MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis ("MD&A") of the financial condition and performance of MEG Energy Corp. ("MEG" or the "Corporation") for the three and nine months ended September 30, 2022 was approved by the Corporation's Audit Committee on November 9, 2022. 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, 2022, the audited annual consolidated financial statements and notes thereto for the year ended December 31, 2021, the 2021 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*
    - *Operating expenses 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 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 had evaluated, as at December 31, 2021, contained approximately 2.0 billion barrels of gross proved plus probable ("2P") bitumen reserves concentrated on leases within 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.sedar.com.

2. OPERATIONAL AND FINANCIAL HIGHLIGHTS

The Corporation generated funds flow from operating activities of $501 million and adjusted funds flow of $496 million in the third quarter of 2022 compared to $212 million and $243 million, respectively, in the third quarter of 2021. These increases were primarily driven by an increase in the WTI benchmark price partially offset by a wider WTI:AWB differential which resulted in an average realized blend sales price of $99.96 per barrel in the third quarter of 2022 compared to $74.54 per barrel in the third quarter of 2021.

Higher bitumen production volumes, which averaged 101,983 barrels per day in the third quarter of 2022 compared to 91,506 barrels per day during the third quarter of 2021, also contributed to increased funds flow from operating activities. Bitumen production reflects strong operational performance following the major planned turnaround that was completed in June 2022.

Capital expenditures were $78 million in the third quarter of 2022 compared to $84 million during the third quarter of 2021. Capital expenditures during the third quarters of 2022 and 2021 were directed towards activities that continue to support strong production performance. The Corporation continues to maintain annual 2022 capital expenditures guidance of $375 million.

Free cash flow during the third quarter of 2022 was $418 million compared to $159 million during the third quarter of 2021.

The Corporation continues to execute on its strategy of allocating free cash flow to ongoing debt reduction and share buybacks. During the third quarter of 2022, the Corporation repurchased US$262 million (approximately $349 million) of outstanding 7.125% senior unsecured notes at a weighted average price of 102.2%. Total debt repurchases year-to-date are US$866 million (approximately $1,121 million). The Corporation also returned $92 million to MEG shareholders during the third quarter of 2022 through 5.6 million shares repurchased for cancellation. The total value of repurchased shares year-to-date is $186 million (10.1 million shares).

As at September 30, 2022, net debt declined to US$1.2 billion resulting in the Corporation increasing the percentage of free cash flow allocated to share buybacks to approximately 50% with the remainder applied to further debt reduction.

The Corporation recognized net earnings of $156 million in the third quarter of 2022 compared to $54 million in the third quarter of 2021. Increased earnings mainly reflect a higher average realized blend sales price partially offset by increases in deferred tax expense, depletion and depreciation expense and an unrealized foreign exchange loss on U.S. dollar denominated debt.

As at September 30, 2022, cash and cash equivalents were $169 million. The Corporation exited the quarter with current and long-term debt totaling $1.8 billion and net debt of approximately $1.6 billion (approximately US$1.2 billion).

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

	Nine months ended September 30		**2022**			**2021**				**2020**
($millions, except as indicated)	**2022**	**2021**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**
Bitumen production - bbls/d	**90,126**	91,386	**101,983**	67,256	101,128	100,698	91,506	91,803	90,842	91,030
Steam-oil ratio	**2.42**	2.44	**2.39**	2.46	2.43	2.42	2.56	2.39	2.37	2.31
Bitumen sales - bbls/d	**89,662**	89,861	**95,759**	73,091	100,186	98,894	92,251	89,980	87,298	95,731
Bitumen realization(1) - $/bbl	**101.68**	59.28	**90.33**	122.69	97.28	71.06	64.91	60.09	52.34	38.64
Operating expenses - $/bbl	**12.43**	8.58	**10.61**	16.05	11.54	10.78	9.23	8.11	8.39	8.43
Operating expenses net of power revenue(1) - $/bbl	**8.79**	6.00	**5.45**	12.97	8.98	8.20	7.17	5.54	5.25	6.98
Non-energy operating costs(2) - $/bbl	**4.90**	4.12	**4.49**	5.65	4.74	4.56	4.46	3.84	4.05	4.70
Cash operating netback(1) - $/bbl	**70.61**	31.71	**62.63**	81.75	70.21	37.87	37.31	31.30	26.03	18.66
General & administrative expense - $/bbl of bitumen production volumes	**1.84**	1.68	**1.72**	2.37	1.61	1.58	1.72	1.56	1.77	1.65
Funds flow from operating activities	**1,500**	493	**501**	412	587	260	212	160	121	81
Per share, diluted	**4.80**	1.59	**1.63**	1.31	1.87	0.83	0.68	0.51	0.39	0.26
Adjusted funds flow(3)	**1,533**	551	**496**	478	559	274	243	184	124	88
Per share, diluted(3)	**4.91**	1.78	**1.61**	1.52	1.78	0.88	0.78	0.59	0.40	0.29
Free cash flow(3)	**1,263**	326	**418**	374	471	168	159	113	54	48
Revenues	**4,673**	3,014	**1,571**	1,571	1,531	1,307	1,091	1,009	914	786
Net earnings (loss)	**743**	105	**156**	225	362	177	54	68	(17)	16
Per share, diluted	**2.38**	0.34	**0.51**	0.72	1.15	0.57	0.17	0.22	(0.06)	0.05
Capital expenditures	**270**	225	**78**	104	88	106	84	71	70	40
Long-term debt, including current portion	**1,803**	2,769	**1,803**	2,026	2,440	2,762	2,769	2,820	2,852	2,912
Net debt(3) - C$	**1,634**	2,559	**1,634**	1,782	2,150	2,401	2,559	2,661	2,798	2,798
Net debt(3) - US$	**1,193**	2,007	**1,193**	1,384	1,722	1,897	2,007	2,145	2,226	2,194

(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

The Corporation continues to participate actively in the Pathways Alliance. On October 4, 2022 the Pathways Alliance announced that it was the successful proponent in the Government of Alberta's Request for Full Project Proposals For Carbon Sequestration Hubs with respect to the Pathways Alliance proposed carbon capture and storage hub near Cold Lake, Alberta. As the successful proponent, the Pathways Alliance will enter into an agreement with the Government of Alberta to further evaluate the proposed Cold Lake hub to define and establish the suitability and capacity of the location as a carbon sequestration hub.

In addition, the Pathways Alliance continues to advance the work necessary to evaluate and construct the proposed carbon capture and storage facilities in the oil sands region of northern Alberta, including: early engagement with Indigenous communities along the proposed CO2 transportation and storage network corridor; conducting engineering studies for phase 1 CO2 capture facilities; completed pre-engineering work on the 400-

kilometre pipeline that will carry captured CO_2 to the storage hub and commencing more detailed engineering work; and conducting environmental field programs to support required regulatory applications.

For further details on the Corporation's approach to ESG matters, please refer to the Corporation's 2021 ESG Report available in the "Sustainability" section of the Corporation's website at www.megenergy.com and the most recently filed AIF on www.sedar.com.

4. NET EARNINGS

	Three months ended September 30		Nine months ended September 30	
($millions, except per share amounts)	**2022**	**2021**	**2022**	**2021**
Net earnings	**$ 156**	$ 54	**$ 743**	$ 105
Per share, diluted	**$ 0.51**	$ 0.17	**$ 2.38**	$ 0.34

The Corporation recognized net earnings of $156 million and $743 million for the three and nine months ended September 30, 2022, respectively, compared to $54 million and $105 million during the same periods of 2021. Increased net earnings during the three and nine months ended September 30, 2022 were primarily due to stronger average realized blend sales prices partially offset by increases in deferred tax expense, depletion and depreciation expense and an unrealized foreign exchange loss on U.S. dollar denominated debt. Net earnings recognized during the three and nine months ended September 30, 2021 were reduced by realized losses on commodity risk management, whereas the Corporation has not entered into significant commodity risk management contracts for 2022.

5. REVENUES

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

	Three months ended September 30		Nine months ended September 30	
($millions)	**2022**	**2021**	**2022**	**2021**
Sales from:				
Production	**$ 1,204**	$ 868	**$ 3,821**	$ 2,376
Purchased product[1]	**386**	225	**930**	610
Petroleum revenue	**$ 1,590**	$ 1,093	**$ 4,751**	$ 2,986
Royalties	**(66)**	(23)	**(171)**	(44)
Petroleum revenue, net of royalties	**$ 1,524**	$ 1,070	**$ 4,580**	$ 2,942
Power revenue	**$ 46**	$ 18	**$ 90**	$ 64
Transportation revenue	**1**	3	**3**	8
Other revenue	**$ 47**	$ 21	**$ 93**	$ 72
Revenues	**$ 1,571**	$ 1,091	**$ 4,673**	$ 3,014

(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, 2022, revenues increased from the same periods of 2021 primarily as a result of the increase in the average blend sales price which was mostly driven by the increase in WTI prices. This was partially offset by a wider WTI:AWB differential and increased royalties as a result of higher benchmark WTI pricing.

6. RESULTS OF OPERATIONS

Bitumen Production and Steam-Oil Ratio

	Three months ended September 30		Nine months ended September 30	
	2022	**2021**	**2022**	**2021**
Bitumen production – bbls/d	**101,983**	91,506	**90,126**	91,386
Steam-oil ratio (SOR)	**2.39**	2.56	**2.42**	2.44

Bitumen Production

Bitumen production increased 11% during the three months ended September 30, 2022 compared to the same period of 2021 reflecting strong operational performance following the major planned turnaround completed in June 2022 and timing of new wells, redrills and workovers.

Bitumen production during the nine months ended September 30, 2022 was impacted by the major planned turnaround as well as an unplanned electrical event at the Christina Lake facility in the second quarter. By June 30, 2022, the Christina Lake facility had returned to full production. The first and third quarters of 2022 reflect strong operational performance driven by capital expenditures aimed at optimal production. In comparison, there were no significant turnaround activities during the nine months ended September 30, 2021, with targeted maintenance having minimal impact on production.

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 Steam-Oil Ratio ("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 for the three and nine months ended September 30, 2022, compared to the same periods of 2021, due to the timing of new production using enhanced completion designs and delivery of our 2022 redrill and field workover program.

Funds Flow from Operating Activities and Adjusted Funds Flow

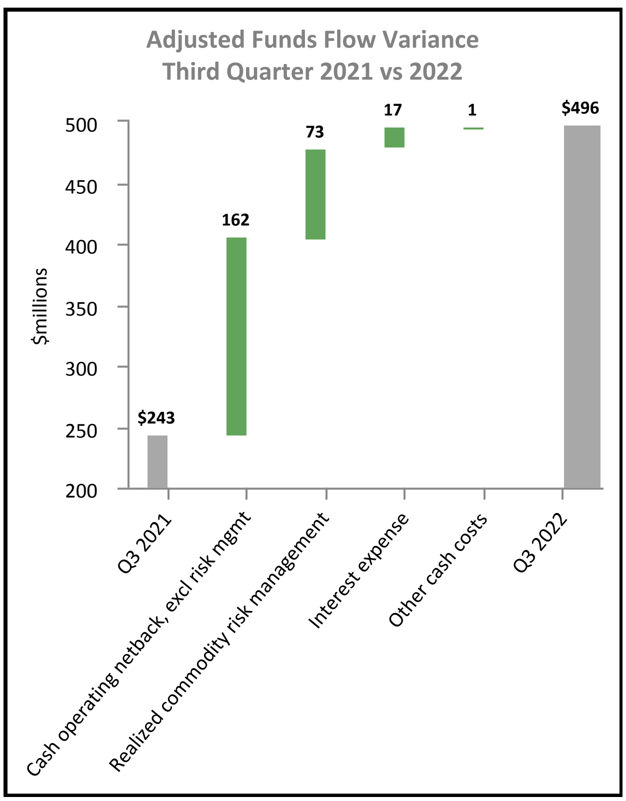
Funds flow from operating activities is an IFRS measure in the Corporation's consolidated statement of cash flow. Adjusted funds flow is calculated as funds flow from operating activities excluding items not considered part of ordinary continuing operating results. Adjusted funds flow is used by management 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 provides a meaningful metric for management by establishing a clear link between the Corporation's cash flows and the cash operating netback.

