THIRD QUARTER | 2023

REPORT TO SHAREHOLDERS FOR THE PERIOD ENDED SEPTEMBER 30, 2023

Report to Shareholders for the period ended September 30, 2023

(All financial figures are expressed in Canadian dollars ($ or C$) and all references to barrels are per barrel of bitumen, unless otherwise noted)

The Corporation's Non-GAAP and Other Financial Measures are detailed in the Advisory section of this report to shareholders. They include: cash operating netback, bitumen realization net of transportation and storage expense, operating expenses net of power revenue, energy operating costs net of power revenue, non-energy operating costs, energy operating costs, adjusted funds flow, free cash flow and net debt.

MEG Energy Corp. reported third quarter 2023 operational and financial results on November 6, 2023.

"Increased bitumen production and strong bitumen realizations resulted in over $400 million of free cash flow in the quarter allowing us to advance our debt reduction and return of capital strategy while continuing to deliver safe and reliable operations," said Derek Evans Chief Executive Officer. "At current oil prices we expect to reach our US$600 million net debt target in mid-2024, at which point our return of capital to shareholders will rise from 50% to 100% of free cash flow, and at the same time, we will be well-positioned to sanction highly economic projects for modest production growth over the next few years. MEG's financial turnaround and current business strength has been governed by the Board of Directors led over the last few years by Ian Bruce as Chair. His business insight, support and kindness will be greatly missed."

Third quarter 2023 highlights include:

- Funds flow from operating activities ("FFO") and adjusted funds flow ("AFF") of $492 million, or $1.71 per share. Year-to-date FFO and AFF totaled $1,118 million and $1,044 million, or $3.85 and $3.60 per share, respectively;
- Bitumen production of 103,726 barrels per day ("bbls/d") at a 2.28 steam-oil ratio ("SOR") reflecting the Corporation's continued focus on short-cycle redevelopment programs, enhanced completion designs and optimized well spacing. Year-to-date bitumen production averaged 98,835 bbls/d;
- Bitumen realization after net transportation and storage expense of $84.75 per barrel reflecting the Corporation's strategic market access together with supportive supply/demand fundamentals for its Access Western Blend ("AWB") product. Bitumen realization after net transportation and storage expense in the first nine months of 2023 was $62.04 per barrel;
- Free cash flow ("FCF") of $409 million after $83 million of capital expenditures. Year-to-date FCF totaled $699 million after $345 million of capital expenditures;
- Debt repayment of US$68 million (approximately $92 million) during the third quarter of 2023 and US$194 million (approximately $263 million) year-to-date. Net debt declined to US$885 million (approximately $1.2 billion) at the end of the third quarter of 2023;
- MEG returned $58 million to shareholders during the third quarter of 2023 through the buyback and cancellation of 2.3 million shares at a weighted average price of $25.40 per share. Year-to-date buybacks totaled 10.3 million shares, returning $227 million to shareholders;
- Operating expenses net of power revenue of $5.11 per barrel. Power revenue more than offset energy operating costs, resulting in a recovery of energy operating costs net of power revenue of $0.04 per barrel and non-energy operating costs of $5.15 per barrel. Year-to-date operating expenses net of power revenue were $5.91 per barrel, including non-energy operating costs of $5.16 per barrel and $0.75 per barrel of energy operating costs net of power revenue;

- 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; and

- On September 13, 2023, Fitch Ratings raised the Corporation's long-term issuer credit rating to BB- with a stable outlook from B+ and affirmed the issue-level rating on the Corporation's senior unsecured notes at BB-.

Financial Results

AFF and FFO in the third quarter of 2023 decreased to $492 million from $496 million and $501 million, respectively, in the comparative 2022 period. Increased sales volumes due to higher bitumen production largely offset a 6% decline in cash operating netback, to $58.64 per barrel, reflecting a higher bitumen realization after net transportation and storage expense more than offset by increased post-payout royalties.

Third quarter 2023 bitumen realization after net transportation and storage expense rose to $84.75 from $74.75 per barrel in the same period of 2022. A lower WTI oil price was more than offset by narrower WTI:AWB differentials and a weaker Canadian dollar. In addition, diluent expense fell from $9.63 to $0.06 per barrel reflecting a lower purchase cost of diluent relative to WTI, narrower WTI:AWB differentials and use of diluent linefill recorded at a lower historical accounting value. Diluent costs were fully recovered through blend sales in the third quarter of 2023 compared to a 79% recovery in the same 2022 period.

The Corporation’s Christina Lake operation reached post-payout status under the Oil Sands Royalty Regulation in the second quarter of 2023. The resulting royalty rate increase raised third quarter 2023 royalties to $181 million from $66 million in the same period of 2022.

The Corporation sold 73% and 66% of blend sales volumes in the USGC market during the third quarters of 2023 and 2022, respectively. Average heavy oil apportionment on the Enbridge mainline system was 1% and 3% in those periods.

Third quarter 2023 FCF was $409 million, compared to $418 million in the same period of 2022, reflecting lower AFF and an increase in capital spending.

Capital expenditures rose to $83 million in the third quarter of 2023 from $78 million in the same quarter of 2022 due to increased 2023 scope, inflation and timing of field development and maintenance activities.

Net earnings increased to $249 million in the third quarter of 2023 from $156 million in the comparative 2022 period, mainly reflecting a smaller unrealized foreign exchange loss on long-term debt.

Operating Results

Bitumen production rose approximately 2% in the third quarter of 2023 to 103,726 bbls/d, from 101,983 bbls/d in the same period of 2022. Higher 2023 production was delivered at a 2.28 SOR, a 5% reduction from 2.39 in the third quarter of 2022. This reflects the Corporation's continued focus on short-cycle redevelopment programs, enhanced completion designs, optimized well spacing and targeted facility enhancements.

Third quarter 2023 non-energy operating costs increased to $5.15 per barrel of bitumen sales from $4.49 per barrel during the same period of 2022, primarily reflecting the timing of maintenance activities and inflationary pressures on the cost of services, treating chemicals and staff costs.

Power revenue exceeded energy operating costs in the third quarter of 2023 generating a $0.04 per barrel net recovery relative to a $0.96 per barrel expense in the comparable 2022 period. Weaker natural gas prices reduced energy operating costs more than the offsetting impact of a lower realized price on power revenue. Power revenue offset 101% and 84% of energy operating costs in the third quarters of 2023 and 2022, respectively.

Debt Repurchases and Share Buybacks

The $409 million of third quarter 2023 FCF was used to fund working capital requirements, repurchase debt and buy back shares. The Corporation repurchased US$68 million (approximately $92 million) of outstanding 7.125% senior unsecured notes at a weighted average price of 101.7%. Share buybacks totaled $58 million through the repurchase and cancellation of 2.3 million shares at a weighted average price of $25.40 per share. Year-to-date the Corporation repurchased US$194 million (approximately $263 million) of outstanding 7.125% senior unsecured notes at a weighted average price of 102.1%, and share buybacks totaled $227.4 million through the repurchase and cancellation of 10.3 million shares at a weighted average price of $22.07 per share.

The Corporation remains focused on its strategy of debt reduction and returning capital to shareholders. From April 1, 2022 through November 3, 2023, 33.1 million shares have been repurchased and cancelled returning $668 million to shareholders at a weighted average price of $20.16 per share. Debt repurchases have totaled US$853 million (approximately $1.1 billion) over that same period.

Capital Allocation Strategy

Approximately 50% of 2023 FCF is being allocated to debt reduction with the remainder applied to share buybacks. 100% of FCF will be returned to shareholders when the Corporation reaches its US$600 million net debt target, which is expected to occur mid-2024 at current oil prices. The Corporation exited the third quarter of 2023 with net debt of US$885 million.

Sustainability and Pathways Update

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 in 2022 and early 2023, including the establishment of a new mid-term absolute GHG emissions reduction target of 0.63 megatonnes per annum by year-end 2030 (an approximately 30% reduction from 2019 levels); $72 million spent on goods and services provided by Indigenous businesses in 2022 (a 30% increase over 2021); launching our Diversity, Equity and Inclusion education and awareness campaign focused on amplifying the voices of every team member to enhance our decision making, innovation, employee engagement and the Corporation's long-term success; and the continued advancement of safety management programs and systems to ensure safe, sustainable and reliable operations.

MEG, along with its Pathways Alliance ("Alliance") peers, continues to progress pre-work on the proposed foundational carbon capture and storage ("CCS") project, which will transport CO2 via pipeline from multiple oil sands facilities to be stored safely and permanently underground in the Cold Lake region of Alberta. During the third quarter of 2023, technical teams continued to advance detailed evaluations of the proposed carbon storage hub. The Alliance is working to obtain a carbon sequestration agreement from the Government of Alberta by year-end 2023 to support regulatory submissions. In addition, the Alliance continued to advance engineering work, environmental field programs to minimize the project's environmental disturbance, and consultations with Indigenous and local communities along the proposed CO2 transportation and storage network corridor. The 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. Updated draft legislation was released for consultation in the third quarter of 2023. It will be important for governments to work together with industry to ensure that the ITC implementation delivers required support to enable CCS project development.

For further details on the 2023 ESG Report and on the Corporation's approach to ESG matters, please refer to the "Sustainability" section of the Corporation's website at www.megenergy.com and the most recently filed AIF on www.sedarplus.ca.

Outlook

The 2023 guidance remains unchanged. Forecast bitumen production for the second half of the year is unchanged at approximately 105,000 bbls/d, with annual production still trending towards the low end of the guidance range and non-energy operating costs and G&A expense still trending towards the high end of their respective ranges.

The Corporation has capacity to ship 100,000 bbls/d of AWB blend sales, on a pre-apportionment basis, to the USGC market via its committed FSP capacity. In addition, 20,000 bbls/d of capacity is contracted on the TMX pipeline system to Canada's West Coast. TMX is scheduled to come into service at the end of the first quarter of 2024, which will further broaden MEG's market access.

Summary of 2023 Guidance	
Capital expenditures	$450 million
Bitumen production - annual average[(1)]	100,000 - 105,000 bbls/d
Non-energy operating costs	$4.75 - $5.05 per bbl
G&A expense	$1.70 - $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 bbls/d.

Adjusted Funds Flow Sensitivity

MEG's production is comprised entirely of crude oil and AFF is highly correlated with crude oil benchmark prices and light-heavy oil differentials. The following table provides an annual sensitivity estimate to the most significant market variables.

Variable	Range	2023 AFF Sensitivity[(1)(2)] - C$mm
WCS Differential (US$/bbl)	+/- US$1.00/bbl	+/- C$45mm
WTI (US$/bbl)	+/- US$1.00/bbl	+/- C$27mm
Bitumen Production (bbls/d)	+/- 1,000 bbls/d	+/- C$17mm
Condensate (US$/bbl)	+/- US$1.00/bbl	+/- C$14mm
Exchange Rate (C$/US$)	+/- $0.01	+/- C$9mm
Non-Energy Opex (C$/bbl)	+/- C$0.25/bbl	+/- C$6mm
AECO Gas[(3)] (C$/GJ)	+/- C$0.50/GJ	+/- C$2mm

(1) Each sensitivity is independent of changes to other variables.
(2) Assumes low end of 2023 production guidance, US$80.00/bbl WTI, US$18.50/bbl WTI:AWB Edmonton discount, US$9.00/bbl WTI:AWB Gulf Coast discount, C$1.32/US$ F/X rate, condensate purchased at 100% of WTI and one bbl of bitumen per 1.44 bbls of blend sales (1.44 blend ratio).
(3) Assumes 1.3 GJ/bbl of bitumen, 70% of 150 MW of power generation sold externally and a 30.0 GJ/MWh heat rate.

ADVISORY

Forward-Looking Information

This quarterly report contains forward-looking information and should be read in conjunction with the "Forward-Looking Information" contained within the Advisory section of this quarter's Management's Discussion and Analysis and Press Release.

Non-GAAP and Other Financial Measures

Certain financial measures in this report to shareholders 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 14 "Non-GAAP and Other Financial Measures" of the Corporation's third quarter of 2023 Management's Discussion and Analysis for detailed descriptions of these measures.

This Management's Discussion and Analysis ("MD&A") of the financial condition and performance of MEG Energy Corp. ("MEG" or the "Corporation") for the three and nine months ended *September 30, 2023 was approved by the Corporation's Audit Committee on November 6, 2023. This MD&A should be read in conjunction with the Corporation's unaudited interim consolidated financial statements and notes thereto for the* three and nine months ended *September 30, 2023, the audited annual consolidated financial statements and notes thereto for the year ended December 31, 2022, the 2022 annual MD&A and the Corporation's most recently filed Annual Information Form ("AIF"). This MD&A and the unaudited interim consolidated financial statements and comparative information have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") 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.

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 14 "Non-GAAP and Other Financial Measures" of this MD&A for further descriptions of the measures noted below.

1. *Non-GAAP financial measures and ratios:*
    - *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*
    - *Per barrel figures associated with non-GAAP financial measures*
2. *Supplementary financial measures and ratios:*
    - *Non-energy operating costs*
    - *Energy operating costs*
    - *Per barrel figures associated with supplementary financial measures*
3. *Capital management measures:*
    - *Adjusted funds flow*
    - *Free cash flow*
    - *Net debt*

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1. BUSINESS DESCRIPTION

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, 2022, contained approximately 1.94 billion barrels of gross proved plus probable ("2P") bitumen reserves at the Christina Lake Project. For information regarding MEG's estimated reserves contained in the report prepared by GLJ, please refer to the Corporation's 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.

The Christina Lake Project, which contains all the Corporation's 2P reserves has regulatory approval in place for 210,000 bbls/d of production. At a steam-oil ratio ("SOR") of 2.2, MEG has developed oil processing capacity of approximately 110,000 bbls/d at its Christina Lake central plant facility, prior to any impact from scheduled maintenance activity or outages. The typical average annual production decline rate at the Christina Lake Project is approximately 10% to 15% and at an annual production level of approximately 103,700 bbls/d, MEG has a 2P reserve life index of greater than 50 years.

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. MEG also uses cogeneration, also known as combined heat and power generation, 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 calculated based on data reported to Environment Canada, the Alberta Energy Regulator and the Alberta Electric System Operator. In addition, in 2022, as part of a broader development strategy, MEG introduced enhanced completion designs and optimized inter-well spacing all focused on reducing SOR. MEG achieved an average SOR of 2.36 in 2022 compared to the *in situ* industry volume weighted average of 3.0.[2]

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 U.S. Gulf Coast ("USGC") refineries and export terminals. MEG is also a shipper on the Trans Mountain Expansion Project ("TMX") which, when in service, 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 and rail terminals. The diluent system is well connected to key pipeline and storage systems in the Edmonton/Fort Saskatchewan

[1] Scope 1 and scope 2 emissions
[2] Annual 2022 data as per the Alberta Energy Regulator ST53.

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. MEG has also contracted capacity on the Bayou Bridge pipeline to access USGC refineries and export facilities beyond Texas.

2. OPERATIONAL AND FINANCIAL HIGHLIGHTS

The Corporation generated funds flow from operating activities and adjusted funds flow of $492 million in the third quarter of 2023. After $83 million of capital expenditures, the Corporation's remaining free cash flow of $409 million was used to fund working capital and continue to repay debt and return capital to shareholders. During the third quarter of 2023, the Corporation purchased US$68 million (approximately $92 million) of outstanding 7.125% senior unsecured notes and returned $58 million to MEG shareholders through the repurchase and cancellation of 2.3 million shares.

Average bitumen production in the third quarter of 2023 rose to 103,726 barrels per day ("bbls/d") from 101,983 bbls/d in the same period of 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 the third quarter of 2023 decreased to $492 million, from $501 million and $496 million, respectively, in the same period of 2022. Increased sales volumes, due to higher bitumen production, largely offset a $3.99 per barrel decline in cash operating netback to $58.64 per barrel. The decrease in cash operating netback reflected a higher bitumen realization after net transportation and storage expense, which was more than offset by increased post-payout royalties. Bitumen realization after net transportation and storage expense rose to $84.75 per barrel in the third quarter of 2023 from $74.75 per barrel in the third quarter of 2022 reflecting narrower WTI:AWB differentials, reduced diluent expense and a weaker Canadian dollar, partially offset by a lower WTI oil price.

Despite the decrease in adjusted funds flow, net earnings increased to $249 million in the third quarter of 2023 from $156 million in the third quarter of 2022 mainly reflecting a lower unrealized foreign exchange loss on long-term debt as the Canadian dollar weakened less during the 2023 period.

Year-to-date the Corporation generated funds flow from operating activities of $1,118 million and adjusted funds flow of $1,044 million. After $345 million of capital expenditures, the Corporation had $699 million of free cash flow to fund working capital and continue to repay debt and return capital to shareholders. During the nine months ended September 30, 2023, the Corporation purchased US$194 million (approximately $263 million) of outstanding 7.125% senior unsecured notes and returned $227 million to MEG shareholders through the repurchase and cancellation of 10.3 million shares.

At September 30, 2023, cash and cash equivalents were $125 million. The Corporation exited the quarter with total debt and net debt of approximately $1,323 million and $1,198 million (US$885 million), respectively.

