonette gas plants. Construction of the 10-29 plant expansion will continue in 2023 as planned. Engineering and procurement for both plants will be completed in the event that the Company chooses to accelerate the 5-31 expansion.

Kiwetinohk continues to monitor commodity prices and will make further adjustments to its 2023 capital program as needed. As an operator with a controlling ownership in most of its assets and processing infrastructure, Kiwetinohk can be nimble and respond quickly to changes in economic conditions.

The following table summarizes Kiwetinohk's updated guidance for 2023:

2023 Financial & Operational Guidance		Revised May 2, 2023	Original December 14, 2022
Production (2023 average) [1]	Mboe/d	22.0 - 25.0	24.5 - 28.5
Oil & liquids	Mbbl/d	10.1 - 11.5	12.1 - 14.0
Natural gas [2]	MMcf/d	71.4 - 81.0	74.4 - 87.0
Financial			
Royalty rate	%	10% - 12%	10% - 12%
Operating costs	$/boe	$8.25 - $9.25	$8.25 - $9.25
Transportation	$/boe	$6.00 - $6.50	$6.25 - $7.25
Corporate G&A expense [3]	$MM	$24 - $27	$24 - $27
Cash taxes [4]	$MM	$0	$0
Capital guidance	$MM	$318- $342	$378 - $402
Upstream	$MM	$300 - $320	$360 - $380
DCET	$MM	$240 - $255	$270 - $285
Plant expansion, production maintenance and other	$MM	$60 - 65	$90 - $95
Green Energy	$MM	$18 - $22	$18 - $22

2023 Adjusted Funds Flow from Operations sensitivities as at May 2, 2023 [5]		
US$70/bbl WTI & US$2.75/MMBtu HH	CAD$MM	$250 - $285
US$80/bbl WTI & US$3.25/MMBtu HH	CAD$MM	$280 - $315
2023 Net debt to Adjusted Funds Flow from Operations sensitivities as at May 2, 2023 [5]		
US$70/bbl WTI & US$2.75/MMBtu HH	X	0.5x - 0.8x
US$80/bbl WTI & US$3.25/MMBtu HH	X	0.3x - 0.6x
2023 Adjusted Funds Flow from Operations sensitivities at at December 14, 2022 [5]		
US$70/bbl WTI & US$4.50/MMBtu HH	CAD$MM	$355 - $410
US$80/bbl WTI & US$5.00/MMBtu HH	CAD$MM	$390 - $450
2023 Net debt to Adjusted Funds Flow from Operations sensitivities as at December 14, 2022 [5]		
US$70/bbl WTI & US$4.50/MMBtu HH	X	0.3x - 0.5x
US$80/bbl WTI & US$5.00/MMBtu HH	X	0.1x - 0.4x

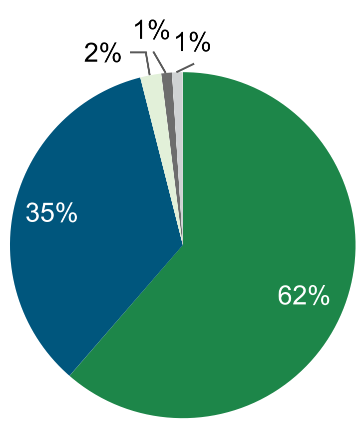
1 – Production and cash operating costs include scheduled downtime to accommodate plant expansion work in the third quarter.
2 – Chicago sales of ~90% expected for rest of year.
3 – Includes G&A expenses for all divisions of the Company – Corporate, Upstream, Green Energy (power & hydrogen) and Business development.
4 – The Company expects to pay cash taxes of approximately $0.3 million on its US subsidiary during 2023. No Canadian taxes are anticipated in 2023.
5 – Non-GAAP measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Please refer to the section "Non-GAAP Measures" herein.

Capital expenditures

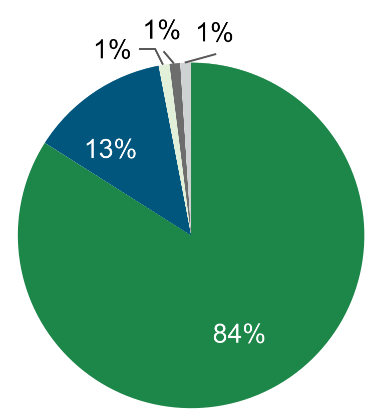
$000s	Q1 2023	Q1 2022
Drilling, completions, and equipping	**66,812**	47,188
Facilities, pipelines, roads and optimization	**37,686**	5,592
Green Energy projects	**2,023**	540
Land and other	**900**	462
Capitalized G&A	**1,208**	430
Capital expenditures [1]	**108,629**	54,212
Upstream net dispositions [1]	**(781)**	(238)
Capital and net dispositions [1]	**107,848**	53,974

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.

Capital expenditures Q1 2023[1]



Capital expenditures Q1 2022[1]



1 – Capital expenditures shown are before acquisitions and dispositions.

Drilling, completions and equipping
Facilities, pipelines, roads and optimization
Green Energy projects
Land and other
Capitalized G&A

Drilling, completions and equipping

For the three months ended March 31, 2023, the Company spent $66.8 million, in order to drill four new wells in Placid which began initial flowback early in the second quarter of 2023. In Simonette, the Company completed and tied in three wells on the 04-34 pad, and commenced drilling on a four well pad. Operations were subsequently suspended during the second quarter to manage the Caribou calving season, spring breakup and to pause during this time of relative natural gas price weakness. The Company will finish drilling and completing these four wells late in the third quarter.