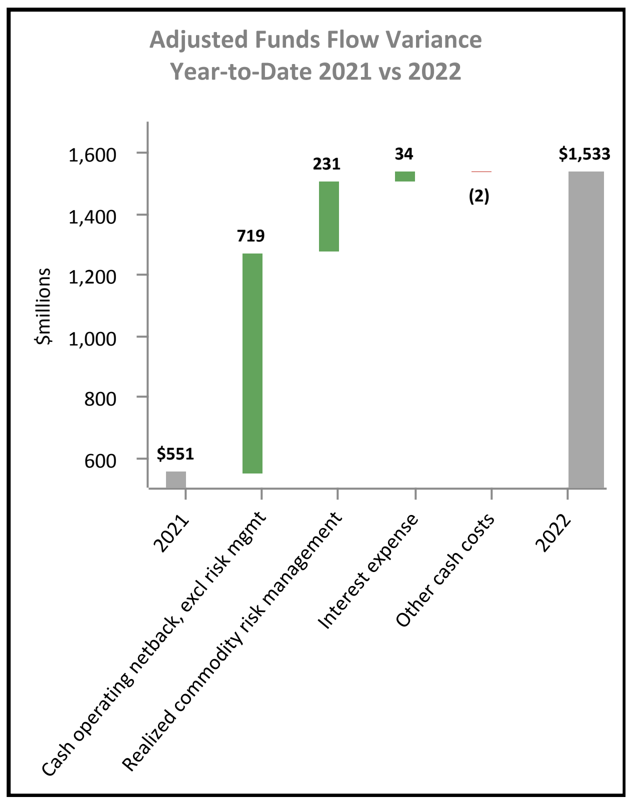
The following table reconciles funds flow from operating activities to adjusted funds flow:

	Three months ended September 30		Nine months ended September 30	
($millions)	**2022**	**2021**	**2022**	**2021**
Funds flow from operating activities	**$ 501**	$ 212	**$ 1,500**	$ 493
Adjustments:				
Impact of cash-settled SBC units subject to equity price risk management[1]	**(5)**	4	**79**	27
Realized equity price risk management gain[1]	**—**	—	**(46)**	(8)
Settlement expense[2]	**—**	21	**—**	21
Payments on onerous contract	**—**	6	**—**	18
Adjusted funds flow	**$ 496**	$ 243	**$ 1,533**	$ 551
Per share, diluted	**$ 1.61**	$ 0.78	**$ 4.91**	$ 1.78

(1) *As of June 30, 2022, the impact of these items have been removed from the capital management measure of Adjusted Funds Flow. All prior period measures have been adjusted to conform to the current period presentation. Please refer to section 14 "Non-GAAP and Other Financial Measures" of this MD&A.*

(2) *During the third quarter of 2021, the Corporation reached an agreement to settle the litigation matter commenced in 2014 relating to legacy issues involving a unit train transloading facility in Alberta. Under the agreement, the Corporation paid the sum of $21 million in full and final settlement of the claim and the claim was discontinued.*





During the three and nine months ended September 30, 2022, funds flow from operating activities and adjusted funds flow increased compared to the same periods of 2021, driven mainly by a higher cash operating netback reflecting stronger WTI benchmark prices and increased blend sales volumes sold in the U.S. Gulf Coast ("USGC") market, partially offset by wider WTI:AWB differentials. Additionally, realized commodity risk management losses in 2021 reduced adjusted funds flow in the 2021 periods. There were no significant commodity risk management contracts in place during 2022.

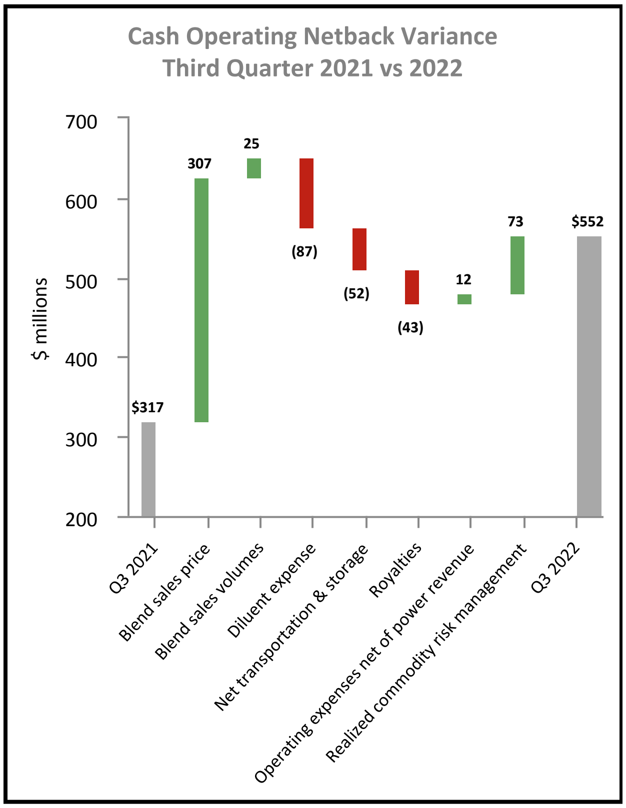
Cash Operating Netback

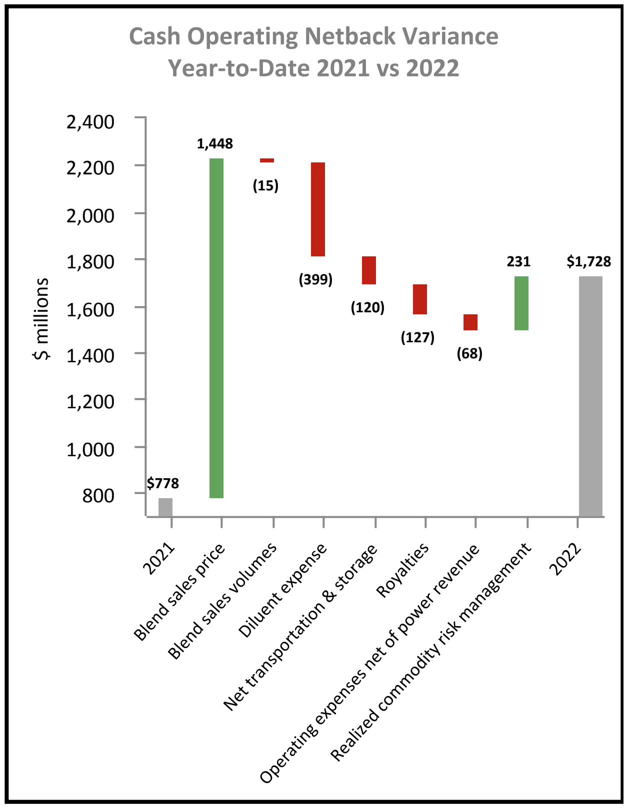
The following table summarizes the Corporation's cash operating netback. Unless otherwise indicated, the per barrel calculation for the periods indicated below are based on bitumen sales volume.

	Three months ended September 30				Nine months ended September 30			
	2022		2021		2022		2021	
($millions, except as indicated)		$/bbl		$/bbl		$/bbl		$/bbl
Sales from production	**$ 1,204**		$ 868		**$ 3,821**		$ 2,376	
Sales from purchased product[1]	**386**		225		**930**		610	
Petroleum revenue	**$ 1,590**		$ 1,093		**$ 4,751**		$ 2,986	
Purchased product[1]	**(383)**		(218)		**(919)**		(587)	
Blend sales[2][3]	**$ 1,207**	**$ 99.96**	$ 875	$ 74.54	**$ 3,832**	**$109.94**	$ 2,399	$ 68.40
Diluent expense	**(411)**	**(9.63)**	(324)	(9.63)	**(1,343)**	**(8.26)**	(944)	(9.12)
Bitumen realization[3]	**$ 796**	**$ 90.33**	$ 551	$ 64.91	**$ 2,489**	**$101.68**	$ 1,455	$ 59.28
Net transportation and storage[3][4]	**(137)**	**(15.58)**	(85)	(10.03)	**(384)**	**(15.66)**	(264)	(10.76)
Royalties	**(66)**	**(7.47)**	(23)	(2.67)	**(171)**	**(6.98)**	(44)	(1.77)
Operating expenses net of power revenue[3]	**(48)**	**(5.45)**	(60)	(7.17)	**(215)**	**(8.79)**	(147)	(6.00)
Realized gain (loss) on commodity risk management	**7**	**0.80**	(66)	(7.73)	**9**	**0.36**	(222)	(9.04)
Cash operating netback[3]	**$ 552**	**$ 62.63**	$ 317	$ 37.31	**$ 1,728**	**$ 70.61**	$ 778	$ 31.71
Bitumen sales volumes - bbls/d		**95,759**		92,251		**89,662**		89,861

(1) *Sales and purchases of oil products 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 includes costs associated with moving and storing AWB to optimize the timing of delivery, net of third-party recoveries on diluent transportation arrangements.*

Included in blend sales is the purchase and sale of third-party products related to marketing asset optimization activities. These transactions are undertaken to recover fixed costs related to underutilized 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 the counterparty or through financial price risk management.





Bitumen Realization

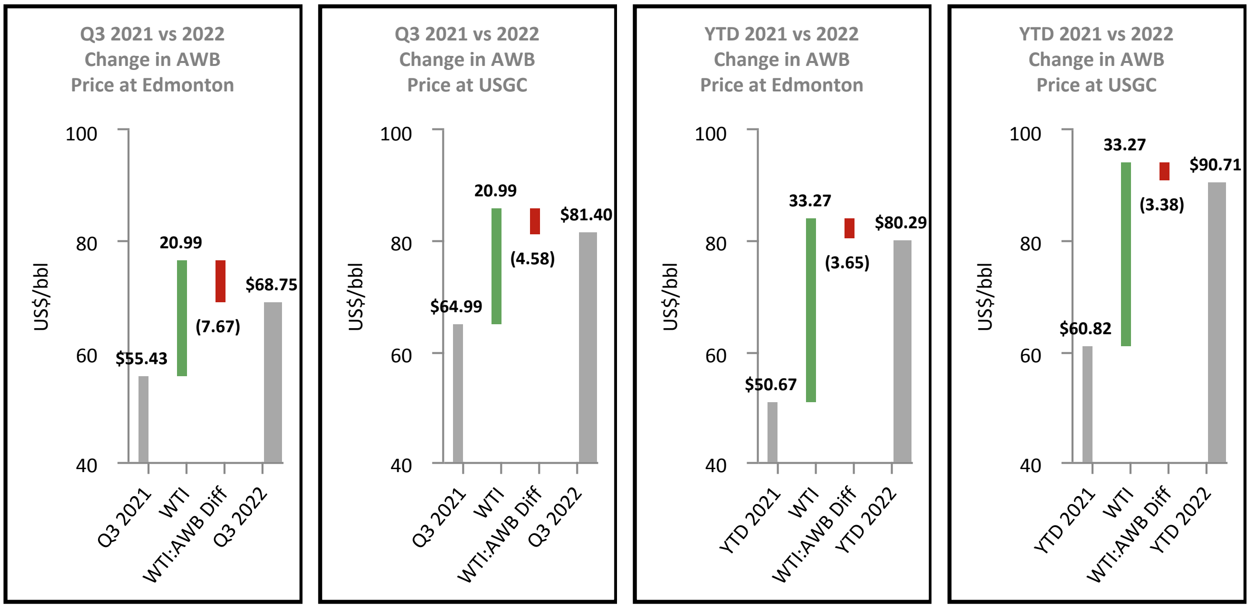
Bitumen realization represents the Corporation's blend sales less diluent expense, expressed on a per barrel of bitumen sold basis. Blend sales represents the Corporation's revenue from its oil blend known as AWB, which is comprised of bitumen produced at the Christina Lake Project blended with purchased diluent. Also included in blend sales are net profits from third-party purchases and sales associated with asset optimization activities. Diluent expense is impacted by Canadian and U.S. benchmark pricing, the amount of diluent required which is impacted by seasonal temperatures and pipeline specifications, 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. The cost of diluent purchased is partially offset by the sales of such diluent in blend volumes. Bitumen realization per barrel fluctuates primarily based on average benchmark prices and light:heavy oil differentials.

