Management’s Discussion and Analysis

This Management’s Discussion and Analysis (“MD&A”) of Pieridae Energy Limited (“Pieridae”, “we”, “our” or the “Company”) provides a review by management of the financial performance and position of the Company, as well as the trends and external factors which may impact our prospects. This MD&A has been prepared as of August 13, 2024, and should be read in conjunction with the Company’s unaudited interim condensed consolidated financial statements and the accompanying notes for the three and six months ended June 30, 2024, (the “Interim Financial Statements”) and the MD&A and audited consolidated financial statements and the accompanying notes for the years ended December 31, 2023 and 2022 (the “Consolidated Financial Statements”), as well as Pieridae’s Annual Information Form (“AIF”). The Interim Financial Statements are prepared in accordance with International Financial Reporting Standards (“IFRS” or “GAAP”) as issued by the International Accounting Standards Board (“IASB”). Our reporting currency is the Canadian dollar. All amounts are presented in Canadian dollars, unless otherwise stated.

When preparing our MD&A, we consider the materiality of information. Information is considered material if (i) such information results in, or would reasonably be expected to result in, a significant change in the market price or value of our shares; (ii) there is a substantial likelihood that a reasonable investor would consider it important in making an investment decision; or (iii) it would significantly alter the total mix of information available to investors. We evaluate materiality with reference to all relevant circumstances, including potential market sensitivity.

Condensate is a natural gas liquid as defined by National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities*. Throughout this MD&A, natural gas liquids (“NGLs”) comprise all NGLs as defined by NI 51-101 other than condensate, which is disclosed separately. Reference is made to crude oil and natural gas in common units called barrel of oil equivalent (“boe”). A boe is derived by converting six thousand cubic feet (“mcf”) of natural gas to one barrel (“bbl”) of crude oil (6 mcf:1 bbl). This conversion may be misleading, particularly if used in isolation, since the 6 mcf:1 bbl ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In comparing the value ratio using current crude oil prices relative to natural gas prices, the 6 mcf:1 bbl conversion ratio may be misleading as an indication of value.

We are publicly traded on the TSX Exchange under the symbol PEA.TO. Continuous disclosure materials are available on our website, www.pieridaeenergy.com, or on SEDAR, www.sedarplus.com.

SPECIAL NOTE REGARDING NON-GAAP FINANCIAL MEASURES

This MD&A includes references to financial measures such as net operating income (“NOI”), netback, operating netback, net debt, adjusted operating expense, adjusted working capital and funds flow from operations (“FFO”). Management believes these financial measures are important to the understanding of our business activities. These financial measures are not defined by IFRS and therefore are referred to as non-GAAP measures. The non-GAAP measures we use may not be comparable to similar measures presented by other companies. We use these non-GAAP measures to evaluate our performance. The non-GAAP measures should not be considered an alternative to, or more meaningful than, measures determined in accordance with IFRS, as an indication of our performance. The non-GAAP measures are reconciled to their closest GAAP measure. Refer to “Non-GAAP Measures” section within this MD&A.

CAUTIONARY NOTE REGARDING FORWARD-LOOKING INFORMATION

Certain of the statements contained herein including, without limitation, management plans and assessments of future plans and operations, our expected capital budget, our future business plan and strategy, our criteria for evaluating acquisitions and other opportunities, our intentions with respect to future acquisitions and other opportunities, plans and timing for development of undeveloped and probable resources, timing of when we may be taxable, estimated abandonment and reclamation costs, plans regarding hedging, wells to be drilled, the weighting of commodity expenses, expected production and performance of oil and natural gas properties, results and timing of projects, access to adequate pipeline capacity and third-party infrastructure, growth expectations, supply and demand for oil, NGLs, and natural gas, industry conditions, government regulations and regimes, and capital expenditures and the nature of capital expenditures and the timing and method of financing thereof, may constitute “forward-looking statements” or “forward-looking information” within the meaning of Applicable Securities Laws (as defined herein) (collectively “forward-looking statements”). Words such as “may”, “will”, “should”, “could”, “anticipate”, “believe”, “expect”, “intend”, “plan”, “potential”, “continue”, “shall”, “estimate”, “expect”, “propose”, “might”, “project”, “predict”, “forecast”, “target”, “goal” and similar expressions may be used to identify these forward-looking statements. These statements reflect management's current beliefs and are based on information currently available to management.

The forward-looking statements are based on current expectations, estimates and projections about the Company and the industry in which we operate, which speak only as of the earlier of the date such statements were made or as of the date of the report or document in which they are contained, and are subject to known and unknown risks and uncertainties that could cause the actual results, performance or achievements of the Company to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such risks and uncertainties include, among others: general economic and business conditions which will, among other things, impact demand for and market prices of the Company's products, and volatility of and assumptions regarding crude oil, natural gas, and NGL prices.

Forward-looking statements involve significant risk and uncertainties. A number of factors could cause actual results to differ materially from the results discussed in the forward-looking statements including, but not limited to, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, volatility of commodity prices, currency fluctuations, imprecision of resources estimates, environmental risks, competition from other producers, incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions, delays resulting from or inability to obtain required regulatory approvals, ability to access sufficient capital from internal and external sources, and the risk factors outlined under "Risk Factors" and elsewhere herein. The recovery and resource estimates of our reserves provided herein are estimates only and there is no guarantee that the estimated resources will be recovered. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements.

Forward-looking statements are based on a number of factors and assumptions which have been used to develop such forward-looking statements, but which may prove to be incorrect. Although we believe that the expectations reflected in such forward-looking statements are reasonable, undue reliance should not be placed on forward-looking statements because we can give no assurance that such expectations will prove to be correct. In addition to other factors and assumptions which may be identified in this document, assumptions have been made regarding, among other things: the impact of increasing competition; the general stability of the economic and political environment in which we operate; the timely receipt of any required regulatory approvals; our ability to obtain qualified staff, equipment and services in a timely and cost efficient manner; the ability of the operator of the projects which we have an interest in to operate the field in a safe, efficient and effective manner; our ability to obtain financing on acceptable terms; the ability to replace and expand oil and natural gas resources through acquisition, development and exploration; the timing and costs of pipeline, storage and facility construction and expansion and our ability to secure adequate product transportation; future oil and natural gas prices; currency, exchange and interest rates; the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which we operate; timing and amount of capital expenditures, future sources of funding, production levels, weather conditions, success of exploration and development activities, access to gathering, processing and pipeline systems, advancing technologies, and our ability to successfully market oil and natural gas products.

Readers are cautioned that the foregoing list of factors is not exhaustive. Additional information on these and other factors that could affect our operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedarplus.com), and at on our website (www.pieridaeenergy.com). Although the forward-looking statements contained herein are based upon what management believes to be reasonable assumptions, management cannot assure that actual results will be consistent with these forward-looking statements. Investors should not place undue reliance on forward-looking statements. These forward-looking statements are made as of the date hereof and we assume no obligation to update or review them to reflect new events or circumstances except as required by applicable securities laws.

Forward-looking statements contained herein concerning the oil and gas industry and our general expectations concerning this industry are based on estimates prepared by management using data from publicly available industry sources as well as from reserve reports, market research, industry analysis, and on assumptions based on data and knowledge of this industry which we believe to be reasonable. However, this data is inherently imprecise, although generally indicative of relative market positions, market shares and performance characteristics. While we are not aware of any misstatements regarding any industry data presented herein, the industry involves risks and uncertainties and is subject to change based on numerous factors.

DEFINITIONS AND ABBREVIATIONS

Bcf	Billion cubic feet	**MMcf**	Million cubic feet
Bcm	Billion cubic metres	**MMBtu**	Million British thermal units
Mcf	Thousand cubic feet	**Bbl**	Barrel
GJ	Gigajoules	**Boe**	Barrel of oil equivalent
USD	United States Dollars		

PIERIDAE'S OBJECTIVES AND STRATEGY

Pieridae is a Canadian energy company headquartered in Calgary, Alberta, and a significant upstream producer and midstream gathering and processing ("G&P") operator with core assets concentrated along the foothills of the Rocky Mountains. Our business is focused on safely producing, processing and delivering treated natural gas, condensate, NGLs and sulphur to market.

We are excited about the opportunities within our asset base and in the regions where we operate. As we continue to mature our deep inventory of conventional drilling prospects, we are focused on diversifying revenue and improving cash flow by increasing third-party utilization of our gathering and processing infrastructure. This infrastructure consists primarily of three major facilities – the "Waterton Facility", the "Jumping Pound Facility" and the "Caroline Facility", which are strategically located in central and southern Alberta to provide customers competitive processing and egress to natural gas, condensate, NGL, and sulphur markets. We continue to leverage the long-term, low decline characteristics of our reserve base and supporting infrastructure to create long-term shareholder value. The following items are also fundamental to our strategic vision:

- Sustaining a safe and regulatory compliant business.
- Building and continuously improving efficient, cost-effective operations.
- Establishing community and Indigenous partnerships.
- Pursuing opportunities to further integrate environmental, social and governance ("ESG") principles into our business, including implementing a carbon emissions management plan targeting significant emissions intensity reductions.

