THIRD QUARTER | 2020

REPORT TO SHAREHOLDERS FOR THE PERIOD ENDED SEPTEMBER 30, 2020

Report to Shareholders for the period ended September 30, 2020

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

MEG Energy Corp. reported third quarter 2020 operational and financial results on October 26, 2020.

MEG continues to proactively respond to the safety and financial challenges associated with the COVID-19 pandemic and remains committed to ensuring the health and safety of all of its personnel and the safe and reliable operation of the Christina Lake facility.

"Our 75-day major scheduled plant turnaround was successfully completed in August with production coming back stronger than previously expected" said Derek Evans, President and Chief Executive Officer. "As we head into year end, we are increasing annual production guidance, decreasing annual G&A and non-energy operating cost guidance and expect to build free cash flow through the balance of the year with 80% of our WTI exposure on our fourth quarter sales hedged at approximately US$46 per barrel."

MEG remains well positioned from a financial liquidity perspective, benefiting not only from its significant 2020 hedge book and the term and structure of its outstanding indebtedness and credit facility, but also from the low decline and low cost structure of its high-quality Christina Lake asset.

Third quarter financial and operating highlights include:

- Adjusted funds flow of $27 million ($0.09 per share), impacted by lower sales volumes due to major planned turnaround activities;
- Quarterly production volumes of 71,516 barrels per day (bbls/d) at a steam-oil ratio (SOR) of 2.36, while completing major planned turnaround activities. Due to better than expected production levels during and post-turnaround, annual average production guidance has been revised higher to 81,000 - 82,000 bbls/d;
- Net operating costs of $6.05 per barrel, including record low non-energy operating costs of $3.96 per barrel and power sales which had the impact of offsetting 34% of per barrel energy operating costs, resulting in a net energy operating cost of $2.09 per barrel;
- Total capital investment of $36 million in the quarter was directed to sustaining capital and planned turnaround activities. Approximately 75% of MEG's $150 million 2020 capital budget has been invested to the end of the third quarter; and
- $49 million of cash-on-hand at September 30, 2020 with approximately 80% of WTI exposure on fourth quarter forecast sales hedged at average WTI price of US$45.76. MEG's $800 million modified covenant-lite revolver remains undrawn.

Blend Sales Pricing and North American Market Access

MEG realized an average AWB blend sales price of US$34.13 per barrel during the third quarter of 2020 compared to US$15.12 per barrel in the second quarter of 2020. The increase in average AWB blend sales price quarter over quarter was primarily a result of the average WTI price increasing by US$13.08 per barrel in addition to the average WTI:AWB differential at Edmonton narrowing by US$2.96 per barrel. MEG sold 62% of its sales volumes to the U.S. Gulf Coast ("USGC") in the third quarter of 2020 compared to 35% in the second quarter of 2020. The increase in sales to the USGC in the third quarter of 2020 is primarily a result of the Corporation's increased contracted transportation capacity on the Flanagan South and Seaway Pipeline systems ("FSP") effective July 1, 2020 from 50,000 bbls/d to 100,000 bbls/d.

Transportation and storage costs averaged US$10.07 per barrel of AWB blend sales in the third quarter of 2020 compared to US$5.92 per barrel of AWB blend sales in the second quarter of 2020. The increase in transportation and storage costs is primarily due to the fixed costs associated with increased FSP contracted capacity and lower apportionment on the Enbridge mainline. Also, the increased costs were allocated to 7% lower AWB blend sales volumes quarter over quarter. The additional transportation capacity afforded by higher FSP contracted capacity and lower apportionment was underutilized by MEG during the third quarter of 2020 due to the planned turnaround. Subject to the level of actual apportionment on the Enbridge mainline system, transportation costs are expected to average between US$7.50 and US$8.50 per barrel of AWB blend sales through the remainder of 2020 and 2021.

MEG's AWB blend sales by rail was 13,189 bbls/d (all FOB Edmonton) in the third quarter of 2020, representing 14% of total blend sales, compared to 4,391 bbls/d (all FOB Edmonton) in the second quarter of 2020. The increase in barrels sold via rail quarter over quarter was a result of a balanced approach to rail cost mitigation efforts undertaken by the Corporation in the third quarter of 2020 given the relative economics of sales by contracted rail transportation compared to pipeline transportation costs.

Operational Performance

Bitumen production averaged 71,516 bbls/d in the third quarter of 2020, compared to 75,687 bbls/d in the second quarter of 2020. Bitumen production in the third quarter of 2020 was impacted by major planned turnaround activities at the Phase 1 and 2 facilities, which began in early June 2020 and were completed mid-August 2020. The 2020 turnaround was extended in duration to 75 days and expanded in scope, relative to base budget, in order to minimize staff levels at site during COVID-19 and maximize utilization of MEG's internal resources thereby lowering overall cash costs. MEG also made the decision to advance turnaround activities from 2021 to significantly reduce the 2021 turnaround requirements.

Non-energy operating costs averaged $3.96 per barrel of bitumen sales in the third quarter of 2020 compared to $4.09 per barrel in the second quarter of 2020. Net energy operating costs averaged $2.09 per barrel in the third quarter of 2020 compared to $2.05 in the second quarter of 2020. During the nine months ended September 30, 2020, the Corporation was able to benefit from non-recurring cost reductions of approximately $13 million including the Canadian Emergency Wage Subsidy ("CEWS") program.

General & administrative expense ("G&A") was $10 million, or $1.50 per barrel of production, in the third quarter of 2020 compared to $9 million, or $1.29 per barrel of production, in the second quarter of 2020. Total aggregate G&A has remained relatively consistent quarter over quarter and included the impact of MEG's continuing efforts to drive efficiency into its cost structure through salary rollbacks, reductions in staffing levels and vendor concessions, as well as various government led initiatives, including CEWS. During the nine months ended September 30, 2020, the Corporation was able to benefit from non-recurring cost reductions of approximately $5 million including the CEWS program.

Adjusted Funds Flow and Net Loss

MEG's bitumen realization averaged $39.68 per barrel in the third quarter of 2020 compared to $10.18 per barrel in the second quarter of 2020. The increase in average bitumen realization quarter over quarter was driven by the higher WTI price and lower diluent cost. Also, a higher portion of sales volumes reached the USGC market, increasing the realized price earned.

Offsetting the increase in bitumen realization during the third quarter of 2020, compared to the second quarter of 2020, was a decrease in the realized commodity risk management gain of $31.91 per barrel, quarter over quarter, and an increase in transportation and storage costs of $6.78 per barrel, quarter over quarter. The decrease in the realized commodity risk management gain was driven by an increase in the WTI price compared to the WTI fixed price contracts in place. The increase in transportation and storage costs was due to the increased fixed costs associated with the increased transportation capacity on FSP. These changes contributed to the decrease in the Corporation's cash operating netback to $16.58 per barrel in the third quarter of 2020 compared to $25.84 per barrel in the second quarter of 2020. The decreased cash operating netback drove the decrease in the Corporation's adjusted funds flow from $89 million in the second quarter of 2020 to $27 million in the third quarter of 2020.

The Corporation recognized a net loss of $9 million in the third quarter of 2020 compared to a net loss of $80 million in the second quarter of 2020. The decrease in the net loss in the third quarter of 2020, compared to the second quarter of 2020, was primarily the result of a decreased unrealized loss on commodity risk management contracts partially offset by decreased cash operating netback and a decreased unrealized gain on foreign exchange.

Capital Expenditures

MEG invested $36 million in the third quarter of 2020 compared to $20 million in the second quarter of 2020. Of the $36 million, $21 million was directed towards sustaining and maintenance activities with the remaining $15 million related to the 75-day planned turnaround at the Christina Lake Phase 1 and 2 facilities which was completed mid-August.

COVID-19 Global Pandemic

The Corporation continues to proactively respond to the safety and financial challenges associated with COVID-19 and remains committed to ensuring the health and safety of all its personnel and business partners, and the safe and reliable operation of the Christina Lake facility. The screening procedures and protocols implemented by the Corporation's COVID-19 task force during the first quarter of 2020 currently remain in place to ensure continued safe and reliable operations. During the third quarter of 2020, the Corporation focused on a transition to resuming normal operations which included the majority of office staff returning to the Calgary office and site personnel resuming normal operating schedules at the Christina Lake site. Management will continue to monitor this situation to determine what, if any, additional measures might need to be taken to ensure that the health and safety of its people remain a top priority.

Outlook

Based on better than expected production performance during and post-turnaround, MEG is revising upward its full year 2020 average production from 78,000 – 80,000 bbls/d to 81,000 – 82,000 bbls/d. Compared to the original guidance of 94,000 – 97,000 bbls/d announced November 21, 2019, approximately half of the difference is due to the impact of the scheduled 75-day major turnaround at the Christina Lake Phase 1 and 2 facilities completed mid-August. The remainder of the difference results from a combination of previously disclosed weather-related production impacts in the first quarter of 2020, voluntary price-related production curtailments in the second quarter of 2020 and the impact of reduced well capital throughout 2020, which made up approximately 80% of the combined $100 million reduction in capital spending announced on March 10 and May 4 of 2020.

G&A expense is now targeted to be in the range of $45 – $47.5 million, or approximately $17.5 million lower than original guidance. Non-energy operating costs are now expected to be in the range of $130 - $135 million, or approximately $32.5 million lower than original guidance. Of the $50 million aggregate reduction in expected costs, approximately $22 million are a result of temporary cost reductions while the remaining $28 million in cost reductions are a result of a continued optimization of operations, reduction in staffing levels and rationalization of ongoing administrative costs.

MEG expects to release its 2021 capital budget in December. While the development of the 2021 capital budget remains in progress, it will be designed to be fully funded with internally generated funds. This is consistent with MEG's financial discipline in 2020, where the current year's capital program remains on track to be fully funded with internally generated funds.

Guidance Update

Summary of 2020 Guidance	Revised Guidance (October 26, 2020)	Previously Revised Guidance (July 27, 2020)	Previously Revised Guidance (May 4, 2020)	Previously Revised Guidance (March 10, 2020)	Original Guidance (November 21, 2019)
Production (1H20)	N/A	N/A	76,000 bbls/d	N/A	N/A
Production (FY20 average)	81,000 - 82,000 bbls/d	78,000-80,000 bbls/d	N/A	93,000-95,000 bbls/d	94,000-97,000 bbls/d
Non-energy operating costs	$130-$135 million[(1)]	$140-$150 million	$140-$150 million	$155-$165 million ($4.50-$4.90 per bbl)	$160-$170 million ($4.50-$4.90 per bbl)
G&A expense	$45-$47.5 million[(1)]	$52.5-$55 million	$52.5-$55 million	$60-$62.5 million ($1.75-$1.85 per bbl)	$62.5-$65 million ($1.75-$1.85 per bbl)
Capital expenditures	$150 million	$150 million	$150 million	$200 million	$250 million

(1) Revised non-energy operating costs and G&A expense guidance ranges include approximately $15 million and $7 million, respectively, of temporary cost reductions including CEWS.

Financial Liquidity

Notwithstanding multi-decade low crude oil prices, MEG generated $85 million of free cash flow in the nine months ended September 30, 2020, and exited the third quarter of 2020 with its credit facility undrawn and $49 million of cash on hand. MEG expects to build free cash flow through the fourth quarter of 2020 with 80% of our WTI exposure hedged at US$45.76 per barrel.

The Corporation's earliest long-term debt maturity is in 2024, represented by US$600 million of senior unsecured notes due March 2024. None of the Corporation's outstanding long-term debt contain financial maintenance covenants. Additionally, MEG's modified covenant-lite $800 million revolving credit facility has no financial maintenance covenant unless drawn in excess of $400 million. If drawn in excess of $400 million, MEG 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 MEG'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.

Q4 2020 and Full Year 2021 Commodity Hedges

For the fourth quarter of 2020, MEG has entered into benchmark WTI fixed price hedges for approximately 80% of forecast bitumen production at an average price of US$45.76 per barrel.

For full year 2021, to date MEG has entered into enhanced WTI fixed price hedges with sold put options for approximately 25% of forecast bitumen production at an average price of US$46.25 per barrel. If in 2021 WTI averages US$38.71 per barrel (the sold put option) or better, MEG will receive US$46.25 per barrel (the fixed price swap) on each barrel hedged. If in 2021 WTI averages less than US$38.71 per barrel, MEG will receive the average 2021 WTI price plus US$7.54 per barrel (the swap spread) on each barrel hedged.

The table below reflects MEG's current Q4 2020 and full year 2021 financial and physical hedge positions.

	Forecast Period	
	Q4 2020	Full Year 2021
WTI Hedges		
WTI Fixed Price Hedges		
Volume (bbls/d)	**69,665**	**—**
Weighted average fixed WTI price (US$/bbl)	**$ 45.76**	**$ —**
Enhanced WTI Fixed Price Hedges with Sold Put Options[1]		
Volume (bbls/d)	**24,500**	**21,000**
Weighted average fixed WTI price (US$/bbl) / Put option strike price (US$/bbl)	**$ 59.11 / $ 52.00**	**$ 46.25 / $ 38.71**
WTI:WCS Differential Hedges		
Volume[2] (bbls/d)	**38,896**	**—**
Weighted average fixed WTI:WCS differential (US$/bbl)	**$ (20.12)**	**$ —**
Condensate Hedges		
Volume[3] (bbls/d)	**23,208**	**10,950**
Weighted average % of WTI landed in Edmonton (%)[4]	**101 %**	**93 %**
Natural Gas Hedges		
Volume[5] (GJ/d)	**—**	**30,000**
Weighted average fixed AECO price (C$/GJ)	**—**	**$ 2.68**

(1) Includes WTI fixed price swaps and WTI sold put options entered into for both Q4 2020 and the full year 2021. For Q4 2020, MEG's average realized WTI price on these hedges is US$7.11 per barrel above actual while WTI prices remain below US$52.00 per barrel. For the full year 2021, MEG's average realized WTI price on these hedges is US$46.25 per barrel, when WTI prices are above US$38.71 per barrel, or US$7.54 per barrel above actual when WTI prices are below US$38.71 per barrel.

(2) Includes approximately 10,900 bbls/d of physical forward blend sales for Q4 2020 at a fixed WTI:AWB differential.

(3) Includes approximately 8,200 bbls/d of physical forward condensate purchases for Q4 2020.

(4) Where applicable, the average % of WTI landed in Edmonton includes estimated net transportation costs to Edmonton.

(5) Includes 5,000 GJ/d of physical forward purchases for 2021 at a fixed AECO price.

ADVISORY

Forward-Looking Information

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

Non-GAAP Measures

Certain financial measures in this report to shareholders including free cash flow and cash operating netback are non-GAAP measures. These 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.

Free Cash Flow

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. Free cash flow is calculated as adjusted funds flow less capital expenditures.

	Three months ended September 30		Nine months ended September 30	
($millions)	**2020**	**2019**	**2020**	**2019**
Net cash provided by (used in) operating activities	**$ (31)**	$ 174	**$ 186**	$ 406
Net change in non-cash operating working capital items	**50**	17	**(28)**	162
Funds flow from operations	**19**	191	**158**	568
Adjustments:				
Contract cancellation[(1)]	**7**	—	**33**	—
Decommissioning expenditures	**1**	1	**3**	1
Adjusted funds flow	**$ 27**	$ 192	**$ 194**	$ 569
Capital expenditures	**(36)**	(40)	**(109)**	(126)
Free cash flow	**$ (9)**	$ 152	**$ 85**	$ 443

(1) Costs incurred to mitigate rail sales contract exposure. The economic decision to divert sales volumes from rail contracts at Edmonton to the USGC more than recovered the cost of contract cancellations. Contract cancellation costs or recoveries are excluded from adjusted funds flow as they are not considered part of ordinary continuing operating results.

Cash Operating Netback

Cash operating netback is a non-GAAP measure widely used in the oil and gas industry as a supplemental measure of a company's efficiency and its ability to fund future capital expenditures. The Corporation's cash operating netback is calculated by deducting the related cost of diluent, blend purchases, transportation and storage, third- party curtailment credits, operating expenses, royalties and realized commodity risk management gains or losses from blend sales and power revenue. The per barrel calculation of cash operating netback is based on bitumen sales volume.

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, 2020 was approved by the Corporation's Audit Committee on October 26, 2020. 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, 2020, the audited annual consolidated financial statements and notes thereto for the year ended December 31, 2019, the 2019 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.

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1. BUSINESS DESCRIPTION

MEG is an energy company focused on sustainable in situ thermal oil production in the southern Athabasca 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 its thermal oil production to refiners throughout North America and internationally.

MEG owns a 100% working interest in over 450 square miles of mineral leases. In the report prepared by GLJ Petroleum Consultants Ltd. ("GLJ") and effective December 31, 2019, GLJ estimated that the leases it had evaluated contained approximately 2.1 billion barrels of gross proved plus probable ("2P") bitumen reserves at the Christina Lake Project. For information regarding MEG's estimated reserves contained in the report prepared by GLJ, please refer to the Corporation's most recently filed AIF, which is available on the Corporation's website at www.megenergy.com and is also available on the SEDAR website at www.sedar.com.

2. OPERATIONAL AND FINANCIAL HIGHLIGHTS

The Corporation continues to proactively respond to the safety and financial challenges associated with the COVID-19 global pandemic ("COVID-19") and remains committed to ensuring the health and safety of all its personnel and business partners, and the safe and reliable operation of the Christina Lake facility. The screening procedures and protocols implemented by the Corporation's COVID-19 task force during the first quarter of 2020 currently remain in place to ensure continued safe and reliable operations. During the third quarter of 2020, the Corporation focused on a transition to resuming normal operations which included the majority of office staff returning to the Calgary office and site personnel resuming pre-pandemic shift operations at the Christina Lake site. Management will continue to monitor this situation to determine what, if any, additional measures might need to be taken to ensure the continued health and safety of its people as its top priority.

Considerable market volatility has dominated 2020 to date. COVID-19 and subsequent measures intended to limit the outbreak globally have had an unprecedented impact on global commodity prices. The first half of 2020 was characterized by extremely negative movements in commodity prices coupled with unprecedented uncertainty regarding near-term crude oil supply and demand, while the third quarter of 2020 saw an improvement in the stability of the global oil market; however, uncertainty regarding the ongoing impact of COVID-19 on global economies, oil demand and commodity prices continues. During the third quarter of 2020, the Corporation continued to take definitive action to enhance its financial position including protecting liquidity with a robust commodity price risk management program, operational flexibility in capital program execution and improving cost efficiencies across the business.

The Corporation generated adjusted funds flow of $27 million in the third quarter of 2020 compared to $192 million in the third quarter of 2019, an 86% decrease, reflecting a lower cash operating netback of $16.58 per barrel in the third quarter of 2020 compared to $32.44 per barrel in the third quarter of 2019. The decrease in cash operating netback was attributable to a lower blend sales price which was driven by the decline in global crude oil prices partially offset by realized gains on commodity price risk management contracts in place during the period. Cash operating netback during the third quarter of 2020 was also impacted by lower production due to the 75-day turnaround completed mid-August and higher transportation and storage costs associated with incremental capacity on the Flanagan South and Seaway Pipeline systems ("FSP"). The Corporation continues to execute on its long-term strategy of market diversification to improve its netback. To the extent that marketing asset capacity is underutilized, the Corporation has and will continue to look to mitigate these associated costs through short and medium-term third-party contracts.

