Management's discussion and analysis

The following is Management's Discussion and Analysis ("MD&A") of the financial performance and results of operations for Kiwetinohk Energy Corp. ("Kiwetinohk" or the "Company") as at and for the years ended December 31, 2023 and 2022. Kiwetinohk's common shares commenced trading on the Toronto Stock Exchange under the symbol KEC on January 14, 2022.

This MD&A should be read in conjunction with the Company's audited consolidated financial statements as at and for the years ended December 31, 2023 and 2022 (the "Financial Statements"). Additional information including that contained in Kiwetinohk's Annual Information Form ("AIF") is available on Kiwetinohk's website at www.kiwetinohk.com and SEDAR+ at www.sedarplus.ca. The Financial Statements have been prepared in accordance with International Financial Reporting Standards ("IFRS"). This MD&A should also be read in conjunction with the Company's disclosure under "Non-GAAP and Other Financial Measurements", "Forward-Looking Statements", "Future Oriented Financial Information", "Abbreviations" and "Oil and Gas Advisories" below.

The reporting currency is the Canadian dollar, and all dollar amounts in this MD&A are stated in Canadian dollars unless otherwise indicated. This MD&A is dated March 5, 2024.

Overview of business

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

Upstream

The upstream business unit is involved in the development and production of petroleum and natural gas reserves in western Canada, with a focus on profitable early to mid-life liquids-rich natural gas properties that are expected to offer competitive economic resource potential. Upstream assets consist of high-netback, liquids-rich natural gas production with development upside and owned infrastructure for processing the majority of the Company's production. These upstream assets provide a foundational base for the Company to pursue and develop energy transition opportunities.

Power

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

Financial and operating highlights

	Q4 2023	Q4 2022	2023	2022
Production				
Oil & condensate (bbl/d)	**8,407**	8,423	**7,183**	6,197
NGLs (bbl/d)	**3,507**	2,664	**2,769**	2,012
Natural gas (Mcf/d)	**76,756**	81,949	**75,810**	57,859
Total (boe/d)	**24,707**	24,745	**22,587**	17,852
Oil and condensate % of production	**34%**	34%	**32%**	35%
NGL % of production	**14%**	11%	**12%**	11%
Natural gas % of production	**52%**	55%	**56%**	54%
Realized prices				
Oil & condensate ($/bbl)	**95.66**	104.96	**96.90**	115.82
NGLs ($/bbl)	**51.44**	68.82	**53.07**	74.06
Natural gas ($/Mcf)	**3.32**	8.12	**3.76**	8.69
Total ($/boe)	**50.17**	70.04	**49.95**	76.72
Royalty expense ($/boe)	**(4.84)**	(5.72)	**(4.72)**	(6.78)
Operating expenses ($/boe)	**(8.55)**	(7.20)	**(8.52)**	(9.70)
Transportation expenses ($/boe)	**(5.49)**	(5.27)	**(5.61)**	(5.31)
Operating netback [1] ($/boe)	**31.29**	51.85	**31.10**	54.93
Realized gain (loss) on risk management ($/boe) [2]	**0.23**	(6.58)	**1.50**	(13.33)
Realized gain (loss) on risk management - purchases ($/boe) [2]	**1.20**	(2.36)	**1.69**	(5.23)
Net commodity sales from purchases (loss) ($/boe) [1]	**(0.51)**	3.16	**(0.80)**	7.07
Adjusted operating netback [1]	**32.21**	46.07	**33.49**	43.44
Financial results ($000s, except per share amounts)				
Commodity sales from production	**114,038**	159,457	**411,826**	499,898
Net commodity sales from purchases (loss) [1]	**(1,152)**	7,174	**(6,642)**	46,069
Cash flow from operating activities	**58,946**	87,028	**240,760**	242,850
Adjusted funds flow from operations [1]	**63,697**	101,506	**241,311**	264,082
Per share basic	**1.46**	2.30	**5.49**	6.00
Per share diluted	**1.44**	2.26	**5.43**	5.92
Net debt to annualized adjusted funds flow from operations [1]	**0.77**	0.46	**0.77**	0.46
Free funds flow deficiency from operations (excluding acquisitions/ dispositions) [1]	**(12,713)**	(1,202)	**(65,674)**	(5,647)
Net income (loss)	**48,302**	115,308	**111,896**	190,989
Per share basic	**1.11**	2.61	**2.54**	4.34
Per share diluted	**1.09**	2.57	**2.52**	4.28
Capital expenditures prior to (dispositions) acquisitions [1]	**76,410**	102,708	**306,985**	269,729
Net (dispositions) acquisitions [1]	**(18,000)**	—	**(19,995)**	57,323
Capital expenditures and net (dispositions) acquisitions [1]	**58,410**	102,708	**286,990**	327,052
Balance sheet ($000s, except share amounts)				
Total assets	**1,085,615**	932,650	**1,085,615**	932,650
Long-term liabilities	**305,735**	221,731	**305,735**	221,731
Net debt [1]	**186,523**	122,304	**186,523**	122,304
Adjusted working capital surplus (deficit) [1]	**7,565**	(3,105)	**7,565**	(3,105)
Weighted average shares outstanding				
Basic	**43,710,734**	44,168,157	**43,971,108**	44,045,613
Diluted	**44,172,101**	44,887,920	**44,467,348**	44,593,528
Shares outstanding end of period	**43,662,644**	44,176,710	**43,662,644**	44,176,710
Return on average capital employed ("ROACE") [1]			**21%**	30%
Reserves				
Proved reserves (MMboe) [3]			**123.2**	125.5
Proved reserves per share (boe) [3]			**2.8**	2.9
Proved plus probable reserves (MMboe) [3]			**224.5**	214.5
Proved plus probable reserves per share (boe) [3]			**5.1**	4.9

1 – Non-GAAP and other financial measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. See “Non-GAAP and Other Financial Measures” section of this MD&A
2 – Realized gain (loss) on risk management contracts includes settlement of financial hedges on production and foreign exchange, with gains (loss) on contracts associated with purchases presented separately.
3 – Oil and natural gas reserves are as determined by the Company’s independent qualified reserve evaluator with an effective date of December 31 for the years shown in accordance with the Canadian Oil and Gas Evaluation Handbook and are shown as net working interest reserves before royalties.

Guidance

The Company exited 2023 with strong performance when compared to previously disclosed guidance, meeting or exceeding corporate expectations in all categories. Strong production volumes achieved through new well development in the fourth quarter resulted in corporate sales volumes of 22.6 Mboe/d during 2023 slightly ahead of the mid-point of the Company's guidance of 22.5 Mboe/d and positively contributed to all $/boe metrics. Total capital spending was in line with the midpoint of guidance with power spending trending lower than guidance as the Company continues to defer expenditures as it awaits further clarity from provincial and federal governments on pending electricity regulations.

Kiwetinohk's 2023 actual results as compared to its most recent financial and operational guidance provided on November 7, 2023 are outlined below:

2023 operational & financial results vs guidance		2023 Guidance	2023 Actual	Variance vs Midpoint (%)
Sales volumes	Mboe/d	**21.5 - 23.5**	**22.6**	**0.4%**
Oil & liquids	Mbbl/d	9.5 - 10.4	**10.0**	**—%**
Natural gas	MMcf/d	71.9 - 78.5	**75.8**	**0.8%**
Financial				
Royalty rate	%	10 - 12	**9.5**	**(13.6)%**
Operating costs	$/boe	8.25 - 9.25	**8.52**	**(2.6)%**
Transportation	$/boe	6.00 - 6.50	**5.61**	**(10.2)%**
Corporate G&A expense [1]	$MM	22 - 24	**20.7**	**(10.0)%**
Cash taxes	$MM	—	**0.2**	**—%**
Capital guidance	$MM	**300 - 318**	**307.0**	**(0.6)%**
Upstream	$MM	285 - 300	**293.8**	**0.4%**
DCET [3]	$MM	230 - 240	**244.4**	**4.0%**
Plant expansion, production maintenance and other	$MM	55 - 60	**49.4**	**(14.1)%**
Power	$MM	15 - 18	**13.2**	**(20.0)%**
2023 Adjusted Funds Flow from Operations commodity pricing sensitivities [2]				
US$70/bbl WTI & US$2.75/MMBtu HH	CAD$MM	230 - 250	**241.3**	**0.4%**
US$80/bbl WTI & US$3.25/MMBtu HH	CAD$MM	240 - 265	**241.3**	**(4.6)%**
2023 Net debt to Adjusted Funds Flow from Operations sensitivities [2]				
US$70/bbl WTI & US$2.75/MMBtu HH	X	0.8x - 0.9x	**0.77x**	**(9.4)%**
US$80/bbl WTI & US$3.25/MMBtu HH	X	0.7x - 0.8x	**0.77x**	**2.7%**

1 – Includes G&A expenses for all divisions of the Company – Corporate, Upstream, Power and Business Development.
2 – Non-GAAP and other financial measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. See "Non-GAAP and Other Financial Measures" section of this MD&A.
3 - Includes drilling, completions, and equipping and associated pipelines and roads presented within facilities, pipelines, roads and optimization per the "Capital expenditures" section of this MD&A.

Management continues to execute on its upstream and power development plans and is maintaining its previously disclosed (December 13, 2023) 2024 guidance targets. The Company has provided updated sensitivities on adjusted funds flow from operations (see below) to reflect a weaker outlook for natural gas pricing. The following table summarizes Kiwetinohk's guidance for 2024:

2024 Financial & Operational Guidance		
Production (2024 average) [1]	Mboe/d	24.0 - 27.0
Oil & liquids	%	45% - 49%
Natural gas [1]	%	51% - 55%
Financial		
Royalty rate	%	9% - 11%
Operating costs	$/boe	$8.00 - $8.75
Transportation	$/boe	$6.00 - $6.50
Corporate G&A expense [2]	$MM	$23 - $25
Cash taxes	$MM	$—
Capital guidance	$MM	$275 - $295
Upstream	$MM	$270 - $287
DCET	$MM	$250 - $265
Infrastructure, production maintenance and other	$MM	$20 - $22
Power	$MM	$5 - $8
2024 Adjusted Funds Flow from Operations commodity pricing sensitivities [4]		
US$70/bbl WTI & US$2.00/MMBtu HH	CAD$MM	$260 - $290
US$80/bbl WTI & US$3.00/MMBtu HH	CAD$MM	$305 - $340
US$ WTI +/- $1.00/bbl [5]	CAD$MM	+/- $3.5
US$ Chicago +/- $0.10/MMBtu [5]	CAD$MM	+/- $1.4
CAD$ AECO 5A +/- $0.10/GJ [5]	CAD$MM	+/- $0.9
Exchange Rate (CAD$/US$) +/- $0.01 [5]	CAD$MM	+/- $3.1
2024 Net debt to Adjusted Funds Flow from Operations sensitivities [4]		
US$70/bbl WTI & US$2.00/MMBtu HH	X	0.7x - 0.8x
US$80/bbl WTI & US$3.00/MMBtu HH	X	0.4x - 0.5x

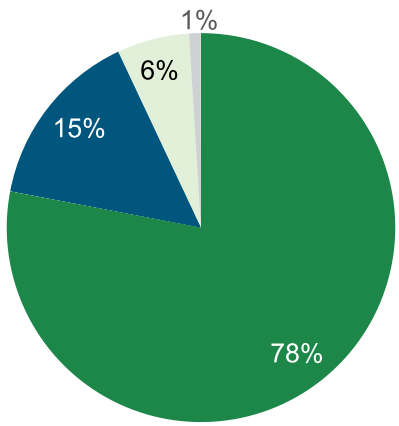
1 – Chicago sales of ~90% expected for 2024.
2 – Includes G&A expenses for all divisions of the Company – corporate, upstream, power and business development.
3 – The Company expects to pay cash taxes of approximately $0.3 million on its US subsidiary during 2024. No Canadian taxes are anticipated in 2024.
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 section "Non-GAAP Measures" herein.
5 – Assumes US$75/bbl WTI, US$2.50/mmbtu HH, US$0.80/mmbtu HH - AECO basis diff, $0.74 USD/CAD.