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

	Nine months ended Sept 30		2023			2022				2021
($millions, except as indicated)	**2023**	**2022**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**
Bitumen production - bbls/d	**98,835**	90,126	**103,726**	85,974	106,840	110,805	101,983	67,256	101,128	100,698
Steam-oil ratio	**2.26**	2.42	**2.28**	2.25	2.25	2.22	2.39	2.46	2.43	2.42
Bitumen sales - bbls/d	**97,194**	89,662	**101,625**	83,531	106,480	113,582	95,759	73,091	100,186	98,894
Bitumen realization after net transportation and storage expense(1) - $/bbl	**62.04**	86.02	**84.75**	57.64	43.40	54.75	74.75	103.29	84.31	59.67
Non-energy operating costs(2) - $/bbl	**5.16**	4.90	**5.15**	5.66	4.77	4.34	4.49	5.65	4.74	4.56
Energy operating costs net of power revenue(1) - $/bbl	**0.75**	3.89	**(0.04)**	0.97	1.36	1.49	0.96	7.32	4.24	3.64
Cash operating netback(1) - $/bbl	**45.19**	70.61	**58.64**	42.38	34.32	43.89	62.63	81.75	70.21	37.87
General & administrative expense - $/bbl of bitumen production volumes	**1.84**	1.84	**1.73**	1.85	1.94	1.62	1.72	2.37	1.61	1.58
Funds flow from operating activities	**1,118**	1,500	**492**	278	348	383	501	412	587	260
Per share, diluted	**3.85**	4.80	**1.71**	0.96	1.19	1.28	1.63	1.31	1.87	0.83
Adjusted funds flow(3)	**1,044**	1,533	**492**	278	274	401	496	478	559	274
Per share, diluted(3)	**3.60**	4.91	**1.71**	0.96	0.94	1.34	1.61	1.52	1.78	0.88
Free cash flow(3)	**699**	1,263	**409**	129	161	295	418	374	471	168
Revenues	**4,209**	4,673	**1,438**	1,291	1,480	1,445	1,571	1,571	1,531	1,307
Net earnings (loss)	**466**	743	**249**	136	81	159	156	225	362	177
Per share, diluted	**1.61**	2.38	**0.86**	0.47	0.28	0.53	0.51	0.72	1.15	0.57
Capital expenditures	**345**	270	**83**	149	113	106	78	104	88	106
Long-term debt, including current portion	**1,323**	1,803	**1,323**	1,382	1,466	1,581	1,803	2,026	2,440	2,762
Net debt(3) - C$	**1,198**	1,634	**1,198**	1,316	1,381	1,389	1,634	1,782	2,150	2,401
Net debt(3) - US$	**885**	1,193	**885**	994	1,020	1,026	1,193	1,384	1,722	1,897

(1) Non-GAAP financial measure - please refer to section 14 "Non-GAAP and Other Financial Measures" of this MD&A.

(2) Supplementary financial measure - please refer to section 14 "Non-GAAP and Other Financial Measures" of this MD&A.

(3) Capital management measure - please refer to section 14 "Non-GAAP and Other Financial Measures" of this MD&A.

3. SUSTAINABILITY AND PATHWAYS UPDATE

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 in 2022 and early 2023, including the establishment of a new mid-term absolute GHG emissions reduction target of 0.63 megatonnes per annum by year-end 2030 (an approximately 30% reduction from 2019 levels); $72 million spent on goods and services provided by Indigenous businesses in 2022 (a 30% increase over 2021); launching our Diversity, Equity and Inclusion education and awareness campaign focused on amplifying the voices of every team member to enhance our decision making, innovation, employee engagement and the Corporation's long-term success; and the continued advancement of safety management programs and systems to ensure safe, sustainable and reliable operations.

MEG, along with its Pathways Alliance ("Alliance") peers, continues to progress pre-work on the proposed foundational carbon capture and storage ("CCS") project, which will transport CO2 via pipeline from multiple oil sands facilities to be stored safely and permanently underground in the Cold Lake region of Alberta. During the third quarter of 2023, technical teams continued to advance detailed evaluations of the proposed carbon storage hub. The Alliance is working to obtain a carbon sequestration agreement from the Government of Alberta by year-end 2023 to support regulatory submissions. In addition, the Alliance continued to advance engineering work, environmental field programs to minimize the project's environmental disturbance, and consultations with Indigenous and local communities along the proposed CO2 transportation and storage network corridor. The 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. Updated draft legislation was released for consultation in the third quarter of 2023. It will be important for governments to work together with industry to ensure that the ITC implementation delivers required support to enable CCS project development.

For further details on the 2023 ESG Report and on the Corporation's approach to ESG matters, please refer to the "Sustainability" section of the Corporation's website at www.megenergy.com and the most recently filed AIF on www.sedarplus.ca.

4. NET EARNINGS

	Three months ended September 30		Nine months ended September 30	
($millions, except per share amounts)	**2023**	**2022**	**2023**	**2022**
Net earnings	**$ 249**	$ 156	**$ 466**	$ 743
Per share, diluted	**$ 0.86**	$ 0.51	**$ 1.61**	$ 2.38

Net earnings increased to $249 million during the three months ended September 30, 2023, compared to $156 million during the same period of 2022, mainly reflecting a smaller unrealized foreign exchange loss on long-term debt during the 2023 period.

Net earnings declined to $466 million during the nine months ended September 30, 2023 compared to $743 million during the same period of 2022 mainly reflecting a lower cash operating netback and higher depletion and depreciation expense, partially offset by a lower unrealized foreign exchange loss on long-term debt and reduced income tax expense.

5. REVENUES

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

	Three months ended September 30		Nine months ended September 30	
($millions)	**2023**	**2022**	**2023**	**2022**
Sales from:				
Production	**$ 1,301**	$ 1,204	**$ 3,286**	$ 3,821
Purchased product[(1)]	**285**	386	**1,095**	930
Petroleum revenue	**$ 1,586**	$ 1,590	**$ 4,381**	$ 4,751
Royalties	**(181)**	(66)	**(270)**	(171)
Petroleum revenue, net of royalties	**$ 1,405**	$ 1,524	**$ 4,111**	$ 4,580
Power revenue	**$ 32**	$ 46	**$ 95**	$ 90
Transportation revenue	**1**	1	**3**	3
Power and transportation revenue	**$ 33**	$ 47	**$ 98**	$ 93
Revenues	**$ 1,438**	$ 1,571	**$ 4,209**	$ 4,673

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

During the three and nine months ended September 30, 2023, petroleum revenue, net of royalties decreased to $1.4 billion and $4.1 billion, respectively, from $1.5 billion and $4.6 billion in the same periods of 2022. Higher third quarter 2023 blend sales volumes and prices were more than offset by increased royalties and reduced sales from purchased product. In the nine months ended September 30, 2023 a weaker average WTI benchmark price, wider WTI:AWB differentials and increased royalties more than offset higher blend sales volumes, increased sales from purchased product and a weaker Canadian dollar.

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

	Three months ended September 30		Nine months ended September 30	
	2023	**2022**	**2023**	**2022**
Bitumen production – bbls/d	**103,726**	101,983	**98,835**	90,126
Steam-oil ratio (SOR)	**2.28**	2.39	**2.26**	2.42

Bitumen Production

Bitumen production increased approximately 2% and 10% in the three and nine months ended September 30, 2023, compared to the same periods of 2022, reflecting the Corporation's continued focus on short-cycle redevelopment programs, enhanced completion designs, optimized well spacing and targeted facility enhancements. Year-to-date 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

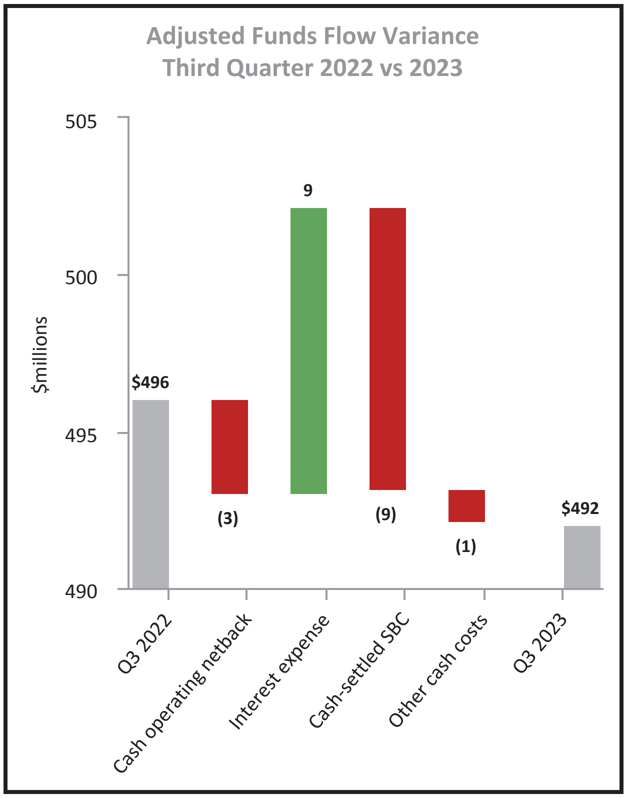
The Corporation uses SAGD technology to recover bitumen. In SAGD operations, steam is injected into the oil reservoir to mobilize bitumen, which is then pumped to the surface. An important metric for thermal oil projects is SOR, which is an efficiency indicator that measures the average amount of steam that is injected into the reservoir for each barrel of bitumen produced. The SOR decreased approximately 5% and 7% during the three and nine months ended September 30, 2023, compared to the same periods of 2022, due to the deployment of enhanced completion designs, execution of our 2023 redevelopment plans and continued emphasis on steam allocation to the highest quality resource.

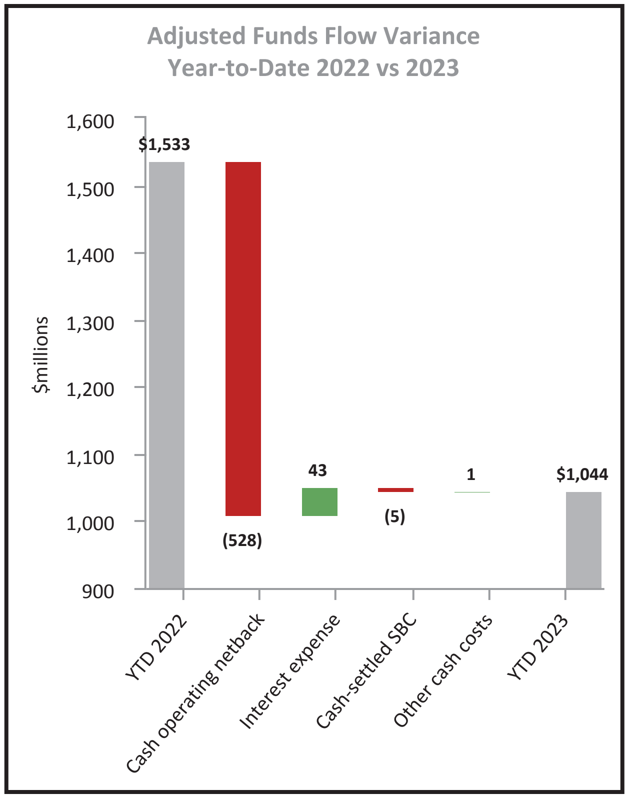
Funds Flow from Operating Activities and Adjusted Funds Flow

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:

	Three months ended September 30		Nine months ended September 30	
($millions)	**2023**	**2022**	**2023**	**2022**
Funds flow from operating activities	**$ 492**	$ 501	**$ 1,118**	$ 1,500
Adjustments:				
Impact of cash-settled SBC units subject to equity price risk management	**—**	(5)	**13**	79
Realized equity price risk management gain	**—**	—	**(87)**	(46)
Adjusted funds flow	**$ 492**	$ 496	**$ 1,044**	$ 1,533
Per share, diluted	**$ 1.71**	$ 1.61	**$ 3.60**	$ 4.91





Funds flow from operating activities and adjusted funds flow during the three months ended September 30, 2023 was similar to the same period of 2022 as a lower cash operating netback and higher cash-settled stock-based compensation expense was largely offset by lower interest expense due to reduced debt levels.

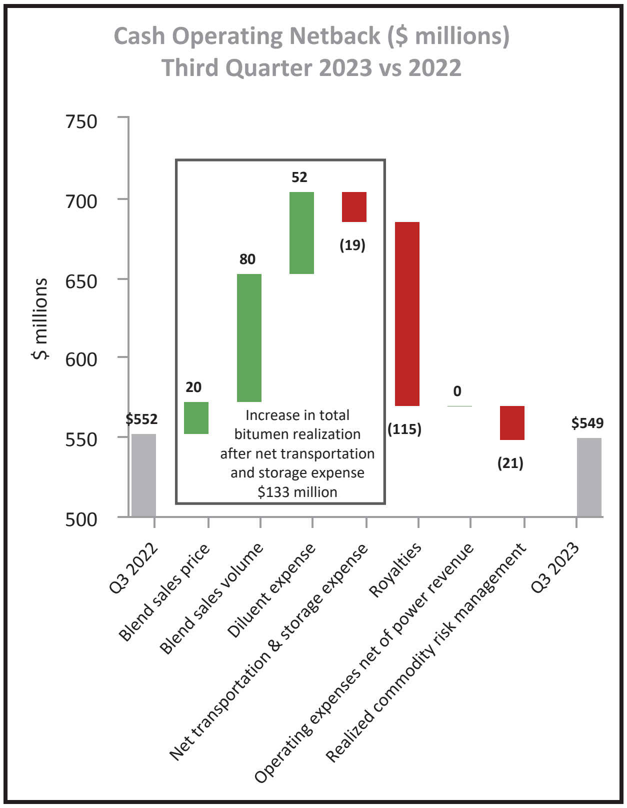
Funds flow from operating activities and adjusted funds flow decreased in the nine months ended September 30, 2023, compared to the same period of 2022, driven mainly by a lower cash operating netback partially offset by lower interest expense due to reduced debt levels.

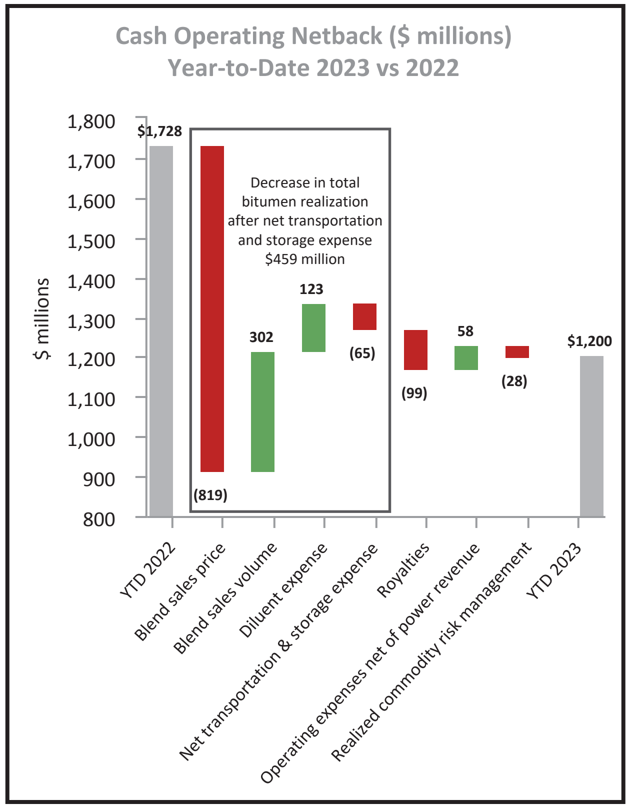
Cash Operating Netback

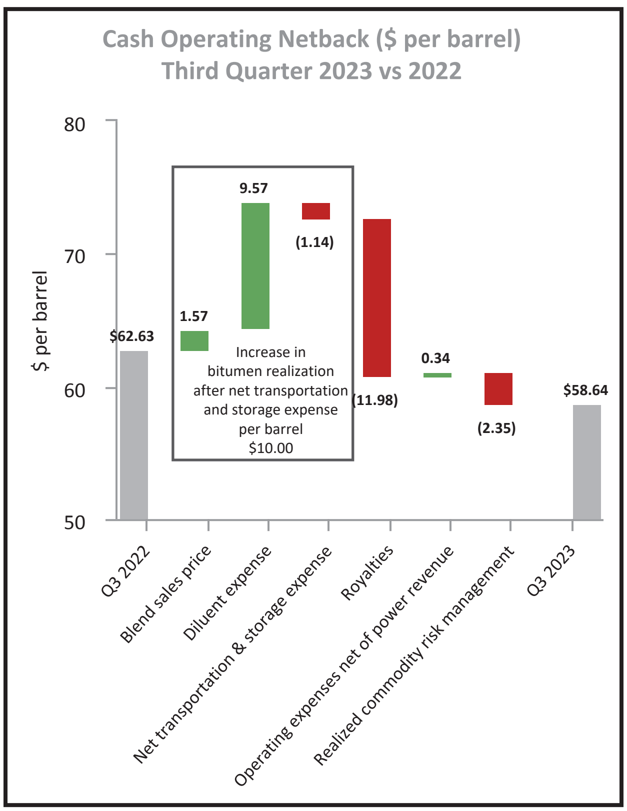
The following table summarizes the Corporation's cash operating netback. Unless otherwise indicated, the per barrel calculations are based on bitumen sales volumes.

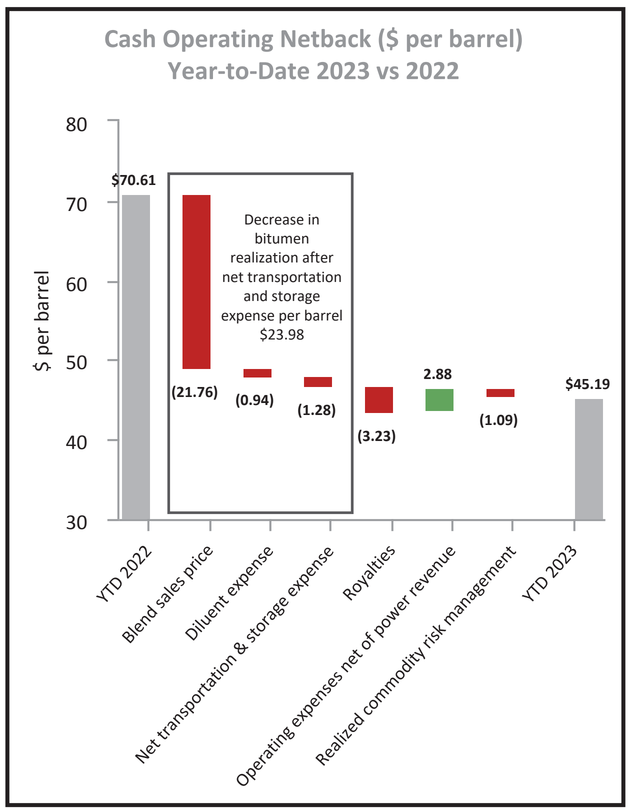
	Three months ended September 30				Nine months ended September 30			
	2023		**2022**		**2023**		**2022**	
($millions, except as indicated)		**$/bbl**		**$/bbl**		**$/bbl**		**$/bbl**
Sales from production	**$1,301**		$1,204		**$3,286**		$3,821	
Sales from purchased product[1]	**285**		386		**1,095**		930	
Petroleum revenue	**$1,586**		$1,590		**$4,381**		$4,751	
Purchased product[1]	**(279)**		(383)		**(1,066)**		(919)	
Blend sales[2][3]	**$1,307**	**$101.53**	$1,207	$99.96	**$3,315**	**$88.18**	$3,832	$109.94
Diluent expense	**(359)**	**(0.06)**	(411)	(9.63)	**(1,220)**	**(9.20)**	(1,343)	(8.26)
Bitumen realization[3]	**$ 948**	**$101.47**	$ 796	$90.33	**$2,095**	**$78.98**	$2,489	$101.68
Net transportation and storage expense[3][4]	**(156)**	**(16.72)**	(137)	(15.58)	**(449)**	**(16.94)**	(384)	(15.66)
Bitumen realization after net transportation and storage expense[3]	**792**	**84.75**	659	74.75	**1,646**	**62.04**	2,105	86.02
Royalties	**(181)**	**(19.45)**	(66)	(7.47)	**(270)**	**(10.21)**	(171)	(6.98)
Operating expenses net of power revenue[3]	**(48)**	**(5.11)**	(48)	(5.45)	**(157)**	**(5.91)**	(215)	(8.79)
Realized gain (loss) on commodity risk management	**(14)**	**(1.55)**	7	0.80	**(19)**	**(0.73)**	9	0.36
Cash operating netback[3]	**$ 549**	**$58.64**	$ 552	$62.63	**$1,200**	**$45.19**	$1,728	$70.61
Bitumen sales volumes - bbls/d		**101,625**		95,759		**97,194**		89,662

(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 14 "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.