During the third quarter of 2020, the Corporation successfully completed a 75-day turnaround at a cost of $15 million in the quarter. Proving its operational flexibility, the Corporation strategically advanced key turnaround activities from 2021 and extended the duration of turnaround activities. Total capital spending of $36 million during the third quarter of 2020 was focused on turnaround activities and sustaining and maintenance capital. Bitumen production averaged 71,516 bbls/d during the third quarter of 2020 compared to 93,278 bbls/d in the third quarter of 2019. The decrease in average bitumen production was driven by the major planned turnaround.

The Corporation incurred a net loss of $9 million for the third quarter of 2020 compared to net earnings of $24 million during the same period of 2019 primarily as a result of a decrease in cash operating netback partially offset by an increase in the unrealized foreign exchange gain.

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		2020			2019				2018
($millions, except as indicated)	2020	2019	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Bitumen production - bbls/d	79,557	92,582	71,516	75,687	91,557	94,566	93,278	97,288	87,113	87,582
Steam-oil ratio	2.33	2.21	2.36	2.32	2.31	2.27	2.26	2.16	2.20	2.22
Bitumen sales - bbls/d	78,354	93,330	67,569	70,397	97,214	94,347	94,992	95,120	89,822	88,283
Bitumen realization - $/bbl	22.54	55.38	39.68	10.18	19.45	46.86	53.37	62.23	50.21	15.31
Net operating costs - $/bbl(1)	5.85	5.01	6.05	6.14	5.51	5.87	4.30	4.66	6.17	4.55
Non-energy operating costs - $/bbl	4.25	4.64	3.96	4.09	4.57	4.49	4.22	4.53	5.22	4.25
Cash operating netback - $/bbl(2)	19.45	33.47	16.58	25.84	16.83	28.33	32.44	37.88	29.80	7.14
Adjusted funds flow(3)	194	569	27	89	78	157	192	227	151	(37)
Per share, diluted	0.63	1.90	0.09	0.29	0.26	0.51	0.63	0.76	0.50	(0.13)
Revenue	1,505	2,938	533	307	665	992	958	1,062	919	520
Net earnings (loss)	(373)	(87)	(9)	(80)	(284)	26	24	(64)	(48)	(199)
Per share, diluted	(1.24)	(0.29)	(0.03)	(0.26)	(0.95)	0.09	0.08	(0.21)	(0.16)	(0.67)
Capital expenditures	109	126	36	20	54	72	40	32	53	144
Cash and cash equivalents	49	154	49	120	62	206	154	399	154	318
Long-term debt - C$	3,030	3,257	3,030	3,096	3,212	3,123	3,257	3,582	3,660	3,740
Long-term debt - US$	2,274	2,459	2,274	2,274	2,275	2,409	2,459	2,737	2,740	2,741

(1) *Net operating costs include energy and non-energy operating costs, reduced by power revenue.*

(2) *Cash operating netback is a non-GAAP measure and does not have a standardized meaning prescribed by IFRS and therefore may not be comparable to similar measures used by other companies. Refer to the "NON-GAAP MEASURES" section of this MD&A.*

(3) *Refer to Note 20 of the interim consolidated financial statements for further details.*

3. SUSTAINABILITY

The Corporation's Environmental, Social and Governance ("ESG") Report, published in 2019, provides details on the Corporation's approach with respect to certain environmental, social and governance related issues and highlights the activities undertaken by the Corporation to address the needs of its shareholders and its employees. The ESG Report details the Corporation's approach to sustainability including its commitment to developing innovative technologies to address climate change and its commitment to developing strong relationships with Indigenous communities and other communities where the Corporation operates. The ESG Report also describes the Corporation's commitment to best practices in the areas of health, safety and the environment and to developing an ethical, respectful, inclusive and diverse workplace.

The Corporation’s 2020 strategic environmental, social and governance (“ESG”) initiatives include:

- establish 2030 and 2050 climate change goals and continue to advance technology solutions to achieve net zero greenhouse gas ("GHG") emissions by 2050;
- develop a robust inclusion and diversity policy to ensure that all employees and contractors feel valued, engaged and respected in the workplace and that the Corporation continues to attract and retain top talent; and
- increase its business relationships with and employment of Indigenous peoples.

To date, the Corporation has set a goal to achieve net zero GHG emissions by 2050 and expanded its social and environmental performance targets which impact executive and employee compensation. Also, to advance the disclosure of ESG initiatives, the Corporation has engaged with strategic stakeholders to focus future ESG performance and disclosure initiatives through an ESG materiality survey and enhanced CDP Climate disclosure with further alignment to the recommendations of the Task Force on Climate-related Financial Disclosures ("TCFD"). Finally, the Corporation continues to integrate ESG practices throughout the business and to monitor and manage ESG risks and opportunities.

Additional information regarding the Corporation's ESG actions, including the ESG Report, CDP Climate Response and CDP Water Response, is available in the "Sustainability" section of the Corporation's website at www.megenergy.com.

4. RESULTS OF OPERATIONS

Bitumen Production and Steam-Oil Ratio

	Three months ended September 30		Nine months ended September 30	
	2020	**2019**	**2020**	**2019**
Bitumen production – bbls/d	**71,516**	93,278	**79,557**	92,582
Steam-oil ratio (SOR)	**2.36**	2.26	**2.33**	2.21

Bitumen Production

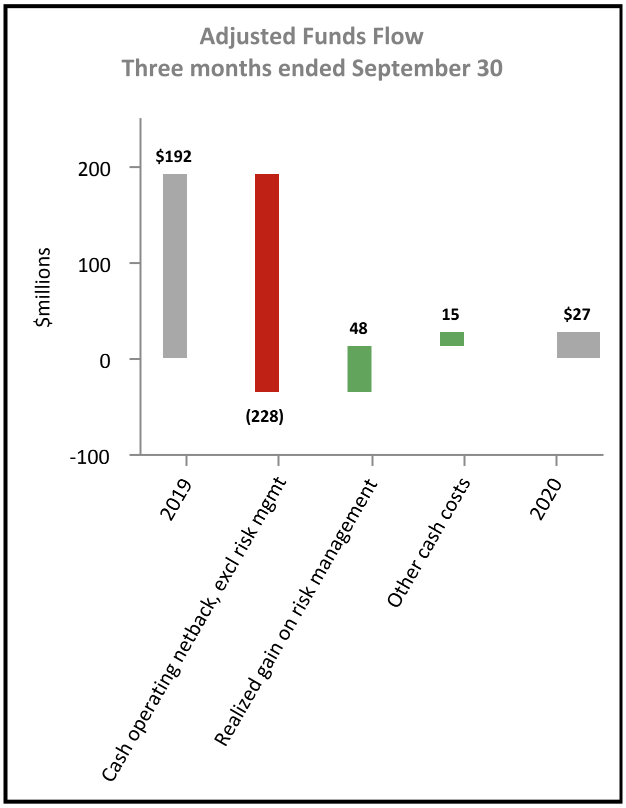
Average bitumen production decreased 23% and 14% during the three and nine months ended September 30, 2020 compared to the same periods of 2019. The decrease in average bitumen production was driven by the major planned turnaround at the Phase 1 and 2 facilities, which began in early June 2020 and was completed mid-August 2020. The 2020 turnaround was extended in duration to 75-days and expanded in scope, relative to base budget, in order to minimize staff levels at site during COVID-19 and maximize utilization of the Corporation's internal resources thereby lowering overall cash costs. The Corporation also made the decision to advance turnaround activities from 2021 to reduce the 2021 turnaround requirements. Average bitumen production during the nine months ended September 30, 2020 was also impacted by reduced capital investment and voluntary price-related production curtailments in April and May 2020 as the Corporation responded to market volatility. Bitumen production in 2019 was limited by the Alberta Government mandated production curtailment, which remains in place but has not impacted production in 2020.

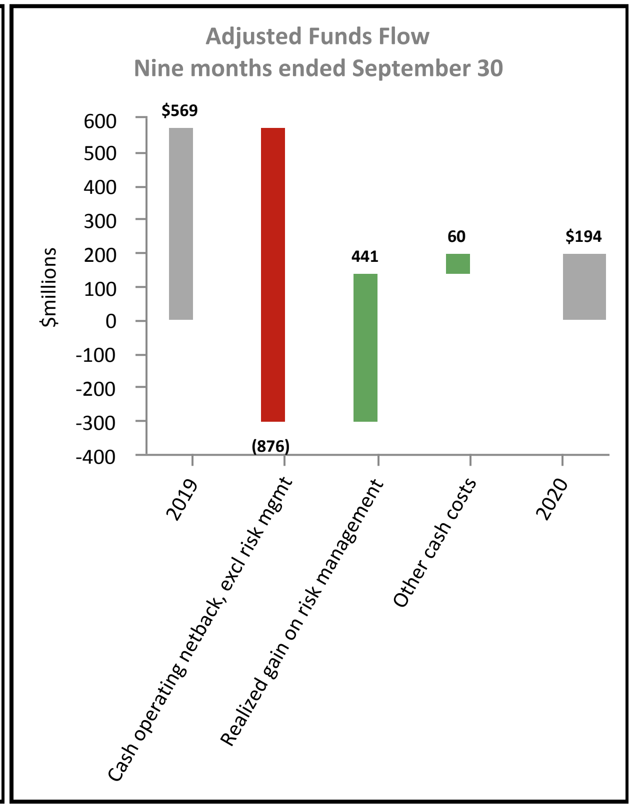
Steam-Oil Ratio

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 increased for the three and nine months ended September 30, 2020, compared to the same periods of 2019, due to the timing of new well pairs and wells being brought into steam circulation and production, as well as actively managing production levels in response to extreme price volatility associated with COVID-19 influenced demand destruction and turnaround activities.

Adjusted Funds Flow

During the three and nine months ended September 30, 2020, adjusted funds flow decreased compared to the same periods of 2019, driven by the Corporation's reduced cash operating netback which was significantly impacted by a sharp decline in global crude oil prices and reduced sales volumes, partially offset by realized gains on commodity price risk management contracts. The continuing priority to drive cost efficiencies into the business as the Corporation maneuvers a volatile market has resulted in reduced general and administrative expense and non-energy operating costs, and lower cash interest costs as a result of overall debt reduction. These cost reductions partially mitigated the decrease in adjusted funds flow during the three and nine months ended September 30, 2020.





The following table reconciles net cash provided by operating activities to adjusted funds flow:

	Three months ended September 30		Nine months ended September 30	
($millions)	**2020**	**2019**	**2020**	**2019**
Net cash provided by (used in) operating activities	**$ (31)**	$ 174	**$ 186**	$ 406
Net change in non-cash operating working capital items	**50**	17	**(28)**	162
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Decommissioning expenditures	**1**	1	**3**	1
Adjusted funds flow	**$ 27**	$ 192	**$ 194**	$ 569

(1) *Costs incurred to mitigate rail sales contract exposure. The economic decision to divert sales volumes from rail contracts at Edmonton to the USGC more than recovered the cost of contract cancellations. Contract cancellation costs or recoveries are excluded from adjusted funds flow as they are not considered part of ordinary continuing operating results.*

Net cash provided by operating activities is an IFRS measure in the Corporation's consolidated statement of cash flow. Adjusted funds flow is calculated as net cash provided by operating activities excluding the net change in non-cash operating working capital, items not considered part of ordinary continuing operating results, and decommissioning expenditures. Adjusted funds flow is used by management to analyze the Corporation's operating performance and cash flow generating ability. By excluding changes in non-cash working capital and other 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.

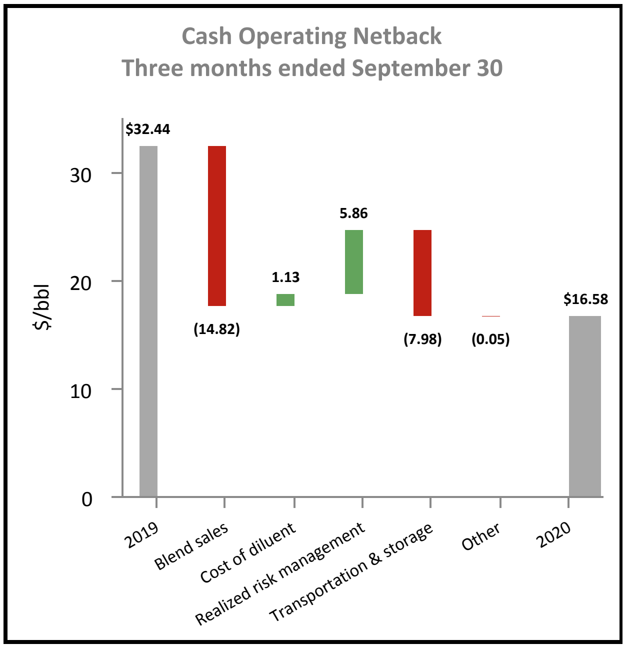
Cash Operating Netback

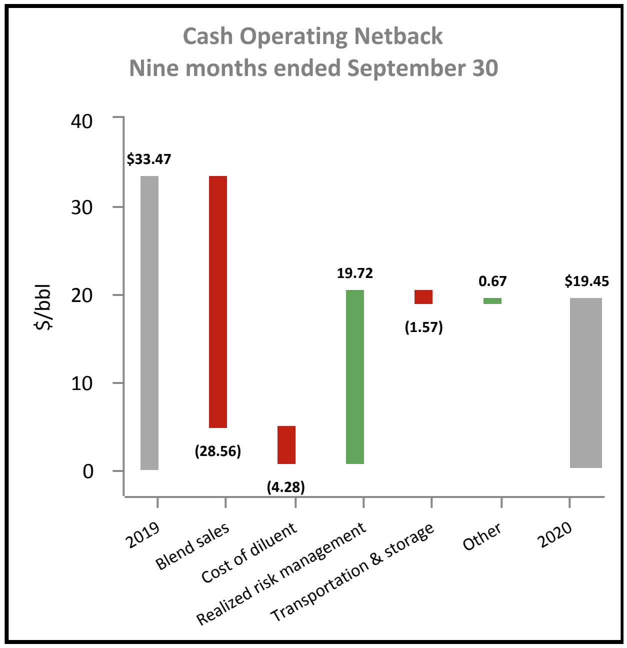
The following table summarizes the Corporation's cash operating netback. Unless otherwise indicated, the per barrel calculation for the periods indicated below are based on bitumen sales volume.

	Three months ended September 30				**Nine months ended September 30**			
	2020		**2019**		**2020**		**2019**	
($millions, except as indicated)		**$/bbl**		**$/bbl**		**$/bbl**		**$/bbl**
Sales from production	**$ 385**		$ 731		**$ 1,035**		$ 2,290	
Sales from purchased product[1]	**140**		224		**437**		626	
Petroleum revenue	**525**		955		**1,472**		2,916	
Purchased product[1]	**(134)**		(221)		**(416)**		(615)	
Blend sales[2]	**$ 391**	**$ 45.44**	$ 734	$ 60.26	**$ 1,056**	**$ 34.34**	$ 2,301	$ 62.90
Cost of diluent	**(144)**	**(5.76)**	(268)	(6.89)	**(572)**	**(11.80)**	(890)	(7.52)
Bitumen realization	**247**	**39.68**	466	53.37	**484**	**22.54**	1,411	55.38
Transportation and storage[3]	**(115)**	**(18.55)**	(93)	(10.57)	**(267)**	**(12.44)**	(277)	(10.87)
Third-party curtailment credits[4]	**—**	**—**	(3)	(0.37)	**2**	**0.08**	(11)	(0.43)
Royalties	**(2)**	**(0.21)**	(13)	(1.54)	**(8)**	**(0.34)**	(34)	(1.34)
Net operating costs	**(38)**	**(6.05)**	(37)	(4.30)	**(126)**	**(5.85)**	(128)	(5.01)
Cash operating netback - excluding realized commodity risk management	**92**	**14.87**	320	36.59	**85**	**3.99**	961	37.73
Realized gain (loss) on commodity risk management	**11**	**1.71**	(37)	(4.15)	**332**	**15.46**	(109)	(4.26)
Cash operating netback[5]	**$ 103**	**$ 16.58**	$ 283	$ 32.44	**$ 417**	**$ 19.45**	$ 852	$ 33.47
Bitumen sales volumes - bbls/d		**67,569**		94,992		**78,354**		93,330

(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) Defined as transportation and storage expense less transportation revenue. Transportation and storage includes costs associated with moving the Corporation's blend from Christina Lake to a final sales location and optimizing the timing of delivery, net of third-party recoveries on diluent transportation arrangements.
(4) The Corporation can purchase or sell production curtailment credits to either increase its production, or sell excess production capacity, compared to its provincially-mandated curtailment level.
(5) A non-GAAP measure as defined in the "NON-GAAP MEASURES" section of this MD&A.

Blend sales includes net revenue related to marketing asset optimization activities focused on the recovery of fixed costs related to any marketing assets during periods of underutilization of such assets, with the goal to strengthen cash operating netback. Asset optimization activities consist of the purchase and sale of third-party products. The Corporation does not engage in speculative trading. The purchase and sale of third-party products requires the Corporation to mitigate exposure to 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 net of cost of diluent, 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. The cost of diluent is impacted by Canadian and U.S. benchmark pricing, the amount of diluent required which is impacted by seasonality and pipeline specifications, the cost of transporting diluent to the production site from both Edmonton and U.S. Gulf Coast ("USGC") markets, the timing of diluent inventory purchases and changes in the value of the Canadian dollar relative to the U.S. dollar. A portion of the cost of diluent is effectively recovered in the sales price of the blended product. 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			
	2020		2019		**2020**		2019	
($millions, except as indicated)		**$/bbl**		**$/bbl**		**$/bbl**		**$/bbl**
Sales from production	**$ 385**		$ 731		**$ 1,035**		$ 2,290	
Sales from purchased product[1]	**140**		224		**437**		626	
Petroleum revenue	**$ 525**		$ 955		**$ 1,472**		$ 2,916	
Purchased product[1]	**(134)**		(221)		**(416)**		(615)	
Blend sales[2]	**$ 391**	**$ 45.44**	$ 734	$ 60.26	**$ 1,056**	**$ 34.34**	$ 2,301	$ 62.90
Cost of diluent	**(144)**	**(5.76)**	(268)	(6.89)	**(572)**	**(11.80)**	(890)	(7.52)
Bitumen realization	**$ 247**	**$ 39.68**	$ 466	$ 53.37	**$ 484**	**$ 22.54**	$ 1,411	$ 55.38

(1) *Sales and purchases of oil products related to marketing asset optimization activities.*
(2) *Blend sales per barrel are based on blend sales volumes.*

Blend sales price decreased by $14.82 per barrel, or 25%, during the three months ended September 30, 2020 compared to the same period of 2019. The decrease in blend sales price during the three months ended September 30, 2020 is due to a lower WTI price partially offset by a narrower WTI:AWB differential at Edmonton.

During the nine months ended September 30, 2020, the blend sales price decreased by $28.56 per barrel, or 45%, compared to the same period of 2019. The decrease in blend sales price during the nine months ended September 30, 2020 is due to a lower WTI price and wider WTI:AWB differentials at Edmonton and the USGC.

The WTI price experienced a significant decline during the three and nine months ended September 30, 2020, largely driven by unprecedented demand shock in the global oil markets due to COVID-19. The change in the WTI:AWB differential at Edmonton and the USGC during the three and nine months ended September 30, 2020 reflected prevailing demand/supply fundamentals for heavy oil and egress constraints moving beyond western Canada.