Capital expenditures

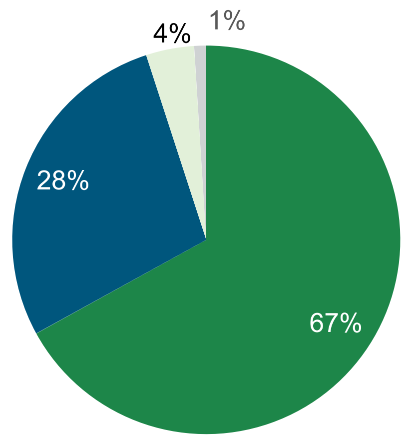
$000s	Q4 2023	Q4 2022	2023	2022
Drilling, completions, and equipping	**59,589**	55,316	**203,875**	197,761
Facilities, pipelines, roads and optimization	**11,541**	29,276	**85,494**	46,055
Power projects	**4,245**	7,624	**12,408**	12,834
Land and other	**—**	1,218	**1,355**	2,017
Capitalized G&A - upstream	**831**	599	**3,087**	1,899
Capitalized G&A - power	**204**	439	**766**	927
Capital expenditures [1]	**76,410**	102,708	**306,985**	269,729
Upstream net (dispositions) acquisitions [1]	**(18,000)**	—	**(19,995)**	54,823
Power net acquisitions [1]	**—**	—	**—**	2,500
Capital and net (dispositions) acquisitions [1]	**58,410**	102,708	**286,990**	327,052

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

Capital expenditures
Q4 2023[1]



Capital expenditures
2023 Annual[1]



1 – Capital expenditures shown are before acquisitions/dispositions.

■ Drilling, completions and equipping ■ Facilities, pipelines, roads and optimization
■ Power projects ■ Land and other ■ Total capitalized G&A

Drilling, completions and equipping

For the three months and year ended December 31, 2023, the Company spent $59.6 million and $203.9 million, respectively, across all operating areas. The Company's development program within Placid included four new Montney wells which were tied in during the second quarter of 2023. In Simonette, the Company completed and tied in nine wells, with the most recent four well Duvernay pad coming on-stream at the end of the fourth quarter. In addition, the Company commenced drilling operations on a three well Duvernay pad in the fourth quarter of 2023, with production expected to be on-stream during the first quarter of 2024.

The Company remains focused on further development of its core Simonette Duvernay lands with a smaller portion of its development capital allocated to delineation and optimization of the well design on the Company's Montney acreage.

Facilities, pipelines, roads and optimization

For the three months and year ended December 31, 2023, the Company spent $11.5 million and $85.5 million, respectively, on facilities, pipelines, roads and production optimization. The Company completed construction of an expansion to the Company's 10-29 processing plant in the Simonette area in the third quarter which increased inlet capacity by ~30 MMcf/d through addition of two new compressors. With this expansion completed, the Company's portion of capital allocated to infrastructure decreased to 15% in the fourth quarter of 2023. In addition, the Company incurred engineering and procurement costs in connection with a future expansion of its 5-31 plant which will add ~15 MMcf/d of inlet capacity. Construction of this expansion has been delayed until it is required to accommodate anticipated production growth. Costs were also incurred to construct roads, leases and pipelines required to execute the Company's drilling program and allow for future production growth.

Power development projects

During the year ended December 31, 2023, the Company continued to advance its power development portfolio, which includes four gas-fired and three solar projects with a total estimated nameplate capacity of approximately 2,150 MW.

For the three months and year ended December 31, 2023, the Company invested $4.4 million and $13.2 million, respectively, to advance all seven power projects. Expenditures included costs to complete engineering, consultations, regulatory reviews, environmental studies, Alberta Electric Systems Operator ("AESO") processes, legal reviews and various pre-Front End Engineering and Design ("FEED") and FEED work, as well as other risk reduction and contracting activities. The majority of power capital expenditures in 2023 was directed to the Homestead Solar and Opal Firm Renewable projects, which remain the Company's most advanced development projects, each at Stage 4 in their respective regulatory approval processes. Alberta Utilities Commission ("AUC") transmission approvals remain as the final key regulatory hurdle for each project prior to commencing construction. Kiwetinohk is seeking external capital to finance its power projects and has engaged a financial advisor to help identify potential financing partners and/or acquirers of the Homestead and/or Opal projects. Funding options for these projects include a partial or outright sale with proceeds helping to fund ongoing development of the remaining portfolio.

The transmission line regulatory approvals for the Homestead project are expected to require an AUC hearing which has delayed a Final Investment Decision ("FID") to the second half of 2024 at the earliest. The Company has selected a large, reputable engineering, procurement and construction ("EPC") firm with experience in utility-scale solar construction for the project. The Company has continued to optimize the design and development plan for Homestead and is reducing its capital cost estimates by $50.0 million to a revised estimated total capital cost of approximately $675.0 million. During 2023, the Company exercised land lease options on its Homestead project to secure its position for future development and retains the ability to terminate these leases upon providing notice to landowners and satisfaction of certain reclamation requirements.

The Company continues to advance detailed engineering on the 101MW Opal project and is currently evaluating the regulatory environment and total estimated capital cost of the project prior to any FID decision. The Company plans to make this decision after seeking and evaluating estimates on total installed costs, with previously disclosed cost estimates expected to be revised due to, among other things the state of the current economic environment, and related inflation and supply chain challenges. In addition, the Company continues to review the status and potential impact of the final form of the Federal Government's Draft Clean Electricity Regulation ("CER") and indications of revisions and will require clarity on regulations before the Company will make a FID and as a result the timing of FID and the related COD has been withdrawn.

Early-stage development and design factors and the status of each project as at March 5, 2024 are summarized in the following table:

<table>
<tr><th>Early-stage power development, design factors & status</th><th>Homestead (Solar 1)</th><th>Opal (Firm Renewable 1) [1]</th><th>Granum (Solar 2)</th><th>Phoenix (Solar 3)</th><th>Black Bear (NGCC 2)</th><th>Flipi (NGCC 1)</th><th>Little Flipi (Firm Renewable 2) [1]</th></tr>
<tr><td>Approximate Capacity (nameplate, AC)</td><td>400 MW</td><td>101 MW</td><td>350 MW</td><td>170 MW</td><td>500 MW</td><td>500 MW</td><td>124 MW</td></tr>
<tr><td>Approximate Capacity (net to grid, AC)</td><td>400 MW</td><td>97 MW</td><td>350 MW</td><td>170 MW</td><td>466 MW [8]</td><td>466 MW [8]</td><td>120 MW</td></tr>
<tr><td>Capacity factor</td><td>26% [5]</td><td>20% [6]</td><td>26% [5]</td><td>26% [5]</td><td>90%</td><td>90%</td><td>20% [6]</td></tr>
<tr><td>Heat rate [7] (MJ/KWH: +/-5%)</td><td>—</td><td>7.6</td><td>—</td><td>—</td><td>6.0</td><td>6.0</td><td>Under Evaluation</td></tr>
<tr><td>AESO stage</td><td>4</td><td>4</td><td>3</td><td>3</td><td>3</td><td>3</td><td>3</td></tr>
<tr><td>Earliest FID date</td><td>H2 2024</td><td rowspan="3" colspan="6">Kiwetinohk is currently limiting its investment in the project to the minimum required to maintain viability and regulatory positioning until further clarity is provided on the regulatory and policy revisions at both the federal and provincial levels. Once clarity is received, the Company will provide further project updates. Accordingly, the estimates of such dates and costs which had been previously provided by Kiwetinohk have been withdrawn. [9]</td></tr>
<tr><td>Earliest COD date [4]</td><td>H2 2026</td></tr>
<tr><td>Total estimated installed approximate capital cost ($ million) [2, 3]</td><td>$675 (Class 2)</td></tr>
</table>

1. The term "Firm Renewable" is a Kiwetinohk-originated term that describes efficient, flexible-output, fast-responding, gas-fired, reciprocating engine power generation. These facilities are also referred to as "gas-fired peakers" in the power industry.
2. Total installed approximate cost estimates are classified in a manner consistent with American Association of Cost Engineering (“AACE”) standards and excludes costs to finance projects. Class 2 estimates have an expected accuracy range of -15% to +20%.
3. None of the Company’s planned power generation projects have a final design, performance projection or cost estimate, or full regulatory approval or internal or external funding. There is no assurance that the power generation projects will proceed as described or at all.
4. If a positive FID is reached, the Company will advance the project towards the estimated Commercial Operations Date (“COD”).
5. First year capacity factor based on DC/AC ratio of 1.39, and bifacial, single axis solar panel tracking design.
6. Designed for intermittent operation. The actual dispatch will be based on market conditions and contracting.
7. Gas-fired generation simple cycle heat rates averaged 9.5 and NGCC heat rates averaged 7 on existing projects within the AESO grid as per publicly available data.
8. Based on current regulations, power providers are restricted to generating a maximum of 466 MW on a single line.
9. Kiwetinohk has withdrawn the forward-looking information previously disclosed in its MD&A and annual information form pertaining to the earliest FID date, the earliest COD date and the total estimated installed approximate capital cost of the Opal, Granum, Phoenix, Black Bear, Flipi and Little Flipi power generation projects. The events and circumstances that led to the Company's decision to withdraw such forward-looking information include uncertainty associated with the regulatory environment (AUC moratorium on renewable energy; draft CER), the current economic environment of increasing inflation rates, supply chain disruptions leading to delays throughout the industry and uncertainty surrounding construction timing, arising from the foregoing factors. As a result, the assumptions previously made by the Company regarding the regulatory environment and the ability to obtain required materials for the projects in a timely and cost-effective manner are no longer valid.

