Report to Shareholders for the period ended September 30, 2019

(All financial figures are expressed in Canadian dollars ($ or C$) unless otherwise noted)

MEG Energy Corp. reported third quarter 2019 operational and financial results on October 30, 2019. Highlights include:

- Adjusted funds flow of $192 million ($0.63 per share) and $152 million free cash flow in the quarter. For the nine months ended September 30, 2019, MEG has generated free cash flow of $443 million;
- Bitumen production volumes of 93,278 barrels per day (bbls/d) at a steam-oil-ratio (SOR) of 2.26;
- Record low net operating costs of $4.30 per barrel, supported by low non-energy operating costs of $4.22 per barrel and strong power sales which had the impact of offsetting 95% of per barrel energy operating costs resulting in a net energy operating expense of $0.08 per barrel;
- Average AWB blend sales price net of transportation and storage costs at Edmonton of US$41.60 which was in-line with the posted AWB index price for the quarter, notwithstanding 44% Enbridge mainline apportionment, highlighting the value of MEG's North American marketing strategy;
- Total capital expenditures of $40 million, primarily consisting of sustaining and maintenance capital; and
- Year-to-date repayment of $481 million of outstanding long-term debt, including $88 million subsequent to the quarter. Management remains committed to applying all free cash flow after sustaining capital to further debt reduction.

"In the first nine months of the year, MEG has generated $569 million of adjusted funds flow which is almost triple our full year 2019 capital investment plan of $200 million" says Derek Evans, President and Chief Executive Officer. "We remain focused on driving efficiencies in our business from an operational and cost perspective and will continue to direct all available free cash flow to debt repayment."

Bitumen production averaged 93,278 bbls/d in the third quarter of 2019, a 6% decrease over the same period in 2018 due to the impact of the Alberta Government's mandated production curtailment program which came into effect January 1, 2019. Third quarter 2019 production was 4% lower than second quarter 2019 production levels as fewer third-party curtailment credits were available for purchase. Bitumen sales exceeded bitumen production by 1,714 bbls/d during the third quarter of 2019 due primarily to the timing of sales over quarter end.

Notwithstanding the 6% decrease in production level year over year, third quarter 2019 per barrel non-energy operating costs of $4.22 and per barrel net operating costs of $4.30 were better than third quarter 2018 per barrel non-energy and net operating costs of $4.38 and $4.34, respectively, due primarily to higher bitumen sales volumes. The Corporation now expects non-energy operating expenses in the range of $4.75 - $5.00 per barrel in 2019. Energy operating costs of $1.51 per barrel in the third quarter of 2019 were largely offset by strong power revenues of $1.43 per barrel, compared to energy operating costs and power revenues of $1.50 and $1.54 per barrel respectively for the same period in 2018.

General and administrative ("G&A") expense of $1.66 per barrel of production in the third quarter of 2019 represents an 8% decrease from second quarter 2019, due primarily to the timing of expenses. The Corporation continues to expect G&A expense in the range of $1.95 - $2.05 per barrel in 2019.

Blend Sales Pricing and North American Market Access

MEG realized a third quarter 2019 average AWB blend sales price of US$45.63 per barrel compared to US$51.72 per barrel in the second quarter of 2019. The change in average AWB blend sales price quarter over quarter is primarily due to a US

$3.37 per barrel reduction in the benchmark WTI index combined with WTI:AWB differentials at Edmonton widening to US$14.52 per barrel from US$12.32 per barrel and at the U.S. Gulf Coast ("USGC") widening to a discount of US$2.50 from a premium of US$1.64 per barrel. MEG sold 33% (26% via pipeline and 7% via rail) of its sales volumes to the USGC market in the third quarter of 2019 compared to 34% (29% via pipeline and 5% via rail) in the second quarter of 2019.

Transportation and storage costs averaged US$5.74 per barrel of AWB blend sales in the third quarter of 2019 compared to US$5.60 per barrel of AWB blend sales for second quarter of 2019 and US$5.00 per barrel of AWB blend sales in third quarter of 2018.

Excluding transportation and storage costs upstream of the Edmonton index sales point, MEG's net AWB blend sales price at Edmonton averaged US$41.60 per barrel in the third quarter of 2019 compared to the posted AWB index price at Edmonton of US$41.93. Notwithstanding that Enbridge mainline apportionment averaged 44%, MEG was able to capture pricing in-line with the Edmonton index on its barrels as a result of its marketing and storage assets ability to move barrels toward higher value markets as well as provide flexibility to avoid the price constrained post-apportionment market at Edmonton. MEG's average pricing against the AWB index price at Edmonton should improve further once MEG's contracted capacity on the Flanagan and Seaway pipeline system doubles to 100,000 bbls/d of AWB blend in mid-2020.

Despite 44% average Enbridge mainline apportionment in the quarter, MEG was required to sell less than 5% of its blend sales into the price constrained post-apportionment market at Edmonton in the third quarter of 2019. These post-apportionment sales typically receive a significant discount to the AWB index price at Edmonton. Avoiding the discounted pricing received by industry in the price constrained post-apportionment market highlights the strategic value of MEG's North American marketing strategy.

MEG's AWB blend sales by rail in the third quarter were 19,560 bbls/d compared to 23,443 bbls/d in the second quarter of 2019. 47% of sales by rail in the third quarter of 2019 were delivered to the USGC compared to 28% in the second quarter of 2019, with the remainder sold at Edmonton. Subject to market conditions at the time, MEG anticipates being in a position to fully utilize its 30,000 bbls/d of rail capacity at the Bruderheim rail terminal in 2020 once the results of the Alberta Petroleum Marketing Commission's crude by rail asset divestiture process are announced. MEG understands that the completion of the process is anticipated to be some time in 2019.

Adjusted Funds Flow and Net Earnings

During the third quarter of 2019, MEG's bitumen realization averaged $53.37 per barrel, compared to $62.23 per barrel in the second quarter of 2019 and $49.63 per barrel in the third quarter of 2018 and was impacted by the same primary factors as average AWB blend sales price.

MEG's cash operating netback averaged $32.44 per barrel in the third quarter of 2019, compared to $37.88 per barrel in second quarter of 2019 and $24.01 per barrel in third quarter of 2018. The cash operating netback in the third quarter of 2019 compared to the second quarter of 2019 reflects a lower realized bitumen sales price partially offset by lower hedging losses.

Adjusted funds flow was impacted by the same primary factors as cash operating netback, resulting in adjusted funds flow of $192 million in the third quarter of 2019, compared to $227 million in the second quarter of 2019 and $116 million in the third quarter of 2018.

The Corporation recognized net earnings of $24 million in the third quarter of 2019 compared to a net loss of $64 million in the second quarter of 2019 and net earnings of $118 million during the third quarter of 2018. The decrease during the third quarter of 2019 compared to the same period of 2018 is due to an unrealized foreign exchange loss and a lower unrealized gain on commodity risk management partially offset by a higher cash operating netback.

Capital Expenditures

Capital expenditures in the third quarter of 2019 totaled $40 million with the majority of expenditures directed toward sustaining and maintenance capital.

In the first nine months of 2019 capital expenditures totaled $126 million relative to MEG's 2019 capital budget of $200 million which was set during the implementation of the Alberta Government's mandated production curtailment program in January 2019. Over the course of 2019 MEG has been successful in finding capital cost savings and undertaking minor scope changes that will allow the Corporation to deliver its original $200 million budget for approximately $170 million. As a result, based on expected operational benefits, including plant integrity and turn-around management, MEG has shifted into 2019 approximately $30 million of expected 2020 capital expenditures to accelerate the completion of the Corporation's in-progress brownfield project at the Phase 2B central processing facility which includes incremental steam generation, water handling and oil treating capacity. This project, which was initiated in 2018, is expected to be completed in the first half of 2020.

Debt Repayment

Up to October 30th MEG has repaid $481 million of outstanding long-term debt in 2019, including $385 million during the third quarter of 2019 and $88 million subsequent to the quarter. Annualized interest savings from these repurchases are expected to be approximately $30 million. These annualized interest savings, when combined with the annualized $14 million of credit fee savings associated with the amendment of MEG's revolving credit facility announced July 30, 2019 brings aggregate credit-related cash cost savings contribution to annual free cash flow to approximately $44 million.

Management remains committed to its stated strategy of continuing to direct all available free cash flow, after funding sustaining capital, toward debt reduction.

Outlook

MEG is revising its 2019 full year production guidance from 90,000 - 92,000 bbls/d to 92,000 - 93,000 bbls/d to reflect year to date production results and the continued impact of the Alberta Government's mandated production curtailment. MEG is also revising its 2019 full year non-energy operating cost guidance from $4.75 - $5.25 per barrel to $4.75 - $5.00 per barrel.

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	
($millions)	**2019**	**2018**	**2019**	**2018**
Net cash provided by (used in) operating activities	**$ 174**	$ 3	**$ 406**	$ 186
Net change in non-cash operating working capital items	**17**	108	**162**	48
Funds flow from (used in) operations	**191**	111	**568**	234
Adjustments:				
Realized gain on foreign exchange derivatives[1]	**—**	—	**—**	(35)
Payments on onerous contracts	**—**	4	**—**	14
Decommissioning expenditures	**1**	1	**1**	4
Adjusted funds flow	**$ 192**	$ 116	**$ 569**	$ 217
Capital expenditures	**(40)**	(139)	**(126)**	(478)
Free cash flow	**$ 152**	$ (23)	**$ 443**	$ (261)

(1) A gain related to the settlement of forward currency contracts to manage the foreign exchange risk on Canadian dollar denominated proceeds related to the sale of assets designated for U.S. dollar denominated long-term debt repayment.

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 month periods ended September 30, 2019 was approved by the Corporation's Audit Committee on October 30, 2019. 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 month periods ended September 30, 2019, the audited annual consolidated financial statements and notes thereto for the year ended December 31, 2018, the 2018 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 oil company focused on sustainable *in situ* thermal oil development and production in the southern Athabasca region of Alberta, Canada. MEG is actively developing enhanced oil recovery projects that utilize steam-assisted gravity drainage ("SAGD") extraction methods to improve the economic recovery of oil as well as lower carbon emissions. MEG transports and sells Access Western Blend ("AWB"or "blend") to refiners throughout North America and internationally.

MEG owns a 100% working interest in over 750 square miles of oil leases. In the GLJ Petroleum Consultants Ltd. Report ("GLJ Report"), effective December 31, 2018 with a preparation date of January 11, 2019, GLJ Petroleum Consultants Ltd. ("GLJ") estimated that the leases it had evaluated contained 2.8 billion barrels of proved plus probable bitumen reserves. For information regarding MEG's estimated reserves contained in the GLJ Report, 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

During the third quarter of 2019, the Corporation repaid $385 million (US$292 million) of long-term debt. On July 30, 2019, the Corporation fully repaid the outstanding senior secured term loan balance of $289 million (US$219 million) and amended and restated the Corporation's existing credit facilities to have new five-year terms and total available credit of $1.3 billion. In addition, during the third quarter of 2019 the Corporation repurchased and extinguished a portion of its 6.5% senior secured second lien notes totaling $96 million (US$73 million). An additional $88 million (US$66 million) of principal was repurchased and extinguished on these notes subsequent to September 30, 2019. Interest savings resulting from the repayment of the senior secured term loan and the repurchase and extinguishment of the senior secured second lien notes are expected to be approximately $30 million annually. The Corporation expects to continue to repay outstanding indebtedness as free cash flow becomes available.

Bitumen production for the three months ended September 30, 2019 averaged 93,278 bbls/d compared to 98,751 bbls/d for the three months ended September 30, 2018. The decrease is primarily the result of the Alberta Government's mandated production curtailment program. Commencing January 1, 2019, the Government of Alberta enacted rules to limit the production of crude oil and bitumen.

Adjusted funds flow in the third quarter of 2019 was $192 million compared to $116 million in the third quarter of 2018, which increased due to a higher cash operating netback of $32.44 per barrel in the third quarter of 2019 compared to $24.01 per barrel in the same period of 2018. Contributing to the improved cash operating netback was a smaller realized loss on commodity risk management and higher bitumen realization due to the positive impact of a narrower WTI:WCS differential on blend sales and lower cost of diluent during the three months ended September 30, 2019.

The Corporation recognized net earnings of $24 million for the three months ended September 30, 2019 compared to net earnings of $118 million for the three months ended September 30, 2018. The decrease is due to an unrealized foreign exchange loss and a lower unrealized gain on commodity risk management, partially offset by a higher cash operating netback.