The Corporation continues to execute on its strategy to partially mitigate the cost of unutilized transportation and storage assets through the purchase and sale of non-proprietary product. These activities added $6 million, or $0.73 per barrel, and $21 million, or $0.68 per barrel to blend sales, during the three and nine months ended September 30, 2020, respectively, compared to $3 million, or $0.24 per barrel, and $11 million, or $0.29 per barrel to blend sales, during the same periods of 2019, respectively. The Corporation does not engage in speculative trading. The purchase and sale of third-party products requires the Corporation to mitigate exposure to 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.

Cost of diluent decreased by $1.13 per barrel, or 16%, during the three months ended September 30, 2020 compared to the same period of 2019. The decrease reflects narrower WTI:AWB differentials and the use of lower priced diluent from inventory resulting in a higher recovery of the cost of diluent through blend sales.

During the nine months ended September 30, 2020, the cost of diluent increased by $4.28 per barrel, or 57%, compared to the same period of 2019. The increase reflects wider WTI:AWB differentials and the use of higher priced diluent from inventory resulting in a lower recovery of the cost of diluent through blend sales.

Transportation and Storage

The Corporation's marketing strategy focuses on maximizing the realized AWB sales price after transportation and storage costs by utilizing its network of pipeline, rail and storage facilities to optimize market access.

	Three months ended September 30				**Nine months ended September 30**			
	2020		**2019**		**2020**		**2019**	
($millions, except as indicated)		**$/bbl**		**$/bbl**		**$/bbl**		**$/bbl**
Transportation and storage	**$ (115)**	**$ (18.55)**	$ (93)	$ (10.57)	**$ (267)**	**$ (12.44)**	$ (277)	$ (10.87)
Bitumen sales volumes - bbls/d		**67,569**		94,992		**78,354**		93,330

Transportation and storage costs on a per barrel basis increased during the three and nine months ended September 30, 2020, compared to the same periods of 2019, as fixed costs were allocated over lower sales volumes, and fixed costs increased during the third quarter of 2020.

During the three months ended September 30, 2020, total transportation and storage costs increased by 24% compared to the same period of 2019. Although transportation costs were reduced due to the suspension of the Corporation's delivered rail transportation to the USGC, this was more than offset by higher costs on the Flanagan South and Seaway pipeline systems ("FSP"). The Corporation’s commitment to move barrels to USGC refineries via FSP increased from 50,000 bbls/d to 100,000 bbls/d in July 2020, subject to apportionment on the Enbridge mainline. This increase in commitment, resulting from the combination of the incremental contracted capacity and low apportionment of 9% during the third quarter of 2020 (44% during the same quarter 2019), resulted in unutilized capacity during the third quarter of 2020 for proprietary product. Approximately 20% of unutilized capacity was mitigated through the purchase and sale of third-party product. To the extent that marketing asset capacity is underutilized, the Corporation has and will continue to look to mitigate these associated costs through short and medium-term third-party contracts.

During the nine months ended September 30, 2020, total transportation and storage costs decreased by 4% compared to the same period of 2019. The decrease is primarily the result of significantly less delivered rail transportation to the USGC partially offset by additional transportation costs associated with the increased capacity on FSP beginning in July 2020 and lower apportionment levels. Beginning in 2020, the Corporation suspended its transport of blend sales by rail to the USGC in favour of increasing its blend sales freight on board ("FOB") at rail terminals at Edmonton. The Corporation no longer leases rail cars nor has contracted rail commitments beyond loading capacity of FOB sales at Edmonton.

Royalties

The Corporation's royalty expense is calculated based on price-sensitive royalty rates set by the Government of Alberta. The royalty rate applicable to the Corporation's Christina Lake operation, which is currently in pre-payout, starts at 1% of bitumen sales and increases for every dollar that 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 applicable royalty rate is then applied to revenue for royalty purposes.

	Three months ended September 30				Nine months ended September 30			
	2020		2019		2020		2019	
($millions, except as indicated)		**$/bbl**		**$/bbl**		**$/bbl**		**$/bbl**
Royalties	**$ (2)**	**$ (0.21)**	$ (13)	$ (1.54)	**$ (8)**	**$ (0.34)**	$ (34)	$ (1.34)

The decrease in royalties for the three and nine months ended September 30, 2020, compared to the same periods of 2019, is the result of the decrease in the WTI benchmark price.

Net Operating Costs

Net operating costs are comprised of the sum 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 provincial power grid displaces other power sources that have a higher carbon intensity, thereby reducing the Corporation's carbon footprint.

	Three months ended September 30				Nine months ended September 30			
	2020		2019		2020		2019	
($millions, except as indicated)		**$/bbl**		**$/bbl**		**$/bbl**		**$/bbl**
Operating costs - non-energy	**$ (25)**	**$ (3.96)**	$ (37)	$ (4.22)	**$ (91)**	**$ (4.25)**	$ (118)	$ (4.64)
Operating costs - energy	**(20)**	**(3.17)**	(13)	(1.51)	**(67)**	**(3.11)**	(56)	(2.19)
Power revenue	**7**	**1.08**	13	1.43	**32**	**1.51**	46	1.82
Net operating costs	**$ (38)**	**$ (6.05)**	$ (37)	$ (4.30)	**$ (126)**	**$ (5.85)**	$ (128)	$ (5.01)
Average natural gas purchase price (C$/mcf)		**$ 2.77**		1.38		**$ 2.49**		$ 2.01
Average realized power sales price (C$/Mwh)		**$ 39.03**		50.30		**$ 48.41**		$ 59.20

Non-energy operating costs decreased for the three and nine months ended September 30, 2020, compared to the same periods of 2019. Contributing to the decrease were various government led initiatives to assist the industry through unprecedented market volatility. The federal government has taken steps to provide various subsidy programs and the provincial and municipal governments have provided relief by reducing regulatory monitoring costs and taxes. In addition, the Corporation has taken measures to reduce costs through salary rollbacks, reductions in staffing levels and vendor concessions. During the nine months ended September 30, 2020, the Corporation was able to benefit from non-recurring cost reductions of $13 million including the Canadian Emergency Wage Subsidy ("CEWS") program.

Total net energy operating costs increased for the three and nine months ended September 30, 2020, compared to the same periods of 2019, predominantly due to the AECO natural gas market strengthening and the Alberta power pool market softening.

Total net operating costs for the three and nine months ended September 30, 2020 were essentially flat compared to the same periods of 2019. However, net operating costs per barrel increased for the three and nine months ended September 30, 2020, compared to the same periods of 2019, due to fixed costs allocated over lower sales volumes.

Realized Gain or Loss on Commodity Risk Management

The Corporation enters into financial commodity risk management contracts to increase the predictability of the Corporation's cash flow by managing commodity price volatility.

	Three months ended September 30				**Nine months ended September 30**			
	2020		**2019**		**2020**		**2019**	
($millions, except as indicated)		**$/bbl**		**$/bbl**		**$/bbl**		**$/bbl**
Realized gain (loss) on commodity risk management	**$ 11**	**$ 1.71**	$ (37)	$ (4.15)	**$ 332**	**$ 15.46**	$ (109)	$ (4.26)

Realized gains recognized on commodity risk management contracts have significantly increased during the three and nine months ended September 30, 2020, compared to the same periods of 2019 mainly due to the unprecedented decline in the WTI price in the first half of 2020 compared to the WTI fixed price contracts in place. Realized losses were recognized during the three and nine months ended September 30, 2019. Refer to the commodity risk management discussion within the “OTHER OPERATING RESULTS” section of this MD&A for further details.

Marketing Activity

The following tables summarize the Corporation's blend sales, net of transportation and storage at Edmonton by sales market for the periods noted to assist in understanding the Corporation's marketing portfolio. All per barrel figures presented in this section of the MD&A are based on US$ per barrel of blend sales volumes unless otherwise indicated:

	Three months ended September 30, 2020				
	Edmonton (US$/bbl)		USGC (US$/bbl)		
(US$ per barrel of blend sales, unless otherwise indicated)	Pipeline	Rail	Pipeline(3)	Rail	TOTAL (US$/bbl)
WTI - benchmark	$ 40.93	$ 40.93	$ 40.93	$ —	$ 40.93
Differential - WTI:AWB at sales point	(10.73)	(20.52)	(2.17)	—	(6.80)
Blend sales price	30.20	20.41	38.76	—	34.13
Transportation and storage(1)	(2.36)	(6.32)	(13.88)	—	(10.07)
Transportation and storage from Christina Lake to Edmonton(2)	2.36	2.36	2.36	—	2.36
Blend sales price, net of transportation & storage at Edmonton	$ 30.20	$ 16.45	$ 27.24	$ —	$ 26.42
Total blend sales - bbls/d	22,275	13,189	58,015	—	93,479
% of total sales	24 %	14 %	62 %	— %	100 %

	Edmonton (US$/bbl)	USGC (US$/bbl)	USGC premium (US$/bbl)
Average blend sales price by location	$ 26.56	$ 38.76	$ 12.20
Transportation and storage(1)	(3.84)	(13.88)	(10.04)
Transportation and storage from Christina Lake to Edmonton(2)	2.36	2.36	—
Blend sales price, net of transportation & storage at Edmonton	$ 25.08	$ 27.24	$ 2.16

	Three months ended September 30, 2019				
	Edmonton (US$/bbl)		USGC (US$/bbl)		
(US$ per barrel of blend sales, unless otherwise indicated)	Pipeline	Rail	Pipeline	Rail	TOTAL (US$/bbl)
WTI - benchmark	$ 56.45	$ 56.45	$ 56.45	$ 56.45	$ 56.45
Differential - WTI:AWB at sales point	(15.20)	(12.05)	(2.33)	(3.34)	(10.82)
Blend sales price	41.25	44.40	54.12	53.11	45.63
Transportation and storage(1)	(1.71)	(4.20)	(10.81)	(23.21)	(5.74)
Transportation and storage from Christina Lake to Edmonton(2)	1.71	1.71	1.71	1.71	1.71
Blend sales price, net of transportation & storage at Edmonton	$ 41.25	$ 41.91	$ 45.02	$ 31.61	$ 41.60
Total blend sales - bbls/d	78,906	10,308	33,989	9,252	132,455
% of total sales	59 %	8 %	26 %	7 %	100 %

	Edmonton (US$/bbl)	USGC (US$/bbl)	USGC premium (US$/bbl)
Average blend sales price by location	$ 41.61	$ 53.90	$ 12.29
Transportation and storage(1)	(1.99)	(13.46)	(11.47)
Transportation and storage from Christina Lake to Edmonton(2)	1.71	1.71	—
Blend sales price, net of transportation & storage at Edmonton	$ 41.33	$ 42.15	$ 0.82

(1) *Defined as transportation and storage expenses less transportation revenue, per barrel of blend sales volumes. For reference, total transportation and storage costs per barrel, based on bitumen sales volumes, were C$18.55 per barrel for the three months ended September 30, 2020 compared to C$10.57 per barrel for the three months ended September 30, 2019.*

(2) *Includes all transportation and storage costs associated with moving barrels of blend from Christina Lake to Edmonton sales point.*

(3) *Sales from marketing asset optimization activities are recognized in the blend sales price and not as a recovery of transportation and storage costs for consistency with the financial statements. These activities contributed US$0.88 per barrel to the blend sales price at the USGC. If presented as a transportation and storage cost recovery, transportation and storage costs per barrel at the USGC would be US$13.00 per barrel compared to US$13.88 per barrel and the WTI:AWB differential at the USGC would be US$3.05 per barrel compared to US$2.17 per barrel.*

(4) *Results are translated at the average foreign exchange rate of 1.3316 for the three months ended September 30, 2020 and 1.3207 for the three months ended September 30, 2019.*

	Nine months ended September 30, 2020				
	Edmonton (US$/bbl)		USGC (US$/bbl)		
(US$ per barrel of blend sales, unless otherwise indicated)	Pipeline	Rail	Pipeline[3]	Rail	TOTAL (US$/bbl)
WTI - benchmark	$ 38.32	$ 38.32	$ 38.32	$ 38.32	$ 38.32
Differential - WTI:AWB at sales point	(19.34)	(17.32)	(3.15)	11.34	(12.96)
Blend sales price	18.98	21.00	35.17	49.66	25.36
Transportation and storage[1]	(2.05)	(5.31)	(12.42)	(24.73)	(6.42)
Transportation and storage from Christina Lake to Edmonton[2]	2.05	2.05	2.05	1.82	2.05
Blend sales price, net of transportation & storage at Edmonton	$ 18.98	$ 17.74	$ 24.80	$ 26.75	$ 20.99
Total blend sales - bbls/d	55,404	15,142	40,906	759	112,211
% of total sales	49 %	14 %	36 %	1 %	100 %

	Edmonton (US$/bbl)	USGC (US$/bbl)	USGC premium (US$/bbl)
Average blend sales price by location	$ 19.41	$ 35.44	$ 16.03
Transportation and storage[1]	(2.75)	(12.64)	(9.89)
Transportation and storage from Christina Lake to Edmonton[2]	2.05	2.05	—
Blend sales price, net of transportation & storage at Edmonton	$ 18.71	$ 24.85	$ 6.14

	Nine months ended September 30, 2019				
	Edmonton (US$/bbl)		USGC (US$/bbl)		
(US$ per barrel of blend sales, unless otherwise indicated)	Pipeline	Rail	Pipeline	Rail	TOTAL (US$/bbl)
WTI - benchmark	$ 57.06	$ 57.06	$ 57.06	$ 57.06	$ 57.06
Differential - WTI:AWB at sales point	(14.82)	(10.63)	0.08	(2.77)	(9.74)
Blend sales price	42.24	46.43	57.14	54.29	47.32
Transportation and storage[1]	(1.74)	(4.15)	(10.65)	(24.00)	(5.70)
Transportation and storage from Christina Lake to Edmonton[2]	1.74	1.74	1.74	1.74	1.74
Blend sales price, net of transportation & storage at Edmonton	$ 42.24	$ 44.02	$ 48.23	$ 32.03	$ 43.36
Total blend sales - bbls/d	77,821	12,397	35,610	8,156	133,984
% of total sales	58 %	9 %	27 %	6 %	100 %

	Edmonton (US$/bbl)	USGC (US$/bbl)	USGC premium (US$/bbl)
Average blend sales price by location	$ 42.82	$ 56.61	$ 13.79
Transportation and storage[1]	(2.07)	(13.14)	(11.07)
Transportation and storage from Christina Lake to Edmonton[2]	1.74	1.74	—
Blend sales price, net of transportation & storage at Edmonton	$ 42.49	$ 45.21	$ 2.72

(1) *Defined as transportation and storage expenses less transportation revenue, per barrel of blend sales volumes. For reference, total transportation and storage costs per barrel, based on bitumen sales volumes, were C$12.44 per barrel for the nine months ended September 30, 2020 compared to C$10.87 per barrel for the nine months ended September 30, 2019.*

(2) *Includes all transportation and storage costs associated with moving barrels of blend from Christina Lake to Edmonton sales point.*

(3) *Sales from marketing asset optimization activities are recognized in the blend sales price and not as a recovery of transportation and storage costs for consistency with the financial statements. These activities contributed US$1.37 per barrel to the blend sales price at the USGC (pipeline). If presented as a transportation and storage cost recovery, transportation and storage costs per barrel at the USGC (pipeline) would be US$11.05 per barrel compared to US$12.42 per barrel and the WTI:AWB differential at the USGC (pipeline) would be US$4.52 per barrel compared to US$3.15 per barrel.*

(4) *Results are translated at the average foreign exchange rate of 1.3541 for the nine months ended September 30, 2020 and 1.3292 for the nine months ended September 30, 2019.*

Effective July 1, 2020, the Corporation's contracted transportation capacity on FSP increased from 50,000 bbls/d to 100,000 bbls/d. The Corporation's access to the USGC, where sales pricing is not subject to the same light:heavy oil differential as at the Edmonton market, translated into premiums earned on blend sales at the USGC over the Edmonton market of US$2.16 per barrel and US$6.14 per barrel for the three and nine months ended September 30, 2020, respectively. This compares to premiums of US$0.82 per barrel and US$2.72 per barrel at the USGC compared to the Edmonton market during the same periods of 2019. The increased premiums, compared to the same periods of 2019, are primarily due to an increased portion of volumes being sold at the USGC via pipeline (62% and 36%, respectively, compared to 26% and 27% for the same periods of 2019, respectively) as well as the suspension of delivered USGC rail activity in early 2020.

Excluding transportation and storage costs upstream of the Edmonton market, the Corporation's net AWB blend sales price at Edmonton averaged US$26.42 per barrel during the three months ended September 30, 2020 compared to the posted AWB benchmark price at Edmonton of US$30.45 per barrel. This variance is a result of a wider fixed differential on FOB rail sales compared to the WTI:AWB differential at Edmonton comprising 14% of sales in the period, in addition to higher fixed transportation costs associated with the increased transportation capacity to the USGC and lower apportionment, partially offset by asset optimization activities. The Corporation's increased FSP transportation capacity was not fully utilized during the three months ended September 30, 2020 as production was impacted by major planned turnaround activity.

Excluding transportation and storage costs upstream of the Edmonton market, the Corporation's net AWB blend sales price averaged US$20.99 per barrel during the nine months ended September 30, 2020 compared to the posted AWB benchmark price at Edmonton of US$22.76 per barrel. This is largely the result of increased sales exposure to the Edmonton market due to higher levels of apportionment in the first quarter of 2020 which preceded the Corporation's increased FSP transportation commitment. Also impacting the blend sales price year-to-date is the wider fixed differential on FOB rail sales compared to the WTI:AWB differential at Edmonton.

Revenue

Revenue represents the total 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	
($millions)	**2020**	2019	**2020**	2019
Sales from:				
Production	**$ 385**	$ 731	**$ 1,035**	$ 2,290
Purchased product[1]	**140**	224	**437**	626
Petroleum revenue	**$ 525**	$ 955	**$ 1,472**	$ 2,916
Royalties	**(2)**	(13)	**(8)**	(34)
Petroleum revenue, net of royalties	**$ 523**	$ 942	**$ 1,464**	$ 2,882
Power revenue	**$ 6**	$ 13	**$ 32**	$ 46
Transportation revenue	**4**	3	**9**	10
Other revenue	**$ 10**	$ 16	**$ 41**	$ 56
Total revenues	**$ 533**	$ 958	**$ 1,505**	$ 2,938

(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 months ended September 30, 2020, total revenues decreased 44% from the same period of 2019 primarily as a result of a 29% reduction in blend sales volumes due to turnaround activities and a decrease in the average blend sales price driven by the decline in WTI prices.

During the nine months ended September 30, 2020, total revenues decreased 49% from the same period of 2019 primarily as a result of the decrease to the average blend sales price driven by the decline in WTI prices, the widening of WTI:AWB differentials and a 16% reduction in blend sales volumes as a result of turnaround activities and voluntary curtailment in April and May 2020.

Net Earnings (Loss)

	Three months ended September 30		Nine months ended September 30	
($millions, except per share amounts)	**2020**	**2019**	**2020**	**2019**
Net earnings (loss)	**$ (9)**	$ 24	**$ (373)**	$ (87)
Per share, diluted	**$ (0.03)**	$ 0.08	**$ (1.24)**	$ (0.29)

The Corporation incurred a net loss for the three months ended September 30, 2020 of $9 million compared to net earnings of $24 million during the same period of 2019 primarily as a result of a decrease in cash operating netback partially offset by an increase in the unrealized foreign exchange gain. The net loss for the nine months ended September 30, 2020 increased from the same period of 2019 primarily as a result of a decrease in cash operating netback and an increase in the unrealized foreign exchange loss partially offset by an increase in the unrealized risk management gain.