Carbon storage hubs

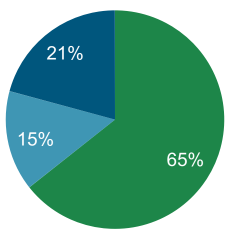
The Company continued to evaluate its two carbon storage hubs during 2023, completing a feasibility study and identifying locations for appraisal wells. Kiwetinohk believes it will be well positioned as a primary user of its awarded carbon hubs through its associated power projects, Opal and Black Bear, which are in the early stages of development and through potential future CCS projects it may develop for its own use and the use of third parties.

Results of operations

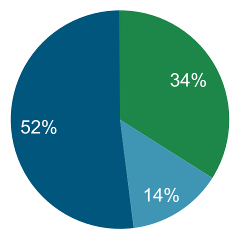
Production

	Q4 2023	Q4 2022	2023	2022
Oil & condensate (bbl/d)	**8,407**	8,423	**7,183**	6,197
NGLs (bbl/d)	**3,507**	2,664	**2,769**	2,012
Natural gas (Mcf/d)	**76,756**	81,949	**75,810**	57,859
Total production (boe/d)	**24,707**	24,745	**22,587**	17,852
Oil and condensate % of production	**34%**	34%	**32%**	35%
NGL % of production	**14%**	11%	**12%**	11%
Natural gas % of production	**52%**	55%	**56%**	54%
Total production volumes %	**100%**	100%	**100%**	100%

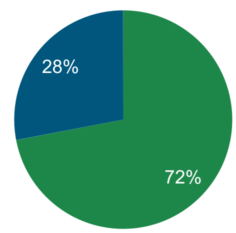
Revenue Mix ($)
Q4 2023



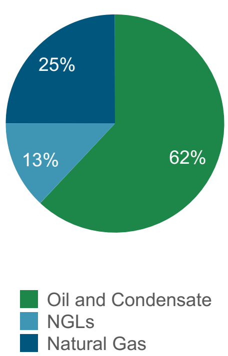
Production Mix (boe)
Q4 2023



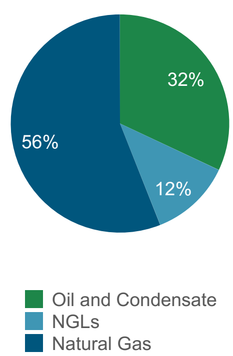
Production by Area (boe)
Q4 2023



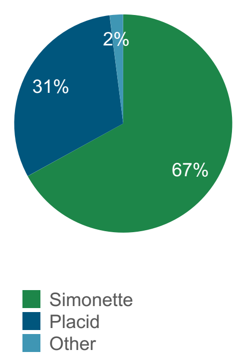
Full-Year 2023



Full-Year 2023



Full-Year 2023



Production during the fourth quarter of 2023 averaged 24,707 boe/d bringing average annual production to 22,587 boe/d in 2023. Quarterly production was consistent with production of 24,745 boe/d in the fourth quarter of 2022 and increased by 27% compared to the annual average of 17,852 boe/d in 2022.

The increase in the Company's annual production volumes is attributable to the 2023 capital development program which resulted in 13 incremental wells contributing to production in 2023. This year over year growth was achieved despite the Company's 2023 production volumes being negatively impacted by the Alberta wildfires during the month of May, which forced a shut-in and loss of production of approximately 1,000 boe/d on an annualized basis.

The composition of the Company's production portfolio during the year ended December 31, 2023 was 32% oil and condensate, 12% NGLs, and 56% natural gas, with the natural gas weighting increasing from 2022 as a result of the new wells brought on stream being more gas weighted compared to historical production. During the fourth quarter of 2023, the Company saw an increase in NGL's as a percent of production as the Company operated its processing facilities at a colder temperature to extract NGLs for sale to the Alberta market.

Benchmark and realized prices

	Q4 2023	Q4 2022	2023	2022
Liquid benchmark prices				
WTI (US$/bbl)	**78.32**	82.65	**77.62**	94.23
WTI (CDN$/bbl)	**106.72**	112.17	**104.78**	122.37
Edmonton Light (CDN$/bbl)	**99.69**	109.84	**100.39**	120.02
Natural gas benchmark prices				
Henry Hub (US$/MMBtu)	**2.88**	6.26	**2.74**	6.64
Chicago City Gate MI (US$/MMBtu)	**2.63**	5.86	**2.81**	6.61
Chicago City Gate DI (US$/MMBtu)	**2.28**	5.37	**2.30**	5.19
AECO 5A (CDN$/GJ)	**2.18**	4.85	**2.50**	5.04
AECO 7A (CDN$/GJ)	**2.52**	5.29	**2.78**	5.27
Foreign exchange rates (CAD/USD)	**0.73**	0.74	**0.74**	0.77

	Q4 2023	Q4 2022	2023	2022
Realized prices (before impact of hedging program)				
Oil & condensate ($/bbl)	**95.66**	104.96	**96.90**	115.82
NGLs ($/bbl)	**51.44**	68.82	**53.07**	74.06
Natural gas ($/Mcf)	**3.32**	8.12	**3.76**	8.69
Total ($/boe)	**50.17**	70.04	**49.95**	76.72

WTI benchmark prices decreased in both the three months and year ended December 31, 2023, from the comparative periods in 2022, averaging $106.72 and $104.78 per barrel compared to $112.17 and $122.37 per barrel, respectively. The reported year over year decreases in benchmark prices are in large part a reflection of the very high prices that prevailed through much of 2022 which was the result of simultaneous supply constraints, exacerbated by Russia's invasion of Ukraine and a resurgence of energy demand following the easing of COVID related lockdowns. Crude oil prices in 2023 are lower, but have remained relatively strong as a result of expectations of a tighter supply given production cuts in Saudi Arabia and ongoing sanctions against Russia which have offset the impact of concerns with respect to impact of weaker economic growth on global demand and growing US crude oil inventories. Edmonton Light benchmark pricing also experienced decreases in 2023 compared to 2022, generally driven by the same factors as WTI prices.

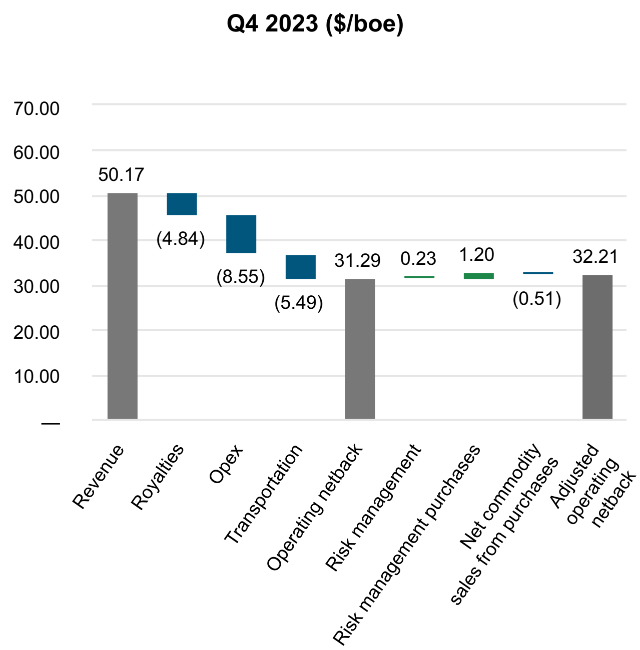
Henry Hub natural gas prices decreased to $2.88 and $2.74 in the three months and year ended December 31, 2023, respectively, when compared to $6.26 and $6.64 in the comparative periods of 2022. Declines were due to record high inventory levels coupled with increased North American production. Henry Hub prices were unusually high in 2022, driven by flat US production growth, a resurgence of domestic demand, increased LNG exports and resulting lower storage levels. The Chicago City Gate monthly index benchmark for natural gas also declined in the three months and year ended December 31, 2023, compared to prior periods for similar reasons. The Chicago City Gate monthly benchmark averaged US $2.63 and US $2.81 per MMBtu compared to US $5.86 and US $6.61 per MMBtu in the comparative periods of 2022, respectively.

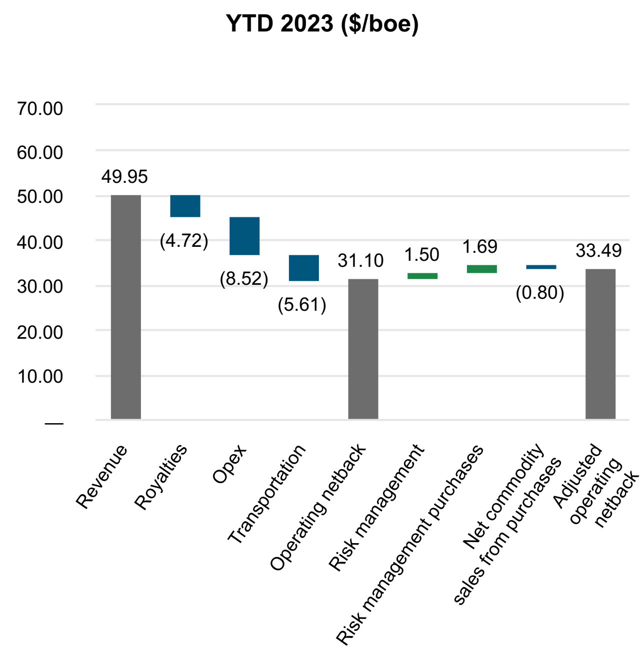
Natural gas prices at AECO in Alberta also decreased as new supply outpaced demand in the basin. On average, AECO 7A spot prices decreased during the three months and year ended December 31, 2023, when compared to the same periods in 2022, decreasing by $2.77/GJ to $2.52/GJ for the fourth quarter of 2023, and by $2.49/GJ to $2.78/GJ for the year.

Operating netback

	Q4 2023	Q4 2022	2023	2022
Realized price ($/boe)	**50.17**	70.04	**49.95**	76.72
Royalty expenses ($/boe)	**(4.84)**	(5.72)	**(4.72)**	(6.78)
Operating expenses ($/boe)	**(8.55)**	(7.20)	**(8.52)**	(9.70)
Transportation expenses ($/boe)	**(5.49)**	(5.27)	**(5.61)**	(5.31)
Operating netback [1]($/boe)	**31.29**	51.85	**31.10**	54.93
Realized gain (loss) on risk management ($/boe) [2]	**0.23**	(6.58)	**1.50**	(13.33)
Realized gain (loss) on risk management - purchases ($/boe) [2]	**1.20**	(2.36)	**1.69**	(5.23)
Net commodity sales from purchases (loss)($/boe) [1]	**(0.51)**	3.16	**(0.80)**	7.07
Adjusted operating netback [1]	**32.21**	46.07	**33.49**	43.44
Total production (boe/d)	**24,707**	24,745	**22,587**	17,852

1 – Non-GAAP and other financial measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. See "Non-GAAP and Other Financial Measures" section of this MD&A.
2 – Realized gain (loss) on risk management includes settlement of financial hedges on production and foreign exchange, with gains on contracts associated with purchases presented separately.