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

Facilities, pipelines, roads and optimization

During the three months ended March 31, 2023, the Company spent $37.7 million, on facilities, pipelines, roads and production optimization with the expansion of the Simonette gas plants underway during the first quarter. The Company incurred approximately $12.0 million on the Simonette gas plant expansions during the first quarter and plans to finish constructing and commission the larger expansion at the 10-29 plant during the second half of 2023 with the 5-31 plant deferred to 2024. The Company intends to continue to incur engineering and procurement costs on both plants to allow for flexibility of the capital program as the Company continues to manage liquidity and debt levels during this period of heightened commodity price volatility. Remaining costs were incurred to construct roads, leases and pipelines required to execute the Company's drilling program and allow for future production growth.

Green Energy development projects

During the first quarter of 2023, the Company continued to advance its power development portfolio, which includes four gas-fired and three solar projects, with a total estimated nameplate capacity of approximately 2,150 MW.

During the first quarter, the Company invested $2.2 million to advance all seven power projects including costs to compete engineering, consultations, regulatory reviews, environmental studies, AESO processes, legal and various pre-FEED and FEED activities. The Company's Homestead Solar and Opal Firm Renewable projects remain the most advanced projects within the portfolio with AUC transmission line approvals as the final key regulatory approval still remaining for the projects. Transmission approvals are currently expected to be obtained by the fourth quarter of 2023 and discussions with a potential financing partner are in an advanced stage on both projects. The Company is also advancing the engineering, procurement and construction (“EPC”) bid evaluation process for the Homestead and Opal projects to continue to progress towards a potential earliest final investment decision (“FID”) in the fourth quarter of 2023.

Early-stage development and design factors and the status of each project as at May 2, 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)	Black Bear (NGCC 2)	Flipi (NGCC 1)	Little Flipi (Firm Renewable 2) [9]
Approximate Capacity (nameplate, AC) [6]	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 CCUS for gas-fired projects. 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 a positive FID 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 building a project schedule.

Carbon storage hubs

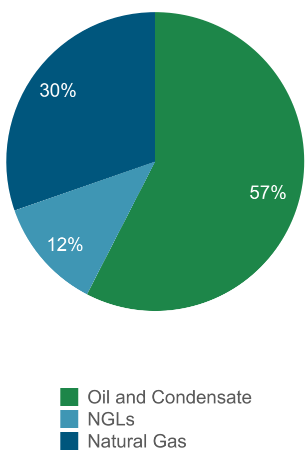
During the fourth quarter of 2022, the Government of Alberta awarded Kiwetinohk the right to advance planning on the Opal Carbon Hub and Black Bear Carbon Hub projects, which together would provide up to an estimated 4 million tonnes/year of sequestration capacity. The Company has continued to evaluate carbon storage hubs during the first quarter of 2023 and believes that Kiwetinohk will be well positioned as a primary user of its awarded carbon hubs through it’s associated power projects in development and potential future CCUS projects.

Results of operations

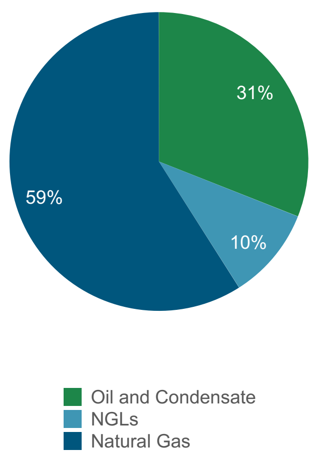
Production

	Q1 2023	Q1 2022
Oil & condensate (bbl/d)	**7,558**	4,364
NGLs (bbl/d)	**2,517**	1,561
Natural gas (Mcf/d)	**83,526**	43,970
Total production (boe/d)	**23,996**	13,253
Oil and condensate % of production	**31%**	33%
NGL % of production	**10%**	12%
Natural gas % of production	**59%**	55%
Total production volumes %	**100%**	100%

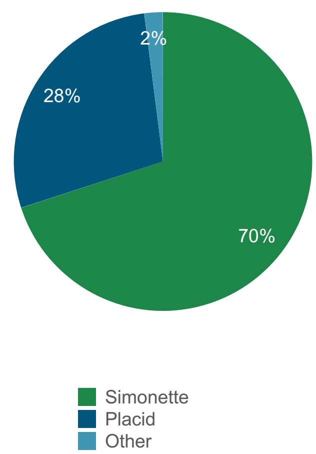
Revenue Mix ($)
Q1 2023



Production Mix (boe)
Q1 2023



Production by Area (boe)
Q1 2023



Production during the first quarter of 2023 averaged 23,996 boe/d compared to 13,253 boe/d in the first quarter of 2022. The Company’s production volumes have increased significantly through the Company's capital program with two additional wells brought on stream in Placid during the second quarter of 2022, ten additional wells brought on stream in Simonette throughout 2022, and an additional three wells brought on stream during the first quarter of 2023. In addition, on September 15, 2022 the Company completed an acquisition of an additional working interest in the Placid area which contributed to production growth when compared to the first quarter of 2022. The Company’s production portfolio during the first quarter of 2023 was 31% oil and condensate, 10% NGLs, and 59% natural gas with increases in the relative gas weighting attributed to new well production having a lower liquids content. Future capital expenditures are expected to target development of additional wells that are expected to enhance the Company's liquids weighting in the second half of 2023.

