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 "Corporation") as at and for the three and nine months ended September 30, 2021. The Corporation was formed as part of the amalgamation of Kiwetinohk Resources Corp. ("KRC") and Distinction Energy Corporation ("Distinction").

This MD&A should be read in conjunction with the Corporation's condensed consolidated interim financial statements and related notes as at and for the three and nine months ended September 30, 2021, (the "Financial Statements") and KRC's audited financial statements as at and for the year ended December 31, 2020. 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 Corporation's disclosure under "Non-GAAP Measurements" and "Forward-Looking Statements" below.

The reporting currency is the Canadian dollar, and all dollar amounts in this MD&A are stated in Canadian dollars unless otherwise indicated. This MD&A is dated November 23, 2021.

Overview of business

The Corporation is engaged in the business of developing an integrated energy transition company focused on production of low carbon energy through the alignment of hydrocarbons and natural gas-fired (with carbon capture) and renewable power generation solutions. The Corporation has executed on its strategy by initially building a risk-diversified, liquids-rich focused upstream portfolio of Western Canadian oil and gas resource plays targeted to provide low-risk, low development cost and low feedstock cost gas for integrated operations and high operating netbacks. Through integration of gas production, the Corporation seeks to capture a larger portion of the hydrocarbons value chain by securing access to the downstream markets, focusing on power in the near to medium term and monitoring hydrogen for the longer-term, while contributing to a profitable and sustainable energy transition with low greenhouse gas emissions.

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 oil and condensate-rich properties that are expected to offer top tier economic resource potential. During the nine months ended September 30, 2021, the Corporation closed a purchase and sale agreement for certain interests in the Simonette area of northwest Alberta and the Willesden Green and Ferrier areas of west central Alberta (the "Simonette Acquisition") and has acquired and completed a plan of arrangement pursuant to section 192 of the *Canada Business Corporations Act* (the "Arrangement") with Distinction. These business acquisitions provide regional and resource diversification in the Montney and Duvernay. The Corporation has also strategically built a land base in the new emerging Clearwater play and is evaluating drilling opportunities. The Corporation continues to screen and evaluate other upstream business consolidation opportunities with a focus on natural gas resource targets providing a competitive discounted break-even price, low-risk and high upside potential on technology, operational effectiveness and favourable physical location to allow for future downstream integration.

The Power business is pursuing the greenfield and/or brownfield development of a diversified Alberta based power generation project portfolio ranging from clean, efficient, and reliable natural gas-fired power with carbon capture and sequestration, to renewable power sources, including solar and wind. This development work has included preparation of preliminary designs, performance estimates and preliminary cost estimates as part of a staged regulatory process that includes stages of increasing refinement and estimate quality as part of the process the Corporation uses to advance projects. The intent will be to proceed towards final design, final performance projection or cost estimate, full regulatory approval and securing of internal and external funding.

By building a portfolio of renewable and natural gas-fired power projects with carbon capture, the Corporation seeks to generate a profitable integrated power business which provides reliable, sustainable energy, lower CO2 emissions and enables maximum renewable capture. The Corporation expects the combination of low-cost natural gas produced from Kiwetinohk's upstream resources, with its planned natural gas-fired and renewable power projects, to increase the gross margin to the Corporation through participation in the full value chain from upstream resource to clean, low emissions power generation.

Kiwetinohk expects to investigate the feasibility of carbon capture, utilization and storage ("CCUS") and may deploy CCUS systems to achieve low emissions levels from its natural gas-fired plants. Kiwetinohk is also monitoring the relevant technologies and looking for investment opportunities in blue and green hydrogen projects.

Financial and operating results:

Financial and operating summary:

	Q3 2021	Q2 2021	Q3 2020	YTD 2021	YTD 2020
Sales volumes					
Condensate (bbl/d)	**4,261**	3,096	18	**2,493**	42
Light oil (bbl/d)	**308**	331	435	**327**	448
Heavy oil (bbl/d)	**39**	29	15	**34**	5
NGLs (bbl/d)	**1,814**	1,220	64	**1,048**	72
Natural gas (mcf/d)	**51,817**	36,723	1,561	**30,089**	1,476
Total (boe/d)	**15,058**	10,797	793	**8,918**	813
Oil and condensate % of production	**31%**	32%	59%	**32%**	61%
NGL % of production	**12%**	11%	8%	**12%**	9%
Natural gas % of production	**57%**	57%	33%	**56%**	30%
Realized prices					
Condensate ($/bbl)	**80.70**	76.60	43.02	**78.97**	55.45
Light oil (bbl/d)	**81.61**	75.61	46.59	**73.92**	48.01
Heavy oil (bbl/d)	**61.90**	57.85	31.06	**56.35**	31.06
NGLs ($/bbl)	**49.74**	42.04	11.15	**46.02**	5.75
Natural gas ($/mcf)	**5.12**	4.06	2.38	**4.67**	2.19
Natural gas ($/GJ)	**4.78**	3.79	1.95	**4.36**	1.81
Total ($/boe)	**48.29**	43.01	32.74	**46.17**	34.01
Royalty expense ($/boe)	**(6.49)**	(2.60)	(3.48)	**(4.83)**	(3.13)
Operating expenses ($/boe)	**(6.69)**	(8.10)	(9.07)	**(7.32)**	(9.58)
Transportation expenses ($/boe)	**(3.98)**	(4.36)	(0.68)	**(4.05)**	(0.73)
Operating netback[1] ($/boe)	**31.13**	27.95	19.51	**29.98**	20.57
Risk management contract realized losses	**(11.82)**	(1.19)	-	**(8.82)**	-
Operating netback including risk management contract realized losses[1] ($/boe)	**19.31**	26.76	19.51	**21.15**	20.57
Financial results ($000s, except per share amounts)					
Commodity sales	**66,898**	42,262	2,388	**112,401**	7,572
Cash flow from operating activities	**29,643**	(15,742)	399	**10,300**	(884)
Adjusted funds from operations[1]	**28,221**	17,904	(540)	**44,577**	(989)
Per share basic	**0.82**	0.06	(0.04)	**1.61**	(0.08)
Per share diluted	**0.82**	0.06	(0.04)	**1.61**	(0.08)
Net income (loss)	**(29,680)**	16,899	(3,545)	**(70,400)**	(14,601)
Per share basic	**(0.86)**	0.06	(0.03)	**(2.19)**	(0.11)
Per share diluted	**(0.86)**	0.06	(0.03)	**(2.19)**	(0.11)
Capital expenditures prior to acquisitions	**(14,753)**	(3,871)	(3,644)	**(18,941)**	(5,458)
Acquisitions	**-**	(276,298)	-	**(282,414)**	-

	Q3 2021	Q2 2021	Q3 2020	YTD 2021	YTD 2020
Balance sheet ($000s, except share amounts)					
Total assets	**588,152**	572,401	120,218	**588,152**	120,218
Long-term liabilities	**138,034**	142,838	4,308	**138,034**	4,308
Net (debt) surplus[1]	**(36,936)**	(42,105)	36,932	**(36,936)**	36,932
Adjusted working capital[1]	**(4,316)**	18,139	36,932	**(4,316)**	36,932
Weighted average shares outstanding	**34,321,566**	29,506,311	13,305,730	**27,667,430**	12,960,638
Shares outstanding end of period	**43,610,140**	33,436,940	14,516,961	**43,610,140**	14,516,961

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 MDA.