	Three months ended September 30				Nine months ended September 30			
	2022		2021		2022		2021	
($millions, except as indicated)		$/bbl		$/bbl		$/bbl		$/bbl
Sales from production	**$ 1,204**		$ 868		**$ 3,821**		$ 2,376	
Sales from purchased product[1]	**386**		225		**930**		610	
Petroleum revenue	**$ 1,590**		$ 1,093		**$ 4,751**		$ 2,986	
Purchased product[1]	**(383)**		(218)		**(919)**		(587)	
Blend sales[2][3]	**$ 1,207**	**$ 99.96**	$ 875	$ 74.54	**$ 3,832**	**$109.94**	$ 2,399	$ 68.40
Diluent expense	**(411)**	**(9.63)**	(324)	(9.63)	**(1,343)**	**(8.26)**	(944)	(9.12)
Bitumen realization[3]	**$ 796**	**$ 90.33**	$ 551	$ 64.91	**$ 2,489**	**$101.68**	$ 1,455	$ 59.28

(1) Sales and purchases of oil products 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.

Blend sales increased by $25.42 per barrel and $41.54 per barrel during the three and nine months ended September 30, 2022, respectively, compared to the same periods of 2021 primarily due to the increase in the WTI benchmark price and an increase in blend sales volumes sold in the USGC market, partially offset by a wider WTI:AWB differential.

Change in crude oil benchmark prices at Edmonton and the USGC:



The Corporation increased the proportion of its blend sales volumes sold in the USGC market to 66% and 67% during the three and nine months ended September 30, 2022 from 38% and 40% during the same periods of 2021, respectively. The increased USGC sales volumes are a result of incremental egress out of the Edmonton area following the completion of the Enbridge Line 3 Pipeline Replacement Project in late 2021. As a result, apportionment levels for heavy oil on the Enbridge mainline system averaged 3% and 4%, respectively, during the three and nine months ended September 30, 2022 compared to 53% and 49% during the same periods of 2021.

Diluent expense per barrel represents the cost of diluent that is unrecovered through blend sales. The diluent expense per barrel during the three months ended September 30, 2022 was consistent with the same period of 2021. Diluent expense per barrel during the nine months ended September 30, 2022 was lower than the same period of 2021 as the price of diluent purchases did not increase at the same rate as the price earned on AWB blend sales, particularly on U.S. sourced diluent.

Total diluent expense was $411 million and $1,343 million during the three and nine months ended September 30, 2022, respectively, compared to $324 million and $944 million during the same periods of 2021. This translates to a cost per barrel of diluent during the three and nine months ended September 30, 2022 of $125.91 and $129.42, respectively, compared to $99.69 and $89.67 for the same periods of 2021. The cost per barrel is impacted by the benchmark condensate price, transportation costs to move diluent to the Christina Lake production site and the timing of use of inventory. The cost of diluent recognized is determined on a weighted-average cost basis and diluent volumes are typically held in inventory for 30 to 60 days. Approximately half of the diluent is sourced from each of Edmonton and Mont Belvieu, Texas. Refer to condensate prices within the "BUSINESS ENVIRONMENT" section of this MD&A for further details.

Net Transportation and Storage

The Corporation's marketing strategy focuses on optimizing its realized AWB sales price after transportation and storage expense by utilizing its network of pipeline and storage facilities to maximize market access.

	Three months ended September 30				Nine months ended September 30			
	2022		2021		2022		2021	
($millions, except as indicated)		**$/bbl**		**$/bbl**		**$/bbl**		**$/bbl**
Transportation and storage expense	**$ (138)**	**$ (15.70)**	$ (88)	$ (10.40)	**$ (387)**	**$ (15.80)**	$ (272)	$ (11.10)
Transportation revenue	**1**	**0.12**	3	0.37	**3**	**0.14**	8	0.34
Net transportation and storage	**$ (137)**	**$ (15.58)**	$ (85)	$ (10.03)	**$ (384)**	**$ (15.66)**	$ (264)	$ (10.76)
Bitumen sales volumes - bbls/d		**95,759**		92,251		**89,662**		89,861

During the three and nine months ended September 30, 2022, net transportation and storage expense, on a total and a per barrel basis, increased compared to the same periods of 2021. Due to low apportionment levels in 2022, the Corporation was able to ship more volumes to the USGC market which drove the increase in transportation costs compared to the same periods of 2021.

When expressed on a US$ per barrel of blend sales basis, net transportation and storage per barrel was US$8.71 and US$8.57 during the three and nine months ended September 30, 2022, respectively, compared to US$5.75 and US$6.02 during the same periods of 2021.

The Corporation partially mitigated the cost of unutilized transportation and storage assets through the purchase and sale of non-proprietary product, or asset optimization activities, which added $3 million, or $0.27 per barrel, to blend sales during the three months ended September 30, 2022 compared to $7 million, or $0.60 per barrel, during the same period of 2021. Asset optimization activities added $11 million, or $0.33 per barrel, to blend sales during the nine months ended September 30, 2022 compared to $23 million, or $0.64 per barrel, during the same period of 2021.

Royalties

The Oil Sands Royalty Regulation, 2009, establishes royalty rates that are linked to the bitumen sales price. The Alberta oil sands royalty payable is based on these price-sensitive royalty rates applied to bitumen production volumes. The applicable royalty rate changes depending on whether the project's status is pre-payout or post-payout. "Payout" is generally defined as the point in time when a project has generated enough net revenue to recover its costs and provide a designated return allowance. When a project reaches payout, its cumulative revenue equals or exceeds its cumulative costs. Costs include specified allowed capital and operating costs pursuant to the Oil Sands Allowed Costs (Ministerial) Regulation.

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

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

The Corporation’s Christina Lake operation is currently in pre-payout and the applicable royalty rate is applied to gross revenues for royalty purposes. We anticipate that our Christina Lake operation will reach payout for royalty purposes near the end of 2022 once its cumulative revenue exceeds its cumulative allowable costs. After payout is achieved, the associated royalty payable will switch to the post-payout formula as described above.

	Three months ended September 30				Nine months ended September 30			
	2022		2021		2022		2021	
		$/bbl		$/bbl		$/bbl		$/bbl
Royalties ($millions)	**$ (66)**	**$ (7.47)**	$ (23)	$ (2.67)	**$ (171)**	**$ (6.98)**	$ (44)	$ (1.77)
WTI benchmark price (C$/bbl)		**$119.56**		$88.92		**$125.84**		$81.12
Effective royalty rate[(1)(2)]		**10.0 %**		5.0 %		**8.1 %**		3.7 %

(1) Effective royalty rate is calculated as royalties expense divided by bitumen realization less transportation and storage expense.

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

The Canadian dollar WTI benchmark price increased 34% and 55% during the three and nine months ended September 30, 2022, respectively, compared to the same periods of 2021. This raised average gross revenues and the average gross royalty rate increasing royalty expense during the three and nine months ended September 30, 2022 compared to the same periods of 2021.

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-related operating activities and energy operating costs reflect the cost of natural gas used for fuel to generate steam and power at the Corporation's facilities. Power revenue is recognized from the sale of surplus power generated by the Corporation's cogeneration facilities at the Christina Lake Project. The Corporation utilizes thermally efficient cogeneration facilities to provide a portion of its steam and electricity requirements. Any excess power that is 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			
	2022		2021		2022		2021	
($millions, except as indicated)		$/bbl		$/bbl		$/bbl		$/bbl
Non-energy operating costs[(1)]	**$ (40)**	**$ (4.49)**	$ (38)	$ (4.46)	**$ (120)**	**$ (4.90)**	$ (101)	$ (4.12)
Energy operating costs[(1)]	**(54)**	**(6.12)**	(40)	(4.77)	**(185)**	**(7.53)**	(110)	(4.46)
Operating expenses	**(94)**	**(10.61)**	(78)	(9.23)	**(305)**	**(12.43)**	(211)	(8.58)
Power revenue	**46**	**5.16**	18	2.06	**90**	**3.64**	64	2.58
Operating expenses net of power revenue[(2)]	**$ (48)**	**$ (5.45)**	$ (60)	$ (7.17)	**$ (215)**	**$ (8.79)**	$ (147)	$ (6.00)
Average delivered natural gas price (C$/mcf)		**$ 4.92**		$ 4.17		**$ 5.97**		$ 3.78
Average realized power sales price (C$/Mwh)		**$217.25**		$ 82.17		**$140.00**		$ 88.33

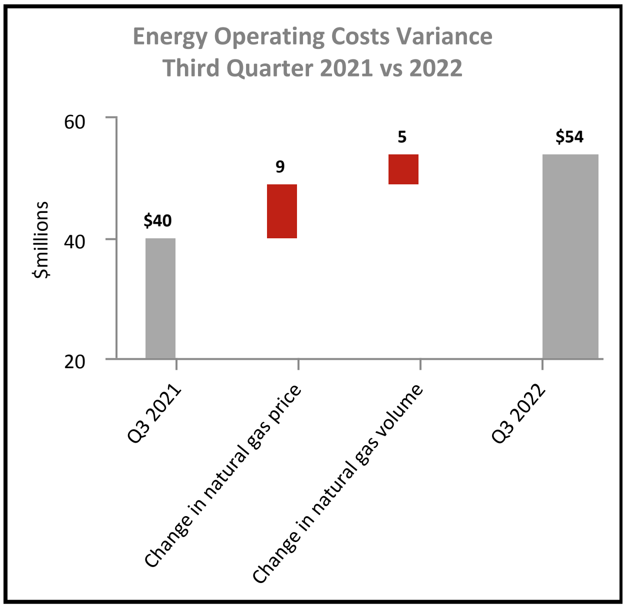
(1) Supplementary financial measure - please refer to section 14 "Non-GAAP and Other Financial Measures" of this MD&A

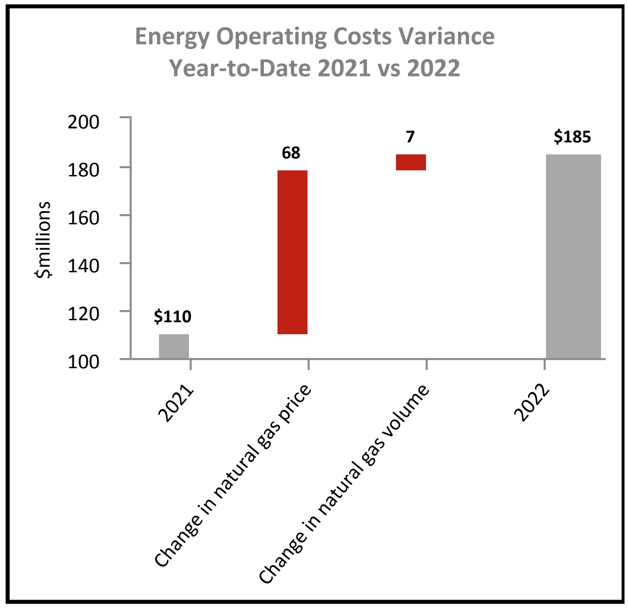
(2) Non-GAAP financial measure - please refer to section 14 "Non-GAAP and Other Financial Measures" of this MD&A.