Capital Expenditures

	Three months ended September 30		Nine months ended September 30	
($millions)	**2020**	**2019**(1)	**2020**	**2019**(1)
Sustaining and maintenance	**$ 21**	$ 25	**$ 70**	$ 66
Turnaround	**15**	—	**25**	—
Phase 2B brownfield expansion	**—**	9	**14**	29
eMVAPEX	**—**	(3)	**—**	10
Field infrastructure, corporate and other	**—**	9	**—**	21
	$ 36	$ 40	**$ 109**	$ 126

(1) Certain prior year costs have been reclassified for consistency with the Corporation's Phase 2B brownfield development plan.

The decrease in capital spending for the three and nine months ended September 30, 2020, compared to the same periods of 2019, reflects the Corporation's decision to reduce capital spending in 2020 due to the economic instability created by COVID-19. Capital expenditures during the three and nine months ended September 30, 2020 were primarily directed towards sustaining and maintenance activities and the 75-day turnaround that began in early June 2020 and was completed in August 2020. The 2020 turnaround was extended in duration and expanded in scope, relative to base budget, in order to minimize staff levels at site during COVID-19 and maximize utilization of the Corporation's internal resources thereby lowering overall cash costs. The Corporation also made the decision to advance turnaround activities from 2021 to capitalize on the low oil price environment and to reduce the 2021 turnaround requirements. Phase 2B brownfield expansion expenditures are currently suspended until market conditions improve.

During the three months ended September 30, 2019, the Corporation received an $8 million Government of Canada grant related to its eMVAPEX pilot.

5. OUTLOOK

Summary of 2020 Guidance	Revised Guidance (October 26, 2020)	Previously Revised Guidance (July 27, 2020)	Previously Revised Guidance (May 4, 2020)	Previously Revised Guidance (March 10, 2020)	Original Guidance (November 21, 2019)
Production (1H20)	N/A	N/A	76,000 bbls/d	N/A	N/A
Production (FY20 average)	81,000 - 82,000 bbls/d	78,000-80,000 bbls/d	N/A	93,000-95,000 bbls/d	94,000-97,000 bbls/d
Non-energy operating costs	$130-$135 million(1)	$140-$150 million	$140-$150 million	$155-$165 million ($4.50-$4.90 per bbl)	$160-$170 million ($4.50-$4.90 per bbl)
G&A expense	$45-$47.5 million(1)	$52.5-$55 million	$52.5-$55 million	$60-$62.5 million ($1.75-$1.85 per bbl)	$62.5-$65 million ($1.75-$1.85 per bbl)
Capital expenditures	$150 million	$150 million	$150 million	$200 million	$250 million

(1) Revised non-energy operating costs and G&A expense guidance ranges include approximately $15 million and $7 million, respectively, of temporary cost reductions including CEWS.

Based on better than expected production performance during and post-turnaround, MEG is revising upward its full year 2020 average production from 78,000 – 80,000 bbls/d to 81,000 – 82,000 bbls/d. Compared to the original guidance of 94,000 – 97,000 bbls/d announced November 21, 2019, approximately half of the difference is due to the impact of the scheduled 75-day major turnaround at the Christina Lake Phase 1 and 2 facilities completed mid-August. The remainder of the difference results from a combination of previously disclosed weather-related production impacts in the first quarter of 2020, voluntary price-related production curtailments in the second quarter of 2020 and the impact of reduced well capital throughout 2020, which made up approximately 80% of the combined $100 million reduction in capital spending announced on March 10 and May 4 of 2020.

G&A expense is now targeted to be in the range of $45 – $47.5 million, or approximately $17.5 million lower than original guidance. Non-energy operating costs are now expected to be in the range of $130 - $135 million, or approximately $32.5 million lower than original guidance. Of the $50 million aggregate reduction in expected costs, approximately $22 million are a result of temporary cost reductions while the remaining $28 million in cost reductions are a result of a continued optimization of operations, reduction in staffing levels and rationalization of ongoing administrative costs.

6. BUSINESS ENVIRONMENT

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

	Nine months ended September 30		2020			2019			
	2020	**2019**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**
Average Benchmark Commodity Prices									
Crude oil prices									
Brent (US$/bbl)	**42.55**	64.73	**43.39**	33.30	50.95	62.50	61.97	68.32	63.90
WTI (US$/bbl)	**38.32**	57.06	**40.93**	27.85	46.17	56.96	56.45	59.82	54.90
Differential – WTI:WCS – Edmonton (US$/bbl)	**(13.69)**	(11.73)	**(9.09)**	(11.47)	(20.53)	(15.83)	(12.24)	(10.67)	(12.29)
Differential – WTI:AWB – Edmonton (US$/bbl)	**(15.56)**	(13.78)	**(10.48)**	(13.44)	(22.78)	(18.44)	(14.52)	(12.32)	(14.50)
AWB – Edmonton (US$/bbl)	**22.76**	43.28	**30.45**	14.41	23.39	38.52	41.93	47.50	40.40
Differential – WTI:AWB – U.S. Gulf Coast (US$/bbl)	**(5.41)**	(0.58)	**(3.20)**	(7.29)	(5.74)	(5.25)	(2.50)	1.64	(0.89)
AWB – U.S. Gulf Coast (US$/bbl)	**32.91**	56.48	**37.73**	20.56	40.43	51.71	53.95	61.46	54.01
Condensate prices									
Condensate at Edmonton (C$/bbl)	**47.51**	70.25	**50.03**	30.72	61.76	70.01	68.73	74.76	67.25
Condensate at Edmonton as % of WTI	**91.6%**	92.6%	**91.8%**	79.6%	99.5%	93.1%	92.2%	93.4%	92.1%
Condensate at Mont Belvieu, Texas (US$/bbl)	**30.07**	47.62	**33.52**	17.43	39.27	50.08	44.34	50.22	48.31
Condensate at Mont Belvieu, Texas as % of WTI	**78.5%**	83.5%	**81.9%**	62.6%	85.1%	87.9%	78.5%	84.0%	88.0%
Natural gas prices									
AECO (C$/mcf)	**2.32**	1.43	**2.48**	2.21	2.26	2.70	0.95	1.12	2.86
Electric power prices									
Alberta power pool (C$/MWh)	**46.69**	58.02	**43.75**	29.94	66.38	47.07	46.95	56.37	70.73
Foreign exchange rates									
C$ equivalent of 1 US$ – average	**1.3541**	1.3292	**1.3316**	1.3860	1.3445	1.3201	1.3207	1.3376	1.3293
C$ equivalent of 1 US$ – period end	**1.3324**	1.3244	**1.3324**	1.3616	1.4120	1.2965	1.3244	1.3091	1.3360

Beginning in early March 2020 and continuing into the third quarter of 2020, market conditions precipitated by COVID-19, and subsequent measures intended to limit the outbreak globally, contributed to an unprecedented impact on global commodity prices. With reduced crude oil demand and excess supply, the price of crude oil and other petroleum products deteriorated significantly during the first half of 2020 and although there has been an improvement in the stability of the global oil market into the third quarter of 2020 there remains uncertainty regarding the ongoing impact of COVID-19 on global commodity prices.

These events and conditions have also caused a significant decrease in the valuation of oil and natural gas companies. These difficulties have been exacerbated in Canada by actions resulting in uncertainty surrounding regulatory, tax, royalty changes and environmental regulation. In addition, the difficulties encountered to obtain the necessary approvals on a timely basis to build pipelines, liquefied natural gas plants and other facilities to provide better access to markets for the oil and natural gas industry in western Canada has led to additional downward price pressure on oil and natural gas produced in western Canada.

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 sales.

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. 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 both the quality differential 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.

On December 3, 2018 the Government of Alberta enacted rules to enable a temporary curtailment of crude oil and bitumen production. The Curtailment Rules came into force on January 1, 2019, and are in place until November 30, 2020, with possible earlier termination or extension. The Curtailment Rules give the Province the authority to make an order to set the maximum combined provincial production amount of crude oil and bitumen on a monthly basis. The limit is monitored closely and adjusted to match export capacity out of the province. The Province will continue to have the authority to re-introduce production limits until December 31, 2021.

On October 31, 2019 the Government of Alberta Special Production Allowance program was enacted to give crude oil and bitumen producers temporary curtailment relief equal to incremental increases in rail shipments. On a monthly basis, operators can apply to increase oil production if additional product is moved by new rail capacity out of the province.

Condensate Prices

In order to facilitate pipeline transportation of bitumen, the Corporation uses condensate as diluent for blending with the Corporation’s bitumen. The Corporation sources its condensate from the Edmonton area, but due to high demand for condensate in the Edmonton market, the Corporation also purchases condensate from the USGC market where pricing is generally lower. The Corporation's committed diluent purchases at the USGC reference benchmark pricing at Mont Belvieu, Texas. The Corporation's per barrel cost of condensate sourced from Mont Belvieu, Texas included net transportation costs of approximately US$6.35 per barrel and US$6.20 per barrel to move the product from Mont Belvieu to the Edmonton area for the three and nine months ended September 30, 2020, respectively.

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. The AECO natural gas price increased during the three and nine months ended September 30, 2020 compared to the same periods of 2019 due to market uncertainty surrounding possible gas supply constraints in 2021 as a result of decreased oil drilling activity and historically low rig counts in 2020.

Electric Power Prices

Electric power prices impact the price that the Corporation receives on the sale of surplus power from the Corporation’s cogeneration facilities. The Alberta power pool price decreased during the three and nine months ended September 30, 2020 compared to the same periods of 2019 primarily as a result of an oversupply of generation in the province.

7. OTHER OPERATING RESULTS

Depletion and Depreciation

	Three months ended September 30		Nine months ended September 30	
($millions, except as indicated)	**2020**	**2019**	**2020**	**2019**
Depletion and depreciation expense	**$ 87**	$ 115	**$ 304**	$ 595
Depletion and depreciation expense per barrel of production	**$ 13.33**	$ 13.43	**$ 13.97**	$ 23.55

Depletion and depreciation expense was impacted by one-time charges as the Corporation narrows its development focus to core assets at Christina Lake. The Corporation incurred an accelerated depreciation expense of $13 million, or $0.60 per barrel, during the nine months ended September 30, 2020 compared to an accelerated depreciation expense of $237 million, or $9.38 per barrel, for the nine months ended September 30, 2019. The accelerated depreciation expense in 2019 was recognized on equipment, materials and engineering costs associated with greenfield expansion projects and a partial upgrading technology project.

Excluding one-time charges, depletion and depreciation expense was $13.33 per barrel and $13.37 per barrel for the three and nine months ended September 30, 2020, respectively, compared to $13.43 per barrel and $14.17 per barrel for the three and nine months ended September 30, 2019. Depletion and depreciation expense per barrel decreased due to lower future development costs.

Exploration Expense

	Three months ended September 30		Nine months ended September 30	
($millions)	**2020**	**2019**	**2020**	**2019**
Exploration expense	**$ —**	—	**$ 366**	58

During the first quarter of 2020, the Corporation discontinued exploration and evaluation activities in certain non-core growth properties and the associated land lease and evaluation costs totaling $366 million were charged to exploration expense during the nine months ended September 30, 2020 compared to $58 million during the same period of 2019. This is a result of focusing on the development of core assets to manage the business through an unpredictable global downturn of unknown duration.

Commodity Risk Management Gain (Loss)

The Corporation enters into financial commodity risk management contracts to increase the predictability of the Corporation's cash flow by managing commodity price volatility. The Corporation has not designated any of its commodity risk management contracts as hedges for accounting purposes. All financial commodity risk management contracts have been recorded at fair value, with all changes in fair value recognized through net earnings (loss). Realized gains or losses on financial commodity risk management contracts are the result of 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.

	Three months ended September 30		Nine months ended September 30	
($millions)	**2020**	**2019**	**2020**	**2019**
Realized:				
Crude oil contracts[1]	**$ 15**	$ (25)	**$ 350**	$ (87)
Condensate contracts[2]	**(4)**	(12)	**(18)**	(22)
Realized commodity risk management gain (loss)	**$ 11**	$ (37)	**$ 332**	$ (109)
Unrealized:				
Crude oil contracts[1]	**$ (36)**	$ 8	**$ 81**	$ (104)
Condensate contracts[2]	**19**	2	**63**	(8)
Unrealized commodity risk management gain (loss)	**$ (17)**	$ 10	**$ 144**	$ (112)
Commodity risk management gain (loss)	**$ (6)**	$ (27)	**$ 476**	$ (221)

(1) Includes WTI fixed price contracts, WTI:WCS fixed differential contracts and WTI enhanced fixed price with sold put options contracts.

(2) Relates to condensate purchase contracts that effectively fix condensate prices at Mont Belvieu, Texas relative to WTI.

During the three months ended September 30, 2020, an $11 million commodity risk management gain was realized on settled commodity risk management contracts partially insulating the Corporation's cash operating netback. The fair value of commodity risk management contracts, which settle in future periods, decreased as forward WTI prices improved and WTI:WCS differentials narrowed during the third quarter of 2020 resulting in a $17 million unrealized commodity risk management loss.

For the nine months ended September 30, 2020, the Corporation recognized a $476 million net gain from commodity risk management primarily due to weakening WTI prices relative to contracted prices. This compares with the $221 million net loss from commodity risk management for the nine months ended September 30, 2019, when WTI prices increased and WTI:WCS differentials narrowed relative to contracted prices.

The realized commodity risk management gain (loss) represents actual contract settlements over the periods presented. 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$/bbl)	**2020**	**2019**	**2020**	**2019**
WTI fixed price contracts[1]:				
Average fixed price	**$ 44.51**	$ 61.76	**$ 53.47**	$ 63.03
Average settlement price	**40.93**	56.45	**38.32**	57.18
Gain (loss) on WTI fixed price contracts	**$ 3.58**	$ 5.31	**$ 15.15**	$ 5.85
WTI:WCS fixed differential contracts:				
Average fixed differential	**$ (20.72)**	$ (21.10)	**$ (20.10)**	$ (21.91)
Average settlement differential	**(9.09)**	(12.24)	**(13.70)**	(11.74)
Gain (loss) on WTI:WCS fixed differential contracts	**$ (11.63)**	$ (8.86)	**$ (6.40)**	$ (10.17)
Condensate purchase contracts:				
Average fixed differential[2]	**$ (5.15)**	$ (5.28)	**$ (5.44)**	$ (5.12)
Average settlement differential	**(7.41)**	(12.12)	**(8.26)**	(9.81)
Gain (loss) on condensate purchase contracts	**$ (2.26)**	$ (6.84)	**$ (2.82)**	$ (4.69)

(1) Excludes enhanced fixed price with sold put option contracts which realized an average gain of US$7.38 per barrel.

(2) Condensate purchase contracts either fix the WTI:condensate differential at Mont Belvieu, Texas relative to WTI or fix the condensate price as a % of WTI.

General and Administrative

	Three months ended September 30		Nine months ended September 30	
($millions, except as indicated)	**2020**	**2019**	**2020**	**2019**
General and administrative expense	**$ 10**	$ 14	**$ 35**	$ 48
General and administrative expense per barrel of production	**$ 1.50**	$ 1.66	**$ 1.61**	$ 1.90

General and administrative ("G&A") expense decreased 29% and 27% for the three and nine months ended September 30, 2020, respectively, compared to the same periods of 2019. Contributing to the decrease was the Corporation's continuing efforts to drive efficiency into its cost structure including salary rollbacks, reductions in staffing levels and vendor concessions as well as various government led initiatives, including the CEWS, to assist the industry through unprecedented market volatility. During the nine months ended September 30, 2020, the Corporation was able to benefit from non-recurring G&A cost reductions of approximately $5 million, including the CEWS program.

During the first half of 2020, a decision was made to roll back salaries across the Corporation, with an emphasis on Board, executive and senior leader compensation. Effective June 1, 2020, base cash compensation for Board members was reduced by 25%. The President and Chief Executive Officer had his annual base salary reduced by 25%, the Chief Operating Officer and Chief Financial Officer each took a 15% annual base salary reduction, vice presidents received a 12% annual base salary rollback and all other employees received a 7.5% annual base salary rollback.

Stock-based Compensation

	Three months ended September 30		Nine months ended September 30	
($millions)	**2020**	**2019**	**2020**	**2019**
Cash-settled expense (recovery)	**$ (1)**	$ 3	**$ (10)**	$ (1)
Equity-settled expense	**2**	5	**9**	20
Equity price risk management (gain) loss[(1)]	**$ 9**	$ —	**$ (11)**	$ —
Stock-based compensation	**$ 10**	$ 8	**$ (12)**	$ 19

(1) Relates to financial derivatives entered into to manage the Corporation's exposure to cash-settled RSUs and 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 Risk Management section of this MD&A for further details.

The Corporation's common share price declined to $2.77 per share as at September 30, 2020, from its value of $3.77 per share as at June 30, 2020 and $7.39 per share as at December 31, 2019, primarily due to the impact of COVID-19 on capital markets which resulted in a $1 million and $10 million cash-settled stock-based compensation recovery during the three and nine months ended September 30, 2020, respectively.

Equity-settled stock-based compensation expense decreased for the three and nine months ended September 30, 2020, compared to the same periods of 2019, due to a decrease in the fair value of awards granted in April 2020 and recoveries as a result of staff reductions. Effective April 1, 2020, a decision was made to reduce the value of target 2020 long-term incentive awards issued to employees and directors by 20%.

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 nine months ended September 30, 2020, an unrealized gain of $11 million was recognized on the increase in share price since inception in March 2020, and an unrealized loss of $9 million was recognized in the three months ended September 30, 2020 as the Corporation's common share priced declined in value during the period.

Foreign Exchange Gain (Loss), Net

	Three months ended September 30		Nine months ended September 30	
($millions)	**2020**	**2019**	**2020**	**2019**
Unrealized foreign exchange gain (loss) on:				
Long-term debt	**$ 67**	$ (41)	**$ (95)**	$ 113
US$ denominated cash and cash equivalents	**3**	3	**12**	(6)
Unrealized net gain (loss) on foreign exchange	**70**	(38)	**(83)**	107
Realized gain (loss) on foreign exchange	**—**	(1)	**(1)**	1
Foreign exchange gain (loss), net	**$ 70**	$ (39)	**$ (84)**	$ 108

C$ equivalent of 1 US$				
Beginning of period	**1.3616**	1.3091	**1.2965**	1.3646
End of period	**1.3324**	1.3244	**1.3324**	1.3244

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 months ended September 30, 2020, the Canadian dollar strengthened relative to the U.S. dollar by 2%, resulting in an unrealized foreign exchange gain of $70 million. During the three months ended September 30, 2019, the Canadian dollar weakened by 1%, resulting in an unrealized foreign exchange loss of $38 million.

During the nine months ended September 30, 2020, the Canadian dollar weakened relative to the U.S. dollar by 3%, resulting in an unrealized foreign exchange loss of $83 million. During the nine months ended September 30, 2019, the Canadian dollar strengthened by 3%, resulting in an unrealized foreign exchange gain of $107 million.

Net Finance Expense

	Three months ended September 30		Nine months ended September 30	
($millions)	**2020**	**2019**	**2020**	**2019**
Interest expense on long-term debt	**$ 59**	$ 69	**$ 183**	$ 210
Interest expense on lease liabilities	**6**	6	**19**	19
Interest income	**—**	(1)	**(2)**	(4)
Net interest expense	**65**	74	**200**	225
Accretion on provisions	**2**	2	**6**	5
Unrealized loss on derivative financial liabilities	**—**	(1)	**—**	(1)
Net finance expense	**$ 67**	$ 75	**$ 206**	$ 229

Average effective interest rate	**7.0%**	6.6%	**6.9%**	6.6%

As a result of the senior secured term loan repayment in July 2019 and partial redemptions on the Corporation's senior secured second lien notes and senior unsecured notes during the second half of 2019 and the first quarter of 2020, net finance expense for the three and nine months ended September 30, 2020 decreased, compared to the same periods of 2019.