Highlights

- KRC and Distinction announced an agreement to combine on June 28, 2021 under the Arrangement whereby KRC acquired all shares of Distinction that it did not already own (approximately 48%) by way of an exchange of 20 KRC shares for each Distinction share. The transaction closed on September 22, 2021. Following the combination the Corporation will operate as Kiwetinohk Energy Corp.
- The Corporation completed a ten to one share consolidation upon closing of the Distinction plan of arrangement.
- Produced an average of 15,058 boe/d in the third quarter of 2021 on a consolidated basis representing a significant increase compared to the same period in 2020.
- Consolidated revenues from production were $66.9 million, a significant increase from the $2.4 million generated in the third quarter of 2020 due to the closing of the Simonette Acquisition and consolidation of Distinction financial and operating results. Condensate, NGLs and oil contributed 63 percent, and gas contributed 37 percent of total revenues in the three months ended September 30, 2021. Revenues have increased due to higher production volumes, as a result of the acquisitions, in combination with significant improvements in realized prices over the comparative periods.
- Net marketing income for the three months ended September 30, 2021 was $5.1 million given the ability to realize greater profits through premium sales contracts in Chicago.
- All of the Kiwetinohk's Alliance pipeline capacity of 103.0 mmcf/d (after temporary assignments) was filled during the third quarter of 2021.
- Adjusted funds flow from operations in the three months ended September 30, 2021 increased to $28.2 million compared to a $0.5 million loss in the three months ended September 30, 2020. The increase is primarily due to the Simonette Acquisition, which has a low operating cost and provides access to rich gas premium sales contracts, and the consolidation of Distinction.
- On September 22, 2021, the Corporation amended and restated its credit agreement and entered into a single $225.0 million Senior Secured Extendible Revolving Facility ("Credit Facility") with a syndicate of banks. The Corporation's available borrowing capacity at September 30, 2021 is $170.0 million after consideration of outstanding letter of credit amounts.
- Invested $12.8 million in exploration and development capital expenditures, excluding acquisition expenditures, during the third quarter. These funded the commencement of drilling for two Duvernay wells in the Simonette area, three Montney wells in the Placid area, one of which was a vertical test of a potential lower Montney zone, and one Clearwater vertical strat test well in the Thorhild area.
- The Corporation hired Janet Annesley as Chief Sustainability Officer and subsequent to quarter end Mike Backus as Chief Operating Officer, Upstream Division.
- Subsequent to September 30, 2021, the Corporation has applied to have its common shares listed on the Toronto Stock Exchange (the "Exchange"). Listing is subject to the approval of the Exchange in accordance with its original listing requirements. The Exchange has not conditionally approved the Corporation's listing application and there is no assurance that the listing application will be approved.

Acquisitions

Simonette Acquisition

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 acquisition closed on April 28, 2021. The purchase price includes up to $15 million of contingent payments that will be required 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 of which $7.5 million of the contingent payments may be settled in common shares of the Corporation at the sole option of the Corporation. The Corporation included an estimated $6.5 million of contingent payment consideration as part of the purchase price of the Simonette Acquisition and subsequently revalued the contingent payment consideration to $11.7 million as at September 30, 2021 , with a $2.4 million and $5.2 million increase in the liability recognized in the consolidated statement of net loss and comprehensive loss for the three and nine months ended September 30, 2021, respectively. The Simonette Acquisition consists of certain multi-zone, oil and liquids-rich natural gas producing assets in the Simonette area of northwest Alberta, including associated infrastructure and additional assets in the Willesden Green, Ferrier and other areas of Alberta. The Simonette Acquisition is aligned with the Corporation's strategy of building an energy transition company focused initially on building a risk-diversified, liquids-rich focused upstream portfolio of Western Canadian oil and gas resource plays. The Simonette Acquisition resulted in a bargain purchase gain of $32.8 million that is mainly attributed to increased reserve value on closing from an increase in forecast pricing.

Settlement agreement

Concurrently, with the closing of the Simonette Acquisition, the Corporation and 1266580 B.C. Ltd., an affiliate of Luminus Energy IE Designated Activity Company ("Luminus Energy"), entered into a settlement agreement to terminate carried interest rights and obligations under a participation agreement made effective by the parties October 16, 2020. A total of $10.0 million was settled and paid to 1266580 B.C. Ltd. as part of the closing procedures of the Simonette Acquisition and has been included in settlement agreement costs in the consolidated statement of net income (loss) and comprehensive income (loss).

Distinction

On October 16, 2020, the Corporation closed its initial investment in Distinction per its previously agreed Investor Agreement whereby the Corporation made a $22.9 million investment in Distinction concurrent with the successful implementation of the restructuring plan to restructure and exit from the Companies' Creditors Arrangement Act ("CCAA"). On January 15, 2021, the Corporation increased its equity ownership in Distinction to 51.6 percent through the exercise of warrants for $40.0 million which included working capital adjustments of $2.5 million.

Following the announcement of the Simonette Acquisition, the management teams of KRC and Distinction began discussions regarding the potential combination of KRC and Distinction. Both management teams believed there would be strategic benefits of a combined entity, including size and scale, aligned corporate strategy, including the consolidation of key assets, improved credit profile, improved access to capital, simplified corporate and management structure, tax benefits, reduced general and administrative expenses and other financial operating efficiencies, as well as upside potential in respect of KRC's integrated energy transition strategy.

On April 6, 2021, Distinction announced the appointment of new KRC executive officers pursuant to the previously disclosed plans and agreements to rebuild Distinction from last year's CCAA process. On April 28, 2021, KRC was able to appoint an independent director onto the Distinction board. As a result, KRC had a controlling interest in Distinction and is actively involved in the day-to-day management and strategic direction of Distinction resulting in the financial and operating results of Distinction being consolidated into KRC effective April 28, 2021.

On June 14, 2021, by way of a private placement, the Corporation purchased 265,331 Class A common shares of Distinction at a price of $15 per Class A common share to maintain an ownership of 51.5 percent following the deemed exercise of 265,331 special warrants.

KRC and Distinction announced an agreement to combine on June 28, 2021 under a plan of arrangement. 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 on August 30, 2021 and the Arrangement closed on September 22, 2021.

Capital expenditures

$000s	Q3 2021	Q2 2021	Q3 2020	YTD 2021	YTD 2020
Land purchases	**203**	181	3,562	**665**	4,705
Drilling, completions, and equipping	**12,820**	1,706	14	**14,551**	624
Facilities	**157**	733	-	**890**	-
Capitalized G&A	**877**	385	-	**1,262**	-
Other	**696**	866	68	**1,573**	129
Total capital	**14,753**	3,871	3,644	**18,941**	5,458
Acquisitions (cash consideration)	**-**	276,298	-	**282,414**	-
Total capital and acquisitions	**14,753**	280,169	3,644	**301,355**	5,458

Acquisitions

The following is a summary of the preliminary Simonette Acquisition and Distinction purchase price allocations:

$000s	Simonette Acquisition	Distinction[1]
Net assets:		
Property, plant and equipment	345,066	107,042
Working capital[2]	1,726	96,269
Risk management contracts	-	(1,245)
Asset retirement obligations	(7,105)	(9,487)
Lease liabilities	(605)	(709)
Deferred tax liability	(9,811)	-
	329,271	191,870
Bargain purchase gain	(32,843)	-
	296,428	191,870
Consideration:		
Cash	282,414	-
Distinction deposit on Simonette Acquisition	7,500	-
Investment[3]	-	96,682
Non-controlling interest[4]	-	95,188
Contingent payment consideration	6,514	-
Total	296,428	191,870

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 $13.02 per share), transaction costs of approximately $1.7 million and an equity gain on investment of $33.8 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 for equity consideration of $101.7 million.