Operating netback for the three months ended December 31, 2023 was $31.29/boe compared to $51.85/boe in the comparable period of 2022. The decrease was primarily attributable to lower average realized prices, which also contributed to reduced royalty expenses per barrel. In addition, operating costs per barrel increased in the fourth quarter of 2023 relative to the comparable period in 2022 as a result of inflationary cost pressure and the timing of maintenance activities. Transportation costs increased due to pipeline toll increases and a change in production composition leading to higher trucking costs.

Year over year, operating netback decreased to $31.10/boe compared to $54.93/boe in 2022. The decrease was primarily attributable to lower average realized prices, which also contributed to reduced royalty expenses per barrel and higher transportation costs as a result of pipeline toll increases and a higher proportion of volume flowing through the higher cost Alliance pipeline. This was partially offset by reduced operating costs as higher production levels resulted in operating efficiencies.

Adjusted operating netback incorporates the impact of risk management contracts and marketing activities. Adjusted operating netback for the three months and year ended December 31, 2023, decreased by $13.86/boe and $9.95/boe, respectively, compared to the same periods in 2022. Gains realized on commodity risk management contracts during 2023 partially mitigated the impact of commodity price declines during the three and twelve month periods. The Company systematically hedges a portion of volumes, in accordance with established risk management guidelines as approved by the Company's board of directors, to manage price volatility and ensure predictable cash flows during a period of significant capital expenditures and growth. In addition, the Company continued to generate income associated with commodity sales from purchases after incorporating the impact of the hedging program, as further described below (see Net commodity sales from purchases).

Commodity sales from production

$000s	Q4 2023	Q4 2022	2023	2022
Oil & condensate	**73,989**	81,338	**254,053**	261,941
NGLs	**16,596**	16,865	**53,629**	54,393
Natural gas	**23,453**	61,254	**104,144**	183,564
Total commodity sales from production	**114,038**	159,457	**411,826**	499,898

Revenue from production decreased to $114.0 million and $411.8 million, respectively, for the three months and year ended December 31, 2023, representing 28% and 18% respective declines over the comparative periods in 2022. Decreases to revenue were due to a weaker commodity price environment with the Company realizing pricing of $50.17/boe and $49.95/boe for the three months and year ended December 31, 2023, respectively, as compared to $70.04/boe and $76.72/boe in the comparative periods of 2022. On an annual basis, the year over year decline in realized pricing was partially offset by greater production in 2023.

Net commodity sales from purchases

$000s	Q4 2023	Q4 2022	2023	2022
Commodity sales from purchases	**18,136**	47,902	**75,573**	268,552
Commodity purchases, transportation and other	**(19,288)**	(40,728)	**(82,215)**	(222,483)
Net commodity sales from purchases (loss) [1]	**(1,152)**	7,174	**(6,642)**	46,069
Realized hedging gain (loss) on purchases	**2,718**	(5,380)	**13,934**	(34,079)
Net commodity sales from purchases after hedging[1]	**1,566**	1,794	**7,292**	11,990
$/boe – before hedging	**(0.51)**	3.16	**(0.80)**	7.07
$/boe – after hedging	**0.69**	0.80	**0.89**	1.84

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

In order to mitigate the cost of transportation service in excess of current production needs, the Company purchases available natural gas volumes in Alberta and/or British Columbia and resells these volumes in Chicago. Other than during wildfire related production shut-ins in May, the Company was able to successfully purchase and fill the balance of its Alliance firm transportation commitment during the year ended December 31, 2023, not met through proprietary field production and temporarily assigned volumes.

As part of its broader risk management program, the Company enters into risk management contracts associated with purchased natural gas volumes for resale to secure the pricing difference between the Alberta and Chicago sales points. To date, this strategy has resulted in positive net commodity sales from purchases after hedging while allowing the Company to utilize its excess transportation commitments on the Alliance pipeline.

The Company does not seek to speculate on price movements for purchased natural gas volumes for resale and manages its excess pipeline commitments by securing third party natural gas volumes. Price differentials between the Chicago and Alberta markets and the associated market risk is monitored on purchased volumes and managed by securing pricing through periodically entering into risk management contracts in accordance with risk management guidelines as approved by the Company's board of directors.

Total net commodity sales from purchases have declined during the three months and year ended December 31, 2023 relative to the comparable periods in 2022. As the Company increases production levels, the quantity of production required to be purchased to fill excess Alliance pipeline commitments, and the risk associated with take or pay pipeline obligations and marketing of purchased volumes is reduced.

In the three months and year ended December 31, 2023, the Company realized losses of $1.2 million and $6.6 million, respectively, on its marketing activities associated with purchasing natural gas to fulfill its transmission commitment on the Alliance pipeline system. Including the offsetting impact of related risk management contracts, the Company realized overall marketing income of $1.6 million and $7.3 million for the three months and year ended December 31, 2023, respectively, relative to $1.8 million and $12.0 million for the comparable periods in 2022.

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 which is designed to protect cash flows from its base production and help ensure sufficient capital and liquidity is available to execute its strategy and complete its planned capital development program.

Risk management contracts are entered into at prices that the Company believes enhance the probability of capital projects meeting or exceeding their targeted financial return hurdles. All risk management contracts are entered into in accordance with the Company's risk management policy, ensuring the Company retains its ability to cover all outstanding risk management liabilities when they arise. The Company also regularly reviews its credit exposure to the counterparties that it enters into risk management contracts with.

$000s	Q4 2023	Q4 2022	2023	2022
Risk management:				
Unrealized gain	**38,417**	29,475	**37,313**	11,036
Realized gain (loss)	**3,241**	(20,341)	**26,257**	(120,938)
Total gain (loss) on risk management	**41,658**	9,134	**63,570**	(109,902)
Unrealized gain ($/boe)	**16.90**	12.95	**4.53**	1.69
Realized gain (loss) ($/boe)	**1.43**	(8.94)	**3.19**	(18.56)

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

$000s	Q4 2023	Q4 2022	2023	2022
Realized gain (loss) on production	**1,702**	(13,768)	**15,043**	(86,107)
Realized gain (loss) on purchases	**2,718**	(5,380)	**13,934**	(34,079)
Realized loss on foreign exchange	**(1,179)**	(1,193)	**(2,720)**	(752)
Total realized gain (loss)	**3,241**	(20,341)	**26,257**	(120,938)
Realized gain (loss) on production ($/boe)	**0.75**	(6.06)	**1.83**	(13.21)
Realized gain (loss) on purchases ($/boe)	**1.20**	(2.36)	**1.69**	(5.23)
Realized loss on foreign exchange ($/boe)	**(0.52)**	(0.52)	**(0.33)**	(0.12)

For the three months and year ended December 31, 2023, the Company recorded realized gains on risk management contracts of $3.2 million and $26.3 million, respectively. Approximately 84% of the fourth quarter and 53% of the annual gains were related to natural gas volumes purchased for resale required to meet pipeline commitments in excess of the Company's production needs, where the Company hedges price differences between Chicago and Alberta markets at the time of contracting third party natural gas purchases.

Gains were realized on production hedges in the three months and year ended December 31, 2023 relative to significant losses in the comparative periods of 2022. Hedge contract prices in 2023 were generally higher than relevant benchmark prices at the time of settlement resulting in gains in the fourth quarter and for the year ended December 31, 2023, whereas hedge contract prices during the comparable periods in the prior year were significantly lower than the relevant benchmark prices at the time of settlement resulting in larger realized losses. When compared to 2022, gains related to volumes purchased to fill pipeline capacity increased as a result of the differential between Chicago and AECO prices narrowing relative to hedged rates (see – Net commodity sales from purchases).

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

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

The unrealized gain on risk management of $38.4 million and $37.3 million during the three months and year ended December 31, 2023, represents changes in the fair value of risk management contracts outstanding at the end of those periods bringing the portfolio to an asset (net receivable) of $19.5 million as at 2023 (December 31, 2022: net payable of $17.8 million).

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

Type		Q1 2024	Q2 2024	Q3 2024	Q4 2024	2025	2026
Crude oil [1]							
WTI fixed price	bbl/d	500	500	500	500	250	—
WTI buy put	bbl/d	4,100	3,867	2,917	2,000	1,458	—
WTI sell call	bbl/d	3,000	3,000	2,417	1,500	1,458	—
WTI swap average	US$/bbl	$70.62	$70.62	$70.62	$70.62	$74.00	$—
WTI buy put average	US$/bbl	$67.72	$67.46	$68.88	$68.75	$68.97	$—
WTI sell call average	US$/bbl	$79.68	$79.68	$79.27	$76.98	$77.98	$—
Natural gas [1]							
NYMEX Henry Hub fixed price	MMBtu/d	5,000	3,333	2,500	2,500	—	—
NYMEX Henry Hub buy put	MMBtu/d	42,500	40,833	38,333	27,500	21,667	10,000
NYMEX Henry Hub sell call	MMBtu/d	25,000	35,833	33,333	22,500	21,667	10,000
NYMEX Henry Hub fixed price average	US$/MMBtu	$3.07	$3.18	$3.23	$3.23	$—	$—
NYMEX Henry Hub buy put average	US$/MMBtu	$3.17	$3.21	$3.23	$3.32	$3.30	$3.21
NYMEX Henry Hub sell call average	US$/MMBtu	$4.12	$3.92	$3.97	$4.21	$4.74	$4.50
Natural gas transportation [1,2]							
Purchase AECO 5A basis (to NYMEX Henry Hub)	MMBtu/d	30,000	30,000	30,000	10,000	—	—
Sell GDD Chicago basis (to NYMEX Henry Hub) [3]	MMBtu/d	(30,000)	(30,000)	(30,000)	(10,000)	—	—
AECO 5A basis (to NYMEX Henry Hub) average	US$/MMBtu	$(1.23)	$(1.28)	$(1.28)	$(1.28)	$—	$—
GDD Chicago basis (to NYMEX Henry Hub) average [3]	US$/MMBtu	$0.13	$(0.07)	$(0.07)	$(0.07)	$—	$—

1 – Prices per unit and volumes per day are represented at the average amounts for the period.
2 – Natural gas transportation hedges relate to exposure to basis pricing differentials between AECO and Chicago arising from firm transportation commitments.
3 – Gas Daily Daily ("GDD") pricing represents the daily natural gas settlement price in Chicago.

