MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis ("MD&A") of the financial condition and performance of MEG Energy Corp. ("MEG" or the "Corporation") for the year ended December 31, 2023 was approved by the Corporation's Board of Directors on February 29, 2024. This MD&A should be read in conjunction with the Corporation's audited annual consolidated financial statements and Annual Information Form ("AIF") for the year ended December 31, 2023.

Basis of Presentation

This MD&A and the audited annual consolidated financial statements and comparative information have been prepared in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board ("IFRS Accounting Standards") and are presented in millions of Canadian dollars, except where otherwise indicated.

Unless otherwise indicated, all per barrel figures are based on bitumen sales volumes.

Non-GAAP and Other Financial Measures

Certain financial measures in this MD&A are non-GAAP financial measures or ratios, supplementary financial measures and capital management measures. These measures are not defined by IFRS and, therefore, may not be comparable to similar measures provided by other companies. These non-GAAP and other financial measures should not be considered in isolation or as an alternative for measures of performance prepared in accordance with IFRS. Please refer to section 15 "Non-GAAP and Other Financial Measures" of this MD&A for further descriptions of the measures noted below.

Non-GAAP financial measures and ratios include: cash operating netback, blend sales, bitumen realization, net transportation and storage expense, bitumen realization after net transportation and storage expense, operating expenses net of power revenue, energy operating costs net of power revenue, effective royalty rate, and per barrel figures associated with non-GAAP financial measures.

Supplementary financial measures and ratios include: non-energy operating costs, energy operating costs, and per barrel figures associated with supplementary financial measures.

Capital management measures include: adjusted funds flow, free cash flow, and net debt.

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1. 2023 HIGHLIGHTS AND 2024 OUTLOOK

The following table summarizes selected operational and financial information of the Corporation for the periods noted. All dollar amounts are stated in Canadian dollars ($ or C$) unless otherwise noted and all per barrel operational and financial results are based on bitumen sales volumes:

	Three months ended December 31		Year ended December 31	
($millions, except as indicated)	**2023**	**2022**	**2023**	**2022**
Operational results:				
Bitumen production - bbls/d	109,112	110,805	101,425	95,338
Steam-oil ratio	2.28	2.22	2.27	2.36
Bitumen sales - bbls/d	112,634	113,582	101,086	95,691
Benchmark pricing:				
WTI - US$/bbl	78.32	82.65	77.62	94.23
Differential - WTI:AWB - Edmonton - US$/bbl	(23.79)	(29.14)	(20.79)	(20.64)
AWB - Edmonton - US$/bbl	54.53	53.51	56.83	73.59
Differential - WTI:AWB - USGC - US$/bbl	(7.43)	(16.35)	(8.72)	(9.62)
AWB - USGC - US$/bbl	70.89	66.30	68.90	84.61
Financial results:				
Bitumen realization after net transportation and storage expense(1) - $/bbl	63.52	54.75	62.46	76.66
Non-energy operating costs(2) - $/bbl	4.64	4.34	5.01	4.73
Energy operating costs net of power revenue(1) - $/bbl	1.46	1.49	0.95	3.18
Operating expenses net of power revenue(1) - $/bbl	6.10	5.83	5.96	7.91
Cash operating netback(1) - $/bbl	38.65	43.89	43.36	62.61
General & administrative expense - $/bbl of bitumen production	1.89	1.62	1.86	1.78
Funds flow from operating activities	358	383	1,476	1,882
Per share, diluted	1.27	1.28	5.13	6.09
Adjusted funds flow(3)	358	401	1,402	1,934
Per share, diluted(3)	1.27	1.34	4.87	6.26
Capital expenditures	104	106	449	376
Free cash flow(3)	254	295	953	1,558
Debt repayments - US$	128	150	322	1,016
Share repurchases - C$	219	196	446	382
Revenues	1,444	1,445	5,653	6,118
Net earnings	103	159	569	902
Per share, diluted	0.37	0.53	1.98	2.92
Long-term debt, including current portion	1,124	1,581	1,124	1,581
Net debt - US$(3)	730	1,026	730	1,026

(1) Non-GAAP financial measure - please refer to section 15 "Non-GAAP and Other Financial Measures" of this MD&A.
(2) Supplementary financial measure - please refer to section 15 "Non-GAAP and Other Financial Measures" of this MD&A.
(3) Capital management measure - please refer to section 15 "Non-GAAP and Other Financial Measures" of this MD&A.

Financial Results and Capital Resources

The Corporation generated funds flow from operating activities of $1,476 million and adjusted funds flow of $1,402 million during 2023. After $449 million of capital expenditures, the Corporation's remaining free cash flow of $953 million was used to fund working capital, repay debt and return capital to shareholders. During 2023, the Corporation repurchased US$322 million (approximately $437 million) of outstanding 7.125% senior unsecured notes at a weighted average price of 101.7% and returned $446 million to MEG shareholders through the repurchase and cancellation of 19.0 million shares at a weighted average price of $23.54 per share, which is approximately 7% of the December 31, 2022 issued and outstanding shares.

Average annual bitumen production volumes rose 6% in 2023 to 101,425 barrels per day at a steam-oil ratio ("SOR") of 2.27, from 95,338 barrels per day at an SOR of 2.36 in 2022, reflecting the Corporation's continued focus on short-cycle redevelopment programs, enhanced completion designs, optimized well spacing and targeted facility enhancements.

Funds flow from operating activities and adjusted funds flow in 2023 decreased to $1,476 million and $1,402 million, respectively, from $1,882 million and $1,934 million in 2022, driven mainly by a lower cash operating netback partially offset by lower interest expense due to reduced debt levels. Cash operating netback declined $19.25 per barrel to $43.36 per barrel in 2023 mainly reflecting a lower bitumen realization after net transportation and storage expense and increased post-payout royalties. Bitumen realization after net transportation and storage expense fell to $62.46 per barrel in 2023 from $76.66 per barrel in the prior year primarily driven by a lower blend sales price reflecting the 18% decrease in the WTI benchmark price.

Capital expenditures increased to $449 million in 2023 from $376 million in 2022, reflecting increased scope in field development and maintenance activities together with cost inflation. Spending was primarily focused on sustaining and maintenance activities in both years.

The Corporation generated free cash flow of $953 million in 2023 and $1,558 million in 2022.

Annual net earnings declined to $569 million during 2023 from $902 million in 2022. This decline was primarily driven by lower adjusted funds flow, higher depletion and depreciation expense and an onerous contract expense partially offset by reduced deferred tax expense and an unrealized foreign exchange gain on long-term debt.

At December 31, 2023, cash and cash equivalents were $160 million. The Corporation exited 2023 with total debt and net debt of approximately $1,124 million and $964 million (US$730 million), respectively.

2024 Outlook

Summary of 2024 Guidance	
Bitumen production - annual average	102,000 to 108,000 bbls/d
Capital expenditures	$550 million
Non-energy operating costs	$5.10 to $5.40 per bbl
G&A expense	$1.75 to $1.95 per bbl

The 2024 annual production estimate incorporates reduced turnaround activities spread evenly throughout the year. The plan also includes the startup of two well pads, with the first pad on-stream mid-year and the second in the fourth quarter. New pad activity supports the 2024 production estimate and builds well capacity for future growth.

The Corporation's 2024 capital expenditure program will allocate $450 million to sustaining activities and $100 million towards multi-year productive capacity growth. The growth investment reflects the commencement of a three-year project with an estimated total cost of approximately $300 million forecasted to deliver incremental productive capacity around the end of 2026.

The Corporation's balance sheet and operating performance provide a solid foundation to fund the 2024 capital expenditure program. As a result, no WTI or WTI:WCS differential risk management contracts have been entered into for 2024.

2. BUSINESS OVERVIEW AND STRATEGY

MEG is an energy company focused on sustainable *in situ* thermal oil production in the southern Athabasca oil region of Alberta, Canada. MEG is actively developing innovative enhanced oil recovery projects that utilize steam-assisted gravity drainage ("SAGD") extraction methods to improve the responsible economic recovery of oil as well as lower carbon emissions. MEG transports and sells thermal oil (known as Access Western Blend or "AWB") to customers throughout North America and internationally. MEG is a member of the Pathways Alliance, a group of Canada's largest oil sands producers working together to address climate change and achieve the goal of net zero greenhouse gas ("GHG") emissions[1] by 2050.

MEG owns a 100% working interest in approximately 410 square miles of mineral leases. GLJ Ltd. ("GLJ"), an independent qualified reserves and resources evaluator, estimated that the leases it evaluated, as at December 31, 2023, contained approximately 1.93 billion barrels of gross proved plus probable ("2P") bitumen reserves at the Christina Lake Project. The report prepared by GLJ is dated effective December 31, 2023. For information regarding MEG's estimated reserves contained in the report prepared by GLJ, please refer to the Corporation's AIF for the year ended December 31, 2023, which is available on the Corporation's website at www.megenergy.com and is also available on the SEDAR+ website at www.sedarplus.ca.

The Christina Lake Project, which contains all the Corporation's 2P reserves has regulatory approval in place for 210,000 barrels per day of production. MEG has developed oil processing capacity of approximately 110,000 barrels per day at its Christina Lake central plant facility, prior to any impact from scheduled maintenance activity or outages. The average annual production decline rate at the Christina Lake Project has historically been between 10% and 15% and is anticipated to potentially increase due to new development techniques, including optimized well spacing. At current production levels, MEG has a 2P reserve life index of approximately 50 years.

Asset Strategy

The Corporation has been able to realize production growth over time at the Christina Lake Project while minimizing SOR and associated GHG emissions intensity through the application of proprietary technologies, including MEG's proprietary reservoir technology, eMSAGP, which reduces the amount of steam required to produce a barrel of bitumen, as well as other reservoir technologies, enhanced completion designs, and optimized well spacing. MEG also uses combined heat and power generation, known as cogeneration, to create steam and power from a single heat source. The application of eMSAGP and cogeneration have enabled MEG to lower its GHG emissions intensity more than 15% below the *in situ* industry volume weighted average based on data reported to Environment Canada, the Alberta Energy Regulator and the Alberta Electric System Operator. MEG achieved an average SOR of 2.27 in 2023 compared to the *in situ* industry volume weighted average of approximately 3.0.[2]

MEG is focused on safe and reliable operations and continues to invest in its safety leadership program, for both employees and contractors, to advance operational excellence. This focus is underpinned by a comprehensive Operations Excellence Management System that is intended to support increased production, top tier SOR performance, and a reduced GHG emissions intensity.

During 2024, the Corporation will commence investment in a project to add 15,000 barrels per day of new productive capacity to the existing facility, with an estimated total cost of approximately $300 million over the next three years. With no WTI or WTI:WCS differential risk management contracts in place for 2024 or beyond, the Corporation retains the flexibility to reduce capital expenditures in response to changing market conditions, such as declining oil prices, weaker differentials and inflationary cost pressures.

Capital Allocation Strategy

Since the fourth quarter of 2022, MEG has been allocating 50% of free cash flow to share repurchases with the remainder applied to debt repayment. This free cash flow allocation strategy will remain in place until the

[1] Scope 1 and Scope 2 emissions
[2] Annual 2023 data as per the Alberta Energy Regulator ST53.

Corporation reaches its US$600 million long-term net debt target, which is anticipated to occur in the third quarter of 2024 under a US$75 per barrel WTI oil price assumption. From that point, 100% of free cash flow will be returned to shareholders.

Marketing Strategy

The Corporation employs a marketing strategy that delivers and sells its production to oil markets throughout North America and internationally. MEG owns, leases and contracts for services on multiple facilities to transport, store and deliver AWB to customers. MEG has 100,000 bbls/d of contracted AWB transportation capacity on the Flanagan South and Seaway pipeline systems ("FSP") providing pipeline transportation directly to USGC refineries and export terminals. MEG is also a shipper on the Trans Mountain Expansion Project ("TMX") which is anticipated to be in service during the second quarter of 2024 and will provide MEG with 20,000 bbls/d of contracted AWB transportation capacity to Canada's West Coast. MEG has proprietary and contracted oil storage capacity of approximately 2.1 million barrels in Alberta and strategic locations in the U.S., with marine export capacity at Beaumont, Texas in the USGC. This combination of pipeline access, storage capacity and marine export capacity comprises MEG's strategy of having diversified, long-term and reliable market access to world oil prices for its production.

MEG has a long-term commitment to deliver AWB on the Access Pipeline from its Christina Lake Project to the Edmonton market connecting to local refineries and export pipelines. The Access Pipeline is comprised of an AWB blend pipeline system and diluent pipeline system. The AWB blend pipeline system runs from the Christina Lake Project to the Edmonton area. The diluent pipeline system runs from the Edmonton area to MEG's Christina Lake Project and allows MEG to effectively manage its local and import sourced diluent supply for purposes of blending with its Christina Lake production. The diluent system receives volumes from numerous local diluent production streams and fractionation facilities as well as imported diluent volumes from inbound pipelines. The diluent system is well connected to key pipeline and storage systems in the Edmonton/Fort Saskatchewan corridor, including import pipelines for access to Mont Belvieu supply. This system provides a range of diluent supply alternatives and helps to mitigate diluent supply and price risk.

In the Edmonton area, MEG has approximately 1.1 million barrels of storage and terminalling capacity, including approximately 900,000 barrels of capacity contracted at the Stonefell Terminal. The Stonefell Terminal is connected to the Access Pipeline System and provides the Corporation with the ability to: (i) sell and deliver AWB to a variety of markets; (ii) access multiple sources of diluent; and (iii) store both bitumen blend and diluent in periods of market and transportation disruptions or constraints.

MEG has contracted pipeline capacity, storage capacity and marine export capacity in the USGC area. Specifically, MEG has contracted for approximately 1.0 million barrels of storage capacity, along with marine export capacity, at Beaumont, Texas.

Sustainability and Pathways

The Corporation published its third ESG report in September 2023, which discusses its foundational commitments of Business Model Resilience and Governance and the Corporation's priority ESG topics: Health and Safety; Climate Change and GHG Emissions; Water Management; Energy Security; Energy Affordability; and Indigenous Relations. The ESG report illustrates progress in several areas, including the establishment of a new mid-term absolute GHG emissions (Scope 1 and Scope 2) reduction target of 0.63 megatonnes per year by year-end 2030 (which represents approximately 30% of the Corporation's 2019 GHG emissions); $72 million spent on goods and services provided by Indigenous businesses in 2022 (a 30% increase over 2021); the launch of the Corporation's Diversity, Equity and Inclusion education and awareness campaign focused on ensuring that every team member is valued, respected and heard to enhance decision making, innovation, employee engagement and the Corporation's long-term success; and the continued advancement of the Corporation's safety management programs and systems to ensure safe, sustainable and reliable operations.

MEG, along with its Pathways Alliance peers, continues to progress pre-work on the proposed foundational carbon capture and storage ("CCS") project, which will transport CO_2 via pipeline from multiple oil sands facilities to be stored safely and permanently underground in the Cold Lake region of Alberta. The Pathways Alliance continues to advance detailed evaluations of the proposed carbon storage hub and is working to obtain a carbon sequestration agreement from the Alberta Government in the first half of 2024 to support regulatory submissions. In addition, the Pathways Alliance continues to advance engineering work, environmental field programs to minimize the project's environmental disturbance, and consultations with Indigenous and local communities along the proposed CO_2 transportation and storage network corridor. The Pathways Alliance continues to work collaboratively with both the federal and Alberta Governments on the necessary policy and co-financing frameworks required to move the project forward. The federal government has proposed an investment tax credit ("ITC") for CCS projects for all sectors across Canada and introduced implementing legislation for the CCS ITC in November 2023. In addition, the Alberta Government announced an Alberta Carbon Capture Incentive Program ("ACCIP") which aims to help hard-to-abate industries by providing a grant of 12% for new eligible CCS capital costs. The Pathways Alliance is evaluating these proposals and will continue to work with the federal and Alberta Governments to secure the required financial support and regulatory certainty to enable the CCS project to proceed.

Additional information regarding the Corporation's ESG actions, including the Corporation's 2023 ESG Report, is available in the "Sustainability" section of the Corporation's website at www.megenergy.com. The Corporation's ESG Report and contents of MEG's website are expressly not incorporated by reference in this MD&A.

3. FOURTH QUARTER HIGHLIGHTS

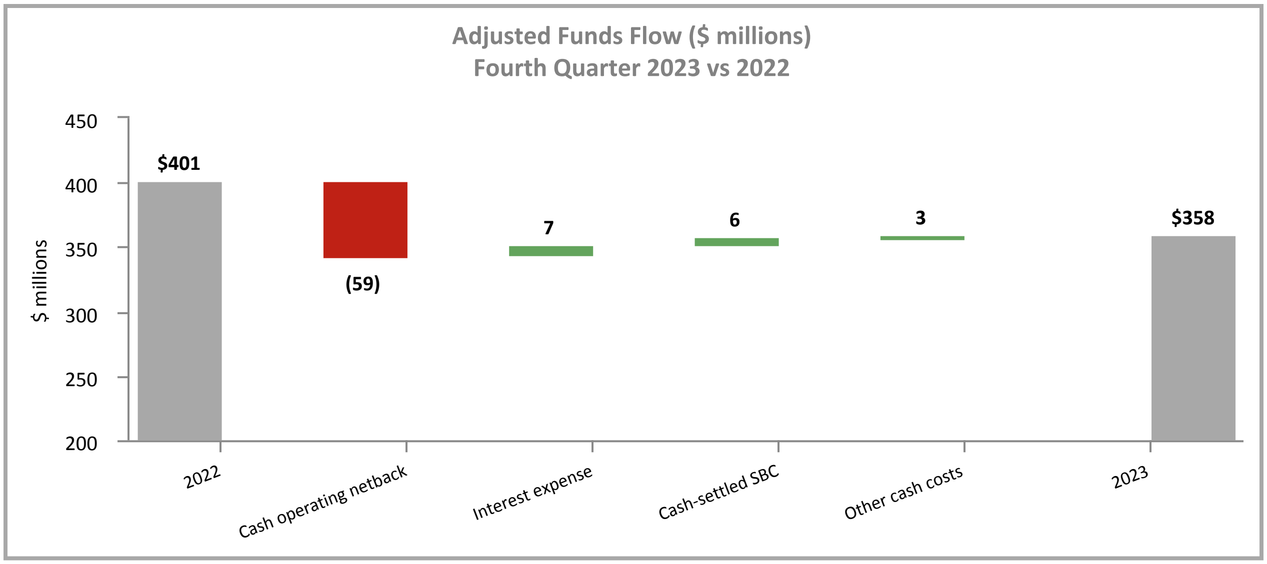
The Corporation generated funds flow from operating activities and adjusted funds flow of $358 million, or $1.27 per share, during the fourth quarter of 2023. After $104 million of capital expenditures, the Corporation's remaining $254 million of free cash flow, together with cash from working capital reductions, was used to repay debt and return capital to shareholders. During the fourth quarter of 2023, the Corporation repaid US$128 million (approximately $173 million) of outstanding 7.125% senior unsecured notes and returned $219 million to shareholders through the repurchase and cancellation of 8.7 million shares at a weighted average price of $25.29 per share.

Average bitumen production in the fourth quarter of 2023 fell 2% from the comparative 2022 period. Production volumes were strong in both periods, reflecting no significant maintenance activities, short-cycle redevelopment programs, enhanced completion designs, optimized well spacing, targeted facility enhancements and continued emphasis on steam allocation to the highest quality resource.

	Three months ended December 31	
	2023	**2022**
Bitumen production – bbls/d	**109,112**	110,805
Steam-oil ratio (SOR)	**2.28**	2.22

The following table reconciles funds flow from operating activities to adjusted funds flow to free cash flow:

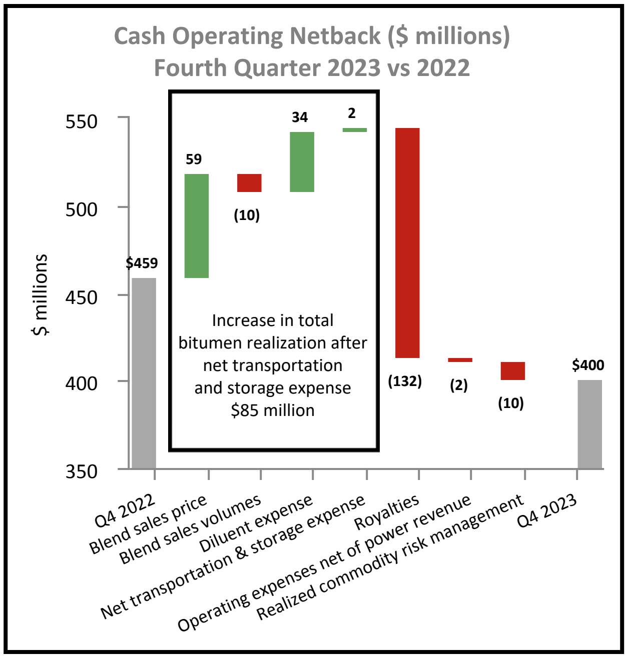
	Three months ended December 31	
($millions)	**2023**	**2022**
Funds flow from operating activities	**$ 358**	$ 383
Adjustments:		
Impact of cash-settled SBC units subject to equity price risk management	**—**	18
Adjusted funds flow	**$ 358**	$ 401
Capital expenditures	**(104)**	(106)
Free cash flow	**$ 254**	$ 295
Adjusted funds flow per share - diluted	**$ 1.27**	$ 1.34

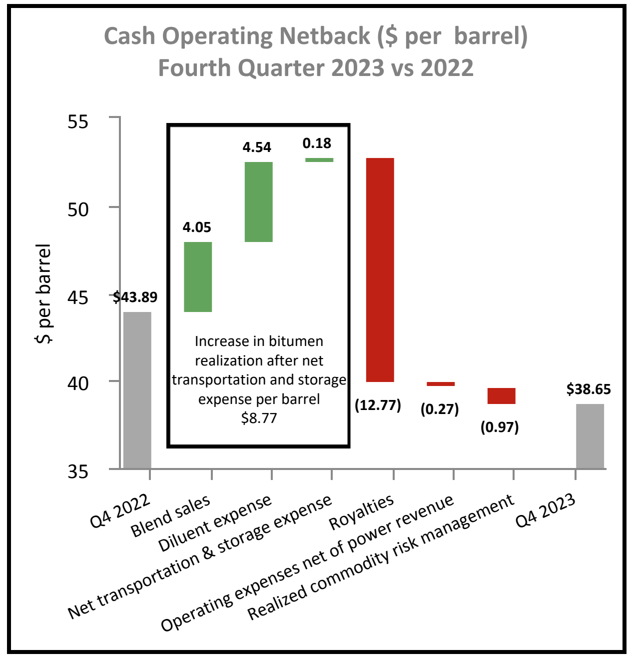


Funds flow from operating activities and adjusted funds flow decreased during the fourth quarter of 2023, compared to the same period of 2022, mainly reflecting a lower cash operating netback partially offset by lower interest expense due to reduced debt levels and a reduction in cash-settled stock-based compensation.