During the three months ended September 30, 2022, operating expenses net of power revenue decreased, compared to the same period of 2021, as a result of the significant increase in power revenue.

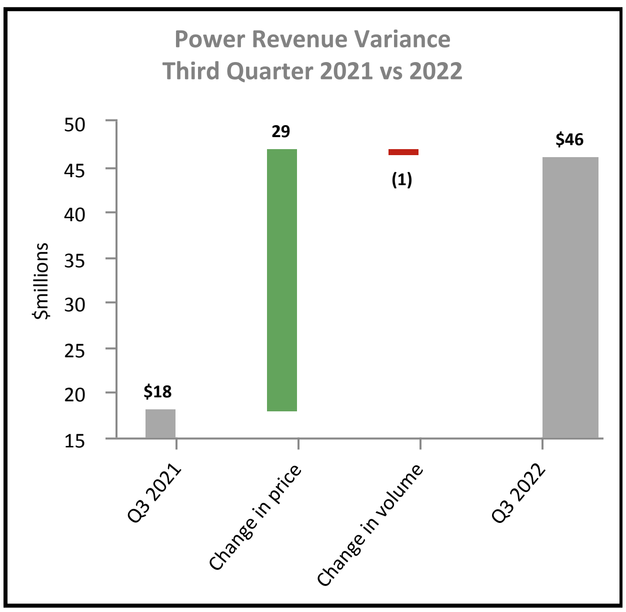
Non-energy operating costs, on a total and per barrel basis, increased for the three months ended September 30, 2022, compared to the same period of 2021, primarily due to inflationary increases in chemical treating and fuel costs and timing of maintenance activities.

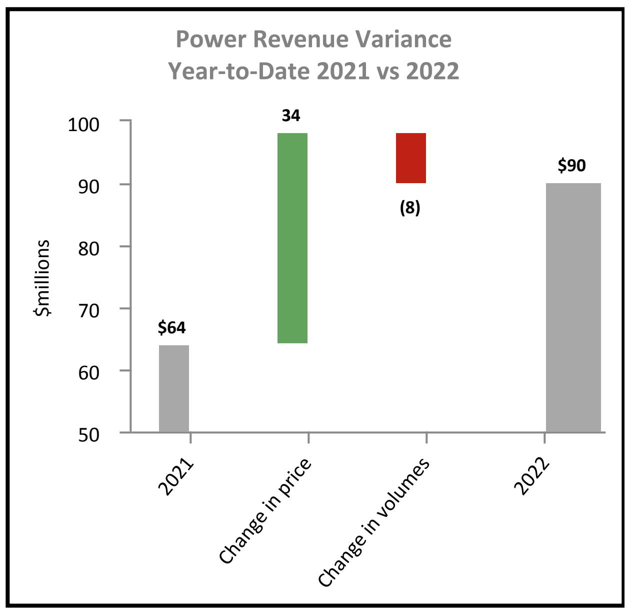
Non-energy operating costs, on a total and per barrel basis, increased for the nine months ended September 30, 2022, compared to the same period of 2021, primarily due to timing of maintenance activities and inflationary increases in chemical treating and fuel costs. During the nine months ended September 30, 2021, the Corporation also benefited from government-led initiatives to assist the industry through unprecedented market volatility which decreased non-energy operating costs in that period.





Energy operating costs, on a total and per barrel basis, increased during the three and nine months ended September 30, 2022, compared to the same periods of 2021, primarily due to the AECO natural gas price strengthening during 2022. Increased production during the three months ended September 30, 2022, compared to the same period of 2021, also caused an increase in natural gas volumes consumed, which increased the energy expense in that period.





Power revenue increased during the three and nine months ended September 30, 2022, compared to the same periods of 2021, as the Alberta power market price strengthened by 121% and 44%, respectively.

Realized Gain or Loss on Commodity Risk Management

To mitigate the Corporation's exposure to fluctuations in commodity prices, the Corporation periodically enters into financial commodity risk management contracts to partially manage its 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.

Realized gains on commodity risk management contracts recognized during the three and nine months ended September 30, 2022 were primarily associated with fixed natural gas purchase contracts and marketing asset optimization contracts. The realized loss recognized in 2021 primarily relates to a strengthening WTI market price compared to WTI fixed price contracts in place. 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			
	2022		**2021**		**2022**		**2021**	
($millions, except as indicated)		**$/bbl**		**$/bbl**		**$/bbl**		**$/bbl**
Realized gain (loss) on commodity risk management	**$ 7**	**$ 0.80**	$ (66)	$ (7.73)	**$ 9**	**$ 0.36**	$ (222)	$ (9.04)

Capital Expenditures

	Three months ended September 30		Nine months ended September 30	
($millions)	**2022**	**2021**	**2022**	**2021**
Sustaining and maintenance	**$ 75**	$ 79	**$ 212**	$ 204
Turnaround	**—**	—	**46**	—
Phase 2B brownfield expansion	**—**	3	**—**	14
Field infrastructure, corporate and other	**3**	2	**12**	7
	$ 78	$ 84	**$ 270**	$ 225

Capital expenditures during the nine months ended September 30, 2022 increased mainly due to the costs incurred for the major planned turnaround at the Phase 2B facility during the second quarter of 2022.

7. OUTLOOK

Summary of 2022 Guidance	**Revised Guidance (June 29, 2022)[1]**	Original Guidance (November 29, 2021)[1]
Bitumen production - annual average	92,000 - 95,000 bbls/d	94,000 - 97,000 bbls/d
Non-energy operating costs	$4.60 - $4.90 per bbl	$4.50 - $4.80 per bbl
G&A expense	$1.75 - $1.90 per bbl	$1.70 - $1.85 per bbl
Capital expenditures	$375 million	$375 million

(1) *2022 guidance includes the impact of the scheduled 30-day turnaround at the Corporation's Christina Lake Phase 2B facility which impacted annual production by approximately 6,000 barrels per day.*

As previously disclosed on June 29, 2022, the Corporation took its Christina Lake Phase 2B facility down for a scheduled major turnaround during the second quarter of 2022. Notwithstanding significant market pressures, the turnaround was safely completed on time and on budget, impacting full year 2022 average production by approximately 6,000 bbls/d. Following the turnaround, the Christina Lake facility experienced an unplanned electrical event which resulted in a slower than forecast production ramp-up during the month of June which impacted full year 2022 average production by approximately 2,000 bbls/d. Due to the slower June production ramp-up MEG revised its full year 2022 average production guidance to 92,000 - 95,000 bbls/d from 94,000 - 97,000 bbls/d. Given the strong production performance following the major planned turnaround completed in the second quarter of 2022, the Corporation expects to achieve the upper end of its production guidance. MEG also revised its full year non-energy operating costs and G&A expense to $4.60 to $4.90 per barrel and $1.75 to $1.90 per barrel, respectively, reflecting lower full year 2022 production guidance.

The Corporation has capacity to ship 100,000 barrels per day of AWB blend sales, on a pre-apportionment basis, to the USGC market via its committed capacity on the Flanagan South and Seaway pipeline systems ("FSP"). The Corporation expects to sell approximately two-thirds of its full year 2022 AWB blend sales volumes into the USGC via FSP with the remainder being sold into the Edmonton market. Based on the USGC sales volume estimate, the Corporation expects full year 2022 total transportation costs to average between US$7.50 and US$8.00 per barrel of AWB blend sales.

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		2022			2021				2020
	2022	2021	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Crude oil prices										
Brent (US$/bbl)	**102.16**	67.73	**97.69**	111.57	97.23	79.78	73.15	68.98	61.06	45.25
WTI (US$/bbl)	**98.09**	64.82	**91.55**	108.41	94.29	77.19	70.56	66.07	57.84	42.66
Differential – WTI:WCS – Edmonton (US$/bbl)	**(15.73)**	(12.51)	**(19.86)**	(12.80)	(14.53)	(14.64)	(13.58)	(11.49)	(12.47)	(9.30)
Differential – WTI:AWB – Edmonton (US$/bbl)	**(17.80)**	(14.15)	**(22.80)**	(14.25)	(16.35)	(16.40)	(15.13)	(13.11)	(14.22)	(10.56)
AWB – Edmonton (US$/bbl)	**80.29**	50.67	**68.75**	94.16	77.94	60.79	55.43	52.96	43.62	32.10
Differential – WTI:AWB – U.S. Gulf Coast (US$/bbl)	**(7.38)**	(4.00)	**(10.15)**	(6.15)	(5.85)	(6.40)	(5.57)	(3.92)	(2.52)	(2.83)
AWB – U.S. Gulf Coast (US$/bbl)	**90.71**	60.82	**81.40**	102.26	88.44	70.79	64.99	62.15	55.32	39.83
Enbridge Mainline heavy crude apportionment %	**4**	49	**3**	0	10	21	53	46	48	22
Condensate prices										
Condensate at Edmonton (C$/bbl)	**124.70**	80.79	**113.97**	138.39	121.74	99.70	87.30	81.55	73.51	55.39
Condensate at Edmonton as % of WTI	**99.1**	99.6	**95.3**	100.0	102.0	102.5	98.2	100.5	100.4	99.6
Condensate at Mont Belvieu, Texas (US$/bbl)	**85.30**	61.79	**72.25**	90.98	92.68	76.62	68.19	61.18	56.00	38.52
Condensate at Mont Belvieu, Texas as a % of WTI	**87.0**	95.3	**78.9**	83.9	98.3	99.3	96.6	92.6	96.8	90.3
Natural gas prices										
AECO (C$/mcf)	**5.86**	3.58	**4.54**	7.89	5.16	5.07	3.92	3.37	3.43	2.88
Electric power prices										
Alberta power pool (C$/MWh)	**144.95**	100.75	**221.90**	122.49	90.47	107.25	100.27	104.73	97.25	46.05
Foreign exchange rates										
C$ equivalent of 1 US$ – average	**1.2829**	1.2515	**1.3059**	1.2766	1.2661	1.2600	1.2602	1.2280	1.2663	1.3031
C$ equivalent of 1 US$ – period end	**1.3700**	1.2750	**1.3700**	1.2872	1.2484	1.2656	1.2750	1.2405	1.2572	1.2755

Crude Oil Prices

Brent crude is the primary world price benchmark for global light sweet crude oil. The price of 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 2021, global crude oil prices strengthened during 2022 as a result of improved demand and declining inventories. Supply uncertainty further supported higher global crude oil prices as the Russian invasion of Ukraine and subsequent sanctions against Russia created concern for significant oil supply disruption. Although some supply relief was provided by the globally coordinated release from strategic petroleum reserves, supply and demand balances remain tight with the OPEC+ group continuing to coordinate the production from its member countries.

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 the Enbridge mainline system. The WCS benchmark at Edmonton reflects heavy oil prices at Hardisty, Alberta.