The amounts above are estimates which were made by management at the time of the preparation of this MD&A based on information then available and the purchase price interim statements of adjustments. Amendments may be made to these amounts as values subject to estimate are finalized for a period of up to one year.

The fair value of property, plant and equipment was based on fair value less cost to dispose methodology which utilizes the present value of expected future cash flows before tax with consideration to other market metrics and transactions. The Simonette Acquisition resulted in a bargain purchase gain of $32.8 million that is mainly attributed to an increase in forecast reserve report pricing at the closing date that was used to value property, plant and equipment.

The fair value of decommissioning obligations was estimated by discounting the inflated cost estimates using a credit-adjusted risk-free rate of 15% with a subsequent remeasurement of the decommissioning obligation using a risk-free rate under the Corporation's accounting policy which resulted in an increase and an overall aggregate decommissioning obligation being recorded of $7.1 million and $9.5 million for the Simonette Acquisition and Distinction respectively at acquisition date.

Kiwetinohk fully consolidated the Distinction business effective April 28, 2021. Based on shareholdings of Distinction and changes in the board of directors, the Corporation at that time had a controlling interest in Distinction. The Corporation fair valued its 51.5 percent equity interest in Distinction immediately prior to consolidation based on the net assets acquired. No consideration was transferred upon the Corporation gaining control of Distinction and the non-controlling interest was recorded at fair value.

Land purchases

The following is a summary of the total consolidated sections that the Corporation has acquired or earned (net of expiries) as of September 30, 2021:

Area name	Gross sections	Net sections
Fox Creek		
Placid	202.0	133.3
Simonette	219.0	219.0
West Simonette	12.0	12.0
Total Fox Creek	**433.0**	**364.3**
Thorhild Region	**90.8**	**88.4**
West Central Alberta Region	**357.1**	**314.4**
Miscellaneous	**152.4**	**93.4**
Total	**1,033.2**	**860.4**

The Simonette Acquisition, which closed on April 28, 2021 contributed approximately 400 gross sections (380 net sections) of various rights in the Simonette, Willesden Green and other areas of Alberta as of the acquisition date. Additionally, as of April 28, 2021, the Corporation controls Distinction which resulted in an additional approximately 202 gross (133 net) sections in the Placid area of Alberta. Kiwetinohk now has a broad and diversified scope of diversified development opportunities with over 80% of the Corporation's land base currently undeveloped.

Drilling

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

	Area			Total	
(wells)	Thorhild	Simonette	Placid	Gross	Net
2020	-	-	-	-	-
Q2 2021	1.0	-	-	1.0	1.0
Q3 2021	1.0	-	-	1.0	1.0
Total	2.0	-	-	2.0	2.0

During the third quarter of 2021 the Corporation commenced drilling two Duvernay horizontal wells from an existing pad in the Simonette area. Rig release occurred in mid-October and mid-November and the Corporation has commenced completion operations and expects to have the two wells onstream in early 2022.

In addition, the Corporation has recently drilled two Placid wells with rig release mid-October and mid-November that were focused on the uppermost of the benches within the Montney. Completion operations and production are anticipated in the first quarter of 2022. A middle bench appears to have interesting properties over a large portion of the land. The Corporation recently cored a vertical test well in order to evaluate the Middle Montney. If petrophysical properties are favorable the Corporation will drill and complete a lateral to test productivity.

The Corporation has drilled its first multi-lateral horizontal well in the Thorhild area and put it on production in June 2021. This initial well encountered unusually heavy and high-viscosity crude oil leading to poor production rates and a decision to shut-in the well. A wide variation in crude oil properties is not uncommon in the Clearwater play. Kiwetinohk is evaluating the next steps for this specific well and has cut core in a recent vertical test well in a different part of the play to assess oil and reservoir characteristics.

Results

Production

	Q3 2021	Q2 2021	Q3 2020	YTD 2021	YTD 2020
Condensate (bbl/d)	**4,261**	3,096	18	**2,493**	42
Light oil (bbl/d)	**308**	331	435	**327**	448
Heavy oil (bbl/d)	**39**	29	15	**34**	5
NGLs (bbl/d)	**1,814**	1,220	64	**1,048**	72
Natural gas (mcf/d)	**51,817**	36,723	1,561	**30,089**	1,476
Total (boe/d)	**15,058**	10,797	793	**8,918**	813
Oil and condensate % of production	**31%**	32%	59%	**32%**	61%
NGL % of production	**12%**	11%	8%	**12%**	9%
Natural gas % of production	**57%**	57%	33%	**56%**	30%
Total production volumes %	**100%**	100%	100%	**100%**	100%

Production in the three months ended September 30, 2021 averaged 15,058 boe/d, a significant increase of approximately 1,800% from the comparative period in 2020. This significant increase in the average production in the third quarter of 2021 compared to the same period in 2020 is due to production volumes associated with the Simonette Acquisition and consolidation of Distinction commencing on April 28, 2021. In the three months ended September 30, 2021, the Simonette Acquisition contributed an average of 8,020 boe/d of total corporate production and Distinction contributed an average of 6,463 boe/d.

Production in the first nine months of 2021 averaged 8,918 boe/d, a significant increase of approximately 1,000% from the comparative period in 2020 due to the acquisitions as described above.

Production from the Simonette Acquisition and Distinction assets both deliver high liquids content natural gas with the Corporation now having an average liquid yield of approximately 117 bbls/mmcf.

The Corporation's production portfolio for the third quarter of 2021 was weighted 31% percent to oil and condensate, 12% percent to NGLs and 57% percent to natural gas. The production portfolio for the comparative quarter in 2020 was 59% percent to oil and condensate, 9% percent to natural gas liquids and 32% percent to natural gas.

Benchmark and realized prices

	Q3 2021	Q2 2021	Q3 2020	YTD 2021	YTD 2020
Liquid benchmark prices					
WTI (US$/bbl)	**67.60**	66.12	40.92	**62.47**	38.34
WTI (CDN$/bbl)	**88.93**	81.07	54.48	**81.10**	51.54
Edmonton Light (CDN$/bbl)	**83.04**	77.35	49.74	**75.63**	43.67
WCS Hardisty (CDN$/bbl)	**72.62**	67.10	42.34	**65.73**	32.88
Natural gas benchmark prices					
Henry Hub (US$/MMBtu)	**4.01**	2.83	2.14	**3.18**	1.92
Chicago City Gate MI (US $/MMBtu)	**3.07**	2.74	1.87	**3.86**	1.81
Chicago City Gate DI (US $/MMBtu)	**4.10**	2.81	1.84	**5.39**	1.74
AECO 5A (CDN $/GJ)	**3.41**	2.93	2.12	**3.11**	1.98
AECO 7A (CDN $/GJ)	**2.94**	2.70	2.04	**3.36**	1.96
Alberta Power					
Daily ($/MWh)	**100.33**	104.73	43.75	**100.12**	46.69
Daily on Peak ($/MWh)	**121.19**	130.52	52.44	**117.82**	55.10
Foreign exchange rates	**0.79**	0.81	0.75	**0.80**	0.74