	Three months ended December 31			
	2023		**2022**	
($millions, except as indicated)		**$/bbl**		**$/bbl**
Sales from production	**$ 1,262**		$ 1,223	
Sales from purchased product(1)	**349**		221	
Petroleum revenue	**1,611**		1,444	
Purchased product(1)	**(334)**		(216)	
Blend sales(2)(3)	**$ 1,277**	**$ 87.33**	$ 1,228	$ 83.28
Diluent expense	**(471)**	**(9.58)**	(505)	(14.12)
Bitumen realization(3)	**806**	**77.75**	723	69.16
Net transportation and storage expense(3)(4)	**(148)**	**(14.23)**	(150)	(14.41)
Bitumen realization after net transportation and storage expense	**658**	**63.52**	573	54.75
Royalties	**(186)**	**(17.92)**	(54)	(5.15)
Operating expenses net of power revenue(3)	**(63)**	**(6.10)**	(61)	(5.83)
Realized gain (loss) on commodity risk management	**(9)**	**(0.85)**	1	0.12
Cash operating netback(3)	**$ 400**	**$ 38.65**	$ 459	$ 43.89
Bitumen sales volumes - bbls/d		**112,634**		113,582

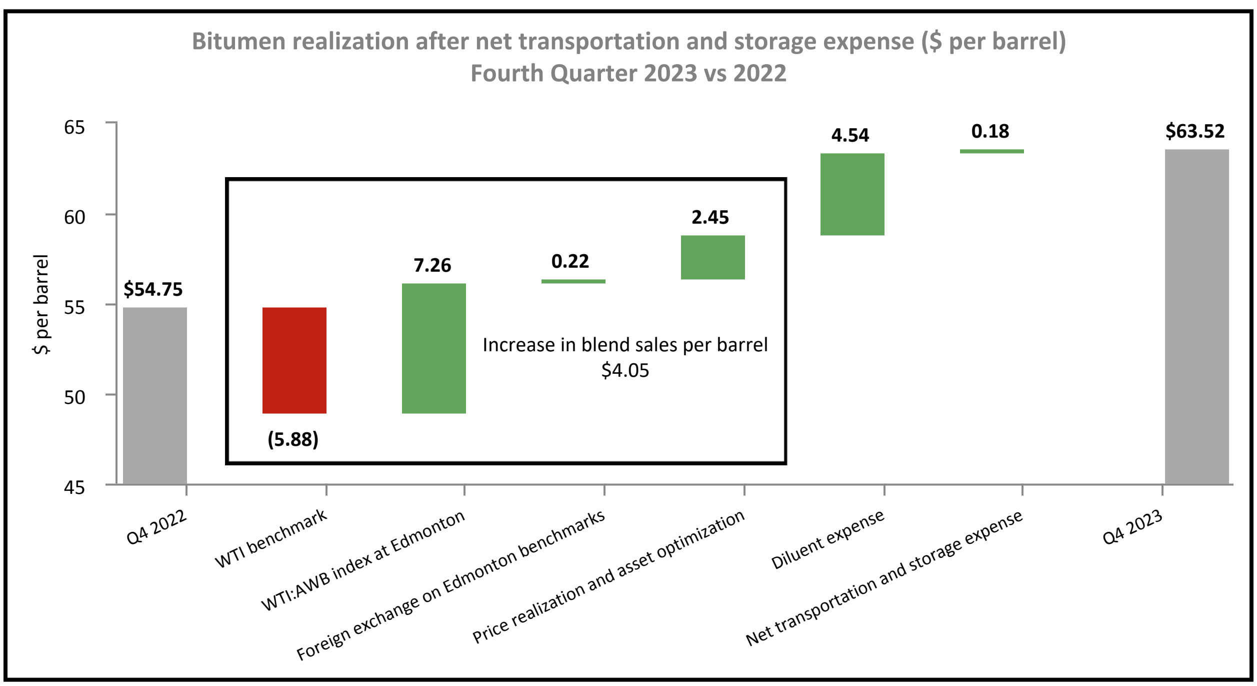
(1) Sales and purchases of oil products mainly related to marketing asset optimization activities.
(2) Blend sales per barrel are based on blend sales volumes.
(3) Non-GAAP financial measure - please refer to section 15 "Non-GAAP and Other Financial Measures" of this MD&A.
(4) Net transportation and storage expense includes costs associated with moving and storing AWB to optimize the timing of delivery, net of third-party recoveries on diluent transportation arrangements.





During the fourth quarter of 2023, cash operating netback decreased by approximately 12% to $400 million, or $38.65 per barrel, compared to $459 million, or $43.89 per barrel, during the same period of 2022. The decrease was mainly driven by increased royalties partially offset by higher bitumen realization after net transportation and storage expense.

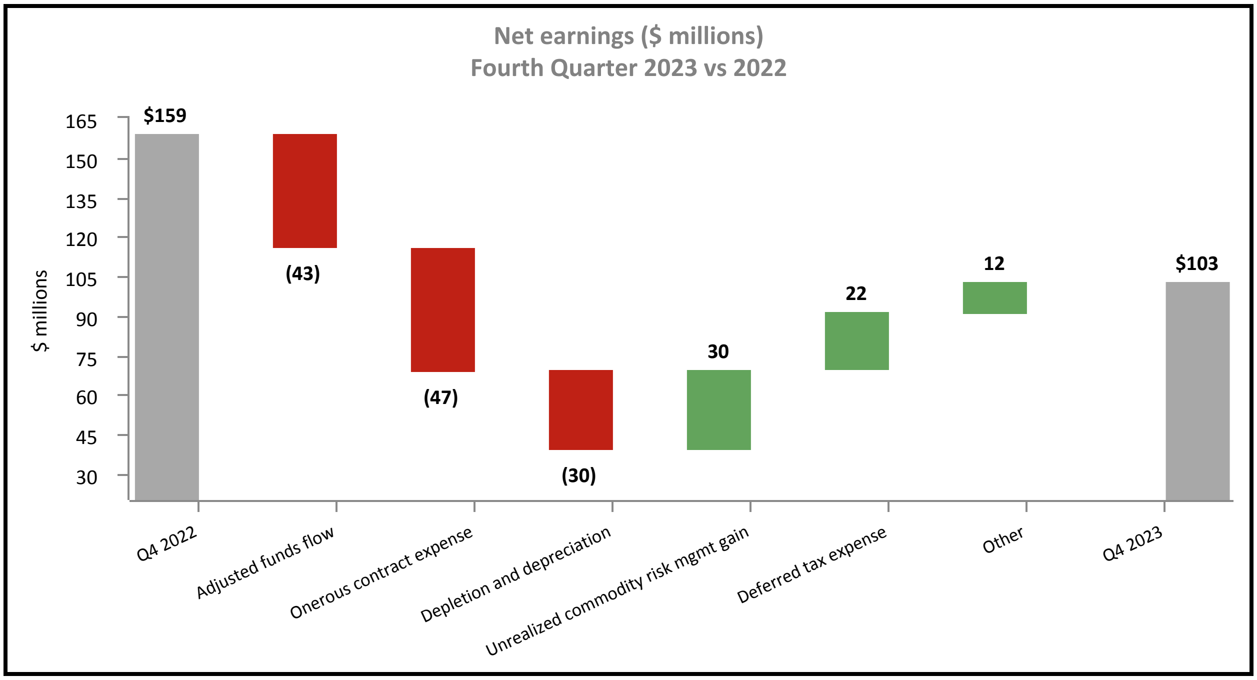
As a result of reaching payout status earlier in the year, royalty expense rose in the fourth quarter of 2023 which increased the effective royalty rate to 28.2% from 9.4% in the same period of 2022.



Bitumen realization after net transportation and storage expense increased 16% to $63.52 per barrel in the fourth quarter of 2023, from $54.75 per barrel in the same period of 2022. The increase was primarily driven by narrower WTI:AWB differentials, at both Edmonton and the USGC, lower diluent expense and the realized price improvement from diverse market access and marketing optimization activities, partially offset by a lower average WTI benchmark price.

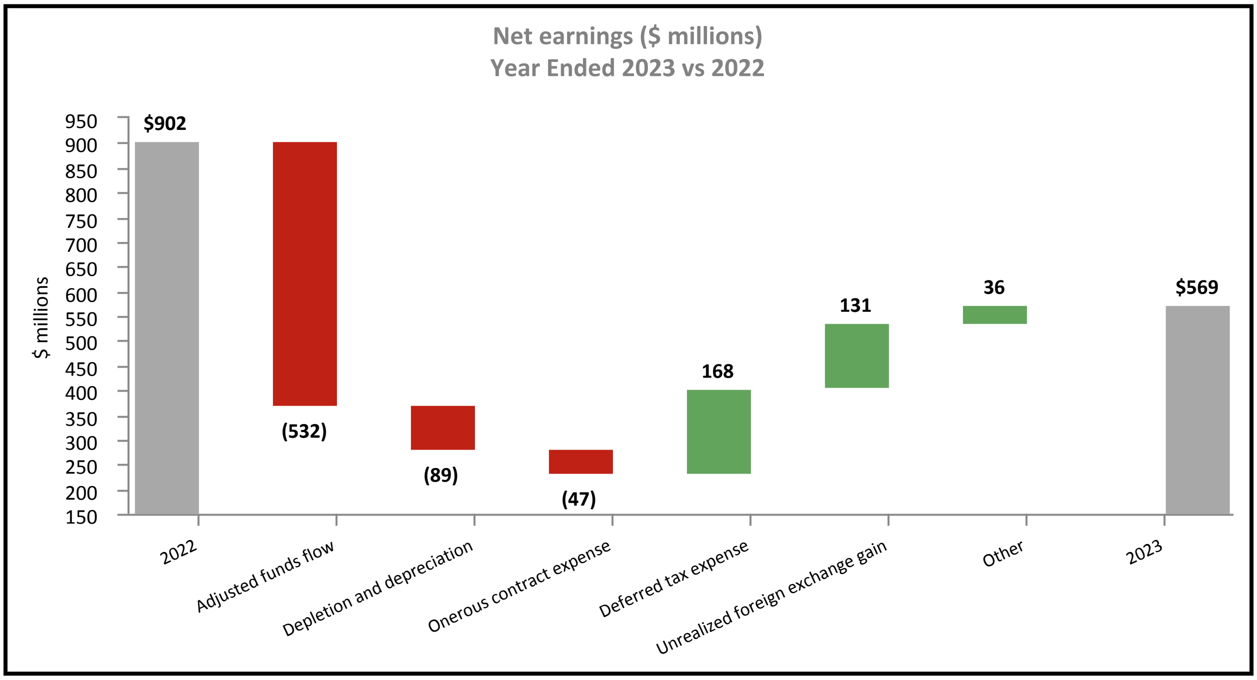
Decreased diluent expense, on a total and per barrel basis, reflects a lower average condensate price, relative to WTI, and narrower WTI:AWB differentials. As a result, the Corporation recovered 79% of diluent costs through blend sales during the fourth quarter of 2023 compared to 71% in the same period of 2022.

The Corporation sold 57% of blend volumes in the USGC during the fourth quarter of 2023 compared to 63% in the same period of 2022. Average heavy oil apportionment on the Enbridge mainline system was 21% and 5% in the fourth quarters of 2023 and 2022, respectively.



Fourth quarter net earnings declined to $103 million in 2023, from $159 million during the same period of 2022. The decrease mainly reflects a lower adjusted funds flow, an onerous contract expense and higher depletion and depreciation expense, partially offset by an unrealized commodity risk management gain and reduced deferred tax expense.

4. NET EARNINGS



Annual net earnings declined to $569 million during 2023 from $902 million in 2022. This decline was primarily driven by lower adjusted funds flow, higher depletion and depreciation expense and an onerous contract expense partially offset by reduced deferred tax expense and an unrealized foreign exchange gain on long-term debt.

5. REVENUES

Revenues are comprised of petroleum revenue, net of royalties, which include sales of third-party products related to marketing asset optimization, and power and transportation revenue.

($millions)		**2023**		**2022**
Sales from:				
Production	**$**	**4,548**	$	5,044
Purchased product[(1)]		**1,444**		1,151
Petroleum revenue	**$**	**5,992**	$	6,195
Royalties		**(456)**		(225)
Petroleum revenue, net of royalties	**$**	**5,536**	$	5,970
Power revenue	**$**	**114**	$	144
Transportation revenue		**3**		4
Power and transportation revenue	**$**	**117**	$	148
Revenues	**$**	**5,653**	$	6,118

(1) The associated third-party purchases are included in the consolidated statement of earnings and comprehensive income under the caption "Purchased product".

During 2023, petroleum revenue, net of royalties decreased to $5.5 billion from $6.0 billion in 2022. A weaker average WTI benchmark price and increased royalties more than offset higher blend sales volumes, increased sales from purchased product and the positive impact of a weaker average Canadian dollar. The increase in sales from purchased product resulted from higher asset optimization activities to mitigate the cost of transportation and storage assets.

Revenues include the sale of third-party products related to marketing asset optimization activities. The associated purchase of third-party products is recognized within "Purchased product" expense. These transactions are mainly undertaken to recover fixed costs related to transportation and storage contracts. The Corporation does not engage in speculative trading. The purchase and sale of third-party products to facilitate marketing asset optimization activities requires the elimination of price risk pursuant to policies approved by the Corporation's Board of Directors, which can be achieved either through physical transactions or through financial price risk management.

6. RESULTS OF OPERATIONS

Bitumen Production and Steam-Oil Ratio

	2023	2022
Bitumen production – bbls/d	**101,425**	95,338
Steam-oil ratio (SOR)	**2.27**	2.36

Bitumen Production

Bitumen production increased approximately 6% in 2023, compared to 2022, reflecting the Corporation's continued focus on short-cycle redevelopment programs, enhanced completion designs, optimized well spacing and targeted facility enhancements. Production was impacted by major planned turnaround activities at the Christina Lake Facility in both years. In 2022, the Corporation also experienced an unplanned electrical event following the turnaround which resulted in a slower than forecast production ramp-up.

Steam-Oil Ratio ("SOR")

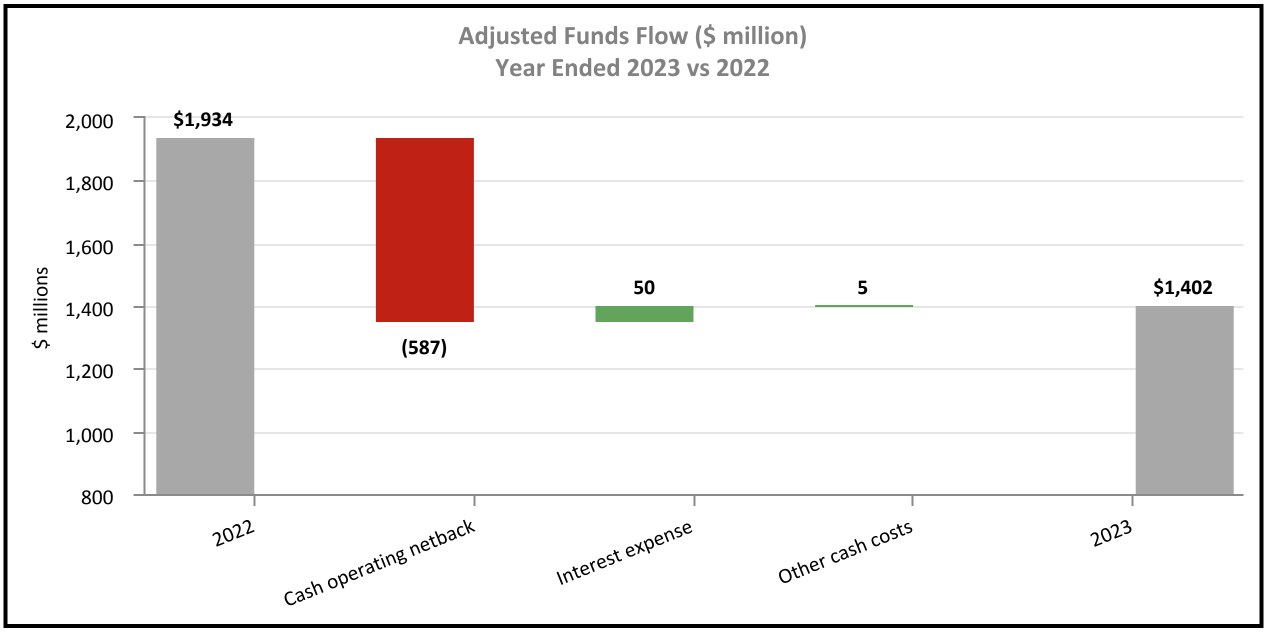
The Corporation uses SAGD technology to recover bitumen. In SAGD operations, steam is injected into the oil reservoir to mobilize bitumen, which is then pumped to the surface. An important metric for thermal oil projects is SOR, which is an efficiency indicator that measures the amount of steam that is injected into the reservoir for each barrel of bitumen produced. The SOR decreased approximately 4%, to 2.27, in 2023 due to the deployment of enhanced completion designs enabling optimal steam placement within the reservoir, execution of the Corporation's 2023 redevelopment plans for infill and re-drilled wells and ramp-up of production from new high-quality well pads.

Funds Flow from Operating Activities and Adjusted Funds Flow

Funds flow from operating activities is an IFRS measure in the Corporation's consolidated statement of cash flow. Adjusted funds flow is calculated as funds flow from operating activities excluding items not considered part of ordinary continuing operations. Adjusted funds flow is used by management to analyze the Corporation's operating performance and cash flow generating ability. By excluding non-recurring adjustments from cash flows, the adjusted funds flow measure establishes a clearer link between cash flows and the cash operating netback.

The following table reconciles funds flow from operating activities to adjusted funds flow:

($millions)	2023	2022
Funds flow from operating activities	**$ 1,476**	$ 1,882
Adjustments:		
Impact of cash-settled SBC units subject to equity price risk management	**13**	98
Realized equity price risk management gain	**(87)**	(46)
Adjusted funds flow	**$ 1,402**	$ 1,934
Adjusted funds flow per share - diluted	**$ 4.87**	$ 6.26



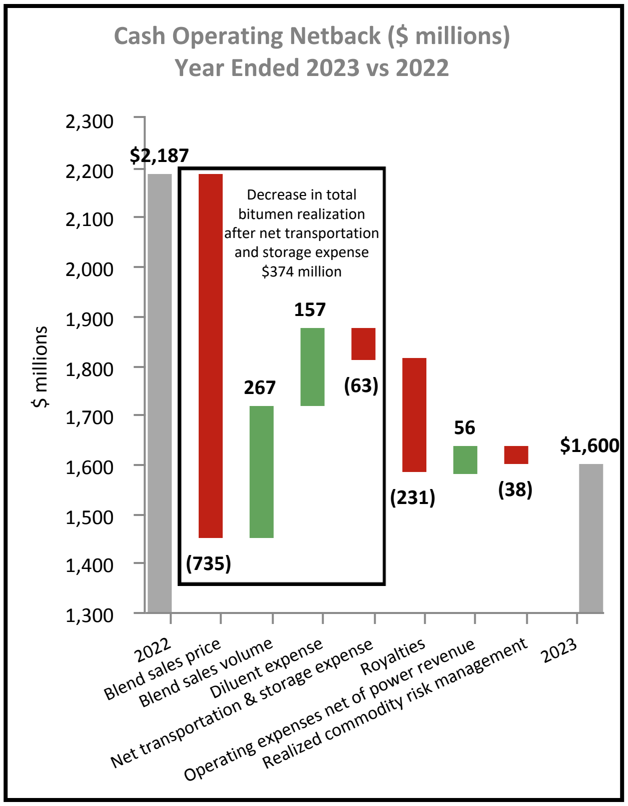
Funds flow from operating activities and adjusted funds flow decreased in 2023, compared to 2022, driven mainly by a lower cash operating netback partially offset by lower interest expense due to reduced debt levels.

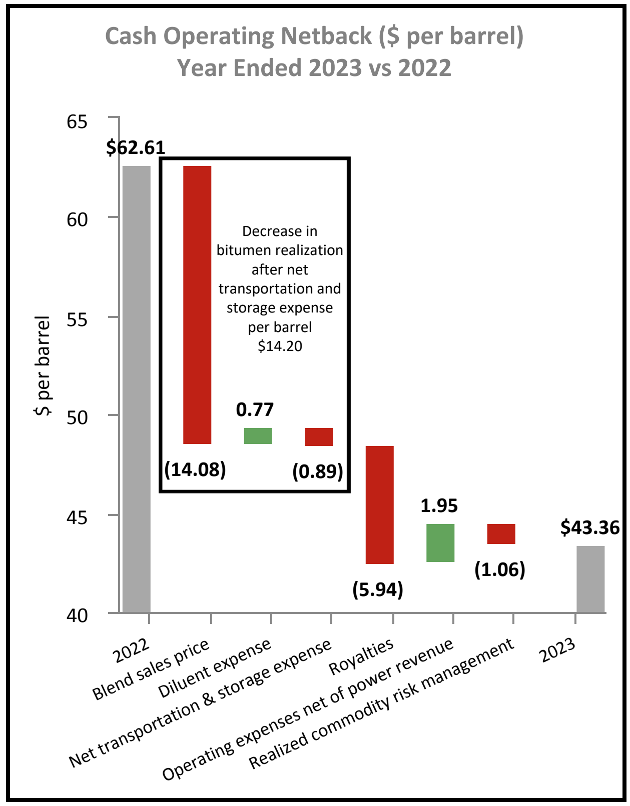
CASH OPERATING NETBACK

The following table summarizes the Corporation's cash operating netback. Unless otherwise indicated, the per barrel calculations are based on bitumen sales volume.