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		2019			2018				2017
($ millions, except as indicated)	**2019**	**2018**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**
Bitumen production - bbls/d	**92,582**	87,781	**93,278**	97,288	87,113	87,582	98,751	71,325	93,207	90,228
Steam-oil ratio	**2.21**	2.19	**2.26**	2.16	2.20	2.22	2.17	2.22	2.17	2.22
Bitumen sales - bbls/d	**93,330**	86,636	**94,992**	95,120	89,822	88,283	93,856	74,418	91,608	94,541
Bitumen realization - $/bbl	**55.38**	44.03	**53.37**	62.23	50.21	15.31	49.63	47.33	35.46	48.01
Net operating costs - $/bbl[1]	**5.01**	5.28	**4.30**	4.66	6.17	4.55	4.34	5.64	5.98	5.86
Non-energy operating costs - $/bbl	**4.64**	4.75	**4.22**	4.53	5.22	4.25	4.38	5.47	4.55	4.53
Cash operating netback - $/bbl[2]	**33.47**	21.19	**32.44**	37.88	29.80	7.14	24.01	18.66	20.31	33.54
Adjusted funds flow[3]	**569**	217	**192**	227	151	(38)	116	18	83	192
Per share, diluted[3]	**1.90**	0.73	**0.63**	0.76	0.50	(0.13)	0.39	0.06	0.28	0.65
Revenue[4]	**2,938**	2,213	**958**	1,062	919	520	803	689	721	755
Net earnings (loss)	**(87)**	80	**24**	(64)	(48)	(199)	118	(179)	141	(24)
Per share, diluted	**(0.29)**	0.27	**0.08**	(0.21)	(0.16)	(0.67)	0.39	(0.61)	0.47	(0.08)
Capital expenditures	**126**	478	**40**	32	53	144	139	191	148	163
Cash and cash equivalents	**154**	373	**154**	399	154	318	373	564	675	464
Long-term debt - C$	**3,257**	3,544	**3,257**	3,582	3,660	3,740	3,544	3,607	3,543	4,668
Long-term debt - US$	**2,459**	2,742	**2,459**	2,737	2,740	2,741	2,742	2,745	2,746	3,729

(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.*

(4) *The total of petroleum revenue, net of royalties and other revenue as presented on the consolidated statement of earnings and comprehensive income. Effective January 1, 2018, petroleum revenues are presented on a gross basis as they represent separate performance obligations, as discussed in the "NEW ACCOUNTING STANDARDS" section of this MD&A. The comparative prior period amounts have been revised to reflect the new presentation.*

3. RESULTS OF OPERATIONS

Bitumen Production and Steam-Oil Ratio

	Three months ended September 30		Nine months ended September 30	
	2019	**2018**	**2019**	**2018**
Bitumen production – bbls/d	**93,278**	98,751	**92,582**	87,781
Steam-oil ratio (SOR)	**2.26**	2.17	**2.21**	2.19

Bitumen Production

Average bitumen production for the three months ended September 30, 2019 decreased 6% compared to the same period of 2018. The decrease was primarily due to the Alberta Government mandated production curtailment program which came into force January 1, 2019. Production curtailment limits are set on a monthly basis and are expected to continue into 2020.

Average bitumen production for the nine months ended September 30, 2019 increased 5% compared to the same period of 2018. This was mainly due to the 33-day turnaround that occurred in the second quarter of 2018, while in comparison, no major turnarounds were completed in the nine months ended September 30, 2019. Also, despite the mandated production curtailment, the Corporation was able to purchase third-party curtailment credits in 2019 which allowed the Corporation to produce at levels above the curtailed limits.

Steam-Oil Ratio

SOR is an important efficiency indicator that measures the average amount of steam that is injected into the reservoir for each barrel of bitumen produced. The Corporation continues to focus on improving efficiency of production through a lower SOR. The SOR increased for the three and nine months ended September 30, 2019 compared to the same periods of 2018 because steam is operationally required to be injected into the reservoirs to maintain production capability notwithstanding the production limits from the Alberta Government mandated production curtailment program.

Adjusted Funds Flow

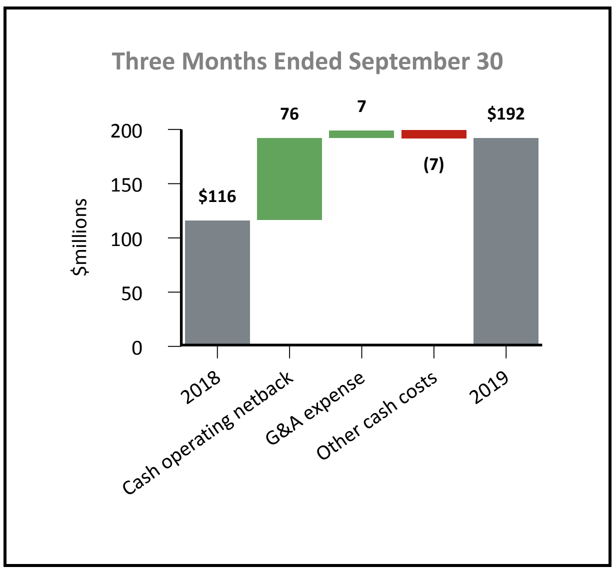
Net cash provided by operating activities is an IFRS measure in the Corporation's consolidated statement of cash flow. Adjusted funds flow is calculated as net cash provided by operating activities excluding the net change in non-cash operating working capital, items not considered part of ordinary continuing 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.

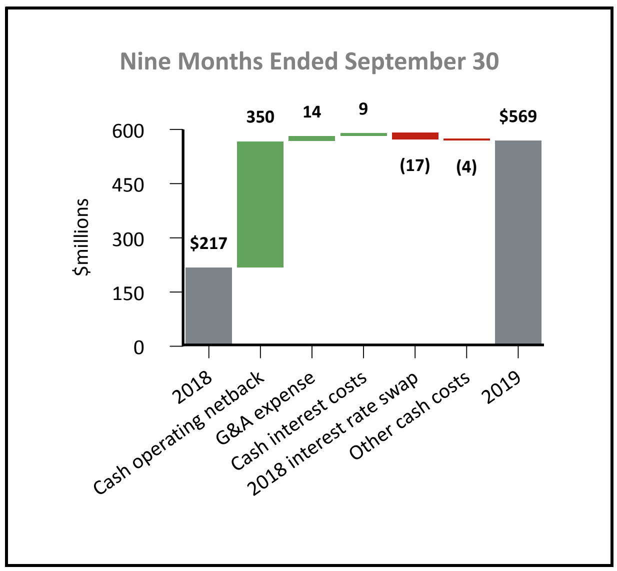
The following table reconciles cash provided by operating activities to adjusted funds flow:

	Three months ended September 30		Nine months ended September 30	
($millions)	**2019**	**2018**	**2019**	**2018**
Net cash provided by (used in) operating activities	**$ 174**	$ 3	**$ 406**	$ 186
Net change in non-cash operating working capital items	**17**	108	**162**	48
Funds flow from (used in) operations	**191**	111	**568**	234
Adjustments:				
Realized gain on foreign exchange derivatives[1]	**—**	—	**—**	(35)
Payments on onerous contracts	**—**	4	**—**	14
Decommissioning expenditures	**1**	1	**1**	4
Adjusted funds flow	**$ 192**	$ 116	**$ 569**	$ 217

(1) A gain related to the settlement of forward currency contracts to manage the foreign exchange risk on Canadian dollar denominated proceeds related to the sale of assets designated for U.S. dollar denominated long-term debt repayment.

Adjusted funds flow increased significantly during the three and nine months ended September 30, 2019 compared to the same periods in 2018, which was driven by the Corporation's improved cash operating netbacks in both periods. In the three months ended September 30, 2019, the improved cash operating netback was mainly the result of a smaller realized loss on commodity risk management, as well as higher bitumen realization. In the nine months ended September 30, 2019, the increase in the cash operating netback was mainly due to a higher realized bitumen price.





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.

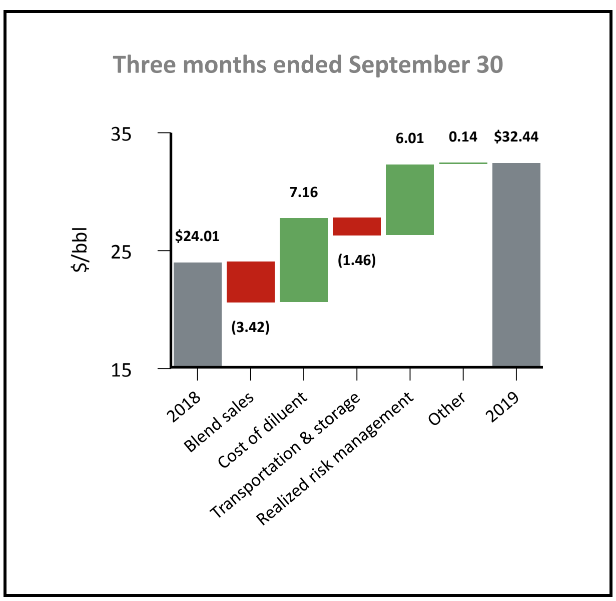
	Three months ended September 30				Nine months ended September 30			
	2019		2018		2019		2018	
($millions, except as indicated)		$/bbl		$/bbl		$/bbl		$/bbl
Blend sales[(1)]	**$ 734**	**$ 60.26**	$ 767	$ 63.68	**$ 2,301**	**$ 62.90**	$ 2,006	$ 58.84
Cost of diluent	**(268)**	**(6.89)**	(338)	(14.05)	**(890)**	**(7.52)**	(965)	(14.81)
Bitumen realization	**466**	**53.37**	429	49.63	**1,411**	**55.38**	1,041	44.03
Transportation and storage[(2)]	**(93)**	**(10.57)**	(78)	(9.11)	**(277)**	**(10.87)**	(184)	(7.78)
Third-party curtailment credits[(3)]	**(3)**	**(0.37)**	—	—	**(11)**	**(0.43)**	—	—
Royalties	**(13)**	**(1.54)**	(18)	(2.01)	**(34)**	**(1.34)**	(37)	(1.56)
	357	**40.89**	333	38.51	**1,089**	**42.74**	820	34.69
Operating costs - non-energy	**(37)**	**(4.22)**	(38)	(4.38)	**(118)**	**(4.64)**	(112)	(4.75)
Operating costs - energy	**(13)**	**(1.51)**	(13)	(1.50)	**(56)**	**(2.19)**	(47)	(1.98)
Power revenue	**13**	**1.43**	13	1.54	**46**	**1.82**	35	1.45
Net operating costs	**(37)**	**(4.30)**	(38)	(4.34)	**(128)**	**(5.01)**	(124)	(5.28)
Cash operating netback - excludes realized commodity risk management	**320**	**36.59**	295	34.17	**961**	**37.73**	696	29.41
Realized gain (loss) on commodity risk management	**(37)**	**(4.15)**	(88)	(10.16)	**(109)**	**(4.26)**	(194)	(8.21)
Cash operating netback[(4)]	**$ 283**	**$ 32.44**	$ 207	$ 24.01	**$ 852**	**$ 33.47**	$ 502	$ 21.20
Bitumen sales - bbls/d		**94,992**		93,856		**93,330**		86,636

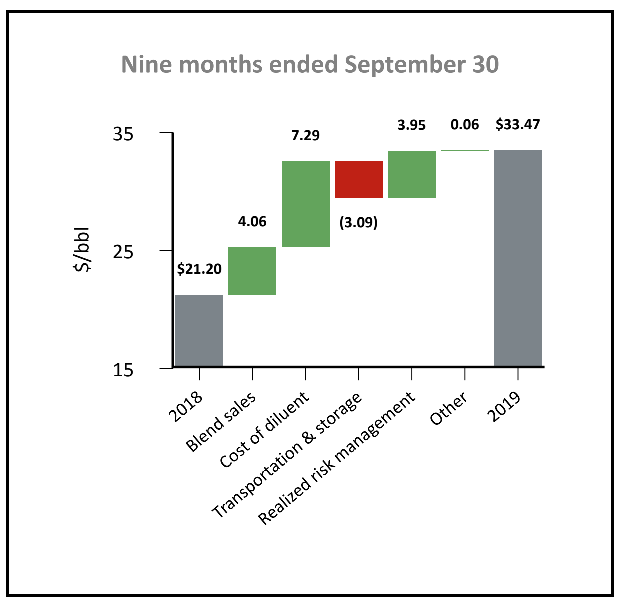
(1) Blend sales consists of petroleum revenue, net of purchased product and net sales of third-party product for marketing-related activity. Blend sales per barrel are based on blend sales volumes.