	Q3 2021	Q2 2021	Q3 2020	YTD 2021	YTD 2020
Realized prices					
Condensate ($/bbl)	**80.70**	76.60	43.02	**78.97**	55.45
Light oil (bbl/d)	**81.61**	75.61	46.59	**73.92**	48.01
Heavy oil (bbl/d)	**61.90**	57.85	31.06	**56.35**	31.06
NGLs ($/bbl)	**49.74**	42.04	11.15	**46.02**	5.75
Natural gas ($/mcf)	**5.12**	4.06	2.38	**4.67**	2.19
Natural gas ($GJ)	**4.78**	3.79	1.95	**4.36**	1.81
Combined ($/boe)	**48.29**	43.01	32.74	**46.17**	34.01

WTI benchmark prices have increased significantly in the three and nine months ended September 30, 2021 over the comparative periods in 2020. The increases are primarily due to the global economic recovery and the return of energy demand as jurisdictions around the world opened-up in the post COVID-19 pandemic environment as well as restricted supply from the Organization of Petroleum Exporting Countries ("OPEC") and Russia. This has resulted in a decrease in global crude oil supplies through the first half of 2021. The markets are expected to remain volatile as the industry balances supply and demand concerns due to the uncertainty around the timing and extent of a COVID-19 recovery.

Similar to WTI, Edmonton Light benchmark pricing experienced increases and averaged $83.04 per barrel in the third quarter of 2021 compared to $49.74 per barrel in the third quarter of 2020.

Natural gas prices have increased in 2021 due to low storage levels, a decrease in supply and U.S. natural gas exports which have continued to drive an increase in year-over-year demand and pricing. The Chicago City Gate monthly index benchmark natural gas for the three and nine months ended September 30, 2021 increased 62% and 133% percent, respectively in comparison to the same periods in 2020. The Chicago City Gate daily index benchmark for natural gas for the three and nine months ended September 30, 2021 increased 122% and 209% percent, respectively in comparison to the same periods in 2020.

AECO 5A prices increased 61% percent and 59% percent, respectively in the three and nine months ended September 30, 2021 in comparison to the same periods in 2020. Canadian natural gas pricing has strengthened due to strong domestic demand for inventory injections as well as increases in pipeline exports.

The Alberta provincial power price averaged $100.33 per MWh in the third quarter of 2021, an increase of 129% percent compared to the third quarter of 2020 as a result of expiring Alberta Power Purchase Agreements, higher natural gas prices and an overall demand recovery along with planned maintenance outages in Alberta.

Detailed realized US gas sales pricing summary

Chicago - US$/MMBtu	Q3 2021	Q2 2021	Q3 2020[1.]	YTD 2021[1.]	YTD 2020[1.]
Chicago City Gate DI	**4.10**	2.81	-	**3.45**	-
Rich gas premium and other	**0.06**	0.14	-	**0.16**	-
Realized price before hedging	**4.16**	2.95	-	**3.61**	-
% of Chicago City Gate MI	**101%**	105%	-	**105%**	-

1 – YTD pricing is from May 2021 onwards to be consistent with the Simonette Acquisition and Distinction business combination.

The Corporation has 90.3 mmcf/d of firm Alliance Pipeline transportation service to Chicago through October 31, 2025. This allows the Corporation to benefit from a rich gas premium agreement for equivalent volumes with Aux Sable whereby liquids contained within the natural gas are extracted, fractionated and sold into the U.S. Midwest refining and petrochemical market, and the remaining natural gas sold into the Chicago area marketplace and interconnecting markets. Prior to the completion of the Arrangement, Kiwetinohk purchased Distinction's natural gas volumes from Simonette at the plant gate and then sold total Simonette natural gas volumes in Chicago under a rich gas premium contract. Following the completion of the Arrangement, these amounts are now sold on a consolidated basis.

Kiwetinohk also has a separate independent transportation agreement with Alliance, which it inherited in the acquisition of Distinction, to deliver 29.7 mmcf/d of natural gas volumes until October 31, 2025 to Chicago that do not receive the same rich gas premium.

Detailed realized Canadian gas sales pricing summary

AECO – CDN $/GJ	Q3 2021	Q2 2021	Q3 2020	YTD 2021	YTD 2020
AECO 5A	**3.41**	2.93	2.21	**3.11**	1.98
Heating content and other	**(0.09)**	0.09	(0.26)	**0.02**	(0.17)
Realized price before hedging	**3.32**	2.90	1.95	**3.13**	1.81
% of AECO 5A	**97%**	99%	88%	**101%**	91%

Kiwetinohk sells natural gas from its Placid property in the Chicago market through the Alliance pipeline system and in the AECO market through the Nova Gas Transmission Ltd. ("NGTL") system. Natural gas that is sweetened at the Corporation's amine facility is further processed at its 25 percent owned sweet natural gas plant ("Bigstone Sweet Plant") which is currently only connected to the NGTL pipeline system. The Alliance meter station at the Bigstone Sweet Plant is expected to be reactivated in the first quarter of 2022 which will allow the Corporation to transport its natural gas on the NGTL and Alliance pipeline systems.

The Corporation has 0.3 mmcf/d of NGTL service which expires in mid-2023, and a separate and independent NGTL contract with Distinction for approximately 20.2 mmcf/d expiring on March 31, 2026.

Detailed realized Canadian condensate and NGL sales pricing summary

Condensate - CDN$/bbl	Q3 2021	Q2 2021	Q3 2020	YTD 2021	YTD 2020
WTI	**88.93**	81.07	54.48	**81.10**	51.54
Edmonton condensate to WTI Differential	**(1.32)**	0.60	(3.38)	**(0.26)**	(1.33)
Edmonton condensate	**87.61**	81.67	51.10	**80.84**	50.21
Differential and other	**(6.91)**	(3.77)	(8.08)	**(1.87)**	5.24
Realized price before hedging	**80.70**	77.90	43.02	**78.97**	55.45
% of Edmonton Condensate	**92%**	95%	84%	**98%**	110%

Realized field condensate prices before risk management contracts were significantly higher in the three and nine months ended September 30, 2021 compared to the same period in 2020 due to the improvement in the Edmonton condensate benchmark price. Canadian condensate differentials improved over the comparative periods as oil sands productions increased, creating demand for condensate as a diluent. Based on location and quality differentials from the production related to the Simonette Acquisition and Distinction business combination the realized price relative to Edmonton Condensate benchmark pricing has increased from the comparative quarter in 2021.

NGLs - CDN$/bbl	Q3 2021	Q2 2021	Q3 2020	YTD 2021	YTD 2020
Realized price before hedging	**49.74**	42.04	11.15	**46.02**	5.75
% of Edmonton Condensate	**56.8%**	51.6%	25.9%	**56.9%**	10.4%

The Corporation's realized price for natural gas liquids for the three and nine months ended September 30, 2021 has significantly increased compared to the same periods in 2020. The increase in average natural gas liquids price is due to an improvement in benchmark pricing, as well as a change in the composition of the Corporation's natural gas liquids.