The Corporation sells AWB, an oil similar to WCS, but generally priced at a discount to the WCS benchmark at Edmonton, with the discount dependent on the quality difference between AWB and WCS and the supply/demand fundamentals for oil in Western Canada. AWB is also sold at the USGC and is sold at a discount or premium to WTI dependent on the supply/demand fundamentals for oil in the USGC region.

WTI:AWB differentials at both Edmonton and the USGC widened during the three and nine months ended September 30, 2022 driven by the U.S. strategic petroleum reserve release and over-supply of sour crude at the USGC as well as reduced demand from China and India.

Enbridge Mainline Heavy Crude Apportionment

During the three and nine months ended September 30, 2022 Enbridge mainline heavy crude apportionment was 3% and 4%, respectively, compared to 53% and 49% during the same periods of 2021. This significant year over year decrease in apportionment is largely attributable to the Enbridge Line 3 Replacement project which was placed into full service in October 2021 and restored 370,000 barrels per day of egress capacity for Western Canadian crude. With decreased apportionment, the Corporation was able to more fully utilize its committed FSP capacity and deliver increased AWB volumes to the USGC, enabling a higher percentage of sales in the USGC market.

Condensate Prices

In order to facilitate pipeline transportation of bitumen, the Corporation uses condensate as diluent for blending with the Corporation’s bitumen. The price of condensate generally correlates with the price of WTI. The Corporation sources its condensate from both the Edmonton area and the USGC, where pricing is generally lower. The Corporation has committed diluent purchases of 20,000 barrels per day from the USGC at Mont Belvieu, Texas reference benchmark pricing. Condensate pricing at Edmonton, as a percentage of WTI, during the three and nine months ended September 30, 2022 was relatively in line with the same periods of 2021. Condensate pricing at Mont Belvieu, Texas, as a percentage of WTI, weakened considerably during the three and nine months ended September 30, 2022 compared to the same periods of 2021 due to the global economic contraction and associated reduction in international demand for condensate and naphtha.

Natural Gas Prices

Natural gas is a primary energy input cost for the Corporation, used as fuel to generate steam for the thermal production process and to create steam and electricity from the Corporation's cogeneration facilities. Global natural gas prices surged over the course of 2022 due to energy supply concerns. The AECO natural gas price rose as well, but to a lesser degree due to egress constraints which limited AECO access to international markets. The AECO natural gas price increased approximately 16% and 64% during the three and nine months ended September 30, 2022 compared to the same periods of 2021.

Electric Power Prices

Electric power prices impact the revenue that the Corporation receives on the sale of surplus power from the Corporation’s cogeneration facilities. The Alberta power pool price strengthened significantly by 121% and 44% during the three and nine months ended September 30, 2022, compared to the same periods of 2021. Contributing to the increase in power prices during these periods is the continued lack of renewable power production during peak load times and coal plant retirements further compounded by annual maintenance at gas fired generation plants.

8. OTHER OPERATING RESULTS

General and Administrative

	Three months ended September 30		Nine months ended September 30	
($millions, except as indicated)	**2022**	**2021**	**2022**	**2021**
General and administrative expense	**$ 16**	$ 14	**$ 44**	$ 41
General and administrative expense per barrel of production	**$ 1.72**	$ 1.72	**$ 1.84**	$ 1.68
Bitumen production – bbls/d	**101,983**	91,506	**90,126**	91,386

General and administrative ("G&A") expense during the three and nine months ended September 30, 2022 increased from the same periods of 2021 primarily due to one-time recruitment payments and an increase in staff costs.

Depletion and Depreciation

	Three months ended September 30		Nine months ended September 30	
($millions, except as indicated)	**2022**	**2021**	**2022**	**2021**
Depletion and depreciation expense	**$ 136**	$ 108	**$ 347**	$ 324
Depletion and depreciation expense per barrel of production	**$ 14.30**	$ 12.78	**$ 14.05**	$ 12.97
Bitumen production – bbls/d	**101,983**	91,506	**90,126**	91,386

Depletion and depreciation expense rose during the three and nine months ended September 30, 2022, compared to the same periods of 2021, primarily due to an increased per barrel depletion and depreciation rate reflecting higher estimated average future development costs. Depletion and depreciation expense during the three months ended September 30, 2022 was also impacted by increased production as the Corporation's field production assets are depreciated on a unit of production basis.

Commodity Risk Management Gain (Loss)

From time to time, the Corporation enters into financial commodity risk management contracts to protect and increase the predictability of the Corporation's cash flow, to 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). The Corporation has not designated any of its commodity risk management contracts as hedges for accounting purposes.

Realized gains or losses on financial commodity risk management contracts are the result of contract 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.

($millions)	Three months ended September 30 2022	Three months ended September 30 2021	Nine months ended September 30 2022	Nine months ended September 30 2021
Realized:				
Crude oil contracts[(1)]	**$ —**	$ (79)	**$ —**	$ (254)
Condensate contracts[(2)]	**—**	10	**—**	27
Natural gas contracts[(3)]	**1**	3	**4**	5
Marketing asset optimization contracts[(4)]	**6**	—	**5**	—
Realized commodity risk management gain (loss)	**$ 7**	$ (66)	**$ 9**	$ (222)
Unrealized:				
Crude oil contracts[(1)]	**$ —**	$ 66	**$ —**	$ (39)
Condensate contracts[(2)]	**1**	(1)	**6**	(20)
Natural gas contracts[(3)]	**—**	4	**3**	15
Marketing asset optimization contracts[(4)]	**(4)**	(1)	**—**	(3)
Unrealized commodity risk management gain (loss)	**$ (3)**	$ 68	**$ 9**	$ (47)
Commodity risk management gain (loss)	**$ 4**	$ 2	**$ 18**	$ (269)

(1) Includes WTI fixed price contracts, WTI enhanced fixed price contracts with sold put options and WTI:WCS fixed differential contracts.
(2) Relates to condensate purchase contracts that effectively fix condensate prices at Mont Belvieu, Texas relative to WTI.
(3) Relates to contracts which fix the AECO price on natural gas purchases.
(4) The Corporation occasionally enters into contracts to fix the spread between WTI prices for consecutive months to support marketing asset optimization activities.

During the three and nine months ended September 30, 2022 the Corporation recognized net gains of $4 million and $18 million, respectively, from commodity risk management compared to a $2 million net gain and a $269 million net loss from commodity risk management during the same periods of 2021. The Corporation entered into minimal commodity risk management contracts in 2022 compared to 2021. Crude oil contracts held in 2022 are related to elimination of price risk on marketing asset optimization activities as required by policies approved by the Corporation's Board of Directors.

The following table provides further details regarding the realized commodity risk management gain (loss):

	Three months ended September 30		Nine months ended September 30	
(US$/bbl, unless otherwise indicated)	**2022**	**2021**	**2022**	**2021**
WTI fixed price contracts[1][2]:				
Average fixed price	**$ —**	$ 46.18	**$ —**	$ 46.77
Average settlement price	**—**	70.55	**—**	62.98
Gain (loss) on WTI fixed price contracts	**$ —**	$ (24.37)	**$ —**	$ (16.21)
WTI:WCS fixed differential contracts:				
Average fixed differential	**$ —**	$ (11.05)	**$ —**	$ (12.13)
Average settlement differential	**—**	(13.46)	**—**	(11.88)
Gain (loss) on WTI:WCS fixed differential contracts	**$ —**	$ 2.41	**$ —**	$ (0.25)
Condensate purchase contracts:				
Average fixed differential[3]	**$ (11.30)**	$ (10.37)	**$ (11.30)**	$ (10.14)
Average settlement differential	**(19.31)**	(2.40)	**(12.78)**	(3.18)
Gain (loss) on condensate purchase contracts	**$ (8.01)**	$ 7.97	**$ (1.48)**	$ 6.96
Natural gas purchase contracts:				
Average fixed price (C$/GJ)	**$ 2.50**	$ 2.60	**$ 2.50**	$ 2.60
Average settlement price (C$/GJ)	**3.95**	3.41	**5.10**	3.09
Gain (loss) on natural gas purchase contracts (C$/GJ)	**$ 1.45**	$ 0.81	**$ 2.60**	$ 0.49

(1) *Includes WTI enhanced fixed price contracts with sold put options.*

(2) *Incremental to these WTI fixed price contracts, the Corporation occasionally enters into contracts to support marketing asset optimization activities by eliminating WTI price risk.*

(3) *Condensate purchase contracts fix the condensate price at Mont Belvieu, Texas relative to WTI.*

Stock-based Compensation

	Three months ended September 30		Nine months ended September 30	
($millions)	**2022**	**2021**	**2022**	**2021**
Cash-settled expense (recovery)	**$ (8)**	$ 13	**$ 47**	$ 48
Equity-settled expense	**4**	4	**14**	12
Equity price risk management (gain) loss[1]	**10**	(7)	**(35)**	(44)
Stock-based compensation expense	**$ 6**	$ 10	**$ 26**	$ 16

(1) *Relates to financial derivatives entered into 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 are unrealized until vesting of the related units occurs. See section 11 "Risk Management" of this MD&A for further details.*

During the three months ended September 30, 2022 the Corporation recognized a cash-settled recovery primarily due to the decrease in the Corporation's share price during the period. Conversely, a cash-settled expense was recognized during the three months ended September 30, 2021 primarily due to the vesting of units as well as the increase in the Corporation's share price. The cash-settled expense for the nine months ended September 30, 2022 and 2021 was primarily due to the increase in the Corporation's share price in both periods.

The equity price risk management (gain) loss is driven by the change in the Corporation's common share price relative to the notional value of the instruments. For the three months ended September 30, 2022, an equity price risk management loss of $10 million was recognized on the decrease in share price during this period compared to a gain of $7 million during the same period of 2021. For the nine months ended September 30, 2022, an equity price risk management gain of $35 million was recognized on the increase in share price during this period compared to a gain of $44 million during the same period of 2021.

Foreign Exchange Gain (Loss), Net

	Three months ended September 30		Nine months ended September 30	
($millions)	**2022**	**2021**	**2022**	**2021**
Unrealized foreign exchange gain (loss) on:				
Long-term debt	**$ (121)**	$ (77)	**$ (163)**	$ 9
US$ denominated cash and cash equivalents	**23**	(1)	**28**	(3)
Foreign currency risk management contracts	**—**	—	**7**	—
Unrealized net gain (loss) on foreign exchange	**(98)**	(78)	**(128)**	6
Realized gain (loss) on foreign exchange	**(1)**	1	**(3)**	1
Foreign exchange gain (loss), net	**$ (99)**	$ (77)	**$ (131)**	$ 7

C$ equivalent of 1 US$				
Beginning of period	**1.2872**	1.2405	**1.2656**	1.2755
End of period	**1.3700**	1.2750	**1.3700**	1.2750

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 Corporation's foreign exchange gain (loss) is the Corporation's long-term debt which is denominated in U.S. dollars.

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 an unrealized foreign exchange loss of $98 million and $128 million, respectively.

During the three months ended September 30, 2021, the Canadian dollar weakened by 3% resulting in an unrealized foreign exchange loss of $78 million. During the nine months ended September 30, 2021, the Canadian dollar strengthened slightly relative to the U.S. dollar resulting in an unrealized foreign exchange gain of $6 million.