	2023		2022	
($millions, except as indicated)		$/bbl		$/bbl
Sales from production	**$ 4,548**		$ 5,044	
Sales from purchased product[1]	**1,444**		1,151	
Petroleum revenue	**$ 5,992**		$ 6,195	
Purchased product[1]	**(1,400)**		(1,135)	
Blend sales[2][3]	**$ 4,592**	**$ 87.94**	$ 5,060	$ 102.02
Diluent expense	**(1,691)**	**(9.30)**	(1,848)	(10.07)
Bitumen realization[3]	**$ 2,901**	**$ 78.64**	$ 3,212	$ 91.95
Net transportation and storage expense[3][4]	**(597)**	**(16.18)**	(534)	(15.29)
Bitumen realization after net transportation and storage expense[3]	**$ 2,304**	**$ 62.46**	$ 2,678	$ 76.66
Royalties	**(456)**	**(12.37)**	(225)	(6.43)
Operating expenses net of power revenue[3]	**(220)**	**(5.96)**	(276)	(7.91)
Realized gain (loss) on commodity risk management	**(28)**	**(0.77)**	10	0.29
Cash operating netback[3]	**$ 1,600**	**$ 43.36**	$ 2,187	$ 62.61
Bitumen sales volumes - bbls/d		**101,086**		95,691

(1) Sales and purchases of oil products mainly related to marketing asset optimization activities.
(2) Blend sales per barrel are based on blend sales volumes.
(3) Non-GAAP financial measure - please refer to section 15 "Non-GAAP and Other Financial Measures" of this MD&A.
(4) Net transportation and storage expense includes costs associated with moving and storing AWB to optimize the timing of delivery, net of third-party recoveries on diluent transportation arrangements.





During 2023, cash operating netback, on a total and per barrel basis, decreased compared to 2022 mainly reflecting a lower bitumen realization after net transportation and storage expense, higher royalties and a realized commodity risk management loss partially offset by lower operating expenses net of power revenue.

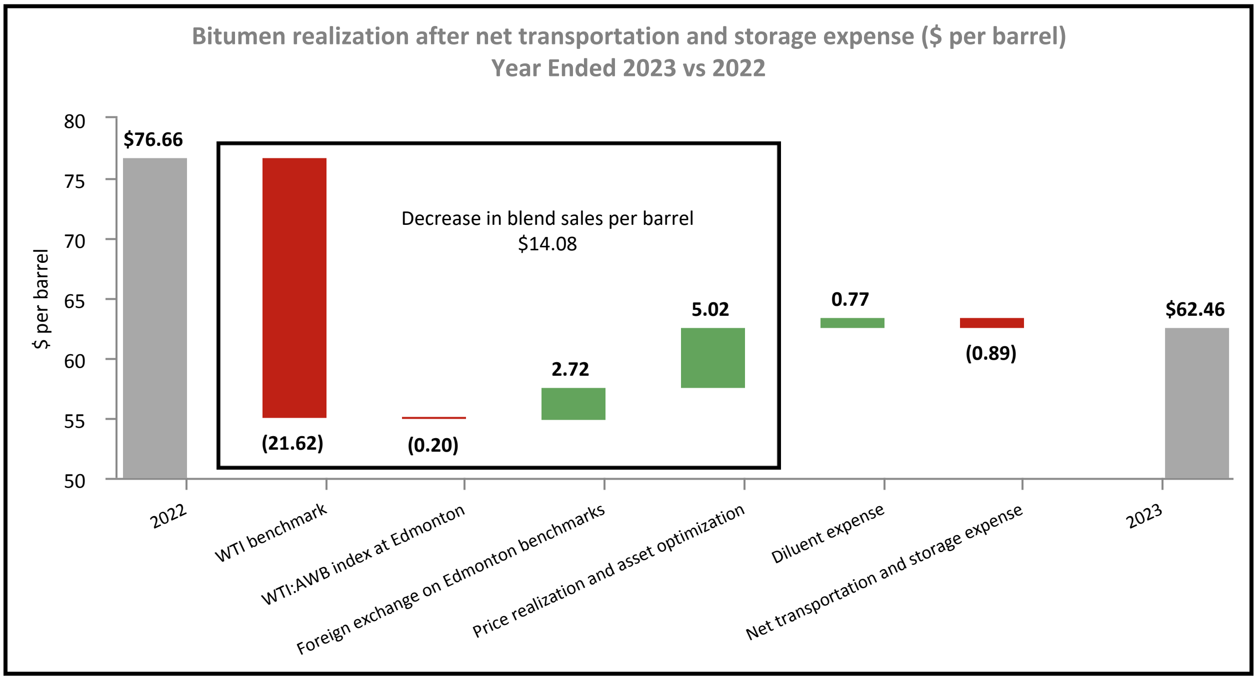
Bitumen Realization after Net Transportation and Storage Expense

Bitumen realization after net transportation and storage expense reflects the effective realized bitumen price at Christina Lake and is calculated as blend sales less diluent expense and net transportation and storage expense. Blend sales represents the Corporation's revenue from its oil blend known as AWB, which is comprised of bitumen produced at the Christina Lake Project blended with purchased diluent. Diluent expense is impacted by Canadian and U.S. benchmark pricing, the amount of diluent required, which is impacted by pipeline specification seasonality, the cost of transporting diluent to the production site from both Edmonton and USGC markets, the timing of diluent inventory purchases and changes in the value of the Canadian dollar relative to the U.S. dollar. Diluent volumes are typically held in inventory for 30 to 60 days and approximately 20,000 barrels per day of diluent is sourced from the Mont Belvieu, Texas market with the remainder from Edmonton. The cost of purchased diluent is partially offset by the sales of such diluent in blend volumes.

The Corporation's marketing strategy focuses on maximizing bitumen realization after net transportation and storage expense by utilizing its network of pipeline and storage facilities to optimize market access. Bitumen realization after net transportation and storage expense per barrel fluctuates primarily based on the WTI benchmark price and the WTI:AWB differential.

	2023		2022	
($millions, except as indicated)		$/bbl		$/bbl
Sales from production	**$ 4,548**		$ 5,044	
Sales from purchased product[1]	**1,444**		1,151	
Petroleum revenue	**$ 5,992**		$ 6,195	
Purchased product[1]	**(1,400)**		(1,135)	
Blend sales[2][3]	**$ 4,592**	**$ 87.94**	$ 5,060	$ 102.02
Diluent expense	**(1,691)**	**(9.30)**	(1,848)	(10.07)
Bitumen realization[3]	**$ 2,901**	**$ 78.64**	$ 3,212	$ 91.95
Net transportation and storage expense[3]	**(597)**	**(16.18)**	(534)	(15.29)
Bitumen realization after net transportation and storage expense	**$ 2,304**	**$ 62.46**	$ 2,678	$ 76.66
Bitumen sales volumes - bbls/d		**101,086**		95,691

(1) *Sales and purchases of oil products mainly related to marketing asset optimization activities.*
(2) *Blend sales per barrel are based on blend sales volumes.*
(3) *Non-GAAP financial measure - please refer to section 15 "Non-GAAP and Other Financial Measures" of this MD&A.*



Bitumen realization after net transportation and storage expense decreased 19%, to $62.46 per barrel, in 2023, from $76.66 per barrel in 2022, primarily driven by a lower blend sales price.

The blend sales price decreased 14% to $87.94 per barrel in 2023, from $102.02 per barrel in 2022, reflecting a lower average WTI benchmark price partially offset by the realized price improvement from diverse market access and marketing optimization activities together with a weaker Canadian dollar relative to the U.S. dollar.

The diluent expense per barrel, which represents the average cost of diluent after recoveries through blend sales, was largely unchanged year-over-year with a recovery of 80% during 2023 compared to 81% in 2022.

The Corporation sold 66% of its blend sales volumes in the USGC market during both 2023 and 2022. Average heavy oil apportionment on the Enbridge mainline system was 9% and 5% in those years, respectively.

	2023		2022	
($millions, except as indicated)		$/bbl		$/bbl
Transportation and storage expense	$ (600)	$ (16.27)	$ (538)	$ (15.41)
Transportation revenue	3	0.09	4	0.12
Net transportation and storage expense	$ (597)	$ (16.18)	$ (534)	$ (15.29)
Bitumen sales volumes - bbls/d		101,086		95,691

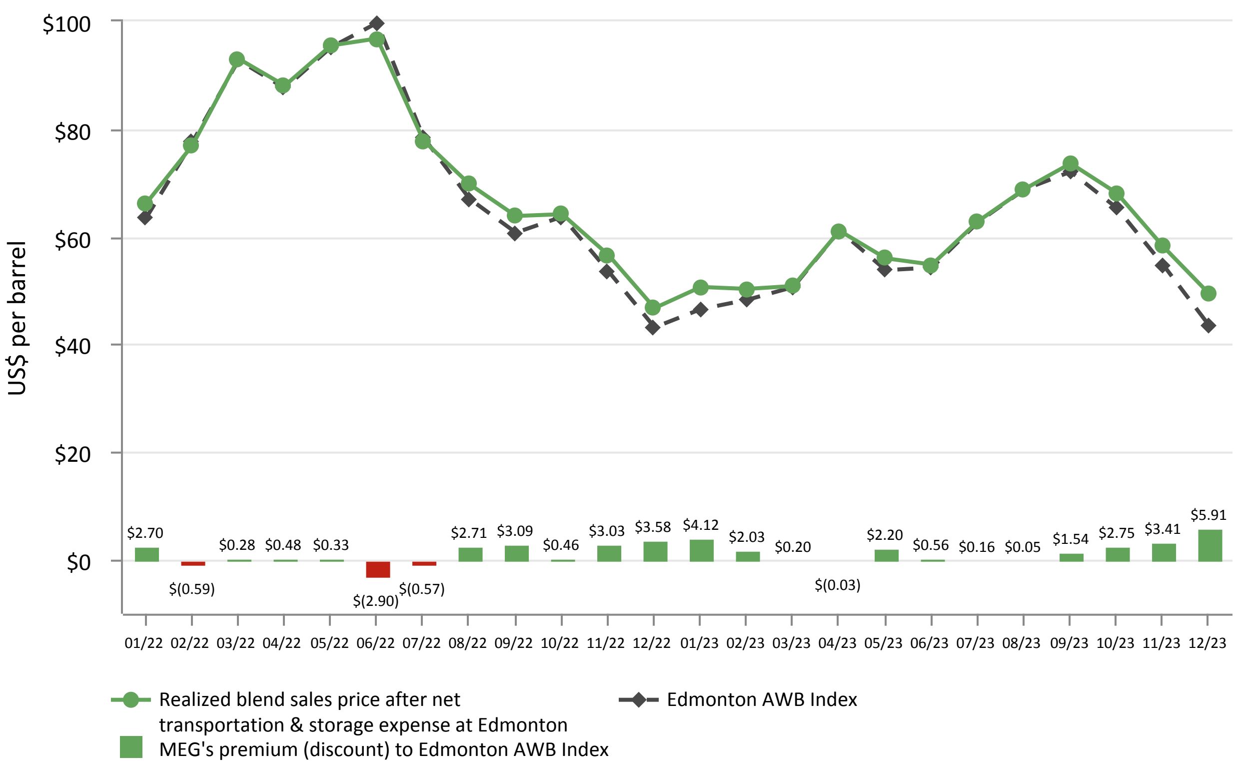
Net transportation and storage expense in 2023, on a total and per barrel basis, rose relative to 2022 primarily reflecting higher volumes transported to the USGC, higher pipeline tolls to the USGC and a weaker Canadian dollar relative to the U.S. dollar.

When expressed on a US$ per barrel of blend sales basis, net transportation and storage expense was US$8.47 during 2023 compared to US$8.27 during 2022.

The Corporation partially mitigated the cost of transportation and storage assets through the purchase and sale of non-proprietary product. These asset optimization activities added $44 million, or $0.84 per barrel, to blend sales in 2023 compared to $16 million, or $0.31 per barrel, in 2022.

Marketing transportation and storage assets are strategically utilized to access diverse global markets and enhance realized prices. The premium (discount) on the realized blend sales price, net of transportation and storage, at Edmonton relative to the Edmonton AWB index, provides an indication of value derived through transportation and storage commitments.

Premium (discount) on realized blend sales price after net transportation and storage expense, at Edmonton relative to AWB index price at Edmonton



In 2023 and 2022, the Corporation's ability to access the USGC increased the realized blend sales price compared to the Edmonton AWB index by US$2.10 and US$1.17 per barrel, respectively.

Royalties

The Oil Sands Royalty Regulation, 2009, establishes royalty rates that are linked to the WTI price measured in Canadian dollars. The royalty payable is calculated on bitumen production and applies price-sensitive royalty rates to gross or net revenue depending on whether the project's status is pre or post payout. "Payout" is generally defined as the point in time when a project has generated enough net revenue to recover costs and provide a designated return allowance. When a project reaches payout, its cumulative revenue equals or exceeds cumulative costs.

The pre-payout royalty is based on the project's gross revenue multiplied by a gross revenue royalty rate. Gross revenues are comprised of bitumen realization after transportation and storage expense attributed to the project. The gross revenue royalty rate starts at 1% and increases every dollar the WTI oil price in Canadian dollars is priced above $55 per barrel, to a maximum of 9% when the Canadian dollar WTI price is $120 per barrel or higher.

The post-payout royalty is the greater of (i) the gross revenue royalty; or (ii) the net revenue royalty. Net revenues are comprised of bitumen realization after transportation and storage expense attributed to the project and allowed operating and capital costs. The net revenue royalty rate starts at 25% and increases for every dollar the Canadian dollar WTI oil price is above $55 per barrel to a maximum of 40% when the Canadian dollar WTI price is $120 per barrel or higher.

The Corporation's Christina Lake operation reached payout status in the second quarter of 2023.

($millions)	**2023**	**2022**
Bitumen realization	**$ 2,901**	$ 3,212
Transportation and storage expense	**(600)**	(538)
Transportation revenue	**3**	4
Bitumen realization after net transportation and storage expense	**$ 2,304**	$ 2,678
Royalties	**$ 456**	$ 225
Effective royalty rate[(1)(2)]	**19.8 %**	8.4 %

(1) Effective royalty rate is calculated as royalties divided by bitumen realization after net transportation and storage expense.
(2) Non-GAAP financial measure - please refer to section 15 "Non-GAAP and Other Financial Measures" of this MD&A.

As a result of reaching payout status royalty expense increased, compared to 2022, resulting in a higher effective royalty rate.

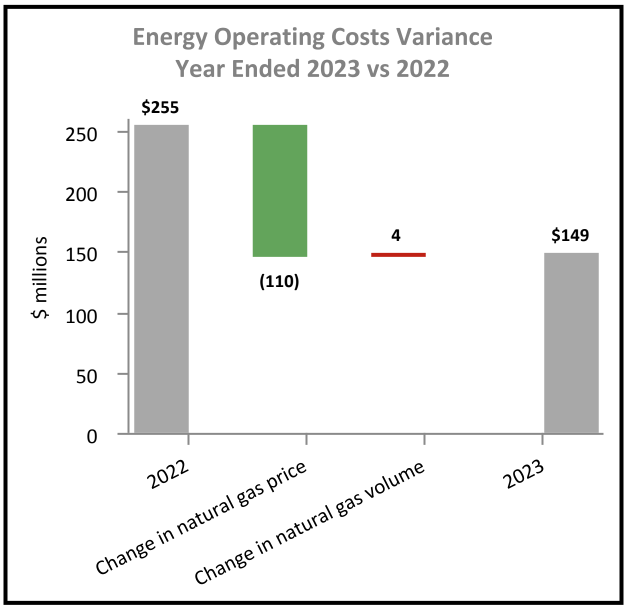
Operating Expenses net of Power Revenue

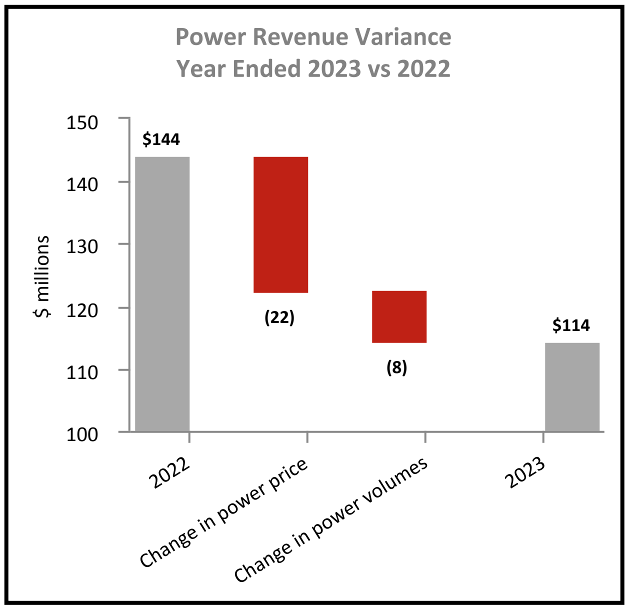
Operating expenses net of power revenue are comprised of non-energy operating costs and energy operating costs, reduced by power revenue. Non-energy operating costs relate to production-oriented operating activities and energy operating costs reflect the cost of natural gas used for fuel to generate steam and power. Power revenue is recognized from the sale of surplus power generated by the Christina Lake Project cogeneration facilities. The excess power sold into the Alberta electrical grid displaces other power sources that have a higher carbon intensity, thereby reducing the Corporation's overall carbon footprint.

	2023		2022	
($millions, except as indicated)		$/bbl		$/bbl
Non-energy operating costs[1]	**$ (185)**	**$ (5.01)**	$ (165)	$ (4.73)
Energy operating costs[1]	**(149)**	**(4.03)**	(255)	(7.29)
Operating expenses	**(334)**	**(9.04)**	(420)	(12.02)
Power revenue	**114**	**3.08**	144	4.11
Operating expenses net of power revenue[2]	**$ (220)**	**$ (5.96)**	$ (276)	$ (7.91)
Energy operating costs net of power revenue[2]	**$ (35)**	**$ (0.95)**	$ (111)	$ (3.18)
Average delivered natural gas price (C$/mcf)		**$ 3.38**		$ 5.87
Average realized power sales price (C$/Mwh)		**$ 136.50**		$ 162.33

(1) Supplementary financial measure - please refer to section 15 "Non-GAAP and Other Financial Measures" of this MD&A.
(2) Non-GAAP financial measure - please refer to section 15 "Non-GAAP and Other Financial Measures" of this MD&A.

Non-energy operating costs in 2023, on a total and per barrel basis, increased compared to 2022 primarily reflecting timing of maintenance activities and inflationary pressures on the cost of services, treating chemicals and staff.





Lower energy operating costs in 2023, on a total and per barrel basis, primarily reflect a weaker AECO natural gas price relative to 2022. Natural gas volumes were similar in both years, despite higher bitumen production in 2023, resulting in a lower SOR for 2023.

Power revenue decreased from 2022 to 2023 reflecting a 16% decline in the realized power price and lower power sales volumes.

Overall, 2023 energy operating costs net of power revenue per barrel decreased to $0.95 from $3.18 in 2022 as lower natural gas costs more than offset reduced power revenue.

Realized Gain (Loss) on Commodity Risk Management

The Corporation periodically enters financial commodity risk management contracts to manage exposure on blend sales, condensate purchases, natural gas purchases and power sales. Financial commodity risk management contracts are also used to eliminate price risk on marketing asset optimization activities pursuant to Board approved policies.

Refer to the commodity risk management discussion within the "OTHER OPERATING RESULTS" section of this MD&A for further details.

	2023		2022	
($millions, except as indicated)		**$/bbl**		**$/bbl**
Realized gain (loss) on commodity risk management	**$ (28)**	**$ (0.77)**	$ 10	$ 0.29

Capital Expenditures

($millions)	2023	2022
Sustaining and maintenance	**$ 367**	$ 311
Turnaround	**66**	46
Field infrastructure, corporate and other	**16**	19
	$ 449	$ 376

Higher capital expenditures during 2023, compared to 2022, were driven by increased scope, inflation and timing of field development and maintenance activities. Turnarounds at the Christina Lake facility, which occurred in the second quarters of both years, were successfully completed on time. However, 2023 turnaround costs reflect a larger planned turnaround scope, found work, inflationary pressures on labour costs and supply chain challenges.

7. OUTLOOK

The Corporation's 2023 annual results were in line with the November 28, 2022 guidance ranges.

Summary of 2023 Guidance	Annual Results	Original Guidance (November 28, 2022)(1)
Capital expenditures	$449 million	$450 million
Bitumen production - annual average(1)	101,425 bbls/d	100,000 to 105,000 bbls/d
Non-energy operating costs	$5.01 per bbl	$4.75 to $5.05 per bbl
General and administrative expense	$1.86 per bbl	$1.70 to $1.90 per bbl

(1) 2023 guidance includes the bitumen production impact of the second quarter turnaround which impacted annual average bitumen production by approximately 6,000 barrels per day.

On November 27, 2023 the Corporation released its 2024 operating and capital guidance.

The 105,000 barrels per day estimated production range mid-point for 2024 is approximately 4% higher than 2023 and incorporates reduced turnaround activities spread evenly throughout the year. The plan also includes the startup of two well pads, with the first pad on-stream mid-year and the second in the fourth quarter. New pad activity supports the 2024 production estimate and builds well capacity for future growth.