QUARTERLY HIGHLIGHTS

The tables below provide a summary of the consolidated financial results for the quarters of 2024, 2023 and 2022:

	2024		2023				2022	
($ 000s unless otherwise noted)	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Production								
Natural gas (mcf/d)	157,077	175,356	174,211	155,763	159,427	186,156	179,143	181,030
Condensate (bbl/d)	2,472	2,781	2,384	2,020	2,300	2,657	2,469	2,911
NGLs (bbl/d)	2,210	2,613	1,921	2,273	2,216	2,784	2,389	2,876
Sulphur (tonne/d)	1,376	1,491	1,284	1,124	1,362	1,457	1,348	1,312
Total production (boe/d) (1)	30,861	34,620	33,340	30,253	31,087	36,467	34,715	35,959
Third-party volumes processed (mcf/d) (2)	53,763	58,212	70,060	61,093	55,750	63,396	49,304	66,224
Financial								
Natural gas price ($/mcf)								
Realized before Risk Management Contracts (3)	1.14	2.53	2.32	2.65	2.39	3.24	5.08	4.38
Realized after Risk Management Contracts (3)	2.71	3.21	3.12	3.25	3.03	5.12	5.24	3.62
Benchmark natural gas price	1.17	2.48	2.29	2.59	2.40	3.25	5.20	4.28
Condensate price ($/bbl)								
Realized before Risk Management Contracts (3)	99.96	91.18	97.15	97.47	84.81	107.22	110.24	103.71
Realized after Risk Management Contracts (3)	87.75	84.49	86.34	80.49	105.84	106.70	117.67	105.82
Benchmark condensate price ($/bbl)	105.62	98.43	104.30	106.30	93.25	107.05	115.24	115.66
Processing and marketing revenue	4,203	5,072	11,919	6,603	5,410	6,401	9,310	7,650
Net income (loss)	(19,196)	(6,284)	7,414	(16,254)	4,182	13,639	114,662	(1,573)
Net income (loss) $ per share, basic	(0.12)	(0.04)	0.05	(0.11)	0.03	0.09	0.72	(0.01)
Net income (loss) $ per share, diluted	(0.12)	(0.04)	0.03	(0.11)	0.03	0.08	0.70	(0.01)
Net Operating Income (4)	7,652	23,418	25,441	11,650	43,843	49,995	67,711	30,014
Cashflow provided by operating activities	(1,555)	7,049	31,983	7,577	27,533	37,109	40,134	9,899
Funds flow from operations (4)	(4,874)	12,044	14,269	(1,422)	35,432	37,413	57,641	17,721
Total assets	585,940	590,531	638,541	564,921	575,849	587,641	615,477	473,642
Adjusted working capital deficit (5)	(37,986)	(31,671)	(31,830)	(21,454)	(6,258)	(22,275)	(11,249)	(46,419)
Net debt (4)	(219,204)	(209,964)	(204,046)	(205,536)	(181,670)	(202,180)	(214,503)	(254,489)
Capital expenditures (6)	5,003	4,897	9,306	16,363	9,384	20,486	19,037	7,216

(1) Total production excludes sulphur.
(2) Third-party volumes processed are raw natural gas volumes by activity month, which do not include accounting accruals.
(3) Includes physical commodity and financial risk management contracts inclusive of cash flow hedges, together ("Risk Management Contracts").
(4) Refer to the "Net Operation Income", "Capital Resources" and "non-GAAP measures" sections of this MD&A for reference to non-GAAP measures.
(5) Adjusted working capital is a non-GAAP measure and is calculated as accounts payable and accrued liabilities, less cash and cash equivalents, restricted cash, accounts receivable, prepaids and deposits.
(6) Excludes reclamation and abandonment activities.

SECOND QUARTER 2024 OPERATIONAL AND FINANCIAL HIGHLIGHTS

Highlights for the second quarter of 2024 include:

- Produced 30,861 boe/d (85% natural gas).
- Grew third-party raw natural gas processing volumes at our Caroline Facility by 40% from Q1 2024 to 37.1 MMcf/d (gross) from producers actively drilling in areas which are tied into the Caroline gas gathering system.
- Continued to reduce field and facility operating costs when normalized for a favorable carbon compliance cost revision recognized in the comparative quarter, reflecting successful optimization initiatives, power and fuel gas reduction programs, and labour efficiency improvement efforts.
- Generated NOI of $7.7 million (Operating Netback of $2.74/boe) reflecting historically low natural gas prices and the impact of the unplanned shut-in of the Jumping Pound Facility from mid-March to mid-May. Additional voluntary shut-ins continue in our Clearwater field in Central Alberta ("CAB") and our Ekwan field in Northeast BC due to low natural gas prices.
- Incurred capital expenditures of $5.0 million focused primarily on the sulphur condenser repairs at Jumping Pound that were completed in May, along with certain well and facility optimization initiatives.
- The Company's discounted unrealized gain on its natural gas and C5 hedge positions at June 30, 2024 was approximately $59.2 million using the June 30, 2024 forward strip.

Highlights subsequent to the second quarter of 2024 include:

- Divested Goldboro, Nova Scotia assets for $12.0 million, completing the Company's strategic pivot to focus on operating and growing our upstream and midstream processing businesses.
- Completed a non-brokered private placement of 12.8 million common shares at $0.35 per share for gross proceeds of $4.5 million to a supportive existing shareholder.
- Settled the Company's 18% convertible bridge loan in full for $24.0 million, including outstanding principal and accrued interest.
- Completed the shut-in of approximately 6,250 boe/d of operated and 995 boe/d of non-operated uneconomic production in Central Alberta that flows to a third-party facility due to low AECO gas prices and high processing costs. This shut-in brings the aggregate voluntary economic shut-in production to approximately 9,370 boe/d, preserving reserve value during a period of unprecedented low natural gas prices.

2024 OUTLOOK

Pieridae's priorities for 2024 remain:

- Maximize operated processing facility reliability to meet production targets and maximize processing and marketing revenue by leveraging our available deep cut natural gas processing capacity.
- Reduce operating expenses to improve corporate netback.
- Optimize fuel gas consumption to reduce raw gas shrinkage, increase sales revenue, and lower carbon emission compliance costs.
- Reduce long-term debt to deleverage the balance sheet.

Pieridae's 2024 capital budget is highlighted by low-cost well and facility optimization projects and the second and final phase of the maintenance turnaround at the Waterton Facility, scheduled for September and October. Pieridae owns and operates three major sour gas processing facilities that each require periodic maintenance turnarounds on a five-to-six-year cycle.

The Company is also undertaking a de-bottlenecking project at the Caroline Facility in the third quarter, which is necessary to increase effective throughput capacity, and is driven by ongoing demand for increased third-party gas processing volumes. This facility optimization project includes a production outage of approximately 2 weeks and is expected to cost approximately $0.5 million. Subsequent to the debottlenecking, the facility will be capable of processing significantly higher third-party raw gas volumes expected to materialize through the second half of 2024 and into 2025.

The scope and timing of all capital projects continues to be scrutinized in the context of low natural gas prices. Pieridae does not intend to resume its foothills development drilling program until the natural gas price outlook improves.

Pieridae continually evaluates the economic performance of its producing assets to optimize NOI during periods of sustained low commodity prices. Over the past several months, we have elected to temporarily shut-in selected low-margin properties within the following areas:

	Production (boe/d)
Central Alberta	8,018
Northeast BC	870
Northern Alberta	482
Current Voluntarily Shut-in Production	**9,370**

Reactivating shut-in production when pricing returns to economic levels is not expected to take longer than one to two weeks. However, we will only do so when natural gas prices recover to levels that support sustainable economics.

As a result of shut-ins and uncertainty surrounding duration of low natural gas prices, Pieridae is temporarily withdrawing its 2024 production guidance, which will be revisited later this year. NOI and Operating Netback projections have each been revised down to reflect the decrease in the 2024 average projected AECO basis price.

The Company's revised 2024 guidance, incorporating the above commodity price, production, and capital expenditure impacts is as follows:

	Revised 2024 Guidance		Previous 2024 Guidance	
($ 000s unless otherwise noted)	Low	High	Low	High
Total production (boe/d) (1)	***Withdrawn - TBD***		31,500	33,000
Net Operating Income (2)(4)(5)	55,000	70,000	65,000	85,000
Operating Netback ($/boe) (3)(4)(5)	5.00	6.00	6.00	7.00
Capital expenditures	30,000	35,000	30,000	35,000

(1) Temporarily withdrawn.
(2) Refer to the NOI section of the Company's MD&A for reference to non-GAAP measures.
(3) Refer to Operating Netback section of the Company's MD&A for reference to non-GAAP measures.
(4) Assumes unhedged average 2024 AECO price of $1.50/GJ and average 2024 WTI price of USD$80/bbl.
(5) Accounts for impact of hedge contracts in place at August 12, 2024.

FUNDS FLOW FROM OPERATIONS

Management considers FFO an important measure to evaluate our corporate cash flow. FFO is calculated as cash provided by operating activities, excluding settlement of decommissioning obligations and changes in non-cash working capital. Expenditures on decommissioning obligations are excluded as it is managed through the capital budgeting process.

The following table summarizes the Company's FFO for the three and six months ended June 30, 2024, and 2023:

	Three months ended June 30		Six months ended June 30	
($ 000s)	2024	2023	2024	2023
Cash provided by (used in) operating activities	**(1,555)**	27,533	**5,494**	64,642
Settlement of decommissioning obligations	**666**	375	**4,684**	887
Changes in non-cash working capital	**(3,985)**	7,524	**(3,008)**	7,316
Funds flow from operations (1)	**(4,874)**	35,432	**7,170**	72,845

(1) FFO is a non-GAAP measure. Management considers FFO an important measure to evaluate our operational performance as it demonstrates our ability to generate cash. FFO equals cash provided by operating activities, less settlement of decommissioning obligations and changes in non-cash working capital.

