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, 2022. The Company was formed as part of the amalgamation of Kiwetinohk Resources Corp. ("KRC") and Distinction Energy Corporation ("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 condensed consolidated interim financial statements as at and for the three months ended March 31, 2022 (the "Financial Statements") and the audited financial statements as at and for the year ended December 31, 2021. 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 Measurements", "Forward-Looking Statements", "Future oriented financial information" and "Abbreviations" 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 11, 2022.

Overview of business

Kiwetinohk's mission is to build a profitable energy transition business which provides clean, reliable, dispatchable, low-cost 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 highly competitive economic resource potential. On February 17, 2021, KRC and Distinction entered into various agreements to participate as to 50 percent each in a $320 million asset acquisition of oil and natural gas properties in the Simonette region (the "Simonette Acquisition"). On April 28, 2021, the Company gained control of Distinction and began consolidating the results of Distinction. These assets consist of high-netback, liquids rich natural gas production with development upside and substantial spare processing capacity from owned infrastructure. These upstream assets provide a foundational base for the Company to pursue and develop energy transition opportunities. As a result of the significant growth in the upstream business through these acquisitions, the Company has included the fourth quarter of 2021 as additional comparative information within this MD&A.

Green energy

The Green Energy business unit is pursuing greenfield and/or brownfield development of a diversified Alberta-based power generation project portfolio that includes clean, efficient, and reliable natural gas-fired power with carbon capture and sequestration and renewable power sources, including solar and wind. Development work has included preparation of preliminary designs, environmental studies, permitting, consultation, Alberta Electric System Operator ("AESO") stage reviews and studies, pre-front end engineering and design ("FEED") and FEED reviews, performance estimates and preliminary cost projections. The Company's process of advancing projects involves progressing through stages of review and increasing design refinement and estimate quality with an intent to proceed to final design, full regulatory approval and securing of internal and external funding for projects that prove to meet the Company's investment criteria. Successful execution of Green Energy projects will enable the production of clean, reliable, dispatchable low-cost energy and provide downstream markets for integration of the Company's future gas production, allowing it to capture a larger portion of the hydrocarbons value chain.

Financial and operating results

	Q1 2022	Q4 2021	Q1 2021
Production			
Condensate (bbl/d)	**3,475**	3,092	77
Light oil (bbl/d)	**876**	844	344
Heavy oil (bbl/d)	**13**	13	33
NGLs (bbl/d)	**1,561**	1,572	92
Natural gas (Mcf/d)	**43,970**	41,410	1,169
Total (boe/d)	**13,253**	12,442	741
Oil and condensate % of production	**33%**	32%	61%
NGL % of production	**12%**	13%	13%
Natural gas % of production	**55%**	55%	26%
Realized prices			
Condensate ($/bbl)	**115.77**	99.21	77.96
Light oil ($/bbl))	**115.85**	92.29	65.23
Heavy oil ($/bbl)	**85.83**	81.60	48.28
NGLs ($/bbl)	**66.03**	65.61	24.41
Natural gas ($/Mcf)	**6.35**	6.64	3.19
Total ($/boe)	**66.96**	61.48	48.62
Royalty recovery (expense) ($/boe)	**(6.74)**	(6.80)	(3.19)
Operating expenses ($/boe)	**(9.56)**	(8.28)	(8.80)
Transportation expenses ($/boe)	**(4.55)**	(5.20)	(0.71)
Operating netback [1] ($/boe)	**46.11**	41.20	35.92
Net commodity sales from purchases ($/boe) [1]	**0.50**	2.50	-
Realized loss on risk management contracts ($/boe) [4]	**(11.09)**	(11.86)	-
Adjusted operating netback [1]	**35.52**	31.84	35.92
Financial results ($000s, except per share amounts)			
Commodity sales from production	**79,866**	70,267	3,242
Net commodity sales from purchases (loss) [1]	**596**	2,854	-
Cash flow from (used in) operating activities	**25,332**	25,518	(3,579)
Adjusted funds flow from (used in) operations [1]	**37,002**	30,763	(3,313)
Per share basic [2,3]	**0.84**	0.71	(0.17)
Per share diluted [2,3]	**0.84**	0.71	(0.17)
Net debt to annualized adjusted funds flow from operations [1]	**0.66**	0.74	2.28
Free funds flow (deficiency) from operations [1]	**(17,210)**	(1,195)	(3,631)
Net income (loss)	**(24,552)**	44,306	(46,267)
Per share basic [2,3]	**(0.56)**	1.02	(2.43)
Per share diluted [2,3]	**(0.56)**	1.02	(2.43)
Capital expenditures prior to acquisitions/(dispositions)	**54,212**	31,958	318
Acquisitions (dispositions)	**(238)**	-	7,500
Total capital expenditures	**53,974**	31,958	7,818
Balance sheet ($000s, except share amounts)			
Total assets	**662,245**	614,337	140,216
Long-term liabilities	**145,549**	124,587	3,173
Net debt (surplus) [1]	**73,521**	51,512	(9,698)
Adjusted working capital deficit (surplus) [1]	**21,466**	18,644	(54,400)
Weighted average shares outstanding [2,3]			
Basic and diluted	**43,815,340**	43,622,942	19,006,112
Shares outstanding end of period [2]	**44,042,515**	43,674,583	19,696,633

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.
2 – As part of the Arrangement (as defined below), Kiwetinohk consolidated the outstanding Kiwetinohk common shares, stock options and performance warrants on a 10 to 1 basis. This MD&A and all information related to common shares, stock options, performance warrants and per share amounts, have been restated to reflect the share consolidation for all periods presented.
3 – Per share amounts are based on weighted average basic and diluted shares, respectively.
4 – Realized loss on risk management contracts includes settlement of hedges on physical production and natural gas purchases.

YTD 2022 Highlights

Upstream

- Sales volumes averaged 13,253 boe/d in Q1, exceeding production guidance of 12,000-13,000 boe/d, due to strong performance from base operations and bringing new wells onstream ahead of schedule.
- Recent weekly production averaging 16,500 boe/d as new wells came on-line.
- Record quarterly adjusted funds flow from operations[1] of $37.0 million.
- Operating netbacks[1] up $4.91/boe from Q4/21 to $46.11/boe in Q1/22.
- Two Simonette wells drilled in Q4/21 completed and brought on-stream.
- Two additional Simonette wells drilled on time and on budget in Q1 are in the final stages of completion and expected to be onstream ahead of plan in the coming weeks.
- Started drilling a new Simonette four-well pad with targeted completion mid-year.
- Two Placid wells completed on time and on budget; initial flow back underway.
- Capital spending totaled $54.2 million, predominately on development at Fox Creek.
- Net commodity sales from purchases[1] of natural gas in Q1 of $0.6 million.
- Completed non-core land sales for aggregate proceeds of $4.1 million in March and April.

Green Energy

- Received Alberta Environment and Parks (AEP) referral letter for the 400 MW Homestead Solar Energy Project (Solar 1) concluding the project is low risk to wildlife and wildlife habitat.
- Submitted an AEP industrial application and Alberta Utilities Commission (AUC) power plant and substation application on March 31 and April 5 respectively, for the 101 MW Opal Power Plant Project (Firm Renewable 1).
- Submitted an AUC power plant and substation application for Project Homestead on April 27.

Financial Capacity

- Available credit facility capacity[1] at March 31, 2022 was $237.7 million.
- Filed a short-form base shelf prospectus to provide financing flexibility and additional options for quicker access to public equity and/or debt markets up to $500 million.
- Net debt to annualized adjusted funds flow from operations[1] remained well within the Company's target range of 1.0x at 0.66x during the quarter.
- Secured an additional $15 million of letter of credit facility capacity that is supported by a performance security guarantee from Export Development Canada.

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[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. Please refer to the Company's MD&A as at and for the three months ended March 31, 2022 under the section "Non-GAAP Measures" available on Kiwetinohk's SEDAR profile at www.sedar.com

Guidance & sensitivities

As a result of strong year-to-date results, Kiwetinohk is increasing 2022 annual production guidance by 500 boe/d at the high end of previous guidance. Kiwetinohk's Green Energy business also updated its 2022 capital plan to $15 million to $20 million (from a prior range of $10 million to $20 million), as the Company continues to advance efforts on acquiring early-stage development projects to expand its Green Energy portfolio. The spending will help advance Kiwetinohk's suite of low-carbon and zero-carbon power projects through planning, regulatory approvals, engineering and design, and financing.