Other Expenses

	Three months ended September 30		Nine months ended September 30	
	2020	2019	**2020**	2019
Contract cancellation	**$ 7**	—	**$ 33**	—
Severance and restructuring	**4**	—	**8**	12
Research and development	**—**	3	**—**	7
Other expenses	**$ 11**	$ 3	**$ 41**	$ 19

Contract cancellation costs were incurred to mitigate rail sales contract exposure. The economic decision to divert sales volumes from rail contracts at Edmonton to the USGC more than recovered the cost of contract cancellations.

Income Tax

	Three months ended September 30		Nine months ended September 30	
($millions)	**2020**	2019	**2020**	2019
Income tax expense (recovery)	**$ (20)**	$ 15	**$ (84)**	$ (19)
Effective tax rate	**78 %**	38 %	**19 %**	18 %

As at September 30, 2020, the Corporation had approximately $7.2 billion of available Canadian tax pools and recognized a deferred income tax asset of $345 million. Estimated future taxable income is expected to be sufficient to realize the deferred income tax asset.

The effective tax rate of 19% for the nine months ended September 30, 2020 is lower than the Canadian statutory rate of 25% due to the tax effect of realized and unrealized foreign exchange losses on the Corporation's debt.

During the second quarter of 2019, the Government of Alberta enacted legislation to reduce the corporate tax rate from 12% to 8% by January 1, 2022. As a result, the Corporation recognized a one-time deferred income tax expense of $34 million associated with the rate reduction, as the rate change reduced the value of the Corporation's deferred tax asset as at June 30, 2019. Acceleration of the rate change to 8% by July 1, 2020 was announced during the second quarter of 2020 and had no further impact given the Corporation's tax horizon. The Corporation does not expect to pay Canadian income taxes during the next five years.

8. LIQUIDITY AND CAPITAL RESOURCES

($millions)	**September 30, 2020**	December 31, 2019
Second Lien:		
6.5% senior secured second lien notes (September 30, 2020 - US$496 million; December 31, 2019 - US$596 million; due 2025)	**$ 661**	$ 773
Unsecured:		
7.0% senior unsecured notes (September 30, 2020 - US$600 million; December 31, 2019 - US$1 billion; due 2024)	**799**	1,297
7.125% senior unsecured notes (September 30, 2020 - US$1.2 billion; December 31, 2019 - US$nil; due 2027)	**1,599**	—
6.375% senior unsecured notes (September 30, 2020 - US$nil; December 31, 2019 - US$800 million; due 2023)	**—**	1,037
Less:		
Debt redemption premium	**—**	29
Unamortized deferred debt discount and debt issue costs	**(29)**	(13)
Long-term debt	**3,030**	3,123
Cash and cash equivalents	**(49)**	(206)
Net debt[(1)]	**$ 2,981**	$ 2,917

(1) Net debt is reconciled to long-term debt in accordance with IFRS in Note 20 of the interim consolidated financial statements.

During the nine months ended September 30, 2020 net debt increased by $64 million due to the decrease in cash and cash equivalents and the weakening of the Canadian dollar relative to the US dollar, partially offset by the partial redemption of the Corporation's 6.5% senior secured second lien notes.

On January 31, 2020 the Corporation successfully closed a private offering of $1.6 billion (US$1.2 billion) in aggregate principal amount of 7.125% senior unsecured notes due February 2027. On February 18, 2020, the net proceeds of the offering, together with cash on hand, were used to:

- Fully redeem $1 billion (US$800 million) of the 6.375% senior unsecured notes due January 2023 at a redemption price of 101.063%;
- Partially redeem $530 million (US$400 million) of the US$1.0 billion 7.0% senior unsecured notes due March 2024 at a redemption price of 102.333%; and
- Pay fees and expenses related to the offering.

Concurrent with the private offering, on February 18, 2020, the Corporation redeemed $132 million (US$100 million) in aggregate principal amount of its 6.5% senior secured second lien notes due January 2025 at a redemption price of 104.875%.

In total, $180 million of cash on hand was used to fund the partial redemption of the second lien notes, to fund the call premiums associated with the redemption of the 2023 and 2024 notes, and to pay debt issue costs associated with the transactions.

The Corporation's cash and cash equivalents balance was $49 million as at September 30, 2020 compared to $206 million as at December 31, 2019. Adjusted funds flow of $194 million during the nine months ended September 30, 2020 was more than offset by the repayment of debt and capital expenditures. Refer to the "Cash Flow Summary" section for further details.

The Corporation has total available credit under two facilities of $1.3 billion, comprised of $800 million under the revolving credit facility and $500 million under a letter of credit facility guaranteed by Export Development Canada ("EDC Facility"). Letters of credit under the EDC facility do not consume capacity of the revolving credit facility. The revolving credit facility and the EDC Facility have a maturity date of July 30, 2024. The maturity dates of the revolving credit facility and the EDC Facility include a feature that would cause the maturity dates to spring back to 91 days prior to the maturity date of certain material debt of the Corporation if such debt has not been repaid or refinanced prior to such date. The revolving credit facility, EDC facility and senior secured second lien notes are secured by substantially all the assets of the Corporation.

The Corporation continues to proactively respond to the current business environment. In May 2020, the Corporation reduced capital guidance by $100 million compared to original guidance. On October 26, 2020, the Corporation issued revised 2020 guidance which reduced non-energy operating costs by $32.5 million and G&A costs by $17.5 million compared to original guidance. Meeting current and future obligations while navigating the uncertainty associated with COVID-19 is supported by the Corporation's financial framework including a strong commodity risk management program securing cash flow through 2020 and extending into 2021, and credit risk management policies minimizing exposure related to customer receivables primarily to investment grade customers in the energy industry. The Corporation's earliest maturing long-term debt is approximately three and a half years out, represented by US$600 million of senior unsecured notes due March 2024. None of the Corporation’s outstanding long-term debt contain financial maintenance covenants. Additionally, the Corporation's modified covenant-lite $800 million revolving credit facility has no financial maintenance covenant unless drawn in excess of $400 million. If drawn in excess of $400 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.

As at September 30, 2020, the Corporation had $785 million of unutilized capacity under the $800 million revolving credit facility and the Corporation had $85 million of unutilized capacity under the $500 million EDC facility. A letter of credit of $15 million was issued under the revolving credit facility during the nine months ended September 30, 2020. Letters of credit issued under the revolving credit 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	
($millions)	**2020**	**2019**	**2020**	**2019**
Net cash provided by (used in):				
Operating activities	**$ (31)**	$ 174	**$ 186**	$ 406
Investing activities	**(36)**	(33)	**(145)**	(158)
Financing activities	**(6)**	(389)	**(209)**	(405)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency	**2**	3	**11**	(7)
Change in cash and cash equivalents	**$ (71)**	$ (245)	**$ (157)**	$ (164)

Cash Flow – Operating Activities

The shift to net cash used in operating activities for the three months ended September 30, 2020 and the decrease in net cash provided by operating activities for the nine months ended September 30, 2020, compared to net cash provided by operating activities in the same periods of 2019, is primarily due to decreased blend sales as a result of lower benchmark crude oil prices and decreased blend sales volumes, partially offset by realized commodity risk management gains.

Cash Flow – Investing Activities

Net cash used in investing activities increased during the three months ended September 30, 2020 compared to the same period of 2019, reflecting timing of working capital changes.

Net cash used in investing activities decreased during the nine months ended September 30, 2020 compared to the same period of 2019 which aligns with the Corporation's reduced capital spending.

Cash Flow – Financing Activities

Net cash used in financing activities during the nine months ended September 30, 2020 included the redemption of a portion of the 6.5% senior secured second lien notes totaling $132 million (US$100 million) as well as debt redemption premiums and other refinancing costs incurred related to the January 31, 2020 refinancing.

Net cash used in financing activities during the three and nine months ended September 30, 2019 included the repayment of the outstanding senior secured term loan balance of $289 million (US$219 million) and the repurchase and extinguishment of $96 million (US$73 million) of principal on the 6.5% senior secured second lien notes.

9. RISK MANAGEMENT

Commodity Price 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 and natural gas purchases. The Corporation also 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 crude oil sales and condensate purchases outstanding as at September 30, 2020:

As at September 30, 2020			
Crude Oil Sales Contracts	**Volumes (bbls/d)(1)**	**Term**	**Average Price (US$/bbl)(1)**
WTI Fixed Price	59,826	Oct 1, 2020 - Dec 31, 2020	$46.60
WTI:WCS Fixed Differential	28,000	Oct 1, 2020 - Dec 31, 2020	$(20.27)
Enhanced Fixed Price with Sold Put Option			
WTI Fixed Price/Sold Put Option Strike Price	24,500	Oct 1, 2020 - Dec 31, 2020	$59.11 / $52.00
WTI Fixed Price/Sold Put Option Strike Price	2,000	Jan 1, 2021 - Dec 31, 2021	$47.50 / $36.00
Condensate Purchase Contracts			
WTI:Mont Belvieu Fixed Differential	7,250	Oct 1, 2020 - Dec 31, 2020	$(7.63)
WTI:Mont Belvieu Fixed Differential	10,950	Jan 1, 2021 - Dec 31, 2021	$(10.37)
WTI:Mont Belvieu Fixed Differential	200	Jan 1, 2022 - Dec 31, 2022	$(11.30)
WTI:Mont Belvieu Fixed % of WTI	7,750	Oct 1, 2020 - Dec 31, 2020	93.1 %
Natural Gas Purchase Contracts	**Volumes (GJ/d)(1)**	**Term**	**Average Price (C$/GJ)(1)**
AECO Fixed Price	5,000	Jan 1, 2021 - Dec 31, 2021	$2.73

(1) The volumes, prices and percentages in the above table represent averages for various contracts with differing terms and prices. The average *price and percentages for the portfolio may not have the same payment profile as the individual contracts and are provided for indicative purposes.*

The Corporation entered into the following financial commodity risk management contracts relating to crude oil sales between September 30 and October 26, 2020:

Subsequent to September 30, 2020			
Crude Oil Sales Contracts	**Volumes (bbls/d)(1)**	**Term**	**Average Price (US$/bbl)(1)**
WTI Fixed Price	21,265	Oct 1, 2020 - Oct 31, 2020	$40.48
WTI Fixed Price	8,200	Nov 1, 2020 - Nov 30, 2020	$41.16
Enhanced Fixed Price with Sold Put Option			
WTI Fixed Price/Sold Put Option Strike Price	19,000	Jan 1, 2021 - Dec 31, 2021	$46.12 / $39.00
Natural Gas Purchase Contracts	**Volumes (GJ/d)(1)**	**Term**	**Average Price (C$/GJ)(1)**
AECO Fixed Price	20,000	Jan 1, 2021 - Dec 31, 2021	$2.67

(1) The volumes and prices in the above table represent averages for various contracts with differing terms and prices. The average *price and percentages for the portfolio may not have the same payment profile as the individual contracts and are provided for indicative purposes.*

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, 2020:

Commodity	Sensitivity Range	Increase	Decrease
Crude oil commodity price	± US$5.00 per bbl applied to WTI contracts	$ (42)	$ 41
Crude oil differential price(1)	± US$5.00 per bbl applied to WTI:WCS differential contracts	$ 17	$ (17)

(1) *As the WCS differential is expressed as a discount to WTI, an increase in the differential results in a lower WCS price and a decrease in the differential results in a higher WCS price.*

The Corporation had the following physical commodity risk management contracts relating to crude oil sales, condensate purchases and natural gas purchases outstanding as at October 26, 2020:

Crude Oil Sales Contracts	**Volumes (bbls/d)(1)**	**Term**	**Average Price (US$/bbl)(1)**
WTI:AWB Fixed Differential	13,150	Oct 1, 2020 - Dec 31, 2020	$(20.75)
Condensate Purchase Contracts			
WTI:Condensate Fixed Differential	8,200	Oct 1, 2020 - Dec 31, 2020	$(5.31)
Natural Gas Purchase Contracts	**Volumes (GJ/d)(1)**	**Term**	**Average Price (C$/GJ)(1)**
AECO Fixed Price	5,000	Jan 1 - Dec 31, 2020	$2.70

(1) *The volumes and prices in the above table represent averages for various contracts with differing terms and prices. The* average *price for the portfolio may not have the same payment profile as the individual contracts and is provided for indicative purposes.*

Equity Price Risk Management

The Corporation enters into financial equity price risk management contracts to increase the predictability of the Corporation's cash flow by managing share price volatility. 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. Net cash provided by (used in) operating activities is impacted when these stock-based compensation units are ultimately settled. The Corporation entered into these equity price risk management contracts to manage its exposure on approximately 9 million cash-settled RSUs and PSUs vesting between 2021 and 2023.

10. SHARES OUTSTANDING

As at September 30, 2020, the Corporation had the following share capital instruments outstanding or exercisable:

(millions)	**Units**
Common shares	**302.7**
Convertible securities	
Stock options(1)	**5.0**
Equity-settled RSUs and PSUs	**6.7**

(1) *4.5 million stock options were exercisable as at September 30, 2020.*

As at October 23, 2020, the Corporation had 302.7 million common shares, 5.0 million stock options and 6.6 million equity-settled restricted share units and equity-settled performance share units outstanding, and 4.5 million stock options exercisable.

11. 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, 2020. These maturities may differ significantly from the actual maturities of these obligations. In particular, debt under the senior secured credit facilities, the senior secured second lien notes, and the senior unsecured notes may be retired earlier due to mandatory or discretionary repayments or redemptions.

($millions)	2020	2021	2022	2023	2024	Thereafter	Total
Commitments:							
Transportation and storage[1]	$ 105	$ 427	$ 417	$ 459	$ 445	$ 6,025	$ 7,878
Diluent purchases	53	22	22	18	—	—	115
Other operating commitments	5	15	14	13	11	45	103
Variable office lease costs	1	4	4	4	4	30	47
Total Commitments	164	468	457	494	460	6,100	8,143
Other Obligations:							
Lease obligations	13	50	40	36	34	520	693
Long-term debt[2]	—	—	—	—	799	2,260	3,059
Interest on long-term debt[2]	53	213	213	213	171	246	1,109
Decommissioning obligation[3]	—	5	5	5	5	787	807
Obligations	**$ 230**	**$ 736**	**$ 715**	**$ 748**	**$ 1,469**	**$ 9,913**	**$ 13,811**

(1) *This represents transportation and storage commitments from 2020 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 secured second lien notes, the senior unsecured notes, and associated interest payments based on interest and foreign exchange rates in effect on September 30, 2020.*

(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.

The Corporation is the defendant to a statement of claim originally filed in 2014 in relation to legacy issues involving a unit train transloading facility in Alberta. The claim was amended in the fourth quarter of 2017 asserting a significant increase to damages claimed. The Corporation filed a statement of defense in the first quarter of 2018. The Corporation continues to view this claim as without merit and will continue to defend against this claim. The Corporation believes that any liabilities that might arise from this matter are unlikely to have a material effect on its financial position.

12. NON-GAAP MEASURES

Cash operating netback is a non-GAAP measure. 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 measure widely used in the oil and gas industry as a supplemental measure of a company's efficiency and its ability to fund future capital expenditures. The Corporation's cash operating netback is calculated by deducting the related cost of diluent, blend purchases, transportation and storage, third-party curtailment credits, operating expenses, royalties and realized commodity risk management gains or losses from blend sales and power revenue. The per barrel calculation of cash operating netback is based on bitumen sales volume.

13. 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, 2019.

In March 2020, the World Health Organization declared a global pandemic following the emergence and rapid spread of a novel strain of coronavirus ("COVID-19"). The outbreak and subsequent measures intended to limit COVID-19 globally have contributed to significant declines and volatility in capital and financial markets, and adversely impacted the global commodity market, most notably the dramatic decline in worldwide demand for crude oil. There are no comparable recent events that provide guidance as to the long-term effect that COVID-19 may have, including continuing global efforts to contain the spread and severity of the virus, and as a result, the ultimate impact of the outbreak is highly uncertain and subject to change. The full extent of the impact of COVID-19 on the Corporation’s operations and future financial performance is currently unknown. The continued impact on capital and financial markets on a macro-scale presents uncertainty and risk with respect to the Corporation’s performance, and the estimates and assumptions used by Management in the preparation of its financial results.

Additional estimates, assumptions and judgments in response to COVID-19 have been disclosed in the interim consolidated financial statements as at September 30, 2020 regarding valuation assessments related to the Corporation's inventories, property, plant and equipment, exploration and evaluation assets, long-term pipeline linefill, decommissioning provision and deferred income tax asset.

14. 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.

Risks Related to COVID-19 Global Pandemic

The Corporation's operations, operating results and financial condition could be materially adversely impacted by events related to COVID-19 and actions taken by government authorities in response to COVID-19. COVID-19 has resulted in, and may continue to result in, among other things: increased volatility in financial markets and foreign currency exchange rates; disruptions to global supply chains; labour shortages; reductions in trade volumes; temporary operational restrictions and restrictions on gatherings greater than a certain number of individuals, shelter in place declarations and quarantine orders, business closures and travel bans; an overall slowdown in the global economy; political and economic instability; and civil unrest. In particular, COVID-19, and actions taken by governmental authorities in response thereto, have resulted in, and may continue to result in, a reduction in the demand for oil and reduced oil prices. Also, there is an increased risk that oil storage could reach capacity in Canada and the USGC as a result of the decreased demand. A prolonged period of decreased demand for, and lower prices of crude oil, and any applicable storage constraints, could also result in the Corporation voluntarily curtailing or shutting-in production, which could adversely impact our business, financial condition and results of operations.

If crude oil prices continue to remain at low levels for an extended period of time, or if the costs to develop the Corporation’s resources significantly increases, the carrying value of its assets may be subject to impairment and net earnings could be adversely affected.

The Corporation is subject to risks relating to a temporary suspension or physical interruption of its operations impacted by a COVID-19 outbreak, particularly at the Corporation’s sole operating facility at Christina Lake. In the event an employee or contractor at the Corporation’s Christina Lake site becomes infected with COVID-19, it could place the Corporation’s entire site workforce at risk, which could result in the suspension of operations. Such a suspension in operations could also be mandated by governmental authorities in response to COVID-19. This would have a significant negative impact on, or shut-down of, the Corporation's production levels, potentially for a sustained period of time, which could adversely impact our business, financial condition and results of operations.

In addition, the disruption and volatility in global capital markets that has resulted, and may continue to result, from COVID-19 could increase our cost of capital and adversely affect our ability to access the capital markets on a timely basis, or at all.

COVID-19 continues to rapidly evolve and the extent to which it may impact our business, financial condition and results of operations, as well as our future capital expenditures and other discretionary items, will depend on future developments, which are highly uncertain and cannot be predicted with any degree of confidence, including: the geographic spread of the virus; the duration and extent of COVID-19, further actions that may be taken by governmental authorities, including in respect of travel restrictions and business disruptions; the severity of the disease; its impact on healthcare systems to manage increases in patients; and the effectiveness of actions taken to contain the virus and treat the disease. To the extent that COVID-19 adversely affects our business, financial condition and results of operations, it may also have the effect of heightening many of the other risks described in the 2019 annual MD&A and the most recently filed AIF.

15. 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 interim and 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.

16. 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.