NET OPERATING INCOME

The following table summarizes the Company's NOI for the three and six months ended June 30, 2024, and 2023:

	Three months ended June 30			Six months ended June 30		
($ 000s)	2024	2023	% Change	2024	2023	% Change
Revenue before Risk Management Contracts	**46,565**	61,759	(25)	**120,929**	156,273	(23)
Gain on physical commodity contracts	**1,591**	10,289	(85)	**3,537**	41,176	(91)
Realized gain on Financial Contracts (1)	**18,215**	3,301	452	**25,494**	3,682	592
Revenue after Risk Management Contracts	**66,371**	75,349	(12)	**149,960**	201,131	(25)
Processing, marketing and other revenue (2)	**4,347**	5,561	(22)	**9,563**	16,192	(41)
Revenue	**70,718**	80,910	(13)	**159,523**	217,323	(27)
Royalties (3)	**(5,589)**	16,594	(134)	**(14,362)**	1,888	(861)
Operating	**(52,999)**	(48,982)	8	**(104,503)**	(115,455)	(9)
Transportation	**(4,478)**	(4,679)	(4)	**(9,588)**	(9,918)	(3)
Net Operating Income (4)	**7,652**	43,843	(83)	**31,070**	93,838	(67)

(1) Includes gains or losses on financial risk management contracts and cash flow hedges, together ("Financial Contracts").
(2) Other revenue includes marketing and transportation and gathering income. In addition to these items, for the six months ended June 30, 2023, other revenue includes a one-time non-refundable deposit paid to Pieridae following an unsuccessful asset disposition, which did not close due to the purchaser's failure to meet closing obligations.
(3) For the three and six months ended June 30, 2023, our gas cost allowance ("GCA") deduction was impacted by a one-time favorable adjustment of $18.0 million, which was not repeated in the current period.
(4) NOI is a non-GAAP measure. Management considers NOI an important measure to evaluate our operational performance as it demonstrates our field level profitability. NOI equals revenue including realized gains (losses) on Financial Contracts, less royalties, operating expenses, and transportation expenses.

OPERATING NETBACK PER BOE

The following table summarizes the Company's operating netback for the three and six months ended June 30, 2024, and 2023:

	Three months end June 30			Six months ended June 30		
($ per boe)	2024	2023	% Change	2024	2023	% Change
Revenue before Risk Management Contracts	**16.58**	21.83	(24)	**20.29**	25.56	(21)
Gain on physical commodity contracts	**0.57**	3.63	(84)	**0.59**	6.74	(91)
Realized gain on Financial Contracts	**6.49**	1.17	455	**4.28**	0.60	613
Revenue after Risk Management Contracts	**23.64**	26.63	(11)	**25.16**	32.90	(24)
Processing, marketing and other revenue	**1.55**	1.97	(21)	**1.60**	2.66	(40)
Revenue	**25.19**	28.60	(12)	**26.76**	35.56	(25)
Royalties	**(1.99)**	5.87	(134)	**(2.41)**	0.31	(877)
Operating	**(18.87)**	(17.31)	9	**(17.54)**	(18.89)	(7)
Transportation	**(1.59)**	(1.65)	(4)	**(1.61)**	(1.62)	(1)
Operating Netback ($/boe) [1]	**2.74**	15.51	(82)	**5.20**	15.36	(66)

(1) Operating Netback per boe is a "non-GAAP measure". Management considers operating netback an important measure to evaluate the Company's operational performance as it demonstrates Pieridae's field level profitability relative to current commodity prices. Operating netback equals revenue including realized gains (losses) on Financial Contracts, less royalties, operating expenses and transportation expenses calculated on a per BOE basis.

NET OPERATING INCOME SENSITIVITY ANALYSIS

The following table summarizes the Company's NOI sensitivity for the three and six months ended June 30, 2024:

	Three months ended June 30				Six months ended June 30			
	2024	% Change	$ Impact	% Impact	% 2024	$ Change	% Impact	% Impact
Business Environment [1] [2]								
WTI price (USD/bbl) [3]	**80.78**	10	1,062	14	**78.95**	10	2,692	9
AECO price ($/mcf) [4]	**1.17**	10	1,602	21	**1.83**	10	1,406	5
Sulphur price ($/tonne)	**103.19**	10	189	2	**99.01**	10	301	1
USD/CAD average exchange rate [5]	**0.7309**	10	965	13	**0.7363**	10	2,448	8
Operational [1] [6] [7]								
NGLs & condensate production (bbl/d)	**4,682**	10	2,306	30	**5,037**	10	4,606	15
Natural gas production (mcf/d)	**157,077**	10	7,149	93	**166,217**	10	7,945	26
Sulphur production (tonne/d)	**1,376**	10	204	3	**1,433**	10	378	1
Royalty burden	**11.6**	1	482	6	**11.5**	1	1,245	4
Operating expense ($/boe)	**(18.87)**	10	5,300	69	**(17.54)**	10	10,450	34

(1) Calculations are performed independently and may not be indicative of actual results that would occur when multiple variables change simultaneously.
(2) The indicative impact on NOI is only applicable within a limited range of these amounts as royalty burden is held constant.
(3) Includes the impact of WTI price on NGL (C3, C4) and condensate (C5) prices assuming a correlation to USD WTI.
(4) Includes the impact of AECO price on NGL (C2) price assuming a correlation to AECO.
(5) Includes the impact of foreign exchange on NGL and Condensate prices assuming a correlation to USD WTI.
(6) Includes the impact of physical commodity hedges that were in place during the period.
(7) Operational assumptions are based upon the results for the three and six months ended June 30, 2024, and the calculated impact on NOI is only applicable within a limited range of these amounts.

PRODUCTION

The following table summarizes the Company's production by commodity for the three and six months ended June 30, 2024, and 2023:

	Three months ended June 30			Six months ended June 30		
	2024	2023	% Change	2024	2023	% Change
Natural gas (mcf/d)	**157,077**	159,427	(1)	**166,217**	172,717	(4)
Condensate (bbl/d)	**2,472**	2,300	7	**2,626**	2,478	6
NGLs (bbl/d)	**2,210**	2,216	-	**2,411**	2,499	(4)
Sulphur (tonne/d) [1]	**1,376**	1,362	1	**1,433**	1,409	2
Total production (boe/d) [1]	**30,861**	31,087	(1)	**32,740**	33,763	(3)
Natural gas production (%)	**85**	85	-	**85**	85	-
Liquids production (%)	**15**	15	-	**15**	15	-

(1) Production amounts exclude sulphur.

Production By Area

The following table summarizes the Company’s production by core area for the three and six months ended June 30, 2024, and 2023:

	Three months ended June 30			Six months ended June 30		
	2024	2023	% Change	2024	2023	% Change
Waterton	**9,451**	9,144	3	**9,384**	9,174	2
Jumping Pound	**2,839**	4,581	(38)	**4,710**	6,210	(24)
Caroline	**6,348**	5,142	23	**6,118**	5,267	16
Central Alberta	**8,467**	8,787	(4)	**8,477**	9,300	(9)
Northern Alberta	**3,390**	2,979	14	**3,487**	3,208	9
Northeast BC	**366**	454	(19)	**564**	604	(7)
Total production (boe/d)	**30,861**	31,087	(1)	**32,740**	33,763	(3)

(1) Production amounts exclude sulphur.

For the three and six months ended June 30, 2024, total production remained relatively consistent with comparative quarters. The following items contributed to changes for these periods:

- Production in our Jumping Pound area was shut-in for approximately ten weeks between March and May 2024 due to the unplanned sulphur condenser repair at the Jumping Pound Facility (1,350 boe/d and 1,196 boe/d, respectively).
- Production in our CAB area was impacted by the voluntary shut-in of our Clearwater gas field due to low natural gas prices. Also contributing to the decrease were minor compression and field maintenance related outages (293 boe/d and 810 boe/d, respectively).
- In the first and second quarter of 2023, our Caroline Facility experienced significant downtime due to an unplanned maintenance outage which was not repeated in 2024, increasing production by 667 boe/d and 339 boe/d, respectively.
- Certain properties in our Northern Alberta area realized better runtime due to well optimization work and improved third-party processing facility access in 2024 as compared to the same periods in 2023 (improvement of 413 boe/d and 283 boe/d, respectively).

Processing and Marketing Volumes

Pieridae owns and operates three gas processing facilities and related infrastructure located through the Alberta foothills. In addition to our own produced volumes, these facilities process working interest owner production and third-party production. Our facilities offer various services including raw gas sweetening, deep-cut natural gas liquids recovery, NGL fractionation, sulphur processing, and product marketing.

The following table summarizes the gross third-party processing and handling of raw gas volumes processed by facility for the three and six months ended June 30, 2024 and 2023:

	Three months ended June 30			Six months ended June 30		
(mcf/d)	2024	2023	% Change	2024	2023	% Change
Waterton	**5,607**	1,226	357	**5,708**	3,022	89
Jumping Pound	**11,097**	19,085	(42)	**18,758**	25,520	(26)
Caroline	**37,059**	35,439	5	**31,781**	31,011	2
Total	**53,763**	55,750	24	**56,247**	59,553	(6)

(1) Volumes shown are by activity month, which does not include accounting accruals.

Changes to third-party processed volumes are a result of the following:

- Waterton – Third-party volumes processed at our Waterton Facility were higher than both the comparative periods as a result of third-party outages in the prior year.
- Jumping Pound – Due to the Jumping Pound Facility outage, 42% less third-party volumes were processed during the quarter and 26% less for the year. These volumes have returned to normal rates following completion of the repair work.
- Caroline – Late in the first quarter, a new third-party tie-in to our Caroline Facility was completed, which resulted in increased feedstock volumes in the second quarter. A new third-party well pad was tied in during July 2024, providing another long-term incremental processing and marketing revenue stream from a producer actively drilling within the Caroline area.