Benchmark and realized prices

	Q1 2023	Q1 2022
Liquid benchmark prices		
WTI (US$/bbl)	**76.13**	94.29
WTI (CDN$/bbl)	**102.90**	119.42
Edmonton Light (CDN$/bbl)	**99.01**	101.85
Natural gas benchmark prices		
Henry Hub (US$/MMBtu)	**3.42**	4.95
Chicago City Gate MI (US$/MMBtu)	**4.32**	5.75
Chicago City Gate DI (US$/MMBtu)	**2.64**	4.42
AECO 5A (CDN$/GJ)	**3.05**	4.49
AECO 7A (CDN$/GJ)	**4.12**	4.35
Foreign exchange rates (CAD/USD)	**0.74**	0.79

	Q1 2023	Q1 2022
Realized prices (before impact of hedging program)		
Oil & condensate ($/bbl)	**100.25**	115.70
NGLs ($/bbl)	**65.55**	66.03
Natural gas ($/Mcf)	**4.84**	6.35
Total ($/boe)	**55.30**	66.96

Canadian dollar WTI benchmark prices decreased 14% in the three months ended March 31, 2023, over the comparative period of 2022. The decrease is due to a deterioration of world economic conditions and expectations of demand for crude oil, Russian supply sanctions having limited overall impact compared to projections, coupled with increased supply from both OPEC and the US. WTI benchmark prices averaged $102.90 CAD per barrel compared to $119.42 CAD per barrel in the comparative period of 2022.

Edmonton Light benchmark pricing also experienced decreases in 2023 compared to 2022, generally driven by the same factors as those impacting WTI prices. For the three months ended March 31, 2023, Edmonton Light benchmark prices averaged $99.01 per barrel compared to $101.85 CDN$/bbl in 2022.

Natural gas prices decreased in the three months ended March 31, 2023 when compared to the prior year due to higher storage levels, increased production, lack of winter weather demand and a decrease in US LNG exports. At March 31, 2023, natural gas prices had fallen significantly from their recent highs in mid-summer 2022 due in large part to an outage at the Freeport LNG terminal and Lower-48 storage levels recovering closer to five-year averages. The Chicago City Gate monthly index benchmark for natural gas for the three months ended March 31, 2023 decreased to US $4.32/MMBtu compared to US $5.75/MMBtu during the same period in 2022.

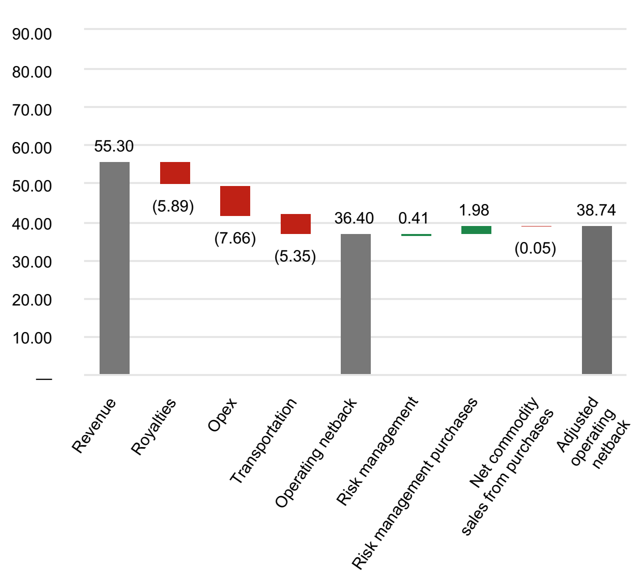
The AECO market in Alberta experienced volatility during the three months ended March 31, 2023, due to late winter weather in March moving prices up. This resulted in a tighter differential between both the Chicago and Henry Hub vs. Alberta sales points in the first quarter of 2023.

Operating netback

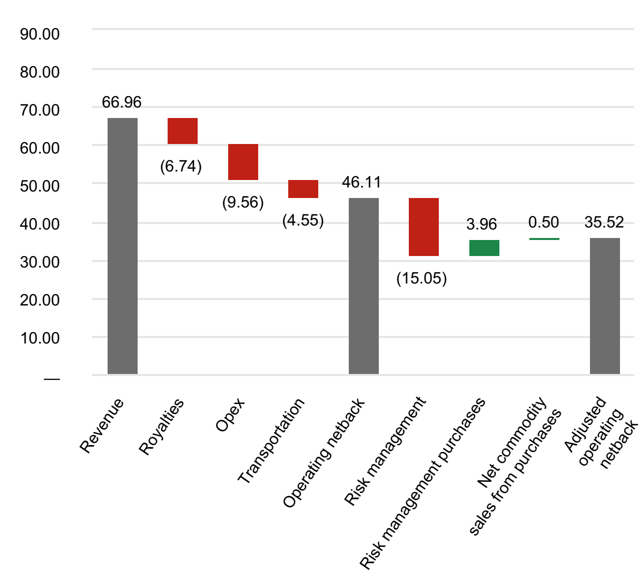
	Q1 2023	Q1 2022
Realized price ($/boe)	**55.30**	66.96
Royalty expenses ($/boe)	**(5.89)**	(6.74)
Operating expenses ($/boe)	**(7.66)**	(9.56)
Transportation expenses ($/boe)	**(5.35)**	(4.55)
Operating netback [1]($/boe)	**36.40**	46.11
Realized gain (loss) on risk management ($/boe) [2]	**0.41**	(15.05)
Realized gain on risk management contracts - purchases ($/boe) [2]	**1.98**	3.96
Net commodity sales from purchases (loss)($/boe) [1]	**(0.05)**	0.50
Adjusted operating netback [1]	**38.74**	35.52
Total production (boe/d)	**23,996**	13,253

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

Q1 2023 ($/boe)



Q1 2022 ($/boe)



Operating netback during the quarter ended March 31, 2023 was $36.40/boe compared to $46.11/boe in the same period in 2022. The decrease was primarily driven by a significant drop in average realized pricing which declined by $11.66/boe relative to the comparable period in 2022. The decrease in realized pricing led to reduced royalty expenses. Operating expenses decreased for the three month periods as a result of higher production volumes, demonstrating the value of the Company's owned and operated infrastructure. Transportation costs increased as the Company flowed a larger proportion of produced natural gas to the higher netback Chicago market.