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

Type		Q1 2024	Q2 2024	Q3 2024	Q4 2024	2025	2026
Foreign exchange							
Sell USD CAD (monthly average)	US$	$9.0 MM	$9.0 MM	$9.0 MM	$9.0 MM	$16.5 MM	$— MM
USD CAD buy put	US$	$5.0 MM	$5.0 MM	$5.0 MM	$5.0 MM	$2.5 MM	$5.0 MM
USD CAD sell call	US$	$5.0 MM	$5.0 MM	$5.0 MM	$5.0 MM	$2.5 MM	$5.0 MM
USD CAD fixed sell rate		$1.33	$1.33	$1.33	$1.33	$1.34	$—
USD CAD put rate		$1.32	$1.32	$1.32	$1.32	$1.33	$1.28
USD CAD call rate		$1.34	$1.34	$1.34	$1.34	$1.38	$1.35

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

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

$000s	2023	2022
Short term risk management asset	**10,708**	2,554
Long term risk management asset	**8,838**	—
Short term risk management liability	**—**	(13,687)
Long term risk management liability	**—**	(6,634)
Total risk management contracts asset (liability)	**19,546**	(17,767)

$000s	2023	2022
Asset (liability) on produced volumes	**9,186**	(17,466)
Asset on purchased volumes	**3,616**	131
Asset (liability) on foreign exchange contracts	**6,744**	(432)
Total risk management liability	**19,546**	(17,767)

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

Type		Q1 2024	Q2 2024	Q3 2024	Q4 2024	2025	2026
Crude oil contracts [1,2]							
WTI fixed price	bbl/d	250	750	750	1,000	188	—
WTI buy put	bbl/d	333	500	500	500	167	—
WTI sell call	bbl/d	333	500	500	500	167	—
WTI swap average	US$/bbl	$74.67	$74.67	$74.67	$73.75	$73.16	$—
WTI buy put average	US$/bbl	$70.00	$70.00	$70.00	$70.00	$70.00	$—
WTI sell call average	US$/bbl	$78.55	$78.55	$78.55	$78.55	$77.22	$—
Natural gas [1,2]							
NYMEX Henry Hub buy put	MMBtu/d	—	—	—	5,000	2,292	3,125
NYMEX Henry Hub sell call	MMBtu/d	—	—	—	5,000	2,292	3,125
NYMEX Henry Hub buy put average	US$/MMBtu	$—	$—	$—	$3.08	$3.15	$3.03
NYMEX Henry Hub sell call average	US$/MMBtu	$—	$—	$—	$4.30	$4.78	$4.89

1 – Prices per unit and volumes per day are represented at the average amounts for the period.
2 – Additional contracts were layered into the Company's existing risk management portfolio as part of the Company's risk management policy. The Company does not seek to speculate on commodity price movements through the hedging program.

Royalty expense

$000s	Q4 2023	Q4 2022	2023	2022
Royalty expense	**11,000**	13,023	**38,919**	44,154
As a % of revenue	**9.6 %**	8.2 %	**9.5 %**	8.8 %
$/boe	**4.84**	5.72	**4.72**	6.78

The Company pays Crown, freehold, and overriding royalties on production volumes. Royalties for the three months and year ended December 31, 2023 decreased to $11.0 million and $38.9 million, respectively, as compared to $13.0 million and $44.2 million in the comparative periods of 2022 due to the decline in realized prices over the same period.

The Company continues to benefit from Alberta's drilling and completion cost allowance program, which provides a 5% royalty rate on a well's initial production until the well's cumulative revenue from all hydrocarbon products equals a maximum threshold. Royalties as a percentage of revenue for the three months and year ended December 31, 2023 of 9.6% and 9.5%, respectively, increased over the same periods in 2022 due to more royalties attributable to wells coming off the royalty allowance program in 2023 as compared to the prior periods.

Operating expenses

$000s	Q4 2023	Q4 2022	2023	2022
Operating expenses	**19,428**	16,399	**70,250**	63,204
$/boe	**8.55**	7.20	**8.52**	9.70

Operating costs include amounts incurred to extract commodities to the surface including expenditures for field operators, gas and liquids processing, gathering and compression, utilities, chemicals and maintenance related costs. Operating costs during the three months and year ended December 31, 2023 increased by 18.5% to $19.4 million and by 11.1% to $70.3 million, respectively, due to increased production volumes on an annual basis and higher levels of activity.

For the three months ended December 31, 2023, operating expenses per boe increased by 18.7% to $8.55/boe as a result of overall inflationary cost pressure and higher maintenance costs incurred during 2023. The Company aligned the timing of its prior year maintenance activities with its plant turnaround in the third quarter of 2022 to limit production downtime, leading to decreased operating costs in the fourth quarter of 2022.

On a per barrel basis, operating expenses for the year ended December 31, 2023 decreased by 12.2% to $8.52/boe as higher production led to operating efficiencies. In addition, 2022 operating costs included incremental costs related to facility turnaround costs and a decision to use temporary flowback equipment ahead of permanent tie-in operations to accelerate profitable new well production in the first half of 2022.

Transportation expenses

$000s	Q4 2023	Q4 2022	2023	2022
Transportation expenses	**12,479**	12,000	**46,214**	34,628
$/boe	**5.49**	5.27	**5.61**	5.31

Transportation expenses are incurred to deliver oil and natural gas commodities from the Company's production sites to the delivery point of sale. The Company has contracted for firm transportation service on the Alliance pipeline system from Alberta to Chicago and on the NGTL system in Alberta. The balance of costs pertains to trucking charges and pipeline fees related to oil, NGL and condensate transportation charges.

Transportation expenses for the three months and year ended December 31, 2023 were $12.5 million and $46.2 million, respectively, as compared to $12.0 million and $34.6 million in the respective 2022 periods. Per barrel transportation expenses increased by 4.2% to $5.49/boe and 5.6% to $5.31/boe over the same periods. The increase resulted from the Company flowing a higher proportion of natural gas production to the higher cost Alliance pipeline in 2023, pipeline toll and annual rate increases on transportation contracts, and higher costs for trucking in the fourth quarter of 2023 as a result of changes in production composition.

Adjusted funds flow from operations

$000s	Q4 2023	Q4 2022	2023	2022
Cash flows from operating activities	**58,946**	87,028	**240,760**	242,850
Net change in non-cash working capital from operating activities	**3,786**	11,238	**(4,290)**	16,280
Asset retirement obligation expenditures	**198**	3,184	**4,074**	4,771
Transaction costs	**767**	56	**767**	181
Adjusted funds flow from operations [1]	**63,697**	101,506	**241,311**	264,082
$/boe	**28.02**	44.59	**29.27**	40.53

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

Adjusted funds flow from operations during the three months and year ended December 31, 2023 decreased to $63.7 million and $241.3 million relative to the comparative periods in 2022 ($101.5 million and $264.1 million, respectively.)

On a per barrel basis, adjusted funds flow from operations during the three months and year ended December 31, 2023 decreased by 37% to $28.02/boe and 28% to $29.27/boe, respectively, relative to the comparable periods of 2022. Declines in 2023 were driven by the reduction in adjusted operating netbacks described above and increased financing costs resulting from higher average debt levels outstanding at higher interest rates.

The Company's cash flow from operating activities was $58.9 million and $240.8 million for the three months and year ended December 31, 2023.

Free funds flow from operations

$000s	Q4 2023	Q4 2022	2023	2022
Adjusted funds flow from operations [1]	**63,697**	101,506	**241,311**	264,082
Capital expenditures [1]	**(76,410)**	(102,708)	**(306,985)**	(269,729)
Free funds flow deficiency from operations [1]	**(12,713)**	(1,202)	**(65,674)**	(5,647)
$/boe	**(5.59)**	(0.53)	**(7.97)**	(0.87)

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

During the three months and year ended December 31, 2023, the Company had a free funds flow deficiency of $12.7 million and $65.7 million relative to a deficiency of $1.2 million and $5.6 million in the comparative periods of 2022. The increased deficiency in 2023 resulted from the Company continuing to execute a capital program aimed at generating short and longer-term production growth and cash-flow through development of its existing reserve base and investment in infrastructure required to grow production in future periods.

The Company has been able to fund its capital plan through funds flow from operations and available credit facilities. The Company continuously monitors liquidity and financial performance to ensure sufficient balance sheet strength is maintained. If required, the Company has the ability to adjust future capital spending plans to manage liquidity and/or balance sheet constraints.

General and administrative ("G&A") expenses

$000s	Q4 2023	Q4 2022	2023	2022
Gross G&A expenses	**7,209**	5,521	**24,561**	20,327
Less capitalized G&A	**(1,035)**	(1,038)	**(3,853)**	(2,826)
G&A Expenses	**6,174**	4,483	**20,708**	17,501
$/boe	**2.72**	1.97	**2.51**	2.69

For the three months and year ended December 31, 2023, the Company incurred gross G&A expenses of $7.2 million and $24.6 million, respectively, as compared to $5.5 million and $20.3 million in the comparable periods of 2022, with the increases attributable to Company growth and increased activity levels since 2022.

On a per barrel basis, G&A expenses for the year ended December 31, 2023 decreased by 7% to $2.51/boe compared to the prior year due to the larger production base on an annual basis, offset by higher activity in 2023. For the three months ended December 31, 2023, G&A per boe increased by 38% to $2.72/boe as a result of increased business development activity and higher professional fees incurred in the fourth quarter of 2023.

The Company's G&A expense encompasses corporate activity, the upstream business, and the development of the power business, including the development of renewable and natural gas-fired power generation projects. In addition, the Company continues to evaluate business development opportunities in upstream, power, and carbon capture technology. Administrative and other overhead costs related to development of these activities are also captured within G&A.

Share-based compensation expenses

$000s	Q4 2023	Q4 2022	2023	2022
Equity-settled awards	**1,141**	1,454	**4,494**	9,217
Cash-settled awards	**484**	1,541	**2,207**	2,053
Total share-based compensation expenses	**1,625**	2,995	**6,701**	11,270
$/boe	**0.71**	1.32	**0.81**	1.73

Share-based compensation is the compensation expense recognized for non-cash equity-settled incentive plans including stock options and performance warrants and cash-settled incentive plans including deferred share units, performance share units and restricted share units. The compensation expense for equity-settled awards is based on an estimated grant date fair value of the stock options and warrants, recognized over a graded vesting period by tranche, which results in a higher upfront expense recorded in the earlier years of the vesting periods. The compensation expense related to cash-settled awards is calculated using the fair value method based on the trading price of the Company's shares at the end of each reporting period after adjusting for an estimated forfeiture rate, vesting period, and any applicable performance criteria with changes in fair value recognized as share-based compensation expense.

Total share-based compensation was $1.6 million and $6.7 million for the three months and year ended December 31, 2023 compared to $3.0 million and $11.3 million in the comparable prior year periods due to the graded nature of vesting with the decline on a per barrel basis also attributable to higher production levels in 2023.

Finance costs

$000s	Q4 2023	Q4 2022	2023	2022
Interest and bank charges	**4,400**	2,633	**16,392**	7,424
Accretion of asset retirement obligations	**1,001**	841	**3,677**	2,411
Interest on lease obligations	**533**	216	**1,405**	446
Deferred financing amortization	**160**	322	**914**	1,291
Unrealized gain on foreign exchange	**822**	(208)	**683**	(2,079)
Total finance costs	**6,916**	3,804	**23,071**	9,493
$/boe	**3.04**	1.67	**2.80**	1.46

The Company has a $375 million senior secured extendible revolving facility (the "Credit Facility") with a syndicate of banks. As at December 31, 2023 the Company had drawn $195.0 million on the facility (December 31, 2022 - $102.1 million).