In mid-March 2020, in accordance with the guidance of provincial and federal health officials and to limit the risk and transmission of COVID-19, the Corporation implemented mandatory self-quarantine policies, travel restrictions, enhanced cleaning and sanitation measures, and social distancing measures, including directing the vast majority of its office staff and certain non-essential field staff to work from home from mid-March until mid-September. Monitoring these measures is an ongoing process, and the Corporation continues to follow the guidance of provincial and federal health officials, including the province's phased recovery plan. These changes to processes have not resulted in any material changes to the internal controls over financial reporting.

17. 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
GAAP	Generally Accepted Accounting Principles
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
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

18. ADVISORY

Forward-Looking Information

This document may contain forward-looking information within the meaning of applicable securities laws. This forward-looking information is identified by words such as "anticipate", "believe", "could", "drive", "expect", "estimate", "focus", "forward", "future", "guidance", "may", "on track", "outlook", "plan", "position", "potential", "priority", "should", "strategy", "target", "will", "would" or similar expressions and includes statements about future outcomes, including but not limited to: expectations of future production, revenues, expenses, cash flow, operating costs, steam-oil ratios, pricing differentials, reliability, profitability and capital expenditures; estimates of reserves and resources; anticipated reductions in operating costs as a result of optimization and scalability of certain operations; anticipated sources of funding for operations and capital expenditures; and anticipated regulatory approvals. Such forward-looking information is based on management's expectations and assumptions regarding future growth, results of operations, production, future capital and other expenditures, competitive advantage, plans for and results of drilling activity, environmental matters, and business prospects and opportunities.

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, foreign exchange rates and interest rates; the recoverability of MEG's reserves and contingent resources; MEG's ability to produce and market production of bitumen blend successfully to customers; extent and timelines of the Alberta Government's mandatory production curtailment program, 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; ability to reduce oil sands production, 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; plans for and results of turnaround 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 MEG conducts and will conduct its business; the impact of MEG’s response to the COVID-19 global pandemic; 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.

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, securing 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; legislative and regulatory changes to, amongst other things, tax, land use, royalty and environmental laws and production curtailment; 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; 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; continued weakness and volatility of crude oil and other petroleum products due to decreased global demand due to the COVID-19 pandemic; changes in general economic, market and business conditions; the potential costs associated with ongoing litigation cases; the extent and timelines of the Alberta Government's mandatory production curtailment program; risks of legislative and regulatory changes to, amongst other things, tax, land use, royalty and environmental laws and Federal and Provincial climate change policies; the cost of compliance with current and future environmental laws, including climate change laws; risks related 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, and, risks and uncertainties related to 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; and uncertainties arising in connection with any future acquisitions and/or dispositions of assets.

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 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 production to refiners 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.

Non-GAAP Financial Measures

Certain financial measures in this MD&A do not have a standardized meaning as prescribed by IFRS. Cash operating netback is a non-GAAP financial measure. 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. This measure is presented and described in order to provide shareholders and potential investors with additional measures in understanding the Corporation's ability to generate funds and to finance its operations as well as profitability measures specific to the oil industry. The definition of this non-GAAP measure is presented in the "NON-GAAP MEASURES" section of this MD&A.

19. 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.

20. QUARTERLY SUMMARIES

	2020			2019				2018[1]
Unaudited	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**
FINANCIAL *($millions unless specified)*								
Net earnings (loss)	**(9)**	(80)	(284)	26	24	(64)	(48)	(199)
Per share, diluted	**(0.03)**	(0.26)	(0.95)	0.09	0.08	(0.21)	(0.16)	(0.67)
Adjusted funds flow	**27**	89	78	157	192	227	151	(37)
Per share, diluted	**0.09**	0.29	0.26	0.51	0.63	0.76	0.50	(0.13)
Capital expenditures	**36**	20	54	72	40	33	53	144
Cash and cash equivalents	**49**	120	62	206	154	399	154	318
Working capital	**131**	173	371	123	204	416	175	290
Long-term debt	**3,030**	3,096	3,212	3,123	3,257	3,582	3,660	3,740
Shareholders' equity	**3,495**	3,507	3,593	3,853	3,828	3,795	3,851	3,886
BUSINESS ENVIRONMENT								
Average Benchmark Commodity Prices:								
WTI (US$/bbl)	**40.93**	27.85	46.17	56.96	56.45	59.82	54.90	58.81
Differential – WTI:WCS – Edmonton (US$/bbl)	**(9.09)**	(11.47)	(20.53)	(15.83)	(12.24)	(10.67)	(12.29)	(39.43)
Differential – WTI:AWB – Edmonton (US$/bbl)	**(10.48)**	(13.44)	(22.78)	(18.44)	(14.52)	(12.32)	(14.50)	(44.60)
AWB – Edmonton (US$/bbl)	**30.45**	14.41	23.39	38.52	41.93	47.50	40.40	14.21
Differential – WTI:AWB – U.S. Gulf Coast (US$/bbl)	**(3.20)**	(7.29)	(5.74)	(5.25)	(2.50)	1.64	(0.89)	(6.25)
AWB – U.S. Gulf Coast (US$/bbl)	**37.73**	20.56	40.43	51.71	53.95	61.46	54.01	52.56
C$ equivalent of 1US$ – average	**1.3316**	1.3860	1.3445	1.3201	1.3207	1.3376	1.3293	1.3215
Natural gas – AECO ($/mcf)	**2.48**	2.21	2.26	2.70	0.95	1.12	2.86	1.70
OPERATIONAL **($/bbl unless specified)**								
Blend sales, net of purchased product – bbls/d	**93,479**	100,980	142,380	134,932	132,455	137,120	132,377	126,750
Diluent usage – bbls/d	**(25,910)**	(30,583)	(45,166)	(40,585)	(37,463)	(42,000)	(42,555)	(38,467)
Bitumen sales – bbls/d	**67,569**	70,397	97,214	94,347	94,992	95,120	89,822	88,283
Bitumen production – bbls/d	**71,516**	75,687	91,557	94,566	93,278	97,288	87,113	87,582
Steam-oil ratio (SOR)	**2.36**	2.32	2.31	2.27	2.26	2.16	2.20	2.22
Blend sales	**45.44**	20.96	36.46	56.55	60.26	69.19	59.02	37.76
Cost of diluent	**(5.76)**	(10.78)	(17.01)	(9.69)	(6.89)	(6.96)	(8.81)	(22.45)
Bitumen realization	**39.68**	10.18	19.45	46.86	53.37	62.23	50.21	15.31
Transportation and storage – net	**(18.55)**	(11.77)	(8.63)	(10.75)	(10.57)	(10.80)	(11.27)	(10.28)
Third-party curtailment credits	**—**	—	0.18	(0.21)	(0.37)	(0.89)	—	—
Royalties	**(0.21)**	(0.05)	(0.63)	(1.18)	(1.54)	(2.06)	(0.37)	(0.15)
Operating costs – non-energy	**(3.96)**	(4.09)	(4.57)	(4.49)	(4.22)	(4.53)	(5.22)	(4.25)
Operating costs – energy	**(3.17)**	(3.00)	(3.15)	(2.95)	(1.51)	(1.78)	(3.36)	(1.98)
Power revenue	**1.08**	0.95	2.21	1.57	1.43	1.65	2.41	1.68
Realized gain (loss) on commodity risk management	**1.71**	33.62	11.97	(0.52)	(4.15)	(5.94)	(2.60)	6.81
Cash operating netback	**16.58**	25.84	16.83	28.33	32.44	37.88	29.80	7.14
Power sales price (C$/MWh)	**39.03**	28.34	69.39	49.61	50.30	55.33	70.83	55.38
Power sales (MW/h)	**78**	98	129	124	112	118	128	111
Average cost of diluent ($/bbl of diluent)	**60.48**	45.76	73.09	79.07	77.71	84.95	77.61	89.28
Average cost of diluent as a % of WTI	**111 %**	119 %	118 %	105 %	104 %	106 %	106 %	115 %
Depletion and depreciation rate per bbl of production	**13.33**	13.55	14.83	13.18	13.43	41.22	14.68	13.79
General and administrative expense per bbl of production	**1.50**	1.29	1.96	2.25	1.66	1.81	2.27	2.54
COMMON SHARES								
Shares outstanding, end of period (000)	**302,657**	302,645	299,547	299,508	299,288	299,207	296,857	296,841
Common share price ($) - close (end of period)	**2.77**	3.77	1.67	7.39	5.80	5.02	5.10	7.71

(1) The Corporation adopted IFRS 16 Leases, effective January 1, 2019, therefore prior periods have not been restated.

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

- fluctuations in blend sales pricing due to significant changes in the price of WTI with periods of significant volatility in 2020, which has ranged from a quarterly average of US$27.85/bbl to US$59.82/bbl, and the differential between WTI and the Corporation's AWB at Edmonton, which has ranged from a quarterly average of US$10.48/bbl to US$44.60/bbl driven by supply/demand fundamentals;
- in early March 2020, and continuing into the second quarter of 2020, global crude oil prices experienced multi-decade lows coupled with extreme levels of volatility driven primarily by an unprecedented reduction in global demand due to COVID-19;
- 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 commodity risk management contracts;
- Alberta Government enacted curtailment rules;
- changes in depletion and depreciation expense as a result of changes in production rates, future development costs and uncertainty of future benefits associated with specific non-core assets;
- exploration expense associated with discontinued exploration and evaluation activities in certain non-core growth properties;
- a decrease in general and administrative expense and non-energy costs due to reduction in staffing levels, and various non-recurring cost reductions in 2020;
- 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;
- planned turnaround and other maintenance activities affecting production; and
- voluntary curtailment efforts associated with uneconomic benchmark pricing environments.

21. ANNUAL SUMMARIES

Unaudited	2019	2018[1]	2017[1]	2016[1]	2015[1]	2014[1]
FINANCIAL *($millions unless specified)*						
Net earnings (loss)	(62)	(119)	166	(429)	(1,170)	(106)
Per share, diluted	(0.21)	(0.40)	0.57	(1.90)	(5.21)	(0.47)
Adjusted funds flow	726	180	374	(62)	49	791
Per share, diluted	2.41	0.60	1.29	(0.27)	0.22	3.52
Capital expenditures	198	622	502	140	314	1,314
Cash and cash equivalents	206	318	464	156	408	656
Working capital	123	290	313	96	363	526
Long-term debt	3,123	3,740	4,668	5,053	5,190	4,350
Shareholders' equity	3,853	3,886	3,964	3,287	3,678	4,768
BUSINESS ENVIRONMENT						
Average Benchmark Commodity Prices:						
WTI (US$/bbl)	57.03	64.77	50.95	43.33	48.80	93.00
Differential – WTI:WCS – Edmonton (US$/bbl)	(12.76)	(26.31)	(11.98)	(13.84)	(13.52)	(19.40)
Differential – WTI:AWB – Edmonton (US$/bbl)	(14.95)	(29.99)	(14.09)	(16.40)	(16.69)	(23.58)
AWB – Edmonton (US$/bbl)	42.08	34.78	36.86	26.93	32.11	69.42
Differential – WTI:AWB – U.S. Gulf Coast (US$/bbl)	(1.77)	(6.68)	(7.61)	(11.53)	(8.53)	(10.08)
AWB - U.S. Gulf Coast (US$/bbl)	55.26	58.09	43.34	31.80	40.27	82.92
C$ equivalent of 1US$ – average	1.3269	1.2962	1.2980	1.3256	1.2788	1.1047
Natural gas – AECO ($/mcf)	1.92	1.62	2.29	2.25	2.71	4.50
OPERATIONAL **($/bbl unless specified)**						
Blend sales, net of purchased product – bbls/d	134,223	125,368	115,766	116,586	117,132	97,334
Diluent usage – bbls/d	(40,637)	(38,317)	(35,766)	(36,159)	(36,167)	(30,092)
Bitumen sales – bbls/d	93,586	87,051	80,000	80,427	80,965	67,242
Bitumen production – bbls/d	93,082	87,731	80,774	81,245	80,025	71,186
Steam-oil ratio (SOR)	2.22	2.19	2.31	2.29	2.47	2.48
Blend sales	61.29	53.47	51.39	38.19	42.14	76.11
Cost of diluent	(8.08)	(16.78)	(9.36)	(10.28)	(11.43)	(13.35)
Bitumen realization	53.21	36.69	42.03	27.91	30.71	62.76
Transportation and storage – net	(10.84)	(8.42)	(6.89)	(6.46)	(4.82)	(1.38)
Third-party curtailment credits	(0.37)	—	—	—	—	—
Royalties	(1.30)	(1.20)	(0.77)	(0.29)	(0.70)	(4.36)
Operating costs – non-energy	(4.61)	(4.62)	(4.62)	(5.62)	(6.54)	(8.02)
Operating costs – energy	(2.38)	(1.98)	(2.98)	(3.01)	(3.84)	(6.30)
Power revenue	1.75	1.51	0.76	0.64	0.99	2.26
Realized gain (loss) on commodity risk management	(3.31)	(4.37)	(0.39)	0.08	—	—
Cash operating netback	32.15	17.61	27.14	13.25	15.80	44.96
Power sales price (C$/MWh)	56.70	47.87	21.49	18.74	27.48	48.83
Power sales (MW/h)	121	114	118	115	121	129
Average cost of diluent ($/bbl of diluent)	79.89	91.60	72.32	61.06	67.72	105.94
Average cost of diluent as a % of WTI	106 %	106 %	109 %	106 %	109 %	103 %
Depletion and depreciation rate per bbl of production	20.90	14.12	16.13	16.81	16.00	14.57
General and administrative expense per bbl of production	1.99	2.58	2.94	3.24	4.06	4.29
COMMON SHARES						
Shares outstanding, end of period (000)	299,508	296,841	294,104	226,467	224,997	223,847
Common share price ($) - close (end of period)	7.39	7.71	5.14	9.23	8.02	19.55

(1) *The Corporation adopted IFRS 16 Leases, effective January 1, 2019, therefore prior periods have not been restated.*

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

As at	Note	September 30, 2020	December 31, 2019
Assets			
Current assets			
Cash and cash equivalents	17	**$ 49**	$ 206
Trade receivables and other		**214**	382
Inventories	3	**122**	93
Risk management	19	**64**	—
		449	681
Non-current assets			
Property, plant and equipment	4	**6,043**	6,206
Exploration and evaluation assets	5	**124**	490
Other assets	6	**211**	227
Risk management	19	**16**	—
Deferred income tax asset	7	**345**	262
Total assets		**$ 7,188**	$ 7,866
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities		**$ 256**	$ 379
Interest payable		**28**	74
Current portion of provisions and other liabilities	9	**32**	28
Risk management	19	**2**	77
		318	558
Non-current liabilities			
Long-term debt	8	**3,030**	3,123
Provisions and other liabilities	9	**345**	332
Risk management	19	**—**	—
Total liabilities		**3,693**	4,013
Shareholders' equity			
Share capital	10	**5,460**	5,443
Contributed surplus		**174**	182
Deficit		**(2,174)**	(1,801)
Accumulated other comprehensive income		**35**	29
Total shareholders' equity		**3,495**	3,853
Total liabilities and shareholders' equity		**$ 7,188**	$ 7,866

Commitments and contingencies (Note 21)

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

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

		Three months ended September 30		Nine months ended September 30	
	Note	**2020**	**2019**	**2020**	**2019**
Revenues					
Petroleum revenue, net of royalties	12	**$ 523**	$ 942	**$ 1,464**	$ 2,882
Other revenue	12	**10**	16	**41**	56
Total revenues		**533**	958	**1,505**	2,938
Expenses					
Diluent and transportation	13	**263**	364	**848**	1,177
Operating expenses		**44**	50	**158**	174
Purchased product		**134**	221	**416**	615
Third-party curtailment credits		**—**	3	**(2)**	11
Depletion and depreciation	4, 6	**87**	115	**304**	595
Exploration expense	5	**—**	—	**366**	58
General and administrative		**10**	14	**35**	48
Stock-based compensation	11	**10**	8	**(12)**	19
Net finance expense	15	**67**	75	**206**	229
Other expenses	16	**11**	3	**41**	19
Gain on asset dispositions	6	**—**	—	**(6)**	(14)
Commodity risk management (gain) loss, net	19	**6**	27	**(476)**	221
Foreign exchange (gain) loss, net	14	**(70)**	39	**84**	(108)
Earnings (loss) before income taxes		**(29)**	39	**(457)**	(106)
Income tax expense (recovery)		**(20)**	15	**(84)**	(19)
Net earnings (loss)		**(9)**	24	**(373)**	(87)
Other comprehensive income (loss), net of tax					
Items that may be reclassified to profit or loss:					
Foreign currency translation adjustment		**(4)**	2	**6**	(6)
Comprehensive income (loss)		**$ (13)**	$ 26	**$ (367)**	$ (93)
Net earnings (loss) per common share					
Basic	18	**$ (0.03)**	$ 0.08	**$ (1.24)**	$ (0.29)
Diluted	18	**$ (0.03)**	$ 0.08	**$ (1.24)**	$ (0.29)

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

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

	Share Capital	Contributed Surplus	Deficit	Accumulated Other Comprehensive Income	Total Shareholders' Equity
Balance as at December 31, 2019	**$ 5,443**	**$ 182**	**$ (1,801)**	**$ 29**	**$ 3,853**
Stock-based compensation	**—**	**9**	**—**	**—**	**9**
RSUs vested and released	**17**	**(17)**	**—**	**—**	**—**
Comprehensive income (loss)	**—**	**—**	**(373)**	**6**	**(367)**
Balance as at September 30, 2020	**$ 5,460**	**$ 174**	**$ (2,174)**	**$ 35**	**$ 3,495**
Balance as at December 31, 2018	$ 5,427	$ 170	$ (1,751)	$ 39	$ 3,885
IFRS 16 opening deficit adjustment	—	—	12	—	12
Stock-based compensation	—	23	—	—	23
Stock options exercised	1	—	—	—	1
RSUs vested and released	14	(14)	—	—	—
Comprehensive income (loss)	—	—	(87)	(6)	(93)
Balance as at September 30, 2019	$ 5,442	$ 179	$ (1,826)	$ 33	$ 3,828

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

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

		Three months ended September 30		Nine months ended September 30	
	Note	2020	2019	2020	2019
Cash provided by (used in):					
Operating activities					
Net earnings (loss)		**$ (9)**	$ 24	**$ (373)**	$ (87)
Adjustments for:					
Deferred income tax expense (recovery)		**(20)**	15	**(83)**	(19)
Depletion and depreciation	4, 6	**87**	115	**304**	595
Exploration expense	5	**—**	—	**366**	58
Stock-based compensation	11	**11**	5	**(2)**	20
Unrealized net (gain) loss on foreign exchange	14	**(70)**	38	**83**	(107)
Unrealized net (gain) loss on commodity risk management	19	**17**	(10)	**(144)**	112
Amortization of debt discount and debt issue costs		**2**	4	**6**	14
Gain on asset dispositions	6	**—**	—	**(6)**	(14)
Other		**3**	—	**7**	3
Decommissioning expenditures	9	**(1)**	(1)	**(3)**	(1)
Net change in other liabilities		**(1)**	1	**3**	(6)
Funds flow from operating activities		**19**	191	**158**	568
Net change in non-cash working capital items	17	**(50)**	(17)	**28**	(162)
Net cash provided by (used in) operating activities		**(31)**	174	**186**	406
Investing activities					
Capital expenditures	4	**(35)**	(40)	**(109)**	(126)
Net proceeds on dispositions	6	**—**	—	**6**	17
Other		**—**	(1)	**—**	—
Net change in non-cash working capital items	17	**(1)**	8	**(42)**	(49)
Net cash provided by (used in) investing activities		**(36)**	(33)	**(145)**	(158)
Financing activities					
Issue of 7.125% senior unsecured notes	8	**—**	—	**1,581**	—
Repayment and redemption of long-term debt	8	**—**	(385)	**(1,723)**	(393)
Debt redemption premium and refinancing costs	8	**—**	—	**(49)**	—
Issue of shares, net of issue costs		**—**	1	**—**	1
Receipts on leased assets	17	**—**	—	**1**	1
Payments on leased liabilities	17	**(6)**	(5)	**(19)**	(14)
Net cash provided by (used in) financing activities		**(6)**	(389)	**(209)**	(405)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency		**2**	3	**11**	(7)
Change in cash and cash equivalents		**(71)**	(245)	**(157)**	(164)
Cash and cash equivalents, beginning of period		**120**	399	**206**	318
Cash and cash equivalents, end of period		**$ 49**	$ 154	**$ 49**	**$ 154**

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

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

1. CORPORATE INFORMATION

MEG Energy Corp. (the "Corporation") was incorporated under the *Alberta Business Corporations Act* on March 9, 1999. The Corporation's shares trade on the Toronto Stock Exchange under the symbol "MEG". The Corporation owns a 100% interest in over 450 square miles of mineral leases in the southern Athabasca region of Alberta and is primarily engaged in sustainable *in situ* thermal oil production at its Christina Lake Project.