Adjusted operating netback was $38.74/boe for the quarter ended March 31, 2023. The Company incurred realized gains on risk management contracts of $2.39/boe for the three months, which partially offset decreases in realized pricing given a portion of produced and purchased volumes were hedged to manage price volatility and ensure more predictable cash flows during a period of significant capital expenditures and growth.

Revenue

$000s	Q1 2023	Q1 2022
Oil & condensate	**68,194**	45,444
NGLs	**14,849**	9,274
Natural gas	**36,378**	25,148
Total commodity sales from production	**119,421**	79,866

During the three months ended March 31, 2023, the Company realized an increase in revenues relative to the comparable period in 2022 as a result of increased production levels partially offset by a decrease in benchmark pricing, period over period. Revenue grew to $119.4 million in the first three months of 2023, representing an increase of $39.6 million or 50% from the first quarter of 2022.

Net commodity sales from purchases

$000s	Q1 2023	Q1 2022
Commodity sales from purchases	**20,498**	60,598
Commodity purchases, transportation and other	**(20,608)**	(60,002)
Net commodity sales from purchases (loss) [1]	**(110)**	596
Realized hedging gain on purchases	**4,279**	4,718
Net commodity sales from purchases after hedging[1]	**4,169**	5,314
$/boe – before hedging	**(0.05)**	0.50
$/boe – after hedging	**1.93**	4.46

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 the first quarter of 2023, 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 ended March 31, 2023, the Company realized a loss of $0.1 million on net commodity sales from purchases related to its marketing activities associated with purchased volumes. Including the offsetting impact of associated risk management contracts, the Company realized a net gain of $4.2 million for the three months ended March 31, 2023.

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 plans and complete the Company's planned 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 possible credit losses where 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.

$000s	Q1 2023	Q1 2022
Risk management:		
Unrealized gain (loss)	**28,811**	(37,510)
Realized gain (loss)	**5,169**	(13,227)
Total gain (loss) on risk management	**33,980**	(50,737)
Unrealized gain (loss) ($/boe)	**13.34**	(31.45)
Realized gain (loss) ($/boe)	**2.39**	(11.09)

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

$000s	Q1 2023	Q1 2022
Realized gain (loss) on production	**1,973**	(18,667)
Realized gain on purchases	**4,279**	4,718
Realized (loss) gain on foreign exchange	**(1,083)**	722
Total realized gain (loss)	**5,169**	(13,227)
Realized gain (loss) on production ($/boe)	**0.91**	(15.65)
Realized gain on purchases ($/boe)	**1.98**	3.96
Realized (loss) gain on foreign exchange ($/boe)	**(0.50)**	0.61

For the three months ended March 31, 2023, the Company recorded realized gains on risk management contracts of $5.2 million which partially offset the impact of reduced commodity prices during the first quarter. Approximately 83% of the gains for the quarter was 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.

Gains on production hedges in the three months ended March 31, 2023 were realized relative to losses during the first quarter of 2022 as a result of lower benchmark pricing relative to hedged levels. When compared to the first quarter of 2022, gains related to volumes purchased to fill pipeline capacity declined as a result of the differential between Chicago and AECO prices widening relative to hedged rates (see – Net commodity sales from purchases).

With respect to financial contracts, which are derivative financial instruments, management has elected not to use hedge accounting and consequently records the fair value of its natural gas 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 income (loss) and comprehensive income (loss).

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

The unrealized gain on risk management of $28.8 million during the first quarter of 2023, represent changes in the fair value of risk management contracts during the period with the resulting revaluation of the Company's hedging program bringing the portfolio to an asset (net receivable) of $11.0 million as at March 31, 2023.

The Company has the following risk management contracts outstanding as of March 31, 2023:

Type		Q2 2023	Q3 2023	Q4 2023	2024	2025
Crude oil [1]						
WTI fixed price	bbl/d	1,700	1,950	1,100	500	—
WTI buy put	bbl/d	2,750	1,917	2,000	1,250	—
WTI buy call	bbl/d	—	500	500	—	—
WTI sell call	bbl/d	2,250	1,917	2,000	750	—
WTI swap average	US$/bbl	$68.70	$68.05	$70.41	$70.62	$—
WTI buy put average	US$/bbl	$77.73	$74.21	$74.25	$67.20	$—
WTI buy call average [4]	US$/bbl	$—	$85.00	$85.00	$—	$—
WTI sell call average	US$/bbl	$91.49	$88.30	$87.92	$77.62	$—
Natural gas [1,2]						
NYMEX Henry Hub fixed price	MMBtu/d	12,500	12,500	8,000	2,500	—
NYMEX Henry Hub buy put	MMBtu/d	24,500	27,000	22,000	12,500	3,347
NYMEX Henry Hub sell call	MMBtu/d	9,500	14,500	14,500	7,500	3,347
NYMEX Henry Hub buy call	MMBtu/d	5,000	5,000	5,000	—	—
NGI Chicago basis to NYMEX Henry Hub	MMBtu/d	12,500	12,500	—	—	—
NYMEX Henry Hub fixed price average	US$/MMBtu	$3.35	$3.35	$3.34	$3.23	$—
NYMEX Henry Hub buy put average	US$/MMBtu	$4.84	$4.64	$4.48	$3.60	$3.00
NYMEX Henry Hub sell call average	US$/MMBtu	$5.41	$5.32	$5.23	$4.70	$4.35
NYMEX Henry Hub buy call average [4]	US$/MMBtu	$8.00	$7.00	$7.00	$—	$—
NGI Chicago basis to NYMEX Henry Hub average	US$/MMBtu	$0.01	$0.01	$—	$—	$—
Natural gas transportation [1,2,3]						
Purchase AECO 5A basis (to NYMEX Henry Hub)	MMBtu/d	25,000	25,000	8,333	—	—
Sell GDD Chicago basis (to NYMEX Henry Hub)	MMBtu/d	(25,000)	(25,000)	(8,333)	—	—
AECO 5A basis (to NYMEX Henry Hub) average	US$/MMBtu	$(1.28)	$(1.28)	$(1.28)	$—	$—
GDD Chicago basis (to NYMEX Henry Hub) average	US$/MMBtu	$0.10	$0.10	$0.10	$—	$—