BENCHMARK PRICES

The following table outlines our benchmark commodity pricing for the three and six months ended June 30, 2024:

	Three months ended June 30				Six months ended June 30		
	2024	2023	% Change	Q1 2024	2024	2023	% Change
Natural Gas							
AECO ($/mcf)	**1.17**	2.40	(51)	2.48	**1.83**	2.82	(35)
Henry Hub (USD/MMbtu)	**2.05**	2.13	(4)	2.43	**2.23**	2.40	(7)
Chicago Citygate (USD/MMbtu)	**1.65**	1.99	(17)	2.79	**2.22**	2.33	(5)
Basis Differential AECO-NYMEX Premium (Discount) (USD/MMbtu)	**(1.19)**	(0.34)	(250)	(0.58)	**(0.89)**	(1.33)	(33)
Condensate							
C5 at Edmonton ($/bbl)	**105.62**	93.25	13	98.43	**102.02**	100.11	2
West Texas Intermediate crude oil (USD/bbl)	**80.78**	73.71	10	77.13	**78.95**	74.92	5
Sulphur ($/tonne)	**103.19**	114.92	(10)	94.84	**99.01**	142.49	(31)
USD/CAD average exchange rate	**0.7309**	0.7447	(2)	0.7418	**0.7363**	0.7420	(1)

We sell natural gas into the TC Energy Nova Gas Transmission Ltd. system and 100% of our natural gas production is priced at AECO. AECO pricing is derived from the Henry Hub and Chicago markets less an AECO basis differential related to the transportation of Canadian gas into the United States ("US") gas transportation system.

US and AECO natural gas pricing decreased for the three and six months ended June 30, 2024 as compared to 2023. Mild weather during the winter season, nearly full natural gas storage, and record levels of production in the first half of 2024 in Canada and the US continue to place downward pressure on spot natural gas prices.

We primarily sell produced condensate into the Edmonton market for use as diluent to reduce the viscosity of heavy oil for transportation through pipelines. Condensate pricing is highly correlated to the WTI crude oil price. WTI pricing increased relative to the comparative periods as a result of improved US oil demand and falling inventories. Condensate pricing followed similar trends to WTI.

The Company's sulphur production is sold into a variety of markets including directly to North American fertilizer manufacturers as well as international markets through Vancouver or Tampa Bay sulphur export terminals. In 2024, sulphur benchmark prices declined compared to 2023, which was a volatile year for sulphur markets with prices ranging from $85/tonne to $224/tonne at Vancouver.

REALIZED PRICES

The following table summarizes the Company's realized pricing for the three and six months ended June 30, 2024 and 2023:

	Three months ended June 30				Six months ended June 30		
	2024	2023	% Change	Q1 2024	2024	2023	% Change
Realized Natural Gas Price							
Before Risk Management Contracts ($/mcf)	**1.14**	2.39	(52)	2.53	**1.87**	2.85	(34)
After Risk Management Contracts ($/mcf)	**2.71**	3.03	(11)	3.21	**2.98**	4.15	(28)
Realized Condensate Price							
Before Risk Management Contracts ($/bbl)	**99.96**	84.81	18	91.18	**95.31**	96.76	(1)
After Risk Management Contracts ($/bbl)	**87.75**	105.84	(17)	84.49	**86.03**	106.30	(19)
NGLs ($/bbl)	**27.58**	32.09	(14)	37.69	**33.05**	38.65	(14)
Sulphur ($/tonne)	**18.43**	22.78	(19)	14.49	**16.38**	24.99	(34)

The following table outlines our volumes sold at spot price versus our volumes sold under Risk Management Contracts for the three and six months ended June 30, 2024 and 2023:

	Three months ended June 30				Six months ended June 30			
	2024		2023		2024		2023	
(% of product volume)	% spot	% hedge	% spot	% hedge	% spot	% hedge	% spot	% hedge
Natural gas	**28**	**72**	46	54	**29**	**71**	39	61
Condensate	**27**	**73**	50	50	**36**	**64**	53	47
NGLs	**100**	**-**	100	-	**100**	**-**	100	-
Sulphur	**25**	**75**	22	78	**22**	**78**	22	78
Total production (1)	**33**	**67**	57	43	**34**	**66**	45	55

(1) Total production excludes sulphur.

We are contractually obligated to sell the majority of our sulphur production for $6.00/tonne FOB facility gate under a fixed-price physical contract which expires on December 31, 2025. For comparison, average realized sulphur prices for the three and six months ended June 30, 2024 would have been $51.97/tonne and $51.80/tonne, respectively ($108.72/tonne and $105.56/tonne for the three and six months ended June 30, 2023, respectively), net of transportation costs, if this sulphur contract was not in place.

RISK MANAGEMENT CONTRACTS

Our risk management program is governed by our hedge policy. Our hedge policy is designed to manage risks associated with volatility in natural gas, NGL, and power prices, and fluctuations in foreign exchange rates. Risk management contracts are not meant to be speculative and are considered within the broader framework of financial stability and flexibility. We continuously review the need and requirement to utilize risk management contracts. As at June 30, 2024, our future production is hedged in accordance with the thresholds of our senior loan agreements, which requires approximately 65% of our forecasted PDP natural gas and condensate production to be hedged, net of annualized royalties, from 2024 to 2027.

Financial Contracts are considered derivative financial instruments. Their impacts are recorded at fair value with changes in fair value and unrealized gains and losses being recognized in net income if hedge accounting is not applied, and through other comprehensive income ("OCI") if hedge accounting is applied. Realized gains and losses are recognized in net income. We classify our AECO natural gas swaps and our WTI crude oil collars and swaps as cash flow hedges and apply hedge accounting accordingly. There was no hedge ineffectiveness identified as of June 30, 2024.

Fixed price physical power purchase and commodity sales contracts are recognized in the applicable financial statement line item they are associated with; physical power contracts are recognized in operating expense, and physical commodity contracts are recognized in revenue. Physical risk management contracts are not considered to be derivative financial instruments as they are settled based on physical receipt or delivery of the product and therefore are not recorded at fair value.

The following realized gains or losses were generated from our Risk Management Contracts for the three and six months ended June 30, 2024 and 2023:

	Three months ended June 30		Six months ended June 30	
($ 000s)	**2024**	**2023**	**2024**	**2023**
Gain (loss) on physical power contracts	**(3,523)**	10,296	**453**	19,604
Gain on physical commodity contracts				
AECO	**1,591**	8,819	**3,537**	39,672
WTI	**-**	1,504	**-**	1,504
Realized gain (loss) on Financial Contracts				
AECO	**20,961**	368	**29,931**	908
WTI	**(2,746)**	2,932	**(4,437)**	2,774
Total realized gain on Risk Management Contracts (1)	**16,283**	23,919	**29,484**	64,462

(1) Realized gains on Risk Management Contracts include physical commodity and financial risk management contracts inclusive of cash flow hedges.

The following unrealized gains or losses were generated from our Financial Contracts for the three and six months ended June 30, 2024 and 2023:

	Three months ended June 30		Six months ended June 30	
($ 000s)	**2024**	**2023**	**2024**	**2023**
Unrealized gain (loss) on Financial Contracts (1)				
AECO	**-**	243	**-**	884
WTI	**-**	(346)	**-**	(449)
Unrealized gain (loss) on Financial Contracts, net of tax (2)				
AECO	**1,587**	7,962	**(20,704)**	7,962
WTI	**2,507**	(823)	**(5,972)**	(823)
Total unrealized gain (loss) on Financial Contracts (3)	**4,094**	7,036	**(26,676)**	7,574

(1) Recognized in net income on the Interim Financial Statements.
(2) Recognized in OCI on the Interim Financial Statements.
(3) Unrealized gains on Financial Contracts include financial risk management contracts inclusive of cash flow hedges and are net of tax.

The following fixed price physical commodity sales contracts and power contracts were in place at June 30, 2024:

Type of contract	Quantity	Time Period	Contract Price
Fixed Price - Natural Gas Sales	2,500 GJ/d	Jul 2024 - Oct 2024	CAD $3.73 /GJ
Fixed Price - Natural Gas Sales	5,000 GJ/d	Jul 2024 - Oct 2026	CAD $3.31 /GJ
Fixed Price - Power Purchases	55 MW	Jul 2024 - Dec 2024	CAD $68.39 /MWh
Fixed Price - Power Purchases	55 MW	Jan 2025 - Dec 2025	CAD $79.12 /MWh
Fixed Price - Power Purchases	45 MW	Jan 2026 - Dec 2026	CAD $75.88 /MWh
Fixed Price - Power Purchases	25 MW	Jan 2027 - Dec 2027	CAD $70.19 /MWh

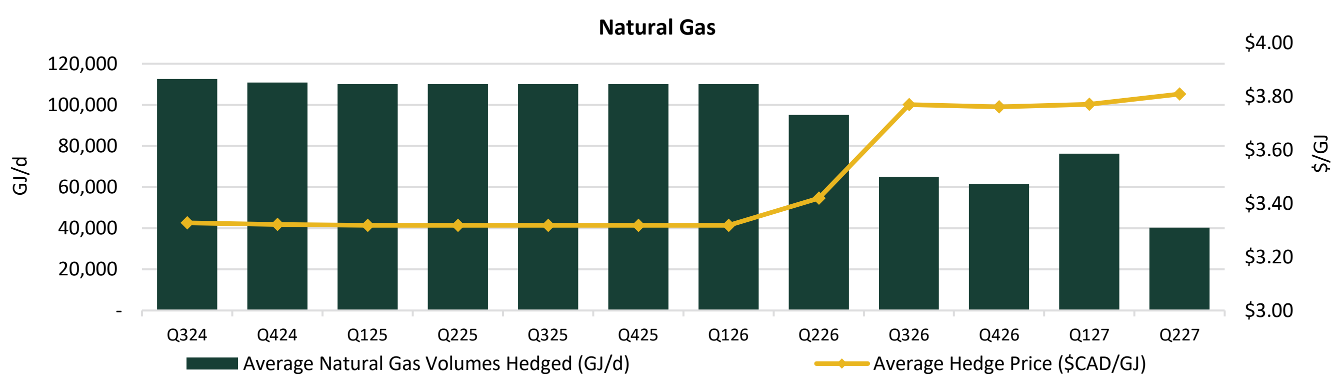
The following Financial Contracts, for which hedge accounting was applied, were in place at June 30, 2024:

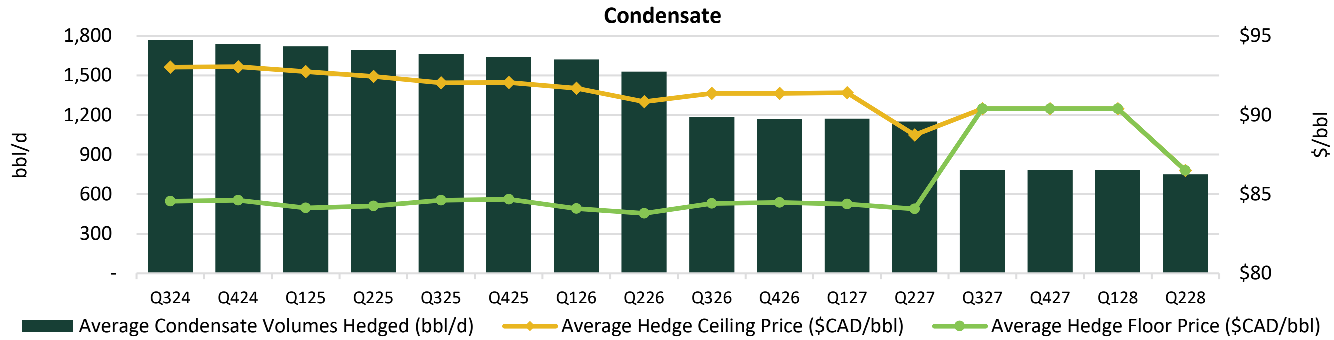
Type of contract	Quantity	Time Period	Contract Price
AECO Natural Gas Swap	30,000 GJ/d	Jul 2024 - May 2026	CAD $3.10 /GJ
AECO Natural Gas Swap	50,000 GJ/d	Jul 2024 - May 2026	CAD $3.30 /GJ
AECO Natural Gas Swap	25,000 GJ/d	Jul 2024 - May 2027	CAD $3.62 /GJ
AECO Natural Gas Swap	35,000 GJ/d	Jun 2026 - May 2027	CAD $3.95 /GJ
AECO Natural Gas Swap	16,200 GJ/d	Jun 2026 - May 2027	CAD $3.63 /GJ
WTI Crude Oil Collar	1,401 bbl/d	Jul 2024 - Dec 2024	CAD $80.00 - $90.75 /bbl
WTI Crude Oil Collar	1,235 bbl/d	Jan 2025 - Dec 2025	CAD $80.00 - $90.75 /bbl
WTI Crude Oil Collar	918 bbl/d	Jan 2026 - Dec 2026	CAD $80.00 - $90.75 /bbl
WTI Crude Oil Collar	761 bbl/d	Jan 2027 - May 2027	CAD $80.00 - $90.75 /bbl
WTI Crude Oil Swap	30 bbl/d	Jul 2024 - Dec 2024	CAD $110.25 /bbl
WTI Crude Oil Swap	275 bbl/d	Jul 2024 - May 2025	CAD $99.80 /bbl
WTI Crude Oil Swap	70 bbl/d	Jul 2024 - May 2026	CAD $104.00 /bbl
WTI Crude Oil Swap	225 bbl/d	Jun 2025 - Dec 2025	CAD $93.07 /bbl
WTI Crude Oil Swap	185 bbl/d	Jan 2026 - May 2026	CAD $90.28 /bbl
WTI Crude Oil Swap	385 bbl/d	Jun 2026	CAD $83.21 /bbl
WTI Crude Oil Swap	15 bbl/d	Jul 2026 - Dec 2026	CAD $88.25 /bbl
WTI Crude Oil Swap	50 bbl/d	Jul 2026 - May 2027	CAD $92.25 /bbl
WTI Crude Oil Swap	780 bbl/d	Jun 2027	CAD $79.14 /bbl
WTI Crude Oil Swap	220 bbl/d	Jun 2025 - Mar 2028	CAD $93.85 /bbl
WTI Crude Oil Swap	135 bbl/d	Jul 2026 - Mar 2028	CAD $90.78 /bbl
WTI Crude Oil Swap	430 bbl/d	Jul 2027 - Mar 2028	CAD $88.52 /bbl
WTI Crude Oil Swap	750 bbl/d	Apr 2028 - Jun 2028	CAD $86.50 /bbl

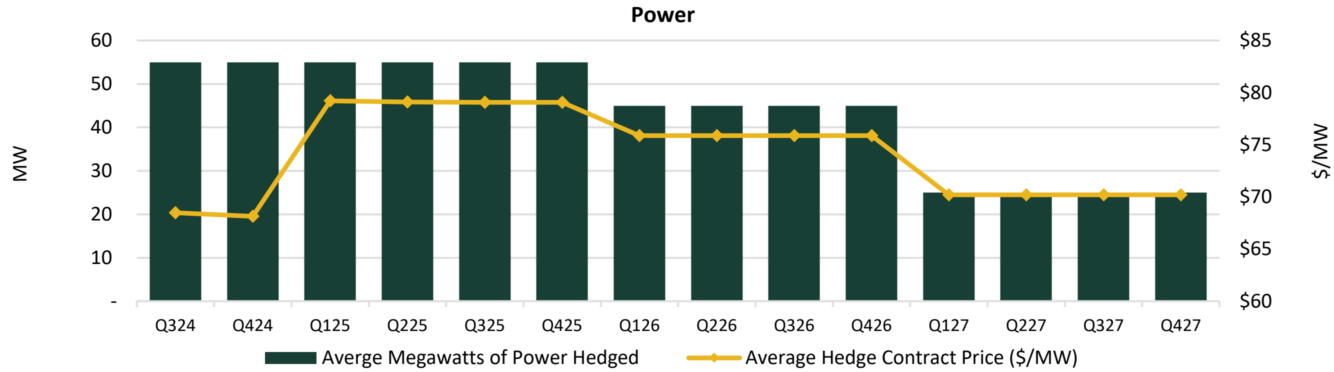
The following financial risk management contracts to hedge foreign exchange exposure, for which hedge accounting was not applied, were in place at June 30, 2024:

Type of contract	Quantity (USD) *($ 000s)*	Time Period	Contract Price
USD Call Option	$5,036	Jul 2024 – Sep 2024	CAD $1.3900
USD Call Option	$4,910	Oct 2024 – Dec 2024	CAD $1.3580
USD Call Option	$4,850	Jan 2025 – Mar 2025	CAD $1.3600
USD Call Option	$4,715	Apr 2025 – Jun 2025	CAD $1.3600

Quarterly Average Physical and Financial Hedged Volumes







REVENUE

The following table summarizes the Company's revenue for the three and six months ended June 30, 2024 and 2023:

	Three months ended June 30			Six months ended June 30		
($ 000s except per boe)	2024	2023	% Change	2024	2023	% Change
Natural gas	**17,821**	43,534	(59)	**60,129**	128,698	(53)
Condensate	**22,482**	19,219	17	**45,557**	44,896	1
NGLs	**5,546**	6,472	(14)	**14,507**	17,481	(17)
Sulphur	**2,307**	2,823	(18)	**4,273**	6,374	(33)
Petroleum and natural gas revenue (1)	**48,156**	72,048	(33)	**124,466**	197,449	(37)
Petroleum and natural gas revenue ($/boe)	**17.15**	25.47	(33)	**20.89**	32.31	(35)
Processing and marketing revenue	**4,203**	5,410	(22)	**9,275**	11,811	(21)
Other revenue (2)	**144**	151	(5)	**288**	4,381	(93)
Realized gain (loss) on Financial Contracts	**18,215**	3,301	452	**25,494**	3,682	592
Total revenue	**70,718**	80,910	(13)	**159,523**	217,323	(27)

(1) Petroleum and natural gas revenue includes gains and losses on physical commodity contracts.
(2) Other revenue includes road use income and contract operating income. In addition to these items, for the six months ended June 30, 2023, other revenue includes a one-time non-refundable deposit paid to Pieridae for a disposition that failed to close.

Petroleum and Natural Gas Revenue

Petroleum and natural gas revenue is derived from the sale of natural gas, condensate, NGLs and sulphur. Fluctuations in revenue occur due to commodity price volatility which is mitigated through our hedge policy. Petroleum and natural gas revenue decreased for the three and six months ended June 30, 2024, which is attributable to lower gas prices partially offset by condensate pricing.