(2) 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.

(3) Includes the cost of purchasing third-party curtailment credits to increase the Corporation's production above provincially-mandated curtailment levels.

(4) A non-GAAP measure as defined in the "NON-GAAP MEASURES" section of this MD&A.





Bitumen Realization

Bitumen realization represents the Corporation's blend sales net of cost of diluent, expressed on a per barrel of bitumen basis. Blend sales represents the Corporation's revenue from its oil blend known as AWB. AWB 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, 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.

	Three months ended September 30				Nine months ended September 30			
	2019		2018		2019		2018	
($millions, except as indicated)		**$/bbl**		**$/bbl**		**$/bbl**		**$/bbl**
Blend sales	**$ 734**	**$ 60.26**	$ 767	$ 63.68	**$ 2,301**	**$ 62.90**	$ 2,006	$ 58.84
Cost of diluent	**(268)**	**(6.89)**	(338)	(14.05)	**(890)**	**(7.52)**	(965)	(14.81)
Bitumen realization	**$ 466**	**$ 53.37**	$ 429	$ 49.63	**$ 1,411**	**$ 55.38**	$ 1,041	$ 44.03
Average Commodity Prices:		**US$/bbl**		**US$/bbl**		**US$/bbl**		**US$/bbl**
WTI		**$ 56.45**		$ 69.50		**$ 57.06**		$ 66.75
Differential – WTI:AWB – Edmonton		**(14.52)**		(25.69)		**(13.78)**		(25.12)
AWB – Edmonton		**$ 41.93**		$ 43.81		**$ 43.28**		$ 41.63
WTI		**$ 56.45**		$ 69.50		**$ 57.06**		$ 66.75
Differential – WTI:AWB – U.S. Gulf Coast		**(2.50)**		(5.63)		**(0.58)**		(6.82)
AWB – U.S. Gulf Coast		**$ 53.95**		$ 63.87		**$ 56.48**		$ 59.93

During the third quarter of 2019, the WTI price decreased by more than the narrowing of the WTI:AWB differential compared to the third quarter of 2018. This resulted in a lower realized blend sales price by $3.42 per barrel, however the narrowed differential positively impacted the cost of diluent. As the differential narrows, a larger portion of the diluent expense, which is linked to the WTI price, is recovered through blend sales. As a result, the cost of diluent decreased by $7.16 per barrel. Together, these factors increased bitumen realization by $3.74 per barrel in the third quarter of 2019 compared to the third quarter of 2018.

During the nine months ended September 30, 2019, the WTI price decreased but was offset by a more significant narrowing of the WTI:AWB differential. As a result, the blend sales price increased by $4.06 per barrel and the narrowing of the differential decreased the cost of diluent by $7.29 per barrel as more of the diluent expense was recovered through blend sales. Together, these factors increased bitumen realization by $11.35 per barrel during the nine months ended September 30, 2019 compared to the same period of 2018.

Another factor increasing bitumen realization during the nine months ended September 30, 2019 was the Corporation's ability to sell increased blend sales volumes into the higher priced USGC market. Approximately 33% of blend sales volumes were delivered to the USGC during the three and nine months ended September 30, 2019, compared to 32% and 29% in the same periods of 2018. Refer to the Marketing Activity section of this MD&A for further details.

Transportation and storage

The Corporation's marketing strategy is focused on maximizing its 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			
	2019		2018		2019		2018	
($millions, except as indicated)		$/bbl		$/bbl		$/bbl		$/bbl
Transportation and storage	**$ (93)**	**$ (10.57)**	$ (78)	$ (9.11)	**$ (277)**	**$ (10.87)**	$ (184)	$ (7.78)

During the three and nine months ended September 30, 2019, transportation and storage costs per barrel increased 16% and 40%, respectively, compared to the same periods of 2018. The increase in costs on a per barrel basis for both periods is primarily the result of increased blend volumes transported by rail, plus the addition of the Bayou Bridge pipeline transportation cost which enables the Corporation to access the eastern USGC market. The increase in transportation and storage costs for the nine months ended September 30, 2019 was also impacted by the incremental transportation costs associated with the Access Pipeline Transportation Services Agreement entered into on March 22, 2018.

Third-party curtailment credits

On December 3, 2018 the Government of Alberta enacted rules to enable a temporary curtailment of crude oil and bitumen production (the "Curtailment Rules"). The Curtailment Rules came into force on January 1, 2019 and 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. This process is managed by the Alberta Energy Regulator who allocate the monthly production limits to each individual production company. Third-party curtailment credits exist when a producer chooses (or is unable) to produce up to its monthly allocated production limit and can transfer these credits to other producers seeking to increase their individual allocated production limit. As a result of the process, a secondary market has developed to transfer curtailment credits between industry producers.

	Three months ended September 30				Nine months ended September 30			
	2019		2018		2019		2018	
($millions, except as indicated)		$/bbl		$/bbl		$/bbl		$/bbl
Third-party curtailment credits	**$ (3)**	**$ (0.37)**	$ —	$ —	**$ (11)**	**$ (0.43)**	$ —	$ —

Curtailment was not in place during the three and nine months ended September 30, 2018. Subject to financial and operational considerations, the Corporation may continue to purchase third-party curtailment credits, if and when they become available.

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			
	2019		2018		2019		2018	
($millions, except as indicated)		$/bbl		$/bbl		$/bbl		$/bbl
Royalties	**$ (13)**	**$ (1.54)**	$ (18)	$ (2.01)	**$ (34)**	**$ (1.34)**	$ (37)	$ (1.56)

The decrease in royalties for the three months ended September 30, 2019 is primarily the result of a decrease in the WTI benchmark price which decreased the Corporation's royalty rate compared to the same period of 2018. The decrease in royalties for the nine months ended September 30, 2019, compared to the same period of 2018, is primarily due to a recovery related to prior year royalty adjustments.

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 and to reduce its overall carbon footprint as excess power is sold into the provincial power grid.

	Three months ended September 30				Nine months ended September 30			
	2019		2018		2019		2018	
($millions, except as indicated)		$/bbl		$/bbl		$/bbl		$/bbl
Operating costs - non-energy	**$ (37)**	**$ (4.22)**	$ (38)	$ (4.38)	**$ (118)**	**$ (4.64)**	$ (112)	$ (4.75)
Operating costs - energy	**(13)**	**(1.51)**	(13)	(1.50)	**(56)**	**(2.19)**	(47)	(1.98)
Power revenue	**13**	**1.43**	13	1.54	**46**	**1.82**	35	1.45
Net operating costs	**$ (37)**	**$ (4.30)**	$ (38)	$ (4.34)	**$ (128)**	**$ (5.01)**	$ (124)	$ (5.28)
Average realized power sales price (C$/Mwh)		**$ 50.30**		$ 51.53		**$ 59.20**		$ 45.42
Average natural gas purchase price (C$/mcf)		**$ 1.38**		$ 1.48		**$ 2.01**		$ 1.88

Net operating costs for the three months ended September 30, 2019 were similar to the three months ended September 30, 2018, with a small per barrel decrease due to higher bitumen sales volumes.

Net operating costs per barrel for the nine months ended September 30, 2019 decreased 5% compared to the same period of 2018 due to higher bitumen sales volumes. On an absolute basis, net operating costs increased due to higher fixed field costs allocated to operations and a higher natural gas purchase price, partially offset by a higher power sales price.

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			
	2019		2018		2019		2018	
($millions, except as indicated)		$/bbl		$/bbl		$/bbl		$/bbl
Realized gain (loss) on commodity risk management	**$ (37)**	**$ (4.15)**	$ (88)	$ (10.16)	**$ (109)**	**$ (4.26)**	$ (194)	$ (8.21)

Realized losses were recognized in all periods due to the settlement of losses on commodity risk management contracts primarily relating to crude oil sales. Refer to the commodity risk management discussion within the "OTHER OPERATING RESULTS" section of this MD&A for further details.

Marketing Activity

The Corporation utilizes a network of pipelines, rail and storage facilities to optimize market access to transport and sell AWB to refiners throughout North America and beyond. AWB is comprised of bitumen produced at the Christina Lake Project blended with purchased diluent and competes with a range of other types of oil to access North American and international refineries. The Corporation's network of storage, pipeline and rail commitments helps to move barrels toward higher value and less volatile markets as well as provide flexibility to avoid selling into the price-constrained post-apportionment market at Edmonton.

The Corporation is well-positioned to access the premium USGC market with blend transportation capacity of 50,000 bbls/d (expanding to 100,000 bbls/d in mid-2020) on the Flanagan South and Seaway pipeline systems, which provide pipeline access from Flanagan, Illinois through Cushing, Oklahoma to USGC refineries. In addition, during the second quarter of 2019, the Corporation's 20,000 bbls/d volume commitment on the Bayou Bridge pipeline commenced with the commissioning of the pipeline. The Bayou Bridge pipeline flows from Beaumont, Texas to St. James, Louisiana adding to the Corporation's marketing infrastructure and pipeline connectivity to the eastern USGC market. Effective January 1, 2019, the Corporation secured unit train loading capacity of 30,000 bbls/d at the Bruderheim terminal for 3 years, with a 1-year extension option. Rail will continue to be an important element of the Corporation's marketing strategy to mitigate Edmonton pricing exposure and to reach premium markets. This combination of strategic marketing assets advances the Corporation's strategy of having long-term, broadening and reliable market access to world oil prices for its production.

Excluding transportation and storage costs upstream of the Edmonton index sales point, the Corporation's blend sales price averaged US$41.60 per barrel in the third quarter of 2019 compared to the posted AWB benchmark price at Edmonton of US$41.93. Notwithstanding that Enbridge Mainline apportionment averaged 44% during the quarter, the Corporation was able to capture pricing in-line with the Edmonton index as a result of its marketing and storage assets and the ability to move barrels to the higher-priced USGC market.

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:

(US$ per barrel of blend sales)	Edmonton (US$/bbl) Pipeline	Edmonton (US$/bbl) Rail	USGC (US$/bbl) Pipeline	USGC (US$/bbl) Rail	TOTAL (US$/bbl)
	Three months ended September 30, 2019				
WTI	$ 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

	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

	Pipeline	Rail	Pipeline	Rail	TOTAL
Total blend sales - bbls/d	78,906	10,308	33,989	9,252	132,455
% of total sales	59%	8%	26%	7%	100%

(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$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) Results are translated at the average foreign exchange rate of 1.3207.

(US$ per barrel of blend sales)	Edmonton (US$/bbl) Pipeline	Edmonton (US$/bbl) Rail	USGC (US$/bbl) Pipeline	USGC (US$/bbl) Rail	TOTAL (US$/bbl)
	Three months ended September 30, 2018				
WTI	$ 69.50	$ —	$ 69.50	$ 69.50	$ 69.50
Differential - WTI:AWB at sales point	(27.84)	—	(5.37)	(6.74)	(20.78)
Blend sales price	41.66	—	64.13	62.76	48.72
Transportation and storage(1)	(1.56)	—	(9.87)	(22.23)	(5.00)
Transportation and storage from Christina Lake to Edmonton(2)	1.56	—	1.56	1.56	1.56
Blend sales price, net of transportation & storage at Edmonton	$ 41.66	$ —	$ 55.82	$ 42.09	$ 45.28

	Edmonton (US$/bbl)	USGC (US$/bbl)	USGC premium (US$/bbl)
Average blend sales price by location	$ 41.66	$ 63.87	$ 22.21
Transportation and storage(1)	(1.56)	(12.18)	(10.62)
Transportation and storage from Christina Lake to Edmonton(2)	1.56	1.56	—
Blend sales price, net of transportation & storage at Edmonton	$ 41.66	$ 53.25	$ 11.59

	Pipeline	Rail	Pipeline	Rail	TOTAL
Total blend sales - bbls/d	89,240	—	33,796	7,787	130,823
% of total sales	68%	—%	26%	6%	100%

(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$9.11 per barrel for the three months ended September 30, 2018.

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

(3) Results are translated at the average foreign exchange rate of 1.3070.

(US$ per barrel of blend sales)	Nine months ended September 30, 2019 Edmonton (US$/bbl) Pipeline	Edmonton (US$/bbl) Rail	USGC (US$/bbl) Pipeline	USGC (US$/bbl) Rail	TOTAL (US$/bbl)
WTI	$ 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

	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

	Pipeline	Rail	Pipeline	Rail	TOTAL
Total blend sales - bbls/d	77,821	12,397	35,610	8,156	133,984
% of total sales	58%	9%	27%	6%	100%

(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$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) Results are translated at the average foreign exchange rate of 1.3292.