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.
4 – The Company has entered into select bought call transactions in order to preserve potential upside associated with swap and collar transactions over the same period.

The Company has the following foreign exchange risk management contracts outstanding at March 31, 2023:

Type		Q2 2023	Q3 2023	Q4 2023	2024	2025
Foreign exchange						
Sell USD CAD (monthly average)	US$	11.5 MM	11.5 MM	11.5 MM	10.0 MM	6.5 MM
USD CAD buy put	US$	15.0 MM	15.0 MM	15.0 MM	11.0 MM	2.5 MM
USD CAD sell call	US$	15.0 MM	15.0 MM	15.0 MM	11.0 MM	2.5 MM
USD CAD fixed sell rate		$1.33	$1.33	$1.33	$1.33	$1.33
USD CAD put rate		$1.32	$1.32	$1.32	$1.32	$1.33
USD CAD call rate		$1.36	$1.36	$1.36	$1.36	$1.38

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

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

$000s	March 31, 2023	December 31, 2022
Short term risk management asset	**20,446**	2,554
Long term risk management asset	**753**	—
Short term risk management liability	**(5,782)**	(13,687)
Long term risk management liability	**(4,373)**	(6,634)
Total risk management contracts asset (liability)	**11,044**	(17,767)

$000s	March 31, 2023	December 31, 2022
Asset (liability) on produced volumes	**8,724**	(17,466)
Asset on purchased volumes	**5,083**	131
Liability on foreign exchange contracts	**(2,763)**	(432)
Total risk management liability	**11,044**	(17,767)

Subsequent to March 31, 2023, the Company entered into the following risk management contracts:

Type		Q2 2023	Q3 2023	Q4 2023	2024	2025
Crude oil contracts [1,2]						
WTI buy put	bbl/d	—	333	500	500	—
WTI sell call	bbl/d	—	333	500	500	—
WTI buy put average	US$/bbl	$—	$46.67	$70.00	$70.00	$—
WTI sell call average	US$/bbl	$—	$55.93	$83.90	$74.50	$—
Natural gas [1,2]						
NYMEX Henry Hub fixed price	MMBtu/d	1,667	2,500	2,500	833	—
NYMEX Henry Hub buy put	MMBtu/d	1,667	7,500	10,000	8,333	—
NYMEX Henry Hub sell call	MMBtu/d	1,667	7,500	10,000	8,333	—
NYMEX Henry Hub fixed price average	US$/MMBtu	$1.93	$2.90	$2.90	$0.97	$—
NYMEX Henry Hub buy put average	US$/MMBtu	$1.93	$2.95	$2.98	$2.99	$—
NYMEX Henry Hub sell call average	US$/MMBtu	$2.17	$3.53	$3.66	$3.75	$—

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	Q1 2023	Q1 2022
Royalty expense	**12,718**	8,039
As a % of revenue	**10.6 %**	10.0 %
$/boe	**5.89**	6.74

The Company pays Crown, freehold, and overriding royalties on production volumes. Royalties in the three months ended March 31, 2023 increased to $12.7 million as compared to $8.0 million in the comparative period of 2022. The Company continues to benefit from Alberta's drilling and completion cost allowance program, 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. During the first quarter royalties as a percentage of revenue were 10.6% which was substantially consistent with the comparative period of 2022.

Operating expenses

$000s	Q1 2023	Q1 2022
Operating expenses	**16,542**	11,402
$/boe	**7.66**	9.56

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 ended March 31, 2023, increased to $16.5 million, due to increased production volumes and higher levels of activity.

On a per boe basis, operating costs decreased by $1.90/boe in the first quarter of 2023 to $7.66/boe compared to $9.56/boe in the first quarter of 2022. Operating costs per boe decreased as a result of higher production volumes demonstrating the value of the Company's owned and operated infrastructure.

Transportation expenses

$000s	Q1 2023	Q1 2022
Transportation expenses	**11,548**	5,424
$/boe	**5.35**	4.55

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. Transportation expense increased when comparing to the comparable prior year priod as the Company flowed approximately 90% of natural gas production to the higher cost Chicago market (2022 - 60%) and incurred incremental costs as a result of NGL production exceeding firm commitments with additional volumes transported at a higher cost posted rate.