The Corporation's 2024 capital expenditure program is $550 million, with $450 million allocated to sustaining activities and $100 million towards multi-year productive capacity growth. The growth investment reflects the commencement of a three-year project with an estimated total cost of approximately $300 million forecasted to deliver incremental productive capacity of 15,000 barrels per day around the end of 2026.

Non-energy operating costs per barrel in 2024 are estimated to rise approximately 5% over 2023, to $5.25 per barrel at the mid-point of our 2024 guidance range, reflecting an increased scope of operations, ongoing facility reliability improvements, and inflationary pressures.

The mid-point of the 2024 per barrel general and administrative ("G&A") expense guidance is in line with 2023, with increased staff costs and support for near-term production growth largely offset by higher forecast production volumes.

Summary of 2024 Guidance	
Bitumen production - annual average	102,000 to 108,000 bbls/d
Capital expenditures	$550 million
Non-energy operating costs	$5.10 to $5.40 per bbl
G&A expense	$1.75 to $1.95 per bbl

8. BUSINESS ENVIRONMENT

The following table shows industry commodity pricing information and foreign exchange rates for the periods noted to assist in understanding their impact on the Corporation's financial results:

AVERAGE BENCHMARK COMMODITY PRICES	**Year ended December 31**		**2023**				**2022**			
	2023	**2022**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**
Crude oil prices										
Brent (US$/bbl)	**81.95**	98.77	**81.61**	85.95	78.01	82.21	88.59	97.69	111.57	97.23
WTI (US$/bbl)	**77.62**	94.23	**78.32**	82.26	73.78	76.13	82.65	91.55	108.41	94.29
Differential – WTI:WCS – Edmonton (US$/bbl)	**(18.71)**	(18.27)	**(21.89)**	(12.91)	(15.16)	(24.88)	(25.89)	(19.86)	(12.80)	(14.53)
Differential – WTI:AWB – Edmonton (US$/bbl)	**(20.79)**	(20.64)	**(23.79)**	(14.38)	(17.37)	(27.63)	(29.14)	(22.80)	(14.25)	(16.35)
AWB – Edmonton (US$/bbl)	**56.83**	73.59	**54.53**	67.88	56.41	48.50	53.51	68.75	94.16	77.94
Differential – WTI:AWB – U.S. Gulf Coast (US$/bbl)	**(8.72)**	(9.62)	**(7.43)**	(4.94)	(7.62)	(14.87)	(16.35)	(10.15)	(6.15)	(5.85)
AWB – U.S. Gulf Coast (US$/bbl)	**68.90**	84.61	**70.89**	77.32	66.16	61.26	66.30	81.40	102.26	88.44
Enbridge Mainline heavy crude apportionment %	**9**	5	**21**	1	1	12	5	3	0	10
Condensate prices										
Condensate at Edmonton (C$/bbl)	**103.40**	121.77	**103.90**	104.62	97.19	107.91	113.17	113.97	138.39	121.74
Condensate at Edmonton as a % of WTI	**98.7**	99.3	**97.4**	94.8	98.1	104.8	100.9	95.3	100.0	102.0
Condensate at Mont Belvieu, Texas (US$/bbl)	**63.96**	80.12	**62.28**	64.90	60.54	68.13	64.57	72.25	90.98	92.68
Condensate at Mont Belvieu, Texas as a % of WTI	**82.4**	85.0	**79.5**	78.9	82.1	89.5	78.1	78.9	83.9	98.3
Natural gas prices										
AECO (C$/mcf)	**2.88**	5.79	**2.51**	2.83	2.67	3.51	5.57	4.54	7.89	5.16
Electric power prices										
Alberta power pool (C$/MWh)	**133.61**	162.13	**81.76**	151.18	159.87	141.63	213.66	221.90	122.49	90.47
Foreign exchange rates										
C$ equivalent of 1 US$ – average	**1.3495**	1.3016	**1.3618**	1.3410	1.3430	1.3520	1.3577	1.3059	1.2766	1.2661
C$ equivalent of 1 US$ – period end	**1.3205**	1.3534	**1.3205**	1.3537	1.3238	1.3528	1.3534	1.3700	1.2872	1.2484

Crude Oil Prices

Brent is the primary world price benchmark for global light sweet crude oil. WTI is the current benchmark for mid-continent North American crude oil prices, at Cushing Oklahoma, and its Canadian dollar equivalent is the basis for determining the royalty rate on the Corporation's bitumen production.

Relative to 2022, crude oil prices were weaker in 2023 as a result of increased supply certainty and the potential for reduced global demand. During the first half of 2022, global crude pricing strengthened as the Russian invasion of Ukraine and subsequent sanctions against Russia created concern for significant oil supply disruption. The relatively muted impact of sanctions on Russian production and the price cap on Russian crude oil and products combined to ease supply uncertainty and exert downward pressure on crude pricing in the latter half of 2022. Pricing weakened further through much of 2023 due to high interest rates, growing recessionary concerns and the perceived negative impact on oil demand, with some offsetting support from the OPEC+ group's coordinated efforts to restrict production and tighten the supply demand balance.

WCS is a blend of heavy oils, consisting of heavy conventional crude oils and bitumen, blended with sweet synthetic, light crude oil or condensate. WCS typically trades at a differential below the WTI benchmark price and can be impacted by apportionment levels on pipelines leaving the Edmonton market. The WCS benchmark at Edmonton reflects heavy oil prices at Hardisty, Alberta.

The Corporation sells AWB, which is similar to WCS but generally prices at a discount reflecting quality differences and heavy sour oil supply/demand fundamentals. AWB is also delivered to the USGC where it is typically sold at a discount to WTI reflecting supply/demand fundamentals for heavy sour oil in that region.

While varied through the year, annual average WTI:AWB differentials at both Edmonton and the USGC in 2023 were relatively in line with 2022.

Condensate Prices

In order to facilitate pipeline transportation, the Corporation uses condensate as diluent for blending with its bitumen. The price of condensate generally correlates with the price of WTI and is sourced from both the Edmonton area and the USGC, where pricing is generally lower. The Corporation has committed diluent purchases of 20,000 barrels per day from the USGC at Mont Belvieu, Texas benchmark pricing. Condensate pricing at Edmonton, as a percentage of WTI, was similar during 2023 and 2022. Condensate pricing at Mont Belvieu, as a percentage of WTI, for 2023 was slightly weaker compared to 2022 due to lower international demand. In general, USGC condensate pricing as a percentage of WTI has remained below historical levels due to lower demand for condensate and naphtha stemming from a global reduction in manufacturing output and the associated curtailment in petrochemical feedstock requirements.

Natural Gas Prices

Natural gas is a primary energy input cost for the Corporation and is used as fuel to generate steam for the thermal production process and to create steam and electricity from cogeneration facilities. The Corporation purchases natural gas in Alberta based on the AECO natural gas index price. The annual average AECO natural gas price decreased 50% in 2023, relative to 2022 primarily due to above average inventories resulting from record natural gas production in North America more than offsetting demand growth along with improved international supply positioning leading to significantly reduced global pricing.

Electric Power Prices

Electric power prices impact the revenue that the Corporation receives on the sale of surplus power from the Christina Lake Project cogeneration facilities. The Alberta power pool price weakened 18% in 2023, compared to 2022, reflecting increasing penetration of renewables and substantially lower natural gas prices.

9. OTHER OPERATING RESULTS

General and Administrative

($millions, except as indicated)		2023		2022
General and administrative	**$**	**69**	$	61
General and administrative expense per barrel of production	**$**	**1.86**	$	1.78
Bitumen production - bbls/d		**101,425**		95,338

G&A expense during 2023 increased compared to 2022 primarily due to higher costs associated with increased staff and salaries.

Depletion and Depreciation

($millions, except as indicated)		2023		2022
Depletion and depreciation expense	**$**	**596**	$	507
Depletion and depreciation expense per barrel of production	**$**	**16.10**	$	14.57
Bitumen production - bbls/d		**101,425**		95,338

During 2023, depletion and depreciation expense rose by $89 million, compared to 2022, mainly reflecting the impact of higher estimated future development costs on the per barrel depletion and depreciation rate as well as increased bitumen production.

Commodity Risk Management Gain (Loss), Net

The Corporation periodically enters into financial commodity risk management contracts to protect and increase the predictability of cash flow, manage commodity input costs and to support marketing asset optimization activities. Financial commodity risk management contracts have been recorded at fair value, with all changes in fair value recognized through net earnings (loss).

Realized gains or losses on financial commodity risk management contracts are the result of settlements during the period. Unrealized gains or losses on financial commodity risk management contracts represent the change in the mark-to-market position of the unsettled commodity risk management contracts during the period, and the offset to the realized risk management gain (loss) recognized on contract settlements.

($millions)		2023		2022
Realized gain (loss) on:				
Condensate contracts(1)	**$**	**(9)**	$	—
Natural gas contracts(2)		**(18)**		5
Marketing asset optimization contracts(3)		**(1)**		5
Realized commodity risk management gain (loss)	**$**	**(28)**	$	10
Unrealized gain (loss) on:				
Condensate contracts(1)	**$**	**10**	$	(11)
Natural gas contracts(2)		**(16)**		(10)
Marketing asset optimization contracts(3)		**2**		—
Unrealized commodity risk management gain (loss)	**$**	**(4)**	$	(21)
Commodity risk management gain (loss)	**$**	**(32)**	$	(11)

(1) Relates to condensate purchase contracts that effectively fix condensate prices at Mont Belvieu, Texas relative to WTI.
(2) Relates to contracts which fix the AECO price on natural gas purchases.

(3) The Corporation occasionally enters into contracts to fix the spread between WTI prices for consecutive months to support marketing asset optimization activities.

Natural gas prices weakened during 2023 resulting in a realized commodity risk management loss. The price of natural gas generally strengthened during 2022, resulting in a realized commodity risk management gain. Condensate prices remained relatively stable through 2023 but weakened significantly in 2022.

Stock-based Compensation

($millions)		**2023**		2022
Cash-settled expense	**$**	**19**	$	69
Equity-settled expense		**25**		17
Equity price risk management gain[1]		**(9)**		(50)
Stock-based compensation expense	**$**	**35**	$	36

(1) Relates to financial equity price risk management contracts entered to manage the Corporation's exposure to cash-settled restricted share units ("RSUs") and performance share units ("PSUs") vesting in 2021, 2022 and 2023 granted under the Corporation's stock-based compensation plans. Amounts were unrealized until vesting of the related units occurred. All financial equity price risk management contracts were fully realized at March 31, 2023. See section 12 "Risk Management" of this MD&A for further details.

The Corporation's share price increased less and there were fewer cash-settled units outstanding in 2023, relative to 2022, which resulted in a lower 2023 cash-settled expense. All of the Corporation's outstanding cash-settled RSUs and PSUs vested during the first quarter of 2023 and the only cash-settled units remaining outstanding are deferred share units ("DSUs").

Equity-settled stock-based compensation expense increased $8 million in 2023 compared to 2022 primarily as a result of an increase in the estimated fair value of awards granted.

The equity price risk management gain is driven by the change in the Corporation's common share price relative to the notional value of the instruments. The $9 million and $50 million equity price risk management gains in 2023 and 2022, respectively, reflect the increasing share price in each of those periods. As at March 31, 2023, all outstanding cash-settled RSUs and PSUs were vested and all financial equity price risk management contracts were fully realized.

Foreign Exchange Gain (Loss), Net

($millions)		**2023**		2022
Unrealized foreign exchange gain (loss) on:				
Long-term debt	**$**	**26**	$	(142)
US$ denominated cash and cash equivalents		**(6)**		25
Foreign currency risk management contracts		**—**		6
Unrealized net gain (loss) on foreign exchange		**20**		(111)
Realized gain (loss) on foreign exchange		**2**		(2)
Foreign exchange gain (loss), net	**$**	**22**	$	(113)

C$ equivalent of 1 US$		
Beginning of period	**1.3534**	1.2656
End of period	**1.3205**	1.3534

The Corporation's foreign exchange gain (loss) is driven by fluctuations in the U.S. dollar to Canadian dollar exchange rate. The primary driver of the foreign exchange gain (loss) is U.S. dollar denominated long-term debt and the magnitude of gains and losses continues to decline as the Corporation repays debt.

During 2023, the Canadian dollar strengthened relative to the U.S. dollar by 2% resulting in an unrealized foreign exchange gain of $20 million.

During 2022, the Canadian dollar weakened 7% relative to the U.S. dollar resulting in an unrealized foreign exchange loss of $111 million.

Net Finance Expense

($millions)	**2023**	2022
Interest expense on long-term debt	**$ 90**	$ 140
Interest expense on lease liabilities	**24**	24
Credit facility fees	**18**	18
Interest income	**(6)**	(4)
Net interest expense	**126**	178
Debt extinguishment expense	**12**	30
Accretion on provisions	**11**	9
Net finance expense	**$ 149**	$ 217

Average effective interest rate	**6.4%**	6.6%

Interest expense on long-term debt decreased during 2023, compared to 2022, primarily reflecting the US$322 million (approximately $437 million) of debt repaid during 2023 and US$1,016 million (approximately $1,325 million) repaid during 2022.

Debt extinguishment expense decreased during 2023, compared to 2022, reflecting lower debt repayments in 2023. Refer to Note 11 of the audited annual consolidated financial statements for further details.

Income Tax

($millions)	**2023**	2022
Earnings before income taxes	**$ 723**	$ 1,222
Effective tax rate	**21 %**	26 %
Income tax expense	**$ 154**	$ 320

As at December 31, 2023, the Corporation had approximately $4.6 billion of available Canadian tax pools, including $3.2 billion of non-capital losses and $0.2 billion of capital losses, and recognized a deferred income tax liability of $177 million.

The effective tax rate for 2023 differed from the Canadian statutory rate of 23% primarily due to the tax effect of foreign exchange gains and losses on the Corporation's U.S. dollar denominated long-term debt.

Other

($millions)	**2023**	2022
Onerous contract expense[(1)]	**$ 47**	$ —
Third party camp recovery	**(1)**	—
Severance and restructuring	**—**	1
Other	**$ 46**	$ 1

(1) During the year ended December 31, 2023, the Corporation recognized an onerous contract expense to reflect the estimated discounted future cash flows associated with a marketing transportation contract.

10. SUMMARY OF ANNUAL INFORMATION

($millions, except per share amounts)	**2023**	2022	2021
Revenue	**$ 5,653**	$ 6,118	$ 4,321
Net earnings (loss)	**569**	902	283
Per share - diluted	**1.98**	2.92	0.91
Total assets	**6,898**	7,033	7,593
Total non-current liabilities	**1,787**	1,996	2,886

Revenue

Revenue in 2023 declined 8% from 2022. A weaker average WTI benchmark price and increased royalties more than offset higher blend sales volumes, increased sales from purchased product and the positive impact of a weaker average Canadian dollar. The increase in sales from purchased product resulted from higher asset optimization activities to mitigate the cost of transportation and storage assets.

Revenue in 2022 rose 42% from 2021 primarily due to an increase in the average blend sales price. A higher WTI price more than offset wider WTI:AWB differentials in 2022. Higher royalties, reflecting increases in the royalty rate and revenue, partially offset the blend sales price.

Net Earnings (Loss)

Annual net earnings declined to $569 million during 2023 from $902 million in 2022. This decline was primarily driven by lower adjusted funds flow, higher depletion and depreciation expense and an onerous contract expense partially offset by reduced deferred tax expense and an unrealized foreign exchange gain on long-term debt.

Net earnings increased to $902 million during 2022 from $283 million in 2021 primarily reflecting a stronger bitumen realization after net transportation and storage expense partially offset by increases in deferred income tax expense, depletion and depreciation expense and an unrealized foreign exchange loss on U.S. dollar denominated debt. Net earnings recognized in 2021 were reduced by realized losses on commodity risk management, whereas the Corporation had significantly fewer commodity risk management contracts in 2022.

Total Assets

Total assets at December 31, 2023 decreased $135 million, to $6.9 billion, from $7.0 billion at December 31, 2022. Cash and cash equivalents were used for debt repayment and share repurchases as part of the capital allocation strategy, the mark-to-market value of risk management assets decreased due to fewer risk management contracts outstanding at December 31, 2023 and property, plant and equipment decreased as depletion and depreciation charges exceeded capital expenditures.

Total assets at December 31, 2022 decreased $560 million, to $7.0 billion, from $7.6 billion at December 31, 2021. The Corporation's deferred tax asset decreased in 2022 as tax pools were utilized to reduce taxable earnings. Cash and cash equivalents were used for debt repayment and share repurchases as part of the capital allocation strategy. Property, plant and equipment also decreased in 2022 as depletion and depreciation charges exceeded capital expenditures.

Total Non-Current Liabilities

Lower total non-current liabilities as at December 31, 2023 compared to December 31, 2022 primarily reflects the US$322 million (approximately $437 million) long-term debt repurchases during 2023. This was partially offset by an increase in the decommissioning provision, the deferred tax liability and the onerous contract provision recognized during the fourth quarter of 2023.

Lower total non-current liabilities as at December 31, 2022 compared to December 31, 2021 primarily reflects the US$1.0 billion (approximately $1.3 billion) long-term debt repaid during 2022.

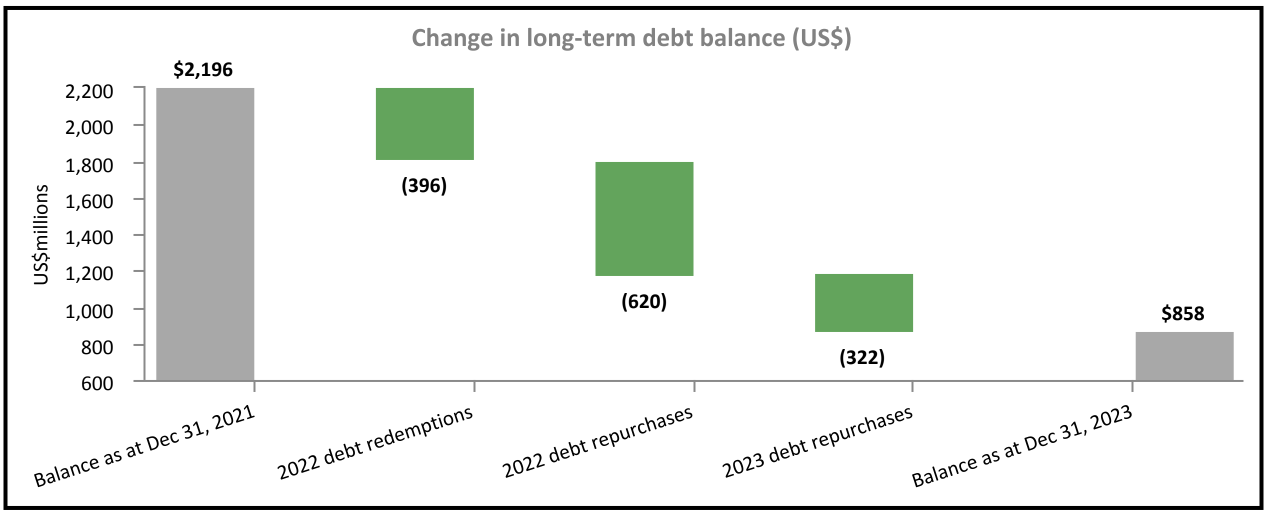
11. LIQUIDITY AND CAPITAL RESOURCES

($millions)	December 31, 2023	December 31, 2022
Unsecured:		
7.125% senior unsecured notes (December 31, 2023 - US$258.2 million; due 2027; December 31, 2022 - US$579.9 million)	**$ 341**	$ 785
5.875% senior unsecured notes (December 31, 2023 - US$600 million; due 2029; December 31, 2022 - US$600 million)	**792**	812
Unamortized deferred debt discount and debt issue costs	**(9)**	(16)
Current and long-term debt	**1,124**	1,581
Cash and cash equivalents	**(160)**	(192)
Net debt - C$(1)(2)	**$ 964**	$ 1,389
Net debt - US$(1)(2)	**$ 730**	$ 1,026

(1) Net debt is reconciled to long-term debt in accordance with IFRS in Note 25 of the audited annual consolidated financial statements.

(2) During 2023, S&P Global Ratings ("S&P"), Fitch Ratings ("Fitch") and Moody's Investors Service ("Moody's") raised the Corporation's long-term issuer credit rating while Moody's also raised the Corporation's issue-level rating on senior unsecured notes. At December 31, 2023, the Corporation's long-term issuer credit rating was BB- (S&P and Fitch) and Ba3 (Moody's) and the Corporation's issue-level rating on senior unsecured notes was B+ (S&P and Fitch) and B1 (Moody's).

The Corporation redeemed, and repurchased and extinguished, its long-term debt as noted below:



The Corporation's cash and cash equivalents decreased to $160 million at December 31, 2023 from $192 million at December 31, 2022. Refer to the "Cash Flow Summary" section for further details.

The Corporation's net debt decreased to US$730 million at December 31, 2023 from US$1,026 million at December 31, 2022.

In 2022, the Corporation initiated the allocation of approximately 25% of free cash flow to share repurchases with the remainder applied to debt repayment. When net debt declined to US$1.2 billion, free cash flow allocated to share repurchases was raised to approximately 50% with the remainder applied to debt repayment. This free cash flow allocation strategy will remain in place until net debt reaches US$600 million, which is anticipated to occur in the third quarter of 2024 assuming a US$75 per barrel WTI price.

Pursuant to the Corporation's normal course issuer bid ("NCIB"), the Corporation is repurchasing for cancellation, from time to time, as it considers advisable, up to a maximum of 28,596,214 of its common shares. The NCIB became effective March 10, 2023 and will terminate on March 9, 2024. The Corporation intends to renew the NCIB for a one-year period, which will allow MEG to repurchase up to an additional 10% of its public float, as defined by the Toronto Stock Exchange ("TSX"), over this period.

The Corporation has $1.2 billion of available credit, comprised of $600 million under a revolving credit facility and $600 million under a letter of credit facility guaranteed by Export Development Canada ("EDC Facility"). Letters of credit under the EDC Facility do not consume capacity of the revolving credit facility. The revolving credit facility and the EDC Facility have maturity dates of October 31, 2026 and are secured by substantially all the assets of the Corporation.