Net Finance Expense

	Three months ended September 30		Nine months ended September 30	
($millions)	**2022**	**2021**	**2022**	**2021**
Interest expense on long-term debt	**$ 35**	$ 55	**$ 125**	$ 166
Interest expense on lease liabilities	**7**	6	**19**	19
Interest income	**(2)**	(1)	**(3)**	(1)
Net interest expense	**40**	60	**141**	184
Debt extinguishment expense	**12**	—	**24**	5
Accretion on provisions	**3**	2	**7**	6
Net finance expense	**$ 55**	$ 62	**$ 172**	$ 195

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

Interest expense on long-term debt decreased during the three and nine months ended September 30, 2022, compared to the same periods of 2021, primarily as a result of debt reduction of US$966 million since the end of the second quarter of 2021.

For the three months ended September 30, 2022, debt extinguishment expense of $12 million was recognized in association with the repurchase and extinguishment of US$262 million (approximately C$349 million) of the Corporation's 7.125% senior unsecured notes which included a cumulative debt redemption premium of $8 million and associated unamortized deferred debt issue costs of $4 million. Refer to Note 6 of the interim consolidated financial statements 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 C$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 6 of the interim consolidated financial statements for further details.

Income Tax

	Three months ended September 30		**Nine months ended September 30**	
($millions)	**2022**	**2021**	**2022**	**2021**
Earnings (loss) before income taxes	**$ 237**	$ 93	**$ 1,020**	$ 140
Effective tax rate	**34 %**	42 %	**27 %**	25 %
Income tax expense (recovery)	**$ 81**	$ 39	**$ 277**	$ 35

As at September 30, 2022, the Corporation had approximately $6.0 billion of available Canadian tax pools, including $4.4 billion of non-capital losses and $0.3 billion of capital losses, and recognized a deferred income tax asset of $18 million. Estimated future taxable income is expected to be sufficient to realize the deferred income tax asset.

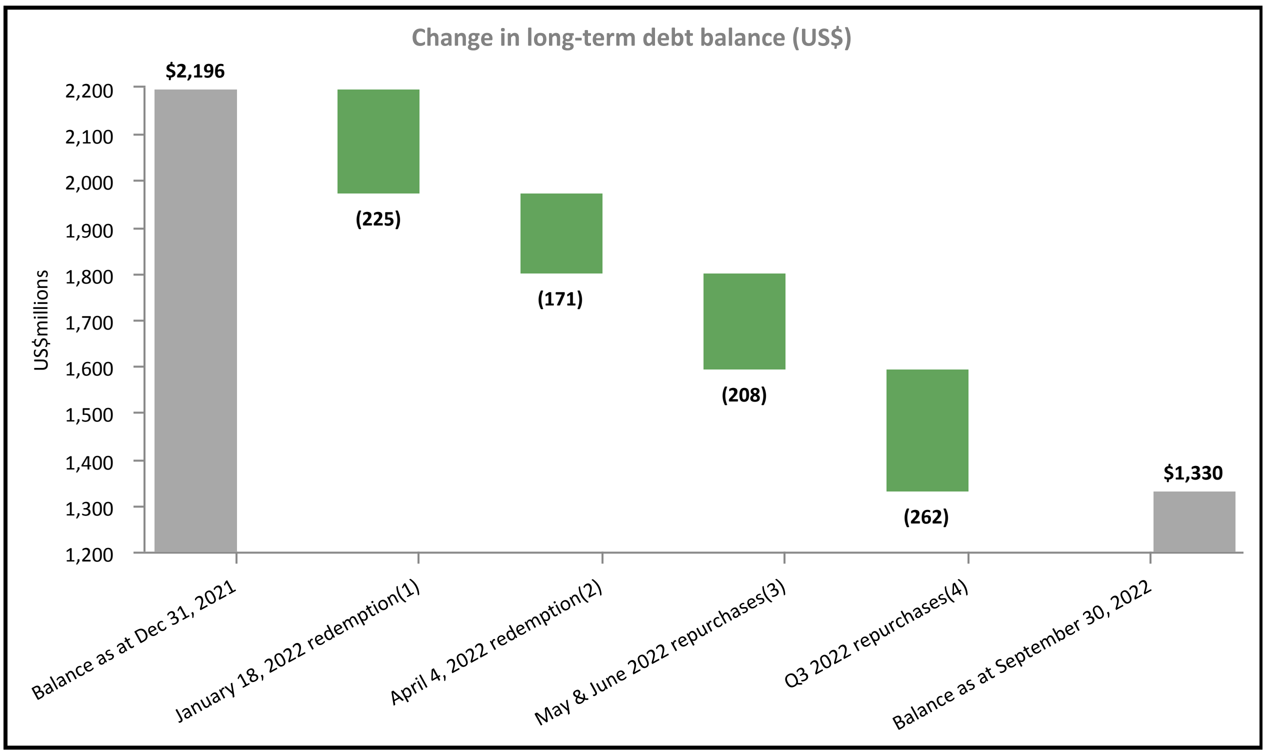
The effective tax rate for the three and nine months ended September 30, 2022 differed from the Canadian statutory rate of 23% primarily due to the tax effect of foreign exchange gains and losses on the Corporation's long-term debt which is denominated in U.S. dollars.

10. LIQUIDITY AND CAPITAL RESOURCES

($millions)	**September 30, 2022**	**December 31, 2021**
Second Lien:		
6.50% senior secured second lien notes (September 30, 2022 - nil; fully redeemed April 4, 2022; December 31, 2021 - US$396 million)	$ —	$ 501
Unsecured:		
7.125% senior unsecured notes (September 30, 2022 - US$729.5 million; due 2027; December 31, 2021 - US$1.2 billion)	**999**	1,519
5.875% senior unsecured notes (September 30, 2022 - US$600 million; due 2029; December 31, 2021 - US$600 million)	**822**	759
Debt redemption premium	**—**	8
Unamortized deferred debt discount and debt issue costs	**(18)**	(25)
Current and long-term debt	**1,803**	2,762
Cash and cash equivalents	**(169)**	(361)
Net debt - C$(1)	**$ 1,634**	$ 2,401
Net debt - US$(1)	**$ 1,193**	$ 1,897

(1) Net debt is reconciled to long-term debt in accordance with IFRS in Note 17 of the interim consolidated financial statements.

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



(1) Redemption price of 101.625% plus accrued and unpaid interest on the 6.50% senior secured second lien notes.

(2) Redemption price of 101.625% plus accrued and unpaid interest on the remaining 6.50% senior secured second lien notes.

(3) Weighted average repurchase price of 103.2% plus accrued and unpaid interest on US$208 million of the Corporation's 7.125% senior unsecured notes due 2027.

(4) Weighted average repurchase price of 102.2% plus accrued and unpaid interest on US$262 million of the Corporation's 7.125% senior unsecured notes due 2027.

The Corporation's cash and cash equivalents balance was $169 million as at September 30, 2022 compared to $361 million as at December 31, 2021. Refer to the "Cash Flow Summary" section for further details.

The Corporation's net debt decreased from US$1.9 billion as at December 31, 2021 to US$1.2 billion as at September 30, 2022 primarily due to US$866 million of debt repayments partially offset by the change in cash balance.

As a result of reaching the net debt target of US$1.2 billion, the Corporation is increasing the percentage of free cash flow allocated to share buy backs to approximately 50% with the remainder applied to further debt reduction. When the Corporation reaches its net debt floor of US$600 million, 100% of free cash flow will be returned to shareholders.

The Corporation has total available credit under two facilities of $1.2 billion, comprised of $600 million under the revolving credit facility and $600 million under a letter of credit facility guaranteed by EDC. 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 a maturity date of October 31, 2026. The revolving credit facility and EDC Facility are secured by substantially all the assets of the Corporation.

Uncertainty associated with commodity market volatility is managed through the Corporation's various financial frameworks. Credit exposure is reduced by targeting sales to primarily investment grade customers in the energy industry. The Corporation's earliest maturing long-term debt is more than 4 years out, represented by US$730 million of senior unsecured notes due February 2027. Additionally, the Corporation's modified covenant-lite $600 million revolving credit facility has no financial maintenance covenant unless drawn in excess of $300 million. If drawn in excess of $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. None of the Corporation's outstanding long-term debt contains financial maintenance covenants or is secured on a *pari passu* basis with the credit facility.

As at September 30, 2022, the Corporation had $596 million of unutilized capacity under the $600 million revolving credit facility and the Corporation had $156 million of unutilized capacity under the $600 million EDC Facility. A letter of credit of $4 million remains outstanding under the revolving credit facility as at September 30, 2022. 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 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. 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 the development of projects 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	
($millions)	**2022**	**2021**	**2022**	**2021**
Net cash provided by (used in):				
Operating activities	**$ 434**	$ 257	**$ 1,362**	$ 449
Investing activities	**(89)**	(69)	**(269)**	(191)
Financing activities	**(444)**	(136)	**(1,313)**	(158)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency	**24**	(1)	**28**	(4)
Change in cash and cash equivalents	**$ (75)**	$ 51	**$ (192)**	$ 96

Cash Flow – Operating Activities

Net cash provided by operating activities for the three and nine months ended September 30, 2022 increased, compared to the same periods of 2021, primarily due to higher benchmark crude oil prices partially offset by a wider WTI:AWB differential. During the three and nine months ended September 30, 2021 net cash provided by operating activities was impacted by realized losses on commodity risk management, whereas the Corporation has not entered into significant commodity risk management contracts for 2022.

Cash Flow – Investing Activities

Net cash used in investing activities increased during the three months ended September 30, 2022, compared to the same period of 2021, reflecting timing differences related to capital expenditure payments.

Net cash used in investing activities increased during the nine months ended September 30, 2022, compared to the same period of 2021, reflecting increased capital spending and lower proceeds on disposal.

Cash Flow – Financing Activities

Net cash used in financing activities for the three and nine months ended September 30, 2022 increased, compared to the same periods of 2021, primarily due to debt repayment and share buybacks as part of the Corporation's strategy to return value to shareholders.

11. RISK MANAGEMENT

Commodity Price Risk Management

To mitigate exposure to fluctuations in commodity prices, the Corporation periodically enters into financial commodity risk management contracts to partially manage its 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 into 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 contract prices is included in the Consolidated Statement of Earnings (Loss) and Comprehensive Income (Loss) and in cash operating netback.

The Corporation had the following financial commodity risk management contracts relating to condensate purchases and natural gas purchases outstanding as at September 30, 2022:

As at September 30, 2022			
Condensate Purchase Contracts	**Volumes (bbls/d)**	**Term**	**Average Price (US$/bbl)**
WTI:Mont Belvieu Fixed Differential	200	Oct 1, 2022 - Dec 31, 2022	$(11.30)
WTI:Mont Belvieu Fixed Differential	10,000	Jan 1, 2023 - Oct 31, 2023	$(11.44)
Natural Gas Purchase Contracts	**Volumes (GJ/d)**	**Term**	**Average Price (C$/GJ)**
AECO Fixed Price	5,000	Oct 1, 2022 - Dec 31, 2023	$2.50

Incremental to these commodity risk management contracts, the Corporation occasionally enters into 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 as at September 30, 2022:

Commodity	Sensitivity Range	Increase	Decrease
Condensate purchase price	± 5% in condensate price as a percentage of WTI	**$ 15**	**$ (15)**
Natural gas purchase price	± C$0.50 per GJ applied to natural gas contracts	**$ 1**	**$ (1)**

Equity Price Risk Management

In 2020, the Corporation entered into 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 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 these equity price risk management contracts in March 2020 to manage its exposure on cash-settled RSUs and PSUs vesting between April 1, 2021 and April 1, 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	
($millions)	**2022**	**2021**	**2022**	**2021**
Unrealized equity price risk management (gain) loss	**$ 10**	$ (7)	**$ 11**	$ (36)
Realized equity price risk management (gain) loss	**—**	—	**(46)**	(8)
Equity price risk management (gain) loss	**$ 10**	$ (7)	**$ (35)**	$ (44)

12. SHARES OUTSTANDING

As at September 30, 2022, the Corporation had the following share capital instruments outstanding or exercisable:

(millions)	**Units**
Common shares:	
Outstanding as at December 31, 2021	306.9
Issued upon exercise of stock options	2.0
Issued upon vesting and release of RSUs and PSUs	2.9
Repurchased for cancellation	(10.1)
Common shares outstanding as at September 30, 2022	**301.6**
Convertible securities:	
Stock options[1]	**0.3**
Equity-settled RSUs and PSUs	**5.2**

(1) All outstanding stock options were exercisable as at September 30, 2022.