(US$ per barrel of blend sales)	Nine months ended September 30, 2018 Edmonton (US$/bbl) Pipeline	Edmonton (US$/bbl) Rail	USGC (US$/bbl) Pipeline	USGC (US$/bbl) Rail	TOTAL (US$/bbl)
WTI	$ 66.75	$ 66.75	$ 66.75	$ 66.75	$ 66.75
Differential - WTI:AWB at sales point	(27.14)	(26.73)	(6.29)	(3.05)	(21.05)
Blend sales price	39.61	40.02	60.46	63.70	45.70
Transportation and storage[(1)]	(1.26)	(8.20)	(9.70)	(22.58)	(4.19)
Transportation and storage from Christina Lake to Edmonton[(2)]	1.26	1.26	1.26	1.26	1.26
Blend sales price, net of transportation & storage at Edmonton	$ 39.61	$ 33.08	$ 52.02	$ 42.38	$ 42.77

	Edmonton (US$/bbl)	USGC (US$/bbl)	USGC premium (US$/bbl)
Average blend sales price by location	$ 39.62	$ 60.70	$ 21.08
Transportation and storage[(1)]	(1.49)	(10.64)	(9.15)
Transportation and storage from Christina Lake to Edmonton[(2)]	1.26	1.26	—
Blend sales price, net of transportation & storage at Edmonton	$ 39.39	$ 51.32	$ 11.93

	Pipeline	Rail	Pipeline	Rail	TOTAL
Total blend sales - bbls/d	85,956	2,935	33,387	2,624	124,902
% of total sales	69%	2%	27%	2%	100%

(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$7.78 per barrel for the nine months ended September 30, 2018.

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

(3) Results are translated at the average foreign exchange rate of 1.2877.

Blend sales for the three months ended September 30, 2019 averaged 132,455 bbls/d compared to 130,823 bbls/d for the three months ended September 30, 2018. During the third quarter of 2019, the Corporation's sales volumes transported by rail was 19,560 bbls/d, 47% of which were delivered to the USGC, compared to 7,787 bbls/d of sales volumes transported by rail for the same period in 2018, all of which were delivered to the USGC.

Blend sales for the nine months ended September 30, 2019 averaged 133,984 bbls/d compared to 124,902 bbls/d for the nine months ended September 30, 2018. During the nine months ended September 30, 2019, the Corporation's sales volumes transported by rail was 20,553 bbls/d, 40% of which were delivered to the USGC, compared to 5,559 bbls/d of sales volumes transported by rail for the same period in 2018, of which 2,624 bbls/d were delivered to the USGC.

Although WTI:WCS differentials at Edmonton narrowed significantly, primarily due to the Alberta Government mandated production curtailment, during the nine months ended September 30, 2019 compared to the same periods of 2018, the Corporation continued to use rail as a mechanism to clear barrels out of the Edmonton market due to continually high Enbridge Mainline apportionment which averaged 42% during the nine months ended September 30, 2019. The use of rail and storage assists in reducing the Corporation's exposure to the post–apportionment market.

Despite the narrowing differentials in the Edmonton market during the three and nine months ended September 30, 2019, the Corporation continued to realize a premium price at the USGC compared to Edmonton. Net of transportation and storage costs, blended barrels sold at the USGC realized a US$0.82 per barrel and US$2.72 per barrel premium to those sold at Edmonton for the three and nine months ended September 30, 2019. This compares to a US$11.59 per barrel and US$11.93 per barrel premium at the USGC compared to Edmonton for the three and nine months ended September 30, 2018, respectively.

The per-barrel premium on blended sales is due to the Corporation's secured access to the USGC, where sales pricing is not subject to the same heavy oil differential as the Edmonton market. The premium recognized in the three and nine months ended September 30, 2019 was lower than the same period of 2018 primarily due to the tighter WTI:AWB differential at Edmonton in 2019.

For the three and nine months ended September 30, 2019, transportation and storage costs per barrel of blend transported by rail destined for the USGC were impacted by demobilization costs related to the change out of its leased rail car fleet to those with the highest safety rating in the industry, plus fixed costs associated with the use of the Bruderheim terminal, which is currently underutilized. Subject to market conditions at the time, MEG anticipates being in a position to fully utilize its 30,000 bbls/d of rail capacity at the Bruderheim rail terminal in 2020 once the results of the Alberta Petroleum Marketing Commission’s crude by rail asset divestiture process are announced. The Corporation understands that the completion of the process is anticipated to be some time in 2019.

Revenue

Revenue represents the total of petroleum revenue, including sales of third-party products for marketing-related activity, net of royalties and other revenue.

	Three months ended September 30		Nine months ended September 30	
($millions)	**2019**	**2018**	**2019**	**2018**
Revenue	**$ 958**	$ 803	**$ 2,938**	$ 2,213

Revenue for the three months ended September 30, 2019 increased 19%, compared to the same period of 2018, as a result of increased blend sales volumes. Revenue for the nine months ended September 30, 2019 increased 33%, compared to the same period of 2018, as a result of the increase in the average blend sales price and increased blend sales volumes.

Net Earnings (Loss)

	Three months ended September 30		Nine months ended September 30	
($millions)	2019	2018	2019	2018
Net earnings (loss)	$ 24	$ 118	$ (87)	$ 80

The decrease in net earnings for the three months ended September 30, 2019 compared to the same period of 2018 is due to an unrealized foreign exchange loss and a lower unrealized gain on commodity risk management partially offset by a higher cash operating netback.

The net loss for the nine months ended September 30, 2019 included an accelerated depreciation expense, after tax of $183 million and an exploration expense, after tax of $45 million as a result of the uncertainty of future benefits from certain non-core assets that do not contribute to the Corporation's development plan or cash flow. The Corporation also recognized an unrealized loss on commodity risk management contracts of $112 million offset by an unrealized foreign exchange gain of $107 million.

Comparatively, net earnings for the nine months ended September 30, 2018 included a gain on asset dispositions of $318 million relating to the sale of the Corporation's 50% interest in the Access Pipeline. This was partially offset by an unrealized foreign exchange loss of $145 million and unrealized losses on commodity risk management contracts totaling $12 million.

Capital Expenditures

	Three months ended September 30		Nine months ended September 30	
($millions)	2019	2018	2019	2018
Sustaining and maintenance	$ 26	$ 47	$ 64	$ 209
Phase 2B brownfield expansion	8	57	34	101
eMSAGP	—	15	—	84
eMVAPEX	(3)	14	8	57
Field infrastructure, corporate and other	9	6	20	27
	$ 40	$ 139	$ 126	$ 478

The decrease in capital spending reflects the Corporation's original 2019 capital budget of $200 million. Capital expenditures in the three and nine months ended September 30, 2019 were primarily directed towards sustaining and maintenance activities as well as completing work already underway on the Phase 2B Brownfield expansion. The Corporation also received an $8 million Government of Canada grant during the three months ended September 30, 2019 related to eMVAPEX.

4. OUTLOOK

Summary of 2019 Guidance	Previous Guidance January 22, 2019	Revised Guidance October 30, 2019
Capital expenditures	$200 million	$200 million
Bitumen production – annual average (bbls/d)	90,000 – 92,000	92,000 – 93,000
Non-energy operating costs ($/bbl)	$4.75 – $5.25	$4.75 – $5.00
General and administrative expense ($/bbl)	$1.95 – $2.05	$1.95 – $2.05

During 2019, the Corporation has been able to purchase third-party curtailment credits, which has positively impacted the Corporation's production and sales results compared to the original guidance assumptions. Based on results achieved to date, the Corporation has revised its 2019 annual guidance. Production volumes are now targeted to be in the range of 92,000 - 93,000 bbls/d and non-energy operating costs in the range of $4.75 - $5.00 per barrel. General and administrative expense remains unchanged in the range of $1.95 - $2.05 per barrel. The Corporation's operational guidance assumes the Alberta Government mandated production curtailment program remains in place for 2019 and into 2020.

The Corporation remains focused on maximizing its AWB sales price and improving overall cost efficiencies of the organization, with available free cash flow directed towards debt repayment. The Corporation's 2019 capital guidance of $200 million remains unchanged. Over the course of 2019, the Corporation has been successful in finding capital cost savings and undertaking minor scope changes that will allow the Corporation to deliver its original $200 million budget for approximately $170 million. As a result, based on expected operational benefits including plant integrity and turn-around management, MEG has shifted into 2019 approximately $30 million of expected 2020 capital expenditures to accelerate the completion of the Corporation's in-progress brownfield project at the Phase 2B central processing facility which includes incremental steam generation, water handling and oil treating capacity. This project, which was initiated in 2018, is expected to be completed in the first half of 2020.

5. 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		2019			2018				2017
	2019	**2018**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**
Average Commodity Prices										
Crude oil prices										
Brent (US$/bbl)	**64.73**	72.68	**61.97**	68.32	63.90	68.08	75.97	74.90	67.18	61.54
WTI (US$/bbl)	**57.06**	66.75	**56.45**	59.82	54.90	58.81	69.50	67.88	62.87	55.40
Differential – WTI:WCS – Edmonton (US$/bbl)	**(11.73)**	(21.93)	**(12.24)**	(10.67)	(12.29)	(39.43)	(22.25)	(19.27)	(24.28)	(12.26)
Differential – WCS:AWB – Edmonton (US$/bbl)	**(2.05)**	(3.19)	**(2.28)**	(1.65)	(2.21)	(5.17)	(3.44)	(2.94)	(3.17)	(2.30)
AWB – Edmonton (US$/bbl)	**43.28**	41.63	**41.93**	47.50	40.40	14.21	43.81	45.67	35.42	40.84
Differential – WTI:AWB – U.S. Gulf Coast (US$/bbl)	**(0.58)**	(6.82)	**(2.50)**	1.64	(0.89)	(6.25)	(5.63)	(7.83)	(7.00)	(5.48)
AWB – U.S. Gulf Coast (US$/bbl)	**56.48**	59.93	**53.95**	61.46	54.01	52.56	63.87	60.05	55.87	49.92
Condensate prices										
Condensate at Edmonton (C$/bbl)	**70.25**	85.30	**68.73**	74.76	67.25	59.63	87.35	88.84	79.72	73.72
Condensate at Edmonton as % of WTI	**92.6%**	99.2%	**92.2%**	93.4%	92.1%	76.7%	96.2%	101.4%	100.2%	104.6%
Condensate at Mont Belvieu, Texas (US$/bbl)	**47.62**	62.73	**44.34**	50.22	48.31	51.21	64.53	64.40	59.27	55.35
Condensate at Mont Belvieu, Texas as % of WTI	**83.5%**	94.0%	**78.5%**	84.0%	88.0%	87.1%	92.8%	94.9%	94.3%	99.9%
Natural gas prices										
AECO (C$/mcf)	**1.43**	1.59	**0.95**	1.12	2.86	1.70	1.28	1.26	2.26	1.84
Electric power prices										
Alberta power pool (C$/MWh)	**58.02**	48.39	**46.95**	56.37	70.73	55.57	54.46	55.92	34.81	22.49
Foreign exchange rates										
C$ equivalent of 1 US$ – average	**1.3292**	1.2877	**1.3207**	1.3376	1.3293	1.3215	1.3070	1.2911	1.2651	1.2717
C$ equivalent of 1 US$ – period end	**1.3244**	1.2924	**1.3244**	1.3091	1.3360	1.3646	1.2924	1.3142	1.2901	1.2518

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 North American 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 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. As a result, the WTI:WCS differential narrowed for the three and nine months ended September 30, 2019 compared to the same periods of 2018.

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 at 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 cost of condensate sourced from Mont Belvieu, Texas includes transportation costs of approximately US$6.50 per barrel of condensate and US$6.16 per barrel of condensate from Mont Belvieu to the Edmonton area for the three and nine months ended September 30, 2019, 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 decreased during the three and nine months ended September 30, 2019 as a result of continued pipeline constraints, lack of demand growth and robust production in the Western Canadian Sedimentary Basin.

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.

Foreign Exchange Rates

Changes in the value of the Canadian dollar relative to the U.S. dollar have an impact on the Corporation's blend sales and diluent expense, as blend sales prices and diluent expense are determined by reference to U.S. benchmarks. Changes in the value of the Canadian dollar relative to the U.S. dollar also have an impact on principal and interest payments on the Corporation's U.S. dollar denominated debt.

The Corporation recognizes net unrealized foreign exchange gains and losses on the translation of U.S. dollar denominated debt and U.S. dollar denominated cash and cash equivalents at each reporting date. As at September 30, 2019 the Canadian dollar had increased in value by approximately 3% against the U.S. dollar compared to its value as at December 31, 2018.