The increase in financing costs for the three months and year ended December 31, 2023 is associated with higher average debt levels and higher interest rates when compared to the comparable prior year periods. During the three months and year ended December 31, 2023 the average outstanding debt was approximately $77 million and $80 million higher than during the same periods in 2022. Average interest rates were approximately 8.2% for the year ended December 31, 2023 (2022 - approximately 6.0%).

Depletion and Depreciation

$000s	Q4 2023	Q4 2022	2023	2022
Depletion	**37,501**	34,717	**126,200**	81,717
Depreciation	**543**	430	**1,950**	1,497
Total depletion and depreciation	**38,044**	35,147	**128,150**	83,214
$/boe	**16.74**	15.44	**15.54**	12.77

Increases in depletion per barrel for the three months and year ended December 31, 2023 are attributable to a greater depletable base resulting from the Company's capital development plan and an increase in year over year estimated future development costs assigned through the Company's 2023 reserve report. Increases in future development costs arose from inflationary pressures and the reallocation of capital to higher liquids developments along with other assumptions utilized by external reserve evaluators, and were offset by an increase in proved and probable reserves assigned.

The Company recognized depletion of $37.5 million for the three months ended December 31, 2023 (2022 - $34.7 million) with the increase due to a higher depletion rate per barrel, slightly offset by a 0.2% decrease in production over the respective periods. Depletion expense for the year ended December 31, 2023 was $126.2 million (2022 - $81.7 million) with the increase due to the greater depletion rate combined with a 26.5% increase in production over the comparative period.

On a per barrel basis, depletion and depreciation costs of $15.54 were incurred during 2023 (2022 - $12.77) which is in line with the Company's long term finding and development costs on a total proved and probable basis as calculated based on the Company's 2023 reserve report.

Income taxes

During the year ended December 31, 2023, the Company incurred approximately $0.2 million in income taxes relating to the Company's United States subsidiary. The Company did not pay any Canadian income taxes in 2023 and does not expect to be taxable in Canada in the near future. As of December 31, 2023, the Company recognized a net deferred tax liability of $10.0 million. The Company's estimated tax pools as at December 31, 2023, are as follows:

Category	Deductibility	$000s
Canadian oil and gas property expense ("COGPE")	10%	187,047
Successored COGPE	10%	1,059
Canadian development expense ("CDE")	30%	201,636
Successored CDE	30%	55,922
Canadian exploration expense ("CEE")	100%	—
Successored CEE	100%	—
Undepreciated capital cost ("UCC")	Primarily 25%, declining balance	170,917
Non-capital losses	100%	225,431
Share/Debt issue costs	5-year straight line	2,853
Other	Various	363
Total estimated tax pools		845,228

Asset retirement obligations

The Company's asset retirement obligations ("ARO") pertain to the Company's wells and related infrastructure. The estimated ARO includes assumptions with respect to actual costs to abandon wells or reclaim the property, the time frame in which such costs will be incurred, and annual inflation factors. The Company estimates the total undiscounted, uninflated, future cash flows to settle its ARO is $112.1 million, or $168.5 million inflated at 1.62% and undiscounted. These cash flows have been discounted using a risk-free interest rate of 3.02% to arrive at the present value estimate of $82.3 million.

There is approximately $26.7 million (December 31, 2022: $31.7 million) of abandonment and reclamation costs associated with inactive wells or facilities where there are no active operations or attributed reserves. Kiwetinohk is currently working on an abandonment program to reduce significantly the inactive decommissioning liabilities over the next five to seven years which exceeds the minimum regulatory requirements.

Select annual information

($000s except per share and production)	2023	2022	2021
Production (average boe/d)	**22,587**	17,852	9,801
Commodity sales from production ($000)	**411,826**	499,898	182,668
Commodity sales from purchases ($000)	**75,573**	268,552	114,517
Cash flow from operating activities	**240,760**	242,850	35,820
Per share (basic)	**5.48**	5.51	1.13
Per share (diluted)	**5.41**	5.45	1.13
Net income (loss)	**111,896**	190,989	(22,315)
Per share (basic)	**2.54**	4.34	(0.70)
Per share (diluted)	**2.52**	4.28	(0.70)
Total assets	**1,085,615**	932,650	614,337
Long-term liabilities	**305,735**	221,731	124,587
Net debt [1]	**186,523**	122,304	51,512
Adjusted working capital surplus (deficit) [1]	**7,565**	(3,105)	18,644

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

Select quarterly information

($000s except per share and production)	2023				2022			2021
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Production (average boe/d)	**24,707**	21,218	20,432	23,996	24,745	16,487	16,810	13,253
Commodity sales from production	**114,038**	94,432	83,935	119,421	159,457	122,644	137,931	79,866
Commodity sales from purchases	**18,136**	19,464	17,475	20,498	47,902	77,623	82,429	60,598
Cash flow from operating activities	**58,946**	60,294	41,360	80,160	87,028	91,710	38,780	25,332
Per share (basic)	**1.35**	1.37	0.94	1.81	1.97	2.08	0.88	0.58
Per share (diluted)	**1.33**	1.36	0.93	1.79	1.94	2.05	0.87	0.58
Net income (loss)	**48,302**	(12,056)	21,701	53,949	115,308	55,379	44,854	(24,552)
Per share (basic)	**1.11**	(0.27)	0.49	1.22	2.61	1.26	1.02	(0.56)
Per share (diluted)	**1.09**	(0.27)	0.49	1.21	2.57	1.24	1.01	(0.56)

Capital resources and liquidity

The Company's objective when managing its balance sheet is to maintain a conservative capital structure that provides financial flexibility to address contingencies and execute on strategic business opportunities. The Company relies on cash flow from operating activities, available funding capacity on the Credit Facility and future equity or debt issuances to fund its capital requirements and any potential acquisitions. The Company anticipates that cash flow from operating activities and availability on its Credit Facility will be sufficient to meet working capital requirements and fund the Company's 2024 capital program.

Credit Facility

On May 31, 2023 the Company completed the annual borrowing base review of the consolidated Credit Facility and confirmed no changes to the borrowing base of $375.0 million. The borrowing base is comprised of an operating facility of $65.0 million and a syndicated facility of $310.0 million.

At December 31, 2023, $195.0 million before deferred financing costs (December 31, 2022 - $119.7 million) was outstanding on the Credit Facility along with $89.4 million (December 31, 2022 - $40.8 million) in letters of credit issued to support transportation and other commitments, of which, $66.1 million has been provided for through the EDC facility (see below), and the remaining $23.3 million were issued under the Credit Facility and reduce the available operating facility capacity.

$000s	Borrowing capacity	Drawn	Letters of credit	Available Capacity
Credit Facility	375,000	195,000	23,300	**156,700**
EDC Facility	75,000	—	66,100	**8,900**
Total				**165,600**

$000s	2023	2022
Credit facility drawn	**195,000**	119,738
Deferred financing costs	**(912)**	(539)
Loans and borrowings	**194,088**	119,199
Adjusted working capital (surplus) deficit [1]	**(7,565)**	3,105
Net debt [1]	**186,523**	122,304
Annualized adjusted funds flow from operations [1]	**241,311**	264,082
Net debt to annualized adjusted funds flow from operations [1]	**0.77**	0.46

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

The Credit Facility is a 364-day committed facility available on a revolving basis which was extended until May 31, 2024, 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, 2025. The borrowing base is determined based on the lenders' evaluation of the Company's petroleum and natural gas reserves at the time and commodity prices.

Interest payable on amounts drawn under the Credit Facility is charged at the prevailing bankers' acceptance rate plus the applicable stamping fees, lenders' prime rate or U.S. base rate plus the applicable margins, depending on the form of borrowing by the Company. The applicable margins and stamping fees are based on a sliding scale pricing grid tied to the ratio of the Company's debt to earnings before interest, taxes, depreciation and amortization ("bank EBITDA ratio"): 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 the relevant bankers' acceptance 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 percent to 1.5625 percent based on the Company's bank EBITDA ratio.

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

The Company plans to continue using the Credit Facility for working capital purposes and to fund go forward capital plans in advance of cash flow from new investments and targets a net debt to last-twelve-months of adjusted funds flow from operations ratio of no more than 1.0 times (2023 - 0.77 times).

EDC letter of credit facility

On June 5, 2023, Kiwetinohk amended and increased the unsecured demand revolving letter of credit facility (the "LC Facility") with Export Development Canada ("EDC") from $15.0 million to $75.0 million. Kiwetinohk's obligations under the LC Facility are supported by a performance security guarantee ("PSG") granted by EDC to the Credit Facility lender to guarantee the payment of certain amounts in respect of LCs. The PSG is valid to May 31, 2024 and may be extended from time-to-time at the option of Kiwetinohk and with the agreement of EDC. At December 31, 2023, the Company has $8.9 million of capacity remaining under the LC Facility (December 31, 2022 - $0.6 million).

Base shelf prospectus

The Company filed a short-form base shelf prospectus ("Prospectus") in April 2022 with no immediate plan to raise equity or debt. The prospectus provides 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. Net proceeds from the sale of any securities issued under the Prospectus could have a wide range of uses including to complete asset or corporate acquisitions, to finance potential future growth opportunities, to repay indebtedness, to finance the Company's ongoing capital program, or for other general corporate purposes.

Share capital

The Company is authorized to issue an unlimited number of voting common shares and an unlimited number of preferred shares, issuable in series.

On December 20, 2022, the Company announced the approval of its normal course issuer bid ("NCIB") to purchase and cancel up to 2.2 million Common Shares over a 12-month period, commencing December 22, 2022. On December 19, 2023, the NCIB was renewed for an additional 12-month period, allowing the Company to purchase and cancel up to 2.2 million Common Shares prior to December 22, 2024.

During the year ended December 31, 2023, the Company purchased 598,776 Common Shares under the NCIB program at a total cost of $7.6 million (an average price of $12.71 per share). The Company weighs the benefits to shareholders of allocating funds to new capital expenditures versus utilizing the NCIB program and will continue to monitor the use of the NCIB program throughout 2024 with the amount and timing of any purchases depending, among other things, on the share price, commodity prices and overall budget projections.

(000s)	Q4 2023	Q4 2022	2023	2022
Weighted average shares outstanding				
Basic	**43,711**	44,168	**43,971**	44,046
Diluted	**44,172**	44,888	**44,467**	44,594
Outstanding securities				
Common shares	**43,663**	44,177	**43,663**	44,177
Stock options[1]	**2,768**	2,717	**2,768**	2,717
Performance warrants[1]	**6,779**	7,555	**6,779**	7,555
Total diluted outstanding securities	**53,210**	54,449	**53,210**	54,449

1 - Balance presented includes all potentially dilutive stock options and performance warrants issued and outstanding and is not limited to those currently available for exercise. Refer to Note 13 of the Consolidated Financial Statements for further information regarding share based compensation plans.

At March 5, 2024, the Company has 43,662,644 Common Shares and no preferred shares outstanding.