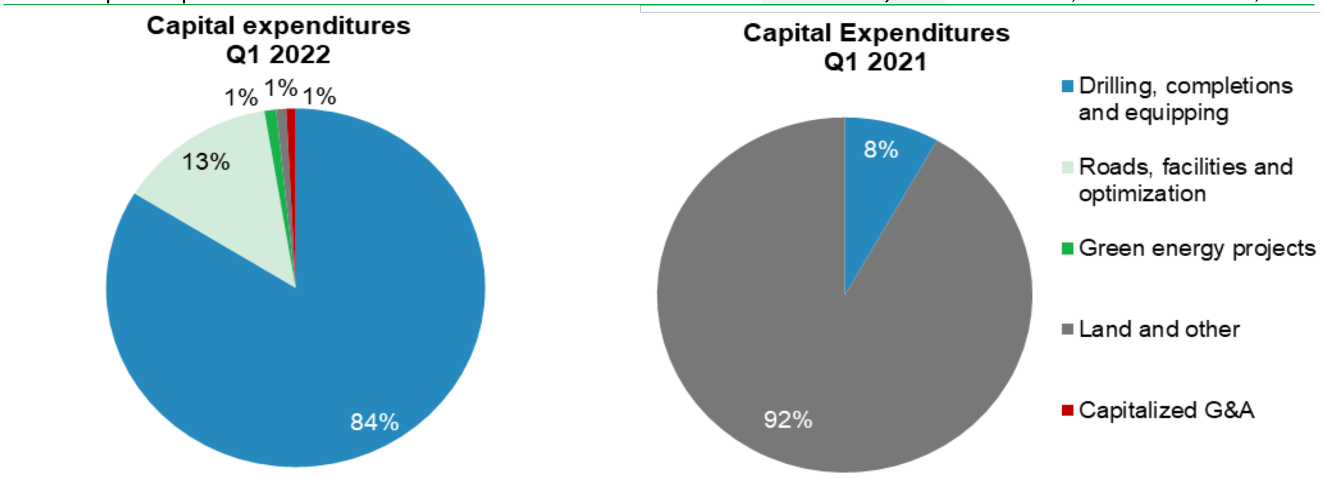
The following table sets forth Kiwetinohk's revised and previous adjusted funds flow from operations, net debt to adjusted funds flow from operations, capital expenditures and production guidance for 2022:

Operational & financial guidance		Revised May 2022	Original March 2022
Production (2022 average) [1]	Mboe/d	**13.5 - 15.5**	13.0 - 15.0
Oil & liquids	Mbbl/d	**6.75 - 7.75**	6.50 - 7.50
Natural gas	MMcf/d	**40.5 - 46.5**	39.0 - 45.0
Production by market [2]	%	100%	
Chicago	%	**80% - 85%**	87% - 97%
AECO	%	**15% - 20%**	3% - 13%
Financial			
Royalty rate (Crown)	%	12% - 15%	
Operating costs [1]	$/boe	$7.50 - $8.50	
Transportation	$/boe	$5.00 - $6.00	
Corporate G&A expense [3]	$MM	$15 - $18	
Cash Taxes	$MM	$0	
Capital guidance	**$MM**	**215 - 240**	**210 - 240**
Upstream	$MM	200 - 220	
Green Energy	$MM	**15 -20**	10 - 20
Drilling - Fox Creek	wells	11	
Duvernay	wells	10	
Montney	wells	1	
Sensitivities			
Adjusted Funds Flow from Operations [4, 5, 6]			
US$70/bbl WTI & US$3.75/MMBtu HH	$MM	**$165 - $175**	$145 - $155
US$80/bbl WTI & US$4.25/MMBtu HH	$MM	**$180 - $190**	$165 - $175
Net debt to Adjusted Funds Flow from Operations [4, 5, 6]			
US$70/bbl WTI & US$3.75/MMBtu HH	X	**0.7x**	1.0x
US$80/bbl WTI & US$4.25/MMBtu HH	X	**0.6x**	0.7x

1 – Production and cash operating costs include a provision for scheduled Fox Creek plant turnarounds.
2 – AECO sales year-to-date were higher than forecast due to timing of the Bigstone Alliance meter reactivation. AECO/Chicago split of ~8-13% expected for rest of year.
3 – Includes all cash G&A expenses for all divisions of the Company – Corporate, Upstream, Green Energy (power & hydrogen) and Business Development.
4 - 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 Company's MD&A as at and for the three months ended March 31, 2022 under the section "Non-GAAP Measures" available on Kiwetinohk's SEDAR profile at www.sedar.com
5 – Q1/22 actual prices with US$70/Bbl WTI flat; US$3.75/MMBtu HH flat; US$0.79/CAD flat thereafter for remainder of 2022 and full year 2023.
6 – Q1/22 actual prices with US$80/Bbl WTI flat; US$4.25/MMBtu HH flat; US$0.81/CAD flat thereafter for remainder of 2022 and full year 2023.

Capital expenditures

$000s	Q1 2022	Q4 2021	Q1 2021
Drilling, completions and equipping	**45,444**	28,742	26
Roads, facilities and optimization	**7,336**	1,184	-
Green energy projects	**540**	867	-
Land and other	**462**	638	292
Capitalized G&A	**430**	527	-
Total before acquisitions/(dispositions)	**54,212**	31,958	318
Cash consideration on acquisitions/(dispositions)	**(238)**	-	7,500
Total capital expenditures	**53,974**	31,958	7,818



1 – Capital expenditures shown are before acquisitions and dispositions.

The majority of the Company's capital expenditures prior to acquisitions were spent on drilling, completions, and equipping.

Drilling, completions and equipping

The following is a summary of drilling activity that the Company has recently completed in Alberta:

	Area			Total	
(wells)	Thorhild	Simonette	Placid	Gross	Net
2021	2.0	2.0	3.0	7.0	7.0
Q1 2022	-	6.0	-	6.0	6.0

Significant activity is underway at Simonette (Duvernay) where the majority of the 2022 development program is focused. Two wells drilled in late 2021 to total depths of more than 8,000 meters are both on production. Two additional wells that were recently completed will also soon contribute at Simonette. This is helping to fill spare capacity at the Simonette plants, contributing to go-forward improvement in operating costs. Four additional wells on a single pad are currently being drilled and are progressing on schedule. Drilling should be completed before the end of June, with completions to follow shortly thereafter.

At Placid (Montney), the two wells drilled in late 2021 were completed in the first quarter of this year on budget. These wells were brought on-stream at the end of the quarter, ahead of schedule.

Since the beginning of the program, learnings have been incorporated and rig and crew performance continue to improve, resulting in acceleration of well spud to onstream production and improved cost performance. This has offset some of the inflationary pressure that we are seeing in the oil field service industry as we continue to actively plan and manage our drilling and completion program.

Roads, facilities and optimization

During the first quarter the Company spent $7.3 million with approximately 55% of the spending focused on the construction of new roads required to complete the Company's drilling program with remaining costs related to the installation of metering stations and connection of new well locations to facilities.

Green energy development projects

Kiwetinohk continues to make significant progress in the development and permitting of its 1,800 MW solar and gas-fired power portfolio. The Company submitted an AUC power plant and substation application for the 400 MW Homestead Solar Energy Project on April 27 following stakeholder consultation and an AEP referral letter concluding the project is low risk to wildlife and wildlife habitat.

Kiwetinohk submitted an AEP industrial application and AUC power plant and substation application on March 31 and April 5 respectively, for the 101 MW Opal Firm Renewable Project.

Kiwetinohk continues to progress development of its NGCC 1 and NGCC 2 projects with pre-FEED analysis, Carbon Capture, Utilization and Storage (CCUS) evaluation and preliminary environmental scoping underway.

As part of the Company's evaluation of financing alternatives for its power portfolio, Kiwetinohk has advanced discussions with several potential partners interested in acquiring project-level equity interests.