Cash operating netback during the three months ended September 30, 2023 decreased from the same period of 2022 mainly driven by higher royalties and a realized commodity risk management loss partially offset by higher bitumen realization after net transportation and storage expense. In the nine months ended September 30, 2023, cash operating netback per barrel decreased approximately 36% from the comparable 2022 period 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.

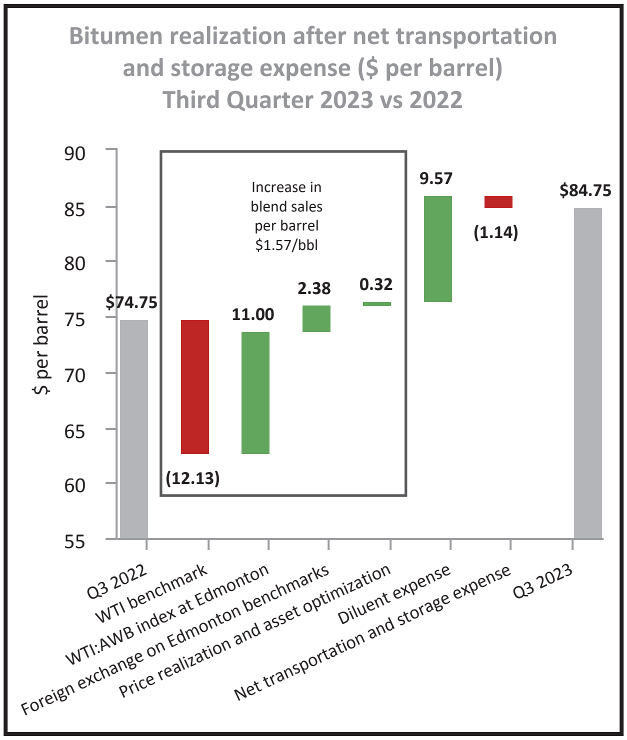
Bitumen Realization after Net Transportation and Storage Expense

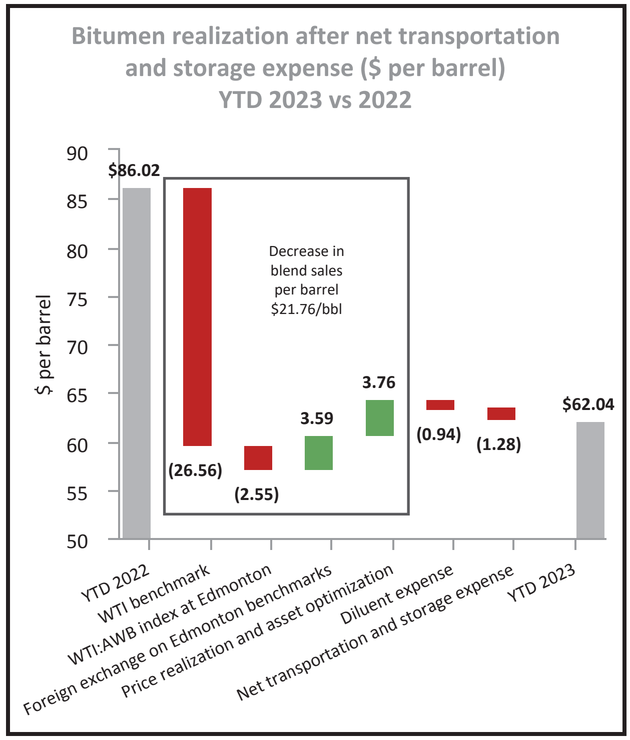
Bitumen realization after net transportation and storage expense represents bitumen sales at Christina Lake and is calculated as blend sales less diluent expense and net transportation and storage expense. Blend sales represents the Corporation's revenue from its oil blend known as AWB, which is comprised 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 bbls/d of diluent is sourced from Mont Belvieu, Texas 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 average benchmark prices and light:heavy oil differentials.

	Three months ended September 30				**Nine months ended September 30**			
	2023		**2022**		**2023**		**2022**	
($millions, except as indicated)		**$/bbl**		**$/bbl**		**$/bbl**		**$/bbl**
Sales from production	**$ 1,301**		$ 1,204		**$ 3,286**		$ 3,821	
Sales from purchased product[1]	**285**		386		**1,095**		930	
Petroleum revenue	**$ 1,586**		$ 1,590		**$ 4,381**		$ 4,751	
Purchased product[1]	**(279)**		(383)		**(1,066)**		(919)	
Blend sales[2][3]	**$ 1,307**	**$101.53**	$ 1,207	$ 99.96	**$ 3,315**	**$ 88.18**	$ 3,832	$109.94
Diluent expense	**(359)**	**(0.06)**	(411)	(9.63)	**(1,220)**	**(9.20)**	(1,343)	(8.26)
Bitumen realization[3]	**$ 948**	**$101.47**	$ 796	$ 90.33	**$ 2,095**	**$ 78.98**	$ 2,489	$101.68
Net transportation and storage expense[3]	**(156)**	**(16.72)**	(137)	(15.58)	**(449)**	**(16.94)**	(384)	(15.66)
Bitumen realization after net transportation and storage expense[3]	**$ 792**	**$ 84.75**	$ 659	$ 74.75	**$ 1,646**	**$ 62.04**	$ 2,105	$ 86.02
Bitumen sales volumes - bbls/d		**101,625**		95,759		**97,194**		89,662

(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 14 "Non-GAAP and Other Financial Measures" of this MD&A.





During the three months ended September 30, 2023, bitumen realization after net transportation and storage expense per barrel increased 13%, to $84.75, compared to the same period of 2022, primarily driven by lower diluent expense.

Diluent expense per barrel decreased to $0.06 in the third quarter of 2023 from $9.63 in the comparable 2022 period. The reduction was mainly driven by market dynamics, which narrowed WTI:AWB differentials and lowered the purchase cost of diluent relative to WTI. Also, the expiration of a long-term diluent transportation and supply contract provided access to diluent linefill that was recorded at a lower historical value and reduced the accounting cost of diluent sold. As a result, almost 100% of diluent costs were recovered through blend sales in the third quarter of 2023 compared to a 79% recovery in the same period of 2022.

The cost per barrel of diluent in the three and nine months ended September 30, 2023 was $101.68 and $110.22, respectively, relative to $125.91 and $129.42, in the comparable 2022 periods.

The blend sales price per barrel increased $1.57, to $101.53, in the third quarter of 2023 compared to the same period of 2022, reflecting narrower WTI:AWB differentials, at both Edmonton and the USGC, a weaker Canadian dollar relative to the U.S. dollar partially offset by a lower WTI benchmark price.

During the nine months ended September 30, 2023, bitumen realization after net transportation and storage expense per barrel decreased 28%, from the same period of 2022, to $62.04, driven by a lower blend sales price, higher diluent expense and increased net transportation and storage expense. The blend sales price decrease reflects a lower WTI benchmark price and wider WTI:AWB differentials, at both Edmonton and the USGC, partially offset by the realized price improvement from diverse market access and marketing optimization activities and a weaker Canadian dollar relative to the U.S. dollar.

The Corporation sold 73% and 70% of its blend sales volumes in the USGC market during the three and nine months ended September 30, 2023, respectively, compared to 66% and 67% during the same periods of 2022. Average heavy oil apportionment on the Enbridge mainline system was 1% and 4%, respectively, during the three and nine months ended September 30, 2023 and 3% and 4% during the comparable 2022 periods.

	Three months ended September 30				Nine months ended September 30			
	2023		2022		2023		2022	
($millions, except as indicated)		**$/bbl**		**$/bbl**		**$/bbl**		**$/bbl**
Transportation and storage expense	**$ (157)**	**$(16.83)**	$ (138)	$(15.70)	**$ (452)**	**$(17.04)**	$ (387)	$(15.80)
Transportation revenue	**1**	**0.11**	1	0.12	**3**	**0.10**	3	0.14
Net transportation and storage expense	**$ (156)**	**$(16.72)**	$ (137)	$(15.58)	**$ (449)**	**$(16.94)**	$ (384)	$(15.66)
Bitumen sales volumes - bbls/d		**101,625**		95,759		**97,194**		89,662

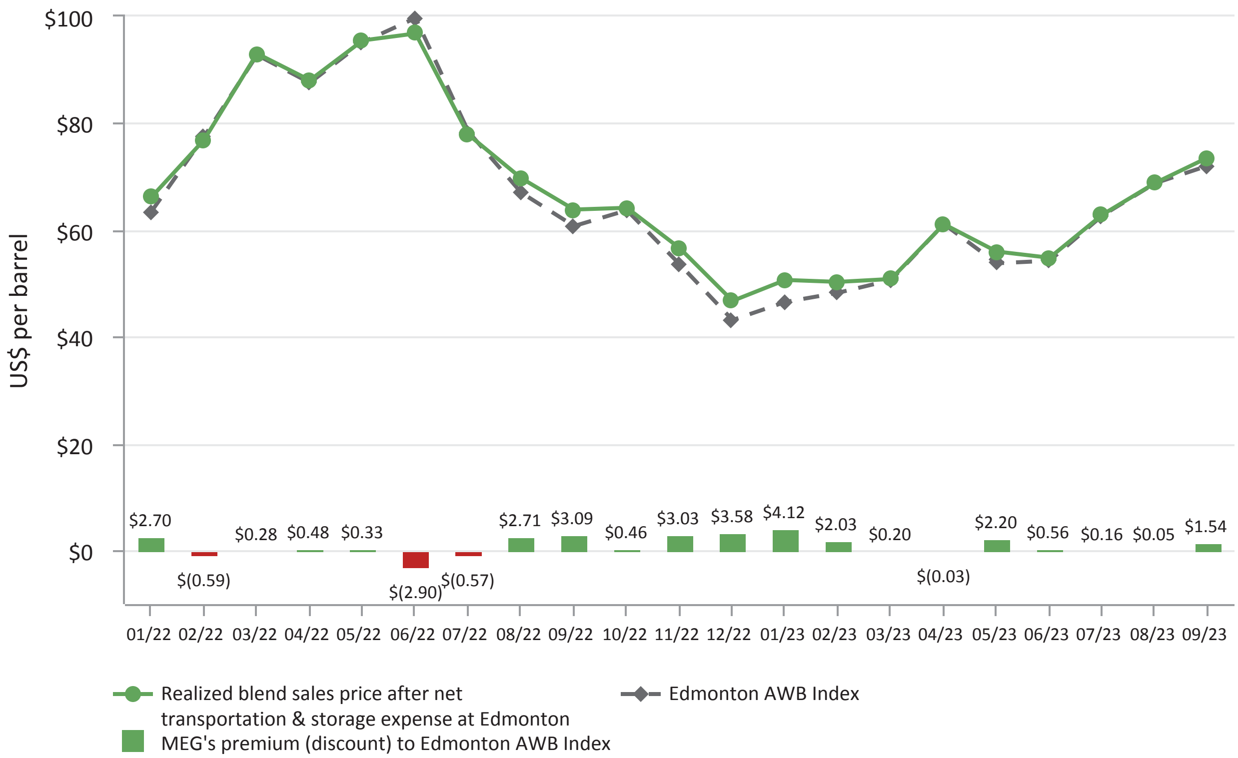
Net transportation and storage expense in the three and nine months ended September 30, 2023, on a total and a per barrel basis, rose relative to the same periods of 2022 primarily reflecting higher volumes transported on FSP, higher base tolls on FSP and a weaker Canadian dollar relative to the U.S. dollar.

When expressed on a US$ per barrel of blend sales basis, net transportation and storage expense was US$9.06 and US$8.88, respectively, during the three and nine months ended September 30, 2023 compared to US$8.71 and US$8.57 during the same periods of 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 contributed $6 million, or $0.50 per barrel, and $29 million, or $0.78 per barrel, to blend sales in the three and nine months ended September 30, 2023, respectively, compared to $3 million, or $0.27 per barrel, and $11 million, or $0.33 per barrel of blend sales, in the same periods of 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 the three and nine months ended September 30, 2023, the Corporation's ability to access the USGC increased the overall average realized price on all blend sales compared to the Edmonton AWB index by US$0.69 and US$1.29 per barrel, respectively.

Royalties

The Oil Sands Royalty Regulation, 2009, establishes royalty rates that are linked to WTI 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 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 WTI price is $120 per barrel or higher.

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

($millions)	Three months ended September 30 2023		Three months ended September 30 2022		Nine months ended September 30 2023		Nine months ended September 30 2022	
Bitumen realization	**$**	**948**	$	796	**$**	**2,095**	$	2,489
Transportation and storage expense		**(157)**		(138)		**(452)**		(387)
Transportation revenue		**1**		1		**3**		3
Bitumen realization after net transportation and storage expense	**$**	**792**	$	659	**$**	**1,646**	$	2,105
Royalties	**$**	**181**	$	66	**$**	**270**	$	171
Effective royalty rate(1)(2)		**22.9 %**		10.0 %		**16.4 %**		8.1 %

(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 14 "Non-GAAP and Other Financial Measures" of this MD&A.

As a result of reaching payout status, the effective royalty rate increased, which increased the royalty expense in the three and nine months ended September 30, 2023 compared to the same periods of 2022. During the nine months ended September 30, 2023, the impact of the increased royalty rate was partially offset by lower gross revenue.

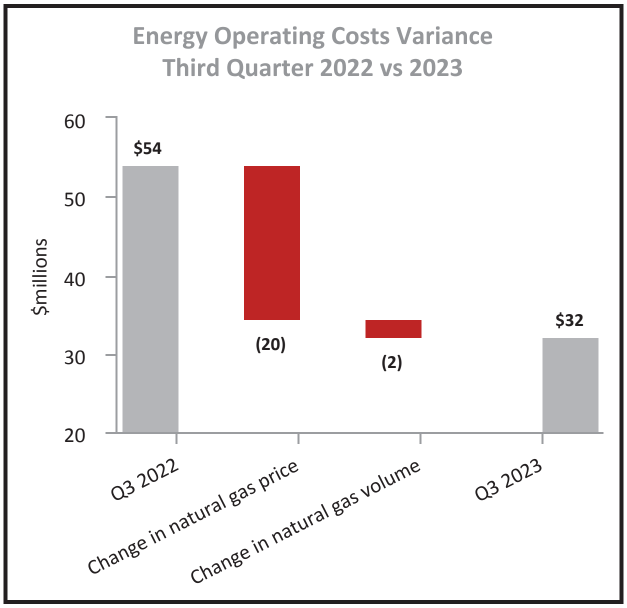
Operating Expenses net of Power Revenue

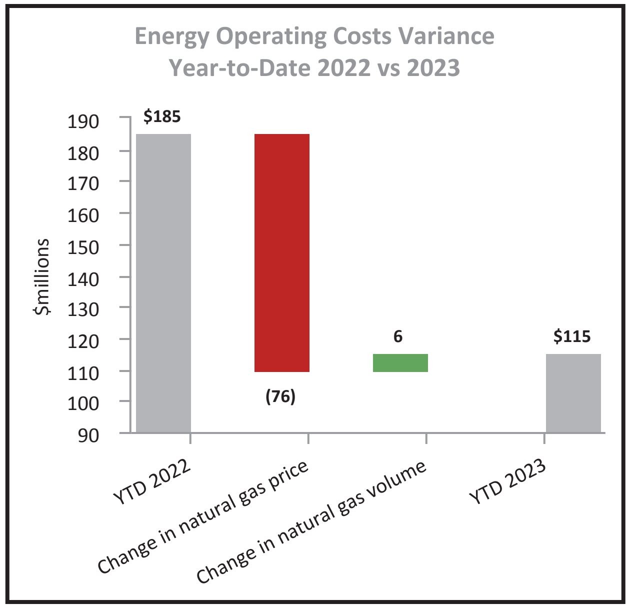
Operating expenses net of power revenue are comprised of non-energy operating costs and energy operating costs, reduced by power revenue. Non-energy operating costs relate to production-oriented operating activities and energy operating costs reflect the cost of natural gas used for fuel to generate steam and power. Power revenue is recognized from the sale of surplus power generated by the Christina Lake Regional 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.