Commodity market volatility is managed through the Corporation's various financial frameworks. Credit exposure is reduced by targeting sales to primarily investment grade customers. The US$258 million of 7.125% senior unsecured notes due February 2027 represents the earliest long-term debt maturity. Additionally, the modified covenant-lite $600 million revolving credit facility has no financial maintenance covenant unless drawn in excess of $300 million, or 50%. If drawn in excess of $300 million, or 50%, the Corporation is required to maintain a quarterly first lien net leverage ratio (first lien net debt to last twelve-month EBITDA) of 3.5 or less. Under the Corporation's credit facility, first lien net debt is calculated as debt under the revolving credit facility plus other debt that is secured on a *pari passu* basis with the revolving credit facility, less cash-on-hand. None of the outstanding long-term debt contains financial maintenance covenants or is secured on a *pari passu* basis with the revolving credit facility.

At December 31, 2023, the Corporation had $600 million of unutilized capacity under the revolving credit facility and with $365 million of issued letters of credit, had $235 million of unutilized capacity under the $600 million EDC Facility. Letters of credit issued under the revolving credit facility or EDC Facility are not included in first lien net debt for purposes of calculating the first lien net leverage ratio.

Management believes current capital resources and the ability to manage cash flow and working capital levels allows the Corporation to meet current and future obligations, make scheduled principal and interest payments, and fund the business for at least the next 12 months. However, no assurance can be given that this will be the case or that future sources of capital will not be necessary. The Corporation's cash flow and project development are dependent on factors discussed in the "RISK FACTORS" section of this MD&A.

Cash Flow Summary

($millions)	**2023**	2022
Net cash provided by (used in):		
Operating activities	**$ 1,349**	$ 1,888
Investing activities	**(478)**	(354)
Financing activities	**(896)**	(1,727)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency	**(7)**	24
Change in cash and cash equivalents	**$ (32)**	$ (169)

Cash Flow – Operating Activities

Net cash provided by operating activities during 2023 decreased, compared to 2022, primarily due to a lower blend sales price, increased royalties and more funds used for working capital requirements partially offset by higher bitumen sales volumes.

Cash Flow – Investing Activities

Net cash used in investing activities increased $124 million during 2023, compared to 2022, reflecting increased capital expenditures and funds used for working capital requirements.

Cash Flow – Financing Activities

Net cash used in financing activities decreased $831 million in 2023, from 2022, reflecting less free cash flow available for debt repayment and share repurchases. Decreased debt repayment was partially offset by higher share repurchases in 2023 as the Corporation increased the free cash flow allocation from 25% to 50% in the fourth quarter of 2022.

12. RISK MANAGEMENT

Commodity Price Risk Management

The Corporation periodically enters financial commodity risk management contracts to manage exposure on blend sales, condensate purchases, natural gas purchases and power sales. Financial commodity risk management contracts are also used to eliminate price risk on marketing asset optimization activities pursuant to Board approved policies.

The Corporation periodically enters physical delivery contracts which are not considered financial instruments and, therefore, no asset or liability has been recognized in the consolidated balance sheet related to these contracts. The impact of realized physical delivery contracts are recognized in the consolidated statement of earnings and comprehensive income and in cash operating netback as the contracts are realized.

The Corporation had the following financial commodity risk management contracts relating to natural gas purchases outstanding at December 31, 2023:

Natural Gas Purchase Contracts	Volumes (GJ/d)	Term	Average Price (C$/GJ)
AECO Fixed Price	30,000	Jan 1, 2024 - Dec 31, 2024	$4.11

Incremental to these commodity risk management contracts, the Corporation occasionally enters contracts to fix the spread between WTI prices for consecutive months to support marketing asset optimization activities.

The Corporation had the following physical commodity risk management contracts relating to natural gas purchases and power sales outstanding as at December 31, 2023:

Natural Gas Purchase Contracts	Volumes (GJ/d)	Term	Average Price (C$/GJ)
AECO Fixed Price	17,313	Jan 1, 2024 - Jan 31, 2024	$2.13
AECO Fixed Price	17,277	Feb 1, 2024 - Feb 29, 2024	$2.13
Power Sales Contracts	**Quantity (MW)**	**Term**	**Average Price (C$/MWh)**
Fixed Price	15	Jan 1, 2024 - Jan 31, 2024	$108.67
Fixed Price	15	Feb 1, 2024 - Feb 29, 2024	$107.00

Equity Price Risk Management

Equity price risk is the risk that changes in the Corporation's own share price impacts earnings and cash flows. Earnings and funds flow from operating activities are impacted when outstanding cash-settled instruments, issued under the stock-based compensation plans, are revalued each period based on the Corporation's share price and recognized in stock-based compensation expense. Net cash provided by (used in) operating activities is impacted when the cash-settled components of these stock-based compensation units are ultimately settled. Equity price risk management (gain) loss is recognized in stock-based compensation expense on the statement of earnings. The unrealized asset (liability) is included in risk management on the balance sheet and any realized asset outstanding at period-end is included in accrued revenues and accounts receivable on the balance sheet. In March 2020, the Corporation entered financial equity price risk management contracts to manage exposure on cash-settled RSUs and PSUs vesting between April 1, 2021 and March 31, 2023.

($millions)	**2023**	2022
Unrealized equity price risk management (gain) loss	**$ 78**	$ (4)
Realized equity price risk management (gain) loss	**(87)**	(46)
Equity price risk management (gain) loss	**$ (9)**	$ (50)

(1) As at March 31, 2023, all outstanding cash-settled RSUs and PSUs were fully vested and all financial equity price risk management contracts were fully realized. DSUs are the only cash-settled units remaining outstanding at December 31, 2023.

13. SHARES OUTSTANDING

At December 31, 2023, the Corporation had the following share capital instruments outstanding or exercisable:

(thousands)	**Units**
Common shares:	
Outstanding at December 31, 2022	291,081
Issued upon exercise of stock options	139
Issued upon vesting and release of equity-settled RSUs and PSUs	2,377
Repurchased for cancellation	(18,955)
Common shares outstanding at December 31, 2023	**274,642**
Convertible securities:	
Stock options[1]	**155**
Equity-settled RSUs and PSUs	**3,698**

(1) All outstanding stock options were exercisable at December 31, 2023.

In 2023, the Corporation repurchased for cancellation 19.0 million common shares under its NCIB program at a weighted average price of $23.54 for a total cost of $446 million.

At February 28, 2024, the Corporation had 272.1 million common shares outstanding, 0.2 million stock options outstanding and exercisable and 3.7 million equity-settled RSUs and PSUs outstanding.

14. CONTRACTUAL OBLIGATIONS, COMMITMENTS AND CONTINGENCIES

Contractual Obligations and Commitments

The information presented in the table below reflects management's estimate of the contractual maturities of obligations at December 31, 2023. These estimates may differ significantly from the actual maturities of these obligations. In particular, debt under the senior secured credit facilities and the senior unsecured notes may be retired earlier due to mandatory or discretionary repayments or redemptions.

($millions)	2024	2025	2026	2027	2028	Thereafter	Total
Commitments:							
Transportation and storage[1]	$ 468	$ 462	$ 440	$ 442	$ 448	$ 5,086	$ 7,346
Diluent purchases	231	20	—	—	—	—	251
Other operating commitments	19	18	18	9	9	59	132
Variable office lease costs	4	4	4	4	5	13	34
Capital commitments	28	—	—	—	—	—	28
Total Commitments	750	504	462	455	462	5,158	7,791
Other Obligations:							
Lease liabilities	37	36	37	37	37	412	596
Long-term debt[2]	—	—	—	341	—	792	1,133
Interest on long-term debt[2]	71	71	71	50	47	6	316
Decommissioning obligation[3]	6	9	9	9	9	789	831
Total Commitments and Obligations	**$ 864**	**$ 620**	**$ 579**	**$ 892**	**$ 555**	**$ 7,157**	**$ 10,667**

(1) This represents transportation and storage commitments from 2024 to 2048, including the estimated TMX commitment which is not yet in service. Excludes finance leases recognized on the consolidated balance sheet.

(2) This represents the scheduled principal repayments of the senior unsecured notes and associated interest payments based on interest and foreign exchange rates in effect on December 31, 2023.

(3) This represents the undiscounted future obligations associated with the decommissioning of the Corporation's assets.

Contingencies

The Corporation is involved in various legal claims associated with the normal course of operations and believes that any liabilities that may arise pertaining to such matters would not have a material impact on its financial position.

15. NON-GAAP AND OTHER FINANCIAL MEASURES

Certain financial measures in this MD&A are non-GAAP financial measures or ratios, supplementary financial measures and capital management measures. These measures are not defined by IFRS and, therefore, may not be comparable to similar measures provided by other companies. These non-GAAP and other financial measures should not be considered in isolation or as an alternative for measures of performance prepared in accordance with IFRS.

Adjusted Funds Flow and Free Cash Flow

Adjusted funds flow and free cash flow are capital management measures and are defined in the Corporation's consolidated financial statements. Adjusted funds flow and free cash flow are presented to assist management and investors in analyzing operating performance and cash flow generating ability. Funds flow from operating activities is an IFRS measure in the Corporation's consolidated statement of cash flow. Adjusted funds flow is calculated as funds flow from operating activities excluding items not considered part of ordinary continuing operating results. By excluding non-recurring adjustments, the adjusted funds flow measure provides a meaningful metric for management and investors by establishing a clear link between the Corporation's cash flows and cash operating netback. Free cash flow is presented to assist management and investors in analyzing performance by the Corporation as a measure of financial liquidity and the capacity of the business to repay debt and return capital to shareholders. Free cash flow is calculated as adjusted funds flow less capital expenditures.

In the second quarter of 2022, an adjustment was made to the presentation of adjusted funds flow and free cash flow. In April 2020, the Corporation issued cash-settled RSUs under its long-term incentive ("LTI") plan when the share price was at a historic low of $1.57 per share. Concurrent with the issuance, the Corporation entered equity price risk management contracts to manage share price volatility in the subsequent three-year period, effectively reducing share price appreciation cash flow risk. The increase in the Corporation's share price from April 2020 to June 30, 2022 resulted in the recognition of a significant cash-settled stock-based compensation expense, which was previously included as a component of adjusted funds flow and free cash flow. The actual cash impact of the 2020 cash-settled RSUs, however, was subject to equity price risk management contracts, so the cash impact over the term of these RSUs was reduced and the change in value did not provide a valuable indication of operating performance.

Therefore, the financial statement impacts of the April 2020 cash-settled stock-based compensation and the equity price risk management contracts were excluded from adjusted funds flow and free cash flow. All prior periods presented have been adjusted to reflect this change in presentation.

As at March 31, 2023, all outstanding cash-settled RSUs and PSUs were fully vested and all financial equity price risk management contracts were fully realized.

The following table reconciles funds flow from operating activities to adjusted funds flow to free cash flow:

	Three months ended December 31		Year ended December 31	
($millions)	**2023**	**2022**	**2023**	**2022**
Funds flow from operating activities	**$ 358**	$ 383	**$ 1,476**	$ 1,882
Adjustments:				
Impact of cash-settled SBC units subject to equity price risk management	**—**	18	**13**	98
Realized equity price risk management gain	**—**	—	**(87)**	(46)
Adjusted funds flow	**358**	401	**1,402**	1,934
Capital expenditures	**(104)**	(106)	**(449)**	(376)
Free cash flow	**$ 254**	$ 295	**$ 953**	$ 1,558

Net Debt

Net debt is a capital management measure and is defined in the Corporation's consolidated financial statements. Net debt is an important measure used by management to analyze leverage and liquidity. Net debt is calculated as long-term debt plus current portion of long-term debt less cash and cash equivalents.

The following table reconciles the Corporation's current and long-term debt to net debt:

As at	**December 31, 2023**	**December 31, 2022**
Long-term debt	**$ 1,124**	$ 1,578
Current portion of long-term debt	**—**	3
Cash and cash equivalents	**(160)**	(192)
Net debt - C$	**$ 964**	$ 1,389
Net debt - US$	**$ 730**	$ 1,026

Cash Operating Netback

Cash operating netback is a non-GAAP financial measure, or ratio when expressed on a per barrel basis. Its terms are not defined by IFRS and, therefore, may not be comparable to similar measures provided by other companies. This non-GAAP financial measure should not be considered in isolation or as an alternative for measures of performance prepared in accordance with IFRS.

Cash operating netback is a financial measure widely used in the oil and gas industry as a supplemental measure of a company's efficiency and its ability to generate cash flow for debt repayment, capital expenditures, or other uses. The per barrel calculation of cash operating netback is based on bitumen sales volumes.

Revenues is an IFRS measure in the Corporation's consolidated statement of earnings and comprehensive income which is the most directly comparable primary financial statement measure to cash operating netback. A reconciliation from revenues to cash operating netback has been provided below:

	Three months ended December 31		Year ended December 31	
($millions)	**2023**	**2022**	**2023**	**2022**
Revenues	**$ 1,444**	$ 1,445	**$ 5,653**	$ 6,118
Diluent expense	**(471)**	(505)	**(1,691)**	(1,848)
Transportation and storage expense	**(148)**	(151)	**(600)**	(538)
Purchased product	**(334)**	(216)	**(1,400)**	(1,135)
Operating expenses	**(82)**	(115)	**(334)**	(420)
Realized gain (loss) on commodity risk management	**(9)**	1	**(28)**	10
Cash operating netback	**$ 400**	$ 459	**$ 1,600**	$ 2,187

Blend Sales and Bitumen Realization

Blend sales and bitumen realization are non-GAAP financial measures, or ratios when expressed on a per barrel basis, and are used as a measure of the Corporation's marketing strategy by isolating petroleum revenue and costs associated with its produced and purchased products and excludes royalties. Their terms are not defined by IFRS and, therefore, may not be comparable to similar measures provided by other companies. These non-GAAP financial measures should not be considered in isolation or as an alternative for measures of performance prepared in accordance with IFRS. Blend sales per barrel is based on blend sales volumes and bitumen realization per barrel is based on bitumen sales volumes.

Revenues is an IFRS measure in the Corporation's consolidated statement of earnings and comprehensive income, which is the most directly comparable primary financial statement measure to blend sales and bitumen realization. A reconciliation from revenues to blend sales and bitumen realization has been provided below:

	Three months ended December 31				Year ended December 31			
	2023		**2022**		**2023**		**2022**	
($millions, except as indicated)		**$/bbl**		**$/bbl**		**$/bbl**		**$/bbl**
Revenues	**$ 1,444**		$ 1,445		**$ 5,653**		$ 6,118	
Power and transportation revenue	**(19)**		(55)		**(117)**		(148)	
Royalties	**186**		54		**456**		225	
Petroleum revenue	**1,611**		1,444		**5,992**		6,195	
Purchased product	**(334)**		(216)		**(1,400)**		(1,135)	
Blend sales	**1,277**	**$ 87.33**	1,228	$ 83.28	**4,592**	**$ 87.94**	5,060	$102.02
Diluent expense	**(471)**	**(9.58)**	(505)	(14.12)	**(1,691)**	**(9.30)**	(1,848)	(10.07)
Bitumen realization	**$ 806**	**$ 77.75**	$ 723	$ 69.16	**$ 2,901**	**$ 78.64**	$ 3,212	$ 91.95

Net Transportation and Storage Expense

Net transportation and storage expense is a non-GAAP financial measure, or ratio when expressed on a per barrel basis. Its terms are not defined by IFRS and, therefore may not be comparable to similar measures provided by other companies. This non-GAAP financial measure should not be considered in isolation or as an alternative for measures of performance prepared in accordance with IFRS. Per barrel amounts are based on bitumen sales volumes.

It is used as a measure of the Corporation’s marketing strategy by focusing on maximizing the realized AWB sales price after transportation and storage expense by utilizing its network of pipeline and storage facilities to optimize market access.

Transportation and storage expense is an IFRS measure in the Corporation's consolidated statements of earnings and comprehensive income.

Power and transportation revenue is an IFRS measure in the Corporation's consolidated statement of earnings and comprehensive income, which is the most directly comparable primary financial statement measure to transportation revenue. A reconciliation from power and transportation revenue to transportation revenue has been provided below.

	Three months ended December 31				Year ended December 31			
	2023		2022		2023		2022	
($millions, except as indicated)		$/bbl		$/bbl		$/bbl		$/bbl
Transportation and storage expense	**$ (148)**	**$(14.23)**	$ (151)	$(14.48)	**$ (600)**	**$(16.27)**	$ (538)	$(15.41)
Power and transportation revenue	**$ 19**		$ 55		**$ 117**		$ 148	
Less power revenue	**(19)**		(54)		**(114)**		(144)	
Transportation revenue	**$ —**	**$ —**	$ 1	$ 0.07	**$ 3**	**$ 0.09**	$ 4	$ 0.12
Net transportation and storage expense	**$ (148)**	**$(14.23)**	$ (150)	$(14.41)	**$ (597)**	**$(16.18)**	$ (534)	$(15.29)

Bitumen Realization after Net Transportation and Storage Expense

Bitumen realization after net transportation and storage expense is a non-GAAP financial measure, or ratio when expressed on a per barrel basis. Its terms are not defined by IFRS and, therefore may not be comparable to similar measures provided by other companies. This non-GAAP financial measure should not be considered in isolation or as an alternative for measures of performance prepared in accordance with IFRS. Per barrel amounts are based on bitumen sales volumes.

It is used as a measure of the Corporation’s marketing strategy by focusing on maximizing the realized AWB sales price after net transportation and storage expense by utilizing its network of pipeline and storage facilities to optimize market access.

	Three months ended December 31				Year ended December 31			
	2023		2022		2023		2022	
($millions, except as indicated)		$/bbl		$/bbl		$/bbl		$/bbl
Bitumen realization(1)	**$ 806**	**$ 77.75**	$ 723	$ 69.16	**$ 2,901**	**$ 78.64**	$ 3,212	$ 91.95
Net transportation and storage expense(1)	**(148)**	**(14.23)**	(150)	(14.41)	**(597)**	**(16.18)**	(534)	(15.29)
Bitumen realization after net transportation and storage expense	**$ 658**	**$ 63.52**	$ 573	$ 54.75	**$ 2,304**	**$ 62.46**	$ 2,678	$ 76.66

(1) *Non-GAAP financial measure as defined in this section.*

Operating Expenses net of Power Revenue and Energy Operating Costs net of Power Revenue

Operating expenses net of power revenue and Energy operating costs net of power revenue are both non-GAAP financial measures, or ratios when expressed on a per barrel basis. Their terms are not defined by IFRS and, therefore, may not be comparable to similar measures provided by other companies. These non-GAAP financial measures should not be considered in isolation or as an alternative for measures of performance prepared in accordance with IFRS. Per barrel amounts are based on bitumen sales volumes.

Operating expenses net of power revenue is used as a measure of the Corporation’s cost to operate its facilities at the Christina Lake project after factoring in the benefits from selling excess power to offset energy costs.

Energy operating costs net of power revenue is used to measure the performance of the Corporation's cogeneration facilities to offset energy operating costs.

Non-energy operating costs and energy operating costs are supplementary financial measures as they represent portions of operating expenses. Non-energy operating costs comprise production-related operating activities and energy operating costs reflect the cost of natural gas used as fuel to generate steam and power. Per barrel amounts are based on bitumen sales volumes.

Operating expenses is an IFRS measure in the Corporation's consolidated statement of earnings and comprehensive income. Power and transportation revenue is an IFRS measure in the Corporation's consolidated statement of earnings and comprehensive income which is the most directly comparable primary financial statement measure to power revenue. A reconciliation from power and transportation revenue to power revenue has been provided below.

	Three months ended December 31				Year ended December 31			
	2023		2022		**2023**		2022	
($millions, except as indicated)		**$/bbl**		$/bbl		**$/bbl**		$/bbl
Non-energy operating costs	**$ (48)**	**$ (4.64)**	$ (45)	$ (4.34)	**$ (185)**	**$ (5.01)**	$ (165)	$ (4.73)
Energy operating costs	**(34)**	**(3.25)**	(70)	(6.71)	**(149)**	**(4.03)**	(255)	(7.29)
Operating expenses	**$ (82)**	**$ (7.89)**	$ (115)	$ (11.05)	**$ (334)**	**$ (9.04)**	$ (420)	$ (12.02)
Power and transportation revenue	**$ 19**		$ 55		**$ 117**		$ 148	
Less transportation revenue	**—**		(1)		**(3)**		(4)	
Power revenue	**$ 19**	**$ 1.79**	$ 54	$ 5.22	**$ 114**	**$ 3.08**	$ 144	$ 4.11
Operating expenses net of power revenue	**$ (63)**	**$ (6.10)**	$ (61)	$ (5.83)	**$ (220)**	**$ (5.96)**	$ (276)	$ (7.91)
Energy operating costs net of power revenue	**$ (15)**	**$ (1.46)**	$ (16)	$ (1.49)	**$ (35)**	**$ (0.95)**	$ (111)	$ (3.18)

Effective royalty rate

Effective royalty rate is a non-GAAP financial ratio. Its terms are not defined by IFRS and, therefore, may not be comparable to similar measures provided by other companies. This non-GAAP financial ratio should not be considered in isolation or as an alternative for measures of performance prepared in accordance with IFRS.

Effective royalty rate enables a comparison between pre and post-payout Crown royalties by calculating a royalty rate on a consistent basis. The actual royalty rate applied will differ from the effective royalty rate.

The effective royalty rate is calculated as royalty expense divided by bitumen realization after net transportation and storage expense (non-GAAP measure reconciled above).