Risk management contracts

In an effort to mitigate commodity price fluctuations for natural gas, crude oil and natural gas liquids, the Corporation enters into financial commodity contracts as part of its risk management program designed to protect cash flows for its base production. Risk management contracts are entered into at prices significantly above operating costs per boe, and all risk management contracts are entered into at 35 to 75 percent in the short to medium term of existing production, ensuring the Corporation retains its ability to cover all outstanding risk management liabilities when they arise. Additionally, the Corporation regularly reviews its credit exposure for counterparties that volumes are purchased from or sold to. The Corporation has the following risk management contracts outstanding as of September 30, 2021:

Foreign exchange

Time Period	Average	Units	Type	Price ($/unit)	Reference price
October 2021	$5.6 MM	$USD/month	Put	$1.227	$CAD to $US

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

Crude oil contracts:

	2021		2022		2023	
Crude Oil - WTI	**$CAD/unit**	bbl/day	**$CAD/unit**	bbl/day	**$CAD/unit**	bbl/day
Swap	73.91	3,370	69.95	750	82.60	900
Collar						
Bought put price	-	-	65.00	2,100	-	-
Sold call price	-	-	76.68	2,100	-	-

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

Natural gas contracts:

	2021		2022		2023	
NYMEX	**$USD/unit**	mmbtu/d	**$USD/unit**	mmbtu/d	**$USD/unit**	mmbtu/d
Swap	2.92	25,500	2.86	18,900	3.53	9,375
NGI Chicago	**$USD/unit**	mmbtu/d	**$USD/unit**	mmbtu/d	**$USD/unit**	mmbtu/d
Basis Swap - Sale	(0.07)	18,650	(0.05)	16,475	0.01	9,375
AECO 5A	**$CAD/unit**	GJ/d	**$CAD/unit**	GJ/d	**$CAD/unit**	GJ/d
Swap	2.20	4,725	2.18	2,150	**-**	-
AECO 5A	**$USD/unit**	mmbtu/d	**$USD/unit**	mmbtu/d	**$USD/unit**	mmbtu/d
Basis Swap - Purchase	1.00	52,500	(0.70)	40,000	-	-
GDD Chicago	**$USD/unit**	mmbtu/d	**$USD/unit**	mmbtu/d	**$USD/unit**	mmbtu/d
Basis Swap - Sale	1.53	52,500	0.27	40,000	**-**	-

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

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 consolidated statement of net income (loss) and comprehensive income (loss).

The fair value of the Corporation's risk management contracts outstanding as at September 30, 2021 is estimated to be a net liability of $64.0 million. 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.

Fair value of risk management contracts

$ 000's	September 30, 2021	December 31, 2020
Natural gas contract	36,155	-
Crude oil contracts	27,621	-
Foreign exchange contracts	218	-
Total risk management contracts	63,994	-

For the three and nine months ended September 30, 2021, the Corporation recorded an unrealized loss on its risk management contracts of $35.7 million and $63.8 million, respectively. The unrealized loss recognized is the difference between the fair values of the risk management contracts outstanding as at September 30, 2021 and the fair values at the beginning of the period. The increase in the fair value liability of the risk management contracts as at September 30, 2021 reflects higher forward pricing for WTI crude oil contracts and natural gas contracts compared to the Corporation's contracted prices.

Subsequent to September 30, 2021, the Corporation entered into the following risk management contracts:

Natural gas contracts:

	2021		2022		2023	
AECO 5A	**$USD/unit**	mmbtu/d	**$USD/unit**	mmbtu/d	**$USD/unit**	mmbtu/d
Basis Swap - Purchase	(0.27)	40,000	(1.33)	23,000	-	-
GDD Chicago	**$USD/unit**	mmbtu/d	**$USD/unit**	mmbtu/d	**$USD/unit**	mmbtu/d
Basis Swap - Sale	(0.07)	40,000	0.05	23,000	**-**	-

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

Operating netback

$/boe	Q3 2021	Q2 2021	Q3 2020	YTD 2021	YTD 2020
Realized price	**48.29**	43.01	32.74	**46.17**	34.01
Royalty recovery/(expense) ($/boe)	**(6.49)**	(2.60)	(3.48)	**(4.83)**	(3.13)
Operating expenses ($/boe)	**(6.69)**	(8.10)	(9.07)	**(7.32)**	(9.58)
Transportation expenses ($/boe)	**(3.98)**	(4.36)	(0.68)	**(4.05)**	(0.73)
Operating netback[1]	**31.13**	27.95	19.51	**29.98**	20.57
Daily Sales Volume (boe/d)	**15,058**	10,797	793	**8,918**	813

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 increased by 11 percent to $31.13 per boe in the third quarter of 2021 as compared to $27.95 per boe in the second quarter of 2021 due to the benefit of higher commodity prices in the quarter and lower operating expenses offset by some prior period adjustments in royalties.

Revenue

$000s	Q3 2021	Q2 2021	Q3 2020	YTD 2021	YTD 2020
Condensate	**31,636**	21,580	72	**53,759**	642
Light oil	**2,312**	2,275	1,865	**6,604**	5,888
Heavy oil	**224**	155	44	**523**	44
NGLs	**8,300**	4,668	66	**13,171**	113
Natural gas	**24,426**	13,583	341	**38,345**	885
Total	**66,898**	42,262	2,388	**112,401**	7,572

Revenues increased by $24.6 million during the third quarter of 2021 as compared to $42.3 million in the second quarter of 2021. Higher revenues were realized as the Corporation operated the Simonette and Distinction assets for a full quarter as compared to two months during the second quarter of 2021. In addition, commodity prices continued to remain strong during the third quarter of 2021.

Marketing

$000s	Q3 2021	Q2 2021	Q3 2020	YTD 2021	YTD 2020
Marketing revenue					
Sale of purchased natural gas	**38,349**	17,771	-	**56,120**	-
Marketing expense					
Cost of purchased natural gas	**25,576**	13,903	-	**39,479**	-
Transportation of purchased natural gas	**6,694**	4,428	-	**11,122**	-
Tariff on temporary assignment	**935**	607	-	**1,542**	-
Total marketing expense	**33,205**	18,938	-	**52,143**	-
Net marketing income (loss) [1]	**5,144**	(1,167)	-	**3,977**	-
$/boe	**3.71**	(1.19)	-	**1.63**	-

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 MDA.

The Corporation has 120 mmcf/d of firm transportation service with an additional 7.5 mmcf/d of priority interruptible service on the Alliance pipeline system from Alberta to Chicago with access to rich gas premium pricing on 90.3 mmcf/d from Aux Sable.

On a consolidated basis, the Corporation has natural gas production which used approximately 30% of the firm transportation commitment during the third quarter of 2021. In order to mitigate the cost of transportation service in excess of its needs, the Corporation purchases available natural gas volumes in Alberta and/or British Columbia and resells these volumes in Chicago. The Corporation 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. In the fourth quarter of 2020, Distinction temporarily assigned approximately 17.0 mmcf/d of excess Alliance service through to October 31, 2021 for approximately 50 percent of the associated tariff.

In the three and nine months ended September 30, 2021, the Corporation realized a gain of $5.1 million and $4.0 million, respectively on its marketing activities associated with purchasing natural gas to fulfill its transmission commitment on the Alliance pipeline system based on the arbitrage between the Chicago and AECO benchmark and losses on temporary assignments.

Royalties

$000s	Q3 2021	Q2 2021	Q3 2020	YTD 2021	YTD 2020
Royalty expense	**8,987**	2,559	254	**11,759**	697
As a % of revenue	**13%**	6%	11%	**11%**	9%
$/boe	**6.49**	2.60	3.48	**4.83**	3.13

The Corporation pays crown, freehold, and overriding royalties on production volumes. Production from wells drilled subsequent to January 1, 2017 qualify for reduced Crown royalty rates under the Modern Royalty Framework which currently imposes a five percent royalty rate until certain conditions are met. The Corporation 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.