	Three months ended September 30				Nine months ended September 30			
	2023		2022		2023		2022	
($millions, except as indicated)		$/bbl		$/bbl		$/bbl		$/bbl
Non-energy operating costs(1)	**$ (48)**	**$ (5.15)**	$ (40)	$ (4.49)	**$ (137)**	**$ (5.16)**	$ (120)	$ (4.90)
Energy operating costs(1)	**(32)**	**(3.42)**	(54)	(6.12)	**(115)**	**(4.34)**	(185)	(7.53)
Operating expenses	**(80)**	**(8.57)**	(94)	(10.61)	**(252)**	**(9.50)**	(305)	(12.43)
Power revenue	**32**	**3.46**	46	5.16	**95**	**3.59**	90	3.64
Operating expenses net of power revenue(2)	**$ (48)**	**$ (5.11)**	$ (48)	$ (5.45)	**$ (157)**	**$ (5.91)**	$ (215)	$ (8.79)
Energy operating costs net of power revenue(2)	**$ —**	**$ 0.04**	$ (8)	$ (0.96)	**$ (20)**	**$ (0.75)**	$ (95)	$ (3.89)
Average delivered natural gas price (C$/mcf)		**$ 3.05**		$ 4.92		**$ 3.59**		$ 5.97
Average realized power sales price (C$/Mwh)		**$156.04**		$217.25		**$157.39**		$140.00

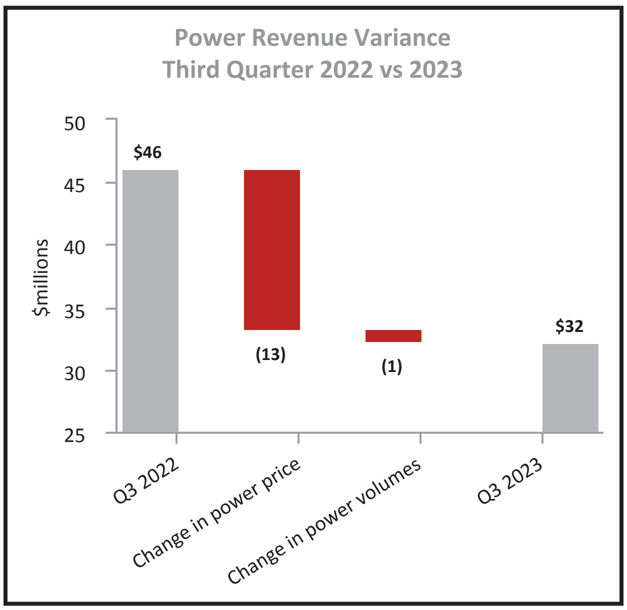
(1) Supplementary financial measure - please refer to section 14 "Non-GAAP and Other Financial Measures" of this MD&A.
(2) Non-GAAP financial measure - please refer to section 14 "Non-GAAP and Other Financial Measures" of this MD&A.

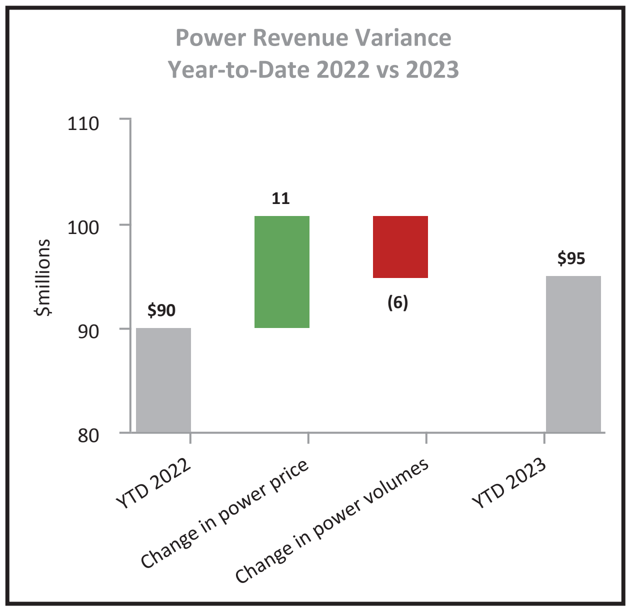
Non-energy operating costs, on a total and per barrel basis, increased in the three and nine months ended September 30, 2023, compared to the same periods of 2022, primarily reflecting higher production rates, timing of maintenance activities and inflationary pressures on cost of services, treating chemicals and staff costs.





Lower energy operating costs in the three and nine months ended September 30, 2023, on a total and per barrel basis, primarily reflect a weaker AECO natural gas price relative to the same periods of 2022. Natural gas volumes were similar in the 2023 and 2022 periods with lower SOR offsetting higher bitumen production rates.





Power revenue during the three months ended September 30, 2023 declined from the same period of 2022 as the realized power price decreased 28%.

Power revenue during the nine months ended September 30, 2023 rose compared to the same period of 2022 reflecting a 12% increase in the realized power price partially offset by reduced power sales volumes.

Energy operating costs net of power revenue per barrel resulted in a recovery of $0.04 during the three months ended September 30, 2023, compared to an expense of $0.96 during the comparable 2022 period, mainly as a result of a weaker AECO natural gas price partially offset by a lower realized power price.

Energy operating costs net of power revenue per barrel decreased to $0.75 during the nine months ended September 30, 2023 from $3.89 during the comparable 2022 period mainly reflecting a weaker AECO natural gas price.

Realized Gain or 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.

	Three months ended September 30				Nine months ended September 30			
	2023		2022		2023		2022	
($millions, except as indicated)		$/bbl		$/bbl		$/bbl		$/bbl
Realized gain (loss) on commodity risk management	**$ (14)**	**$ (1.55)**	$ 7	$ 0.80	**$ (19)**	**$ (0.73)**	$ 9	$ 0.36

Capital Expenditures

	Three months ended September 30		Nine months ended September 30	
($millions)	2023	2022	2023	2022
Sustaining and maintenance	**$ 77**	$ 75	**$ 270**	$ 212
Turnaround	**—**	—	**66**	46
Field infrastructure, corporate and other	**6**	3	**9**	12
	$ 83	$ 78	**$ 345**	$ 270

Higher capital expenditures during the three and nine months ended September 30, 2023, compared to the same periods of 2022, were primarily 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 2023 and 2022, were successfully completed on time. However, costs in the second quarter of 2023 reflect a larger planned turnaround scope, found work, inflationary pressures on labour costs and ongoing supply chain challenges.

7. OUTLOOK

The 2023 guidance remains unchanged. Forecast bitumen production for the second half of the year is unchanged at approximately 105,000 bbls/d, with annual production still trending towards the low end of the guidance range and non-energy operating costs and G&A expense still trending towards the high end of their respective ranges.

The Corporation has capacity to ship 100,000 bbls/d of AWB blend sales, on a pre-apportionment basis, to the USGC market via its committed FSP capacity. In addition, 20,000 bbls/d of capacity is contracted on the TMX pipeline system to Canada's West Coast. TMX is scheduled to come into service at the end of the first quarter of 2024, which will further broaden MEG's market access.

Summary of 2023 Guidance	
Capital expenditures	$450 million
Bitumen production - annual average[(1)]	100,000 - 105,000 bbls/d
Non-energy operating costs	$4.75 - $5.05 per bbl
G&A expense	$1.70 - $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 bbls/d.*

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	Nine months ended September 30		2023			2022				2021
	2023	2022	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Crude oil prices										
Brent (US$/bbl)	**82.06**	102.16	**85.95**	78.01	82.21	88.59	97.69	111.57	97.23	79.78
WTI (US$/bbl)	**77.39**	98.09	**82.26**	73.78	76.13	82.65	91.55	108.41	94.29	77.19
Differential – WTI:WCS – Edmonton (US$/bbl)	**(17.65)**	(15.73)	**(12.91)**	(15.16)	(24.88)	(25.89)	(19.86)	(12.80)	(14.53)	(14.64)
Differential – WTI:AWB – Edmonton (US$/bbl)	**(19.79)**	(17.80)	**(14.38)**	(17.37)	(27.63)	(29.14)	(22.80)	(14.25)	(16.35)	(16.40)
AWB – Edmonton (US$/bbl)	**57.60**	80.29	**67.88**	56.41	48.50	53.51	68.75	94.16	77.94	60.79
Differential – WTI:AWB – U.S. Gulf Coast (US$/bbl)	**(9.14)**	(7.38)	**(4.94)**	(7.62)	(14.87)	(16.35)	(10.15)	(6.15)	(5.85)	(6.40)
AWB – U.S. Gulf Coast (US$/bbl)	**68.25**	90.71	**77.32**	66.16	61.26	66.30	81.40	102.26	88.44	70.79
Enbridge Mainline heavy crude apportionment %	**4**	4	**1**	1	12	5	3	0	10	21
Condensate prices										
Condensate at Edmonton (C$/bbl)	**103.24**	124.70	**104.62**	97.19	107.91	113.17	113.97	138.39	121.74	99.70
Condensate at Edmonton as % of WTI	**99.2**	99.1	**94.8**	98.1	104.8	100.9	95.3	100.0	102.0	102.5
Condensate at Mont Belvieu, Texas (US$/bbl)	**64.52**	85.30	**64.90**	60.54	68.13	64.57	72.25	90.98	92.68	76.62
Condensate at Mont Belvieu, Texas as a % of WTI	**83.4**	87.0	**78.9**	82.1	89.5	78.1	78.9	83.9	98.3	99.3
Natural gas prices										
AECO (C$/mcf)	**3.00**	5.86	**2.83**	2.67	3.51	5.57	4.54	7.89	5.16	5.07
Electric power prices										
Alberta power pool (C$/MWh)	**150.89**	144.95	**151.18**	159.87	141.63	213.66	221.90	122.49	90.47	107.25
Foreign exchange rates										
C$ equivalent of 1 US$ – average	**1.3453**	1.2829	**1.3410**	1.3430	1.3520	1.3577	1.3059	1.2766	1.2661	1.2600
C$ equivalent of 1 US$ – period end	**1.3537**	1.3700	**1.3537**	1.3238	1.3528	1.3534	1.3700	1.2872	1.2484	1.2656

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 the third quarter of 2022, crude oil prices were weaker in the third quarter of 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 in the first half of 2023 due to growing global recessionary concerns and the perceived negative impact on oil demand before strengthening again in the third quarter of 2023 driven by the tight supply demand balance resulting from increasing global oil demand and the OPEC+ group's coordinated production cuts.

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.

WTI:AWB differentials at both Edmonton and the USGC narrowed in the second and third quarter of 2023 after widening through late 2022 and early 2023. The narrowing during the second and third quarters of 2023 reflects increased demand for Canadian heavy oil driven by relatively low worldwide heavy sour crude inventories, strong refining margins and rising heavy crude processing capacity in Asia and the Middle East.

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 bbls/d from the USGC at Mont Belvieu, Texas benchmark pricing. Condensate pricing at both Edmonton and Mont Belvieu, as a percentage of WTI, was similar during the three months ended September 30, 2023 and 2022. Condensate pricing at Mont Belvieu during the nine months ended September 30, 2023, however, weakened compared to the same period of 2022 due to lower international demand in the second and third quarters. In general, condensate pricing as a percentage of WTI price 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. AECO natural gas prices decreased 38% and 49% in the three and nine months ended September 30, 2023, respectively, relative to the same periods of 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 32% in the three months ended September 30, 2023, compared to the same period of 2022, reflecting increasing penetration of renewables and substantially lower natural gas prices. The Alberta power pool price strengthened by 4% in the nine months ended September 30, 2023, compared to the same period of 2022, reflecting the pass through of facility operating cost escalation including higher carbon tax costs, increased offer pricing for marginal power generation in Alberta, and elevated export market pricing.

9. OTHER OPERATING RESULTS

General and Administrative

($millions, except as indicated)	Three months ended September 30 2023	Three months ended September 30 2022	Nine months ended September 30 2023	Nine months ended September 30 2022
General and administrative expense	**$ 17**	$ 16	**$ 50**	$ 44
General and administrative expense per barrel of production	**$ 1.73**	$ 1.72	**$ 1.84**	$ 1.84
Bitumen production – bbls/d	**103,726**	101,983	**98,835**	90,126

General and administrative ("G&A") expense during the nine months ended September 30, 2023 increased compared to the same period of 2022 primarily due to higher staff costs.

Depletion and Depreciation

($millions, except as indicated)	Three months ended September 30 2023	Three months ended September 30 2022	Nine months ended September 30 2023	Nine months ended September 30 2022
Depletion and depreciation expense	**$ 146**	$ 136	**$ 406**	$ 347
Depletion and depreciation expense per barrel of production	**$ 15.28**	$ 14.30	**$ 15.01**	$ 14.05
Bitumen production – bbls/d	**103,726**	101,983	**98,835**	90,126

Depletion and depreciation expense rose during the three and nine months ended September 30, 2023, compared to the same periods of 2022, primarily due to increased production and an increase in the per barrel depletion and depreciation rate from higher estimated future development costs.

Commodity Risk Management Gain (Loss)

The Corporation periodically enters 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.

	Three months ended September 30		Nine months ended September 30	
($millions)	2023	2022	2023	2022
Realized:				
Condensate contracts(1)	**$ (7)**	$ —	**$ (5)**	$ —
Natural gas contracts(2)	**(5)**	1	**(12)**	4
Marketing asset optimization contracts(3)	**(2)**	6	**(2)**	5
Realized commodity risk management gain (loss)	**$ (14)**	$ 7	**$ (19)**	$ 9
Unrealized:				
Condensate contracts(1)	**$ 5**	$ 1	**$ 6**	$ 6
Natural gas contracts(2)	**2**	—	**(10)**	3
Marketing asset optimization contracts(3)	**—**	(4)	**—**	—
Unrealized commodity risk management gain (loss)	**$ 7**	$ (3)	**$ (4)**	$ 9
Commodity risk management gain (loss)	**$ (7)**	$ 4	**$ (23)**	$ 18

(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 and condensate prices weakened during the three and nine months ended September 30, 2023 resulting in realized commodity risk management losses. The price of natural gas generally strengthened during the comparative periods of 2022, resulting in realized commodity risk management gains.

Stock-based Compensation

	Three months ended September 30		Nine months ended September 30	
($millions)	2023	2022	2023	2022
Cash-settled expense (recovery)	**$ 6**	$ (8)	**$ 23**	$ 47
Equity-settled expense	**4**	4	**18**	14
Equity price risk management (gain) loss(1)	**—**	10	**(9)**	(35)
Stock-based compensation expense	**$ 10**	$ 6	**$ 32**	$ 26

(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 11 "Risk Management" of this MD&A for further details.*

The Corporation's share price increased during the third quarter of 2023 resulting in a cash-settled expense. A decrease in share price during the third quarter of 2022 generated a cash-settled recovery. The Corporation's share price increased more significantly in the nine months ended September 30, 2022 compared to the same period of 2023 which resulted in a decrease in cash-settled expense year-over-year. In addition, there were fewer units outstanding during the nine months ended September 30, 2023 relative to the same period of 2022. All 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").

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 $35 million equity price risk management gains in the nine months ended September 30, 2023 and 2022, respectively, reflect the increased 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

	Three months ended September 30		Nine months ended September 30	
($millions)	**2023**	**2022**	**2023**	**2022**
Unrealized foreign exchange gain (loss) on:				
Long-term debt	**$ (32)**	$ (121)	**$ (1)**	$ (163)
US$ denominated cash and cash equivalents	**4**	23	**1**	28
Foreign currency risk management contracts	**—**	—	**—**	7
Unrealized net gain (loss) on foreign exchange	**(28)**	(98)	**—**	(128)
Realized gain (loss) on foreign exchange	**—**	(1)	**1**	(3)
Foreign exchange gain (loss), net	**$ (28)**	$ (99)	**$ 1**	$ (131)

C$ equivalent of 1 US$				
Beginning of period	**1.3238**	1.2872	**1.3534**	1.2656
End of period	**1.3537**	1.3700	**1.3537**	1.3700

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 the three months ended September 30, 2023, the Canadian dollar weakened relative to the U.S. dollar by 2% resulting in an unrealized foreign exchange loss of $28 million.

During the three and nine months ended September 30, 2022, the Canadian dollar weakened relative to the U.S. dollar by 6% and 8%, respectively, resulting in unrealized foreign exchange losses of $98 million and $128 million, respectively.

Net Finance Expense

	Three months ended September 30		Nine months ended September 30	
($millions)	**2023**	**2022**	**2023**	**2022**
Interest expense on long-term debt	**$ 27**	$ 35	**$ 84**	$ 125
Interest expense on lease liabilities	**5**	7	**17**	19
Interest income	**—**	(2)	**(4)**	(3)
Net interest expense	**32**	40	**97**	141
Debt extinguishment expense	**2**	12	**8**	24
Accretion on provisions	**3**	3	**9**	7
Net finance expense	**$ 37**	$ 55	**$ 114**	$ 172

Average effective interest rate	**6.4%**	6.6%	**6.4%**	6.7%

Interest expense on long-term debt decreased during the three and nine months ended September 30, 2023, compared to the same periods of 2022, primarily reflecting the US$985 million (approximately $1.3 billion) in debt reduction from April 1, 2022 through September 30, 2023.

Debt extinguishment expense decreased during the three and nine months ended September 30, 2023, compared to the same periods of 2022, reflecting lower debt repurchases in 2023. Refer to Note 14 of the interim consolidated financial statements for further details.

Income Tax

	Three months ended September 30		Nine months ended September 30	
($millions)	**2023**	**2022**	**2023**	**2022**
Earnings (loss) before income taxes	**$ 319**	$ 237	**$ 597**	$ 1,020
Effective tax rate	**22 %**	34 %	**22 %**	27 %
Income tax expense (recovery)	**$ 70**	$ 81	**$ 131**	$ 277

As at September 30, 2023, the Corporation had approximately $5.0 billion of available Canadian tax pools, including $3.4 billion of non-capital losses and $0.4 billion of capital losses, and recognized a deferred income tax liability of $152 million.

The effective tax rate differs 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.