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

2. BASIS OF PRESENTATION

The unaudited interim consolidated financial statements ("interim consolidated financial statements") were prepared using the same accounting policies and methods as those used in the Corporation's audited consolidated financial statements for the year ended December 31, 2019. The interim consolidated financial statements are in compliance with International Accounting Standard 34, Interim Financial Reporting ("IAS 34"). Accordingly, certain information and footnote disclosure normally included in annual financial statements prepared in accordance with International Financial Reporting Standards ("IFRS"), as issued by the International Accounting Standards Board ("IASB"), has been omitted or condensed. The preparation of interim consolidated financial statements in accordance with IAS 34 requires the use of certain critical accounting estimates. It also requires management to exercise judgment in applying the Corporation's accounting policies. The areas involving a higher degree of judgment or complexity, or areas where assumptions and estimates are significant to the consolidated financial statements, have been set out in Note 4 of the Corporation's audited consolidated financial statements for the year ended December 31, 2019. These interim consolidated financial statements should be read in conjunction with the Corporation's audited consolidated financial statements for the year ended December 31, 2019.

In March 2020, the World Health Organization declared a global pandemic following the emergence and rapid spread of a novel strain of coronavirus ("COVID-19"). The outbreak and subsequent measures intended to limit COVID-19 globally contributed to significant declines and volatility in capital and financial markets, and adversely impacted global commodity markets, most notably the dramatic decline in worldwide demand for crude oil. There are no comparable recent events that provide guidance as to the long term effect that COVID-19 may have, including global efforts to contain the spread and severity of the virus.

The full extent of the impact of COVID-19 on the Corporation's operations and future financial performance is currently unknown. The continued impact on capital and financial markets on a macro-scale presents uncertainty and risk with respect to the Corporation's performance, and estimates and assumptions used in the preparation of its financial results.

Additional estimates, assumptions and judgments in response to COVID-19 have been disclosed in these interim consolidated financial statements regarding valuation assessments related to the Corporation's inventories, property, plant and equipment, exploration and evaluation assets, long-term pipeline linefill, decommissioning provision and deferred income tax asset.

These interim consolidated financial statements are presented in Canadian dollars ($ or C$), which is the Corporation's functional currency and were approved by the Corporation's Audit Committee on October 26, 2020.

3. INVENTORIES

As at	September 30, 2020	December 31, 2019
Bitumen blend	**$ 105**	$ 73
Diluent	**10**	13
Material and supplies	**7**	7
	$ 122	$ 93

Inventories are measured at the lower of cost and net realizable value. No inventory impairments were recognized at September 30, 2020.

4. PROPERTY, PLANT AND EQUIPMENT

	Crude oil	Transportation and storage	Right-of-use assets	Corporate assets	Total
Cost					
Balance as at December 31, 2019	$ 9,077	$ 159	$ 263	$ 78	$ 9,577
Additions	110	—	40	—	150
Dispositions	(3)	(70)	—	—	(73)
Lease modification	—	—	(6)	—	(6)
Change in decommissioning liabilities	1	—	—	—	1
Balance as at September 30, 2020	**$ 9,185**	**$ 89**	**$ 297**	**$ 78**	**$ 9,649**
Accumulated depletion and depreciation					
Balance as at December 31, 2019	$ 3,199	$ 102	$ 25	$ 45	$ 3,371
Depletion and depreciation	282	—	18	4	304
Dispositions	(3)	(70)	—	—	(73)
Lease modification	—	—	4	—	4
Balance as at September 30, 2020	**$ 3,478**	**$ 32**	**$ 47**	**$ 49**	**$ 3,606**
Carrying amounts					
Balance as at December 31, 2019	$ 5,878	$ 57	$ 238	$ 33	$ 6,206
Balance as at September 30, 2020	**$ 5,707**	**$ 57**	**$ 250**	**$ 29**	**$ 6,043**

Included in the cost of property, plant and equipment is $244 million of assets under construction as at September 30, 2020 (December 31, 2019 – $229 million).

In light of the significant degradation and volatility in global crude oil prices, international oil supply and demand imbalances, and the uncertainty surrounding the economic impact of COVID–19, a test for impairment was performed at March 31, 2020, and no impairment charges were required. The economic conditions that were present at March 31, 2020 that required a test for impairment have improved, and therefore no indicators of impairment existed at September 30, 2020.

When completing the impairment test as at March 31, 2020, estimating the recoverable amount of the Corporation's CGU involved several assumptions and estimates which were subject to estimation uncertainty, as well as a significant degree of judgment. Significant estimates involved in the calculation included pricing assumptions, production and cost assumptions and the appropriate discount rate. The Corporation engages GLJ Petroleum Consultants Ltd. ("GLJ") to prepare an annual reserve report, which contains the pricing, production and cost assumptions that form the basis for determining the recoverable amount. The report is prepared as at December 31, 2019, and therefore adjustments were made to reflect the updated commodity pricing at the time of impairment testing. Other adjustments to the report are made as necessary to reflect the change in the economic environment. The appropriate discount rate requires a significant amount of judgment, and a sensitivity analysis was performed to ensure that a 1-2% change in the discount rate did not affect the conclusion reached that no impairment was required.

5. EXPLORATION AND EVALUATION ASSETS

Cost		
Balance as at December 31, 2019	$	490
Additions		—
Exploration expense		(366)
Dispositions		—
Balance as at September 30, 2020	**$**	**124**

The Corporation is focused on the development of its core asset Christina Lake as it continues to manage the business through an unpredictable global economic downturn arising from COVID-19. During the first quarter of 2020, the Corporation discontinued exploration and evaluation activities in certain non-core growth properties. Land lease and evaluation costs associated with these assets of $366 million were charged to exploration expense during the first quarter of 2020. The remaining assets were allocated to the related CGU for impairment testing and no impairment was required.

6. OTHER ASSETS

As at	September 30, 2020		December 31, 2019	
Non-current pipeline linefill[(a)]	**$**	**180**	$	190
Finance sublease receivables		**17**		18
Intangible assets[(b)]		**8**		9
Deferred financing costs		**4**		7
Prepaid transportation costs[(c)]		**8**		9
		217		233
Less current portion		**(6)**		(6)
	$	**211**	$	227

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

   In light of the significant and acute decline in commodity prices associated with the COVID–19 global pandemic, long-term pipeline linefill was tested for impairment under IAS 2 by comparing the carrying value to the net realizable value, and no impairment was recorded due to the long-term nature of the transportation contracts. The uncertainty surrounding the duration and depth of unprecedented low commodity prices, combined with significant volatility in commodity prices increases the estimation uncertainty associated with the net realizable value at September 30, 2020, and actual results could differ from the estimates.

b. As at September 30, 2020, intangible assets consist of $8 million invested in software that is not an integral component of the related computer hardware (December 31, 2019 – $9 million). Depreciation of $1 million was recognized for the nine months ended September 30, 2020 (December 31, 2019 – $2 million). At the beginning of 2020, the Corporation sold patents that were recorded at a nominal amount, and recognized a gain on asset disposition of $6 million. During the comparative nine month period in 2019, the Corporation sold internally generated emission performance credits that were recorded at a nominal amount, and recognized a gain on asset dispositions of $12 million.

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

7. DEFERRED INCOME TAX ASSET

As at September 30, 2020, the Corporation recognized a deferred tax asset of $345 million (December 31, 2019 - $262 million). The deferred tax asset is reviewed at each balance sheet date to assess whether it is probable that the related tax benefit will be realized. As at September 30, 2020, the Corporation estimates that future taxable income is expected to be sufficient to realize the deferred tax asset. The estimates used to determine future taxable income are subject to measurement uncertainty and actual results could differ from estimates.

8. LONG-TERM DEBT

As at	September 30, 2020	December 31, 2019
Second Lien:		
6.5% senior secured second lien notes (September 30, 2020 - US$496 million; December 31, 2019 - US$596 million; due 2025)	**$ 661**	$ 773
Unsecured:		
7.0% senior unsecured notes (September 30, 2020 - US$600 million; December 31, 2019 - US$1 billion; due 2024)	**799**	1,297
7.125% senior unsecured notes (September 30, 2020 - US$1.2 billion; December 31, 2019 - US$nil; due 2027)	**1,599**	—
6.375% senior unsecured notes (September 30, 2020 - US$nil; December 31, 2019 - US$800 million; due 2023)	**—**	1,037
	3,059	3,107
Less:		
Debt redemption premium	**—**	29
Unamortized deferred debt discount and debt issue costs	**(29)**	(13)
	$ 3,030	$ 3,123

The U.S. dollar denominated debt was translated into Canadian dollars at the period end exchange rate of US$1 = C$1.3324 (December 31, 2019 – US$1 = C$1.2965).

During the first quarter of 2020, the Corporation successfully closed a private offering of $1.6 billion (US$1.2 billion) in aggregate principal amount of 7.125% senior unsecured notes due February 2027. On February 18, 2020, the net proceeds of the offering, together with cash on hand, were used to:

- Fully redeem $1 billion (US$800 million) of the 6.375% senior unsecured notes due January 2023 at a redemption price of 101.063%;
- Partially redeem $530 million (US$400 million) of the US$1.0 billion 7.00% senior unsecured notes due March 2024 at a redemption price of 102.333%; and
- Pay fees and expenses related to the offering.

Concurrent with the private offering, on February 18, 2020, the Corporation redeemed $132 million (US$100 million) in aggregate principal amount of its 6.5% senior secured second lien notes due January 2025 at a redemption price of 104.875%. Cash on hand was used to fund this senior secured second lien notes partial redemption.

The Corporation's total credit available under two facilities is $1.3 billion, comprised of $800 million under the revolving credit facility and $500 million under a letter of credit facility, guaranteed by Export Development Canada ("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 both have a maturity date of July 30, 2024. The maturity dates of the revolving credit facility and the EDC Facility include a feature that would cause the maturity dates to spring back to 91 days prior to the maturity date of certain material debt of the Corporation if such debt has not been repaid or refinanced prior to such date.

The revolving credit facility does not contain a financial maintenance covenant unless the Corporation is drawn under the revolving credit facility in excess of $400 million. If the facility is drawn in excess of $400 million, the Corporation is required to maintain a first lien net debt to last twelve months earnings before interest, tax, depreciation and amortization ratio of 3.50 or less. The financial maintenance covenant, if triggered, will be tested quarterly. Issued letters of credit are not included in the calculation of the ratio.

The revolving credit facility, EDC facility and senior secured second lien notes are secured by substantially all the assets of the Corporation.

As at September 30, 2020, the Corporation had $785 million of unutilized capacity under the $800 million revolving credit facility and the Corporation had $85 million of unutilized capacity under the $500 million letter of credit facility. A letter of credit of $15 million was issued under the revolving credit facility during the nine months ended September 30, 2020.

9. PROVISIONS AND OTHER LIABILITIES

As at	September 30, 2020	December 31, 2019
Lease liabilities[(a)]	**$ 292**	$ 281
Decommissioning provision[(b)]	**75**	71
Other liabilities	**10**	8
Provisions and other liabilities	**377**	360
Less current portion	**(32)**	(28)
Non-current portion	**$ 345**	$ 332

a. Lease liabilities:

As at	September 30, 2020	December 31, 2019
Balance, beginning of period	**$ 281**	$ 131
IFRS 16 opening balance sheet adjustment	**—**	160
Additions	**20**	13
Modifications	**6**	(4)
Payments	**(34)**	(45)
Interest expense	**19**	26
Balance, end of period	**292**	281
Less current portion	**(27)**	(22)
Non-current portion	**$ 265**	$ 259

The Corporation's minimum lease payments are as follows:

As at	September 30, 2020
Within one year	**$ 52**
Later than one year but not later than five years	**154**
Later than five years	**506**
Minimum lease payments	**712**
Amounts representing finance charges	**(420)**
Net minimum lease payments	**$ 292**

The Corporation has short-term leases with lease terms of twelve months or less as well as low-value leases. As these lease costs are incurred they are recognized as either general and administrative expense or operating expense depending on their nature. As at September 30, 2020, the present value of these arrangements is $3 million (December 31, 2019 - $2 million), using the Corporation's estimated incremental borrowing rate.

b. Decommissioning provision:

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

As at	September 30, 2020	December 31, 2019
Balance, beginning of period	**$ 71**	$ 65
Changes in estimated life and estimated future cash flows	**3**	(2)
Changes in discount rates	**(2)**	2
Liabilities incurred and disposed, net	**—**	1
Liabilities settled	**(3)**	(2)
Accretion	**6**	7
Balance, end of period	**75**	71
Less current portion	**(5)**	(6)
Non-current portion	**$ 70**	$ 65

The decommissioning provision represents the present value of the estimated future costs for the reclamation and abandonment of the Corporation's property, plant and equipment and exploration and evaluation assets. The total undiscounted amount of the estimated future cash flows to settle the decommissioning obligations is $807 million (December 31, 2019 – $827 million). The Corporation's estimated weighted average credit-adjusted risk free rate increased 0.4% during the nine months ended September 30, 2020. As at September 30, 2020, the Corporation has estimated the net present value of the decommissioning obligations using a weighted average credit-adjusted risk-free rate of 14.1% (December 31, 2019 – 13.7%) and an inflation rate of 2.1% (December 31, 2019 - 2.1%). The decommissioning provision is estimated to be settled in periods up to the year 2066 (December 31, 2019 - periods up to the year 2066).

10. SHARE CAPITAL

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

Changes in issued common shares are as follows:

	Nine months ended September 30, 2020			Year ended December 31, 2019		
	Number of shares (thousands)		Amount	Number of shares (thousands)		Amount
Balance, beginning of year	**299,508**	**$**	**5,443**	296,841	$	5,427
Issued upon exercise of stock options	**39**		**—**	266		2
Issued upon vesting and release of RSUs and PSUs	**3,110**		**17**	2,401		14
Balance, end of period	**302,657**	**$**	**5,460**	299,508	$	5,443

11. STOCK-BASED COMPENSATION

	Three months ended September 30				Nine months ended September 30			
		2020		2019		2020		2019
Cash-settled expense (recovery)[(i)]	**$**	**(1)**	$	3	**$**	**(10)**	$	(1)
Equity-settled expense		**2**		5		**9**		20
Equity price risk management (gain) loss[(ii)]		**9**		—		**(11)**		—
Stock-based compensation	**$**	**10**	$	8	**$**	**(12)**	$	19

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

(ii) Relates to financial derivatives entered into to manage the Corporation's exposure to cash-settled RSUs and 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 note 19(d) for further details.

A $10 million cash-settled recovery was recognized during the nine months ended September 30, 2020 due to the decrease in the Corporation's share price, and associated decrease in value of cash-settled RSUs, PSUs and DSUs compared to December 31, 2019, which translates to a reduced liability and expense recovery at September 30, 2020. As at September 30, 2020, the Corporation recognized a liability of $11 million relating to the fair value of cash-settled RSUs, PSUs and DSUs (December 31, 2019 – $25 million). The current portion of $5 million is included within accounts payable and accrued liabilities and $6 million is included as a non-current liability within provisions and other liabilities based on the expected payout dates of the individual awards.

12. REVENUES

	Three months ended September 30		Nine months ended September 30	
	2020	**2019**	**2020**	**2019**
Sales from:				
Production	**$ 385**	$ 731	**$ 1,035**	$ 2,290
Purchased product[i]	**140**	224	**437**	626
Petroleum revenue	**$ 525**	$ 955	**$ 1,472**	$ 2,916
Royalties	**(2)**	(13)	**(8)**	(34)
Petroleum revenue, net of royalties	**$ 523**	$ 942	**$ 1,464**	$ 2,882
Power revenue	**$ 6**	$ 13	**$ 32**	$ 46
Transportation revenue	**4**	3	**9**	10
Other revenue	**$ 10**	$ 16	**$ 41**	$ 56
Total revenues	**$ 533**	$ 958	**$ 1,505**	$ 2,938

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

a. Disaggregation of revenue from contracts with customers

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

	Three months ended September 30					
	2020			**2019**		
	Petroleum Revenue			**Petroleum Revenue**		
	Proprietary	**Third-party**	**Total**	**Proprietary**	**Third-party**	**Total**
Country:						
Canada	**$ 115**	**$ —**	**$ 115**	$ 450	$ 52	$ 502
United States	**270**	**140**	**410**	281	172	453
	$ 385	**$ 140**	**$ 525**	$ 731	$ 224	$ 955

	Nine months ended September 30					
	2020			**2019**		
	Petroleum Revenue			**Petroleum Revenue**		
	Proprietary	**Third-party**	**Total**	**Proprietary**	**Third-party**	**Total**
Country:						
Canada	**$ 507**	**$ 34**	**$ 541**	$ 1,399	$ 222	$ 1,621
United States	**528**	**403**	**931**	891	404	1,295
	$ 1,035	**$ 437**	**$ 1,472**	$ 2,290	$ 626	$ 2,916

Other revenue recognized during the three and nine months ended September 30, 2020 and 2019 is attributed to Canada.

b. Revenue-related assets

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

As at	September 30, 2020	December 31, 2019
Petroleum revenue	**$ 182**	$ 342
Other revenue	**3**	9
Total revenue-related assets	**$ 185**	$ 351

Revenue-related receivables are typically settled within 30 days. As at September 30, 2020 and December 31, 2019, there was no material expected credit loss required against revenue-related receivables.