Royalties in the third quarter of 2021 increased to $9.0 million as a result of higher pricing, additional royalties attributed to the Simonette Acquisition and Distinction business combination being reflected for a full quarter and some additional prior period adjustments being recorded. The overall royalty rate for the nine months ended September 30, 2021 of 10.5% reflects the benefit from estimated gas cost allowance credits on the Simonette Acquisition which was able to offset some of the royalty increase on Distinction wells which are in part burdened with higher Crown rates from wells under the old royalty regime along with wells that have come off of royalty holidays. When a well comes off of royalty holiday, under the old royalty regime, 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).

Operating expenses

$000s	Q3 2021	Q2 2021	Q3 2020	YTD 2021	YTD 2020
Operating expenses	**9,271**	7,954	661	**17,811**	2,132
$/boe	**6.69**	8.10	9.07	**7.32**	9.58

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 of $6.69 per boe in the third quarter of 2021 were lower by 17 percent on a per barrel basis compared to the second quarter of 2021. The decrease in operating costs is a result of cost savings associated with 100% owned and operated infrastructure in the Simonette property and reversal of prior period accruals now that the Corporation has a greater history and understanding of the property with a continued focus on overall cost savings.

Transportation expenses

$000s	Q3 2021	Q2 2021	Q3 2020	YTD 2021	YTD 2020
Transportation expenses	**5,520**	4,287	50	**9,854**	163
$/boe	**3.98**	4.36	0.68	**4.05**	0.73

Transportation costs are incurred to deliver oil and natural gas commodities from the Corporation's production to the delivery point of sale. Prior to the Simonette Acquisition and Distinction business combination the Corporation did not have any significant transportation costs. The Corporation 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 from operations

$000s	Q3 2021	Q2 2021	Q3 2020	YTD 2021	YTD 2020
Cash flow from (used) in operating activities	**29,643**	(15,742)	399	**10,300**	(884)
Change in non-cash operating working capital	**(4,087)**	18,008	(940)	**15,322**	(105)
Restructuring costs	**1,617**	832	-	**2,449**	-
Acquisition costs	**1,048**	4,806	-	**6,506**	-
Settlement costs	**-**	10,000	-	**10,000**	-
Adjusted funds from operations[1]	**28,221**	17,904	(541)	**44,577**	(989)
$/boe	20.37	18.22	(7.41)	18.31	(0.08)

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 $28.2 million and $44.6 million, respectively for the three and nine months ended September 30, 2021 as a result of the Simonette Acquisition and Distinction business combination now being reflected for a full quarter. The Corporation's cash flow used in operating activities was $29.6 million and $10.3 million for the three and nine months ended September 30, 2021. Cash flow used in operating activities has been adjusted for changes in non-cash operating working capital, non-recurring restructuring costs associated with Distinction's CCAA process, acquisition costs to complete the Simonette Acquisition and Distinction business combination and $10.0 million in one-time settlement costs to terminate certain carried interest rights and obligations (see – "Settlement agreement" section of this MD&A).

Other income

$000s	Q3 2021	Q2 2021	Q3 2020	YTD 2021	YTD 2020
Share in earnings of associate and excess fair value	**-**	(15,182)	-	**(21,251)**	-

The Corporation had a 51.6 percent ownership interest in Distinction and prior to April 28, 2021 accounted for its investment under the equity method. As of April 28, 2021, the Corporation obtained control over Distinction and began to consolidate the results of Distinction. The year to date $21.3 million gain is in part due to a $0.5 million share in Distinction's earnings through April 28, 2021 with $20.8 million to related a revaluation of the investment to the estimated net asset fair value on April 28, 2021.

General and administrative ("G&A") expenses

$000s	Q3 2021	Q2 2021	Q3 2020	YTD 2021	YTD 2020
G&A expenses	**2,825**	2,783	1,340	**7,604**	3,938
Less management fee	**-**	(314)	-	**(957)**	-
Net G&A	**2,825**	2,469	1,340	**6,647**	3,938
$/boe	**2.04**	2.51	18.37	**2.73**	17.69

G&A expenses increased to $2.8 million in the third quarter of 2021 as compared to the prior year quarter. This is a 15% increase compared to the second quarter of 2021 and is a direct result of increased activity levels, staffing costs from employees and consultants and other related expenses to support the growing business. G&A on a $/boe basis is lower relative to the second quarter of 2021 due to cost savings with the amalgamation of two entities.

A significant portion of employee and consultant G&A activity continues to be directly related to business development initiatives on a strategy to capture a larger portion of the hydrocarbons value chain by securing access to the downstream markets of power, petrochemicals, and LNG/LPG. As a result, G&A expenses on a $ per boe basis were considerably higher prior to reporting production from the Simonette Acquisition and Distinction business combination.

The Corporation continued to provide management services to Distinction based on an agreed fee-per-boe basis that commenced in October 2020 until the Distinction amalgamation which occurred on September 22, 2021. Management fees incurred during the three and nine months ended September 30, 2021, from consolidation of Distinction on April 28, 2021 have been fully eliminated in the consolidated statement of net income (loss) and comprehensive income (loss).

G&A expenses exclude restructuring costs related to Distinction that are one time and non-recurring.

Exploration and evaluation expense (“E&E”)

$000s	Q3 2021	Q2 2021	Q3 2020	YTD 2021	YTD 2020
E&E other	**18**	2,159	640	**3,127**	2,013
E&E depletion	**560**	1,025	2,335	**4,546**	11,451
E&E impairment	**1,400**	-	-	**47,415**	-
Total	**1,978**	3,184	2,975	**55,088**	13,464

The Corporation is continuously evaluating various projects and upstream business opportunities, which are expensed as incurred until the Corporation has purchased the related land and has a legal right to explore. The Corporation 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 depletion in the second quarter of 2021 is as a result of production declines and a lower E&E balance subject to depletion.

With the Simonette Acquisition and associated lands acquired, the Corporation 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 $46.0 million. Additionally, the Corporation recognized $1.4 million in exploration and evaluation expenses during the three and nine months ended September 30, 2021 for well costs incurred during the second quarter of 2021 on a new drill in the Clearwater play which may not be fully recoverable based on well performance to date.

Share-based compensation

$000s	Q3 2021	Q2 2021	Q3 2020	YTD 2021	YTD 2020
Share-based compensation	**2,486**	**3,740**	548	**10,156**	1,617

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 the vesting period. The expense is based on a graded vesting pattern by tranche, which results in a higher upfront expense that is recorded in the earlier years. Share-based expense decreased by $1.3 million in the third quarter of 2021 from the second quarter of 2021 and increased by $1.9 million from the prior year quarter. Adjusting for the 10:1 share consolidation, the Corporation granted 1.3 million options and 5.0 million performance warrants during the nine months ended September 30, 2021 and also assumed 0.6 million Distinction options.

Income taxes

The Corporation did not pay any income taxes in 2021 and does not expect to be taxable in the near future. The Corporation initially recognized a deferred tax liability of $9.5 million on the Simonette Acquisition and Distinction business combination where tax pools acquired were less than the accounting basis. This was subsequently recovered through the consolidated statement of net income (loss) and comprehensive income (loss) as the Corporation has sufficient tax pools however a deferred tax asset has not been recognized given the uncertainty of future realization.

Asset retirement obligations

The Corporation's asset retirement obligations ("ARO") of $87.8 million pertain to the Corporation's wells and related infrastructure with the large increase in the quarter 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 $29.5 million of inactive 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 three to five years.