	Three months ended December 31		Year ended December 31	
($millions)	**2023**	**2022**	**2023**	**2022**
Bitumen realization	**$ 806**	$ 723	**$ 2,901**	$ 3,212
Transportation and storage expense	**(148)**	(151)	**(600)**	(538)
Transportation revenue	**—**	1	**3**	4
Bitumen realization after net transportation and storage expense	**$ 658**	$ 573	**$ 2,304**	$ 2,678
Royalties	**$ 186**	$ 54	**$ 456**	$ 225
Effective royalty rate	**28.3 %**	9.4 %	**19.8 %**	8.4 %

16. CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The Corporation's critical accounting policies and estimates are those estimates having a significant impact on the financial position and operations and that require management to make judgments, assumptions and estimates in the application of IFRS. Judgments, assumptions and estimates are based on historical experience and other factors that management believes to be reasonable under current conditions. As events occur and additional information is obtained, these judgments, assumptions and estimates may be subject to change. Detailed disclosure of the material accounting policies and the significant accounting estimates, assumptions and judgments can be found in the Corporation's annual audited consolidated financial statements for the year ended December 31, 2023.

17. TRANSACTIONS WITH RELATED PARTIES

The Corporation did not enter into any significant related party transactions during the year ended December 31, 2023 and December 31, 2022, other than compensation of key management personnel. The Corporation considers directors and executive officers of the Corporation as key management personnel.

($millions)	**2023**	**2022**
Share-based compensation	**$ 21**	$ 46
Salaries and short-term employee benefits	**5**	7
	$ 26	$ 53

The decrease in share-based compensation to key management personnel in 2023 reflects fewer cash-settled units outstanding in 2023, relative to 2022, and a comparatively larger increase in the Corporation's share price in 2022. All of the Corporation's outstanding cash-settled RSUs and PSUs vested during the first quarter of 2023 and the only cash-settled units which remain outstanding are DSUs.

18. RISK FACTORS

The Corporation's primary focus is on the ongoing development and operation of its thermal oil assets. In developing and operating these assets, the Corporation is and will be subject to many risks, including among others, operational risks, risks related to economic conditions, environmental and regulatory risks, and financing risks. Many of these risks impact the oil and gas industry as a whole. Further information regarding the risk factors which may affect the Corporation is contained in the most recently filed AIF, which is available on the Corporation’s website at www.megenergy.com and is also available on the SEDAR+ website at www.sedarplus.ca.

If any event arises from the risk factors set forth below, the Corporation's business, prospects, financial condition, results of operations or cash flows and, in some cases, the Corporation's reputation could be materially adversely affected. The Corporation has an Enterprise Risk Management ("ERM") Program, which is a continuous process to manage, monitor, analyze and take action on risks that threaten the Corporation's ability to reach its strategic objectives. The ERM program ensures the risks are appropriately categorized within a risk matrix, and risk mitigation strategies are employed when deemed necessary.

Risk Arising from Operations

MEG's operating results and the value of its reserves and contingent resources depend, in part, on the price received for bitumen and on the operating costs of the Christina Lake Project and MEG's other projects, all of which may significantly vary from that currently anticipated. If such operating costs increase or MEG does not achieve its expected revenues, MEG's earnings and cash flow will be reduced and its business and financial condition may be materially adversely affected. Principal factors, amongst others, which could affect MEG's operating results include (without limitation):

- a decline in oil prices or widening of differentials between various crude oil prices;
- increases in the price applied to GHG emissions;
- lower than expected reservoir performance, including, but not limited to, lower oil production rates and/or higher SOR, or the inability to recognize continued or increased efficiencies from the Corporation’s production enhancement program which uses a combination of proprietary reservoir technologies (including eMSAGP) and enhanced completion designs, optimized inter-well spacing, short-cycle high return redevelopment projects and steam allocation techniques;
- reduced access to or an increase in the cost of diluent;
- an increase in the cost of natural gas;
- the reliability of MEG's facilities;
- the safety and reliability of the Access Pipeline, other pipelines, tankage and vessels that transport or stores MEG's products;
- the need to replace significant portions of existing wells, referred to as "workovers", or the need to drill additional wells;
- the cost to transport bitumen, diluent and bitumen blend, and the cost to dispose of certain by-products;
- the availability and cost of insurance and the inability to insure against certain types of losses;
- severe weather or catastrophic events such as fires, lightning, earthquakes, extreme cold weather, storms or explosions;
- seasonal weather patterns and the corresponding effects of the spring thaw on accessibility to MEG's properties;
- international and regional relations, and other geopolitical tensions and events, including war, international conflict, military action, regional hostilities, terrorism, economic sanctions, embargoes and trade disputes;
- the availability of water supplies and the ability to transmit power on the electrical transmission grid;
- changes in the political landscape and/or legal, tax and regulatory regimes in Canada, the United States and elsewhere;
- the ability to obtain further approvals and permits for MEG's future projects;
- the ability to attract or access capital as a result of changing investor priorities and trends, including as a result of climate change, ESG initiatives, the adoption of decarbonization policies and the general stigmatization of the oil and gas industry;
- the availability of pipeline capacity and other transportation and storage facilities for MEG's bitumen blend;
- refining markets for MEG's bitumen blend;
- increased royalty payments resulting from changes in regulatory regimes;
- inflationary pressures and increased supply costs;
- unavailability of, or increased cost of, skilled labour;
- unavailability of, or increased cost of, materials;
- the cost of chemicals used in MEG's operations, including, but not limited to, in connection with water and/or oil treatment facilities;

- the availability of and access to drilling equipment;
- access to Federal and Provincial Government support and the necessary policy and co-financing framework required to advance the Pathways Alliance projects;
- the cost of compliance with applicable regulatory regimes, including, but not limited to, environmental regulation; and
- the negative impacts of public health crises and the potential global economic impacts.

Status and Stage of Development

While the first three phases of the Christina Lake Project are operational, additional phases and other projects may not be completed on time (or at all), and the costs associated with additional phases may be greater than expected. The Corporation has developed oil processing capacity of approximately 110,000 bbls/d at its Christina Lake central plant facility, prior to any impact of scheduled maintenance activity or outages through the phased construction of the Christina Lake Project as well as several low-cost debottlenecking and expansion projects and the application of its proprietary reservoir technologies. Projects, including the three-year project to deliver incremental productive capacity growth around the end of 2026, and production enhancement initiatives may not be completed on budget, on time or at all, and the costs associated with additional phases and other projects, if and when approved, may be greater than the Corporation expects.

Additional phases of development of the Christina Lake Project may also suffer from delays, cancellations, interruptions or increased costs due to many factors, some of which may be beyond the Corporation's control, including (without limitation):

- future capital expenditures to be made by the Corporation and/or a determination by MEG not to devote capital expenditures to a given project;
- engineering and/or procurement performance falling below expected levels of output or efficiency;
- construction performance falling below expected levels of output or efficiency;
- denial or delays in receipt of regulatory approvals, additional requirements imposed by changes in laws or non-compliance with conditions imposed by regulatory approvals;
- a determination not to proceed with, or to delay, development of a given project;
- labour disputes or disruptions, declines in labour productivity or the unavailability of, or increased cost of, skilled labour;
- increases in the cost of materials;
- changes in project scope or errors in design;
- additional requirements imposed by changes in laws, including environmental laws and regulations;
- the availability of and access to drilling equipment; and
- severe weather or catastrophic events such as fire, earthquakes, extreme cold weather, storms or explosions.

If any of the above events occur, they could have a material adverse effect on the Corporation's ability to continue to develop the Christina Lake Project, which would materially adversely affect its business, financial condition, results of operations and prospects. In addition, if any of the Corporation's future phases do not become operational after it has made significant investments therein, the Corporation's operations may not generate sufficient revenue to support its capital structure.

Concentration of Production in Single Project

All of MEG's current production and a significant amount of future production, is or will be generated by the Christina Lake Project and transported to markets on the Access Pipeline, Enbridge Mainline and Flanagan South and Seaway Pipelines. Any event that interrupts operations at the Christina Lake Project or the operations of these pipelines may result in a significant loss or delay in production.

Long-Term Reliance on Third Parties

The Christina Lake Project depends on the availability and successful operation of certain infrastructure owned and operated by third parties or joint ventures with third parties, including (without limitation):

- pipelines for the transport of natural gas, diluent and blended bitumen;
- power transmission grids supplying and exporting electricity; and
- other third-party transportation infrastructure such as roads, airstrips, terminals and vessels.

For example, the Christina Lake Project depends on the successful operation of the Access Pipeline. Any interruption in the operation of the Access Pipeline or other pipeline infrastructure could have a material adverse impact on MEG by limiting its ability to transport blended bitumen to end markets and increasing MEG's cost for both sourcing diluent and transporting its blended bitumen. Such interruptions could result in all or a portion of MEG's production being shut-in. In addition, if certain pipelines currently forecast to be built or currently under construction are not completed on time, to the specifications MEG expects, or at all, MEG's anticipated costs could increase and MEG’s operating results would be adversely affected.

The unavailability or decreased capacity of any or all of the infrastructure described above could negatively impact the operation of the Christina Lake Project, which in turn, may have a material adverse effect on MEG’s results of operations, financial condition and prospects.

Tax Laws

Income tax laws and regulations and other laws and government incentive programs may in the future be changed or interpreted in a manner that has a material adverse effect on the Corporation's results of operations, financial condition and prospects. Tax authorities having jurisdiction over the Corporation may disagree with the manner in which we calculate our tax liabilities such that the Corporation's provision for income taxes may not be sufficient, or such authorities could change their administrative practices to the Corporation's detriment or to the detriment of our shareholders. In addition, all of our tax filings are subject to audit by tax authorities who may disagree with such filings in a manner that adversely affects the Corporation and its shareholders.

In Canada, in the 2022 Fall Economic Statement released by the Department of Finance, a new tax on share buybacks by public corporations was proposed. Under the proposed legislation ("Bill C-59"), certain transactions taking place on or after January 1, 2024, will be subject to a two percent "buyback tax" that would apply on the "net value" of share buybacks by public corporations in Canada. There are certain exemptions to the buyback tax, including where the repurchased securities have certain debt-like characteristics or for certain types of reorganization transactions. Bill C-59 is currently being considered in Parliament.

In addition, from time to time during periods of higher energy commodity prices various foreign governments have implemented or proposed the implementation of windfall taxes on energy companies. For example, in September 2022 the European Union approved a temporary 33% windfall tax on fossil fuel companies' profits made in 2022 and 2023 exceeding a four-year historical average by 20%. Although the Canadian federal government has not proposed such a tax, any decision to implement such a tax may have a material adverse effect on the Corporation's results of operations, financial condition and prospects.

Claims Made by Indigenous Peoples

Indigenous Peoples have claimed Indigenous title and rights to a substantial portion of western Canada. Certain Indigenous Peoples have filed a claim against the Government of Canada, the Province of Alberta, certain governmental entities and the Regional Municipality of Wood Buffalo (which includes the City of Fort McMurray, Alberta) claiming, among other things, Indigenous title to large areas of lands surrounding Fort McMurray, including the lands on which the Christina Lake Project, MEG's other projects and most of the other oil sands operations in Alberta are located. Such claims, and other similar claims that may be initiated, if successful, could have a significant adverse effect on MEG and the Christina Lake Project and MEG's other projects.

On December 3, 2020, the federal government introduced Bill C-15, An Act respecting the United Nations Declaration on the Rights of Indigenous Peoples which requires the Federal Government to ensure all Canadian laws are consistent with the United Nations Declaration on the Rights of Indigenous People ("UNDRIP"), implement an action plan to achieve UNDRIP's objectives and table a report on the process of aligning the laws of Canada and on the action plan. On June 21, 2021, Bill C-15 received Royal Assent and came immediately into force. Additional processes may be created or legislation amended or introduced associated with project development and operations, further increasing uncertainty with respect to project regulatory approval timelines and requirements.

In June 2021, in British Columbia, an Indigenous group was able to establish that cumulative effects within its traditional territory had reached a "tipping point" resulting in infringement of their treaty rights. The court determined that British Columbia could not authorize new activities within this First Nation's traditional territory, pending consultation and negotiation with the First Nation. In response to the decision, on January 18, 2023, the Government of British Columbia and the First Nation reached an agreement which sets forth the parties' joint approach to land, water and resource management, including certain limits for new petroleum and natural gas development and options for First Nation revenue sharing. While the long-term impacts of this decision on Indigenous law in Canada overall and in Alberta are not yet fully understood, as this decision does not create a binding precedent in Alberta, a similar claim, if successful, that encompasses the Christina Lake Project and/or MEG's other projects could have a significant adverse effect on MEG.

RISKS RELATING TO ECONOMIC CONDITIONS, COMMODITY PRICING, DIFFERENTIALS AND EXCHANGE RATE FLUCTUATIONS

Fluctuations in Market Prices of Crude Oil, Bitumen Blend and Differentials

MEG's results of operations and financial condition will be dependent upon, among other things, the prices that it receives for the bitumen, bitumen blend or other bitumen products that it sells, and the prices that it receives for such products will be closely correlated to the price of crude oil. Historically, crude oil markets have been volatile and are likely to continue to be volatile in the future. Crude oil prices, and differentials between world crude oil prices and Canadian heavy crude oil prices, have fluctuated widely during recent years and are subject to fluctuations in response to relatively minor changes in supply, demand, market uncertainty and other factors that are beyond MEG's control. These factors include, but are not limited to:

- global energy policy, including (without limitation) the ability of the Organization of Petroleum Exporting Countries ("OPEC") and OPEC+ members, to set and maintain production levels and influence prices for crude oil;
- political instability and hostilities;
- domestic and foreign supplies of crude oil;
- the overall level of energy demand;
- weather conditions;
- government regulations including curtailment orders;
- taxes;
- currency exchange rates;
- the availability of refining capacity and transportation infrastructure, including pipelines;
- the effect of worldwide environmental and/or energy conservation measures;
- the price and availability of alternative energy supplies;
- the risk of novel viruses (similar to COVID-19), including governmental policy and emergency response measures and related economic downturn related to same; and
- the overall global economic environment.

Any prolonged period of low crude oil prices, a widening of differentials, or an increase in diluent prices relative to crude oil prices could result in a decision by MEG to suspend or slow development activities, to suspend or slow the construction or expansion of bitumen recovery projects or to suspend or reduce production levels. Any of such actions could have a material adverse effect on MEG's results of operations, financial condition and prospects.

The market prices for heavy oil (which includes bitumen blends) are lower than the established market prices for light and medium grades of oil, due principally to diluent prices and the higher transportation and refining costs associated with heavy oil. Also, the market for heavy oil is more limited than for light and medium grades of oil, making it more susceptible to supply and demand fluctuations. These factors all contribute to price differentials. Future price differentials are uncertain and any widening in heavy oil differentials specifically could have an adverse effect on MEG's results of operations, financial condition and prospects.

MEG conducts an assessment of the carrying value of its assets to the extent required by IFRS. If crude oil prices decline or differentials widen, the carrying value of MEG's assets could be subject to downward revision, and MEG's earnings could be adversely affected by any reduction in such carrying value.

Public Health Crises and Related Impacts

Public health crises can result in volatility and disruptions in the supply, demand and pricing for petroleum products, global supply chains and financial markets, as well as declining trade and market sentiment and reduced mobility of people, all of which could affect commodity prices, interest rates, credit ratings, credit risk and inflation. Governmental reaction to the pandemic and restrictions and limitations applied by governments including travel restrictions, quarantines or site closures, as well as the pace of relaxation of such restrictions and limitations, particularly in large oil markets such as China, could adversely impact MEG in many ways, including the price MEG may achieve on sales of its products, ability of MEG’s employees and contractors to perform their duties, increase technology and security risk due to extended and company-wide telecommuting, disruptions in MEG’s supply chain (including necessary contractors), increase the risk that oil storage could reach capacity in Canada and the USGC as a result of decreased demand, lead to a disruption in MEG’s resource acquisition or permitting activities and cause disruption in MEG’s relationship with customers.

International Developments and Geopolitical Risks

MEG is exposed to the financial and operational risks associated with uncertain international and regional relations, and other geopolitical tensions and events, including war, international conflict, military action, regional hostilities, terrorism and trade disputes. Examples of current conflicts which may present risks to the Corporation include, but are not limited to, Russia and Ukraine, Israel and Palestine, Sudan and wider unrest in the Middle East. The outcome of these conflicts is uncertain and is likely to have wide-ranging consequences on the peace and stability of their respective regions and the world economy. Certain countries including Canada and the United States, impose financial and trade sanctions against countries in response to conflict (e.g., Russia), which sanctions may have far reaching effects on the global economy. Disruption of supplies of oil and natural gas due to conflicts in a region or disruptions to trade routes could cause a significant worldwide supply shortage of oil and natural gas and have a significant impact on worldwide prices of oil and natural gas. A lack of supply of energy and high prices of oil and natural gas could have a significant adverse impact on the world economy. The long-term impacts of the conflicts and the international response relating to such conflicts remains uncertain.

General Economic Conditions, Business Environment, Inflation and Other Risks

MEG's business is subject to general economic conditions. Adverse changes in general economic and market conditions could negatively impact demand for crude oil, bitumen and bitumen blends, revenue, operating costs, results of financing efforts, timing and extent of capital expenditures, credit risk and counterparty risk.

Volatility in crude oil, bitumen blend, natural gas and diluent prices, fluctuations in interest rates, product supply and demand fundamentals, market competition, labour market supplies, risks associated with technology, risks of a widespread pandemic, MEG's ability to generate sufficient cash flow to meet its current and future obligations, MEG's ability to access external sources of debt and equity capital, general economic and business conditions, MEG's ability to make capital investments and the amounts of capital investments, risks associated with potential future lawsuits and regulations, assessments and audits (including income tax and royalties) against MEG (and its subsidiary), political and economic conditions in the geographic regions in which MEG and its subsidiary operate, difficulty or delays in obtaining necessary regulatory approvals, a significant decline in MEG's reputation, and such other risks and uncertainties, could individually or in the aggregate have a material adverse impact on MEG's business, prospects, financial condition, results of operation or cash flows. Challenging market conditions and the health of the economy as a whole may have a material adverse effect on MEG's results of operations, financial condition and prospects. There can be no assurance that any risk management steps taken by MEG with the objective of mitigating the foregoing risks will avoid future loss due to the occurrence of such risks. While MEG does not believe that inflation has had a material effect on MEG's business, financial condition or results of operations to date, if operation or labour costs were to become subject to significant inflationary pressures, MEG may not be able to fully offset such higher costs. Inability or failure to do so could harm MEG's business, financial condition and results of operations.

The successful operation of the Corporation's business will depend upon the availability of, and competition for, skilled labour and supply of required goods and services. There is a risk that the Corporation may have difficulty sourcing the required labour and goods and services required in its operations. The risk could manifest itself through an inability to recruit new employees or contractors without a dilution of talent, to train, develop and retain high quality and experienced employees or contractors without unacceptably high attrition, and to satisfy an employee's work/life balance and desire for competitive compensation. The labour market in Alberta is particularly tight due to a strengthening commodity price environment and increased field activities after a prolonged period of weak commodity prices, lack of work certainty, lower wages and the COVID-19 pandemic which resulted in an exodus of skilled workers from the oil and gas industry. Labour, equipment and materials necessary for the Corporation's operations may also be in short supply, subject to substantial cost inflation, and the Corporation may experience substantial delays in transportation of materials given global supply chain constraints and logistics.

The nature of MEG's operations results in exposure to fluctuations in bitumen, diluent and gas prices. Natural gas is a significant component of MEG's cost structure, as it is used to generate steam for the SAGD process and to create electricity at MEG's cogeneration facility. Diluent, such as condensate, is also one of MEG's significant commodity inputs and is used as part of MEG's product marketing strategy and to decrease the viscosity of the bitumen in order to allow it to be transported.

Historically, crude oil and electricity prices have been positively correlated with the prices of condensate and natural gas. As a result, MEG expects to be able to offset a portion, or all, of the increase in its costs associated with an increase in the price of natural gas or condensate with an increase in revenue that results from higher oil prices and electricity sold from MEG's cogeneration units. MEG believes that this correlation has been caused by factors that are not within its control, and investors are cautioned not to rely on this correlation continuing. If the prices of these commodities cease to be positively correlated, and the price of crude oil or electricity falls while the prices of natural gas or diluent rise or remain steady, MEG's results of operations, financial condition and prospects could be adversely affected.

Variations in Foreign Exchange Rates and Interest Rates

Most of MEG's revenues are based on the U.S. dollar, since revenue received from the sale of bitumen and bitumen blends is generally referenced to a price denominated in U.S. dollars, and MEG incurs most of its operating and other costs in Canadian dollars. As a result, MEG is impacted by exchange rate fluctuations between the U.S. dollar and the Canadian dollar, and any strengthening of the Canadian dollar relative to the U.S. dollar could negatively impact MEG's operating margins and cash flows. In addition, as MEG reports its operating results in Canadian dollars, fluctuations in product pricing and in the rate of exchange between the U.S. dollar and Canadian dollar affect MEG's reported results.

Further, MEG's debt is denominated in U.S. dollars. Fluctuations in exchange rates and interest rates may significantly increase or decrease the amount of debt and interest expense recorded on MEG's financial statements, which could have a significant effect on MEG's results of operations and financial condition.

Risk Management Strategies

MEG periodically uses physical and financial instruments to manage its exposure to fluctuations in commodity prices, exchange rates and interest rates. MEG's engagement in such risk management activities could expose it to credit related losses in the event of non-performance by counterparties to the physical or financial instruments. Additionally, if bitumen, diluent or gas prices, interest rates or exchange rates increase above or decrease below those levels specified in any risk management agreements, such arrangements may prevent MEG from realizing the full benefit of such increases or decreases. In addition, any future commodity risk management arrangements could cause MEG to suffer financial loss, if it is unable to produce sufficient quantities of the commodity to fulfill its obligations, if it is required to pay a margin call on a risk management contract or if it is required to pay royalties based on a market or reference price that is higher than MEG's fixed ceiling price.

To the extent that risk management activities are employed to address commodity prices, exchange rates, interest rates or other risks, risks associated with such activities and strategies, including (without limitation) counterparty risk, settlement risk, basis risk, liquidity risk and market risk, could impact or negate such activities and strategies, which would have a negative impact on MEG's results of operations, financial position and prospects.