Commitments, contractual obligations, and contingencies

$ millions	2024	2025	2026	2027	2028	Thereafter
Accounts payable	59.3	—	—	—	—	—
Cash-settled compensation liability [1]	1.2	0.7	0.1	—	—	1.2
Loans and borrowings [2]	—	195.0	—	—	—	—
Gathering, processing and transport	77.3	68.1	15.8	17.2	17.3	23.1
Natural gas purchases	11.9	—	—	—	—	—
Upstream and corporate lease liabilities	1.8	2.2	2.2	2.2	2.2	5.7
Power lease liabilities[3]	2.0	1.3	1.3	1.3	1.3	25.9
Power construction	—	0.6	—	—	—	—
Other	0.4	0.4	0.4	0.4	0.4	0.4
Total	153.9	268.3	19.8	21.1	21.2	56.3

1 – Cash outflows relating to the DSU cash-settled compensation liability will be paid when each director retires. The Company has no available information to estimate the year of cash outflow and therefore the entirety of the DSU expected outflow has been assigned to “Thereafter”.
2 – Assumes current debt drawn is repaid at the current maturity date of the Credit Facility.
3 – The Company has not reached a final investment decision ("FID") on power projects as of the date hereof. The Company has the ability to terminate the lease and remove this financial obligation if FID is not achieved.

The Company currently has natural gas transportation commitments on the Nova Gas Transmission Ltd. and Alliance pipelines, with a commitment to deliver approximately 120.0 MMcf per day of gas to Chicago on Alliance through October 2025.

The Company currently has secured 16,800 GJ per day of gas supply (approximately 14.8 MMcf per day) from natural gas producers through October 2024, allowing the Company to fully utilize its remaining Alliance pipeline capacity after taking into account deliveries of its own production.

Lease liabilities represent the undiscounted payments required under lease obligations as described in Note 6 of the consolidated financial statements.

The Company may be involved in litigation and disputes arising in the normal course of operations. Management is of the opinion that any potential litigation will not have a material adverse impact on the Company’s financial position or results of operations as at December 31, 2023.

Related party information

For the quarter and year ended December 31, 2023, the Company incurred a total of $0.1 million and $0.7 million, respectively (December 31, 2022 – $0.1 million and $1.4 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; and
- The Company has engaged an energy information services company to assist in the evaluation of prospective upstream oil and gas properties. A director of the Company is the Chairman of the Board of Directors of this company.

All related party transactions are incurred in the normal course of operations and recorded at the exchange amount which approximates the fair value of the services provided. There are no contractual commitments associated with related parties.

Environment, social and governance

Kiwetinohk regularly reviews its environmental, social and governance ("ESG") risks and management strategies, and published its 2023 ESG report (for the 2022 reporting year) on November 9, 2023 in alignment with the Sustainability Accounting Standards Board ("SASB") data standards for Oil & Gas – Exploration and Production and with the Task Force on Climate-related Financial Disclosures ("TCFD") framework.

Risk factors and risk management

The Company's management team is focused on long-term strategic planning and has identified key material risks, uncertainties and opportunities associated with the Company's business that can impact the financial position, operations, cash flows and future prospects of the business. The following information is a summary of only certain risk factors, and is not an exhaustive list, nor should it be taken as a complete summary or description of all risks relating to the Company or its securities and should be read in conjunction with the "Risk Factors" as presented in the Company's AIF dated March 5, 2024 available on the SEDAR+ website at www.sedarplus.ca.

• risks associated with developing and operating the power generation and renewable energy business;	• licenses and permits;
• substantial capital requirements to conduct future operations and acquire and develop reserves;	• government regulations;
• the ability of the Company to achieve its investment and development objectives;	• industry shortages;
• possible shortage of fresh water and surface and groundwater licenses;	• health, safety and environmental risks;
• natural gas, oil and electricity demand and prices;	• competition in the crude oil and natural gas industry;
• exploration, development and production risks;	• greenhouse gas emissions regulations, carbon taxes and environmental compliance costs;
• risks associated with exploration, development and production of crude oil and natural gas, and drilling for unconventional oil, NGL and natural gas;	• development of regulatory and voluntary emissions offset regulations and markets;
• hydraulic fracturing and seismic activity;	• coronavirus, variants or derivations of it and other pandemics;
• government regulations;	• market constraints, including processing and transportation, and access to services and equipment;
• the ability of the Company to successfully execute its energy transition strategy;	• talent, recruitment and retention of key personnel;
• the risks and limitations of forecasting reserves data;	• technology and cybersecurity risks;
• global economic and financial conditions;	• seasonality and climate related risks;
• interest, currency and inflation rates and supply chain issues;	• environmental, health and safety requirements; and
• capital market and industry conditions;	• the other factors discussed under "Risk Factors" within the Company's AIF.

In order to reduce risk the Company employs subject matter experts that are highly qualified professionals with clearly defined roles and responsibilities, seeks to operate and control the majority of properties and projects that it invests in, utilizes proven technologies and pursues new technologies where appropriate.

Control environment

Disclosure controls and procedures

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

Kiwetinohk’s Chief Executive Officer and the Chief Financial Officer evaluated the effectiveness of the design and operation of the Company’s DC&P. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded the Company’s DC&P were effective as at December 31, 2023.

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

Internal controls over financial reporting

Internal controls over financial reporting (“ICFR”), as defined in NI 52-109 Certification of Disclosure in Issuers’ Annual and Interim Filings, is a set of processes designed to provide reasonable assurance that all assets are safeguarded, transactions are appropriately authorized, and facilitate the preparation of relevant, reliable, and timely information. It should be noted that a control system, including the Company's disclosure and internal controls and procedures, no matter how well conceived can provide only reasonable, but not absolute assurance that the objectives of the control system will be met, and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud.

Kiwetinohk’s Chief Executive Officer and the Chief Financial Officer evaluated the effectiveness of the Company’s ICFR as defined in Canada by NI 52-109. The assessment was based on the framework in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded the Company’s ICFR was effective as of December 31, 2023. No changes were made to the Company’s ICFR during the year ended December 31, 2023 that have materially affected, or are reasonably likely to materially affect, the ICFR.

Financial reporting

Critical accounting estimates

The significant accounting judgements and estimates used by the Company are discussed in the notes of the December 31, 2023 financial statements. Certain accounting policies require that management make appropriate decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, and expenses. Management reviews its estimates on a regular basis. The emergence of new information and changed circumstances may result in actual results or changes to estimate amounts that differ materially from current estimates.

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

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

Future Accounting Pronouncements

The following are future accounting pronouncements issued and not yet effective as at December 31, 2023. The Company intends to adopt these standards as they become effective and is in the process of evaluating the impacts, if any, on the consolidated financial statements and does not expect a significant impact.

IAS 1 Presentation of Financial Statements
Effective January 1, 2024, amendments to the classification of a liability as current or non-current require that only covenants with which an entity is required to comply on or before the reporting date affect the classification of a liability as current or non-current. An entity also has to disclose information to convey the risk to users that non-current liabilities with covenants could become repayable within twelve months. This is not expected to have a material impact on the Company's financial statements.

IAS 7 Statement of Cash Flows & IFRS 7 Financial Instruments: Disclosures
Effective January 1, 2024, amendments in Supplier Finance Arrangements do not define supplier finance arrangements and instead provide the characteristics of an arrangement for which an entity is required to provide the information and add various disclosure objectives and requirements to sufficiently explain the impact of these arrangements on the financial statements. Additionally, supplier finance arrangements are added as an example within the liquidity risk disclosure requirements. This is not expected to have a material impact on the Company's financial statements.

IFRS 16 Leases
Effective January 1, 2024, amendments to the sale and leaseback subsequent recognition criteria require a seller-lessee to subsequently measure the lease liability arising from a leaseback in a way that does not recognize any amount of the gain or loss that relates to the right of use it retains. This is not expected to have a material impact on the Company's financial statements.

Financial instruments and risk management

The Company's financial instruments are classified and measured at amortized cost or fair value through profit or loss ("FVTPL").

Financial assets are measured at amortized cost if the financial asset is held within a business model whose objective is to hold financial assets in order to collect contractual cash flows, and the contractual cash flows give rise on specified dates to cash flows that are solely payments of principal and interest on the principal amount outstanding. All other financial assets are measured at FVTPL.

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

Credit risk

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

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

Liquidity risk

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

Market risk

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

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

Off-balance sheet arrangements

Except as disclosed in the Financial Statements, the Company has not entered into any guarantee or off-balance sheet arrangements that would materially impact the financial position or results of operations as at December 31, 2023.

Other

Non-GAAP and other financial measures

Throughout this MD&A and in other materials disclosed by the Company, the Company uses various specified financial measures including "non-GAAP financial measures", "non-GAAP financial ratios" and "capital management measures", as defined in National Instrument 52-112 Non-GAAP and Other Financial Measures Disclosure and explained in further detail below. These non-GAAP and other financial measures presented in this MD&A should not be considered in isolation or as a substitute for performance measures prepared in accordance with IFRS and should be read in conjunction with the Financial Statements. Readers are cautioned that these non-GAAP measures do not have any standardized meanings and should not be used to make comparisons between Kiwetinohk and other companies without also taking into account any differences in the method by which the calculations are prepared.

Non-GAAP Financial Measures

Operating netback & adjusted operating netback

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

$000s	Q4 2023	Q4 2022	2023	2022
Commodity sales from production	**114,038**	159,457	**411,826**	499,898
Royalty expenses	**(11,000)**	(13,023)	**(38,919)**	(44,154)
Operating expenses	**(19,428)**	(16,399)	**(70,250)**	(63,204)
Transportation expenses	**(12,479)**	(12,000)	**(46,214)**	(34,628)
Operating netback	**71,131**	118,035	**256,443**	357,912
Realized gain (loss) on risk management	**523**	(14,961)	**12,323**	(86,859)
Realized gain (loss) on risk management - purchases	**2,718**	(5,380)	**13,934**	(34,079)
Net commodity sales from purchases (loss)	**(1,152)**	7,174	**(6,642)**	46,069
Adjusted operating netback	**73,220**	104,868	**276,058**	283,043

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

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

$000s	Q4 2023	Q4 2022	2023	2022
Cash flow used in investing activities	**67,044**	103,343	**303,031**	330,152
Net change in non-cash investing working capital	**(8,634)**	(635)	**(5,791)**	3,400
Settlement of contingent consideration	**—**	—	**(10,250)**	(6,500)
Capital expenditures and net acquisitions (dispositions)	**58,410**	102,708	**286,990**	327,052
Cash used in acquisitions	**—**	—	**(1,286)**	(61,681)
Proceeds from disposition	**18,000**	—	**21,281**	4,358
Net (dispositions) acquisitions	**18,000**	—	**19,995**	(57,323)
Capital expenditures	**76,410**	102,708	**306,985**	269,729

Earnings before interest and taxes

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

$000s	Q4 2023	Q4 2022	2023	2022
Net income	**48,302**	115,308	**111,896**	190,989
Finance costs	**6,916**	3,804	**23,071**	9,493
Total income taxes (recovery)	**18,793**	(23,671)	**33,961**	(23,671)
EBIT	**74,011**	95,441	**168,928**	176,811

Average capital employed

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

$000s	2023	2022
Beginning of year		
Shareholders' equity	**600,619**	397,434
Net debt	**122,304**	51,512
Capital employed	**722,923**	448,946
End of year		
Shareholders' equity	**710,202**	600,619
Net debt	**186,523**	122,304
Capital employed	**896,725**	722,923
Average capital employed	**809,824**	585,935

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

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

Non-GAAP Financial Ratios

Operating netback per boe & adjusted operating netback per boe

"Operating netback per boe" and "adjusted operating netback per boe" is calculated as operating netback and adjusted operating netback, respectively, divided by total production for the period as measured by boe. Operating netback per boe and adjusted operating netback per boe are key industry benchmarks and assist management with evaluating operating performance and efficiency on a comparable basis. The Company has disclosed the calculations of operating netback per boe & adjusted operating netback per boe in this MD&A within the Results of Operations section.