Processing and Marketing Revenue

Processing and marketing revenue is primarily derived from fees charged to third parties for processing and handling their produced volumes through our gas processing facilities. The following table summarizes the Company's processing and marketing revenue by facility for the three and six months ended June 30, 2024 and 2023:

	Three months ended June 30			Six months ended June 30		
($ 000s except per boe)	**2024**	**2023**	**% Change**	**2024**	**2023**	**% Change**
Waterton	**658**	260	153	**1,327**	1,024	30
Jumping Pound	**1,277**	1,835	(30)	**3,711**	5,032	(26)
Caroline	**2,071**	3,076	(33)	**3,734**	5,246	(29)
Central Alberta	**100**	124	(19)	**232**	285	(19)
Northern Alberta	**97**	115	(16)	**271**	223	(22)
Total	**4,203**	5,410	(22)	**9,275**	11,810	(21)

For the three and six ended June 30, 2024, processing and marketing revenue decreased by 22% and 21%, respectively due primarily to gas prices and facility availability during the periods:

- Waterton – increased due to third-party volumes being restored after being shut-in by the producer.
- Jumping Pound – decreased during the period due to the unplanned Jumping Pound facility outage, diminished our ability to process third-party volumes, in turn decreasing revenue.
- Caroline – while third-party volumes continue to increase, revenue during the period decreased due to lower commodity prices. Additionally, third-party sulphur remelt processing volumes decreased 45% period over period reflecting lower demand for sulphur processing and shipping as a result of lower sulphur pricing.

ROYALTIES

The following table summarizes the Company's royalty obligations for the three and six months ended June 30, 2024 and 2023:

	Three months ended June 30			Six months ended June 30		
($ 000s except per boe)	**2024**	**2023**	**% Change**	**2024**	**2023**	**% Change**
Gross royalties	**11,127**	10,772	3	**28,506**	34,827	(18)
Gas cost allowance	**(5,538)**	(27,366)	(80)	**(14,144)**	(36,715)	(61)
Royalties	**5,589**	(16,594)	134	**14,362**	(1,888)	861
Royalties ($/boe)	**1.99**	(5.87)	134	**2.41**	(0.31)	877
Royalties as percentage of petroleum and natural gas revenue (%)	**12**	(23)	35	**12**	(1)	13

For the three and six months ended June 30, 2024, net royalties as a percentage of petroleum and natural gas revenue remained at approximately 12%.

Gross natural gas royalties are reduced by GCA, which is provided by the Alberta Crown ("Crown") to account for operating and capital expenses incurred to process and transport the Crown's royalty portion of natural gas production. For the three and six months ended June 30, 2023, our GCA deduction was impacted by a one-time favorable adjustment of $18.0 million, which resulted in a larger GCA deduction not repeated in the current period.

OPERATING EXPENSE

The following table summarizes the Company's operating and adjusted operating expenses for the three and six months ended June 30, 2024 and 2023:

	Three months ended June 30			Six months ended June 30		
($ 000s except per boe)	**2024**	**2023**	**% Change**	**2024**	**2023**	**% Change**
Operating expense	**52,999**	48,982	8	**104,503**	115,455	(9)
Processing and marketing revenue	**4,203**	5,410	(22)	**9,275**	11,811	(21)
Sulphur revenue	**2,307**	2,823	(18)	**4,273**	6,374	(93)
Adjusted operating expense	**46,489**	40,749	14	**90,955**	97,270	(8)
Operating expense ($/boe) (1)	**18.87**	17.31	9	**17.54**	18.89	(7)
Adjusted operating expense ($/boe) (1)	**16.55**	14.40	14	**15.28**	15.92	(6)

(1) Adjusted operating expense is a "non-GAAP measure". Adjusted operating expense provides an industry-comparable view of operating expenses for our sour gas processing facilities by accounting for all third-party volumes running through these facilities. Adjusted operating expense is calculated as operating expenses, less third-party processing revenue and sulphur revenue.

For the three and six months ended June 30, 2024, operating expenses increased by 8% and decreased by 9% compared to the same periods in 2023. In the second quarter of 2023, a favorable revision of $6.2 million was made to carbon compliance costs. Normalized for this one-time adjustment, operating expense decreased by 4%, primarily reflecting ongoing field maintenance optimization and cost reduction and efficiency efforts.

During the first half of 2024, decreases in power consumption and fuel gas usage and cost contributed significantly to the reduction in operating costs. Power consumption was lower as a result of both the Jumping Pound Facility outage and consumption reduction initiatives implemented at various sites, resulting in a savings of $2.0 million. Despite outages in both the current and comparative periods, which typically increase demand for fuel gas, fuel gas consumption was lower, attributable to the timing of outages and lower cost of gas in the current year which reduced expenses by $3.8 million.

Field and facility operating costs have also decreased in the period reflecting the ongoing cost reduction initiatives undertaken while maintaining safe and effective operations. A focus on fuel gas reduction continues to reduce emissions intensity at our three facilities resulting in lower year-to-date carbon compliance costs.

We are committed to improving operating costs through cost reduction initiatives and by increasing throughput volumes in our facilities. Our aggregate cost reduction efforts are focused on:

- Reducing fuel gas consumption in the field and in facilities. Lower fuel gas use increases natural gas sales and decreases carbon emissions intensity and resulting emissions compliance costs.
- Reducing power consumption through optimization while continuing to hedge power price exposure.
- Reducing dependence on third-party contractors for routine operations in our facilities by training and empowering employees.
- Centralizing contracting and procurement and deploying category management to ensure efficiencies and economies of scale in our supply chain.
- Optimizing maintenance activities and costs while maintaining and improving operating reliability.

Due to the high proportion of fixed costs in our operating expense structure, volume changes are highly impactful to per boe values. The following table summarizes the Company's operating cost by core area for the three and six months ended June 30, 2024 and 2023:

	Three months ended June 30			Six months ended June 30		
($ per boe)	**2024**	**2023**	**% Change**	**2024**	**2023**	**% Change**
Waterton	**15.42**	16.58	(7)	**14.46**	16.24	(11)
Jumping Pound	**37.45**	22.95	63	**21.94**	18.77	17
Caroline	**19.04**	16.61	15	**18.64**	25.41	(27)
Central Alberta	**18.05**	14.01	29	**18.98**	16.52	15
Northern Alberta	**12.30**	17.30	(29)	**12.17**	17.78	(32)
Northeast BC	**40.62**	47.80	(15)	**34.56**	46.04	(25)

Adjusted Operating Expense

Adjusted operating expense reflects our view that while our three facilities are significantly more complex and costlier to operate than similar sweet-gas processing facilities, they offer acid gas extraction, deep-cut NGL recovery, NGL fractionation at two of our three major gas facilities, and sulphur recovery. Significant available excess capacity also enables Pieridae to process third-party production, which materially contributes to the Company's operating netback. These facilities thereby create additional revenue opportunities for the Company through sulphur sales and NGL value additions, along with third-party processing revenue. We believe that by showing these adjusted operating expenses, we are able to show the significant value of our facility and infrastructure ownership.

Adjusted operating expense is a non-GAAP measure. Adjusted operating expense provides an industry-comparable view of the cash cost to operate our assets. Processing third-party volumes does not add materially to the cost of operating our facilities. Adjusted operating expense is calculated as operating expenses, less processing and marketing revenue and sulphur revenue.

The following table summarizes the Company's adjusted operating expense by area for the three months ended June 30, 2024:

($ per boe)	**Waterton**	**Jumping Pound**	**Caroline**	**Central Alberta**	**Northern Alberta**	**Northeast BC**	**Total**
Operating expense	15.42	37.45	19.04	18.05	12.30	40.62	**18.87**
Less:							
Processing and marketing revenue	0.77	4.94	3.58	0.13	0.32	-	**1.50**
Sulphur revenue	0.45	0.17	0.62	1.95	0.05	-	**0.82**
Adjusted operating expense [1]	**14.20**	**32.34**	**14.84**	**15.97**	**11.93**	**40.62**	**16.55**

The following table summarizes the Company's adjusted operating expense by area for the six months ended June 30, 2024:

($ per boe)	Waterton	Jumping Pound	Caroline	Central Alberta	Northern Alberta	Northeast BC	Total
Operating expense	14.26	21.94	18.64	18.98	12.17	34.56	**17.54**
Less:							
Processing and marketing revenue	0.78	4.33	3.35	0.15	0.43	-	**1.56**
Sulphur revenue	0.42	0.19	0.71	1.69	(0.01)	-	**0.70**
Adjusted operating expense (1)	**13.06**	**17.42**	**14.58**	**17.14**	**11.75**	**34.56**	**15.28**

The following table summarizes the Company's adjusted operating expense by area for the three months ended June 30, 2023:

($ per boe)	Waterton	Jumping Pound	Caroline	Central Alberta	Northern Alberta	Northeast BC	Total
Operating expense	16.58	22.95	16.61	14.01	17.30	47.80	**17.31**
Less:							
Processing and marketing revenue	0.31	4.40	6.57	0.16	0.42	-	**1.91**
Sulphur revenue	0.51	0.20	0.50	2.59	0.05	-	**1.00**
Adjusted operating expense (1)	**15.76**	**18.35**	**9.54**	**11.26**	**16.83**	**47.80**	**14.40**

The following table summarizes the Company's adjusted operating expense by area for the six months ended June 30, 2023:

($ per boe)	Waterton	Jumping Pound	Caroline	Central Alberta	Northern Alberta	Northeast BC	Total
Operating expense	16.24	18.77	25.41	16.52	17.78	46.04	**18.89**
Less:							
Processing and marketing revenue	0.62	4.48	5.50	0.17	0.38	-	**1.93**
Sulphur revenue	0.71	0.36	0.57	2.50	0.06	-	**1.04**
Adjusted operating expense (1)	**14.91**	**13.93**	**19.34**	**13.85**	**17.34**	**46.04**	**15.92**

The following table summarizes the Company's adjusted operating cost per boe by core area for the three and six months ended June 30, 2024, and 2023:

	Three months ended June 30			Six months ended June 30		
($ per boe)	2024	2023	% Change	2024	2023	% Change
Waterton	**14.20**	15.76	(10)	**13.06**	14.91	(12)
Jumping Pound	**32.34**	18.35	76	**17.42**	13.93	25
Caroline	**14.84**	9.54	56	**14.58**	19.34	(25)
Central Alberta	**15.97**	11.26	42	**17.14**	13.85	24
Northern Alberta	**11.93**	16.83	(29)	**11.75**	17.34	(32)
Northeast BC	**40.62**	47.80	(15)	**34.56**	46.04	(25)

For the three and six months ended June 30, 2024 our area base operating expense per boe changed as compared to 2023 primarily for the following reasons:

- Waterton – reduced power and maintenance costs in the current quarter and year-to-date decreased operating expense.
- Jumping Pound – lower production and third-party revenue due to the outage at this facility.
- Caroline – lower operating costs in the comparative period due to adjustments to carbon compliance costs. Lower processing and marketing revenue in the current period, as previously discussed.
- CAB – increased third-party processing fees paid in the current period.
- Northern Alberta Foothills – higher volumes due to better runtime than the comparative period.
- Northeast BC – volumes restricted in Q2 because of wildfires. This area remains shut-in due to the low gas price environment.