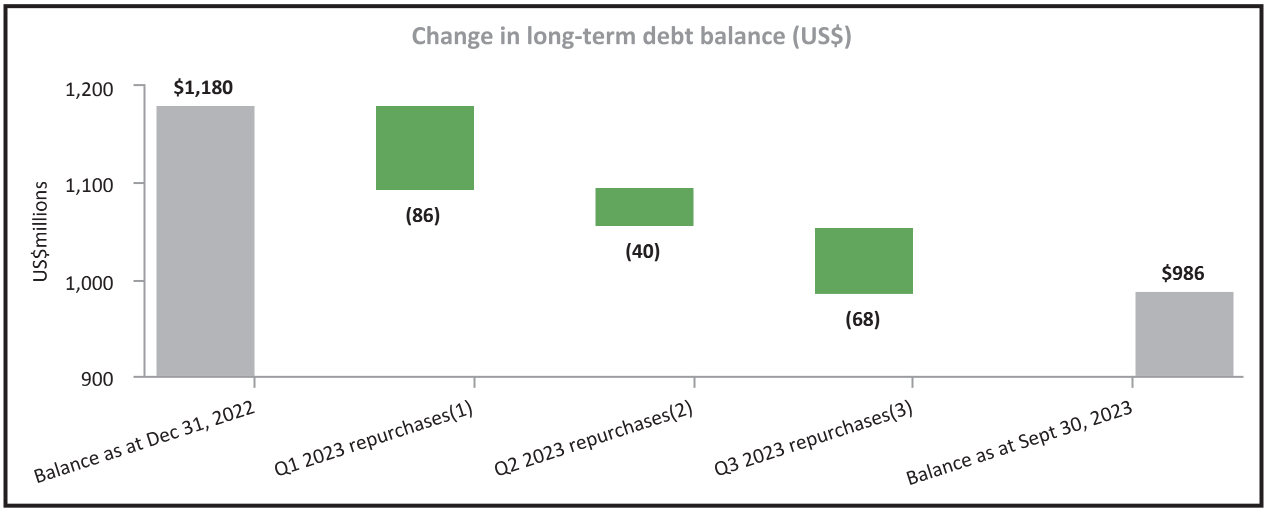
10. LIQUIDITY AND CAPITAL RESOURCES

($millions)	**September 30, 2023**	**December 31, 2022**
Unsecured:		
7.125% senior unsecured notes (Sept 30, 2023 - US$385.6 million; due 2027; December 31, 2022 - US$579.9 million)	**$ 522**	$ 785
5.875% senior unsecured notes (Sept 30, 2023 - US$600 million; due 2029; December 31, 2022 - US$600 million)	**812**	812
Unamortized deferred debt discount and debt issue costs	**(11)**	(16)
Current and long-term debt	**1,323**	1,581
Cash and cash equivalents	**(125)**	(192)
Net debt - C$[1][2]	**$ 1,198**	$ 1,389
Net debt - US$[1][2]	**$ 885**	$ 1,026

(1) Net debt is reconciled to long-term debt in accordance with IFRS in Note 18 of the interim consolidated financial statements.

(2) On April 14, 2023, S&P Global Ratings raised the Corporation's long-term issuer credit rating to BB- with a stable outlook from B+ and affirmed the issue-level rating on the Corporation's senior unsecured notes at BB-. On May 24, 2023 Moody's Investors Service raised the Corporation's long-term issuer rating to Ba3 with a stable outlook from B1 and raised the issue-level rating on the Corporation's senior unsecured notes to B1 from B2. On September 13, 2023, Fitch Ratings raised the Corporation's long-term issuer credit rating to BB- with a stable outlook from B+ and affirmed the issue-level rating on the Corporation's senior unsecured notes at BB-.

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



(1) *Weighted average repurchase price of 102.2% plus accrued and unpaid interest on US$86 million of the Corporation's 7.125% senior unsecured notes due 2027.*

(2) *Weighted average repurchase price of 102.3% plus accrued and unpaid interest on US$40 million of the Corporation's 7.125% senior unsecured notes due 2027.*

(3) *Weighted average repurchase price of 101.7% plus accrued and unpaid interest on US$68 million of the Corporation's 7.125% senior unsecured notes due 2027.*

The Corporation's cash and cash equivalents decreased to $125 million at September 30, 2023 from $192 million at December 31, 2022. Refer to the "Cash Flow Summary" section for further details.

The Corporation's net debt was US$885 million at September 30, 2023 compared to US$1,026 million at December 31, 2022.

At the beginning of 2022, the Corporation started allocating all free cash flow to debt reduction. During the second quarter of 2022, upon reaching net debt of US$1.7 billion, the Corporation initiated the allocation of approximately 25% of free cash flow to share buybacks with the remainder applied to debt reduction. At the end of the third quarter of 2022, net debt declined to US$1.2 billion and free cash flow allocated to share buybacks was raised to approximately 50% with the remainder applied to debt reduction. The current free cash flow allocation strategy will remain in place until net debt reaches US$600 million, which is expected to occur mid-2024 at current oil prices.

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$385.6 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 September 30, 2023, the Corporation had $600 million of unutilized capacity under the revolving credit facility and $138 million of unutilized capacity remained 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

	Three months ended September 30		Nine months ended September 30	
($millions)	**2023**	**2022**	**2023**	**2022**
Net cash provided by (used in):				
Operating activities	**$ 332**	$ 434	**$ 813**	$ 1,362
Investing activities	**(125)**	(89)	**(373)**	(269)
Financing activities	**(152)**	(444)	**(507)**	(1,313)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency	**4**	24	**—**	28
Change in cash and cash equivalents	**$ 59**	$ (75)	**$ (67)**	$ (192)

Cash Flow – Operating Activities

Net cash provided by operating activities during the three months ended September 30, 2023 decreased, compared to the same period of 2022, primarily due to changes in working capital requirements and higher royalties expense partially offset by increased bitumen sales volumes.

Net cash provided by operating activities during the nine months ended September 30, 2023 decreased, compared to the same period of 2022, primarily due to changes in working capital requirements and a lower realized blend sales price partially offset by higher bitumen sales volumes.

Cash Flow – Investing Activities

Net cash used in investing activities increased $36 million and $104 million during the three and nine months ended September 30, 2023, compared to the same periods of 2022, reflecting increased capital spending and changes in working capital requirements.

Cash Flow – Financing Activities

Net cash used in financing activities decreased $292 million during the three months ended September 30, 2023, compared to the same period of 2022, primarily due to decreased debt repayment and lower share buybacks under the Corporation's capital allocation strategy reflecting lower free cash flow.

Net cash used in financing activities decreased $806 million in the nine months ended September 30, 2023, from the same period of 2022 due to lower free cash flow. Decreased debt repayment was partially offset by higher share buybacks in 2023 as the Corporation allocated 50% of free cash flow to share buybacks starting in the fourth quarter of 2022.

11. 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 (loss) and comprehensive income (loss) and in cash operating netback as the contracts are realized.

The Corporation had the following financial commodity risk management contracts relating to condensate purchases and natural gas purchases outstanding at September 30, 2023:

As at September 30, 2023			
Condensate Purchase Contracts	**Volumes (bbls/d)**	**Term**	**Average Price (US$/bbl)**
WTI:Mont Belvieu Fixed Differential	10,000	Oct 1, 2023 - Oct 31, 2023	$(11.44)
Natural Gas Purchase Contracts	**Volumes (GJ/d)**	**Term**	**Average Price (C$/GJ)**
AECO Fixed Price	35,000	Oct 1, 2023 - Dec 31, 2023	$3.88
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 following table summarizes the sensitivity of cash operating netback, adjusted funds flow and earnings (loss) before income tax of fluctuating commodity prices on the Corporation's open financial commodity risk management positions in place at September 30, 2023:

Commodity	Sensitivity Range	Increase	Decrease
Condensate purchase price	± 5% in condensate price as a percentage of WTI	**$ 2**	**$ (2)**
Natural gas purchase price	± C$0.50 per GJ applied to natural gas contracts	**$ 7**	**$ (7)**

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 (loss). The unrealized asset (liability) is included in risk management on the balance sheet and any realized asset outstanding at period-end is included in trade receivables and other 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.

	Three months ended September 30		Nine months ended September 30	
($millions)	**2023**	**2022**	**2023**	**2022**
Unrealized equity price risk management (gain) loss	**$ —**	$ 10	**$ 78**	$ 11
Realized equity price risk management (gain) loss	**—**	—	**(87)**	(46)
Equity price risk management (gain) loss	**$ —**	$ 10	**$ (9)**	$ (35)

(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 September 30, 2023.

12. SHARES OUTSTANDING

At September 30, 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	136
Issued upon vesting and release of equity-settled RSUs and PSUs	2,377
Repurchased for cancellation	(10,304)
Common shares outstanding at September 30, 2023	**283,290**
Convertible securities:	
Stock options[1]	**168**
Equity-settled RSUs and PSUs	**3,717**

(1) All outstanding stock options were exercisable at September 30, 2023.

In the third quarter of 2023, the Corporation repurchased for cancellation 2.3 million common shares under its NCIB program at a weighted average price of $25.40 for a total cost of $58.0 million.

At November 3, 2023, the Corporation had 281.4 million common shares outstanding, 0.2 million stock options outstanding and exercisable and 3.7 million equity-settled RSUs and PSUs outstanding.

13. 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 September 30, 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)	**2023**	**2024**	**2025**	**2026**	**2027**	**Thereafter**	**Total**
Commitments:							
Transportation and storage[1]	$ 109	$ 482	$ 474	$ 453	$ 456	$ 5,554	$ 7,528
Diluent purchases	271	14	—	—	—	—	285
Other operating commitments	5	18	17	17	8	24	89
Variable office lease costs	1	4	4	4	4	17	34
Capital commitments	45	—	—	—	—	—	45
Total Commitments	431	518	495	474	468	5,595	7,981
Other Obligations:							
Lease obligations	10	38	30	28	29	434	569
Current and long-term debt[2]	—	—	—	—	522	812	1,334
Interest on long-term debt[2]	21	85	85	85	52	54	382
Decommissioning obligation[3]	1	4	9	9	9	796	828
Total Commitments and Obligations	**$ 463**	**$ 645**	**$ 619**	**$ 596**	**$ 1,080**	**$ 7,691**	**$ 11,094**

(1) This represents transportation and storage commitments from 2023 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 September 30, 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.

14. 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.

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

	Three months ended September 30		Nine months ended September 30	
($millions)	**2023**	**2022**	**2023**	**2022**
Funds flow from operating activities	**$ 492**	$ 501	**$ 1,118**	$ 1,500
Adjustments:				
Impact of cash-settled SBC units subject to equity price risk management	**—**	(5)	**13**	79
Realized equity price risk management gain	**—**	—	**(87)**	(46)
Adjusted funds flow	**492**	496	**1,044**	1,533
Capital expenditures	**(83)**	(78)	**(345)**	(270)
Free cash flow	**$ 409**	$ 418	**$ 699**	$ 1,263

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	**September 30, 2023**	**December 31, 2022**
Long-term debt	**$ 1,323**	$ 1,578
Current portion of long-term debt	**—**	3
Cash and cash equivalents	**(125)**	(192)
Net debt - C$	**$ 1,198**	$ 1,389
Net debt - US$	**$ 885**	$ 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 (loss) and comprehensive income (loss) 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:

($millions)	Three months ended September 30 2023	Three months ended September 30 2022	Nine months ended September 30 2023	Nine months ended September 30 2022
Revenues	**$ 1,438**	$ 1,571	**$ 4,209**	$ 4,673
Diluent expense	**(359)**	(411)	**(1,220)**	(1,343)
Transportation and storage expense	**(157)**	(138)	**(452)**	(387)
Purchased product	**(279)**	(383)	**(1,066)**	(919)
Operating expenses	**(80)**	(94)	**(252)**	(305)
Realized gain (loss) on commodity risk management	**(14)**	7	**(19)**	9
Cash operating netback	**$ 549**	$ 552	**$ 1,200**	$ 1,728

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 (loss) and comprehensive income (loss), 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 September 30				Nine months ended September 30			
	2023		2022		2023		2022	
($millions, except as indicated)		$/bbl		$/bbl		$/bbl		$/bbl
Revenues	**$ 1,438**		$ 1,571		**$ 4,209**		$ 4,673	
Power and transportation revenue	**(33)**		(47)		**(98)**		(93)	
Royalties	**181**		66		**270**		171	
Petroleum revenue	**1,586**		1,590		**4,381**		4,751	
Purchased product	**(279)**		(383)		**(1,066)**		(919)	
Blend sales	**1,307**	**$ 101.53**	1,207	$ 99.96	**3,315**	**$ 88.18**	3,832	$ 109.94
Diluent expense	**(359)**	**(0.06)**	(411)	(9.63)	**(1,220)**	**(9.20)**	(1,343)	(8.26)
Bitumen realization	**$ 948**	**$ 101.47**	$ 796	$ 90.33	**$ 2,095**	**$ 78.98**	$ 2,489	$ 101.68

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 (loss) and comprehensive income (loss).

Power and transportation revenue is an IFRS measure in the Corporation's consolidated statement of earnings (loss) and comprehensive income (loss), 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 September 30				Nine months ended September 30			
	2023		2022		2023		2022	
($millions, except as indicated)		**$/bbl**		**$/bbl**		**$/bbl**		**$/bbl**
Transportation and storage expense	**$ (157)**	**$ (16.83)**	$ (138)	$ (15.70)	**$ (452)**	**$ (17.04)**	$ (387)	$ (15.80)
Power and transportation revenue	**$ 33**		$ 47		**$ 98**		$ 93	
Less power revenue	**(32)**		(46)		**(95)**		(90)	
Transportation revenue	**$ 1**	**$ 0.11**	$ 1	$ 0.12	**$ 3**	**$ 0.10**	$ 3	$ 0.14
Net transportation and storage expense	**$ (156)**	**$ (16.72)**	$ (137)	$ (15.58)	**$ (449)**	**$ (16.94)**	$ (384)	$ (15.66)

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 bitumen sales price after net transportation and storage expense by utilizing its network of pipeline and storage facilities to optimize market access.

	Three months ended September 30				Nine months ended September 30			
	2023		2022		2023		2022	
($millions, except as indicated)		**$/bbl**		**$/bbl**		**$/bbl**		**$/bbl**
Bitumen realization[1]	**$ 948**	**$101.47**	$ 796	$ 90.33	**$ 2,095**	**$ 78.98**	$ 2,489	$101.68
Net transportation and storage expense[1]	**(156)**	**(16.72)**	(137)	(15.58)	**(449)**	**(16.94)**	(384)	(15.66)
Bitumen realization after net transportation and storage expense	**$ 792**	**$ 84.75**	$ 659	$ 74.75	**$ 1,646**	**$ 62.04**	$ 2,105	$ 86.02

(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 (loss) and comprehensive income (loss). Power and transportation revenue is an IFRS measure in the Corporation's consolidated statement of earnings (loss) and comprehensive income (loss) 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 September 30				**Nine months ended September 30**			
	2023		**2022**		**2023**		**2022**	
($millions, except as indicated)		**$/bbl**		**$/bbl**		**$/bbl**		**$/bbl**
Non-energy operating costs	**$ (48)**	**$ (5.15)**	$ (40)	$ (4.49)	**$ (137)**	**$ (5.16)**	$ (120)	$ (4.90)
Energy operating costs	**(32)**	**(3.42)**	(54)	(6.12)	**(115)**	**(4.34)**	(185)	(7.53)
Operating expenses	**$ (80)**	**$ (8.57)**	$ (94)	$ (10.61)	**$ (252)**	**$ (9.50)**	$ (305)	$ (12.43)
Power and transportation revenue	**$ 33**		$ 47		**$ 98**		$ 93	
Less transportation revenue	**(1)**		(1)		**(3)**		(3)	
Power revenue	**$ 32**	**$ 3.46**	$ 46	$ 5.16	**$ 95**	**$ 3.59**	$ 90	$ 3.64
Operating expenses net of power revenue	**$ (48)**	**$ (5.11)**	$ (48)	$ (5.45)	**$ (157)**	**$ (5.91)**	$ (215)	$ (8.79)
Energy operating costs net of power revenue	**$ —**	**$ 0.04**	$ (8)	$ (0.96)	**$ (20)**	**$ (0.75)**	$ (95)	$ (3.89)

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 September 30		**Nine months ended September 30**	
($millions)	**2023**	**2022**	**2023**	**2022**
Bitumen realization	**$ 948**	$ 796	**$ 2,095**	$ 2,489
Transportation and storage expense	**(157)**	(138)	**(452)**	(387)
Transportation revenue	**1**	1	**3**	3
Bitumen realization after net transportation and storage expense	**$ 792**	$ 659	**$ 1,646**	$ 2,105
Royalties	**$ 181**	$ 66	**$ 270**	$ 171
Effective royalty rate	**22.9 %**	10.0 %	**16.4 %**	8.1 %

15. 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 significant accounting policies and the significant accounting estimates, assumptions and judgments can be found in the Corporation's annual consolidated financial statements for the year ended December 31, 2022.

16. 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.

17. 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.

18. 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 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, will 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.

19. 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
AWB	Access Western Blend
$ or C$	Canadian dollars
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
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
PSU	Performance share units
RSU	Restricted share units
SAGD	Steam-Assisted Gravity Drainage
SOR	Steam-oil ratio
SBC	Stock-based compensation
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

20. 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; 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 bbls/d at a current steam oil-oil ratio of 2.2 prior to any impact from scheduled maintenance activity or outages; the Corporation's statement that the typical average production decline rate at the Christina Lake Project is approximately 10% to 15%; the Corporation's statement that, at an annual production level of 103,700 bbl/d, MEG has a 2P reserves life index of greater than 50 years; 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 marketing strategy and marketing asset optimization strategy; the Corporation's expectations regarding the Pathways Alliance projects and government support of these projects; 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 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 2023 guidance, including its second-half 2023 production, full year production, non-energy operating costs, G&A expense, capital expenditures and transportation costs and all statements relating to the Corporation's effective royalty rate; the Corporation's expectation that TMX will come into service at the end of the first quarter of 2024; the Corporation's expectations regarding global crude oil prices and global crude oil demand and supply balances; the Corporation's expectation of allocating 50% of free cash flow to share buybacks with the remaining cash flow applied to ongoing debt reduction until it reaches a net debt floor of US$600 million, which is expected to occur in mid-2024 at current oil prices; the Corporation's continued focus on debt reduction 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 2023 and 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; the impact of the Corporation's response to the COVID-19 global pandemic; 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 Corporation’s response to the COVID-19 global pandemic; the severity and duration of the COVID-19 pandemic; the potential for a temporary suspension of operations impacted by an outbreak of COVID-19; actions taken by OPEC+ in relation to supply management; the impact of the Russian invasion of Ukraine and associated sanctions on commodity prices; 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; 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.