6. OTHER OPERATING RESULTS

Depletion and Depreciation

	Three months ended September 30		Nine months ended September 30	
($millions)	**2019**	**2018**	**2019**	**2018**
Depletion and depreciation expense	**$ 115**	$ 126	**$ 595**	$ 341
Depletion and depreciation expense per barrel of production	**$ 13.43**	$ 13.85	**$ 23.55**	$ 14.23

With the corporate strategy shifting away from production growth in the near term, an assessment of existing assets was completed during the second quarter of 2019. Given the uncertainty of future benefits associated with specific non-core assets that do not contribute to the Corporation's development plan or cash flow, the Corporation incurred a one-time accelerated depreciation expense of $237 million, or $9.38 per barrel in the second quarter of 2019. Accelerated depreciation was recognized on equipment, materials and engineering costs associated with greenfield expansion projects at Christina Lake which will not be pursued in the foreseeable future and on a partial upgrading technology project. None of these non-core assets relate to the current development plans of Christina Lake, Surmont or May River.

Depletion and depreciation expense was $13.43 per barrel for the three months ended September 30, 2019. The decrease from the same period of 2018 is a result of the reduction in depreciable assets due to the accelerated depreciation expense recorded in the second quarter of 2019, as well as a decrease in future development costs. Depletion and depreciation expense, excluding the accelerated depreciation expense, was $14.17 per barrel for the nine months ended September 30, 2019. The decrease from the same period of 2018 is primarily due to increased bitumen production volumes.

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	
($millions)	**2019**	**2018**	**2019**	**2018**
Realized:				
Crude oil contracts[1]	**$ (25)**	$ (85)	**$ (87)**	$ (192)
Condensate contracts[2]	**(12)**	(3)	**(22)**	(2)
Realized commodity risk management gain (loss)	**$ (37)**	**$ (88)**	**$ (109)**	**$ (194)**
Unrealized:				
Crude oil contracts[1]	**$ 8**	$ 102	**$ (104)**	$ (13)
Condensate contracts[2]	**2**	6	**(8)**	1
Unrealized commodity risk management gain (loss)	**$ 10**	**$ 108**	**$ (112)**	**$ (12)**
Commodity risk management gain (loss)	**$ (27)**	**$ 20**	**$ (221)**	**$ (206)**

(1) Includes WTI fixed price contracts, WTI collars and WTI:WCS fixed differential contracts.

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

The Corporation recognized a $27 million net loss from commodity risk management contracts for the three months ended September 30, 2019 as losses from narrowing WTI:WCS differentials over the quarter were partially offset by gains from declining WTI prices. Comparatively, in the three months ended September 30, 2018, the Corporation recognized a $20 million net gain from commodity risk management as gains from widening WTI:WCS differentials were partially offset by losses from rising WTI prices.

For the nine months ended September 30, 2019, the Corporation recognized a $221 million loss from commodity risk management due to narrowing WTI:WCS differentials, rising WTI prices and declining condensate prices. This compares with the $206 million net loss from commodity risk management for the nine months ended September 30, 2018, when losses from rising WTI prices were partially offset by gains from widening WTI:WCS differentials.

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 gains (losses):

	Three months ended September 30		Nine months ended September 30	
($/bbl)	**2019**	**2018**	**2019**	**2018**
WTI fixed price contracts:				
Average fixed price	**$ 61.76**	$ 54.16	**$ 63.03**	$ 53.66
Average settlement price	**$ 56.45**	$ 69.50	**$ 57.18**	$ 66.78
Gain (loss) on WTI fixed price contracts	**$ 5.31**	$ (15.34)	**$ 5.85**	$ (13.12)
WTI:WCS fixed differential contracts				
Average fixed differential	**$ (21.10)**	$ (15.65)	**$ (21.91)**	$ (14.80)
Average settlement differential	**$ (12.24)**	$ (22.25)	**$ (11.74)**	$ (21.93)
Gain (loss) on WTI:WCS fixed differential contracts	**$ (8.86)**	$ 6.60	**$ (10.17)**	$ 7.13
Condensate purchase contracts:				
Average fixed differential(1)	**$ (5.28)**	$ 3.38	**$ (5.12)**	$ 2.46
Average settlement differential	**$ (12.12)**	$ (4.97)	**$ (9.81)**	$ (4.81)
Gain (loss) on condensate purchase contracts	**$ (6.84)**	$ (8.35)	**$ (4.69)**	$ (7.27)

(1) *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	
($millions)	**2019**	**2018**	**2019**	**2018**
General and administrative expense	**$ 14**	$ 21	**$ 48**	$ 62
General and administrative expense per barrel of production	**$ 1.66**	$ 2.35	**$ 1.90**	$ 2.60

General and administrative expense per barrel decreased 29% and 27% for the three and nine months ended September 30, 2019 respectively, compared to the same periods of 2018, primarily due to the reduction of staffing levels in February 2019. The Corporation anticipates annual 2019 general and administrative expense to average $1.95 to $2.05 per barrel.

Stock-based Compensation

	Three months ended September 30		Nine months ended September 30	
($millions)	**2019**	**2018**	**2019**	**2018**
Cash-settled expense (recovery)	**$ 3**	$ 1	**$ (1)**	$ 23
Equity-settled expense	**5**	6	**20**	16
Stock-based compensation	**$ 8**	$ 7	**$ 19**	$ 39

Stock-based compensation for the nine months ended September 30, 2019 decreased, compared to the same period of 2018, due to a decrease in the Corporation's share price and a reduction in the number of share-based units due to reduced staffing levels offset by a one-time charge of $10 million related to the accelerated expense of units for retirement eligible employees which was recorded during the second quarter of 2019.

Foreign Exchange Gain (Loss), Net

	Three months ended September 30		Nine months ended September 30	
($millions)	**2019**	**2018**	**2019**	**2018**
Unrealized foreign exchange gain (loss) on:				
Long-term debt	**$ (41)**	$ 60	**$ 113**	$ (145)
Other	**3**	(2)	**(6)**	—
Unrealized net gain (loss) on foreign exchange	**(38)**	58	**107**	(145)
Realized gain (loss) on foreign exchange	**(1)**	1	**1**	(3)
Realized gain (loss) on foreign exchange derivatives	**—**	—	**—**	35
Foreign exchange gain (loss), net	**$ (39)**	$ 59	**$ 108**	$ (113)

C$ equivalent of 1 US$				
Beginning of period	**1.3091**	1.3142	**1.3646**	1.2518
End of period	**1.3244**	1.2924	**1.3244**	1.2924

Net foreign exchange gains and losses are primarily due to the translation of U.S. dollar denominated debt as a result of the strengthening or weakening of the Canadian dollar compared to the U.S. dollar during each period. For the three months ended September 30, 2019, the Canadian dollar weakened by 1%, resulting in an unrealized foreign exchange loss of $38 million. For the three months ended September 30, 2018, the Canadian dollar strengthened by 2%, resulting in an unrealized foreign exchange gain of $58 million.

For the nine months ended September 30, 2019, the Canadian dollar strengthened by 3%, resulting in an unrealized foreign exchange gain of $107 million. For the nine months ended September 30, 2018, the Canadian dollar weakened by 3%, resulting in an unrealized foreign exchange loss of $145 million.

In March 2018, the Corporation successfully completed the sale of its 50% interest in the Access Pipeline and its 100% interest in the Stonefell Terminal for cash proceeds of C$1.52 billion and other consideration of C$90 million. Upon entering into the sale agreement, the Corporation entered into forward currency contracts to manage the foreign exchange risk on the Canadian dollar denominated sale proceeds designated for U.S. dollar denominated long-term debt repayment. The Corporation settled these forward currency contracts on closing of the sale and realized a foreign exchange gain of $35 million.

Net Finance Expense

($millions)	Three months ended September 30 2019	Three months ended September 30 2018	Nine months ended September 30 2019	Nine months ended September 30 2018
Interest expense on long-term debt	**$ 69**	$ 68	**$ 210**	$ 218
Interest expense on lease liabilities	**6**	4	**19**	9
Interest income	**(1)**	(2)	**(4)**	(6)
Net interest expense	**74**	70	**225**	221
Accretion on provisions	**2**	2	**5**	6
Unrealized loss (gain) on derivative financial liabilities(1)	**(1)**	—	**(1)**	2
Realized loss (gain) on interest rate swaps	**—**	—	**—**	(17)
Net finance expense	**$ 75**	$ 72	**$ 229**	$ 212
Average effective interest rate(2)	**6.6%**	6.6%	**6.6%**	6.4%

(1) Derivative financial liabilities include the 1% interest rate floor and the interest rate swap that was settled in March 2018.
(2) Defined as the weighted average interest rate applied to all outstanding debt, including the impact of interest rate swaps.

Net finance expense for the nine months ended September 30, 2019 increased, compared to the same period of 2018, primarily due to the termination of the Corporation's interest rate swap contracts during the first quarter of 2018, which effectively fixed the interest rate on a portion of its senior secured term loan, and realized a gain of $17 million for the nine months ended September 30, 2018.

Income Tax

($millions)	Three months ended September 30 2019	Three months ended September 30 2018	Nine months ended September 30 2019	Nine months ended September 30 2018
Income tax expense (recovery)	**$ 15**	$ 24	**$ (19)**	$ (50)
Effective tax rate	**38%**	26%	**18%**	17%

As at September 30, 2019, the Corporation had approximately $7.4 billion of available Canadian tax pools and recognized a deferred income tax asset of $251 million. Estimated future taxable income is expected to be sufficient to realize the deferred income tax asset.

The effective tax rate of 38% for the three months ended September 30, 2019 is higher than the Canadian statutory rate of 26.5% primarily due to the impact of unrealized foreign exchange losses on the Corporation's debt. The effective tax rate of 18% for the nine months ended September 30, 2019 is lower than the Canadian statutory rate due to the impact of unrealized foreign exchange gains on the Corporation's debt as well as a one-time deferred income tax expense of $33 million related to the Alberta tax rate reduction in the second quarter of 2019.

7. LIQUIDITY AND CAPITAL RESOURCES

($millions)	September 30, 2019	December 31, 2018
First Lien:		
Senior secured term loan (September 30, 2019 – nil; December 31, 2018 – US$225 million)	**$ —**	$ 307
Second Lien:		
6.5% senior secured second lien notes (September 30, 2019 - US$677 million; December 31, 2018 US$750 million; due 2025)	**897**	1,023
Unsecured:		
6.375% senior unsecured notes (US$800 million; due 2023)	**1,060**	1,092
7.0% senior unsecured notes (US$1 billion; due 2024)	**1,324**	1,365
Less:		
Unamortized deferred debt discount and debt issue costs	**(24)**	(29)
Unamortized financial derivative liability discount	**—**	(1)
Long-term debt	**3,257**	3,757
Cash and cash equivalents	**(154)**	(318)
Net debt[(1)]	**$ 3,103**	$ 3,439

(1) *The non-GAAP measure of net debt is reconciled to long-term debt in accordance with IFRS in the "NON-GAAP MEASURES" section of this MD&A.*

During the nine months ended September 30, 2019 net debt decreased by $336 million. The Corporation's long-term debt repayments included the repayment of the outstanding senior secured term loan balance of $289 million (US $219 million) and the repurchase and extinguishment of a portion of its 6.5% senior secured second lien notes totaling $96 million (US$73 million). The Corporation expects to continue to repay outstanding indebtedness as free cash flow becomes available.

The value of the Canadian dollar increased relative to the U.S. dollar, which further reduced the balance of the U.S. dollar denominated debt. As at September 30, 2019, all of the Corporation's long-term debt was denominated in U.S. dollars.

The Corporation's cash and cash equivalents balance was $154 million as at September 30, 2019 compared to $318 million as at December 31, 2018. Adjusted funds flow of $569 million during the nine months ended September 30, 2019 was more than offset by the repayment of debt, capital expenditures, and the significant decrease in non-cash working capital during the first quarter of 2019 relating to the settlement of December 2018 revenues when benchmark crude oil prices were significantly lower. Refer to the "Cash Flow Summary" section for further details.

On July 30, 2019, the Corporation repaid the outstanding senior secured term loan balance of US$219 million. Concurrent with the senior secured term loan repayment, the Corporation amended and restated its revolving credit facility and the EDC Facility and extended the maturity date of each facility by 2.75 years to July 30, 2024. The maturity dates of the revolving credit facility and the EDC Facility include a feature that will 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 Corporation has reduced the total available credit under the two facilities to C$1.3 billion, comprised of C$800 million under the revolving credit facility and C$500 million under the EDC Facility. Letters of credit under this facility do not consume capacity of the revolving credit facility. The reduction of the total available credit is expected to reduce fees going forward by approximately $14 million annually.