Existing project schedules remain unchanged with the 400 MW Homestead Solar Energy Project and the 101 MW Opal Firm Renewable Project both expected to reach FIDs by year end.

Early-stage development and design factors and the status of each project as at May 11, 2022 are summarized in the following tables:

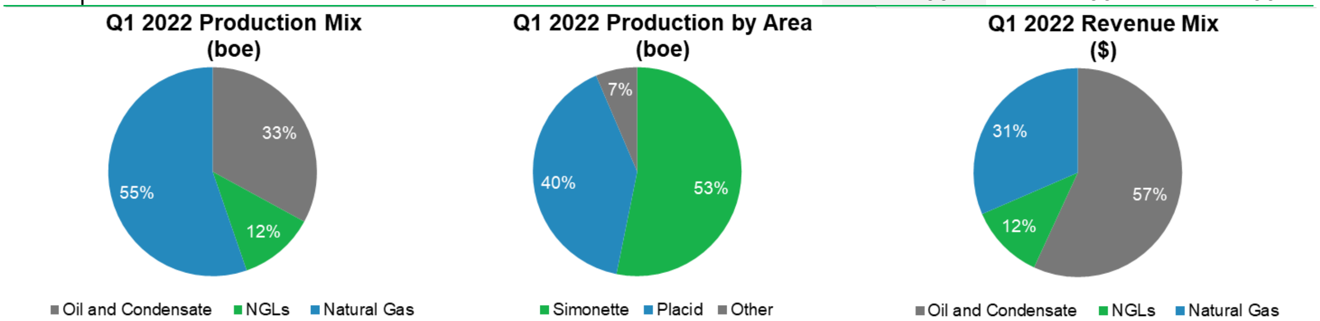
	Homestead (Solar 1)	Solar 2	Opal (Firm Renewable 1)	NGCC 1	NGCC 2
Nameplate/Net to Grid Capacity	400 MW	300 MW	101 MW 97 MW	500 MW 460 MW	500MW 460 MW
AESO Stage	2	1	2	2	2
Site Control	Options secured	Options secured	Land acquisition in progress	Options secured	Land acquisition in progress
Public Consultation	Completed	Planning underway	Completed	Planning underway	Planning underway
Regulatory / Environmental	AEP referral letter received; AUC power plant application submitted in April 2022	AEP referral letter received	AEP industrial application and AUC power plant application submitted in March/April 2022	Environmental work underway	Environmental work underway
Engineering	Pre-FEED complete; FEED near completion	BD complete	FEED complete	BD complete; Pre-FEED underway	BD complete; Pre-FEED underway
Targeted FID	Q3 2022	Q2 2023	Q4 2022	Q3 2024	Q4 2023
Targeted COD [4]	Q4 2024	Q2 2025	Q4 2024	Q3 2027	Q4 2026
Total installed capital cost ($ million) [1, 2, 3]	$655 (Class 3)	$492 (Class 3)	$156 (Class 3)	$875 (Class 4)	$875 (Class 4)

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. CCUS costs are estimated to be an incremental 60 to 80% of the total installed cost based on an engineering study by Gas Liquids Engineering (GLE).
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 FID decision is reached the Company will advance the project towards an estimated Commercial Operations Date (COD).
5 - The term "Firm Renewable" is a Kiwetinohk-originated term that describes efficient, flexible-output, fast-responding, gas-fired, internal reciprocating engine-drive power generation that address the need for stability that has been revealed as wind and solar renewable power grows to become a more significant proportion of a grid's power supply.

Results of operations

Production

	Q1 2022	Q4 2021	Q1 2021
Condensate (bbl/d)	3,475	3,092	77
Light oil (bbl/d)	876	844	344
Heavy oil (bbl/d)	13	13	33
NGLs (bbl/d)	1,561	1,572	92
Natural gas (Mcf/d)	43,970	41,410	1,169
Total production (boe/d)	13,253	12,442	741
Oil and condensate % of production	33%	32%	61%
NGL % of production	12%	13%	13%
Natural gas % of production	55%	55%	26%
Total production volumes %	100%	100%	100%



Production during the first quarter of 2022 averaged 13,253 boe/d compared to 741 boe/d in the first quarter of 2021. The Company's production volumes increased significantly with the closing of the Simonette Acquisition and consolidation of Distinction operating results commencing on April 28, 2021. The Company's production portfolio during the first quarter of 2022 was 33% oil and condensate, 12% NGLs, and 55% natural gas, with the largest growth in production seen in natural gas and condensate as compared to 2021.

The Simonette area contributed on average 7,050 boe/d during the three months ended March 31, 2022 while Placid contributed an average of 5,348 boe/d. The Simonette and Placid assets both deliver high liquids content natural gas with the Company now having an average liquid yield of approximately 135 bbls/MMcf.

Benchmark and realized prices

	Q1 2022	Q4 2021	Q1 2021
Liquid benchmark prices			
WTI (US$/bbl)	**94.29**	77.19	57.79
WTI (CDN$/bbl)	**119.42**	97.20	73.22
Edmonton Light (CDN$/bbl)	**101.85**	92.14	66.51
WCS Hardisty (CDN$/bbl)	**100.98**	78.82	57.46
Natural gas benchmark prices			
Henry Hub (US$/MMBtu)	**4.95**	5.83	2.72
Chicago City Gate MI (US$/MMBtu)	**5.75**	5.87	2.62
Chicago City Gate DI (US$/MMBtu)	**4.42**	4.59	9.25
AECO 5A (CDN$/GJ)	**4.49**	4.41	2.99
AECO 7A (CDN$/GJ)	**4.35**	4.69	2.78
Alberta Power			
Daily (CDN$/MWh)	**89.97**	107.33	97.26
Daily on Peak (CDN$/MWh)	**105.03**	121.13	120.21
Foreign exchange rates (CAD/USD)	**0.79**	0.79	0.79

	Q1 2022	Q4 2021	Q1 2021
Realized prices			
Condensate ($/bbl)	115.77	99.21	77.96
Light oil ($/bbl)	115.85	92.29	65.23
Heavy oil ($/bbl)	85.83	81.60	48.28
NGLs ($/bbl)	66.03	65.61	24.41
Natural gas ($/Mcf)	6.35	6.64	3.19
Total ($/boe)	66.96	61.48	48.62

WTI benchmark prices increased significantly in the first quarter of 2022 when compared to those prevailing in first quarter of 2021. The increase is primarily as a result of Russia's invasion of Ukraine and related supply sanctions, aided by 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 ("OPEC"). This, along with increased capital discipline amongst producers has resulted in global crude oil demand outpacing supply during the first quarter of 2022. WTI prices averaged $119.42/boe in the three month period ended March 31, 2022 compared to $73.22/boe for the comparable period in 2021, an increase of 63%.

Similar to WTI, Edmonton Light benchmark pricing has experienced significant increases in 2022 when compared to 2021 levels. For the three months ended March 31, 2022, Edmonton Light benchmark prices averaged $101.85 per barrel compared to $66.51 per barrel in 2021, respectively.

Natural gas prices increased in the first quarter of 2022 when compared to the comparable period in 2021 due to low storage levels, a decrease in supply due to lower investment and an increase in US natural gas exports all of which have continued to drive an increase in quarter over quarter demand and pricing. The Chicago City Gate monthly index benchmark for natural gas for the three months ended March 31, 2022 increased to US $5.75/MMBtu compared to US $2.62/MMBtu, representing an increase in pricing of 120%. The Chicago City Gate daily index benchmark for natural gas for the three months ended March 31, 2022 decreased 52% from the prior year period as gas prices were driven to record high levels in the first quarter of 2021 due to a loss in US production during an extremely high period of demand for natural gas driven by extreme cold weather.

The Company has a total of 120 MMcf/d of firm Alliance Pipeline transportation service to Chicago contracted through October 31, 2025 that was acquired through both the Simonette and Distinction transactions (see "Acquisitions" for a description of these transactions). The Company has a liquids extraction agreement with Aux Sable until October 31, 2023 whereby liquids contained within the natural gas are extracted, fractionated and sold into the US Midwest refining and petrochemical market, and the remaining natural gas sold into the Chicago area marketplace and interconnecting markets.