Adjusted funds flow from operations

$000s	Q1 2023	Q1 2022
Cash flows from operating activities	**80,160**	25,332
Net change in non-cash working capital from operating activities	**(7,323)**	11,014
Asset retirement obligation expenditures	**3,144**	656
Adjusted funds flow from operations [1]	**75,981**	37,002
$/boe	**35.18**	31.02

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 from operations increased to $76.0 million for the three months ended March 31, 2023, relative to 37.0 million in the comparable period. The increase is primarily attributable to a 44% increase in production quarter over quarter, offset by weaker commodity prices, which resulted in the Company realizing a $5.2 million gain on risk management contracts compared to the prior period's $13.2 million realized loss.

The Company's cash flow from operating activities was $80.2 million for the three months ended March 31, 2023. Cash flow from operating activities has been adjusted for the net change in non-cash working capital from operating activities and asset retirement obligation expenditures.

Free funds flow deficiency from operations

$000s	Q1 2023	Q1 2022
Adjusted funds flow from operations [1]	**75,981**	37,002
Capital expenditures [1]	**(108,629)**	(54,212)
Free funds flow deficiency from operations [1]	**(32,648)**	(17,210)
$/boe	**(15.12)**	(14.43)

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 ended March 31, 2023 was $32.6 million relative to a free funds flow deficiency of $17.2 million in the comparative period of 2022. The Company had significantly higher upstream capital expenditures during the first quarter of 2023 as the Company continues to develop the Fox Creek core area. The Company has been able to manage capital spending through funds flow from operations and available credit facilities and continuously monitors the Company's liquidity and financial performance to ensure balance sheet strength and has the ability to adjust future capital spending plans if required to manage liquidity and/or balance sheet constraints.

General and administrative ("G&A") expenses

$000s	Q1 2023	Q1 2022
Gross G&A expenses	**5,583**	5,406
Less capitalized G&A	**(1,208)**	(430)
G&A Expenses	**4,375**	4,976
$/boe	**2.03**	4.17

Gross G&A expenses increased to $5.6 million during the three months ended March 31, 2023 as compared to $5.4 million in the comparable period of 2022. G&A expense is consistent with the first quarter of 2022 on a gross basis, however on a per boe basis, the three months ended March 31, 2023 decreased by 51% given the company's growth in production over the same period.

A portion of G&A expense continues to be directly related to business development initiatives in the Green Energy segment including the development of renewable and natural gas-fired power generation projects as well as early stage investigation of opportunities of carbon capture technology and hydrogen production.

Share-based compensation expenses

$000s	Q1 2023	Q1 2022
Share-based compensation expenses	**1,196**	3,285
$/boe	**0.55**	2.75

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 $1.2 million for the three months ended March 31, 2023 compared to $3.3 million in the comparable prior year period with declines attributed to the graded vesting of grants with higher expensing recognized in earlier periods and as a result of a decline in fair value of cash-settled plans.

Finance costs

$000s	Q1 2023	Q1 2022
Interest and bank charges	**3,382**	926
Accretion of asset retirement obligations	**865**	437
Interest on lease obligations	**220**	11
Deferred financing amortization	**324**	323
Unrealized (gain) loss foreign exchange	**(4)**	879
Total finance costs	**4,787**	2,576
$/boe	**2.22**	2.16

The Company has a $375 million senior secured extendible revolving facility (the "Credit Facility") with a syndicate of banks. As at March 31, 2023 the Company had drawn $139.9 million on the facility (March 31, 2022 - $119.7 million), net of deferred financing charges. The increase in financing costs for the three months ended March 31, 2023 is associated with higher average debt levels outstanding and higher interest rates during the periods.

Depletion and Depreciation

$000s	Q1 2023	Q1 2022
Depletion	**31,440**	12,571
Depreciation	**448**	342
Total depletion and depreciation	**31,888**	12,913
$/boe	**14.77**	10.83

Increase in depletion for the three months ended March 31, 2023 is attributable to increases in the Company's depletable base associated with a significant capital development plan and a higher production volume over the comparative period of 2022. The Company recognized depletion of $31.4 million for the three months ended March 31, 2023 (2022 - $12.6 million).

Income taxes

During the first quarter of 2023, the Company incurred approximately $0.2 million in income taxes 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 March 31, 2023, the Company recognized a deferred tax asset of $7.3 million. Deferred tax assets have been recognized net of deferred tax liabilities. The Company's estimated tax pools as at March 31, 2023, are as follows:

Category	Deductibility	$000s
Canadian oil and gas property expense ("COGPE")	10%	193,880
Successored COGPE	10%	1,147
Canadian development expense ("CDE")	30%	203,650
Successored CDE	30%	73,979
Canadian exploration expense ("CEE")	100%	—
Successored CEE	100%	4,878
Undepreciated capital cost ("UCC")	Primarily 25%, declining balance	153,677
Non-capital losses	100%	190,015
Share/Debt issue costs	5-year straight line	2,796
Other	Various	(1,797)
Total estimated tax pools		822,225

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 $113.0 million, or $175.6 million inflated at 1.68% and undiscounted. These cash flows have been discounted using a risk-free interest rate of 3.02% to arrive at the present value estimate of $84.1 million.

There is approximately $28.6 million of abandonment and reclamation costs associated with inactive wells or facilities where there are no active operations or attributed reserves. Kiwetinohk is currently working on an abandonment program to reduce significantly the inactive decommissioning liabilities over the next five to seven years which exceeds the minimum regulatory requirements.