Adjusted funds flow from operations per boe

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

Return on average capital employed

"Return on average capital invested" or "ROACE" is calculated as EBIT divided by the average capital employed. ROACE is used by management to measure the effectiveness of its capital management and its ability to generate returns for shareholders. The following table includes the updated calculation of ROACE for the years ended December 31, 2023 and 2022.

$000s	2023	2022
Earnings before interest and taxes	**168,928**	176,811
Average capital employed	**809,824**	585,935
ROACE	**21%**	30%

Capital Management Measures

Adjusted funds flow from operations

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

Free funds flow (deficiency) from operations

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

Adjusted working capital surplus (deficit)

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

$000s	2023	2022
Current assets	**87,951**	96,062
Current liabilities	**(69,678)**	(110,300)
Working capital surplus (deficit)	**18,273**	(14,238)
Short term risk management contracts net liability (asset)	**(10,708)**	11,133
Adjusted working capital surplus (deficit)	**7,565**	(3,105)

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

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

Supplementary Financial Measures

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

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

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

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

Forward-Looking Statements

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

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

- the Company's vision of incorporating carbon capture technology and hydrogen production to its portfolio, all as a part of a broader, integrated portfolio of clean energy assets;
- the Company's growth strategy, including identification and development of natural gas-fired power generation and renewable projects and the Company's plans the power portfolio to create future profitable markets for the Company's natural gas production;
- the Company's 2024 financial and operational guidance;
- the timing and amount of cash taxes for the Company's US subsidiary and the Company's expectations regarding being taxable in Canada and the timing thereof;
- timing and costs related to a potential future expansion of the 5-31 gas plant and the associated expected increase to inlet capacity;
- receipt of further clarity from provincial and federal governments regarding pending electricity regulations;
- successful execution of the Company's power projects and the impacts thereof;
- expectations regarding the bringing on-stream of the Duvernay pad and the timing thereof;
- timing for the Company's Homestead Solar project to reach FID and COD;
- receipt of regulatory approvals, including AUC transmission line approval, for the Company's power projects, including the Homestead Solar and Opal Firm Renewable projects, and timing thereof;
- submission of applications and receipt of certain regulatory approvals, for the broader power portfolio, and timing thereof;
- the duration and outcome of AUC hearings if required on its power projects;
- the expected structure of a financing arrangement for power projects, or the portfolio, including external capital and/or sale of projects;
- the anticipated outcomes of successful execution of the Company's investment and financing strategies for its power project portfolio;
- the Company's expectations of costs required to bring power projects to FID;
- the Company's use and development of carbon hubs;
- development, evaluation and permitting of the Company's solar and gas-fired power portfolio;
- perceived benefits of the Company's hub projects;
- expectations regarding Kiwetinohk being the primary user of its awarded carbon hubs;
- future investigations by the Company of CCS;
- anticipated contingent payments from acquisitions and the timing thereof;
- the timing and costs of the Company's capital projects, including, but not limited to, drilling, production and completion of certain wells;
- the continuing costs of engineering and procurement;
- the anticipated outcomes of the Company's capital program;
- expectations regarding the Company's working capital requirements and funding of the Company's capital program;
- estimated nameplate capacity for the Company's power development portfolio;
- anticipated well production;
- asset retirement obligations and the estimated future cash flows to settle such obligations;
- the expectation of reducing the inactive asset retirement obligations over the next five to seven years through the creation of an abandonment program;
- operating and capital costs in 2024;
- sufficiency of funds to meet the Company's working capital requirements and anticipated drilling through 2024;
- timing for the next scheduled redetermination of the borrowing base on the Company's consolidated Credit Facility and EDC letter of credit facility;
- 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;
- the Company's expectations on timing and use of the NCIB program during 2024;
- the Company's expectations regarding the impact of future accounting pronouncements on the consolidated financial statements;

- expectations regarding the Company’s ability to continue to manage risk through hedging contracts and risk management contracts;
- the Company’s ability to continue to meet its pipeline transportation commitments;
- expectations regarding the future risk associated with take or pay pipeline obligations;
- the Company’s ability to continue to benefit from Alberta’s drilling and completion cost allowance program;
- the expected demand for, and prices and inventory levels of, petroleum products, including NGL;
- the impact of current market conditions on the Company;

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

- the expectation of ~90% of natural gas sales being directed to the Chicago market during 2024;
- the timing and costs of the Company's capital projects, including drilling and completion of certain wells;
- costs to abandon wells or reclaim property;
- the expectation of adding value through delineating the Duvernay and Montney assets and retaining core land;
- the impact of the Federal Government's draft CER
- the impact of the Generation Approvals Pause Regulation on renewable development;
- 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 impact that the Company's projects under development will have on the power grid, including its ability to create a stable and sustainable power supply;
- the Company's unique position to deliver additional value to shareholders;
- the regulatory framework regarding royalties, taxes, power, renewable and environmental matters in the jurisdictions in which the Company operates;
- the ability of the Company to obtain the required capital to finance its exploration, development and other operations and meet its commitments and financial obligations;
- the ability of the Company to extend the PSG under the EDC LC Facility;
- the ability of the Company to secure adequate product processing, transportation, fractionation and storage capacity on acceptable terms and the capacity and reliability of facilities;
- anticipated timelines and budgets being met in respect of drilling and completions programs and other operations;
- the impact of natural disaster, war, hostilities, civil insurrection, pandemics (including COVID-19), instability and political and economic conditions (including the ongoing Russian-Ukrainian conflict) on the Company;
- the ability of the Company to successfully market its products;
- power project debt will be held at the project level;
- power projects will be funded by third parties, as currently anticipated; and
- the Company's operational success and results being consistent with current expectations.

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

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

- those risks set out in the AIF under "Risk Factors";
- the ability of management to execute its business plan;
- general economic and business conditions;
- the ability of the Company to proceed with the power generation projects as described or at all;
- risks of natural disaster, war, hostilities, civil insurrection, pandemics (including COVID-19), instability and political and economic conditions (including the ongoing Russian-Ukrainian conflict) in or affecting jurisdictions in which the Company operates;
- the risks of the power and renewable industries;
- operational and construction risks associated with certain projects;
- the possibility that government policies or laws may change or governmental approvals may be delayed or withheld;
- risks relating to regulatory approvals and financing;
- uncertainty regarding provincial and federal government electricity regulations and policies;
- uncertainty involving the forces that power certain renewable projects;
- the Company's ability to enter into or renew leases;
- potential delays or changes in plans with respect to power and solar projects or capital expenditures;
- risks associated with rising capital costs and timing of project completion;
- fluctuations in commodity and power prices, foreign currency exchange rates and interest rates;
- inflation and increased pricing and costs for services, personnel and other items;
- risks inherent in the Company's marketing operations, including credit risk;
- health, safety, environmental and construction risks;
- risks associated with existing and potential future lawsuits and regulatory actions against the Company;
- uncertainties as to the availability and cost of financing;
- the ability to secure adequate product processing, transportation, fractionation and storage capacity on acceptable terms;
- processing, pipeline and fractionation infrastructure outages, disruptions and constraints;
- financial risks affecting the value of the Company's investments; and
- other risks and uncertainties described elsewhere in this document and in Kiwetinohk's other filings with Canadian securities authorities.

Readers are cautioned that the foregoing list is not exhaustive of all possible risks and uncertainties.

The forward-looking statements and information contained in this MD&A speak only as of the date of this MD&A and the Company undertakes no obligation to publicly update or revise any forward-looking statements or information, except as expressly required by applicable securities laws.

Future Oriented Financial Information

This MD&A contains information that may constitute future-orientated financial information or financial outlook information (collectively, "FOFI") about the Company's prospective financial performance, financial position or cash flows, all of which is subject to the same assumptions, risk factors, limitations and qualifications as set forth above. In particular, this MD&A contains adjusted funds flow from operations and net debt to annualized adjusted funds flow from operations. Readers are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise or inaccurate and, as such, undue reliance should not be placed on FOFI. The Company's actual results, performance and achievements could differ materially from those expressed in, or implied by, FOFI. The Company has included FOFI in order to provide readers with a more complete perspective on the Company's future operations and management's current expectations relating to the Company's future performance. Readers are cautioned that such information may not be appropriate for other purposes. FOFI contained herein was made as of the date of this MD&A. Unless required by applicable laws, the Company does not undertake any obligation to publicly update or revise any FOFI statements, whether as a result of new information, future events or otherwise.

Abbreviations

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

Oil and gas advisories

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

This MD&A includes references to sales volumes of "Oil and condensate", "NGLs" and "Natural gas" and revenues therefrom. National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities, includes condensate within the NGLs product type. The Company has disclosed condensate as combined with crude oil and separately from other NGLs since the price of condensate as compared to other NGLs is currently significantly higher, and the Company believes that this crude oil and condensate presentation provides a more accurate description of its operations and results therefrom. Crude oil therefore refers to light oil, medium oil, tight oil, and condensate. NGLs refers to ethane, propane, butane, and pentane combined. Natural gas refers to conventional natural gas and shale gas combined.

CORPORATE INFORMATION

Management

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Chief Sustainability Officer

Mike Backus
Chief Operating Officer, Upstream

Jakub Brogowski
Chief Financial Officer

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Sue Kuethe
Executive VP, Land and Community Inclusion

Chris Lina
Senior Vice President, Projects

Craig Parsons
Vice President, Finance, Power Division

Fareen Sunderji
President, Power

Lisa Wong
Senior Vice President, Business Systems

Board of Directors

Kevin Brown
Board Chair

Beth Reimer-Heck
Lead Director

Judith Athaide
Director

Colin Bergman
Director

Pat Carlson
Director and Chief Executive Officer

Leland Corbett
Director

Kaush Rakhit
Director

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Director

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Legal Counsel

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Norton Rose Fulbright Canada LLP
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Transfer Agent

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Stock Symbol

KEC
Toronto Stock Exchange