TRANSPORTATION EXPENSE

The following table summarizes the Company's transportation expense for the three and six months ended June 30, 2024 and 2023:

	Three months ended June 30			Six months ended June 30		
($ 000s except per boe)	2024	2023	% Change	2024	2023	% Change
Transportation expense	**4,478**	4,679	(4)	**9,588**	9,918	(3)
Transportation expense ($/boe)	**1.59**	1.65	(4)	**1.61**	1.62	(1)

Transportation expense is partially influenced by the cost of fuel gas, which is based on AECO pricing. In the current period, AECO pricing was lower, resulting in decreased transportation expenses. Approximately 96% of our natural gas production is shipped under firm service transport contracts, which provides Pieridae guaranteed fixed cost access to pipeline transportation.

GENERAL AND ADMINISTRATIVE EXPENSE

The following table summarizes the Company's general and administrative ("G&A") expense for the three and six months ended June 30, 2024 and 2023:

	Three months ended June 30			Six months ended June 30		
($ 000s except per boe)	**2024**	**2023**	**% Change**	**2024**	**2023**	**% Change**
G&A expense	**6,316**	6,588	(4)	**11,911**	11,816	1
G&A expense ($/boe)	**1.78**	2.33	(24)	**2.00**	1.93	4

G&A expense decreased during the three months ended June 30, 2024, on both an overall basis and per boe as compared to the same period in 2023 reflecting slightly lower staffing costs. For the six months ended June 30, 2024 G&A expense remained relatively consistent both on a total and per boe basis. We continue to focus on cost reduction initiatives including the ongoing optimization of staffing and external consultant levels to ensure we operate as efficiently as possible.

FINANCE EXPENSE

The following table summarizes the Company's finance expense for the three and six months ended June 30, 2024 and 2023:

	Three months ended June 30			Six months ended June 30		
($ 000s)	**2024**	**2023**	**% Change**	**2024**	**2023**	**% Change**
Cash portion of interest expense	**5,274**	3,767	40	**10,705**	7009	53
Non-cash interest paid in-kind	**1,011**	1,792	(44)	**1,997**	4,442	(55)
	6,285	5,559	13	**12,702**	11,451	11
Accretion of financing costs	**1,223**	3,268	(63)	**2,413**	8,039	(70)
Accretion of decommissioning obligations	**584**	548	7	**1,149**	1,062	8
Interest on lease liabilities	**58**	57	2	**122**	109	12
Other charges	**235**	65	262	**141**	(78)	(281)
Loss on debt extinguishment	-	6,859	(100)	-	6,859	(100)
Total finance expense	**8,385**	16,356	(49)	**16,527**	27,442	(40)

In June, 2023, we completed a debt refinancing, realizing lower debt service costs. Under the new debt facilities, interest is incurred primarily in USD and is subject to fluctuations in the USD/CAD exchange rates; we have initiated currency hedges to provide downside protection on a portion of our USD denominated debt service costs.

The majority of Pieridae's interest expense for the quarter ended June 30, 2024 is comprised of interest on variable rate debt, the remainder being fixed rate debt. Conversely, in the prior year, the entire balance was interest on fixed rate debt.

DEPLETION AND DEPRECIATION

The following table summarizes the Company's depletion and depreciation for the three and six months ended June 30, 2024 and 2023:

	Three months ended June 30			Six months ended June 30		
($ 000s)	**2024**	**2023**	**% Change**	**2024**	**2023**	**% Change**
Depletion and depreciation	**15,043**	16,218	(7)	**31,373**	32,846	(4)

Depletion and depreciation expense remained consistent with the comparative period. A reduction in future development costs added to the depletable base was offset by an increased depletion rate as a result of decreased reserves.

SHARE-BASED COMPENSATION

The following table summarizes the Company's share-based compensation expense for the three and six months ended June 30, 2024 and 2023:

	Three months ended June 30			Six months ended June 30		
($ 000s)	**2024**	**2023**	**% Change**	**2024**	**2023**	**% Change**
Share-based compensation	**682**	513	33	**1,429**	530	170

Our share-based compensation is comprised of expense recognized under our Stock Option Plan, Restricted Share Unit ("RSU") Plan and Deferred Share Unit Plan. Share based compensation expense increased in the three and six months ended June 30, 2024 compared to the 2023 due primarily to an increase in RSU expense as a result of an increase in Pieridae's share price and number of RSUs outstanding. RSUs are valued at the five-day volume-weighted average share price and the number of awards outstanding at each reporting period.

CAPITAL EXPENDITURES

The following table summarizes the Company's capital expenditures for the three and six months ended June 30, 2024 and 2023:

	Three months ended June 30			Six months ended June 30		
($ 000s)	2024	2023	% Change	2024	2023	% Change
Facilities and well optimization	**1,249**	1,170	7	**4,152**	2,313	80
Turnarounds	**2,832**	4,285	(34)	**3,754**	6,637	(43)
Land	**71**	76	(7)	**247**	168	47
Facilities maintenance	**122**	490	(75)	**222**	551	(60)
Development	**4**	2,847	(100)	**4**	17,506	(100)
Seismic	-	200	(100)	-	200	(100)
Corporate	**725**	316	129	**1,521**	2,495	(39)
Capital expenditures	**5,003**	9,384	(47)	**9,900**	29,870	(67)
Reclamation and abandonment	**666**	375	77	**4,684**	887	428
Total capital expenditures	**5,669**	9,759	(42)	**14,584**	30,757	(53)

Our focus during the period was, and continues to be, cash flow preservation. As a result, our capital expenditures for the second quarter and year-to-date are significantly lower than in the comparative periods. Notable capital spending for the current reporting periods is as follows:

- Facilities and Well Optimization – ongoing field and facility capital optimization programs to support mitigation of our natural reserve decline rates and to support facility reliability.
- Turnarounds – maintenance turnarounds for the current period include costs related to the Jumping Pound Facility outage and planning for phase two of the Waterton Turnaround.
- Corporate Capital – corporate capital expenditures are comprised of capitalized G&A, information technology expenses and purchase of capital inventory.
- Reclamation and Abandonment – expenditures are related to reclamation and abandonment activities, primarily in Northeast BC.

LIQUIDITY AND CAPITAL RESOURCES

Capital Resources

As at June 30, 2024, our capital structure was comprised of share capital, adjusted working capital and long-term debt. The following table summarizes our capital structure at June 30, 2024 and December 31, 2023:

($ 000s)	June 30, 2024	December 31, 2023
Adjusted working capital (deficit) (1)	**(37,986)**	(31,830)
Current portion of long-term debt	**(32,776)**	(30,748)
Long-term debt	**(148,442)**	(141,468)
Net debt (2)	**(219,204)**	(204,046))
Shareholders' equity	**142,058**	174,406

(1) Adjusted working capital is a non-GAAP measure and is calculated as accounts payable and accrued liabilities, less cash and cash equivalents, restricted cash, accounts receivable, prepaid expenses and other.

(2) Net debt is a non-GAAP measure. Management considers net debt an important measure as it demonstrates our ability to pay off our debt and take on new debt, if necessary.

Cash and Cash Equivalents

We held $11.2 million in cash and cash equivalents and restricted cash of $0.5 million as at June 30, 2024.

Guarantee Facility from Export Development Canada

Pieridae holds a $12.0 million unsecured guarantee facility with Export Development Canada. This facility provides a 100% guarantee to the issuing banks of our existing and future trade and commercial letters of credit. There was $7.8 million drawn at June 30, 2024, as compared to $5.9 million at December 31, 2023. Effective July 1, 2024, the Company renewed the facility and re-purposed $2.0 million into a foreign exchange facility to allow for increased hedged capability, reducing the trade and commercial facility to $10.0 million.

Long-Term Debt

Our long-term debt consists of a USD $150 million and a CAD $20 million debt facility; refer to note 7 of the Interim Financial Statements.

The USD $150 million long-term debt facility is comprised of a USD $120 million, 45-month senior facility and USD $30 million 51-month subordinated notes ("Subordinated Notes"), which are both held by Pieridae Alberta Production Limited ("PAPL"), a wholly owned subsidiary.

The CAD $20 million facility is an 18-month Bridge Term Loan held in Pieridae Energy Limited ("PEL") which has no direct recourse against the assets or cashflows of PAPL.