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 drawn in excess of $400 million under the revolving credit facility 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. Following the full repayment of the outstanding senior secured term loan, the Corporation has no first lien debt outstanding and, to date, the Corporation has never drawn funds under the revolving credit facility.

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

As at September 30, 2019, no amount had been drawn under the Corporation's $800 million revolving credit facility, and the Corporation had $121 million of unutilized capacity under the $500 million letter of credit facility.

During the three months ended September 30, 2019, the Corporation repurchased and extinguished a portion of its 6.5% senior secured second lien notes totaling $96 million (US$73 million). An additional $88 million (US$66 million) of principal was repurchased and extinguished on the notes subsequent to September 30, 2019.

Interest savings resulting from the term loan repayment and the repurchase and extinguishment of a portion of the senior secured second lien notes are expected to be approximately $30 million annually.

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.

Risk Management

Commodity Price Risk Management

To mitigate the Corporation's exposure to fluctuations in oil prices, the Corporation periodically enters into financial commodity risk management contracts to partially manage its exposure on blend sales and condensate 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, 2019:

As at September 30, 2019	Volumes (bbls/d)[(1)]	Term	Average Price (US$/bbl)[(1)]
Crude Oil Sales Contracts			
WTI Fixed Price	71,418	Oct 1, 2019 - Dec 31, 2019	$61.00
WTI Fixed Price	19,052	Jan 1, 2020 - Dec 31, 2020	$59.41
WTI:WCS Fixed Differential	57,050	Oct 1, 2019 - Dec 31, 2019	$(21.15)
WTI: WCS Fixed Differential	17,000	Jan 1, 2020 - Dec 31, 2020	$(22.18)
Condensate Purchase Contracts			
WTI:Mont Belvieu Fixed Differential	5,250	Oct 1, 2019 - Dec 31, 2019	$(7.56)
WTI:Mont Belvieu Fixed Differential	7,250	Jan 1, 2020 - Dec 31, 2020	$(7.63)
WTI:Mont Belvieu Fixed Differential	3,000	Jan 1, 2021 - Dec 31, 2021	$(10.55)
WTI:Mont Belvieu Fixed % of WTI	9,750	Oct 1, 2019 - Dec 31, 2019	92.2 %
WTI:Mont Belvieu Fixed % of WTI	7,750	Jan 1, 2020 - Dec 31, 2020	93.1 %

(1) The volumes, prices and percentages 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 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, 2019:

Commodity	Sensitivity Range	Increase	Decrease
Crude oil commodity price	± US$1.00 per bbl applied to WTI contracts	$ (18)	$ 18
Crude oil differential price(1)	± US$1.00 per bbl applied to WTI:WCS differential contracts	$ 15	$ (15)

(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, power sales, natural gas purchases and propane purchases outstanding as at September 30, 2019:

As at September 30, 2019	Volumes(1)	Term	Average Price(1)
Crude Oil Sales Contracts	**(bbls/d)**		**(US$/bbl)**
WTI:AWB Fixed Differential	13,150	Jan 1, 2020 - Dec 31, 2020	(20.75)
Condensate Purchase Contracts	**(bbls/d)**		**(US$/bbl)**
WTI:Edmonton Fixed Differential	13,337	Oct 1, 2019 - Dec 31, 2019	(1.96)
WTI:Edmonton Fixed Differential	4,127	Jan 1, 2020 - Dec 31, 2020	(5.63)
Power Sales Contracts	**(MW)**		**(C$/MW)**
Fixed Price Power Sales	30	Oct 1, 2019 - Dec 31, 2019	54.33
Gas Purchases Contracts	**(Mcf/d)**		**(C$/Mcf)**
Fixed Price Gas Purchases	23,904	Oct 1, 2019 - Dec 31, 2019	2.10
Propane Purchases Contracts	**(m^3/d)**		**(C$/$M^3$)**
Fixed Price Propane Purchases	145	Oct 1, 2019 - Dec 31, 2019	171.94

(1) The volumes and prices in the above tables 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 are provided for indicative purposes.*

The Corporation entered into the following commodity risk management contracts relating to crude oil sales and condensate purchases between September 30, 2019 and October 30, 2019:

Subsequent to September 30, 2019	Volumes (bbls/d)(1)	Term	Average Prices (US$/bbl)(1)
Crude Oil Sales Contracts			
WTI Fixed Price	15,000	Jan 1, 2020 - Jan 31, 2020	$56.24
Condensate Purchase Contracts			
WTI:Mont Belvieu Fixed Differential	2,000	Jan 1, 2021 - Dec 31, 2021	$(10.26)

(1) 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.*

Cash Flow Summary

	Three months ended September 30		Nine months ended September 30	
($millions)	**2019**	**2018**	**2019**	**2018**
Net cash provided by (used in):				
Operating activities	**$ 174**	$ 3	**$ 406**	$ 186
Investing activities	**(33)**	(187)	**(158)**	1,002
Financing activities	**(389)**	(4)	**(405)**	(1,280)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency	**3**	(3)	**(7)**	1
Change in cash and cash equivalents	**$ (245)**	$ (191)	**$ (164)**	$ (91)

Cash Flow – Operating Activities

The increases in net cash provided by operating activities for the three and nine months ended September 30, 2019 are primarily due to higher bitumen realizations. During the nine months ended September 30, 2019, this was offset by a $220 million decrease in non-cash working capital during the first quarter of 2019 relating to the settlement of December 2018 revenues when benchmark crude oil prices were significantly lower.

Cash Flow – Investing Activities

The decrease in net cash used in investing activities during the third quarter of 2019 is due to reduced capital spending activity. This compares to the third quarter of 2018 when there was an increase in capital spending activity directed toward growth initiatives and sustaining capital activities at the Christina Lake project.

Net cash used in investing activities for the nine months ended September 30, 2019 reflects reduced capital spending activity and the receipt of cash proceeds of $17 million, related to the sale of earned Emission Performance Credits and the sale of exploration and evaluation assets. The comparative period in 2018 includes cash proceeds of $1.5 billion from the sale of the Corporation's 50% interest in the Access Pipeline and its 100% interest in the Stonefell Terminal that closed in the first quarter of 2018.

Cash Flow – Financing Activities

Net cash used in financing activities for the three months ended September 30, 2019 was $389 million which included the repayment of the outstanding senior secured term loan balance of $289 million (US$219 million), the repurchase and extinguishment of $96 million (US$73 million) of principal on the 6.5% senior secured second lien notes as well as payments on leased liabilities of $5 million, which have been reclassified from operating activities following the adoption of IFRS 16. Net cash used in financing activities for the three months ended September 30, 2018 was $4 million which included a quarterly term loan principal repayment of $4 million.

Net cash used in financing activities for the nine months ended September 30, 2019 was $405 million which included the repayment of the outstanding senior secured term loan balance of $289 million (US$219 million) and quarterly senior secured term loan repayments of $8 million, the repurchase and extinguishment of $96 million (US$73 million) of principal on the 6.5% senior secured second lien notes and payments on leased liabilities of $14 million, which have been reclassified from operating activities following the adoption of IFRS 16. Net cash used in financing activities for the nine months ended September 30, 2018 was $1.3 billion which consisted of a $1.3 billion partial repayment of the Corporation's senior secured term loan from the majority of the net cash proceeds from the sale of the Corporation's 50% interest in the Access Pipeline and its 100% interest in the Stonefell Terminal.

8. SHARES OUTSTANDING

As at September 30, 2019, the Corporation had the following share capital instruments outstanding or exercisable:

(millions)	Units
Common shares	**299.3**
Convertible securities	
Stock options[1]	**7.6**
Equity-settled RSUs and PSUs	**6.6**

(1) 6.1 million stock options were exercisable as at September 30, 2019.

As at October 29, 2019, the Corporation had 299.3 million common shares, 7.2 million stock options and 6.6 million equity-settled restricted share units and equity-settled performance share units outstanding, and 5.7 million stock options exercisable.

9. 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, 2019. 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)	2019	2020	2021	2022	2023	Thereafter	Total
Transportation and storage[1]	$ 89	$ 390	$ 433	$ 438	$ 456	$ 6,299	$ 8,105
Long-term debt[2]	—	—	—	—	1,059	2,221	3,280
Interest on long-term debt[2]	56	219	219	219	157	86	956
Decommissioning obligation[3]	1	5	2	3	3	710	724
Diluent purchases	101	115	21	21	18	—	276
Office lease rentals	5	22	21	20	18	133	219
Other commitments[4]	7	15	11	9	9	49	100
Total	**$ 259**	**$ 766**	**$ 707**	**$ 710**	**$ 1,720**	**$ 9,498**	**$ 13,660**

(1) This represents transportation and storage commitments from 2019 to 2048, including pipeline commitments which are awaiting regulatory approval and are not yet in service.

(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, 2019.

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

(4) This represents the future commitments associated with the Corporation's capital program, and other operating and maintenance commitments.

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.

10. 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 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.

11. CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The Corporation's critical accounting 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.

For a detailed discussion regarding the Corporation's critical accounting policies and estimates, please refer to the Corporations 2018 annual MD&A. Additional estimates, assumptions and judgments are detailed in the Corporation's unaudited interim consolidated financial statements.

12. NEW ACCOUNTING STANDARDS

IFRS 16 *Leases*

The IASB issued IFRS 16, *Leases* ("IFRS 16"), which replaces IAS 17 *Leases*, and is effective for annual periods beginning on or after January 1, 2019. IFRS 16, a single recognition and measurement model applicable to lessees, requires recognition of lease assets and lease liabilities on the balance sheet. The standard eliminates the classification of leases as either operating leases or finance leases for lessees, essentially treating all leases as finance leases. Short-term leases and leases for low-value assets are exempt from recognition and will continue to be treated as operating leases. The accounting requirements for lessors is substantially unchanged and a lessor will continue to classify leases as either finance leases or operating leases.

The Corporation adopted IFRS 16 *Leases,* effective January 1, 2019, using the modified retrospective approach. The modified retrospective approach does not require restatement of prior period comparative financial information as the cumulative effect is recognized as an adjustment to the opening deficit on the transition date and the standard is applied prospectively. Therefore, the comparative information in the Corporation's condensed Consolidated balance sheet, Consolidated statement of earnings (loss) and comprehensive income, Consolidated statement of changes in shareholders' equity, and Consolidated statement of cash flow have not been restated.

On adoption of IFRS 16, the Corporation elected to use the following practical expedients permitted by the standard:

- Applied a single discount rate to a portfolio of leases with similar characteristics;
- Accounted for leases with a remaining term of less than 12 months as at January 1, 2019 as short-term leases;
- Used hindsight when determining the lease term where the contract contained options to extend or terminate the lease;
- Excluded initial direct costs from the measurement of the right-of-use ("ROU") asset as at January 1, 2019; and Relied on the Corporation's previous assessment of whether leases were onerous under IAS 37 *Provisions, Contingent Liabilities and Contingent Assets* immediately before initial application as an alternative to performing an impairment review on the ROU assets. ROU assets have been adjusted by the amount of the onerous contracts provision recognized in the consolidated financial statements as at December 31, 2018.

The impacts of the adoption of IFRS 16, as at January 1, 2019, are as follows:

		IFRS 16 Opening Balance Sheet Adjustments			
	Reported balance as at Dec 31, 2018	**Finance Sublease Receivables[(a)]**	**Transportation Leases[(b)]**	**Office Leases[(b)]**	**Restated balance as at January 1, 2019**
Assets					
Property, plant and equipment	$ 6,646		$ 17	$ 41	$ 6,704
Other assets	221	19			240
Deferred income tax asset	237	(5)		1	233
Liabilities					
Provisions and other liabilities	(294)		(17)	(44)	(355)
Shareholders' Equity					
Deficit	1,751	(14)		2	1,739
	$ 8,561	**$ —**	**$ —**	**$ —**	**$ 8,561**

a. On adoption, the Corporation has recognized finance sublease receivables in relation to certain sublease arrangements that were previously recognized on the consolidated balance sheet as at December 31, 2018 within the onerous contracts provision.

b. On adoption, the Corporation has recognized lease liabilities in relation to lease arrangements measured at the present value of the remaining lease payments as at December 31, 2018, and discounted using the Corporation’s estimated incremental borrowing rate as of January 1, 2019. The associated right-of-use assets were measured at the amount equal to the lease liability, adjusted by the amount of any prepaid or accrued lease payments, on January 1, 2019.