Global Financial Markets

The market events and conditions that transpired in past years in connection with the global financial crisis, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, have, among other things, caused significant volatility in commodity prices. These events and conditions caused a loss of confidence in the broader U.S., European Union and global credit and financial markets and resulted in the collapse of, and government intervention in, numerous major banks, financial institutions and insurers, and created a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. These factors negatively impacted enterprise valuations and impacted the performance of the global economy. A new global financial crisis may exacerbate these market events and conditions.

Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties regarding the supply and demand fundamentals for petroleum products due to the current state of the world's economies, actions taken by the OPEC and OPEC+ countries, and the ongoing risks facing the North American and global economies and new supplies of crude oil which may be created by the application of new drilling technology to unconventional resource plays. It is possible that petroleum prices could move lower for a considerable period of time.

Climate Change Risks

Climate change may introduce new risks to MEG’s business including both physical risks and transitional risks. Certain of these climate change risks include the following:

Transitional Risks

Transitional risks include a broader set of risks associated with a global transition to a less carbon-intensive economy. A negative impact from transitional risks could result in loss of customers, revenue loss, delays in obtaining regulatory approvals for pipelines and other projects, increased operating, capital, financing or regulatory costs, diminished shareholder confidence, continuing changes to laws and regulations affecting MEG’s business or erosion or loss of public support towards the hydrocarbon-based energy sector.

Policy and Legal Risks

Negative consequences which could arise as a result of changes to the current and emerging regulatory environment include, but are not limited to, changes in environmental and emissions regulation of current and future projects by governmental authorities, which could result in changes to facility design and operating requirements, potentially increasing the cost of construction, operation and abandonment. Policy and legal risks are further discussed under the heading "Environmental and Regulatory Risks - Environmental Considerations" below.

Marketing Risks

Negative impacts from transitional risks and physical risks could result in constrained egress out of western Canada which could impact MEG’s operating results. In terms of reputational risk, negative public perception of the Alberta oil sands could result in delays in obtaining regulatory approvals for pipelines and other projects increasing competition for market access. Future legislation or policies that limit the purchase of crude oil or bitumen produced from the oil sands may be adopted in domestic and/or foreign jurisdictions, which, in turn, may limit the world market for this crude oil, reduce its price and may result in stranded assets or an inability to further develop oil resources. In terms of physical risk, potential increases in extreme weather events may impede operation of pipelines, storage infrastructure as well as refineries.

Reputational Risks

Reputational risks include numerous factors which could negatively affect MEG's reputation, including general public perceptions of the energy industry, negative publicity relating to pipeline incidents, unpopular expansion plans or new projects, opposition from organizations and populations opposed to fossil fuels development, specifically oil sands projects and pipeline projects, including expansions thereof.

Negative public perceptions of the Alberta oil sands, where thermal oil operations are located, may impair the profitability of MEG's current or future oil sands projects. Further, with increasing public focus on climate change and GHG emissions, the scale of the global energy transition away from fossil fuels and the potential acceleration of the global energy transition, the reputations of oil and gas companies generally may become increasingly unfavourable. There are added social pressures which demand governments and companies to work to mitigate the risks associated with climate change, decrease GHG emissions and move towards decarbonization. Specifically, there is a reputational risk in connection with MEG's ability to meet increasing climate reporting and emission reduction expectations from key stakeholders. MEG has been actively preparing and adapting to manage and respond to investors' increasing expectations by proactively setting voluntary GHG emission (Scope 1 and Scope 2) reduction targets, investing in energy efficiency and emissions reduction projects, integrating ESG across its business and linking executive compensation to progress on ESG goals and objectives.

Development of the Alberta oil sands has received considerable attention on the subjects of environmental impact, climate change, GHG emissions and Indigenous engagement. The influence of anti-fossil fuels activists (with a focus on oil sands) targeting equity and debt investors, lenders and insurers may result in policies which reduce support for or investment in the Alberta oil sands sector. Concerns about oil sands may, directly or indirectly, impair the profitability of MEG's current oil sands projects, and the viability of future oil sands projects, by creating significant regulatory uncertainty leading to uncertainty in economic modeling of current and future projects and delays relating to the sanctioning of future projects. In addition, evolving decarbonization policies of institutional investors, lenders and insurers could affect MEG's ability to access capital pools. Certain insurance companies have taken actions or announced policies to limit available coverage for companies which derive some or all of their revenue from the oil sands sector. As a result of these policies, premiums and deductibles for some or all of MEG's insurance policies could increase substantially. In some instances, coverage may become unavailable or available only for reduced amounts of coverage. As a result, MEG may not be able to extend or renew existing policies, or procure other desirable insurance coverage, either on commercially reasonable terms, or at all.

Technology Risks

MEG's mid-term and long-term goals related to reaching net zero (Scope 1 and Scope 2) GHG emissions (which is inherently uncertain due to the potentially long timeframe and certain factors outside of MEG's control, including the availability and cost effectiveness of current and future emissions reductions technologies) is subject to numerous risks and uncertainties. MEG's actions taken in implementing such a target may expose MEG to certain additional and/or heightened financial and operational risks.

Technological advancements and innovations associated with the global transition to a less carbon-intensive economy may impact the demand for MEG's products. This may include the advancement of alternative energy supplies and carbon performance of petroleum competitors.

Physical Risks

Physical risks associated with climate change may include chronic physical risks such as severe changes to seasonal weather patterns and the corresponding effects of seasonal conditions and temperatures or acute physical risks which include catastrophic events such as fires, lightning, extreme cold weather, or storms, any of which may impact MEG's operations.

ESG Related Goals

As a part of MEG's strategic priority to retain its position as a responsible leader in the energy industry, MEG remains committed to its long-term goal of achieving net zero (Scope 1 and Scope 2) GHG emissions by 2050. In addition, in early 2023 MEG revised its mid-term target to focus on reducing absolute GHG emissions (Scope 1 and Scope 2) by 0.63 megatonnes per year by year-end 2030 which represents approximately 30% of the Corporation's 2019 GHG emissions. To achieve these goals, among others, and to respond to changing market demand, MEG may incur additional costs and invest in new technologies and innovation. It is possible that the return on these investments may be less than expected, and government regulatory and financial support to assist in achieving these goals may be less than expected or inadequate, each of which may have an adverse effect on MEG's business, financial condition and reputation.

Generally speaking, MEG's ESG targets, including those related to GHG emissions, and others associated with diversity, relationships with stakeholders, including Indigenous stakeholders and wildlife habitat reclamation, depend significantly on MEG's ability to execute its current business strategy, each of which can be impacted by the numerous risks and uncertainties associated with MEG’s business and other industry factors.

MEG recognizes that its ability to adapt to and succeed in a lower-carbon economy will be compared against its peers. Investors and other stakeholders increasingly compare companies based on ESG-related performance, including climate-related performance. Failure by MEG to achieve its ESG targets, or a perception among key stakeholders that MEG's ESG targets are insufficient, could adversely affect, among other things, MEG's reputation and ability to attract capital. The continued focus on climate change by investors may lead to higher costs of capital for MEG as the pressure to reduce emissions increases. MEG's ability to attract capital may also be adversely impacted if financial institutions and investors incorporate sustainability and ESG considerations as a part of their portfolios or adopt restrictive decarbonization policies.

There is also a risk that some or all of the expected benefits and opportunities of achieving some or all of MEG’s various ESG targets may fail to materialize, may cost more to achieve or may not occur within anticipated or stated timeframes. In addition, there are risks that the actions taken by MEG in implementing these targets and ambitions relating to ESG focus areas, may have a negative impact on MEG’s business, including adverse impacts on operations or increased costs and capital expenditures, which may in turn negatively impact future operating and financial results.

Environmental and Regulatory Risks

Environmental considerations

MEG’s operations are, and will continue to be, affected in varying degrees by federal and provincial laws and regulations regarding the protection of the environment. Should there be changes to existing laws or regulations, MEG's competitive position within the thermal oil industry may be adversely affected, and many industry participants have greater resources than MEG to adapt to legislative changes.

No assurance can be given that future environmental approvals, laws or regulations will not adversely impact MEG's ability to develop and operate its oil sands projects, increase or maintain production or control its costs of production. Equipment which can meet future environmental standards may not be available on an economic or timely basis and instituting measures to ensure environmental compliance in the future may significantly increase operating costs or reduce output. There is a risk that the federal and/or provincial governments could pass future legislation that would progressively increase taxes on air emissions (specifically GHGs) or require, directly or indirectly, reductions in air emissions produced by energy industry participants, which MEG may be unable to mitigate.

All phases of the thermal oil business present environmental risks and hazards and are subject to environmental legislation and regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, permit requirements, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil sands operations and restrictions on water usage and land disruption. The legislation also requires that wells and facility sites be constructed, operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Corporation to incur costs to remedy such discharge.

There has also been increased activism relating to climate change and public opposition to fossil fuels. The Federal Government and certain provincial governments in Canada have responded to these shifting societal attitudes by adopting ambitious emissions reduction targets and supporting legislation, including measures relating to carbon pricing, clean energy, field and emission standards, and alternative energy incentives and mandates. Concerns over climate change, fossil fuel extraction, GHG emissions, and water and land-use practices could lead governments to enact additional or more stringent laws and regulations applicable to the Corporation and other companies in the energy industry in general. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs, and both the Federal Government and the Government of Alberta have imposed more stringent environmental legislation that affects the thermal oil production industry. In addition, there is a risk that the federal and/or provincial governments could pass new legislation that would tax air emissions or require, directly or indirectly, reductions in air emissions produced by energy industry participants, which the Corporation may be unable to mitigate. Should there be changes to existing laws or regulations, the Corporation's competitive position within the thermal oil production industry may be adversely affected.

No assurance can be given that future environmental approvals, laws or regulations will not adversely impact the Corporation's ability to develop and operate its thermal oil production projects or increase or maintain production or control its costs of production. Changes to environmental regulations, including regulation relating to climate change, could impact the demand or pricing for the Corporation's products, or could require increased capital expenditures, operating expenses, abandonment and reclamation obligations and distribution costs, which may not be recoverable in the marketplace and which may result in current operations or future projects becoming less profitable or uneconomic. Equipment which can meet future environmental standards may not be available on an economic or timely basis and instituting measures to ensure environmental compliance in the future may significantly increase operating costs or reduce output.

Any requirement to develop or implement new technology in response to future environmental standards could require a significant investment of capital and resources, and any delay in or failure to identify, develop and implement such technologies could prevent the Corporation from being able to operate profitably or being able to successfully compete with other companies.

No assurance can be given that environmental laws and regulations will not result in a curtailment of production, a cap on emissions or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on the Corporation's results of operations, financial condition and prospects. The Corporation believes that it is reasonably likely that the trend towards stricter standards in environmental legislation will continue and anticipates that capital and operating costs may increase as a result of more stringent environmental laws.

Greenhouse Gas Regulations

The direct and indirect costs of the various GHG regulations, current and emerging in both Canada and the United States, including any limits on oil sands emissions and the Canadian Federal Government's implementation of the Paris Agreement through the *Net Zero Emissions Accountability Act*, *GGPPA*, the Clean Fuel Regulation (the "*Clean Fuel Standard")*, the provincial government's implementation of the *TIER Regulation,* M*ethane Emission Reduction Regulation* and any other federal or provincial carbon or other emission pricing system, may adversely affect MEG's business, operations and financial results. New or additional carbon taxes or similar costs could significantly increase operating costs or reduce output. Equipment that meets future GHG emission standards may not be available on an economic basis and other compliance methods to reduce emissions or emissions intensity to future required levels may significantly increase operating costs or reduce the output of the projects. Offset, performance or fund credits may not be available for acquisition or may not be available on an economical basis. Any failure to meet GHG emission reduction compliance obligations may have a material adverse effect on the Corporation's business and result in fines, penalties and the suspension of operations.

On December 11, 2020, the Government of Canada released a document entitled A Healthy Environment and a Healthy Economy which outlined 64 new and updated policies and programs to achieve net zero by 2050. This included a proposal to increase the carbon price under the GGPPA by $15 per year, starting in 2023, up to $170 per tonne of carbon pollution in 2030. The intent of the price adjustment is to incentivize cleaner fuel choices and discourage pollution-intensive investments.

On July 6, 2022, the Government of Canada enacted the *Clean Fuel Standard* under the *CEPA* as the enabling statute. The *Clean Fuel Standard* incentivizes producers and importers of gasoline and diesel to reduce the carbon intensity of liquid fossil fuels. As MEG's business and production facilities entails the production of crude oil, the *Clean Fuel Standard* is not applicable. Since the *Clean Fuel Standard* only considers those facilities producing gasoline or diesel, the cogeneration facilities used by MEG (for combined heat and power generation) also do not apply to the *Clean Fuel Standard*.

Future federal legislation, including the implementation of potential international requirements enacted under Canadian law, as well as provincial legislation and emissions reduction requirements and or production limits, may require the reduction of GHG or other industrial air emissions, or emissions intensity, from the Corporation's operations and facilities. Mandatory emissions reduction requirements or caps on emissions or production may result in increased operating costs and capital expenditures for oil and natural gas producers. The Corporation is unable to predict the impact of emissions reduction legislation on the Corporation and it is possible that such legislation may have a material adverse effect on MEG's financial condition, results of operations and prospects.

Climate-Related Goals

The Corporation’s mid-term target of reducing its absolute GHG emissions (Scope 1 and Scope 2) by 0.63 megatonnes per year by year-end 2030 and long-term goal of reaching net zero emissions (Scope 1 and Scope 2) by 2050 (which is inherently uncertain due to the potentially long timeframe and certain factors outside of the Corporation’s control, including the application of future technologies) is subject to numerous risks and uncertainties. The Corporation’s actions taken in implementing such targets may expose the Corporation to certain additional and/or heightened financial and operational risks.

All of the Corporation’s climate related goals, including those related to GHG emissions, and others associated with diversity, relationships with stakeholders, including Indigenous stakeholders and environmental performance depend significantly on the Corporation’s ability to execute its current business strategy, which can be impacted by the numerous risks and uncertainties associated with the Corporation’s business and other industry factors. There is a risk that some or all of the expected benefits and opportunities of achieving some or all of the Corporation’s climate-related goals may fail to materialize, may cost more to achieve or may not occur within anticipated or stated timeframes. In addition, there are risks that the actions taken by the Corporation in implementing these goals, and in making efforts to achieve such goals, may have a negative impact on the Corporation’s business, including adverse impacts on operations or increased costs and capital expenditures which may in turn negatively impact our future operating and financial results.

Cogeneration Regulation

The Canadian Federal Government has announced its intention to develop the Clean Electricity Regulations ("CER") under the *Canadian Environmental Protection Act,* 1999 in furtherance of a net zero electricity system by 2035. The CER would establish an emissions standard where a regulated generation unit would be prohibited from operating where its emissions performance exceeds an established intensity limit. In addition, emissions below the established intensity limit may also be subject to financial compliance requirements, such as offset purchases or paying an amount that corresponds to the federal carbon price applicable in the given year. As a result, compliance with the CER could require that the Corporation incur significant capital expense to capture CO_2 emissions for its cogeneration facilities to remain operational and additional expense in respect of emissions below the prescribed intensity limit. As a significant portion of the Corporation's SAGD steam supply is tied to cogeneration, compliance with the CER could have a material adverse effect on the Corporation's results of operations, financial condition and prospects.

The AUC regulates cogeneration facilities under the *Hydro and Electric Energy Act*. Effective from April 25, 2022, the AUC implemented a streamlined process for applications to construct new power plants one megawatt or greater and less than 10 megawatts. This streamlined process will likely result in more available resources for the AUC to determine other proceedings, which will likely benefit proponents such as MEG for constructing new power plants greater than 10 megawatts and requiring a full proceeding for approval.

In Alberta the *Oil Sands Emissions Limit Act* came into force in December 2016 and limits the amount of GHG emissions produced by all oil sands sites combined in Alberta to 100 megatonnes in any year, which limit has not been reached. While uncertainties remain until Alberta implements regulations, it is clear that this Act considers any emissions from cogeneration facilities to be excluded in the determination of GHG emissions from that oil sand site.

Any facilities with direct emissions of 100,000 tonnes of carbon in a year are subject to the *TIER* that regulates carbon emissions. Cogeneration facilities are eligible for emission offsets under the *TIER* if the electricity generated falls under the prescribed high-performance benchmark for electricity. In 2023, the effective benchmark for electricity was 0.3626 tonnes of carbon per megawatt hour. This benchmark is set to be more stringent each year, with the 2024 benchmark being 0.3552 tonnes of carbon per megawatt hour.

See, "Regulatory Matters – Environmental Regulation – Greenhouse Gases and Industrial Air Pollutants" section in the Corporation's most recently filed AIF.

Cybersecurity

The Corporation's operations may be negatively impacted by a cybersecurity incident. MEG uses forms of information technology in its operations and such use creates various cybersecurity threats including the possibility of security breaches, operational disruptions and the release of non-public information (such as financial data, supplier and customer information and employee information). Although MEG has taken various steps to protect itself against such risks, its efforts may not always be successful, especially because of the rapidly changing nature of such cybersecurity threats. Any increase in the number of personnel working remotely may enhance the risks associated with cybersecurity threats. In the event of a cybersecurity incident, MEG's operations could be disrupted resulting in potential loss of customers, violation of laws and additional liabilities to the business.

Risks Relating to Financing and the Corporation's Indebtedness

Restrictions Contained in Credit Facility, Notes and Debt Service Obligations

MEG’s indebtedness contains certain restrictions, including mandatory prepayment obligations. For example, upon the occurrence of any event of default under the revolving credit facility and EDC Facility, MEG's lenders and other secured parties could elect to declare all amounts outstanding thereunder, together with accrued interest, to be immediately due and payable and to terminate any commitments to extend further credit. If the lenders and other secured parties under the revolving credit facility and the EDC Facility accelerate the payment of the indebtedness outstanding thereunder, MEG's assets may not be sufficient to repay in full that indebtedness and MEG's other indebtedness.

The restrictions in the revolving credit facility, the EDC Facility and the indentures governing the the Corporation's senior unsecured notes may adversely affect MEG's ability to finance its future operations and capital needs and to pursue available business opportunities. Moreover, any new indebtedness MEG incurs may impose financial restrictions and other covenants on MEG that may be more restrictive than the revolving credit facility, the EDC Facility and the indentures governing the notes.

The Corporation's indebtedness could materially and adversely affect it in a number of ways. For example, it could:

- require the Corporation to dedicate a portion of its cash flow to service payments on its indebtedness, thereby reducing the availability of cash flow to fund working capital, capital expenditures, development efforts and other general corporate purposes;
- increase the Corporation's vulnerability to general adverse economic and industry conditions;
- limit the Corporation's flexibility in planning for, or reacting to, changes in its business and the industry in which it operates;
- place the Corporation at a competitive disadvantage compared to its competitors that have less debt;
- expose the Corporation to the risk of increased interest rates as the revolving credit facility and the EDC Facility are at variable rates of interest; and

- limit the Corporation's ability to borrow additional funds to meet its operating expenses and for other purposes.

The Corporation may not generate sufficient cash flow and may not have available access to future borrowings in an amount sufficient to enable it to make payments with respect to its indebtedness or to fund its other capital needs. In these circumstances, the Corporation may need to refinance all or a portion of its indebtedness on or before maturity. Without such financing, the Corporation could be forced to sell assets or secure additional financing to make up for any shortfall in its payment obligations under unfavorable circumstances. However, the Corporation may not be able to raise additional capital or secure additional financing on terms favourable to it or at all, and the terms of the revolving credit facility, the EDC Facility, certain other permitted obligations and the indentures governing the notes may limit its ability to sell assets and also restrict the use of proceeds from such a sale.

19. DISCLOSURE CONTROLS AND PROCEDURES

The Corporation's Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") have designed, or caused to be designed under their supervision, disclosure controls and procedures to provide reasonable assurance that: (i) material information relating to the Corporation is made known to the Corporation's CEO and CFO by others, particularly during the period in which the annual filings are being prepared; and (ii) information required to be disclosed by the Corporation in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation. The CEO and CFO have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Corporation's disclosure controls and procedures at the financial year end of the Corporation and have concluded that the Corporation's disclosure controls and procedures were effective at December 31, 2023 for the foregoing purposes.

20. INTERNAL CONTROLS OVER FINANCIAL REPORTING

The CEO and CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting to provide reasonable assurance regarding the reliability of the Corporation's financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The CEO's and CFO's evaluation concluded that internal controls over financial reporting were effective as of December 31, 2023.

The CEO and CFO are required to cause the Corporation to disclose any change in the Corporation's internal controls over financial reporting that occurred during the most recent interim period that has materially affected, or is reasonably likely to materially affect, the Corporation's internal controls over financial reporting. No changes in internal controls over financial reporting were identified during such period that have materially affected, or are reasonably likely to materially affect, the Corporation's internal controls over financial reporting.

It should be noted that a control system, including the Corporation'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. In reaching a reasonable level of assurance, management necessarily is required to apply its judgment in evaluating the cost/benefit relationship of possible controls and procedures.