For the nine months ended ended September 30, 2022, the Corporation repurchased for cancellation 10.1 million common shares under its NCIB at a weighted average price of $18.52 for a total cost of $186 million.

As at November 8, 2022, the Corporation had 298 million common shares outstanding, 0.3 million stock options outstanding and exercisable and 5.1 million equity-settled RSUs and equity-settled 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 the Corporation's obligations as at September 30, 2022. These maturities 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)	2022	2023	2024	2025	2026	Thereafter	Total
Commitments:							
Transportation and storage[1]	$ 110	$ 447	$ 471	$ 445	$ 423	$ 5,466	$ 7,362
Diluent purchases	124	32	—	—	—	—	156
Other operating commitments	5	16	14	13	13	24	85
Variable office lease costs	1	4	4	5	5	22	41
Capital commitments	20	—	—	—	—	—	20
Total Commitments	260	499	489	463	441	5,512	7,664
Other Obligations:							
Lease obligations	14	39	38	29	29	463	612
Current and long-term debt[2]	—	—	—	—	—	1,821	1,821
Interest on long-term debt[2]	30	119	119	119	119	112	618
Decommissioning obligation[3]	1	5	5	5	5	754	775
Total Commitments and Obligations	**$ 305**	**$ 662**	**$ 651**	**$ 616**	**$ 594**	**$ 8,662**	**$ 11,490**

(1) This represents transportation and storage commitments from 2022 to 2048, including pipeline commitments which are awaiting regulatory approval and are 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, 2022.

(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. The Corporation 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 Corporation's share price was at a historic low of $1.57 per share. Concurrent with the issuance, the Corporation entered into 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 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. Since the actual cash impact of the 2020 cash-settled RSUs is subject to equity price risk management contracts, there is no cash impact over the term of these RSUs beyond the value at the date of issue of $1.57 per share.

As a result of the equity risk management contracts, 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. All prior periods presented have been adjusted to reflect this change in presentation. The adjustments to prior periods are as follows:

	2022	**2021**				**2020**		
($millions, except as indicated)	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**
Adjusted funds flow, as previously presented	**$ 587**	$ 266	$ 239	$ 166	$ 127	$ 84	$ 26	$ 89
Adjustments:								
Impact of cash-settled SBC units subject to equity price risk management	**18**	8	4	18	5	4	—	2
Realized equity price risk management gain	**(46)**	—	—	—	(8)	—	—	—
Adjusted funds flow, current presentation	**$ 559**	$ 274	$ 243	$ 184	$ 124	$ 88	$ 26	$ 91
Free cash flow, as previously presented	**$ 499**	$ 160	$ 155	$ 95	$ 57	$ 44	$ (9)	$ 69
Adjustments:								
Impact of cash-settled SBC units subject to equity price risk management	**18**	8	4	18	5	4	—	2
Realized equity price risk management gain	**(46)**	—	—	—	(8)	—	—	—
Free cash flow, current presentation	**$ 471**	$ 168	$ 159	$ 113	$ 54	$ 48	$ (9)	$ 71

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	
($millions)	**2022**	**2021**	**2022**	**2021**
Funds flow from operating activities	**$ 501**	$ 212	**$ 1,500**	$ 493
Adjustments:				
Impact of cash-settled SBC units subject to equity price risk management	**(5)**	4	**79**	27
Realized equity price risk management gain	**—**	—	**(46)**	(8)
Settlement expense	**—**	21	**—**	21
Payments on onerous contract	**—**	6	**—**	18
Adjusted funds flow	**496**	243	**1,533**	551
Capital expenditures	**(78)**	(84)	**(270)**	(225)
Free cash flow	**$ 418**	$ 159	**$ 1,263**	$ 326

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, 2022**	**December 31, 2021**
Long-term debt	**$ 1,771**	$ 2,477
Current portion of long-term debt	**32**	285
Cash and cash equivalents	**(169)**	(361)
Net debt - C$	**$ 1,634**	$ 2,401
Net debt - US$	**$ 1,193**	$ 1,897

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:

	Three months ended September 30		Nine months ended September 30	
($millions)	**2022**	**2021**	**2022**	**2021**
Revenues	**$ 1,571**	$ 1,091	**$ 4,673**	$ 3,014
Diluent expense	**(411)**	(324)	**(1,343)**	(944)
Transportation and storage expense	**(138)**	(88)	**(387)**	(272)
Purchased product	**(383)**	(218)	**(919)**	(587)
Operating expenses	**(94)**	(78)	**(305)**	(211)
Realized gain (loss) on commodity risk management	**7**	(66)	**9**	(222)
Cash operating netback	**$ 552**	$ 317	**$ 1,728**	$ 778

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			
	2022		**2021**		**2022**		**2021**	
($millions, except as indicated)		**$/bbl**		**$/bbl**		**$/bbl**		**$/bbl**
Revenues	**$ 1,571**		$ 1,091		**$ 4,673**		$ 3,014	
Other revenue	**(47)**		(21)		**(93)**		(72)	
Royalties	**66**		23		**171**		44	
Petroleum revenue	**1,590**		1,093		**4,751**		2,986	
Purchased product	**(383)**		(218)		**(919)**		(587)	
Blend sales	**1,207**	**$ 99.96**	875	$ 74.54	**3,832**	**$ 109.94**	2,399	$ 68.40
Diluent expense	**(411)**	**(9.63)**	(324)	(9.63)	**(1,343)**	**(8.26)**	(944)	(9.12)
Bitumen realization	**$ 796**	**$ 90.33**	$ 551	$ 64.91	**$ 2,489**	**$ 101.68**	$ 1,455	$ 59.28

Net Transportation and Storage

Net transportation and storage 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. Per barrel amounts are based on bitumen sales volumes.

Transportation and storage expense, is an IFRS measure in the Corporation's consolidated statement of earnings (loss) and comprehensive income (loss).

Other 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 other revenue to transportation revenue has been provided below.

	Three months ended September 30				Nine months ended September 30			
	2022		2021		2022		2021	
($millions, except as indicated)		$/bbl		$/bbl		$/bbl		$/bbl
Transportation and storage expense	**$ (138)**	**$ (15.70)**	$ (88)	$ (10.40)	**$ (387)**	**$ (15.80)**	$ (272)	$ (11.10)
Other revenue	**$ 47**		$ 21		**$ 93**		$ 72	
Less power revenue	**(46)**		(18)		**(90)**		(64)	
Transportation revenue	**$ 1**	**$ 0.12**	$ 3	$ 0.37	**$ 3**	**$ 0.14**	$ 8	$ 0.34
Net transportation and storage	**$ (137)**	**$ (15.58)**	$ (85)	$ (10.03)	**$ (384)**	**$ (15.66)**	$ (264)	$ (10.76)

Operating Expenses net of Power Revenue

Operating expenses net of power revenue 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 cost to operate its facilities at the Christina Lake project after factoring in the benefits from selling excess power to offset energy 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). Other 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 other revenue to power revenue has been provided below.

	Three months ended September 30				Nine months ended September 30			
	2022		2021		2022		2021	
($millions, except as indicated)		$/bbl		$/bbl		$/bbl		$/bbl
Non-energy operating costs	**$ (40)**	**$ (4.49)**	$ (38)	$ (4.46)	**$ (120)**	**$ (4.90)**	$ (101)	$ (4.12)
Energy operating costs	**(54)**	**(6.12)**	(40)	(4.77)	**(185)**	**(7.53)**	(110)	(4.46)
Operating expenses	**$ (94)**	**$ (10.61)**	$ (78)	$ (9.23)	**$ (305)**	**$ (12.43)**	$ (211)	$ (8.58)
Other revenue	**$ 47**		$ 21		**$ 93**		$ 72	
Less transportation revenue	**(1)**		(3)		**(3)**		(8)	
Power revenue	**$ 46**	**$ 5.16**	$ 18	$ 2.06	**$ 90**	**$ 3.64**	$ 64	$ 2.58
Operating expenses net of power revenue	**$ (48)**	**$ (5.45)**	$ (60)	$ (7.17)	**$ (215)**	**$ (8.79)**	$ (147)	$ (6.00)

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 is a measure of the Corporation's royalty rate to enable 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 (non-GAAP measure) less transportation and storage expense.

	Three months ended September 30		Nine months ended September 30	
($millions)	**2022**	**2021**	**2022**	**2021**
Bitumen realization	**$ 796**	$ 551	**$ 2,489**	$ 1,455
Transportation and storage expense	**(138)**	(88)	**(387)**	(272)
	$ 658	$ 463	**$ 2,102**	$ 1,183
Royalties	**$ 66**	$ 23	**$ 171**	$ 44
Effective royalty rate	**10.0 %**	5.0 %	**8.1 %**	3.7 %

15. CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The Corporation's critical accounting policies and estimates are those estimates having a significant impact on the Corporation's 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 used by the Corporation can be found in the Corporation's annual consolidated financial statements for the year ended December 31, 2021.

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.sedar.com.

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, can provide only reasonable, but not absolute, assurance that the objectives of the control system will be met and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud. In reaching a reasonable level of assurance, management necessarily is required to apply its judgment in evaluating the cost/benefit relationship of possible controls and procedures.

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
eMVAPEX	enhanced Modified VAPour EXtraction
ESG	Environment, Social and Governance
FSP	Flanagan South and Seaway Pipeline
GAAP	Generally Accepted Accounting Principles
GHG	Greenhouse Gas
IFRS	International Financial Reporting Standards
LIBOR	London Interbank Offered Rate
MD&A	Management’s Discussion and Analysis
PSU	Performance share units
RSU	Restricted share units
SAGD	Steam-Assisted Gravity Drainage
SOR	Steam-oil ratio
SBC	Stock-based compensation
U.S.	United States
US$	United States dollars
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 marketing strategy and marketing asset optimization strategy; the Corporation’s ability to realize production growth over time at the Christina Lake Project while minimizing GHG emissions intensity through cogeneration and the application of its proprietary technologies; the Corporation’s annual 2022 capital expenditures guidance of $375 million; the impact on production of the Corporation capital expenditures aimed at optimal production; the impact on SOR of the Corporation’s enhanced completion designs and redrill and field workover program; the Corporation’s expectation that the Christina Lake operation will reach payout for royalty purposes in the fourth quarter of 2022; all statements relating to the Corporation’s revised 2022 guidance, including its 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 of achieving the upper end of its June 29, 2022 production guidance range; the Corporation’s expectation of selling approximately two-thirds of its full year 2022 AWB blend sales volumes into the USGC via FSP with the remainder being sold into the Edmonton market; 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 at which time the Corporation expects to allocate 100% of free cash flow to shareholders; the Corporation’s continued focus on debt reduction as a key component of its capital allocation strategy; 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; 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 2022 hedge book.

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 and 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.sedar.com.

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.sedar.com.