Significant Accounting Policies

Leases

The Corporation has applied IFRS 16 using the modified retrospective approach. As a result, the comparative information contained herein has been accounted for in accordance with the Corporation's previous accounting policies which can be found in the audited consolidated financial statements for the year ended December 31, 2018.

The following accounting policy is applicable as of January 1, 2019:

The Corporation assesses whether a contract is a lease based on whether the contract conveys the right to control the use of an underlying asset for a period of time in exchange for consideration.

As Lessee

Leases are recognized as a lease liability and a corresponding ROU asset at the date on which the leased asset is available for use by the Corporation. Liabilities and assets arising from a lease are initially measured on a present value basis. Lease liabilities are measured at the present value of the remaining lease payments, discounted using the Corporation's estimated incremental borrowing rate when the rate implicit in the lease is not readily available. The corresponding right-of-use assets are measured at the amount equal to the lease liability.

The lease liability is measured at amortized cost using the effective interest method. It is remeasured when there is a change in the future lease payments arising from a change in an index or rate, if there is a change in the amount expected to be payable under a residual value guarantee or if there is a change in the assessment of whether the Corporation will exercise a purchase, extension or termination option that is within the control of the Corporation.

The ROU asset, initially measured at an amount equal to the corresponding lease liability, is depreciated on a straight-line basis, over the shorter of the estimated useful life of the asset or the lease term. The ROU asset may be adjusted for certain remeasurements of the lease liability and impairment losses.

Upon adoption of IFRS 16, there is an increase to depletion and depreciation expense on right-of-use assets, an increase to net finance expense on lease liabilities, a reduction to general and administrative expense and a reduction to transportation expense. Accounting treatment of existing sale and leasebacks resulting in a finance lease under IAS 17 remain unchanged.

Lease payments are allocated between the lease liability and finance costs. Cash outflows for repayment of the principal portion of the lease liability is classified as cash flows from financing activities. The interest portion of the lease payments is classified as cash flows from operating activities.

Leases that have terms of less than twelve months or leases on which the underlying asset is of low value are recognized as an expense in the consolidated statement of earnings (loss) on a straight-line basis over the lease term.

As Lessor

Accounting requirements for lessors is substantially unchanged and a lessor will continue to classify leases as either finance leases or operating leases, and disclosure requirements are enhanced. As an intermediate lessor, the Corporation accounts for its interest in the head lease and subleases separately. The Corporation has reassessed subleases previously classified as operating leases under IAS 17 to determine whether each sublease should be classified as an operating lease or a finance lease. An operating lease that is reclassified to a finance lease is accounted for as a new finance lease entered into on January 1, 2019.

13. 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 construction risks, operations risks, project development risks and political-economic risks. Further information regarding the risk factors which may affect the Corporation is contained in the most recently filed Annual Information Form ("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.

14. DISCLOSURE CONTROLS AND PROCEDURES

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

15. 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.

16. 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

17. ADVISORY

Forward-Looking Information

This document may contain forward-looking information 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.

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 include, but are not limited to: risks associated with the oil and gas industry, for example, results securing access to markets and transportation infrastructure and the commitments and risks therein; extent and timelines of the Alberta Government's mandatory production curtailment program; availability of capacity on the electricity transmission grid; uncertainty of reserve and resource estimates; uncertainty associated with estimates and projections relating to production, costs and revenues; health, safety and environmental risks; risks of legislative and regulatory changes to, amongst other things, tax, land use, royalty and environmental laws and Federal and Provincial climate change policies; 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; risks and uncertainties associated with securing and maintaining the necessary regulatory approvals and financing to proceed with the Corporation's future phases and the expansion and/or operation of the Corporation's projects; risks and uncertainties related to the timing of completion, commissioning, and start-up, of the Corporation's future phases, expansions and projects; the operational risks and delays in the development, exploration, production, and the capacities and performance associated with the Corporation's projects; 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 which is available 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 oil company focused on sustainable *in situ* thermal oil development and production in the southern Athabasca region of Alberta, Canada. The Corporation is actively developing enhanced oil recovery projects that utilize SAGD extraction methods to improve the economic recovery of oil as well as lower carbon emissions. MEG transports and sells AWB or blend 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 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 and reconciliation of this non-GAAP measure is presented in the “NON-GAAP MEASURES” section of this MD&A.

18. 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.

19. QUARTERLY SUMMARIES

	2019			2018				2017
Unaudited	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**
FINANCIAL ($millions unless specified)								
Net earnings (loss)	**24**	(64)	(48)	(199)	118	(179)	141	(24)
Per share, diluted	**0.08**	(0.21)	(0.16)	(0.67)	0.39	(0.61)	0.47	(0.08)
Adjusted funds flow	**192**	227	151	(38)	116	18	83	192
Per share, diluted	**0.63**	0.76	0.50	(0.13)	0.39	0.06	0.28	0.65
Capital expenditures	**40**	33	53	144	139	191	148	163
Cash and cash equivalents	**154**	399	154	318	373	564	675	464
Working capital	**204**	416	175	290	274	211	446	313
Long-term debt	**3,257**	3,582	3,660	3,740	3,544	3,607	3,543	4,668
Shareholders' equity	**3,828**	3,795	3,851	3,886	4,068	3,946	4,113	3,964
BUSINESS ENVIRONMENT								
WTI (US$/bbl)	**56.45**	59.82	54.90	58.81	69.50	67.88	62.87	55.40
Differential – WTI:WCS – Edmonton (US$/bbl)	**(12.24)**	(10.67)	(12.29)	(39.43)	(22.25)	(19.27)	(24.28)	(12.26)
Differential – WCS:AWB – Edmonton (US$/bbl)	**(2.28)**	(1.65)	(2.21)	(5.17)	(3.44)	(2.94)	(3.17)	(2.30)
AWB – Edmonton (US$/bbl)	**41.93**	47.50	40.40	14.21	43.81	45.67	35.42	40.84
Differential – WTI:AWB – U.S. Gulf Coast (US$/bbl)	**(2.50)**	1.64	(0.89)	(6.25)	(5.63)	(7.83)	(7.00)	(5.48)
AWB – U.S. Gulf Coast (US$/bbl)	**53.95**	61.46	54.01	52.56	63.87	60.05	55.87	49.92
C$ equivalent of 1US$ – average	**1.3207**	1.3376	1.3293	1.3215	1.3070	1.2911	1.2651	1.2717
Natural gas – AECO ($/mcf)	**0.95**	1.12	2.86	1.70	1.28	1.26	2.26	1.84
OPERATIONAL ($/bbl unless specified)								
Blend sales, net of purchased product – bbls/d	**132,455**	137,120	132,377	126,750	130,823	108,237	135,701	135,533
Diluent usage – bbls/d	**(37,463)**	(42,000)	(42,555)	(38,467)	(36,967)	(33,819)	(44,093)	(40,992)
Bitumen sales – bbls/d	**94,992**	95,120	89,822	88,283	93,856	74,418	91,608	94,541
Bitumen production – bbls/d	**93,278**	97,288	87,113	87,582	98,751	71,325	93,207	90,228
Steam-oil ratio (SOR)	**2.26**	2.16	2.20	2.22	2.17	2.22	2.17	2.22
Blend sales	**60.26**	69.19	59.02	37.76	63.68	62.41	51.20	56.81
Cost of diluent	**(6.89)**	(6.96)	(8.81)	(22.45)	(14.05)	(15.08)	(15.74)	(8.80)
Bitumen realization	**53.37**	62.23	50.21	15.31	49.63	47.33	35.46	48.01
Transportation and storage – net	**(10.57)**	(10.80)	(11.27)	(10.28)	(9.11)	(8.28)	(5.99)	(7.00)
Third-party curtailment credits	**(0.37)**	(0.89)	—	—	—	—	—	—
Royalties	**(1.54)**	(2.06)	(0.37)	(0.15)	(2.01)	(1.64)	(1.03)	(0.84)
Operating costs – non-energy	**(4.22)**	(4.53)	(5.22)	(4.25)	(4.38)	(5.47)	(4.55)	(4.53)
Operating costs – energy	**(1.51)**	(1.78)	(3.36)	(1.98)	(1.50)	(1.79)	(2.64)	(2.03)
Power revenue	**1.43**	1.65	2.41	1.68	1.54	1.62	1.21	0.70
Realized gain (loss) on commodity risk management	**(4.15)**	(5.94)	(2.60)	6.81	(10.16)	(13.11)	(2.15)	(0.77)
Cash operating netback	**32.44**	37.88	29.80	7.14	24.01	18.66	20.31	33.54
Power sales price (C$/MWh)	**50.30**	55.33	70.83	55.38	51.53	51.02	35.50	21.37
Power sales (MW/h)	**112**	118	128	111	117	98	130	129
Depletion and depreciation rate per bbl of production	**13.43**	41.22	14.68	13.79	13.85	16.08	13.22	14.26
COMMON SHARES								
Shares outstanding, end of period (000)	**299,288**	299,207	296,857	296,841	296,813	296,751	294,105	294,104
Volume traded (000)	**158,246**	163,295	191,935	151,873	128,363	166,016	89,721	76,531
Common share price ($)								
High	**6.64**	6.79	8.62	11.70	11.51	11.24	6.43	6.82
Low	**4.31**	4.06	4.75	7.25	6.78	4.49	4.28	4.54
Close (end of period)	**5.80**	5.02	5.10	7.71	8.03	10.96	4.55	5.14

Changes to net earnings (loss) in comparative quarters from 2017 to 2019 is primarily due to commodity price volatility and the impact on the Corporation's realized blend sales price, unrealized commodity risk management gains and losses, combined with the impact of changes in foreign exchange rates on the Corporation's U.S. dollar denominated debt.

Variability in unrealized commodity risk management gains and losses quarter over quarter has had an impact on the Corporation's quarterly net earnings (loss). Volatility in North American crude oil prices have continued to drive substantial changes in the value of the Corporation's commodity price risk management contracts. Under the Corporation's strategic commodity risk management program, derivative financial instruments are employed to increase the predictability of the Corporation's cash flow, by managing commodity price volatility.

The Corporation has recognized quarterly fluctuations in adjusted funds flow over the past eight quarters primarily due to volatility in crude oil prices.

Capital expenditures have decreased consistently from 2017 to 2019. The decrease in capital spending during 2019 reflects the Corporation's disciplined approach to capital growth.

Production volumes have steadily increased from 2017 to 2019, with interquartile fluctuations due to turnaround activities within specific quarters. Supported by proprietary reservoir technologies, the Corporation has been able to steadily increase production through a series of low-cost debottlenecking and expansion projects and the redeployment of steam into new well pairs. In 2019, production has been limited by the Alberta Government mandated production curtailment program.