Select quarterly information

($000s except per share and production)	2023 Q1	2022 Q4	2022 Q3	2022 Q2	2022 Q1	2021 Q4	2021 Q3	2021 Q2
Production (average boe/d)	**23,996**	24,745	16,487	16,810	13,253	12,422	15,058	10,797
Commodity sales from production	**119,421**	159,457	122,644	137,931	79,866	70,267	66,898	42,261
Commodity sales from purchases	**20,498**	47,902	77,623	82,429	60,598	58,398	38,349	17,770
Cash flow from (used in) operating activities	**80,160**	87,028	91,710	38,780	25,332	25,509	29,643	(15,753)
Per share (basic)	**1.81**	1.97	2.08	0.88	0.58	0.58	0.86	(0.53)
Per share (diluted)	**1.79**	1.94	2.05	0.87	0.58	0.58	0.86	(0.53)
Net income (loss)	**53,949**	115,308	55,379	44,854	(24,552)	44,306	(34,080)	13,726
Per share (basic)	**1.22**	2.61	1.26	1.02	(0.56)	1.02	(0.99)	0.47
Per share (diluted)	**1.21**	2.57	1.24	1.01	(0.56)	1.02	(0.99)	0.47

Capital resources and liquidity

The Company's objective when managing its balance sheet is to maintain a conservative capital structure that provides financial flexibility to address contingencies and execute on strategic business opportunities. 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 November 22, 2022 the Company confirmed through the semi-annual redetermination process a Credit Facility of $375.0 million with a syndicate of banks.The Credit Facility is comprised of an operating facility of $65.0 million and a syndicated facility of $310.0 million.

At March 31, 2023, $139.9 million before deferred financing costs (December 31, 2022- $119.7 million) was outstanding on the Credit Facility along with $38.1 million (December 31, 2022 - $40.8 million) in letters of credit issued to support transportation and other commitments, of which, $14.4 million has been provided for through the Export Development Canada ("EDC") facility, resulting in $23.7 million in letters of credit which reduce the available operating facility capacity.

$000s	Credit Facility	EDC Facility	Drawn	Letters of credit	Capacity [1]
Credit Facility	375,000	15,000	139,947	38,076	**211,977**

1 – Non-GAAP 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 Measures" section of this MD&A.

$000s	March 31, 2023	December 31, 2022
Credit facility drawn	**139,947**	119,738
Deferred financing costs	**(215)**	(539)
Loans and borrowings	**139,732**	119,199
Adjusted working capital deficit[1]	**17,808**	3,105
Net debt [1]	**157,540**	122,304
Adjusted funds flow from operations [1]	**303,061**	264,082
Net debt to annualized adjusted funds flow from operations [1]	**0.52**	0.46

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 (March 31, 2023 - 0.52x).

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 Export Development Canada ("EDC"). Kiwetinohk's obligations under the LC Facility are supported by a performance security guarantee ("PSG"). 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 March 31, 2023, the Company has $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 its normal course issuer bid ("NCIB") to purchase and cancel up to 2.2 million Common Shares over a 12-month period, commencing December 22, 2022. During the three months ended March 31, 2023, the Company purchased 67,939 common shares at a total cost of $0.8 million ($11.75 per share). Subsequent to March 31, 2023, the Company has repurchased approximately 88,000 additional shares at a total cost of $1.0 million ($11.53 per share).

(000s)	Q1 2023	Q1 2022
Weighted average shares outstanding		
Basic	**44,219**	43,815
Diluted	**44,749**	43,815
Outstanding securities		
Common shares	**44,185**	44,043
Stock options	**2,601**	2,741
Performance warrants	**7,095**	7,852
Total diluted outstanding securities	**53,881**	54,636

At May 2, 2023, the Company has 44,097,217 common shares and no preferred shares outstanding.

Commitments, contractual obligations, and provisions

$ millions	2023	2024	2025	2026	2027	Thereafter
Gathering, processing and transport	55.6	77.1	67.9	15.6	17.1	42.7
Natural gas purchases	30.0	5.0	—	—	—	—
Cash-settled compensation liability [1]	1.6	—	—	—	—	0.7
Accounts payable	78.7	—	—	—	—	—
Contingent payment consideration	1.9	—	—	—	—	—
Lease liabilities	0.5	1.8	2.1	2.2	2.2	7.8
Other	—	0.4	0.4	0.4	0.4	0.7
Loans and borrowings [2]	139.9		—	—	—	—
Total	308.2	84.3	70.4	18.1	19.6	51.9

1 – cash outflows relating to the DSU cash-settled compensation liability will be paid when each director retires. The Company has no available information to estimate the year of cash outflow and therefore the entirety of the DSU expected outflow been assigned to "Thereafter".
2 – represents current debt drawn repaid at the end of the Credit Facility term

The Company currently has 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 43,100 GJ per day of gas supply (approximately 37.8 MMcf per day) from natural gas producers through 2023 and approximately 37,000 GJ per day through January 2024, 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 three months ended March 31, 2023, the Company incurred a total of $0.2 million (March 31, 2022 – $0.6 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.

Environment, social and governance

Kiwetinohk regularly reviews 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.

Kiwetinohk will release its 2023 ESG report in the third quarter with focus on 2022 Company results across safety, greenhouse gas emissions, asset retirement, Indigenous and community inclusion, diversity and water.

Risk factors and risk management

The Company's management team is focused on long-term strategic planning and has identified key material risks, uncertainties and opportunities associated with the Company's business that can impact the financial position, operations, cash flows and future prospects of the business. There were no significant changes in key risks identified during the three months ended March 31, 2023. For additional information on risk factors, refer to the Company's audited financial statements as at and for the year ended December 31, 2022 and the Company's Annual Information Form ("AIF") dated March 7, 2023 available on the Company's website at www.kiwetinohk.com or on the SEDAR website at www.sedar.com.