21. 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.

22. QUARTERLY SUMMARIES

	2023			2022				2021
Unaudited	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**
FINANCIAL *($millions unless specified)*								
Net earnings (loss)	**249**	136	81	159	156	225	362	177
Per share, diluted	**0.86**	0.47	0.28	0.53	0.51	0.72	1.15	0.57
Funds flow from operating activities	**492**	278	348	383	501	412	587	260
Per share, diluted	**1.71**	0.96	1.19	1.28	1.63	1.31	1.87	0.83
Adjusted funds flow(1)	**492**	278	274	401	496	478	559	274
Per share, diluted(1)	**1.71**	0.96	0.94	1.34	1.61	1.52	1.78	0.88
Capital expenditures	**83**	149	113	106	78	104	88	106
Free cash flow(1)	**409**	129	161	295	418	374	471	168
Working capital	**495**	231	219	289	395	437	465	150
Net debt - C$(1)	**1,198**	1,316	1,381	1,389	1,634	1,782	2,150	2,401
Net debt - US$(1)	**885**	994	1,020	1,026	1,193	1,384	1,722	1,897
Shareholders' equity	**4,641**	4,441	4,370	4,383	4,418	4,339	4,178	3,808
BUSINESS ENVIRONMENT								
Average Benchmark Commodity Prices:								
WTI (US$/bbl)	**82.26**	73.78	76.13	82.65	91.55	108.41	94.29	77.19
Differential – WTI:WCS – Edmonton (US$/bbl)	**(12.91)**	(15.16)	(24.88)	(25.89)	(19.86)	(12.80)	(14.53)	(14.64)
Differential – WTI:AWB – Edmonton (US$/bbl)	**(14.38)**	(17.37)	(27.63)	(29.14)	(22.80)	(14.25)	(16.35)	(16.40)
AWB – Edmonton (US$/bbl)	**67.88**	56.41	48.50	53.51	68.75	94.16	77.94	60.79
Differential – WTI:AWB – U.S. Gulf Coast (US$/bbl)	**(4.94)**	(7.62)	(14.87)	(16.35)	(10.15)	(6.15)	(5.85)	(6.40)
AWB – U.S. Gulf Coast (US$/bbl)	**77.32**	66.16	61.26	66.30	81.40	102.26	88.44	70.79
Enbridge Mainline heavy apportionment	**1 %**	1 %	12 %	5 %	3 %	0 %	10 %	21 %
C$ equivalent of 1US$ – average	**1.3410**	1.3430	1.3520	1.3577	1.3059	1.2766	1.2661	1.2600
Natural gas – AECO ($/mcf)	**2.83**	2.67	3.51	5.57	4.54	7.89	5.16	5.07
OPERATIONAL **($/bbl unless specified)**								
Blend sales, net of purchased product – bbls/d	**140,002**	119,187	154,197	160,163	131,327	105,517	146,382	141,280
Diluent usage – bbls/d	**(38,377)**	(35,656)	(47,717)	(46,581)	(35,568)	(32,426)	(46,196)	(42,386)
Bitumen sales – bbls/d	**101,625**	83,531	106,480	113,582	95,759	73,091	100,186	98,894
Bitumen production – bbls/d	**103,726**	85,974	106,840	110,805	101,983	67,256	101,128	100,698
Steam-oil ratio (SOR)	**2.28**	2.25	2.25	2.22	2.39	2.46	2.43	2.42
Blend sales(2)	**101.53**	87.81	76.07	83.28	99.96	128.20	105.79	82.43
Diluent expense	**(0.06)**	(10.27)	(17.89)	(14.12)	(9.63)	(5.51)	(8.51)	(11.37)
Bitumen realization(2)	**101.47**	77.54	58.18	69.16	90.33	122.69	97.28	71.06
Net transportation and storage expense(2)	**(16.72)**	(19.90)	(14.78)	(14.41)	(15.58)	(19.40)	(12.97)	(11.39)
Bitumen realization after net transportation and storage expense(2)	**84.75**	57.64	43.40	54.75	74.75	103.29	84.31	59.67
Royalties	**(19.45)**	(7.69)	(3.18)	(5.15)	(7.47)	(8.67)	(5.24)	(3.54)
Non-energy operating costs(3)	**(5.15)**	(5.66)	(4.77)	(4.34)	(4.49)	(5.65)	(4.74)	(4.56)
Energy operating costs(3)	**(3.42)**	(3.92)	(5.57)	(6.71)	(6.12)	(10.40)	(6.80)	(6.22)
Power revenue	**3.46**	2.95	4.21	5.22	5.16	3.08	2.56	2.58
Realized gain (loss) on commodity risk management	**(1.55)**	(0.94)	0.23	0.12	0.80	0.10	0.12	(10.06)
Cash operating netback(2)	**58.64**	42.38	34.32	43.89	62.63	81.75	70.21	37.87
Revenues	**1,438**	1,291	1,480	1,445	1,571	1,571	1,531	1,307
Power sales price (C$/MWh)	**156.04**	150.19	162.90	219.81	217.25	117.94	91.50	95.22
Power sales (MW/h)	**97**	71	118	116	98	82	121	117
Average cost of diluent ($/bbl of diluent)	**101.68**	111.85	116.01	117.72	125.91	140.61	124.23	108.96
Average cost of diluent as a % of WTI	**92 %**	113 %	113 %	105 %	105 %	102 %	104 %	112 %
Depletion and depreciation rate per bbl of production	**15.28**	14.88	14.86	15.84	14.30	14.35	13.58	13.63
General and administrative expense per bbl of production	**1.73**	1.85	1.94	1.62	1.72	2.37	1.61	1.58
COMMON SHARES								
Shares outstanding, end of period (000)	**283,290**	285,566	288,614	291,081	301,649	307,271	307,596	306,865
Common share price ($) - close (end of period)	**26.43**	21.00	21.71	18.85	15.46	17.82	17.07	11.70

(1) *Capital management measure - please refer to section 14 "Non-GAAP and Other Financial Measures" of this MD&A.*
(2) *Non-GAAP financial measure - please refer to section 14 "Non-GAAP and Other Financial Measures" of this MD&A.*
(3) *Supplementary financial measure - please refer to section 14 "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 differentials;
- 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, 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.

23. ANNUAL SUMMARIES

	2022	2021	2020	2019	2018[1]	2017[1]	2016[1]
FINANCIAL *($millions unless specified)*							
Net earnings (loss)	902	283	(357)	(62)	(119)	166	(429)
Per share, diluted	2.92	0.91	(1.18)	(0.21)	(0.40)	0.57	(1.90)
Funds flow from operating activities	1,882	753	239	741	169	343	(69)
Per share, diluted	6.09	2.42	0.78	2.46	0.56	1.18	(0.31)
Adjusted funds flow[2]	1,934	826	281	724	175	371	(63)
Per share, diluted[2]	6.26	2.65	0.92	2.41	0.58	1.28	(0.28)
Capital expenditures	376	331	149	198	622	508	140
Free cash flow[2]	1,558	495	132	526	(447)	(137)	(203)
Working capital	289	150	55	123	290	313	96
Net debt - C$[2]	1,389	2,401	2,798	2,917	3,422	4,205	4,897
Net debt - US$[2]	1,026	1,897	2,194	2,250	2,508	3,359	3,647
Shareholders' equity	4,383	3,808	3,506	3,853	3,886	3,964	3,287
BUSINESS ENVIRONMENT							
Average Benchmark Commodity Prices:							
WTI (US$/bbl)	94.23	67.91	39.40	57.03	64.77	50.95	43.33
Differential – WTI:WCS – Edmonton (US$/bbl)	(18.27)	(13.04)	(12.60)	(12.76)	(26.31)	(11.98)	(13.84)
Differential – WTI:AWB – Edmonton (US$/bbl)	(20.64)	(14.71)	(14.32)	(14.95)	(29.99)	(14.09)	(16.40)
AWB – Edmonton (US$/bbl)	73.59	53.20	25.08	42.08	34.78	36.86	26.93
Differential – WTI:AWB – U.S. Gulf Coast (US$/bbl)	(9.62)	(4.60)	(4.77)	(1.77)	(6.68)	(7.61)	(11.53)
AWB - U.S. Gulf Coast (US$/bbl)	84.61	63.31	34.63	55.26	58.09	43.34	31.80
Enbridge Mainline heavy apportionment	5 %	42 %	24 %	43 %	41 %	20 %	12 %
C$ equivalent of 1US$ – average	1.3016	1.2536	1.3413	1.3269	1.2962	1.2980	1.3256
Natural gas – AECO ($/mcf)	5.79	3.95	2.43	1.92	1.62	2.29	2.25
OPERATIONAL **($/bbl unless specified)**							
Blend sales, net of purchased product – bbls/d	135,873	131,659	118,347	134,223	125,368	115,766	116,586
Diluent usage – bbls/d	(40,182)	(39,521)	(35,626)	(40,637)	(38,317)	(35,766)	(36,159)
Bitumen sales – bbls/d	95,691	92,138	82,721	93,586	87,051	80,000	80,427
Bitumen production – bbls/d	95,338	93,733	82,441	93,082	87,731	80,774	81,245
Steam-oil ratio (SOR)	2.36	2.43	2.32	2.22	2.19	2.31	2.29
Blend sales[3]	102.02	72.20	37.65	61.29	53.47	51.39	38.19
Diluent expense	(10.07)	(9.73)	(10.42)	(8.08)	(16.78)	(9.36)	(10.28)
Net transportation and storage expense[3]	(15.29)	(10.93)	(12.92)	(10.84)	(8.42)	(6.89)	(6.46)
Bitumen realization after net transportation & storage expense[3]	76.66	51.54	14.31	42.37	28.27	35.14	21.45
Curtailment	—	—	0.06	(0.37)	—	—	—
Royalties	(6.43)	(2.25)	(0.31)	(1.30)	(1.20)	(0.77)	(0.29)
Non-energy operating costs[4]	(4.73)	(4.24)	(4.38)	(4.61)	(4.62)	(4.62)	(5.62)
Energy operating costs[4]	(7.29)	(4.94)	(3.29)	(2.38)	(1.98)	(2.98)	(3.01)
Power revenue	4.11	2.58	1.49	1.75	1.51	0.76	0.64
Realized gain (loss) on commodity risk management	0.29	(9.32)	11.34	(3.31)	(4.37)	(0.39)	0.08
Cash operating netback[3]	62.61	33.37	19.22	32.15	17.61	27.14	13.25
Revenues	6,118	4,321	2,292	3,931	2,733	2,474	1,866
Power sales price (C$/MWh)	162.33	90.10	47.81	56.70	47.87	21.49	18.74
Power sales (MW/h)	104	115	108	121	114	118	115
Average cost of diluent ($/bbl of diluent)	126.00	94.88	61.86	79.89	91.60	72.32	61.06
Average cost of diluent as a % of WTI	103 %	111 %	117 %	106 %	109 %	109 %	106 %
Depletion and depreciation rate per bbl of production	14.57	13.15	13.60	20.90	14.12	16.13	16.81
General and administrative expense per bbl of production	1.78	1.65	1.62	1.99	2.58	2.94	3.24
COMMON SHARES							
Shares outstanding, end of period (000)	291,081	306,865	302,681	299,508	296,841	294,104	226,467
Common share price ($) - close (end of period)	18.85	11.70	4.45	7.39	7.71	5.14	9.23

(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 14 "Non-GAAP and Other Financial Measures" of this MD&A.*
(3) *Non-GAAP financial measure - please refer to section 14 "Non-GAAP and Other Financial Measures" of this MD&A.*
(4) *Supplementary financial measure - please refer to section 14 "Non-GAAP and Other Financial Measures" of this MD&A.*

Consolidated Balance Sheet
(Unaudited, expressed in millions of Canadian dollars)

As at	Note	September 30, 2023	December 31, 2022
Assets			
Current assets			
Cash and cash equivalents	15	$ **125**	$ 192
Trade receivables and other	3	**663**	488
Inventories		**333**	185
Risk management	17	**—**	78
		1,121	943
Non-current assets			
Property, plant and equipment	4	**5,723**	5,763
Exploration and evaluation assets	5	**127**	126
Other assets	6	**175**	201
Total assets		$ **7,146**	$ 7,033
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities	7	$ **567**	$ 573
Interest payable		**15**	44
Current portion of long-term debt	8	**—**	3
Current portion of provisions and other liabilities	9	**24**	21
Risk management	17	**20**	13
		626	654
Non-current liabilities			
Long-term debt	8	**1,323**	1,578
Provisions and other liabilities	9	**401**	389
Risk management	17	**3**	5
Deferred income tax liability		**152**	24
Total liabilities		**2,505**	2,650
Shareholders' equity			
Share capital	10	**4,996**	5,164
Contributed surplus		**174**	169
Deficit		**(567)**	(988)
Accumulated other comprehensive income		**38**	38
Total shareholders' equity		**4,641**	4,383
Total liabilities and shareholders' equity		$ **7,146**	$ 7,033

Commitments and contingencies (Note 19)
The accompanying notes are an integral part of these Interim Consolidated Financial Statements.

Consolidated Statement of Earnings and Comprehensive Income
(Unaudited, expressed in millions of Canadian dollars, except per share amounts)

		Three months ended September 30		Nine months ended September 30	
	Note	**2023**	**2022**	**2023**	**2022**
Revenues					
Petroleum revenue, net of royalties	12	**$ 1,405**	$ 1,524	**$ 4,111**	$ 4,580
Power and transportation revenue	12	**33**	47	**98**	93
Revenues		**1,438**	1,571	**4,209**	4,673
Expenses					
Diluent expense		**359**	411	**1,220**	1,343
Transportation and storage expense		**157**	138	**452**	387
Operating expenses		**80**	94	**252**	305
Purchased product		**279**	383	**1,066**	919
Depletion and depreciation	4, 6	**146**	136	**406**	347
General and administrative		**17**	16	**50**	44
Stock-based compensation	11	**10**	6	**32**	26
Net finance expense	14	**37**	55	**114**	172
Other income		**(1)**	—	**(2)**	—
Loss (gain) on asset dispositions		**—**	—	**—**	(3)
Commodity risk management loss (gain), net	17	**7**	(4)	**23**	(18)
Foreign exchange (gain) loss, net	13	**28**	99	**(1)**	131
Earnings before income taxes		**319**	237	**597**	1,020
Income tax expense		**70**	81	**131**	277
Net earnings		**249**	156	**466**	743
Other comprehensive income (loss), net of tax					
Items that may be reclassified to profit or loss:					
Foreign currency translation adjustment		**5**	11	**—**	14
Comprehensive income		**$ 254**	$ 167	**$ 466**	$ 757
Net earnings per common share					
Basic	16	**$ 0.87**	$ 0.51	**$ 1.62**	$ 2.42
Diluted	16	**$ 0.86**	$ 0.51	**$ 1.61**	$ 2.38

The accompanying notes are an integral part of these Interim Consolidated Financial Statements.

Consolidated Statement of Changes in Shareholders' Equity
(Unaudited, expressed in millions of Canadian dollars)

	Share Capital	Contributed Surplus	Deficit	Accumulated Other Comprehensive Income	Total Shareholders' Equity
Balance as at December 31, 2022	**$ 5,164**	**$ 169**	**$ (988)**	**$ 38**	**$ 4,383**
Stock-based compensation	**—**	**18**	**—**	**—**	**18**
Stock options exercised	**1**	**—**	**—**	**—**	**1**
RSUs and PSUs vested and released	**13**	**(13)**	**—**	**—**	**—**
Repurchase of shares for cancellation	**(182)**	**—**	**(45)**	**—**	**(227)**
Comprehensive income	**—**	**—**	**466**	**—**	**466**
Balance as at September 30, 2023	**$ 4,996**	**$ 174**	**$ (567)**	**$ 38**	**$ 4,641**

	Share Capital	Contributed Surplus	Deficit	Accumulated Other Comprehensive Income	Total Shareholders' Equity
Balance as at December 31, 2021	$ 5,486	$ 172	$ (1,875)	$ 25	$ 3,808
Stock-based compensation	—	15	—	—	15
Stock options exercised	34	(10)	—	—	24
RSUs vested and released	11	(11)	—	—	—
Repurchase of shares for cancellation	(179)	7	(14)	—	(186)
Comprehensive income	—	—	743	14	757
Balance as at September 30, 2022	$ 5,352	$ 173	$ (1,146)	$ 39	$ 4,418

The accompanying notes are an integral part of these Interim Consolidated Financial Statements.

Consolidated Statement of Cash Flow
(Unaudited, expressed in millions of Canadian dollars)

		Three months ended September 30		Nine months ended September 30	
	Note	**2023**	**2022**	**2023**	**2022**
Cash provided by (used in):					
Operating activities					
Net earnings		**$ 249**	$ 156	**$ 466**	$ 743
Adjustments for:					
Deferred income tax expense		**68**	81	**129**	277
Depletion and depreciation	4, 6	**146**	136	**406**	347
Stock-based compensation	11	**4**	14	**96**	25
Unrealized loss on foreign exchange	13	**28**	98	**—**	128
Unrealized net (gain) loss on commodity risk management	17	**(7)**	3	**4**	(9)
Amortization of debt discount and debt issue costs		**1**	1	**2**	1
Loss (gain) on asset dispositions		**—**	—	**—**	(3)
Debt extinguishment expense	14	**2**	12	**8**	24
Other		**3**	2	**10**	5
Decommissioning expenditures	9	**(2)**	(2)	**(3)**	(3)
Net change in long-term incentive compensation liability		**—**	—	**—**	(35)
Funds flow from operating activities		**492**	501	**1,118**	1,500
Net change in non-cash working capital items	15	**(160)**	(67)	**(305)**	(138)
Net cash provided by (used in) by operating activities		**332**	434	**813**	1,362
Investing activities					
Capital expenditures	4	**(83)**	(78)	**(345)**	(270)
Net proceeds on dispositions		**—**	—	**—**	3
Other		**—**	—	**(1)**	1
Net change in non-cash working capital items	15	**(42)**	(11)	**(27)**	(3)
Net cash provided by (used in) investing activities		**(125)**	(89)	**(373)**	(269)
Financing activities					
Repayment and redemption of long-term debt	8	**(92)**	(349)	**(263)**	(1,121)
Debt redemption premium and refinancing costs	8	**(2)**	(9)	**(6)**	(26)
Repurchase of shares	10	**(58)**	(92)	**(227)**	(186)
Issue of shares, net of issue costs		**1**	—	**1**	24
Receipts on leased assets	15	**—**	—	**1**	2
Payments on leased liabilities	15	**(5)**	(5)	**(13)**	(17)
Net change in non-cash working capital items	15	**4**	11	**—**	11
Net cash provided by (used in) financing activities		**(152)**	(444)	**(507)**	(1,313)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency		**4**	24	**—**	28
Change in cash and cash equivalents		**59**	(75)	**(67)**	(192)
Cash and cash equivalents, beginning of year		**66**	244	**192**	361
Cash and cash equivalents, end of period		**$ 125**	$ 169	**$ 125**	$ 169

The accompanying notes are an integral part of these Interim Consolidated Financial Statements.