13. DILUENT AND TRANSPORTATION

	Three months ended September 30		Nine months ended September 30	
	2020	**2019**	**2020**	**2019**
Diluent expense	**$ 144**	$ 268	**$ 572**	$ 890
Transportation and storage	**119**	96	**276**	287
Diluent and transportation	**$ 263**	$ 364	**$ 848**	$ 1,177

14. FOREIGN EXCHANGE (GAIN) LOSS, NET

	Three months ended September 30		Nine months ended September 30	
	2020	**2019**	**2020**	**2019**
Unrealized foreign exchange (gain) loss on:				
Long-term debt	**$ (67)**	$ 41	**$ 95**	$ (113)
US$ denominated cash and cash equivalents	**(3)**	(3)	**(12)**	6
Unrealized net (gain) loss on foreign exchange	**(70)**	38	**83**	(107)
Realized (gain) loss on foreign exchange	**—**	1	**1**	(1)
Foreign exchange (gain) loss, net	**$ (70)**	$ 39	**$ 84**	$ (108)
C$ equivalent of 1 US$				
Beginning of period	**1.3616**	1.3091	**1.2965**	1.3646
End of period	**1.3324**	1.3244	**1.3324**	1.3244

15. NET FINANCE EXPENSE

	Three months ended September 30		Nine months ended September 30	
	2020	2019	**2020**	2019
Interest expense on long-term debt	**$ 59**	$ 69	**$ 183**	$ 210
Interest expense on lease liabilities	**6**	6	**19**	19
Interest income	**—**	(1)	**(2)**	(4)
Net interest expense	**65**	74	**200**	225
Accretion on provisions	**2**	2	**6**	5
Unrealized loss on derivative financial liabilities	**—**	(1)	**—**	(1)
Net finance expense	**$ 67**	$ 75	**$ 206**	$ 229

16. OTHER EXPENSES

	Three months ended September 30		Nine months ended September 30	
	2020	2019	**2020**	2019
Contract cancellation(i)	**$ 7**	—	**$ 33**	—
Severance and restructuring	**4**	—	**8**	12
Research and development	**—**	3	**—**	7
Other expenses	**$ 11**	$ 3	**$ 41**	$ 19

(i) Costs incurred to mitigate rail sales contract exposure.

17. SUPPLEMENTAL CASH FLOW DISCLOSURES

	Three months ended September 30		Nine months ended September 30	
	2020	2019	**2020**	2019
Cash provided by (used in):				
Trade receivables and other	**$ 17**	$ 62	**$ 175**	$ (122)
Inventories	**(46)**	6	**(19)**	6
Accounts payable and accrued liabilities	**33**	(21)	**(124)**	(35)
Interest payable	**(55)**	(56)	**(46)**	(60)
	$ (51)	$ (9)	**$ (14)**	$ (211)
Changes in non-cash working capital relating to:				
Operating	**$ (50)**	$ (17)	**$ 28**	$ (162)
Investing	**(1)**	8	**(42)**	(49)
	$ (51)	$ (9)	**$ (14)**	$ (211)
Cash and cash equivalents:[a]				
Cash	**$ 49**	$ 154	**$ 49**	$ 154
Cash equivalents	**—**	—	**—**	—
	$ 49	$ 154	**$ 49**	$ 154
Cash interest paid	**108**	$ 115	**$ 213**	$ 237

a. As at September 30, 2020, $47 million of the Corporation’s total cash and cash equivalents balance was held in U.S. dollars (September 30, 2019 – $62 million). The U.S. dollar cash and cash equivalents balance has been translated into Canadian dollars at the period end exchange rate of US$1 = C$1.3324 (September 30, 2019 – US$1=C$1.3244).

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

	Finance sublease receivables	Lease liabilities	Long-term debt
Balance as at December 31, 2019	$ 18	$ 281	$ 3,123
Cash changes:			
Receipts on leased assets	(1)	—	—
Payments on leased liabilities	—	(19)	—
Issue of 7.125% senior unsecured notes	—	—	1,581
Repayment and redemption of long-term debt	—	—	(1,723)
Debt redemption premium and refinancing costs	—	—	(49)
Non-cash changes:			
Lease liabilities settled		(15)	
Lease liabilities incurred	—	20	—
Lease liabilities modified	—	6	—
Interest expense on lease liabilities	—	19	—
Unrealized (gain) loss on foreign exchange	—	—	95
Amortization of deferred debt discount and debt issue costs	—	—	3
Balance as at September 30, 2020	**$ 17**	**$ 292**	**$ 3,030**

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

18. NET EARNINGS (LOSS) PER COMMON SHARE

	Three months ended September 30		Nine months ended September 30	
	2020	**2019**	**2020**	**2019**
Net earning (loss)	**$ (9)**	$ 24	**$ (373)**	$ (87)
Weighted average common shares outstanding (millions)[(a)]	**303**	300	**302**	298
Dilutive effect of stock options, RSUs and PSUs (millions)[(b)]	**—**	3	**—**	—
Weighted average common shares outstanding – diluted (millions)	**303**	303	**302**	298
Net earnings (loss) per share, basic	**$ (0.03)**	$ 0.08	**$ (1.24)**	$ (0.29)
Net earnings (loss) per share, diluted	**$ (0.03)**	$ 0.08	**$ (1.24)**	$ (0.29)

a. Weighted average common shares outstanding for the three months ended September 30, 2020 includes 571,529 PSUs vested but not yet released (three months ended September 30, 2019 - 381,014 PSUs).

b. For the three and nine months ended September 30, 2020, the Corporation incurred a net loss and therefore there was no dilutive effect of stock options, RSUs and PSUs. If the Corporation had recognized net earnings for the three and nine months ended September 30, 2020, the dilutive effect of stock options, RSUs and PSUs would have been 3.9 million weighted average common shares (three and nine months ended September 30, 2019 - 3.1 million and 2.6 million weighted average common shares, respectively).

19. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

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

a. Fair values:

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

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

As at	**September 30, 2020**		**December 31, 2019**	
	Carrying amount	**Fair value**	**Carrying amount**	**Fair value**
Recurring measurements:				
Financial assets				
Risk management contracts	**$ 80**	**$ 80**	—	—
Financial liabilities				
Long-term debt (Note 8)	**$ 3,059**	**$ 2,820**	$ 3,107	$ 3,160
Risk management contracts	**$ 2**	**$ 2**	$ 77	$ 77

The estimated fair value of long-term debt is derived using quoted prices in an inactive market from a third-party independent broker. The fair value was determined based on estimates as at September 30, 2020 and is expected to fluctuate given the volatility in the debt and commodity price markets.

The fair value of risk management contracts is derived using third-party valuation models which require assumptions concerning the amount and timing of future cash flows and discount rates. Management's assumptions rely on external observable market data including forward prices for commodities, interest rate yield curves and foreign exchange rates. The observable inputs may be adjusted using certain methods, which include extrapolation to the end of the term of the contract.

b. Risk management:

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

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

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

As at	September 30, 2020			December 31, 2019		
	Asset	Liability	Net	Asset	Liability	Net
Gross amount	**$ 107**	**$ (5)**	**$ 102**	$ —	$ (77)	$ (77)
Amount offset	**(27)**	**3**	**(24)**	—	—	—
Net amount	**$ 80**	**$ (2)**	**$ 78**	$ —	$ (77)	$ (77)
Current portion	**$ 64**	**$ (2)**	**$ 62**	$ —	$ (77)	$ (77)
Non-current portion	**16**	**—**	**16**	—	—	—
Net amount	**$ 80**	**$ (2)**	**$ 78**	$ —	$ (77)	$ (77)

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

As at September 30	2020	2019
Fair value of contracts, beginning of year	$ (77)	$ 93
Fair value of contracts realized	332	109
Change in fair value of contracts	(177)	(221)
Fair value of contracts, end of period	**$ 78**	$ (19)

c. Commodity risk management:

The Corporation had the following financial commodity risk management contracts relating to crude oil sales and condensate purchases outstanding as at September 30, 2020:

As at September 30, 2020			
Crude Oil Sales Contracts	**Volumes (bbls/d)[(i)]**	**Term**	**Average Price (US$/bbl)[(i)]**
WTI[(ii)] Fixed Price	59,826	Oct 1, 2020 - Dec 31, 2020	$46.60
WTI:WCS[(iii)] Fixed Differential	28,000	Oct 1, 2020 - Dec 31, 2020	$(20.27)
Enhanced Fixed Price with Sold Put Option			
WTI Fixed Price/Sold Put Option Strike Price	24,500	Oct 1, 2020 - Dec 31, 2020	$59.11 / $52.00
WTI Fixed Price/Sold Put Option Strike Price	2,000	Jan 1, 2021 - Dec 31, 2021	$47.50 / $36.00
Condensate Purchase Contracts			
WTI:Mont Belvieu Fixed Differential	7,250	Oct 1, 2020 - Dec 31, 2020	$(7.63)
WTI:Mont Belvieu Fixed Differential	10,950	Jan 1, 2021 - Dec 31, 2021	$(10.37)
WTI:Mont Belvieu Fixed Differential	200	Jan 1, 2022 - Dec 31, 2022	$(11.30)
WTI:Mont Belvieu Fixed % of WTI	7,750	Oct 1, 2020 - Dec 31, 2020	93.1 %
Natural Gas Purchase Contracts	**Volumes (GJ/d)[(i)]**	**Term**	**Average Price (C$/GJ)[(i)]**
AECO Fixed Price	5,000	Jan 1, 2021 - Dec 31, 2021	$2.73

(i) The volumes and prices in the above table represent averages for various contracts with differing terms and prices. The average price and percentages for the portfolio may not have the same payment profile as the individual contracts and are provided for indicative purposes.
(ii) West Texas Intermediate ("WTI") crude oil
(iii) Western Canadian Select ("WCS") crude oil blend

The Corporation entered into the following financial commodity risk management contracts relating to crude oil sales and condensate purchases subsequent to September 30, 2020. As a result, these contracts are not reflected in the Corporation's Consolidated Financial Statements:

Subsequent to September 30, 2020			
Crude Oil Sales Contracts	**Volumes (bbls/d)(i)**	**Term**	**Average Price (US$/bbl)(i)**
WTI Fixed Price	21,265	Oct 1, 2020 - Oct 31, 2020	$40.48
WTI Fixed Price	8,200	Nov 1, 2020 - Nov 30, 2020	$41.16
Enhanced Fixed Price with Sold Put Option			
WTI Fixed Price/Sold Put Option Strike Price	19,000	Jan 1, 2021 - Dec 31, 2021	$46.12 / $39.00
Natural Gas Purchase Contracts	**Volumes (GJ/d)(i)**	**Term**	**Average Price (C$/GJ)(i)**
AECO Fixed Price	20,000	Jan 1, 2021 - Dec 31, 2021	$2.67

(i) The volumes and prices in the above tables represent averages for various contracts with differing terms and prices. The average price and percentages for the portfolio may not have the same payment profile as the individual contracts and are provided for indicative purposes.

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

	Three months ended September 30		**Nine months ended September 30**	
	2020	**2019**	**2020**	**2019**
Realized loss (gain) on commodity risk management	**$ (11)**	$ 37	**$ (332)**	$ 109
Unrealized loss (gain) on commodity risk management	**17**	(10)	**(144)**	112
Commodity risk management (gain) loss, net	**$ 6**	$ 27	**$ (476)**	$ 221

The following table summarizes the sensitivity of the earnings (loss) before income tax impact of fluctuating commodity prices on the Corporation's open financial commodity risk management positions in place as at September 30, 2020:

Commodity	**Sensitivity Range**	**Increase**	**Decrease**
Crude oil commodity price	± US$5.00 per bbl applied to WTI contracts	**$ (42)**	**$ 41**
Crude oil differential price (i)	± US$5.00 per bbl applied to WTI:WCS differential contracts	**$ 17**	**$ (17)**

(i) As the WCS differential is expressed as a discount to WTI, an increase in the differential results in a lower WCS price and a decrease in the differential results in a higher WCS price.

d. Equity price risk management:

The Corporation enters into financial equity price risk management contracts to increase the predictability of the Corporation's cash flow by managing share price volatility. 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. Net cash provided by (used in) operating activities is impacted when these stock-based compensation units are ultimately settled. The Corporation entered into these equity price risk management contracts to manage its exposure on approximately 9 million cash-settled RSUs and PSUs vesting between 2021 and 2023.

e. Credit risk management:

Credit risk arises from the potential that the Corporation may incur a loss if a counterparty fails to meet its obligations in accordance with agreed terms. The Corporation applies the simplified approach to providing for expected credit losses prescribed by IFRS 9, which permits the use of the lifetime expected loss provision for all trade receivables. The Corporation uses a combination of historical and forward looking information to determine the appropriate loss allowance provisions. Credit risk exposure is mitigated through the use of credit policies governing the Corporation's credit portfolio and with credit practices that limit transactions according to each counterparty's credit quality. A substantial portion of accounts receivable are with investment grade customers in the energy industry and are subject to normal industry credit risk. The Corporation has experienced no material loss in relation to trade receivables. As at September 30, 2020, the Corporation's estimated maximum exposure to credit risk related to trade receivables, deposits and advances was $208 million. All amounts receivable from commodity risk management activities are due from large Canadian banks with strong investment grade credit ratings. Counterparty default risk associated with the Corporation's commodity risk management activities is also partially mitigated through credit exposure limits, frequent assessment of counterparty credit ratings and netting arrangements, as outlined in note 24 of the Corporation's 2019 annual consolidated financial statements.

The Corporation's cash balances are used to fund the development of its properties. As a result, the primary objectives of the investment portfolio are low risk capital preservation and high liquidity. The cash balances are held in high interest savings accounts or are invested in high grade, liquid, short-term instruments such as bankers' acceptances, commercial paper, money market deposits or similar instruments. The cash and cash equivalents balance at September 30, 2020 was $49 million. None of the investments are past their maturity or considered impaired. The Corporation's estimated maximum exposure to credit risk related to its cash and cash equivalents is $49 million.

f. Liquidity risk management:

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

Management believes its current capital resources and its ability to manage cash flow and working capital levels will allow the Corporation to meet its current and future obligations, to make scheduled principal and interest payments, and to fund the other needs of the business for at least the next 12 months. Meeting current and future obligations through the uncertainty associated with COVID–19 is supported by the Corporation's financial framework including a strong commodity risk management program securing cash flow through 2020 and credit risk management policies minimizing exposure related to customer receivables primarily to investment grade customers in the energy industry. However, no assurance can be given that this will be the case or that future sources of capital will not be necessary.

The Corporation's earliest maturing long-term debt is approximately three and a half years out, represented by US$600 million of senior unsecured notes due March 2024. None of the Corporation's outstanding long-term debt contain financial maintenance covenants. Additionally, the Corporation's modified covenant-lite $800 million revolving credit facility has no financial maintenance covenant unless drawn in excess of $400 million. If drawn in excess of $400 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.

20. CAPITAL MANAGEMENT

The Corporation's capital consists of cash and cash equivalents, debt and shareholders' equity. The Corporation's objective for managing capital is to prioritize balance sheet strength while maintaining flexibility to repay debt, fund sustaining capital, return capital to shareholders or fund future production growth. In the current price environment, management believes its current capital resources and its ability to manage cash flow and working capital levels will allow the Corporation to meet its current and future obligations, to make scheduled principal and interest payments, and to fund the other needs of the business for at least the next 12 months. Debt repayment and sustaining capital expenditure activities are anticipated to be funded by the Corporation's adjusted funds flow, cash on hand and/or other available liquidity.

On January 31, 2020, the Corporation closed the refinancing and extension of the maturity profile of its debt portfolio. Following completion of the associated transactions, MEG's first debt maturity was extended to 2024. As at September 30, 2020, the Corporation had $785 million of unutilized capacity under the $800 million revolving credit facility and had $85 million of unutilized capacity under the $500 million letter of credit facility. A letter of credit of $15 million was issued under its revolving credit facility during the nine months ended September 30, 2020.

The following table summarizes the Corporation's net debt:

As at	Note	September 30, 2020	December 31, 2019
Long-term debt	8	**$ 3,030**	$ 3,123
Cash and cash equivalents		**(49)**	(206)
Net debt		**$ 2,981**	$ 2,917

Net debt is an important measure used by management to analyze leverage and liquidity. During the nine months ended September 30, 2020, net debt increased by $64 million due to the weakening of the Canadian dollar relative to the US dollar and decrease in cash and cash equivalents over the period, partially offset by the redemption of its 6.5% senior secured second lien notes.

On January 31, 2020 the Corporation successfully closed a private offering of $1.6 billion (US$1.2 billion) in aggregate principal amount of 7.125% senior unsecured notes due February 2027. On February 18, 2020, the net proceeds of the offering, together with cash on hand, were used to:

- Fully redeem $1 billion (US$800 million) of the 6.375% senior unsecured notes due January 2023 at a redemption price of 101.063%;
- Partially redeem $530 million (US$400 million) of the US$1.0 billion 7.00% senior unsecured notes due March 2024 at a redemption price of 102.333%; and
- Pay fees and expenses related to the offering.

Concurrent with the private offering, on February 18, 2020, the Corporation redeemed $132 million (US$100 million) in aggregate principal amount of its 6.5% senior secured second lien notes due January 2025 at a redemption price of 104.875%. Cash on hand was used to fund this senior secured second lien notes partial redemption.

The following table summarizes the Corporation's funds flow from (used in) operations and adjusted funds flow:

	Note	Three months ended September 30		Nine months ended September 30	
		2020	**2019**	**2020**	**2019**
Net cash provided by (used in) operating activities		**$ (31)**	$ 174	**$ 186**	$ 406
Net change in non-cash operating working capital items		**50**	17	**(28)**	162
Funds flow from (used in) operations		**19**	191	**158**	568
Adjustments:					
Contract cancellation(i)	16	**7**	—	**33**	—
Decommissioning expenditures	9	**1**	1	**3**	1
Adjusted funds flow		**$ 27**	$ 192	**$ 194**	$ 569

(i) Costs incurred to mitigate rail sales contract exposure. Contract cancellation costs or recoveries are excluded from adjusted funds flow as they are not considered part of ordinary continuing operating results.

Management utilizes funds flow from (used in) operations and adjusted funds flow as a measure to analyze operating performance and cash flow generating ability. Funds flow from (used in) operations and adjusted funds flow impacts the level and extent of debt repayment, funding for capital expenditures and returning capital to shareholders. By excluding changes in non-cash working capital, non-recurring items and decommissioning expenditures from cash flows, the funds flow from (used in) operations and adjusted funds flow measures provide meaningful metrics for management by establishing a clear link between the Corporation's cash flows and the operating netbacks from the Christina Lake Project. Funds flow from (used in) operations and adjusted funds flow are not intended to represent net cash provided by (used in) operating activities.

Net debt, funds flow from (used in) operations and adjusted funds flow are not standardized measures and may not be comparable with the calculation of similar measures by other companies.

21. COMMITMENTS AND CONTINGENCIES

a. Commitments

The Corporation’s commitments are enforceable and legally binding obligations to make payments in the future for goods and services. These items exclude amounts recorded on the consolidated balance sheet. The Corporation had the following commitments as at September 30, 2020:

	2020	2021	2022	2023	2024	Thereafter	Total
Transportation and storage(i)	$ 105	$ 427	$ 417	$ 459	$ 445	$ 6,025	$ 7,878
Diluent purchases	53	22	22	18	—	—	115
Other operating commitments	5	15	14	13	11	45	103
Variable office lease costs	1	4	4	4	4	30	47
Commitments	**$ 164**	**$ 468**	**$ 457**	**$ 494**	**$ 460**	**$ 6,100**	**$ 8,143**

(i) This represents transportation and storage commitments from 2020 to 2048, including the Access Pipeline TSA, and pipeline commitments which are awaiting regulatory approval and are not yet in service. Excludes finance leases recognized on the consolidated balance sheet (Note 9(a)).

b. Contingencies

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

The Corporation is the defendant to a statement of claim originally filed in 2014 in relation to legacy issues involving a unit train transloading facility in Alberta. The claim was amended in the fourth quarter of 2017 asserting a significant increase to damages claimed. The Corporation filed a statement of defense in the first quarter of 2018. The Corporation continues to view this claim as without merit and will continue to defend against all such claims. The Corporation believes that any liabilities that might arise from this matter are unlikely to have a material effect on its financial position.