Environmental sustainability is a key focus area of the Corporation 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 Corporation'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 Corporation's combined LMR after the Distinction amalgamation is 5.91.

Select quarterly information

	2021			2020				2019
$000s	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Production (boe/d)	**15,058**	10,797	741	645	793	443	1,204	1,582
Commodity sales ($000)	**66,898**	42,262	3,242	2,186	2,388	1,306	3,879	7,017
Cash flow from operating activities	**29,643**	(15,742)	(3,579)	(777)	399	(1,776)	493	3,884
Per share (basic)	**0.86**	(0.05)	(0.02)	(0.01)	-	(0.01)	-	0.03
Per share (diluted)	**0.86**	(0.05)	(0.02)	(0.01)	-	(0.01)	-	0.03
Net income (loss)	**(29,680)**	16,899	(46,267)	9,732	(3,545)	(3,261)	(7,795)	(10,679)
Per share (basic)	**(0.86)**	(0.06)	(0.24)	0.06	(0.03)	(0.03)	(0.06)	(0.08)
Per share (diluted)	**(0.86)**	(0.06)	(0.24)	0.06	(0.03)	(0.03)	(0.06)	(0.08)

On November 23, 2021, the Corporation had 43,598,103 common shares issued and outstanding.

As a result of the Simonette Acquisition and Distinction consolidation, which both occurred on April 28, 2021, the Corporation had a significant increase to production and operating results in the second quarter of 2021. The loss on risk management contracts in the third quarter of 2021 contributed to the net loss during the period.

Capital resources and liquidity

The Corporation's objective when managing its capital is to maintain a conservative structure that will allow it to provide financial flexibility to execute on strategic and new business opportunities. It relies on current production, cash on hand, and future equity issuances to fund its capital demands. The Corporation anticipates sufficient cash flow from operations from the Simonette Acquisition and availability on its credit facility in order to meet working capital requirements and fund anticipated drilling on the Simonette Acquisition and Distinction acreage for the remainder of the 2021 / 2022 winter drilling season.

Credit facility

The Corporation has secured a combined $225.0 million senior credit facility from a syndicate of banks of which $96.3 million was initially drawn to fund the Simonette Acquisition. At September 30, 2021 the Corporation had $34.2 million (before issues costs) outstanding on the Credit Facility along with $20.8 million in letters of credit to support transportation and other commitments. Subsequent to September 30, 2021, the Corporation entered into additional letters of credit of approximately $31.0 million to support natural gas purchases to fill the Alliance pipeline. Additionally, the Corporation increased its operating facility to $65 million.

$000	Authorized	Drawn	Letters of credit	Capacity
Kiwetinohk credit facility	225,000	34,178	20,837	169,985

$000s	September 30, 2021
Credit facility drawn	34,178
Less deferred financing costs	(1,558)
Loans and borrowings per balance sheet	32,620

$000s	September 30, 2021	December 31, 2020
Current assets	40,797	57,692
Current liabilities	(93,280)	(3,291)
Working capital surplus (deficit)	(52,483)	54,401
Plus current fair value of risk management contract liability	48,167	-
Adjusted working capital surplus (deficit)[1]	(4,316)	54,401
Plus credit facility capacity	169,985	-
Available funding[1]	165,669	54,401

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 MDA.

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 based on the lenders' evaluation of the Corporation'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 Corporation. The applicable margins and stamping fees are based on a sliding scale pricing grid tied to the Corporation's debt to earnings before interest, taxes, depreciation and amortization 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 Corporation's debt to EBITDA ratio.

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

Moving forward the Corporation plans to use its 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 funds flow from operations ratio of no more than 1.0 times.

Share capital

The Corporation is authorized to issue an unlimited number of voting common shares. During the second quarter of 2021, the Corporation fully drew on its remaining equity line of credit and the Corporation raised $33.4 million in a private placement for $334.3 million in total aggregate equity proceeds since inception.

As part of the Arrangement, Kiwetinohk issued 10.2 million (post consolidation) common shares and acquired all of the Distinction common shares not already owned and consolidated the outstanding Kiwetinohk common shares, stock options and performance warrants on a 10 to 1 basis with capital warrants being cancelled at the same time. The share consolidation has been retroactively presented in the following table.
Kiwetinohk also inherited the Distinction reporting issuer status as part of the Arrangement.

(000s)	3-months ended September 30, 2021	3-months ended September 30, 2020	9-months ended September 30, 2021	Year ended December 31, 2020
Weighted average shares outstanding				
Basic	**34,322**	13,306	**27,667**	12,961
Diluted	**34,322**	13,306	**27,667**	12,961
Outstanding securities				
Common shares	**43,610**	14,517	**43,610**	18,724
Stock options	**3,217**	1,234	**3,217**	1,288
Performance warrants	**7,609**	2,470	**7,609**	2,579
Capital warrants	**-**	2,007	**-**	2,007
Total diluted outstanding securities	**54,436**	20,228	**54,436**	24,598

Commitments

$000s	2021	2022	2023	2024	2025	Thereafter
Gathering, processing and transport[1]	15.1	61.6	62.5	64.6	56.4	56.9
Natural gas purchases	29.2	97.2	-	-	-	-
Office, equipment and software	0.1	0.2	0.1	-	-	-
Accounts payable	33.8	-	-	-	-	-
Credit facility	-	2.0	38.0	-	-	-
Other	0.5	0.4	0.4	0.4	0.4	1.4
Total	78.7	161.4	101.0	65.0	56.8	58.3

1 – Gas transportation contracts include Alliance commitments of 90.3 mmcf/d related to the Simonette Acquisition, 29.7 mmcf/d related to Distinction in addition to various NGL and condensate transportation commitments and other processing commitments.

As part of the Simonette Acquisition, the Corporation 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 Corporation is able to capture a rich gas premium price based on the Aux Sable contract through October 2023. Through Distinction the Corporation 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 do not receive the same rich gas premium.

The Corporation currently has secured approximately 90 thousand GJ per day of gas supply from several natural gas producers through 2022, allowing the Corporation to fully utilize its Alliance pipeline capacity and Aux Sable rich gas premium contract. As a result, the Corporation is able to use proceeds from purchased gas volumes sold to meet all of its transportation and purchase commitments. The Corporation generated $5.1 million in net marketing income during the third quarter of 2021 on purchased gas.

At September 30, 2021 the Corporation has an available borrowing capacity of $170.0 million. With sufficient capacity on its credit facility and anticipated positive cash flows from operating activities the Corporation expects to have the ability to meet all of its commitments during the next twelve months at a minimum.

Related Party Information

For the three months and nine months ended September 30, 2021, the Corporation incurred a total of $0.9 million and $1.9 million, respectively (September 30, 2020 - $0.5 million and $0.8 million), on the following related party transactions:

- The Corporation has retained a law firm to provide legal services on corporate matters. A director of the Corporation is a partner of this law firm.
- The Corporation has engaged an energy information services company to assist in the evaluation of prospective upstream oil and gas properties. A director of the Corporation is the CEO of this firm.
- The Corporation is working with an upstream oilfield services company. A VP of the Corporation is the president of this oilfield services company. Subsequent to September 30, 2021 the VP has resigned from the upstream oilfield service company.

Upon closing of the Arrangement with Distinction, the Corporation has a net receivable balance of $0.6 million outstanding from previous Directors and employees of Distinction for withholding taxes incurred upon the surrender and exchange of all remaining Distinction restricted share units at the time of closing.