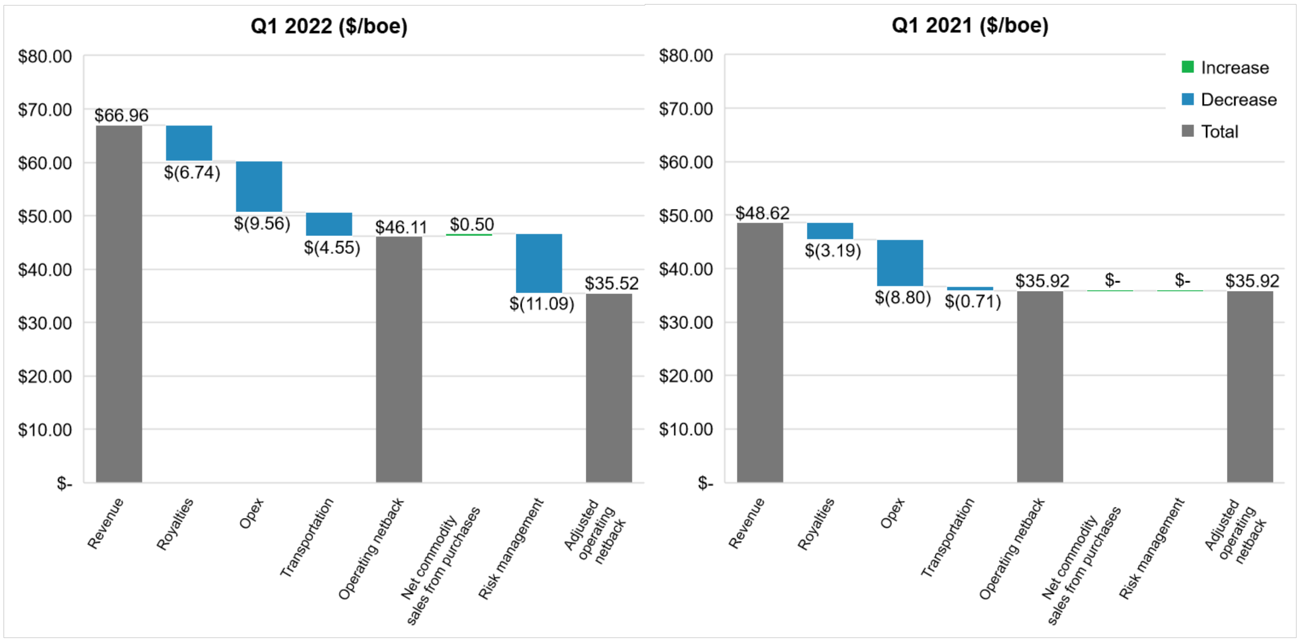
Kiwetinohk also sells natural gas in the AECO market through the Nova Gas Transmission Ltd. ("NGTL") system. Natural gas that is sweetened (through the removal of hydrogen sulfide) at the Company's amine facility is further processed at its 25 percent owned sweet natural gas plant ("Bigstone Sweet Plant") which is currently connected to the NGTL pipeline system. The Alliance meter station at the Bigstone Sweet Plant was reconnected on April 21, 2022 which will allow the Company to transport its natural gas on both the NGTL and Alliance pipeline systems.

The Company has contracted for approximately 20.5 MMcf/d of transportation service on NGTL with 0.3 MMcf/d expiring in mid-2023, and a further 0.2 MMcf/d expiring at the end of Q1 2024. The remaining 20.0 MMcf/d is held until March 31, 2026.

Operating netback

	Q1 2022	Q4 2021	Q1 2021
Realized price ($/boe)	**66.96**	61.48	48.62
Royalty expenses ($/boe)	**(6.74)**	(6.80)	(3.19)
Operating expenses ($/boe)	**(9.56)**	(8.28)	(8.80)
Transportation expenses ($/boe)	**(4.55)**	(5.20)	(0.71)
Operating netback [1]($/boe)	**46.11**	41.20	35.92
Net commodity sales from purchases [1] ($/boe)	**0.50**	2.50	-
Realized loss on risk management contracts ($/boe)	**(11.09)**	(11.86)	-
Adjusted operating netback [1]	**35.52**	31.84	35.92
Total production (boe/d)	**13,253**	12,422	741

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.



Operating netback during the quarter ended March 31, 2022 was $46.11/boe compared to $35.92/boe in the same period in the prior year primarily driven by a $18.34/boe or 38% increase in average realized pricing. The increase in realized pricing was offset by higher royalty expenses of $6.74/boe during the current period quarter versus $3.19/boe in the same period prior year resulting from crown royalty incentives coming to an end on older production. Additionally, with significant growth in production levels achieved through acquisitions and gas production being shipped to Chicago, the Company's transportation expense increased from $0.71/boe to $4.55/boe.

After taking into account the impact of net commodity sales from purchases and risk management activities, adjusted operating netback was $35.52 boe/d for the quarter ended March 31, 2022 a 1% decrease compared to the prior year. The Company incurred a realized loss on risk management contracts of $11.09/boe as the Company managed price volatility to ensure predictable cash flows during a period of significant capital expenditures and growth.

Revenue

$000s	Q1 2022	Q4 2021	Q1 2021
Condensate	**36,210**	28,218	543
Light oil	**9,135**	7,166	2,017
Heavy oil	**99**	97	144
NGLs	**9,274**	9,488	202
Natural gas	**25,148**	25,298	336
Total commodity sales from production	**79,866**	70,267	3,242

Revenues increased to $79.9 million for the quarter ended March 31, 2022, an increase of $76.6 million from the $3.2 million generated in the first quarter of 2021. The increase was a result of a significant increase in production achieved through acquisitions and higher pricing realized across all products when compared to the first quarter of 2021.

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 purchased natural gas and help ensure sufficient capital and liquidity is available to pursue its ongoing growth plans. Risk management contracts are entered into at prices that enhance the probability of the Company's assets and investments meeting or exceeding their targeted financial return hurdles. All risk management contracts are entered into in accordance with the Company's risk management Policy, which has been approved by the Board of Directors. Among other things, the risk management Policy requires that risk management contracts be only used in conjunction with known underlying exposures and not for speculative purposes and includes limits that ensure the Company has sufficient underlying assets to cover all outstanding risk management liabilities when they arise. Additionally, the Company regularly reviews its credit exposure to physical and financial counterparties.

$ 000's	Q1 2022	Q4 2021	Q1 2021
Unrealized gain (loss) on risk management contracts	**(37,510)**	33,916	1,275
Realized loss on risk management contracts	**(13,227)**	(13,547)	(3,023)
Total gain (loss) on risk management contracts	**(50,737)**	20,369	(1,748)
Unrealized gain (loss) ($/boe)	**(31.45)**	29.68	19.12
Realized gain (loss) ($/boe)	**(11.09)**	(11.86)	(45.34)

For the three months ended March 31, 2022, the Company recorded realized losses on risk management contracts of $13.2 million. The unrealized loss on risk management contracts of $37.5 million for the three months ended March 31, 2022, represents changes in the fair value of risk management contracts during 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. As risk management contracts are entered into to hedge underlying exposures, the Company does not expect to settle these contracts in advance of their scheduled maturity dates. 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 March 31, 2022:

Type	Unit	Q2 2022	Q3 2022	Q4 2022	2023	2024
Crude oil						
WTI fixed price	bbl/d	750	750	750	900	-
WTI fixed price (USD)	bbl/d	-	-	-	275	500
WTI buy put	bbl/d	2,167	2,033	1,883	-	-
WTI sell call	bbl/d	2,167	2,033	1,883	-	-
WTI swap average	CDN$/bbl	$69.95	$69.95	$69.95	$82.60	-
WTI swap average	US$/bbl	-	-	-	$70.41	$70.62
WTI buy put average	CDN$/bbl	$65.00	$65.00	$65.00	-	-
WTI sell call average	CDN$/bbl	$76.69	$76.67	$76.65	-	-
Natural gas [2]						
NYMEX Henry Hub fixed price	MMBtu/d	21,167	20,350	15,350	11,375	2,500
NYMEX Henry Hub buy put	MMBtu/d	2,500	2,500	9,500	2,000	-
NYMEX Henry Hub sell call	MMBtu/d	2,500	2,500	9,500	2,000	-
NGI Chicago basis to NYMEX Henry Hub	MMBtu/d	19,600	18,450	17,950	9,375	-
NYMEX Henry Hub fixed price average	US$/MMBtu	$2.99	$2.99	$2.71	$3.35	$3.23
NYMEX Henry Hub buy put average	US$/MMBtu	$3.00	$3.00	$4.03	$3.00	-
NYMEX Henry Hub sell call average	US$/MMBtu	$4.75	$4.75	$4.93	$3.81	-
NGI Chicago basis to NYMEX Henry Hub average	US$/MMBtu	($0.145)	($0.170)	($0.064)	$0.008	-
AECO 5A fixed price	GJ/d	2,250	2,025	2,025	-	-
AECO 5A average	CDN$/GJ	$2.26	$2.09	$2.09	-	-
Natural gas transportation [2,3]						
Purchase AECO 5A basis (to NYMEX Henry Hub)	MMBtu/d	80,000	80,000	26,667	-	-
Sell GDD Chicago basis (to NYMEX Henry Hub)	MMBtu/d	(80,000)	(80,000)	(26,667)	-	-
AECO 5A basis (to NYMEX Henry Hub) average	US$/MMBtu	($1.25)	($1.25)	($1.25)	-	-
GDD Chicago basis (to NYMEX Henry Hub) average)	US$/MMBtu	($0.12)	($0.12)	($0.12)	-	-
Foreign exchange						
Sell USD CAD (monthly average)	US$	$5.0 MM	$5.0 MM	$1.7 MM	-	-
USD CAD buy put	US$	$5.0 MM	$5.0 MM	$1.7 MM	-	-
USD CAD sell call	US$	$5.0 MM	$5.0 MM	$1.7 MM	-	-
USD CAD fixed sell rate		1.29	1.29	1.29		
USD CAD put		1.25	1.25	1.21		
USD CAD call rate		1.30	1.30	1.30	-	-

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

$ 000's	March 31, 2022	December 31, 2021
Short term risk management contracts	**56,319**	26,115
Long term risk management contracts	**9,994**	2,688
Total risk management contracts liability	**66,313**	28,803

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

Type	Unit	Q2 2022	Q3 2022	Q4 2022	2023
Natural gas [2]					
NYMEX Henry Hub buy put	MMBtu/d	-	-	-	2,375
NYMEX Henry Hub sell call	MMBtu/d	-	-	-	2,375
NYMEX Henry Hub buy put average	US$/MMBtu	-	-	-	$5.00
NYMEX Henry Hub sell call average	US$/MMBtu	-	-	-	$13.75
Foreign exchange					
USD CAD buy put	US$	$833 M	$2.5 MM	$2.5 MM	$625 M
USD CAD sell call	US$	$833 M	$2.5 MM	$2.5 MM	$625 M
USD CAD put rate		1.26	1.26	1.26	1.26
USD CAD call rate		1.30	1.30	1.30	1.30

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.

Net commodity sales from purchases

$000s	Q1 2022	Q4 2021	Q1 2021
Commodity sales from purchases	**60,598**	58,398	-
Commodity purchases, transportation and other	**(60,002)**	(55,544)	-
Net commodity sales from purchases [1]	**596**	2,854	-
$/boe	**0.50**	2.50	-

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.

In order to mitigate the cost of transportation service in excess of its 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 quarter after corporate field production and temporarily assigned volumes. The Company also enters into risk management contracts associated with marketing activities to protect the basis differential between the Alberta and Chicago sales points on the pipeline including related foreign exchange contracts.

In the three months ended March 31, 2022, the Company realized net commodity sales from purchases of $0.6 million on its marketing activities associated with purchasing natural gas to fulfill its transmission commitment on the Alliance pipeline system. The Company has natural gas production which utilized approximately 20% of the Alliance transportation commitment during the first quarter of 2022, with the remaining capacity filled through purchases.

Royalty expense

$000s	Q1 2022	Q4 2021	Q1 2021
Royalty expense (recovery)	**8,039**	7,766	213
As a % of revenue	**10%**	11%	7%
$/boe	**6.74**	6.80	3.19

The Company pays Crown, freehold, and overriding royalties on production volumes. Royalties in the first quarter of 2022 increased to $8.0 million compared to $0.2 million in the same period in prior year. Royalties increased from 7% as a percentage of revenues for the first quarter of 2021 to 10% in the current quarter. The increase is primarily a result of higher pricing and additional royalties attributed to the Simonette and Distinction acquisitions.

Some Distinction wells are burdened with higher Crown rates under an older royalty regime. Under the old royalty regime, when a well comes off of a royalty holiday, the Crown royalty rate for field condensate and natural gas liquids can increase up to an average of approximately 40 percent (depending on individual well factors and benchmark prices).

Production from wells drilled subsequent to January 1, 2017 qualify for reduced Crown royalty rates under the Modernized Royalty Framework which currently imposes a five percent royalty rate until certain conditions are met. The Company is able to further benefit from gas cost allowance (Crown royalty credits) based in part on the amortization of historical capital and operating costs incurred in the gathering and processing of the Crown's share of natural gas production.

Operating expenses

$000s	Q1 2022	Q4 2021	Q1 2021
Operating expenses	**11,402**	9,460	587
$/boe	**9.56**	8.28	8.80

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 increased significantly in the first quarter of 2022 compared to the prior year as production volumes increased by 12,512 boe/day through acquisitions.

On a per boe basis, operating costs increased to $9.56/boe during the three months ended March 31, 2022 compared to $8.80/boe in the first quarter of 2021. The increase was a result of inflationary cost pressures in the field as companies respond to increased levels of activity throughout the Western Canadian basin in response to strong commodity pricing.

Transportation expenses

$000s	Q1 2022	Q4 2021	Q1 2021
Transportation expenses	**5,424**	5,939	47
$/boe	**4.55**	5.20	0.71

Transportation expenses are incurred to deliver oil and natural gas commodities from the Company's production to the delivery point of sale. Prior to the 2021 acquisitions, the Company did not have any significant transportation costs. The Company now 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.

Adjusted funds flow from (used in) operations

$000s	Q1 2022	Q4 2021	Q1 2021
Cash flow from (used in) operating activities	**25,332**	25,518	(3,579)
Net change in non-cash working capital from operating activities	**11,014**	2,168	266
Asset retirement obligation expenditures	**656**	671	-
Restructuring costs	**-**	9	-
Acquisition costs	**-**	2,397	-
Settlement costs	**-**	-	-
Adjusted funds flow from (used in) operations [1]	**37,002**	30,763	(3,313)
$/boe	**31.02**	26.92	(49.68)

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.

Adjusted funds from operations increased to $37.0 million for the three months ended March 31, 2022 as a result of the Simonette and Distinction acquisitions. The Company's cash flow from operating activities was $25.3 million for the three months ended March 31, 2022. Cash flow from (used in) operating activities has been adjusted for the net change in non-cash working capital from operating activities, expenditures on asset retirement obligations, restructuring costs associated with Distinction's CCAA process, acquisition costs and one-time settlement costs to terminate certain carried interest rights and obligations.

Free funds flow (deficiency) from operations

$000s	Q1 2022	Q4 2021	Q1 2021
Adjusted funds flow from (used in) operations	**37,002**	30,763	(3,313)
Capital expenditures (excluding acquisitions and dispositions)	**(54,212)**	(31,958)	(318)
Free funds flow deficiency from operations [1]	**(17,210)**	(1,195)	(3,631)
$/boe	**(14.43)**	(1.05)	(54.45)

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.

Free funds flow (deficiency) from operations during the quarter ended March 31, 2022 was $17.2 million relative to $3.6 million used in the prior year quarter. The Company had higher capital expenditures during the quarter ended March 31, 2022 due to drilling and completions activity as the Company continues to develop the core upstream operations.