21. ABBREVIATIONS

The following provides a summary of common abbreviations used in this document:

Financial and Business Environment

AECO	Alberta natural gas price reference location
AIF	Annual Information Form
AUC	Alberta Utilities Commission
AWB	Access Western Blend
$ or C$	Canadian dollars
CEPA	Canadian Environmental Protection Act, 1999
DSU	Deferred Share Units
EDC	Export Development Canada
eMSAGP	enhanced Modified Steam And Gas Push
ERM	Enterprise Risk Management
ESG	Environment, Social and Governance
FSP	Flanagan South and Seaway Pipeline
G&A	General and administrative
GAAP	Generally Accepted Accounting Principles
GGPPA	Greenhouse Gas Pollution Pricing Act
GHG	Greenhouse Gas
IFRS	International Financial Reporting Standards
LTI	Long-term incentive
NCIB	Normal Course Issuer Bid
MD&A	Management's Discussion and Analysis
OPEC	Organization of Petroleum Exporting Countries
OPEC+	Organization of Petroleum Exporting Countries plus an informal association of other oil producing countries
PSU	Performance Share Units
RSU	Restricted Share Units
SAGD	Steam-Assisted Gravity Drainage
SOR	Steam-oil ratio
SBC	Stock-based compensation
TIER	Technology Innovation and Emissions Reduction Regulation
TMX	Trans Mountain Expansion
U.S.	United States
US$	United States dollars
USGC	United States Gulf Coast
WCS	Western Canadian Select
WTI	West Texas Intermediate

Measurement

bbl	barrel
bbls/d	barrels per day
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
MW	megawatts
MW/h	megawatts per hour

22. ADVISORY

Forward-Looking Information

This document may contain forward-looking information within the meaning of applicable Canadian securities laws. These statements relate to future events or MEG's future performance. All statements other than statements of historical fact may be forward-looking statements. This forward-looking information is intended to be identified by words such as “anticipate”, “believe”, “continue”, “could”, “drive”, “expect”, “estimate”, “focus”, “forward”, “future”, “guidance”, “intend”, “may”, “on track”, “outlook”, “plan”, “position”, “potential”, “priority”, “project”, “should”, “strategy”, “target”, “will”, “would” or similar expressions and includes statements about future outcomes.

Forward-looking statements are often, but not always, identified by such words. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. In particular, and without limiting the foregoing, this document contains forward looking statements with respect to: the Corporation’s business strategy, focus and future plans; the Corporation’s 2024 outlook, including its expectations regarding 2024 annual production, capital expenditures, non-energy operating costs, general and administrative costs and SOR; the Corporation’s expectation that reduced turnaround activities and the startup of two well pads will support its higher 2024 production estimate and well capacity for future growth; the Corporation’s statements regarding its 2024 capital budget, including its estimate of the cost of the proposed three-year growth project and that the project will deliver incremental productive capacity around the end of 2026; the Corporation’s expectation that its balance sheet and operating performance will provide a solid foundation to fund the 2024 capital program; statements regarding the Corporation’s estimated reserves; the Corporation’s expectation that the Christina Lake Project has an oil processing capacity of approximately 110,000 barrels per day prior to any impact from scheduled maintenance activity or outages; the Corporation’s statement that the average annual production decline rate at the Christina Lake Project has historically been between 10% to 15 % and is anticipated to potentially increase due to new development techniques, including optimized well spacing; the Corporation’s statement that, at current production levels, MEG has a 2P reserves life index of approximately 50 years; all statements regarding the impact on SOR of the Corporation’s proprietary reservoir technology and enhanced completion designs, optimized inter-well spacing and development and redevelopment program; the Corporation’s belief that its focus on operational excellence will support increased production, top tier SOR performance and reduced GHG emissions intensity; the Corporation’s expectation of allocating 50% of free cash flow to share repurchases with the remaining cash flow applied to ongoing debt repayment until it reaches a net debt floor of US$600 million, which is expected to occur in the third quarter of 2024 at current oil prices, and thereafter returning 100% of free cash flow to shareholders; the Corporation’s expectation that the proposed three-year growth strategy will add 15,000 barrels per day of new productive capacity at an estimated cost of approximately $300 million over the next three years; the Corporation’s statement that it retains flexibility to adjust capital expenditures in response to changing market conditions; the Corporation’s marketing strategy and marketing asset optimization strategy; the Corporation’s expectation that TMX will come into service in the second quarter of 2024; the Corporation's expectation that its marketing transportation and storage assets will enable it to access diverse global markets and enhance realized prices; the Corporation’s 2030 GHG emissions (Scope 1 and Scope 2) reduction target and its expectations regarding the Pathways Alliance projects and government support of these projects; the Corporation’s ability to sell excess power into the Alberta electrical grid to displace other power sources that have a higher carbon intensity, thereby reducing the Corporation's overall carbon footprint; all statements relating to the Corporation’s annual 2024 guidance, including its full year production, capital expenditures, non-energy operating costs, and general and administrative expenses; the Corporation’s expectations regarding global crude oil prices and global crude oil demand and supply balances; the Corporation’s continued focus on debt repayment as a key component of its capital allocation strategy; the Corporation’s expectations regarding its current capital resources and its ability to manage cash flow and working capital levels will allow the Corporation to meet its current and future obligations, to make scheduled principal and interest payments, and to fund the other needs of the business; and the Corporation’s statements regarding its 2024 commodity risk management contracts.

Forward-looking information contained in this document is based on management's expectations and assumptions regarding, among other things: future crude oil, bitumen blend, natural gas, electricity, condensate and other diluent prices, differentials, the level of apportionment on the Enbridge Mainline system, transportation costs, foreign exchange rates and interest rates; the recoverability of the Corporation's reserves and contingent resources; the Corporation's ability to produce and market production of bitumen blend successfully to customers; future growth, results of operations and production levels; future capital and other expenditures; revenues, expenses and cash flow; operating costs; reliability; continued liquidity and runway to sustain operations through a prolonged market downturn; MEG's ability to reduce or increase production to desired levels, including without negative impacts to its assets; anticipated reductions in operating costs as a result of optimization and scalability of certain operations; anticipated sources of funding for operations and capital investments; plans for and results of drilling activity; the regulatory framework governing royalties, land use, taxes and environmental matters, including the timing and level of government production curtailment and federal and provincial climate change policies, in which the Corporation conducts and will conduct its business; actions taken by OPEC+ in relation to supply management; and business prospects and opportunities. By its nature, such forward-looking information involves significant known and unknown risks and uncertainties, which could cause actual results to differ materially from those anticipated.

These risks and uncertainties include, but are not limited to, risks and uncertainties related to: the oil and gas industry, for example, the securing of adequate access to markets and transportation infrastructure (including pipelines and rail) and the commitments therein; the availability of capacity on the electricity transmission grid; the uncertainty of reserve and resource estimates; the uncertainty of estimates and projections relating to production, costs and revenues; health, safety and environmental risks, including public health crises, such as the COVID-19 pandemic, and any related actions taken by governments and businesses; legislative and regulatory changes to, amongst other things, tax, land use, royalty and environmental laws and production curtailment; the cost of compliance with current and future environmental laws, including climate change laws; risks relating to increased activism and public opposition to fossil fuels and oil sands; assumptions regarding the volatility of commodity prices, interest rates and foreign exchange rates; commodity price, interest rate and foreign exchange rate swap contracts and/or derivative financial instruments that the Corporation may enter into from time to time to manage its risk related to such prices and rates; timing of completion, commissioning, and start-up, of the Corporation's turnarounds; the operational risks and delays in the development, exploration, production, and the capacities and performance associated with the Corporation's projects; the Corporation's ability to reduce or increase production to desired levels, including without negative impacts to its assets; the Corporation's ability to finance sustaining capital expenditures; the Corporation's ability to maintain sufficient liquidity to sustain operations through a prolonged market downturn; changes in credit ratings applicable to the Corporation or any of its securities; the potential for a temporary suspension of operations impacted by public health crises; actions taken by OPEC+ in relation to supply management; the impact of the Russian invasion of Ukraine and associated sanctions on commodity prices and the impact of other international and regional relations and other geopolitical tensions and events; the availability and cost of labour and goods and services required in the Corporation's operations, including inflationary pressures; supply chain issues including transportation delays; the cost and availability of equipment necessary to our operations; the impact of a cybersecurity incident; and changes in general economic, market and business conditions.

Although the Corporation believes that the assumptions used in such forward-looking information are reasonable, there can be no assurance that such assumptions will be correct. Accordingly, readers are cautioned that the actual results achieved may vary from the forward-looking information provided herein and that the variations may be material. Readers are also cautioned that the foregoing list of assumptions, risks and factors is not exhaustive.

Further information regarding the assumptions and risks inherent in the making of forward-looking statements can be found in the Corporation's most recently filed AIF, along with the Corporation's other public disclosure documents. Copies of the AIF and the Corporation's other public disclosure documents are available through the SEDAR+ website at www.sedarplus.ca.

The forward-looking information included in this document is expressly qualified in its entirety by the foregoing cautionary statements. Unless otherwise stated, the forward-looking information included in this document is made as of the date of this document and the Corporation assumes no obligation to update or revise any forward-looking information to reflect new events or circumstances, except as required by law.

MEG Energy Corp. is an energy company focused on sustainable in situ thermal oil production in the southern Athabasca oil region of Alberta, Canada. The Corporation is actively developing innovative enhanced oil recovery projects that utilize SAGD extraction methods to improve the responsible economic recovery of oil as well as lower carbon emissions. MEG transports and sells its thermal oil (known as AWB) to customers throughout North America and internationally. The Corporation's common shares are listed on the Toronto Stock Exchange under the symbol "MEG".

Estimates of Reserves and Resources

For information regarding the Corporation's estimated reserves and resources, please refer to the Corporation's most recently filed AIF.

23. ADDITIONAL INFORMATION

Additional information relating to the Corporation, including its AIF, is available on the Corporation's website at www.megenergy.com and is also available on SEDAR+ at www.sedarplus.ca.

24. QUARTERLY SUMMARIES

	2023				2022			
Unaudited	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**
FINANCIAL *($millions unless specified)*								
Net earnings (loss)	**103**	249	136	81	159	156	225	362
Per share, diluted	**0.37**	0.86	0.47	0.28	0.53	0.51	0.72	1.15
Funds flow from operating activities	**358**	492	278	348	383	501	412	587
Per share, diluted	**1.27**	1.71	0.96	1.19	1.28	1.63	1.31	1.87
Adjusted funds flow(1)	**358**	492	278	274	401	496	478	559
Per share, diluted(1)	**1.27**	1.71	0.96	0.94	1.34	1.61	1.52	1.78
Capital expenditures	**104**	83	149	113	106	78	104	88
Free cash flow(1)	**254**	409	129	161	295	418	374	471
Working capital	**278**	495	231	219	289	395	437	465
Net debt - C$(1)	**964**	1,198	1,316	1,381	1,389	1,634	1,782	2,150
Net debt - US$(1)	**730**	885	994	1,020	1,026	1,193	1,384	1,722
Shareholders' equity	**4,527**	4,641	4,441	4,370	4,383	4,418	4,339	4,178
BUSINESS ENVIRONMENT								
Average Benchmark Commodity Prices:								
WTI (US$/bbl)	**78.32**	82.26	73.78	76.13	82.65	91.55	108.41	94.29
Differential – WTI:WCS – Edmonton (US$/bbl)	**(21.89)**	(12.91)	(15.16)	(24.88)	(25.89)	(19.86)	(12.80)	(14.53)
Differential – WTI:AWB – Edmonton (US$/bbl)	**(23.79)**	(14.38)	(17.37)	(27.63)	(29.14)	(22.80)	(14.25)	(16.35)
AWB – Edmonton (US$/bbl)	**54.53**	67.88	56.41	48.50	53.51	68.75	94.16	77.94
Differential – WTI:AWB – U.S. Gulf Coast (US$/bbl)	**(7.43)**	(4.94)	(7.62)	(14.87)	(16.35)	(10.15)	(6.15)	(5.85)
AWB – U.S. Gulf Coast (US$/bbl)	**70.89**	77.32	66.16	61.26	66.30	81.40	102.26	88.44
Enbridge Mainline heavy apportionment	**21 %**	1 %	1 %	12 %	5 %	3 %	0 %	10 %
C$ equivalent of 1US$ – average	**1.3618**	1.3410	1.3430	1.3520	1.3577	1.3059	1.2766	1.2661
Natural gas – AECO ($/mcf)	**2.51**	2.83	2.67	3.51	5.57	4.54	7.89	5.16
OPERATIONAL **($/bbl unless specified)**								
Blend sales, net of purchased product – bbls/d	**158,850**	140,002	119,187	154,197	160,163	131,327	105,517	146,382
Diluent usage – bbls/d	**(46,216)**	(38,377)	(35,656)	(47,717)	(46,581)	(35,568)	(32,426)	(46,196)
Bitumen sales – bbls/d	**112,634**	101,625	83,531	106,480	113,582	95,759	73,091	100,186
Bitumen production – bbls/d	**109,112**	103,726	85,974	106,840	110,805	101,983	67,256	101,128
Steam-oil ratio (SOR)	**2.28**	2.28	2.25	2.25	2.22	2.39	2.46	2.43
Blend sales(2)	**87.33**	101.53	87.81	76.07	83.28	99.96	128.20	105.79
Diluent expense	**(9.58)**	(0.06)	(10.27)	(17.89)	(14.12)	(9.63)	(5.51)	(8.51)
Bitumen realization(2)	**77.75**	101.47	77.54	58.18	69.16	90.33	122.69	97.28
Net transportation and storage expense(2)	**(14.23)**	(16.72)	(19.90)	(14.78)	(14.41)	(15.58)	(19.40)	(12.97)
Bitumen realization after net transportation and storage expense(2)	**63.52**	84.75	57.64	43.40	54.75	74.75	103.29	84.31
Royalties	**(17.92)**	(19.45)	(7.69)	(3.18)	(5.15)	(7.47)	(8.67)	(5.24)
Non-energy operating costs(3)	**(4.64)**	(5.15)	(5.66)	(4.77)	(4.34)	(4.49)	(5.65)	(4.74)
Energy operating costs(3)	**(3.25)**	(3.42)	(3.92)	(5.57)	(6.71)	(6.12)	(10.40)	(6.80)
Power revenue	**1.79**	3.46	2.95	4.21	5.22	5.16	3.08	2.56
Realized gain (loss) on commodity risk management	**(0.85)**	(1.55)	(0.94)	0.23	0.12	0.80	0.10	0.12
Cash operating netback(2)	**38.65**	58.64	42.38	34.32	43.89	62.63	81.75	70.21
Revenues	**1,444**	1,438	1,291	1,480	1,445	1,571	1,571	1,531
Power sales price (C$/MWh)	**81.66**	156.04	150.19	162.90	219.81	217.25	117.94	91.50
Power sales (MW/h)	**108**	97	71	118	116	98	82	121
Average cost of diluent ($/bbl of diluent)	**110.65**	101.68	111.85	116.01	117.72	125.91	140.61	124.23
Average cost of diluent as a % of WTI	**104 %**	92 %	113 %	113 %	105 %	105 %	102 %	104 %
Depletion and depreciation rate per bbl of production	**19.01**	15.28	14.88	14.86	15.84	14.30	14.35	13.58
General and administrative expense per bbl of production	**1.89**	1.73	1.85	1.94	1.62	1.72	2.37	1.61
COMMON SHARES								
Shares outstanding, end of period (000)	**274,642**	283,290	285,566	288,614	291,081	301,649	307,271	307,596
Common share price ($) - close (end of period)	**23.67**	26.43	21.00	21.71	18.85	15.46	17.82	17.07

(1) *Capital management measure - please refer to section 15 "Non-GAAP and Other Financial Measures" of this MD&A.*
(2) *Non-GAAP financial measure - please refer to section 15 "Non-GAAP and Other Financial Measures" of this MD&A.*
(3) *Supplementary financial measure - please refer to section 15 "Non-GAAP and Other Financial Measures" of this MD&A.*

During the eight most recent quarters the following items have had a significant impact on the Corporation's quarterly results:

- significant variability in blend sales pricing primarily due to high volatility in the price of WTI which ranged from a quarterly average of US$73.78/bbl to US$108.41/bbl;
- variability in WTI:AWB differential at Edmonton which ranged from a quarterly average of US$14.25/bbl to US$29.14/bbl;
- the cost of diluent due to changes in Canadian and U.S. benchmark pricing, the timing of diluent inventory purchases and the impact of foreign exchange;
- changes in the value of the Canadian dollar relative to the U.S. dollar and its impact on blend sales prices, the cost of diluent, interest expense, and foreign exchange gains and losses associated with the Corporation's U.S. dollar denominated debt;
- transition of royalty status for the Christina Lake project from pre-payout to post-payout in the second quarter of 2023, which impacts the Crown royalty rate and resulting royalty expense;
- timing of capital projects;
- inflationary pressure;
- pipeline apportionment and the ability to reach USGC markets;
- fluctuations in natural gas and power pricing;
- gains and losses on risk management contracts;
- changes in depletion and depreciation expense as a result of changes in production rates and future development costs;
- changes in the Corporation's share price and the resulting impact on stock-based compensation and financial equity price risk management contracts; and
- planned turnaround, unplanned outages and other maintenance activities affecting production.

25. ANNUAL SUMMARIES

	2023	2022	2021	2020	2019	2018(1)	2017(1)
FINANCIAL *($millions unless specified)*							
Net earnings (loss)	**569**	902	283	(357)	(62)	(119)	166
Per share, diluted	**1.98**	2.92	0.91	(1.18)	(0.21)	(0.40)	0.57
Funds flow from operating activities	**1,476**	1,882	753	239	741	169	343
Per share, diluted	**5.13**	6.09	2.42	0.78	2.46	0.56	1.18
Adjusted funds flow(2)	**1,402**	1,934	826	281	724	175	371
Per share, diluted(2)	**4.87**	6.26	2.65	0.92	2.41	0.58	1.28
Capital expenditures	**449**	376	331	149	198	622	508
Free cash flow(2)	**953**	1,558	495	132	526	(447)	(137)
Working capital	**278**	289	150	55	123	290	313
Net debt - C$(2)	**964**	1,389	2,401	2,798	2,917	3,422	4,205
Net debt - US$(2)	**730**	1,026	1,897	2,194	2,250	2,508	3,359
Shareholders' equity	**4,527**	4,383	3,808	3,506	3,853	3,886	3,964
BUSINESS ENVIRONMENT							
Average Benchmark Commodity Prices:							
WTI (US$/bbl)	**77.62**	94.23	67.91	39.40	57.03	64.77	50.95
Differential – WTI:WCS – Edmonton (US$/bbl)	**(18.71)**	(18.27)	(13.04)	(12.60)	(12.76)	(26.31)	(11.98)
Differential – WTI:AWB – Edmonton (US$/bbl)	**(20.79)**	(20.64)	(14.71)	(14.32)	(14.95)	(29.99)	(14.09)
AWB – Edmonton (US$/bbl)	**56.83**	73.59	53.20	25.08	42.08	34.78	36.86
Differential – WTI:AWB – U.S. Gulf Coast (US$/bbl)	**(8.72)**	(9.62)	(4.60)	(4.77)	(1.77)	(6.68)	(7.61)
AWB - U.S. Gulf Coast (US$/bbl)	**68.90**	84.61	63.31	34.63	55.26	58.09	43.34
Enbridge Mainline heavy apportionment	**9 %**	5 %	42 %	24 %	43 %	41 %	20 %
C$ equivalent of 1US$ – average	**1.3495**	1.3016	1.2536	1.3413	1.3269	1.2962	1.2980
Natural gas – AECO ($/mcf)	**2.88**	5.79	3.95	2.43	1.92	1.62	2.29
OPERATIONAL **($/bbl unless specified)**							
Blend sales, net of purchased product – bbls/d	**143,063**	135,873	131,659	118,347	134,223	125,368	115,766
Diluent usage – bbls/d	**(41,977)**	(40,182)	(39,521)	(35,626)	(40,637)	(38,317)	(35,766)
Bitumen sales – bbls/d	**101,086**	95,691	92,138	82,721	93,586	87,051	80,000
Bitumen production – bbls/d	**101,425**	95,338	93,733	82,441	93,082	87,731	80,774
Steam-oil ratio (SOR)	**2.27**	2.36	2.43	2.32	2.22	2.19	2.31
Blend sales(3)	**87.94**	102.02	72.20	37.65	61.29	53.47	51.39
Diluent expense	**(9.30)**	(10.07)	(9.73)	(10.42)	(8.08)	(16.78)	(9.36)
Net transportation and storage expense(3)	**(16.18)**	(15.29)	(10.93)	(12.92)	(10.84)	(8.42)	(6.89)
Bitumen realization after net transportation & storage expense(3)	**62.46**	76.66	51.54	14.31	42.37	28.27	35.14
Curtailment	**—**	—	—	0.06	(0.37)	—	—
Royalties	**(12.37)**	(6.43)	(2.25)	(0.31)	(1.30)	(1.20)	(0.77)
Non-energy operating costs(4)	**(5.01)**	(4.73)	(4.24)	(4.38)	(4.61)	(4.62)	(4.62)
Energy operating costs(4)	**(4.03)**	(7.29)	(4.94)	(3.29)	(2.38)	(1.98)	(2.98)
Power revenue	**3.08**	4.11	2.58	1.49	1.75	1.51	0.76
Realized gain (loss) on commodity risk management	**(0.77)**	0.29	(9.32)	11.34	(3.31)	(4.37)	(0.39)
Cash operating netback(3)	**43.36**	62.61	33.37	19.22	32.15	17.61	27.14
Revenues	**5,653**	6,118	4,321	2,292	3,931	2,733	2,474
Power sales price (C$/MWh)	**136.50**	162.33	90.10	47.81	56.70	47.87	21.49
Power sales (MW/h)	**98**	104	115	108	121	114	118
Average cost of diluent ($/bbl of diluent)	**110.34**	126.00	94.88	61.86	79.89	91.60	72.32
Average cost of diluent as a % of WTI	**105 %**	103 %	111 %	117 %	106 %	109 %	109 %
Depletion and depreciation rate per bbl of production	**16.10**	14.57	13.15	13.60	20.90	14.12	16.13
General and administrative expense per bbl of production	**1.86**	1.78	1.65	1.62	1.99	2.58	2.94
COMMON SHARES							
Shares outstanding, end of period (000)	**274,642**	291,081	306,865	302,681	299,508	296,841	294,104
Common share price ($) - close (end of period)	**23.67**	18.85	11.70	4.45	7.39	7.71	5.14

(1) *The Corporation adopted IFRS 16 Leases, effective January 1, 2019, therefore prior periods have not been restated.*
(2) *Capital management measure - please refer to section 15 "Non-GAAP and Other Financial Measures" of this MD&A.*
(3) *Non-GAAP financial measure - please refer to section 15 "Non-GAAP and Other Financial Measures" of this MD&A.*
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