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

Refer to Section – "Highlights" for details of the TSX listing filed subsequent to September 30, 2021.

Refer to Section – "Risk Management Contracts" for risk management contracts entered into subsequent to September 30, 2021.

Refer to Section – "Capital Resources and Liquidity" for letters of credit, increase in operating facility, and additional natural gas purchase commitments.

Health, safety and environmental

The Corporation focuses on conducting transparent, safe, and responsible operations in the communities in which its people live and work.

There is a growing concern related to the risk of climate change and atmospheric pollution, which is motivating a focus on, and reduction of, greenhouse gas emissions. The Corporation is focused on meeting the energy needs of tomorrow with solutions that can demonstrate a movement toward cleaner energy and a reduction in greenhouse gas emissions as Canada transitions to a lower carbon environment. The Corporation is committed to being an energy leader in sustainable exploration and development, while at the same time providing socio-economic benefits to communities impacted by its activities, including Indigenous communities.

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 Corporation'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 Corporation and high involvement of the CEO and CFO in the day-to-day operating activities of the Corporation, there are appropriate disclosure controls and procedures in place to provide reasonable assurance that (i) material information relating to the Corporation is made known to the Corporation's CEO and CFO by others, and (ii) information required to be disclosed by the Corporation to its board of directors is recorded, processed and reported in a timely manner.

Financial reporting

Critical accounting estimates

The significant accounting judgements and estimates used by the Corporation are discussed in Note 3 to the December 31, 2020, 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 and judgments during the three and nine months ended September 30, 2021.

Financial instruments and risk management

The Corporation's financial instruments recognized on the condensed consolidated 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 15 of the Corporation's September 30, 2021 condensed consolidated interim financial statements.

Off-balance sheet arrangements

Except as disclosed in the financial statements, the Corporation has not entered into any guarantee or off balance sheet arrangements that would materially impact the financial position or results of operations as at September 30, 2021.

Other

Risk Factors and Risk Management

Refer to the Corporation's Annual Information Form ("AIF") dated November 23, 2021 and available on the SEDAR website at www.sedar.com for a discussion of the Corporation's risk factors and risk management.

Non-GAAP Measures

Certain information set forth in this document contains non-gaap measures, including "adjusted funds flow from operations", "field netback", "adjusted working capital", "available funding", "net debt" and "net marketing income (loss)". These performance 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 consolidated 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 Corporation 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 revenue less royalty, operating, and transportation expenses on a per unit per production basis.

Operating Netback Including Risk Management Contracts

Operating netback including risk management contracts is operating netback less any risk management contract realized gains or losses on a per unit per production basis.

Adjusted Funds Flow from Operations

Adjusted funds flow from operations is cash flow from operating activities before changes in non-cash working capital from operating activities, decommissioning expenditures, restructuring costs, acquisition costs and settlement agreement costs. Management uses funds flow from operations to analyze performance and considers it a key measure as it demonstrates the Corporation's ability to generate the cash necessary to fund future capital investments, abandonment obligations and to repay debt.

$000s	Q3 2021	Q2 2021	Q3 2020	YTD 2021	YTD 2020
Cash flow from (used) in operating activities	**29,643**	(15,742)	399	**10,300**	(884)
Change in non-cash operating working capital	**(4,087)**	18,008	(940)	**15,322**	(105)
Restructuring costs	**1,617**	832	-	**2,449**	-
Acquisition costs	**1,048**	4,806	-	**6,506**	-
Settlement agreement costs	**-**	10,000	-	**10,000**	-
Adjusted funds from operations	**28,221**	17,904	(540)	**44,577**	(989)

Field Netback

Field Netback is calculated on a total and per boe basis as petroleum and natural gas revenue from production less royalties, operating and transportation expense. Management believes that netback is a key industry benchmark and a measure of performance for the Corporation that provides 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 Working Capital

Adjusted working capital is comprised of current assets less current liabilities excluding the fair value of risk management contracts. Adjusted working capital is used by management to provide a more complete understanding of the Corporation's liquidity. The current fair value 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	September 30, 2021	December 31, 2020
Current assets	40,797	57,692
Current liabilities	(93,280)	(3,291)
Working capital surplus (deficit)	(52,483)	54,401
Plus current fair value of risk management contract liability	48,167	-
Adjusted working capital surplus (deficit)	(4,316)	54,401

Available Funding

Available funding is comprised of adjusted working capital surplus (deficit) plus the available credit facility capacity after deducting drawn amounts and outstanding letters of credit. Available funding is used by management to assess the Corporation's liquidity.

Net Debt

Net debt is comprised of loans and borrowings plus adjusted working capital deficit (surplus) and represents the Corporation's net financing obligations. Net debt is used by management to provide a more complete understanding of the Corporation's capital structure and provides a key measure to assess the Corporation's liquidity.

$000s	September 30, 2021	December 31, 2020
Loans and borrowings	(32,620)	-
Adjusted working capital surplus (deficit)	(4,316)	54,401
Net surplus (debt)	(36,936)	54,401

Net Marketing Income (Loss)
Net marketing income (loss) is revenue from the sale of purchased natural gas less the original commodity purchase, related transportation expense and any related marketing fees. Net marketing income (loss) is used as a key measure of how the Corporation 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 including, without limitation, management's business strategy, management's assessment of future plans and operations. Such forward-looking statements or information are provided for the purpose of providing information about management's current expectations and plans relating to the future. Forward-looking statements or information typically contain statements with words such as "anticipate", "believe", "expect", "plan", "intend", "estimate", "propose", "project", "potential" 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 Corporation.

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 Corporation's gross margin;
- the Corporation'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 Corporation's plans for integration of its upstream and power portfolios;
- the Corporation'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;
- future investigations by the Corporation of CCUS and the deployment of CCUS systems;
- 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 Corporation;
- future requirements with respect to LMR deposits of the Corporation;
- the timing and costs of the Corporation's capital projects, including completion of certain wells;
- near-term land expiries and impairment charges associated therewith;
- sufficiency of funds to meet the Corporation's working capital requirements and anticipated drilling on the Simonette Acquisition and Distinction acreage for the remainder of the 2021 / 2022 winter drilling season;
- 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; and
- the impact of current market conditions on the Corporation.

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 Corporation's capital projects;
- the impact of increasing competition;
- the general stability of the economic and political environment in which the Corporation operates;
- the ability of the Corporation to obtain qualified staff, equipment and services in a timely and cost efficient manner;

- the ability of the operator of the projects that the Corporation 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 Corporation operates; and
- the ability of the Corporation 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 Corporation 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 Corporation 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 Corporation and described in the forward-looking statements or information. These risks and uncertainties include, among other things:

- the ability of management to execute its business plan;
- general economic and business conditions;
- the risk of instability affecting the jurisdictions in which the Corporation 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;
- uncertainty involving the forces that power certain renewable projects;
- the Corporation's ability to enter into or renew leases;
- potential delays or changes in plans with respect to power and solar projects or capital expenditures;
- fluctuations in commodity and power prices, foreign currency exchange rates and interest rates;
- risks inherent in the Corporation'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 Corporation;
- uncertainties as to the availability and cost of financing; and
- financial risks affecting the value of the Corporation's investments.

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 Corporation undertakes no obligation to publicly update or revise any forward-looking statements or information, except as expressly required by applicable securities laws.

Abbreviations

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