22. QUARTERLY SUMMARIES

	2022			2021				2020
Unaudited	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**
FINANCIAL *($millions unless specified)*								
Net earnings (loss)	**156**	225	362	177	54	68	(17)	16
Per share, diluted	**0.51**	0.72	1.15	0.57	0.17	0.22	(0.06)	0.05
Funds flow from operating activities	**501**	412	587	260	212	160	121	81
Per share, diluted	**1.63**	1.31	1.87	0.83	0.68	0.51	0.39	0.26
Adjusted funds flow[(1)]	**496**	478	559	274	243	184	124	88
Per share, diluted[(1)]	**1.61**	1.52	1.78	0.88	0.78	0.59	0.40	0.29
Capital expenditures	**78**	104	88	106	84	71	70	40
Free cash flow[(1)]	**418**	374	471	168	159	113	54	48
Working capital	**395**	437	465	150	199	127	8	55
Net debt - C$[(1)]	**1,634**	1,782	2,150	2,401	2,559	2,661	2,798	2,798
Net debt - US$[(1)]	**1,193**	1,384	1,722	1,897	2,007	2,145	2,226	2,194
Shareholders' equity	**4,418**	4,339	4,178	3,808	3,628	3,564	3,491	3,506
BUSINESS ENVIRONMENT								
Average Benchmark Commodity Prices:								
WTI (US$/bbl)	**91.55**	108.41	94.29	77.19	70.56	66.07	57.84	42.66
Differential – WTI:WCS – Edmonton (US$/bbl)	**(19.86)**	(12.80)	(14.53)	(14.64)	(13.58)	(11.49)	(12.47)	(9.30)
Differential – WTI:AWB – Edmonton (US$/bbl)	**(22.80)**	(14.25)	(16.35)	(16.40)	(15.13)	(13.11)	(14.22)	(10.56)
AWB – Edmonton (US$/bbl)	**68.75**	94.16	77.94	60.79	55.43	52.96	43.62	32.10
Differential – WTI:AWB – U.S. Gulf Coast (US$/bbl)	**(10.15)**	(6.15)	(5.85)	(6.40)	(5.57)	(3.92)	(2.52)	(2.83)
AWB – U.S. Gulf Coast (US$/bbl)	**81.40**	102.26	88.44	70.79	64.99	62.15	55.32	39.83
Enbridge Mainline heavy apportionment	**3 %**	0 %	10 %	21 %	53 %	46 %	48 %	22 %
C$ equivalent of 1US$ – average	**1.3059**	1.2766	1.2661	1.2600	1.2602	1.2280	1.2663	1.3031
Natural gas – AECO ($/mcf)	**4.54**	7.89	5.16	5.07	3.92	3.37	3.43	2.88
OPERATIONAL **($/bbl unless specified)**								
Blend sales, net of purchased product – bbls/d	**131,327**	105,517	146,382	141,280	127,546	129,474	128,236	136,623
Diluent usage – bbls/d	**(35,568)**	(32,426)	(46,196)	(42,386)	(35,295)	(39,494)	(40,938)	(40,892)
Bitumen sales – bbls/d	**95,759**	73,091	100,186	98,894	92,251	89,980	87,298	95,731
Bitumen production – bbls/d	**101,983**	67,256	101,128	100,698	91,506	91,803	90,842	91,030
Steam-oil ratio (SOR)	**2.39**	2.46	2.43	2.42	2.56	2.39	2.37	2.31
Blend sales[(2)]	**99.96**	128.20	105.79	82.43	74.54	69.27	61.28	45.75
Diluent expense	**(9.63)**	(5.51)	(8.51)	(11.37)	(9.63)	(9.18)	(8.94)	(7.11)
Bitumen realization[(2)]	**90.33**	122.69	97.28	71.06	64.91	60.09	52.34	38.64
Net transportation and storage[(2)]	**(15.58)**	(19.40)	(12.97)	(11.39)	(10.03)	(10.91)	(11.41)	(14.11)
Curtailment	**—**	—	—	—	—	—	—	0.03
Royalties	**(7.47)**	(8.67)	(5.24)	(3.54)	(2.67)	(1.71)	(0.85)	(0.23)
Non-energy operating costs[(3)]	**(4.49)**	(5.65)	(4.74)	(4.56)	(4.46)	(3.84)	(4.05)	(4.70)
Energy operating costs[(3)]	**(6.12)**	(10.40)	(6.80)	(6.22)	(4.77)	(4.27)	(4.34)	(3.73)
Power revenue	**5.16**	3.08	2.56	2.58	2.06	2.57	3.14	1.45
Realized gain (loss) on commodity risk management	**0.80**	0.10	0.12	(10.06)	(7.73)	(10.63)	(8.80)	1.31
Cash operating netback[(2)]	**62.63**	81.75	70.21	37.87	37.31	31.30	26.03	18.66
Revenues	**1,571**	1,571	1,531	1,307	1,091	1,009	914	786
Power sales price (C$/MWh)	**217.25**	117.94	91.50	95.22	82.17	88.40	93.27	46.34
Power sales (MW/h)	**98**	82	121	117	101	113	128	125
Average cost of diluent ($/bbl of diluent)	**125.91**	140.61	124.23	108.96	99.69	90.18	80.34	62.37
Average cost of diluent as a % of WTI	**105 %**	102 %	104 %	112 %	112 %	111 %	110 %	112 %
Depletion and depreciation rate per bbl of production	**14.30**	14.35	13.58	13.63	12.78	12.99	13.15	12.64
General and administrative expense per bbl of production	**1.72**	2.37	1.61	1.58	1.72	1.56	1.77	1.65
COMMON SHARES								
Shares outstanding, end of period (000)	**301,649**	307,271	307,596	306,865	306,773	306,716	303,137	302,681
Common share price ($) - close (end of period)	**15.46**	17.82	17.07	11.70	9.89	8.97	6.53	4.45

(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 ranges from a quarterly average of US$42.66/bbl to US$108.41/bbl. The volatility in 2020 was driven by the impact of COVID-19 on supply and demand fundamentals. Supply uncertainty further supported higher global crude oil prices as the February 2022 Russian invasion of Ukraine and subsequent sanctions against Russia created concern for significant oil supply disruption;
- 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;
- timing of capital projects;
- cost reduction efforts;
- 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 implementation of financial equity price risk management contracts, and the resulting impact on stock-based compensation; and
- planned turnaround and other maintenance activities affecting production.

23. ANNUAL SUMMARIES

	2021	2020	2019	2018[1]	2017[1]	2016[1]	2015[1]
FINANCIAL *($millions unless specified)*							
Net earnings (loss)	283	(357)	(62)	(119)	166	(429)	(1,170)
Per share, diluted	0.91	(1.18)	(0.21)	(0.40)	0.57	(1.90)	(5.21)
Funds flow from operating activities	753	239	741	169	343	(69)	34
Per share, diluted	2.42	0.78	2.46	0.56	1.18	(0.31)	0.15
Adjusted funds flow[2]	826	281	724	175	371	(63)	49
Per share, diluted[2]	2.65	0.92	2.41	0.58	1.28	(0.28)	0.22
Capital expenditures	331	149	198	622	508	140	314
Free cash flow[2]	495	132	526	(447)	(137)	(203)	(265)
Working capital	150	55	123	290	313	96	363
Net debt - C$[1]	2,401	2,798	2,917	3,422	4,205	4,897	4,782
Net debt - US$[1]	1,897	2,194	2,250	2,508	3,359	3,647	3,455
Shareholders' equity	3,808	3,506	3,853	3,886	3,964	3,287	3,678
BUSINESS ENVIRONMENT							
Average Benchmark Commodity Prices:							
WTI (US$/bbl)	67.91	39.40	57.03	64.77	50.95	43.33	48.80
Differential – WTI:WCS – Edmonton (US$/bbl)	(13.04)	(12.60)	(12.76)	(26.31)	(11.98)	(13.84)	(13.52)
Differential – WTI:AWB – Edmonton (US$/bbl)	(14.71)	(14.32)	(14.95)	(29.99)	(14.09)	(16.40)	(16.69)
AWB – Edmonton (US$/bbl)	53.20	25.08	42.08	34.78	36.86	26.93	32.11
Differential – WTI:AWB – U.S. Gulf Coast (US$/bbl)	(4.60)	(4.77)	(1.77)	(6.68)	(7.61)	(11.53)	(8.53)
AWB - U.S. Gulf Coast (US$/bbl)	63.31	34.63	55.26	58.09	43.34	31.80	40.27
Enbridge Mainline heavy apportionment	42 %	24 %	43 %	41 %	20 %	12 %	31 %
C$ equivalent of 1US$ – average	1.2536	1.3413	1.3269	1.2962	1.2980	1.3256	1.2788
Natural gas – AECO ($/mcf)	3.95	2.43	1.92	1.62	2.29	2.25	2.71
OPERATIONAL **($/bbl unless specified)**							
Blend sales, net of purchased product – bbls/d	131,659	118,347	134,223	125,368	115,766	116,586	117,132
Diluent usage – bbls/d	(39,521)	(35,626)	(40,637)	(38,317)	(35,766)	(36,159)	(36,167)
Bitumen sales – bbls/d	92,138	82,721	93,586	87,051	80,000	80,427	80,965
Bitumen production – bbls/d	93,733	82,441	93,082	87,731	80,774	81,245	80,025
Steam-oil ratio (SOR)	2.43	2.32	2.22	2.19	2.31	2.29	2.47
Blend sales[3]	72.20	37.65	61.29	53.47	51.39	38.19	42.14
Diluent expense	(9.73)	(10.42)	(8.08)	(16.78)	(9.36)	(10.28)	(11.43)
Bitumen realization[3]	62.47	27.23	53.21	36.69	42.03	27.91	30.71
Transportation & storage expense net of transportation revenue[3]	(10.93)	(12.92)	(10.84)	(8.42)	(6.89)	(6.46)	(4.82)
Curtailment	—	0.06	(0.37)	—	—	—	—
Royalties	(2.25)	(0.31)	(1.30)	(1.20)	(0.77)	(0.29)	(0.70)
Non-energy operating costs[4]	(4.24)	(4.38)	(4.61)	(4.62)	(4.62)	(5.62)	(6.54)
Energy operating costs[4]	(4.94)	(3.29)	(2.38)	(1.98)	(2.98)	(3.01)	(3.84)
Power revenue	2.58	1.49	1.75	1.51	0.76	0.64	0.99
Realized gain (loss) on commodity risk management	(9.32)	11.34	(3.31)	(4.37)	(0.39)	0.08	—
Cash operating netback[3]	33.37	19.22	32.15	17.61	27.14	13.25	15.80
Revenues	4,321	2,292	3,931	2,733	2,474	1,866	1,926
Power sales price (C$/MWh)	90.10	47.81	56.70	47.87	21.49	18.74	27.48
Power sales (MW/h)	115	108	121	114	118	115	121
Average cost of diluent ($/bbl of diluent)	94.88	61.86	79.89	91.60	72.32	61.06	67.72
Average cost of diluent as a % of WTI	111 %	117 %	106 %	109 %	109 %	106 %	109 %
Depletion and depreciation rate per bbl of production	13.15	13.60	20.90	14.12	16.13	16.81	16.00
General and administrative expense per bbl of production	1.65	1.62	1.99	2.58	2.94	3.24	4.06
COMMON SHARES							
Shares outstanding, end of period (000)	306,865	302,681	299,508	296,841	294,104	226,467	224,997
Common share price ($) - close (end of period)	11.70	4.45	7.39	7.71	5.14	9.23	8.02

(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.