Share in earnings of associate

$000s	Q1 2022	Q4 2021	Q1 2021
Share in earnings / excess fair value of associate	**-**	-	9,029

The Company had a 51.6 percent ownership interest in Distinction prior to April 28, 2021 and accounted for its investment under the equity method. As of April 28, 2021, the Company obtained control over Distinction and began to consolidate the results of Distinction. The Company recognized $9.0 million of share in earnings and fair value adjustments in the condensed consolidated interim statement of net loss and comprehensive loss through March 31, 2021.

General and administrative ("G&A") expenses

$000s	Q1 2022	Q4 2021	Q1 2021
Gross G&A expenses	**5,406**	5,589	2,006
Capitalized G&A	**(430)**	(527)	-
G&A expenses	**4,976**	5,062	2,006
$/boe	**4.17**	4.43	19.95

G&A expenses increased by $3.0 million during the quarter ended March 31, 2022 as compared to the first quarter of 2021. The increase is primarily attributable to the significant growth in the Company that occurred in 2021. This included additional employees to support and execute on the Company's strategy and additional costs associated with operating as a public company. A portion of G&A activity continues to be directly related to business development initiatives in the Green Energy segment consistent with Kiwetinohk's strategy to capture a larger portion of the hydrocarbons value chain by securing access to downstream power, and a broader integrated portfolio of clean energy assets.

Gross G&A expenses were reduced by $0.4 million for direct and incremental G&A costs for upstream and green energy projects that were capitalized during the quarter ended March 31, 2022.

Share-based compensation expenses

$000s	Q1 2022	Q4 2021	Q1 2021
Share-based compensation expenses	**3,285**	4,316	3,930
$/boe	**2.75**	3.78	58.93

Share-based compensation is the non-cash compensation expense recognized for stock options, performance warrants and capital warrants. The expense 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.

Share-based compensation was $3.3 million for the three months ended March 31, 2022 compared to $3.9 million in the comparable prior year period.

During the first quarter of 2022, the Company granted 0.1 million options (Q1 2021 – 0.6 million options and 1.2 million performance warrants after adjusting for the 10:1 share consolidation.

Finance costs

$000s	Q1 2022	Q4 2021	Q1 2021
Accretion of asset retirement obligations	**437**	442	19
Interest and bank charges	**926**	1,470	-
Interest on lease obligations	**11**	20	-
Deferred financing amortization	**323**	231	-
Unrealized loss on foreign exchange	**879**	-	-
Total finance costs	**2,576**	2,162	19
$/boe	**2.16**	1.89	0.28

On December 10, 2021 the Company amended and restated its credit agreement entering into a consolidated $315 million senior secured extendible revolving facility (the “Credit Facility”) with a syndicate of banks. As at March 31, 2022 the Company had drawn $52.1 million on the facility, net of deferred financing charges, and the available borrowing capacity at March 31, 2022 is $237.7 million (December 31, 2021 - $228.0 million). Higher levels of debt outstanding and standby fees on the Credit Facility resulted in higher financing fees during the first quarter of 2022 as compared to 2021.

Depreciation and depletion

$000s	Q1 2022	Q4 2021	Q1 2021
Depreciation	**292**	296	110
Depletion	**12,621**	11,846	-
Total depreciation and depletion	**12,913**	12,142	110
$/boe	**10.83**	10.62	1.65

The Company’s depletable base increased with current period acquisition activity. The Simonette and Distinction properties at acquisition date had property, plant, and equipment fair values of $345.1 and $107.0 million, respectively. The acquisitions and higher capital expenditures and production during 2021 resulted in depletion of $12.6 million for the quarter ended March 31, 2022 (Q1 2021 - $0.1 million).

Exploration and evaluation (“E&E”) expenses

$000s	Q1 2022	Q4 2021	Q1 2021
Depletion	**722**	881	1,600
Impairment	**2,025**	-	46,015
Other	**508**	269	2,961
Total E&E expenses	**3,255**	1,150	50,576
$/boe	**2.73**	1.01	758.37

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.

E&E depletion expense is recorded on a unit of production basis for properties that have production but have not yet been transferred to property plant and equipment. The decrease in current quarter 2022 depletion is a result of production declines and a lower E&E depletable base.

With the Simonette Acquisition and associated lands acquired, the Company re-prioritized its development and drilling plans in the first quarter of 2021 to higher-return undeveloped land locations. This is anticipated to result in some near-term land expiries whereby a portion of the E&E assets for existing wells and undeveloped land may not be recoverable, resulting in an impairment charge of $2.0 million in the first quarter of 2022 (Q1 2021 - $46.0 million).

Income taxes

The Company did not pay any income taxes in 2021 and does not expect to be taxable in the near future. A deferred tax asset has not been recognized at March 31, 2022 given uncertainty around future recoverability. The Company's estimated tax pools as at March 31, 2022, are as follows:

Category	Deductibility	$000's
Canadian oil and gas property expense ("COGPE")	10%	193,649
Successored COGPE	10%	1,275
Canadian development expense ("CDE")	30%	86,628
Successored CDE	30%	103,436
Canadian exploration expense ("CEE")	100%	5,300
Successored CEE	100%	15,422
Undepreciated capital cost ("UCC")	Primarily 25%, declining balance	97,755
Non-capital losses	100%	259,429
Share/Debt issue costs	5-year straight line	4,432
Other	Various	(3,482)
Total estimated tax pools		763,705

Asset retirement obligations

The Company's asset retirement obligations ("ARO") of $88.1 million pertain to the Company's wells and related infrastructure with the large increase in the 2021 related to the Simonette Acquisition and Distinction business combination. 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. There is approximately $30.5 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.

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. The Company's Liability Management Rating ("LMR") is within the Alberta Energy Regulator's requirements and as such, no deposits are required or expected to be required in the near term. The Company's combined LMR at March 31, 2022 is 5.01 (5.34 at December 31, 2021).

Select quarterly information

	2022	2021				2020		
	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Production (boe/d)	**13,253**	12,422	15,058	10,797	741	645	793	443
Commodity sales from production ($000)	**79,866**	70,267	66,897	42,262	3,242	2,186	2,388	1,305
Commodity sales from purchases	**60,598**	58,398	38,349	17,770	-	-	-	-
Cash flow from (used in) operating activities	**25,332**	25,518	31,006	(17,125)	(3,579)	(777)	399	(1,776)
Per share (basic) [1,2]	**0.58**	0.58	0.90	(0.58)	(0.19)	(0.05)	0.03	(0.14)
Per share (diluted) [1,2]	**0.58**	0.58	0.90	(0.58)	(0.19)	(0.05)	0.03	(0.14)
Net income (loss) [2]	**(24,552)**	44,306	(34,080)[2]	13,726[3]	(46,267)	9,732	(3,545)	(3,261)
Per share (basic) [1]	**(0.56)**	1.02	(0.99)	0.47	(2.43)	0.64	(0.27)	(0.26)
Per share (diluted) [1]	**(0.56)**	1.02	(0.99)	0.47	(2.43)	0.64	(0.27)	(0.26)

1 – As part of the Arrangement, Kiwetinohk consolidated the outstanding Kiwetinohk common shares, stock options and performance warrants on a 10 to 1 basis. This MD&A and all information related to common shares, stock options, performance warrants and per share amounts, have been restated to reflect the share consolidation for all periods presented.
2 – The Company has restated Q3 2021 operating expenses by $2.0 million and transportation expenses by $2.4 million as a result of revisions to previously accrued expenses.
3 – The Company has adjusted Q2 2021 gain on acquisition by $1.1 million, deferred tax expense $0.3 million, and share in earnings of associate by $4.6 million due to adjustments to estimated fair values of working capital acquired based on new information on the Simonette and Distinction acquisitions.

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 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 through 2022. As at March 31, 2022 the Company has $237.7 million available under the Credit Facility which is sufficient to cover the Company's near term commitments and contractual obligations which includes the settlement of the $77.8 million working capital deficit held at March 31, 2022.

Credit Facility

On December 13, 2021, the Company amended and restated its credit agreement entering into a consolidated credit facility of $315.0 million with a syndicate of banks. The Credit Facility is comprised of an operating facility of $65.0 million and a syndicated facility of $250.0 million.