In order to reduce risk the Company employs subject matter experts that are highly qualified professionals with clearly defined roles and responsibilities, seeks to operate and control the majority of its properties and projects, utilizes proven technologies and will pursue new technologies where appropriate. Other risks are discussed under "Risk Factors" as presented in the AIF.

Control environment

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

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

There were no changes in the Company's internal controls during the period beginning on January 1, 2023, and ending on March 31, 2023, that have materially affected, or are reasonably likely to materially affect, the Company's internal controls over financial reporting. It should be noted that a control system, including the Company's disclosure and internal controls and procedures, no matter how well conceived can provide only reasonable, but not absolute assurance that the objectives of the control system will be met, and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud.

Financial reporting

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. There have been no material changes to the Corporation's critical accounting estimates, judgments and policies during the three months ended March 31, 2023.

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 contingent payment consideration, share based compensation liability, and risk management contracts. Contingent payment consideration, share based compensation liability and risk management contracts are classified as a Level 2 measurement in the fair value measurement hierarchy. All other financial instruments are measured at amortized cost.

Credit risk

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

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

Liquidity risk

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

Market risk

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

The Company uses financial risk management contracts to mitigate its exposure to the potential adverse impact of commodity price and exchange rate volatility. The primary objective of the risk management program is to protect cash flows from base production and ensure sufficient capital and liquidity is available to pursue 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 March 31, 2023.

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	Q1 2023	Q1 2022
Commodity sales from production	**119,421**	79,866
Royalty expenses	**(12,718)**	(8,039)
Operating expenses	**(16,542)**	(11,402)
Transportation expenses	**(11,548)**	(5,424)
Operating netback	**78,613**	55,001
Realized gain (loss) on risk management	**890**	(17,945)
Realized gain on risk management contracts - purchases	**4,279**	4,718
Net commodity sales from purchases (loss)	**(110)**	596
Adjusted operating netback	**83,672**	42,370

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

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

$000s	Q1 2023	Q1 2022
Cash flow used in investing activities	**102,101**	47,676
Net change in non-cash investing working capital	**15,747**	11,298
Settlement of contingent consideration	**(10,000)**	(5,000)
Capital expenditures and net acquisitions (dispositions)	**107,848**	53,974
Cash used in acquisitions	**—**	—
Proceeds from disposition	**781**	238
Net dispositions	**781**	238
Capital expenditures	**108,629**	54,212

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.

Adjusted funds flow from operations per boe

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

Capital Management Measures

Adjusted funds flow from operations

"Adjusted funds flow from operations" is cash flow from operating activities before changes in net change in non-cash working capital from operating activities, asset retirement obligations, and acquisition 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	March 31, 2023	December 31, 2022
Current assets	**90,758**	96,062
Current liabilities	**(93,902)**	(110,300)
Working capital deficit	**(3,144)**	(14,238)
Short term risk management contracts net liability (asset)	**(14,664)**	11,133
Adjusted working capital deficit	**(17,808)**	(3,105)

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

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

Supplementary Financial Measures

This MD&A contains supplementary financial measures expressed as: (i) cash from operating activities, adjusted funds flow 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 anticipated Simonette plant capacity additions and the timing and costs thereof and the effects of such additions on the Company’s production and related facility downtime;
- 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 projects, including 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 transmission line approval, and timing thereof;
- 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;
- 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;
- the Company's expectations regarding cash taxes and when they are expected to be paid 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 and adjustments to the previously communicated 2023 guidance, including anticipated reduction in DCET spending, gas plant processing facility expansion capital deferral, and Green Energy investment decrease;
- 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 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;
- the impact of current market conditions on the Company; and
- the timing of the Company's 2023 ESG report and content therein.

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;
- the ability of the Company to successfully market its products;
- power project debt will be held at the project level;
- power projects will be funded by third parties, as currently anticipated; and
- the Company's operational success and results being consistent with current expectations.

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

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

- those risks set out in the AIF under "Risk Factors";
- the ability of management to execute its business plan;

- general economic and business conditions;
- 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; 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 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. Unless required by applicable laws, the Company does not undertake any obligation to publicly update or revise any FOFI statements, whether as a result of new information, future events or otherwise.

Abbreviations

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

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.

CORPORATE INFORMATION

Management

Pat Carlson
Chief Executive Officer

Jakub Brogowski
Chief Financial Officer

Mike Backus
Chief Operating Officer, Upstream

Janet Annesley
Chief Sustainability Officer

Sue Kuethe
Executive VP, Land and Community Inclusion

Mike Hantzsch
Senior Vice President, Midstream and Market Development

Lisa Wong
Senior Vice President, Business Systems

Chris Lina
Vice President, Projects

Board of Directors

Kevin Brown
Board Chair

Beth Reimer-Heck
Lead Director

Judith Athaide
Director

Pat Carlson
Director and Chief Executive Officer

Leland Corbett
Director

Nancy Lever
Director

Kaush Rakhit
Director

Steve Sinclair
Director

John Whelen
Director

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Bankers

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

Auditor

Deloitte LLP
Calgary, AB

Reserve Engineers

McDaniel & Associates Consultants Ltd.
Calgary, AB

Legal Counsel

Stikeman Elliot LLP
Norton Rose Fulbright Canada LLP
Calgary, AB

Transfer Agent

Computershare
Calgary, AB

Stock Symbol

KEC
Toronto Stock Exchange