All amounts are expressed in millions of Canadian dollars unless otherwise noted.

1. CORPORATE INFORMATION

MEG Energy Corp. (the "Corporation") was incorporated under the *Alberta Business Corporations Act* on March 9, 1999. The Corporation's shares trade on the Toronto Stock Exchange under the symbol "MEG". The Corporation owns a 100% interest in over 410 square miles of mineral leases in the southern Athabasca oil region of Alberta, Canada and is primarily engaged in sustainable *in situ* thermal oil production at its Christina Lake Project.

The corporate office is located at 600 – 3rd Avenue SW, Calgary, Alberta, Canada.

2. BASIS OF PRESENTATION

The unaudited interim consolidated financial statements ("interim consolidated financial statements") were prepared using the same accounting policies and methods as those used in the Corporation's audited consolidated financial statements for the year ended December 31, 2022. The interim consolidated financial statements are in compliance with International Accounting Standard 34, Interim Financial Reporting ("IAS 34"). Accordingly, certain information and footnote disclosure normally included in annual financial statements prepared in accordance with International Financial Reporting Standards (“IFRS”), as issued by the International Accounting Standards Board ("IASB"), has been omitted or condensed. The preparation of interim consolidated financial statements in accordance with IAS 34 requires the use of certain critical accounting estimates. It also requires management to exercise judgment in applying the Corporation's accounting policies. The areas involving a higher degree of judgment or complexity, or areas where assumptions and estimates are significant to the consolidated financial statements, have been set out in Note 4 of the Corporation's audited consolidated financial statements for the year ended December 31, 2022. These interim consolidated financial statements should be read in conjunction with the Corporation's audited consolidated financial statements for the year ended December 31, 2022.

These interim consolidated financial statements are presented in Canadian dollars ($ or C$), which is the Corporation's functional currency and were approved by the Corporation's Audit Committee on November 6, 2023.

3. TRADE RECEIVABLES AND OTHER

As at	September 30, 2023	December 31, 2022
Trade receivables	**$ 646**	$ 473
Deposits and advances	**15**	13
Current portion of sublease receivable	**2**	2
	$ 663	$ 488

4. PROPERTY, PLANT AND EQUIPMENT

	Crude oil	Transportation and storage	Right-of-use assets	Corporate assets	Total
Cost					
Balance as at December 31, 2022	$ 9,883	$ 29	$ 277	$ 79	$ 10,268
Additions	345	—	—	—	345
Change in decommissioning liabilities	20	—	—	—	20
Balance as at September 30, 2023	**$ 10,248**	**$ 29**	**$ 277**	**$ 79**	**$ 10,633**
Accumulated depletion and depreciation					
Balance as at December 31, 2022	$ 4,348	$ 29	$ 70	$ 58	$ 4,505
Depletion and depreciation	392	—	11	2	405
Balance as at September 30, 2023	**$ 4,740**	**$ 29**	**$ 81**	**$ 60**	**$ 4,910**
Carrying amounts					
Balance as at December 31, 2022	$ 5,535	$ —	$ 207	$ 21	$ 5,763
Balance as at September 30, 2023	**$ 5,508**	**$ —**	**$ 196**	**$ 19**	**$ 5,723**

At September 30, 2023, property, plant and equipment was assessed for indicators of impairment and none were identified.

5. EXPLORATION AND EVALUATION ASSETS

Exploration and evaluation assets consist of $127 million in exploration projects which are pending the determination of proved or probable reserves (year ended December 31, 2022 – $126 million). These assets were assessed for indicators of impairment and none were identified.

6. OTHER ASSETS

As at	September 30, 2023	December 31, 2022
Non-current pipeline linefill[a]	**$ 154**	$ 178
Finance sublease receivables	**11**	12
Intangible assets[b]	**3**	4
Prepaid transportation costs[c]	**7**	8
Pathways initiative	**2**	1
	177	203
Less current portion, included in trade receivables and other	**(2)**	(2)
	$ 175	$ 201

a. Non-current pipeline linefill on third-party owned pipelines is classified as a non-current asset as these transportation contracts expire between the years 2025 and 2048.

b. At September 30, 2023, intangible assets consist of software that is not an integral component of the related computer hardware. Depreciation of $1 million was recognized for the nine months ended September 30, 2023 (year ended December 31, 2022 – $1 million).

c. Prepaid transportation costs related to upgrading third-party transportation infrastructure have been capitalized and are being amortized to transportation expense over the 30-year term of the agreement.

7. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

As at	September 30, 2023	December 31, 2022
Trade payables and other	$ 539	$ 473
Current liability for cash-settled stock-based compensation	28	100
	$ 567	$ 573

At September 30, 2023, the Corporation recognized a liability of $28 million relating to the fair value of cash-settled DSUs (December 31, 2022 – $100 million related to the fair value of cash settled RSUs, PSUs and DSUs).

8. LONG-TERM DEBT

As at	September 30, 2023	December 31, 2022
Unsecured:		
7.125% senior unsecured notes (Sept 30, 2023 - US$385.6 million; due 2027; December 31, 2022 - US$579.9 million)	$ 522	$ 785
5.875% senior unsecured notes (Sept 30, 2023 - US$600 million; due 2029; December 31, 2022 - US$600 million)	812	812
	1,334	1,597
Unamortized deferred debt discount and debt issue costs	(11)	(16)
	$ 1,323	$ 1,581
Less current portion of 7.125% senior unsecured notes due 2027	—	(3)
	$ 1,323	$ 1,578

The U.S. dollar denominated debt was translated into Canadian dollars at the period end exchange rate of US$1 = C$1.3537 (December 31, 2022 – US$1 = C$1.3534).

During the nine months ended September 30, 2023, the Corporation repurchased and extinguished US$194 million (approximately $263 million) of its 7.125% senior unsecured notes due February 2027 at a weighted average price of 102.1% plus accrued and unpaid interest. For the nine months ended September 30, 2023, the Corporation recognized a cumulative debt redemption premium of $6 million and associated unamortized deferred debt issue costs of $2 million for debt extinguishment expense of $8 million recognized in net finance expense (Note 14).

9. PROVISIONS AND OTHER LIABILITIES

As at	September 30, 2023	December 31, 2022
Lease liabilities[(a)]	$ 232	$ 244
Decommissioning provision[(b)]	193	166
Provisions and other liabilities	425	410
Less current portion	(24)	(21)
Non-current portion	$ 401	$ 389

a. Lease liabilities:

As at	September 30, 2023	December 31, 2022
Balance, beginning of period	**$ 244**	$ 266
Payments	**(29)**	(48)
Interest expense	**17**	24
Foreign exchange impact	**—**	2
Balance, end of period	**232**	244
Less current portion	**(19)**	(17)
Non-current portion	**$ 213**	$ 227

The Corporation's minimum lease payments are as follows:

As at September 30	2023
Within one year	**$ 41**
Later than one year but not later than five years	**122**
Later than five years	**416**
Minimum lease payments	**579**
Amounts representing finance charges	**(347)**
Net minimum lease payments	**$ 232**

In addition, the Corporation has short-term leases with lease terms of twelve months or less as well as low-value leases. As these lease costs are incurred they are recognized as either general and administrative expense or operating expense depending on their nature. At September 30, 2023, the present value of these arrangements is $1 million (December 31, 2022 - $1 million), using the Corporation's estimated incremental borrowing rate.

b. Decommissioning provision:

The following table presents the decommissioning provision associated with the reclamation and abandonment of the Corporation’s property, plant and equipment and exploration and evaluation assets:

As at	September 30, 2023	December 31, 2022
Balance, beginning of period	**$ 166**	$ 135
Changes in estimated life and estimated future cash flows	**5**	32
Changes in discount rates	**16**	(5)
Liabilities settled	**(3)**	(5)
Accretion	**9**	9
Balance, end of period	**193**	166
Less current portion	**(5)**	(4)
Non-current portion	**$ 188**	$ 162

The decommissioning provision represents the present value of the estimated future costs for the reclamation and abandonment of the Corporation's property, plant and equipment and exploration and evaluation assets. The total undiscounted amount of the estimated future cash flows to settle the decommissioning obligations is $827 million (December 31, 2022 – $830 million). At September 30, 2023, the Corporation has estimated the net present value of the decommissioning obligations using a weighted average credit-adjusted risk-free rate of 8.4% (December 31, 2022 – 9.5%) and an inflation rate of 2.1% (December 31, 2022 - 2.1%). The decommissioning provision is estimated to be settled in periods up to the year 2066 (December 31, 2022 - periods up to the year 2066).

10. SHARE CAPITAL

Common shares are classified as equity. Transaction costs directly attributable to the issuance of shares are recognized as a reduction of shareholders' equity, net of any related income tax. When the Corporation repurchases its own common shares, share capital is reduced by the average carrying value of the shares repurchased. If the average carrying value of the shares exceeds the purchase price, the difference will be recognized as contributed surplus. If the purchase price exceeds the average carrying value of the shares, any previous contributed surplus related to such transactions is reversed. To the extent there is none, the difference is recognized as a reduction to retained earnings.

The Corporation is authorized to issue an unlimited number of common shares without nominal or par value and an unlimited number of preferred shares.

Changes in issued common shares are as follows:

	Nine months ended September 30, 2023		Year ended December 31, 2022	
	Number of shares (thousands)	**Amount**	**Number of shares (thousands)**	**Amount**
Balance, beginning of year	**291,081**	**$ 5,164**	306,865	$ 5,486
Issued upon exercise of stock options	**136**	**1**	2,003	34
Issued upon vesting and release of equity-settled RSUs and PSUs	**2,377**	**13**	2,867	11
Repurchase of shares for cancellation	**(10,304)**	**(182)**	(20,654)	(367)
Balance, end of period	**283,290**	**$ 4,996**	291,081	$ 5,164

On March 8, 2023, the Toronto Stock Exchange ("TSX") approved the renewal of the Corporation's normal course issuer bid ("NCIB"). Pursuant to the NCIB, the Corporation will purchase 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 or such earlier time as the NCIB is completed or terminated at the option of the Corporation.

For the nine months ended September 30, 2023, the Corporation purchased for cancellation 10.3 million common shares under its NCIB at a weighted average price of $22.07 for a total cost of $227 million. Share capital was reduced by the average carrying value of the shares of $17.69 per share. Retained earnings was reduced by $45 million for shares purchased above carrying value.

During 2023, the Corporation issued approximately 2.4 million common shares upon vesting and release of restricted share units ("RSUs") and performance share units ("PSUs").

11. STOCK-BASED COMPENSATION

	Three months ended September 30		Nine months ended September 30	
	2023	**2022**	**2023**	**2022**
Cash-settled expense(i)	**$ 6**	$ (8)	**$ 23**	$ 47
Equity-settled expense	**4**	4	**18**	14
Realized equity price risk management (gain) loss(ii)	**—**	—	**(87)**	(46)
Unrealized equity price risk management (gain) loss(ii)	**—**	10	**78**	11
Stock-based compensation	**$ 10**	$ 6	**$ 32**	$ 26

(i) Cash-settled RSUs, PSUs and DSUs are accounted for as liability instruments and are measured at fair value based on the market value of the Corporation's common shares at each period end and certain estimates including a performance multiplier for PSUs. Fluctuations in the fair value are recognized during the period in which they occur.

(ii) Relates to financial equity price risk management contracts entered to manage the Corporation's exposure to cash-settled RSUs and PSUs vesting between 2021 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 as at March 31, 2023. See note 17(d) for further details.

A $23 million cash-settled expense was recognized during the nine months ended September 30, 2023 due to the increase in the Corporation's share price, and associated increase in value of cash-settled RSUs, PSUs and deferred share units ("DSUs") compared to December 31, 2022. As at September 30, 2023, the Corporation recognized a liability of $28 million relating to the fair value of cash-settled DSUs (December 31, 2022 – $100 million related to the fair value of cash settled RSUs, PSUs and DSUs).

All 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 DSUs.

12. REVENUES

	Three months ended September 30		Nine months ended September 30	
	2023	**2022**	**2023**	**2022**
Sales from:				
Production	**$ 1,301**	$ 1,204	**$ 3,286**	$ 3,821
Purchased product(i)	**285**	386	**1,095**	930
Petroleum revenue	**$ 1,586**	$ 1,590	**$ 4,381**	$ 4,751
Royalties	**(181)**	(66)	**(270)**	(171)
Petroleum revenue, net of royalties	**$ 1,405**	$ 1,524	**$ 4,111**	$ 4,580
Power revenue	**$ 32**	$ 46	**$ 95**	$ 90
Transportation revenue	**1**	1	**3**	3
Power and transportation revenue	**$ 33**	$ 47	**$ 98**	$ 93
Revenues	**$ 1,438**	$ 1,571	**$ 4,209**	$ 4,673

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

a. Disaggregation of revenue from contracts with customers

The Corporation recognized revenue upon delivery of goods and services in the following geographic regions:

	Three months ended September 30					
	2023			2022		
	Petroleum Revenue			Petroleum Revenue		
	Proprietary	**Third-party**	**Total**	**Proprietary**	**Third-party**	**Total**
Country:						
Canada	**$ 319**	**$ 63**	**$ 382**	$ 369	$ 38	$ 407
United States	**982**	**222**	**1,204**	835	348	1,183
	$ 1,301	**$ 285**	**$ 1,586**	$ 1,204	$ 386	$ 1,590

	Nine months ended September 30					
	2023			2022		
	Petroleum Revenue			Petroleum Revenue		
	Proprietary	**Third-party**	**Total**	**Proprietary**	**Third-party**	**Total**
Country:						
Canada	**$ 860**	**$ 207**	**$ 1,067**	$ 1,135	$ 124	$ 1,259
United States	**2,426**	**888**	**3,314**	2,686	806	3,492
	$ 3,286	**$ 1,095**	**$ 4,381**	$ 3,821	$ 930	$ 4,751

For the three and nine months ended September 30, 2023, power and transportation revenue of $33 million and $98 million was attributed to Canada, respectively (three and nine months ended September 30, 2022 – $47 million and $93 million attributed to Canada).

b. Revenue-related assets

The Corporation has recognized the following revenue-related assets in trade receivables and other:

As at	September 30, 2023	December 31, 2022
Petroleum revenue	**$ 625**	$ 427
Power and transportation revenue	**9**	30
Total revenue-related assets	**$ 634**	$ 457

Revenue-related receivables are typically settled within 30 days. At September 30, 2023 and December 31, 2022, there was no material expected credit loss recorded against revenue-related receivables.

13. FOREIGN EXCHANGE (GAIN) LOSS, NET

	Three months ended September 30		Nine months ended September 30	
	2023	**2022**	**2023**	**2022**
Unrealized foreign exchange (gain) loss on:				
Long-term debt	**$ 32**	$ 121	**$ 1**	$ 163
US$ denominated cash and cash equivalents	**(4)**	(23)	**(1)**	(28)
Foreign currency risk management contracts	**—**	—	**—**	(7)
Unrealized net (gain) loss on foreign exchange	**28**	98	**—**	128
Realized (gain) loss on foreign exchange	**—**	1	**(1)**	3
Foreign exchange (gain) loss, net	**$ 28**	$ 99	**$ (1)**	$ 131
C$ equivalent of 1 US$				
Beginning of period	**1.3238**	1.2872	**1.3534**	1.2656
End of period	**1.3537**	1.3700	**1.3537**	1.3700

14. NET FINANCE EXPENSE

	Three months ended September 30		Nine months ended September 30	
	2023	**2022**	**2023**	**2022**
Interest expense on long-term debt	**$ 27**	$ 35	**$ 84**	$ 125
Interest expense on lease liabilities	**5**	7	**17**	19
Interest income	**—**	(2)	**(4)**	(3)
Net interest expense	**32**	40	**97**	141
Debt extinguishment expense	**2**	12	**8**	24
Accretion on provisions	**3**	3	**9**	7
Net finance expense	**$ 37**	$ 55	**$ 114**	$ 172

For the three months ended September 30, 2023, debt extinguishment expense of $2 million was recognized in association with the repurchase and extinguishment of US$68 million (approximately C$92 million) of the Corporation's 7.125% senior unsecured notes, which included a cumulative debt redemption premium of $1 million and associated unamortized deferred debt issue costs of $1 million. Refer to Note 8 for further details.

For the nine months ended September 30, 2023, debt extinguishment expense of $8 million was recognized in association with the repurchase and extinguishment of US$194 million (approximately $263 million) of the Corporation's 7.125% senior unsecured notes, which included a cumulative debt redemption premium of $6 million and associated unamortized deferred debt issue costs of $2 million. Refer to Note 8 for further details.

For the nine months ended September 30, 2022, debt extinguishment expense of $24 million was recognized in association with the repurchase and extinguishment of US$470 million (approximately $617 million) of the Corporation's 7.125% senior unsecured notes, which included a cumulative debt redemption premium of $17 million and associated unamortized deferred debt issue costs of $7 million. Refer to Note 8 for further details.