At March 31, 2022, $53.6 million (December 31, 2021- $34.7 million) (before deferred financing costs) was outstanding on the Credit Facility along with a total of $38.7 million (December 31, 2021 - $52.3 million) in letters of credit issue to support transportation and other commitments, of which, $6.0 million have been issued under the EDC Guaranteed LC Facility (the "LC Facility") (described below), resulting in $32.7 million in letters of credit which reduce the available operating facility capacity.

$000	Authorized	Drawn	Letters of credit	Capacity [1]
Credit Facility and LC Facility	330,000	53,562	38,746	**237,692**

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, 2022	December 31, 2021
Loans and borrowings	**52,055**	32,868
Adjusted working capital deficit [1]	**21,466**	18,644
Net debt [1]	**73,521**	51,512

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.

The Credit Facility is a 364-day committed facility available on a revolving basis until May 31, 2022, 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, 2023. The borrowing base is determined semi-annually 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, or lenders' prime rate or U.S. base rate plus the applicable margins, depending on the form of borrowing by the Company. The applicable margins and stamping fees are based on a sliding scale pricing grid tied to the ratio of the Company's debt to earnings before interest, taxes, depreciation and amortization ratio ("debt to EBITDA ratio") as defined in the Credit Facility agreement. Based on the Company's debt to EBITDA ratio, margins applicable to prime rate or US bas rate loans may range from 1.75 percent to 5.25 percent and stamping fees applicable to bankers' acceptances may range from 2.75 percent to 6.25 percent. The undrawn portion of the Credit Facility is subject to standby fees ranging from 0.6875 percent to 1.5625percent based on the Company's debt to EBITDA ratio.

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 is not subject to any financial covenants under the Credit Facility.

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

EDC Guaranteed LC Facility

On February 10, 2022, Kiwetinohk entered into a new $15.0 million unsecured demand revolving letter of credit 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 February 10, 2023 and may be extended from time-to-time at the option of Kiwetinohk and with the agreement of EDC. As at March 31, 2022, the Company has $9.0 million of capacity remaining under the LC Facility.

Base shelf prospectus

The Company has filed a short-form base shelf prospectus ("Prospectus") 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. In 2021, the Company fully drew on its remaining equity line of credit with ARC Financial Corp. ("ARC") and the Company raised $32.7 million in a private placement.

As part of the Arrangement (see "Acquisitions" below), Kiwetinohk issued 10.2 million common shares and acquired all of the Distinction common shares not already owned by it. All outstanding Kiwetinohk common shares, stock options and performance warrants were consolidated on a 10 to 1 basis with capital warrants being cancelled at the same time. Outstanding shares after giving effect to the share consolidation are retroactively presented in the following table.

(000s)	Q1 2022	Q4 2021	Q1 2021
Weighted average shares outstanding			
Basic	43,815	43,623	19,006
Diluted	43,815	43,623	19,006
Outstanding securities			
Common shares	44,043	43,675	19,697
Stock options	2,741	3,228	1,881
Performance warrants	7,852	7,922	3,762
Capital warrants	-	-	2,007
Total diluted outstanding securities	54,636	54,825	27,347

At May 11, 2022 the Company has 44,111,135 common shares outstanding.

Commitments, contractual obligations, and provisions

$000s	2022	2023	2024	2025	2026	Thereafter
Gathering, processing and transport [1]	52.5	70.9	73.0	63.7	13.5	48.4
Natural gas purchases	92.2	15.8	-	-	-	-
Accounts payable	65.6	-	-	-	-	-
Contingent payment consideration	-	10.0	-	-	-	-
Lease liabilities	0.4	-	-	-	-	-
Land fund	0.4	-	-	-	-	-
Loans and borrowings	-	53.6	-	-	-	-
Risk management contracts	49.2	17.1	-	-	-	-
Other	-	0.4	0.4	0.4	0.4	1.1
Total	260.3	167.8	73.4	64.1	13.9	49.5

1 – Gas transportation contracts include commitments on Alliance, NGTL and various NGL and condensate transportation and other processing commitments.

As part of the Simonette acquisition, the Company assumed natural gas transportation commitments of approximately 90.3 MMcf per day to deliver gas to Chicago on the Alliance pipeline through October 2025. The Company has a liquids extraction agreement with Aux Sable through October 2023. Through Distinction, the Company acquired a separate independent transportation agreement with Alliance to deliver 29.7 MMcf/d of natural gas volumes until October 31, 2025 to Chicago that is not contracted to Aux Sable.

The Company currently has secured 80,000 GJ per day of gas supply (approximately 70.1 MMcf per day) from several natural gas producers through 2022 and approximately 10,000 GJ/d (approximately 8.6 MMcf/d) in 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.

Acquisitions

The following is a summary of the Company's 2021 acquisitions:

$000s	Simonette Acquisition	Distinction [1]
Fair value of net identifiable assets acquired		
Property, plant and equipment	345,066	107,042
Working capital [2]	1,726	90,963
Risk management contracts	-	(215)
Asset retirement obligations	(7,105)	(9,488)
Lease liabilities	(605)	(709)
Deferred tax liability	(9,811)	-
	329,271	187,593
Bargain purchase gain	(32,843)	-
	296,428	187,593
Consideration:		
Cash	282,414	-
Distinction deposit on Simonette Acquisition	7,500	-
Investment [3]	-	96,822
Non-controlling interest [4]	-	90,771
Contingent payment consideration	6,514	-
Total purchase price	296,428	187,593

1 – Includes value of Distinction net identifiable assets as at April 28, 2021 immediately prior to the Simonette Acquisition.
2 – Distinction working capital includes $95.8 million of cash acquired.
3 – The investment is comprised of $62.9 million in cash (average cost of $12.91 per share), transaction costs of approximately $2.8 million and an equity gain on investment of $32.6 million and subsequent to the joint Simonette Acquisition Distinction had $63.3 million of debt and working capital of $0.5 million.
4 – Additional shares were issued pursuant to the Arrangement (as defined below) for equity consideration of $101.7 million.

Simonette Acquisition

On April 28, 2021 KRC and Distinction closed the Simonette Acquisition, an asset acquisition with a purchase price after adjustments of $296.4 million covering certain multi-zone, oil and natural gas properties in the Simonette region. The purchase price includes the current fair value of up to $15 million of contingent payments if average crude oil prices exceed the reference price for WTI of USD $56.00 per barrel in 2021 and USD $62.00 per barrel in 2022. During January 2022, the Company settled the first contingent payment of $5.0 million with an expected payment of $10.0 million in 2023.

The Simonette Acquisition is aligned with the Company's strategy of building an energy transition company focused initially on building a risk-diversified, liquids-rich upstream portfolio of Western Canadian oil and gas resource plays.

Distinction Amalgamation

On January 15, 2021, the Company increased its previous 25 percent equity interest in Distinction to 51.6 percent through the exercise of warrants for $40.0 million which included working capital adjustments of $2.5 million. During April 2021, Distinction announced the appointment of new KRC executive officers to rebuild Distinction from its prior year *Companies' Creditors Arrangement Act* ("CCAA") process. The Company gained control of Distinction and began consolidating the results of Distinction on April 28, 2021.

On June 28, 2021, KRC and Distinction announced an agreement to combine under a plan of arrangement pursuant to section 192 of the *Canada Business Corporations Act* (the "Arrangement" or "business combination") with Distinction. Through the Arrangement, KRC acquired all of the shares of Distinction that it did not already own (approximately 48%) by way of an exchange of 20 KRC shares for each Distinction share. Under the Arrangement, Kiwetinohk inherited the reporting issuer status of Distinction. A special meeting of Distinction shareholders and KRC shareholders to vote on the Arrangement was held and approved on August 30, 2021 and the Arrangement closed on September 22, 2021.

Related party information

For the quarter and year ended March 31, 2022, the Company incurred a total of $0.6 million (2021 - $0.4 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.
- 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 CEO 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.

Subsequent Events

On April 26, 2022 the Company disposed of non-core land and associated wells within the Thorhild Radway land area for proceeds of $3.9 million. Assets and liabilities have been classified as held for sale within the condensed consolidated interim balance sheet as at March 31, 2022. The assets disposed in the second quarter were predominately heavy oil and accounted for approximately 17 boe/d of production in the first quarter of 2022.