As at June 30, 2024, and as at the date of this MD&A the Company was in compliance with, or had obtained the required waivers for, all covenants of the term debt.

The table below summarizes debt obligations as of June 30, 2024 and December 31, 2023:

($ 000s)	Principal Outstanding	June 30, 2024	December 31, 2023
Senior facility			
Revolving loan USD $25,000(1)	**USD 17,800**	**24,363**	19,574
Amortizing term loan USD $85,000(1)	**USD 78,200**	**107,032**	107,924
Delayed draw term loan USD $10,000 (1)(2)	-	-	-
Subordinated notes USD $30,000(1)	**USD 30,000**	**41,061**	39,678
PAPL total debt(3)		**172,456**	167,176
Bridge term loan $20,000(4)	**20,000**	**23,469**	22,028
Pieridae total debt		**195,925**	189,204

(1) Converted to CAD using the month end exchange rate of 1.3687 as at June 30, 2024 and 1.3226 as at December 31, 2023.
(2) The delayed draw term loan must be drawn prior to December 31, 2024. Any amount drawn will be combined with the amortizing term loan, together (the "Term Loan").
(3) Excludes unamortized deferred financing fees of USD$5.0 million.
(4) Includes interest payable in-kind of $4.0 million and excludes unamortized deferred financing fees of $0.1 million.

On July 25, 2024, we issued a binding Bridge Term Loan repayment notice. The Bridge Term Loan was settled in cash on August 1, 2024 for $24.0 million, which included all outstanding principal and accrued interest.

On July 25, 2024, we also announced the sale of our Goldboro assets for cash proceeds of $12.0 million. The sale closed on August 1, 2024. The Goldboro Nova Scotia assets have a net book value to Pieridae of $3.8 million.

Concurrent with the closing of the sale of the Goldboro assets, Pieridae entered into a subscription agreement to issue 12.8 million common shares to an existing shareholder at a price of $0.35 per share, for gross proceeds of $4.5 million. The non-brokered private placement closed on August 2, 2024.

Proceeds from the sale of the Goldboro Nova Scotia assets, the private placement, and existing liquidity were used to repay the Bridge Term Loan.

The table below summarizes our available liquidity as of June 30, 2024 and December 31, 2023:

($ 000s)	June 30, 2024	December 31, 2023
Cash and cash equivalents	**11,167**	18,333
Undrawn delayed draw term loan	**13,687**	13,226
Undrawn senior revolver	**9,855**	13,491
Total available liquidity (1)	**34,709**	45,050

(1) Total available liquidity is a non-GAAP measure. Management considers total available liquidity an important measure to evaluate our cash available to meet financial obligations. Total available liquidity equals cash and cash equivalents plus the undrawn portions of the delayed draw term loan and the undrawn portion of the revolving loan.

Working Capital and Capital Strategy

The following table summarizes the Company's working capital position at June 30, 2024 and December 31, 2023:

($ 000s)	June 30, 2024	December 31, 2023
Cash and cash equivalents	**11,167**	18,333
Restricted cash	**520**	670
Accounts receivable	**45,160**	61,523
Prepaids expenses and other	**8,275**	9,335
Total current assets	**65,122**	89,861
Accounts payable	**22,282**	44,804
Accrued liabilities	**80,826**	77,130
Total current liabilities	**103,108**	121,934
Adjusted working capital (deficit)(1) (1)	**(37,986)**	(31,830)

(1) Adjusted working capital (deficit) is a non-GAAP measure. Management considers adjusted working capital (deficit) an important measure to evaluate our operational liquidity. Adjusted working capital (deficit) equals operational current assets less operational current liabilities.

Our business generally operates with a sustainable working capital deficit. Our adjusted working capital deficit at June 30, 2024 increased compared to December 31, 2023, primarily driven by lower cash and accounts receivable balances, partially offset by a lower accounts payable balance.

We monitor working capital on a continuous basis with a focus on strengthening our balance sheet through sustaining production, and rigorous cost control across our operations and administration. Our capital strategy is aligned with our business strategy and is focused on maintaining sufficient liquidity to fund operations, expand third-party processing and marketing income, and mitigate reserves decline. Our principal sources of liquidity are the undrawn balance on our revolving loan, the undrawn balance on our delayed draw term loan, the remaining portion of the Export Development Canada guarantee facility, and any potential future debt and equity offerings.

SHARE CAPITAL, WARRANTS AND STOCK OPTIONS OUTSTANDING

The following table outlines the Company's share capital, stock options and warrants outstanding at August 13, 2024, June 30, 2024 and December 31, 2023:

	August 13, 2024	June 30, 2024	December 31, 2023
Share capital	171,911,336	159,111,336	159,087,336
Stock options	3,523,600	4,285,206	4,416,690
Stock options – weighted average exercise price ($/share)	$0.70	$0.73	$0.73
Warrants	23,596,322	23,596,322	23,596,322
Warrants – weighted average exercise price ($/warrant)	$0.53	$0.53	$0.53

COMMITMENTS, PROVISIONS AND CONTINGENCIES

The Company has entered into several financial obligations during the normal course of business. As at June 30, 2024, these obligations, and the expected timing of their settlement, are detailed below:

($ 000s)	2024	2025	2026	Thereafter	Total
Firm transportation	6,130	11,919	2,924	-	**20,973**
Premium on foreign exchange hedges	357	327	-	-	**684**
Total	**6,487**	**12,246**	**2,924**	**-**	**21,657**

Provisions and Contingencies

We are involved in various claims and litigation arising in the normal course of business. While the outcome of these matters is uncertain, we believe that any liabilities that may arise from such matters are not likely to have a material effect on the Interim Financial Statements.

Off Balance Sheet Transactions

We do not have any financial arrangements that are excluded from the Interim Financial Statements, nor are any such arrangements outstanding as of the date at this MD&A.

ENVIRONMENTAL, SOCIAL AND GOVERNANCE

We conduct our operations with high standards, aiming to meet or exceed all regulations. The Company's prime consideration is to protect our employees and consultants, the general public, and the environment. Our Liability Management Rating is within both the British Columbia Energy Regulator's ("BCER") and the Alberta Energy Regulator's ("AER") requirements after accounting for a $1.8 million deposit in place with the BCER. Our liability rating in Alberta is calculated by the AER based on the licenses which are in Pieridae's name.

We consider the impact of the changing worldwide demand for carbon-based energy and global advancement of alternative energy sources in our business strategy. Emissions and other regulations impacting climate and climate related matters are constantly evolving and we continue to monitor and implement these changes as necessary.

Our ESG work first assesses our starting point with respect to governance, GHG emissions and social policies, noting the material areas of focus. As we build on our strategic plan, we seek to evolve the business and consider energy transition and associated business opportunities.

RISK FACTORS

We monitor and comply with current government regulations that affect our activities, although operations may be adversely affected by changes in government policy, regulations, or taxation. In addition, we maintain a level of liability and property and business interruption insurance, which is believed adequate for our size and activities. However, we are unable to obtain insurance to cover all risks within the business or in amounts to cover all possible claims. Risk to our business and operations include, but are not limited to:

Risks Related to Pieridae's Business and Industry
Adverse Economic Conditions
Access to Capital
Liquidity
Prices, Volatility and Marketing of Oil, Natural Gas and NGLs
Operational Matters and Hazards
Labour Relations
Development and Production
Regulatory Permits, Licenses and Approvals
Variations in Foreign Exchange and Interest Rates
Skilled Workforce
Pipeline Systems, Rail, Co-ownership of Assets, and Operational Dependence
Facilities Throughput and Utilization
Information Technology Systems and Cyber-Security
Inflation and Cost Management
Hedging Activities
Political Uncertainty and Geo-Political Risk
Project Execution
Climate Change
Climate Change – Physical Risks
Climate Change – Transition Risks
Climate Change Regulations and Carbon Pricing
Royalty Regimes
Environmental
Reputational
Third-party Credit Risk
Technological Change
Competition
Conflicts of Interest
Indigenous Land Rights Claims
Reserve Estimates
Litigation
Insurance Coverage
Breach of Confidentiality
Risks Related to Pieridae's Common Shares
Volatility
Return on Investment
Dilution

Refer to the Company's Annual Information Form for the year ended December 31, 2023, for fulsome discussion of these risks. See also "Cautionary Note Regarding Forward-Looking Information" in this MDA.

SIGNIFICANT ACCOUNTING JUDGEMENTS AND ESTIMATES

The timely preparation of the Interim Financial Statements requires management to make judgments, estimates and assumptions that affect the application of accounting policies and reported amounts of assets and liabilities and income and expenses. Accordingly, actual results may differ from these estimates. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected. The use of significant judgments and estimates made by management in the preparation of the Interim Financial Statements are discussed in note 3 of the Consolidated Financial Statements for the year ended December 31, 2023.

CONTROL ENVIRONMENT

We are required to comply with National Instrument 52-109 "Certification of Disclosure in Issuers' Annual and Interim Filings." The certification of interim filings for the period ended June 30, 2024, requires that we disclose in the interim MD&A any changes in disclosure controls and procedures (DC&P) and internal controls over financial reporting (ICFR) that occurred during the period that have materially affected, or are reasonably likely to materially affect, internal controls over financial reporting. No such changes were made to our DC&P and ICFR during the period ended June 30, 2024.

Internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

NEW ACCOUNTING POLICIES

The Company's significant accounting policies under IFRS are presented in note 3 to the annual consolidated financial statements. Certain information and disclosures normally required to be included in the notes to the annual consolidated financial statements presented in accordance with IFRS have been condensed or omitted in the Interim Financial Statements.