15. SUPPLEMENTAL CASH FLOW DISCLOSURES

	Three months ended September 30		Nine months ended September 30	
	2023	**2022**	**2023**	**2022**
Cash provided by (used in):				
Trade receivables and other	**$ (192)**	$ (2)	**$ (174)**	$ (86)
Inventories[a]	**(102)**	61	**(121)**	(22)
Accounts payable and accrued liabilities	**118**	(89)	**(8)**	37
Interest payable	**(22)**	(37)	**(29)**	(59)
	$ (198)	$ (67)	**$ (332)**	$ (130)
Changes in non-cash working capital relating to:				
Operating	**$ (160)**	$ (67)	**$ (305)**	$ (138)
Investing	**(42)**	(11)	**(27)**	(3)
Financing	**4**	11	**—**	11
	$ (198)	$ (67)	**$ (332)**	$ (130)
Cash and cash equivalents:[b]				
Cash	**$ 125**	$ 169	**$ 125**	$ 169
Cash equivalents	**—**	—	**—**	—
	$ 125	$ 169	**$ 125**	$ 169
Cash interest paid	**$ 46**	$ 70	**$ 99**	$ 173

a. Cash provided by (used in) inventories during the nine months ended September 30, 2023 excludes a $24 million reclassification of pipeline linefill from non-current assets to current inventories.

b. As at September 30, 2023, $90 million of the Corporation's total cash and cash equivalents balance was held in U.S. dollars (September 30, 2022 – $167 million). The U.S. dollar cash and cash equivalents balance has been translated into Canadian dollars at the period end exchange rate of US$1 = C$1.3537 (September 30, 2022 – US$1 = C$1.3700).

The following table provides a reconciliation of assets and liabilities to cash flows arising from financing activities:

	Finance sublease receivables	Lease liabilities	Long-term debt
Balance as at December 31, 2022	$ 12	$ 244	$ 1,581
Financing cash flow changes:			
Receipts on leased assets	(1)	—	—
Payments on leased liabilities	—	(13)	—
Repayment and redemption of long-term debt	—	—	(263)
Debt redemption premium and refinancing costs	—	—	(6)
Other cash and non-cash changes:			
Interest payments on lease liabilities	—	(16)	—
Interest expense on lease liabilities	—	17	—
Unrealized (gain) loss on foreign exchange	—	—	1
Debt extinguishment expense	—	—	8
Amortization of deferred debt discount and debt issue costs	—	—	2
Balance as at September 30, 2023	**$ 11**	**$ 232**	**$ 1,323**

(i) Finance sublease receivables, Lease liabilities & Long-term debt all include their respective current portion.

16. NET EARNINGS PER COMMON SHARE

	Three months ended September 30		Nine months ended September 30	
	2023	**2022**	**2023**	**2022**
Net earnings	**$ 249**	$ 156	**$ 466**	$ 743
Weighted average common shares outstanding (millions)[(a)]	**285**	304	**287**	307
Dilutive effect of stock options and equity-settled RSUs and PSUs (millions)	**3**	4	**3**	5
Weighted average common shares outstanding – diluted (millions)	**288**	308	**290**	312
Net earnings per share, basic	**$ 0.87**	$ 0.51	**$ 1.62**	$ 2.42
Net earnings per share, diluted	**$ 0.86**	$ 0.51	**$ 1.61**	$ 2.38

a. Weighted average common shares outstanding for the three and nine months ended September 30, 2023 include 564,221 and 521,846 PSUs vested but not yet released, respectively (three and nine months ended September 30, 2022 -385,858 and 312,717 PSUs vested but not yet released).

17. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The financial instruments recognized on the consolidated balance sheet are comprised of cash and cash equivalents, trade receivables and other, risk management contracts, accounts payable and accrued liabilities, interest payable and long-term debt.

a. Fair values:

The carrying values of cash and cash equivalents, trade receivables and other, accounts payable and accrued liabilities and interest payable included on the consolidated balance sheet approximates the fair values of the respective assets and liabilities due to the short-term nature of those instruments.

The following fair values are based on Level 2 inputs to fair value measurement:

As at	September 30, 2023		December 31, 2022	
	Carrying amount	Fair value	Carrying amount	Fair value
Recurring measurements:				
Financial assets				
Equity price risk management contracts	$ —	$ —	$ 78	$ 78
Financial liabilities				
Long-term debt (Note 8)	$ 1,334	$ 1,287	$ 1,597	$ 1,570
Commodity risk management contracts	$ 23	$ 23	$ 18	$ 18

The estimated fair value of long-term debt is derived using quoted prices in an inactive market from a third-party independent broker. The fair value was determined based on estimates at September 30, 2023 and is expected to fluctuate given the volatility in the debt and commodity price markets.

The fair value of risk management contracts is derived using quoted prices in an active market from a third-party independent broker. Management's assumptions rely on external observable market data including forward prices for commodities and foreign exchange rates. The observable inputs may be adjusted using certain methods, which include extrapolation to the end of the term of the contract.

b. Risk management:

The Corporation's risk management assets and liabilities consist of condensate swaps, natural gas swaps, and equity swaps. The use of financial risk management contracts is governed by a Risk Management Committee that follows guidelines and limits approved by the Board of Directors. The Corporation does not use financial derivatives for speculative purposes. Financial risk management contracts are measured at fair value, with gains and losses on re-measurement included in the consolidated statement of earnings and comprehensive income in the period in which they arise.

The Corporation's financial risk management contracts are subject to master agreements that create a legally enforceable right to offset, by counterparty, the related financial assets and financial liabilities on the Corporation's balance sheet in all circumstances.

The following table provides a summary of the Corporation's unrealized offsetting financial risk management positions:

As at	September 30, 2023			December 31, 2022		
	Asset	Liability	Net	Asset	Liability	Net
Gross amount	$ —	$ (23)	$ (23)	$ 78	$ (18)	$ 60
Amount offset	—	—	—	—	—	—
Net amount	$ —	$ (23)	$ (23)	$ 78	$ (18)	$ 60
Current portion	$ —	$ (20)	$ (20)	$ 78	$ (13)	$ 65
Non-current portion	—	(3)	(3)	—	(5)	(5)
Net amount	$ —	$ (23)	$ (23)	$ 78	$ (18)	$ 60

The following table provides a reconciliation of changes in the fair value of the Corporation's financial risk management assets and liabilities from January 1 to September 30:

As at September 30	2023	2022
Fair value of contracts, beginning of year	$ 60	$ 70
Fair value of contracts realized	(68)	(55)
Change in fair value of contracts	(15)	60
Fair value of contracts, end of period	$ (23)	$ 75

c. Commodity risk management:

The Corporation had the following financial commodity risk management contracts relating to condensate and natural gas purchases outstanding at September 30, 2023:

As at September 30, 2023			
Condensate Purchase Contracts	**Volumes (bbls/d)[(i)]**	**Term**	**Average Price (US$/bbl)**
WTI:Mont Belvieu Fixed Differential	10,000	Oct 1, 2023 - Oct 31, 2023	$(11.44)
Natural Gas Purchase Contracts	**Volumes (GJ/d)[(i)]**	**Term**	**Average Price (C$/GJ)**
AECO Fixed Price	35,000	Oct 1, 2023 - Dec 31, 2023	$3.88
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 following table summarizes the sensitivity of the earnings (loss) before income tax to the impact of fluctuating commodity prices on the Corporation's open financial commodity risk management positions in place at September 30, 2023:

Commodity	Sensitivity Range	Increase	Decrease
Condensate purchase price	± 5% in condensate price as a percentage of WTI	$ 2	$ (2)
Natural gas purchase price	± C$0.50 per GJ applied to natural gas contracts	$ 7	$ (7)

The following table summarizes the financial commodity risk management gains and losses:

	Three months ended September 30		Nine months ended September 30	
	2023	2022	2023	2022
Realized loss (gain) on commodity risk management	$ 14	$ (7)	$ 19	$ (9)
Unrealized loss (gain) on commodity risk management	(7)	3	4	(9)
Commodity risk management (gain) loss, net	$ 7	$ (4)	$ 23	$ (18)

d. Equity price risk management:

In 2020, the Corporation entered financial equity price risk management contracts to increase the predictability of the Corporation's cash flow by managing share price volatility related to the Corporation's stock-based compensation program. Equity price risk is the risk that changes in the Corporation's own share price will impact earnings and cash flows. Earnings and funds flow from operating activities are impacted when outstanding cash-settled RSUs and PSUs, issued under the Corporation's stock-based compensation plans, are revalued each period based on the Corporation's share price and the revaluation is 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. The Corporation entered into equity price risk management contracts in March 2020 to manage its exposure on cash-settled RSUs and PSUs vesting between April 1, 2021 and March 31, 2023. Equity price risk management (gain) loss is recognized in stock-based compensation expense on the statement of earnings (loss), the unrealized asset (liability) is included in risk management on the balance sheet and any realized asset outstanding at period-end is included in trade receivables and other on the balance sheet.

	Three months ended September 30		Nine months ended September 30	
	2023	**2022**	**2023**	**2022**
Realized equity price risk management (gain) loss	**$ —**	$ —	**$ (87)**	$ (46)
Unrealized equity price risk management (gain) loss	**—**	10	**78**	11
Equity price risk management (gain) loss	**$ —**	$ 10	**$ (9)**	$ (35)

(1) *At March 31, 2023, all outstanding cash-settled RSUs and PSUs were fully vested and all related financial equity price risk management contracts were fully realized. DSUs are the only cash-settled units remaining outstanding at September 30, 2023.*

e. Credit risk management:

Credit risk arises from the potential that the Corporation may incur a loss if a counterparty fails to meet its obligations in accordance with agreed terms. The Corporation applies the simplified approach to providing for expected credit losses prescribed by IFRS 9, which permits the use of the lifetime expected loss provision for all trade receivables. The Corporation uses a combination of historical and forward-looking information to determine the appropriate loss allowance provisions. Credit risk exposure is mitigated through credit policies governing the Corporation's credit portfolio and with credit practices that limit transactions according to each counterparty's credit quality. A substantial portion of accounts receivable are with investment grade customers in the energy industry and are subject to normal industry credit risk. The Corporation has experienced no material loss in relation to trade receivables. At September 30, 2023, the Corporation's estimated maximum exposure to credit risk related to trade receivables, deposits and advances was $661 million. All amounts receivable from commodity risk management activities are due from large Canadian banks with strong investment grade credit ratings. Counterparty default risk associated with the Corporation's commodity risk management activities is also partially mitigated through credit exposure limits, frequent assessment of counterparty credit ratings and netting arrangements.

The Corporation's cash balances are used to repay debt, fund capital expenditures and return capital to shareholders. The cash balances are held in high interest savings accounts or are invested in high grade, liquid, short-term instruments such as bankers' acceptances, commercial paper, money market deposits or similar instruments. The cash and cash equivalents balance at September 30, 2023 was $125 million. None of the investments are past their maturity or considered impaired. The Corporation's estimated maximum exposure to credit risk related to its cash and cash equivalents is $125 million.

f. Liquidity risk management:

Liquidity risk is the risk that the Corporation will not be able to meet its financial obligations as they become due. Liquidity risk also includes the risk that the Corporation cannot generate sufficient cash flow from the Christina Lake Project or is unable to raise further capital to meet its obligations under its debt agreements. The lenders are entitled to exercise any and all remedies available under the debt agreements. The Corporation manages its liquidity risk through the active management of cash, debt and revolving credit facilities and by maintaining appropriate access to credit.

Management believes 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 for at least the next 12 months. Meeting current and future obligations through periods of volatility is supported by the Corporation's financial framework and credit risk management policies minimizing exposure related to customer receivables primarily to investment grade customers in the energy industry. However, no assurance can be given that this will be the case or that future sources of capital will not be necessary.

The US$385.6 million of 7.125% senior unsecured notes due February 2027 represents the earliest long-term debt maturity. None of the Corporation’s outstanding long-term debt contains financial maintenance covenants. Additionally, the Corporation's modified covenant-lite $600 million revolving credit facility has no financial maintenance covenant unless drawn in excess of 50%, or $300 million. If drawn in excess of 50%, or $300 million, 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 credit facility plus other debt that is secured on a *pari passu* basis with the credit facility, less cash on hand.

18. CAPITAL MANAGEMENT

The Corporation's capital consists of cash and cash equivalents, debt and shareholders' equity. The Corporation's objective for managing capital is to prioritize balance sheet strength while maintaining flexibility to repay debt, fund capital expenditures, return capital to shareholders or fund future production growth. In the current price environment, management believes 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 for at least the next 12 months. Debt repayment, share buybacks and capital expenditures are anticipated to be funded by the Corporation's adjusted funds flow, cash-on-hand and/or other available liquidity.

On March 8, 2023, the TSX renewed the NCIB which will allow the Corporation to purchase for cancellation, from time to time, as the Corporation considers advisable, up to a maximum of 28,596,214 common shares of MEG. The NCIB became effective March 10, 2023 and will terminate on March 9, 2024 or such earlier time as the NCIB is completed or terminated at the option of the Corporation.

Currently, 50% of free cash flow is allocated to share buybacks with the remainder applied to debt reduction. This allocation will remain in place until net debt reaches US$600 million, which is expected to occur in mid-2024 at current oil prices.

The following table summarizes the Corporation's net debt:

As at	Note	September 30, 2023	December 31, 2022
Long-term debt	8	**$ 1,323**	$ 1,578
Current portion of long-term debt	8	**—**	3
Cash and cash equivalents		**(125)**	(192)
Net debt - C$		**$ 1,198**	$ 1,389
Net debt - US$		**$ 885**	$ 1,026

Net debt is an important measure used by management to analyze leverage and liquidity.

During the nine months ended September 30, 2023, the Corporation repurchased and extinguished US$194 million (approximately $263 million) of the Corporation's 7.125% senior unsecured notes due February 2027 at a weighted average price of 102.1% plus accrued and unpaid interest.

Beginning with the second quarter of 2022, the Corporation began purchasing MEG common shares for cancellation under the Corporation's NCIB program. For the nine months ended September 30, 2023, the Corporation purchased for cancellation 10.3 million common shares, returning $227 million to MEG shareholders.

On June 24, 2022, the Corporation amended and restated its revolving credit facility and its letters of credit facility guaranteed by Export Development Canada ("EDC Facility") and extended the maturity date of each facility by 2.3

years to October 31, 2026. Total credit available under the two facilities was reduced from $1.3 billion to $1.2 billion and is comprised of $600 million under the revolving credit facility and $600 million under the EDC Facility.

The revolving credit facility has a modified covenant-lite structure, meaning it contains no financial maintenance covenant unless the Corporation is drawn under the revolving credit facility in excess of 50% or $300 million. If drawn in excess of 50%, or $300 million, under the revolving credit facility the Corporation is required to maintain a first lien net debt to last twelve month EBITDA ratio of 3.50 or less. The Corporation continues to have no first lien debt outstanding.

The Corporation's earliest maturing long-term debt is represented by US$385.6 million of 7.125% senior unsecured notes due February 2027. At September 30, 2023, the Corporation had $600 million unutilized capacity under the revolving credit facility and had $138 million of unutilized capacity under the $600 million EDC Facility.

The following table summarizes the Corporation's funds flow from operating activities, adjusted funds flow and free cash flow:

	Three months ended September 30		Nine months ended September 30	
	2023	**2022**	**2023**	**2022**
Funds flow from operating activities	**$ 492**	$ 501	**$ 1,118**	$ 1,500
Adjustments:				
Impact of cash-settled SBC units subject to equity price risk management	**—**	(5)	**13**	79
Realized equity price risk management gain	**—**	—	**(87)**	(46)
Adjusted funds flow	**492**	496	**1,044**	1,533
Capital expenditures	**(83)**	(78)	**(345)**	(270)
Free cash flow	**$ 409**	$ 418	**$ 699**	$ 1,263

Management utilizes funds flow from operating activities, adjusted funds flow and free cash flow as measures to analyze operating performance and cash flow generating ability. Funds flow from operating activities, adjusted funds flow and free cash flow impact the level and extent of debt repayment, funding for capital expenditures and returning capital to shareholders. By excluding non-recurring items from cash flows, the funds flow from operating activities and adjusted funds flow measures provide meaningful metrics for management by establishing a clear link between the Corporation's cash flows and the operating netbacks from the Christina Lake Project. Free cash flow provides a meaningful metric to assist management and investors in analyzing corporate performance as a measure of financial liquidity and the capacity of the business to repay debt and return capital to shareholders. Funds flow from operating activities, adjusted funds flow and free cash flow are not intended to represent net cash provided by (used in) operating activities.

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 restricted share units ("RSUs") under its long-term incentive ("LTI") plan when the Corporation's 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 three-year period following the issuance, effectively eliminating cash flow risk associated with share price appreciation over that time period. The significant increase in the Corporation's share price from April 1, 2020 to March 31, 2023 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. Since the actual cash impact of the 2020 cash-settled RSUs was hedged through the equity price risk management contracts, the cash impact over the term of these RSUs has been reduced.

The Corporation's operating performance and cash flow generating ability are not impacted by the April 2020 cash-settled RSUs issued and the associated equity price risk management contracts, therefore the financial statement impacts of the cash-settled stock-based compensation associated with the April 2020 issuance and the equity price risk management contracts have been excluded from Adjusted Funds Flow and Free Cash Flow.

Net debt, adjusted funds flow and free cash flow are not standardized measures and may not be comparable with the calculation of similar measures by other companies.

19. COMMITMENTS AND CONTINGENCIES

a. Commitments

The Corporation's commitments are enforceable and legally binding obligations to make payments in the future for goods and services. These items exclude amounts recorded on the consolidated balance sheet. The Corporation had the following commitments as at September 30, 2023:

	2023	2024	2025	2026	2027	Thereafter	Total
Transportation and storage[(i)]	$ 109	$ 482	$ 474	$ 453	$ 456	$ 5,554	$ 7,528
Diluent purchases	271	14	—	—	—	—	285
Other operating commitments	5	18	17	17	8	24	89
Variable office lease costs	1	4	4	4	4	17	34
Capital commitments	45	—	—	—	—	—	45
Commitments	**$ 431**	**$ 518**	**$ 495**	**$ 474**	**$ 468**	**$ 5,595**	**$ 7,981**

(i) This represents transportation and storage commitments from 2023 to 2048, including the estimated TMX commitment which is not yet in service. Excludes finance leases recognized on the consolidated balance sheet (Note 9(a)).

b. Contingencies

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