Building Lease
In April 2022, the Company entered into an eight-year lease agreement for office space resulting in an aggregate lease liability of approximately $11.2 million using a discount rate of 7.5 percent.

Health, safety and environmental

As part of integration of the Simonette assets and Distinction Energy, Kiwetinohk is implementing a new health and safety program that applies best practices across all operations. The Company continues to exercise caution with respect to COVID-19 risks by following local government and public health direction and other safeguards.

Kiwetinohk is completing a thorough review and assessment of risks and opportunities arising from and its strategies to manage those risks and opportunities related to its environmental, social and governance ("ESG") matters. The Company plans to publish its first ESG report in mid-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. In order to reduce risk the Company among other things, 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. For additional information on risk factors, refer to the Company's audited financial statements as at and for the year ended December 31, 2021 and "Risk Factors" as presented in the Company's Annual Information Form ("AIF") dated March 23, 2022 available on the SEDAR website at www.sedar.com.

Internal controls

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 to its board of directors is recorded, processed and reported in a timely manner.

There were no changes in the Company's internal controls during the period beginning on January 1, 2022 and ending on March 31, 2022 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 to the December 31, 2021 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, 2022.

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.

All financial liabilities are measured at amortized cost except for those measured at FVTPL which include contingent payment consideration and risk management contracts.

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 that physical and financial transactions are only entered into with strong, credit worthy counterparties and that appropriate forms of credit support are obtained if any counterparties do not meet the Company's credit requirements. Regular internal reviews are performed on the Company's exposure with these counterparties which is typically 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's financial instruments recognized on the condensed consolidated interim balance sheet includes cash, accounts receivable, funds held in trust, accounts payable and accrued liabilities, long term liability, contingent liabilities, loans and borrowings, and risk management contracts. The primary risks are described in Note 16 of the Financial Statements.

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 loss and comprehensive loss to the extent the Company has outstanding financial instruments.

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, 2022.

Other

Non-GAAP measures
Certain information set forth in this document contains non-GAAP measures, including "operating netback", "adjusted operating netback", "adjusted funds flow from (used in) operations", "free funds flow (deficiency)" from operations, "adjusted working capital deficit", "credit facility capacity", "net debt", "net debt to annualized adjusted funds flow from operations", "net commodity sales from purchases", "return on average capital employed" and "average capital employed". These non-GAAP 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.

The Company will use certain measures to analyze operational and financial performance. These non-GAAP measures do not have any standardized meaning prescribed under IFRS and therefore may not be comparable to similar measures presented by other entities nor should it be viewed as an alternative to other possible comparable IFRS measures.

Operating netback
Operating netback is calculated on a per boe basis as commodity sales from production less royalty, operating, and transportation expenses. Kiwetinohk 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.

Management believes that operating netback and adjusted operating netback are key industry benchmarks and useful measure of performance that provides the Company and investors with information that is commonly used by other oil and natural gas producers. The measurement on a per boe basis assists management with evaluating operating performance on a comparable basis.

Adjusted funds flow from (used in) operations
Adjusted funds flow from (used in) operations is cash flow from (used in) 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 (used in) 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.

Free funds flow (deficiency) from operations
Free funds flow (deficiency) from operations is adjusted funds flow from (used in) 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.

Adjusted working capital deficit
Adjusted working capital deficit is comprised of current assets less current liabilities excluding risk management contracts. Adjusted working capital deficit 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.

$000s	March 31, 2022	December 31, 2021
Current assets	**60,897**	47,557
Current liabilities	**(138,682)**	(92,316)
Working capital deficit	**(77,785)**	(44,759)
Short term risk management contracts payable	**56,319**	26,115
Adjusted working capital deficit	**(21,466)**	(18,644)

Credit facility capacity
Credit facility capacity is the total Credit Facility available, less amounts drawn on the Credit Facility and outstanding letters of credit. Credit facility capacity is used by management to assess the Company's liquidity.

Net debt and net debt to annualized adjusted funds flow from operations
Net debt is comprised of loans and borrowings plus adjusted working capital 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.

$000s	March 31, 2022	December 31, 2021
Loans and borrowings	**52,055**	32,868
Adjusted working capital deficit	**21,466**	18,644
Net debt	**73,521**	51,512
Net debt to annualized adjusted funds flow from operations	**0.66**	0.74

Net commodity sales from purchases

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.

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;
- 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;
- timing for the Company’s solar and Firm Renewable projects to reach FID;
- anticipated production increases into the first quarter of 2023;
- 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;
- reactivation of the Alliance meter station at the Bigstone Sweet Plant in the first quarter of 2022;
- future taxes payable by the Company;
- future requirements with respect to LMR deposits of the Company;
- the timing and costs of the Company's capital projects, including, but not limited to, drilling and completion of certain wells;
- the anticipated outcomes of the Company’s capital program;
- anticipated well production;
- asset retirement obligations;
- operating and capital costs in 2022;
- near-term land expiries and impairment charges associated therewith;
- sufficiency of funds to meet the Company's working capital requirements and anticipated drilling on the Simonette Acquisition and Distinction acreage through 2022;
- 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 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;
- costs to abandon wells or reclaim property;
- the impact of increasing inflationary cost pressure;
- 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 Kiwetinohk to obtain the required capital to finance its exploration, development and other operations and meet its commitments and financial obligations;
- the ability of Kiwetinohk 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 COVID-19 pandemic on the Company;
- the impact of the war in Ukraine 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;
- the risk of instability affecting the 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;
- 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 expected capital costs and power generation capacity of the Company’s proposed power generation capital projects and 2022 financial outlook information for the Company, including expected royalty rates, operating costs, transportation expenses, corporate G&A expenses and cash taxes. 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. Kiwetinohk 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

$M	thousand dollars
$MM	million dollars
$/bbl	dollars per barrel
$/boe	dollars per barrel equivalent
$/GJ	dollars per gigajoule
$/Mcf	dollars per thousand cubic feet
AECO	the daily average benchmark price for natural gas at the physical storage and trading hub for natural gas on the TransCanada Alberta transmission system which is the delivery point for various benchmark Alberta index prices
bbl(s)	barrel(s)
bbl/d	barrels per day
boe	barrel of oil equivalent, including crude oil, condensate, natural gas liquids, and natural gas (converted on the basis of one boe per six Mcf of natural gas)
boe/d	barrel of oil equivalent per day
DI	daily index
EBITDA	earnings before interest, income taxes, depreciation, depletion, and amortization
E&E	exploration and evaluation
GJ	gigajoule
GJ/d	gigajoule per day
Henry Hub	the daily average benchmark price for natural gas at the distribution hub on the natural gas pipeline system in Erath, Louisiana
mbbls	thousand barrels
MMboe	million barrels of oil equivalent
Mcf	thousand cubic feet
Mcf/d	thousand cubic standard feet per day
MI	monthly index
MMcf/d	million cubic feet per day
MMBtu	one million British Thermal Units (BTU) is a measure of the energy content in gas
MMBtu/d	one million British thermal units per day
MW	one million watts
MW.h	electrical energy of one million watts acting for one hour
NGLs	natural gas liquids, which includes butane, propane, and ethane
PP&E	property, plant, and equipment
US$/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.

CORPORATE INFORMATION

Management

Pat Carlson
Chief Executive Officer

Jakub Brogowski
Chief Financial Officer

Mike Backus
Chief Operating Officer, Upstream

John Maniawski
President, Green Energy Division

Janet Annesley
Chief Sustainability Officer

Sue Kuethe
Executive VP, Land and Community Inclusion

Mike Hantzsch
Senior Vice President, Midstream and Market Development

Kurt Molnar
Senior Vice President, Business Development

Lisa Wong
Senior Vice President, Business Systems

Chris Lina
Vice President, Projects

Farid Shirkavand
Vice President

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

Corporate Head Office

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Bankers

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

Auditor

Deloitte LLP
Calgary, AB

Reserve Engineers

McDaniel & Associates Consultants Ltd.
Calgary, AB

Legal Counsel

Stikeman Elliott LLP
Norton Rose Fulbright Canada LLP
Calgary, AB

Transfer Agent

Computershare
Calgary, AB

Stock Symbol

KEC
Toronto Stock Exchange