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

As at	Note	September 30, 2019	December 31, 2018
Assets			
Current assets			
Cash and cash equivalents	17	**$ 154**	$ 318
Trade receivables and other		**334**	218
Inventories		**92**	97
Commodity risk management	19	**14**	123
		594	756
Non-current assets			
Property, plant and equipment	3, 5	**6,254**	6,646
Exploration and evaluation assets	6	**490**	550
Other assets	3, 7	**230**	221
Commodity risk management	19	**4**	—
Deferred income tax asset	3	**251**	237
Total assets		**$ 7,823**	$ 8,410
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities		**$ 330**	$ 427
Current portion of long-term debt	8	**—**	17
Current portion of provisions and other liabilities	9	**29**	17
Commodity risk management	19	**31**	6
		390	467
Non-current liabilities			
Long-term debt	8	**3,257**	3,740
Provisions and other liabilities	3, 9	**342**	294
Commodity risk management	19	**6**	24
Total liabilities		**3,995**	4,525
Shareholders' equity			
Share capital	10	**5,442**	5,427
Contributed surplus		**179**	170
Deficit	3	**(1,826)**	(1,751)
Accumulated other comprehensive income		**33**	39
Total shareholders' equity		**3,828**	3,885
Total liabilities and shareholders' equity		**$ 7,823**	$ 8,410

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	**2019**	**2018**	**2019**	**2018**
Revenues					
Petroleum revenue, net of royalties	12	**$ 942**	$ 787	**$ 2,882**	$ 2,169
Other revenue	12	**16**	16	**56**	44
Total revenues		**958**	803	**2,938**	2,213
Expenses					
Diluent and transportation	13	**364**	419	**1,177**	1,158
Operating expenses		**50**	51	**174**	159
Purchased product		**221**	38	**615**	200
Third-party curtailment credits		**3**	—	**11**	—
Depletion and depreciation	5, 7	**115**	126	**595**	341
Exploration expense	6	**—**	1	**58**	1
General and administrative		**14**	21	**48**	62
Stock-based compensation	11	**8**	7	**19**	39
Net finance expense	15	**75**	72	**229**	212
Other expenses		**3**	5	**19**	10
Gain on asset dispositions	6, 7	**—**	—	**(14)**	(318)
Commodity risk management loss (gain), net	19	**27**	(20)	**221**	206
Foreign exchange loss (gain), net	14	**39**	(59)	**(108)**	113
Earnings (loss) before income taxes		**39**	142	**(106)**	30
Income tax expense (recovery)	16	**15**	24	**(19)**	(50)
Net earnings (loss)		**24**	118	**(87)**	80
Other comprehensive income (loss), net of tax					
Items that may be reclassified to profit or loss:					
Foreign currency translation adjustment		**2**	(3)	**(6)**	6
Comprehensive income (loss)		**$ 26**	$ 115	**$ (93)**	$ 86
Net earnings (loss) per common share					
Basic	18	**$ 0.08**	$ 0.40	**$ (0.29)**	$ 0.27
Diluted	18	**$ 0.08**	$ 0.39	**$ (0.29)**	$ 0.27

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)

	Note	Share Capital	Contributed Surplus	Deficit	Accumulated Other Comprehensive Income	Total Shareholders' Equity
Balance as at December 31, 2018		**$ 5,427**	**$ 170**	**$ (1,751)**	**$ 39**	**$ 3,885**
IFRS 16 opening deficit adjustment	3	**—**	**—**	**12**	**—**	**12**
Stock-based compensation		**—**	**23**	**—**	**—**	**23**
Stock options exercised		**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**
Balance as at December 31, 2017		$ 5,404	$ 167	$ (1,629)	$ 23	$ 3,965
IFRS 9 opening deficit adjustment		—	—	(5)	—	(5)
Stock-based compensation		—	19	—	—	19
Stock options exercised		2	(1)	—	—	1
RSUs vested and released		21	(21)	2	—	2
Comprehensive income (loss)		—	—	80	6	86
Balance as at September 30, 2018		$ 5,427	$ 164	$ (1,552)	$ 29	$ 4,068

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)

	Note	Three months ended September 30 2019	Three months ended September 30 2018	Nine months ended September 30 2019	Nine months ended September 30 2018
Cash provided by (used in):					
Operating activities					
Net earnings (loss)		**$ 24**	$ 118	**$ (87)**	$ 80
Adjustments for:					
Deferred income tax expense (recovery)	16	**15**	24	**(19)**	(50)
Depletion and depreciation	5, 7	**115**	126	**595**	341
Exploration expense	6	**—**	1	**58**	1
Stock-based compensation	11	**5**	6	**20**	16
Unrealized net loss (gain) on foreign exchange	14	**38**	(58)	**(107)**	145
Unrealized (gain) loss on commodity risk management	19	**(10)**	(108)	**112**	12
Amortization of debt discount and debt issue costs	8	**4**	3	**14**	11
Gain on asset dispositions	6, 7	**—**	—	**(14)**	(318)
Other		**—**	4	**3**	7
Decommissioning expenditures	9	**(1)**	(1)	**(1)**	(4)
Payments on onerous contracts	9	**—**	(4)	**—**	(14)
Net change in other liabilities		**1**	—	**(6)**	7
Funds flow from operating activities		**191**	111	**568**	234
Net change in non-cash working capital items	17	**(17)**	(108)	**(162)**	(48)
Net cash provided by (used in) operating activities		**174**	3	**406**	186
Investing activities					
Capital expenditures:					
Property, plant and equipment	5	**(40)**	(138)	**(125)**	(477)
Exploration and evaluation	6	**—**	(1)	**(1)**	(1)
Net proceeds on dispositions	6, 7	**—**	—	**17**	1,502
Other		**(1)**	(5)	**—**	(7)
Net change in non-cash working capital items	17	**8**	(43)	**(49)**	(15)
Net cash provided by (used in) investing activities		**(33)**	(187)	**(158)**	1,002
Financing activities					
Issue of shares, net of issue costs		**1**	—	**1**	1
Repayment of long-term debt	17	**(385)**	(4)	**(393)**	(1,281)
Payments on leased liabilities	9	**(5)**	—	**(14)**	—
Receipts on leased assets		**—**	—	**1**	—
Net cash provided by (used in) financing activities		**(389)**	(4)	**(405)**	(1,280)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency		**3**	(3)	**(7)**	1
Change in cash and cash equivalents		**(245)**	(191)	**(164)**	(91)
Cash and cash equivalents, beginning of period		**399**	564	**318**	464
Cash and cash equivalents, end of period		**$ 154**	$ 373	**$ 154**	$ 373

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

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 750 square miles of oil leases in the southern Athabasca region of northern Alberta and is primarily engaged in thermal oil development and production at its 80 section Christina Lake Project.

In the first quarter of 2018, the Corporation successfully completed the sale of its 50% interest in the Access Pipeline and its 100% interest in the Stonefell Terminal.

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, 2018, except as described in Note 3. 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, 2018 and in Note 4 of these interim consolidated financial statements. These interim consolidated financial statements should be read in conjunction with the Corporation’s audited consolidated financial statements for the year ended December 31, 2018.

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 30, 2019.

3. CHANGE IN ACCOUNTING POLICIES

New accounting standards

IFRS 16 *Leases*

The IASB issued IFRS 16, *Leases* ("IFRS 16"), which replaces IAS 17 *Leases*, and is effective for annual periods beginning on or after January 1, 2019. IFRS 16, a single recognition and measurement model applicable to lessees, requires recognition of lease assets and lease liabilities on the balance sheet. The standard eliminates the classification of leases as either operating leases or finance leases for lessees, essentially treating all leases as finance leases. Short-term leases and leases for low-value assets are exempt from recognition and will continue to be treated as operating leases. The accounting requirements for lessors is substantially unchanged and a lessor will continue to classify leases as either finance leases or operating leases.

The Corporation adopted IFRS 16 *Leases,* effective January 1, 2019, using the modified retrospective approach. The modified retrospective approach does not require restatement of prior period comparative financial information as the cumulative effect is recognized as an adjustment to the opening deficit on the transition date and the standard is applied prospectively. Therefore, the comparative information in the Corporation's condensed Consolidated balance sheet, Consolidated statement of earnings (loss) and comprehensive income, Consolidated statement of changes in shareholders' equity, and Consolidated statement of cash flow have not been restated.

On adoption of IFRS 16, the Corporation elected to use the following practical expedients permitted by the standard:

- Applied a single discount rate to a portfolio of leases with similar characteristics;
- Accounted for leases with a remaining term of less than 12 months as at January 1, 2019 as short-term leases;
- Used hindsight when determining the lease term where the contract contained options to extend or terminate the lease;
- Excluded initial direct costs from the measurement of the right-of-use ("ROU") asset as at January 1, 2019; and Relied on the Corporation's previous assessment of whether leases were onerous under IAS 37 *Provisions, Contingent Liabilities and Contingent Assets* immediately before initial application as an alternative to performing an impairment review on the ROU assets. ROU assets have been adjusted by the amount of the onerous contracts provision recognized in the consolidated financial statements as at December 31, 2018.

The impacts of the adoption of IFRS 16, as at January 1, 2019, are as follows:

		IFRS 16 Opening Balance Sheet Adjustments			
	Reported balance as at Dec 31, 2018	**Finance Sublease Receivables**[(a)]	**Transportation Leases**[(b)]	**Office Leases**[(b)]	**Restated balance as at January 1, 2019**
Assets					
Property, plant and equipment	$ 6,646		$ 17	$ 41	$ 6,704
Other assets	221	$ 19			240
Deferred income tax asset	237	(5)		1	233
Liabilities					
Provisions and other liabilities	(294)		(17)	(44)	(355)
Shareholders' Equity					
Deficit	1,751	(14)		2	1,739
	$ 8,561	**$ —**	**$ —**	**$ —**	**$ 8,561**

a. On adoption, the Corporation has recognized finance sublease receivables in relation to certain sublease arrangements that were previously recognized on the consolidated balance sheet as at December 31, 2018 within the onerous contracts provision.

b. On adoption, the Corporation has recognized lease liabilities in relation to lease arrangements measured at the present value of the remaining lease payments as at December 31, 2018, and discounted using the Corporation's estimated incremental borrowing rate as of January 1, 2019. The associated right-of-use assets were measured at the amount equal to the lease liability, adjusted by the amount of any prepaid or accrued lease payments, on January 1, 2019.

Reconciliation of Commitments to Lease Liabilities

The following table provides a reconciliation of the commitments as at December 31, 2018 to the Corporation's lease liabilities as at January 1, 2019:

		Reconciliation
Commitments as at December 31, 2018	$	9,026
Less:		
Agreements that do not contain a lease		(8,842)
Non-lease components		(64)
Short-term and immaterial leases		(12)
Impact of discounting		(25)
		83
Add:		
Finance lease liabilities under IAS 17		131
Provisions previously recognized under IAS 37		77
Lease liabilities as at January 1, 2019	**$**	**291**

Significant Accounting Policies

Leases

The Corporation has applied IFRS 16 using the modified retrospective approach. As a result, the comparative information contained herein has been accounted for in accordance with the Corporation's previous accounting policies which can be found in the audited consolidated financial statements for the year ended December 31, 2018.

The following accounting policy is applicable as of January 1, 2019:

The Corporation assesses whether a contract is a lease based on whether the contract conveys the right to control the use of an underlying asset for a period of time in exchange for consideration.

As Lessee

Leases are recognized as a lease liability and a corresponding ROU asset at the date on which the leased asset is available for use by the Corporation. Liabilities and assets arising from a lease are initially measured on a present value basis. Lease liabilities are measured at the present value of the remaining lease payments, discounted using the Corporation's estimated incremental borrowing rate when the rate implicit in the lease is not readily available. The corresponding right-of-use assets are measured at the amount equal to the lease liability.

The lease liability is measured at amortized cost using the effective interest method. It is remeasured when there is a change in the future lease payments arising from a change in an index or rate, if there is a change in the amount expected to be payable under a residual value guarantee or if there is a change in the assessment of whether the Corporation will exercise a purchase, extension or termination option that is within the control of the Corporation.

The ROU asset, initially measured at an amount equal to the corresponding lease liability, is depreciated on a straight-line basis, over the shorter of the estimated useful life of the asset or the lease term. The ROU asset may be adjusted for certain remeasurements of the lease liability and impairment losses.

Upon adoption of IFRS 16, there is an increase to depletion and depreciation expense on right-of-use assets, an increase to net finance expense on lease liabilities, a reduction to general and administrative expense and a reduction to transportation expense. Accounting treatment of existing sale and leasebacks resulting in a finance lease under IAS 17 remain unchanged.

Lease payments are allocated between the lease liability and finance costs. Cash outflows for repayment of the principal portion of the lease liability is classified as cash flows from financing activities. The interest portion of the lease payments is classified as cash flows from operating activities.

Leases that have terms of less than twelve months or leases on which the underlying asset is of low value are recognized as an expense in the consolidated statement of earnings (loss) on a straight-line basis over the lease term.

As Lessor

Accounting requirements for lessors is substantially unchanged and a lessor will continue to classify leases as either finance leases or operating leases, and disclosure requirements are enhanced. As an intermediate lessor, the Corporation accounts for its interest in the head lease and subleases separately. The Corporation has reassessed subleases previously classified as operating leases under IAS 17 to determine whether each sublease should be classified as an operating lease or a finance lease. An operating lease that is reclassified to a finance lease is accounted for as a new finance lease entered into on January 1, 2019.

4. SIGNIFICANT ACCOUNTING ESTIMATES, ASSUMPTIONS AND JUDGMENTS

The same accounting estimates, assumptions and judgments are used in the unaudited interim consolidated financial statements as were used in the Corporation's audited financial statements. Additional estimates, assumptions and judgments for 2019 are outlined below:

(a) Critical judgments related to leases under IFRS 16, *Leases*

The Corporation applies judgment in reviewing each of its contractual arrangements to determine whether the arrangement contains a lease within the scope of IFRS 16. Leases that are recognized are subject to further judgment and estimation in various areas specific to the arrangement.

When a lease contract contains an option to extend or terminate a lease, the Corporation must use their best estimate to determine the appropriate lease term. Management must consider all facts and circumstances to determine if there is an economic benefit to exercise an extension option or to not exercise a termination option. The lease term must be reassessed if a significant event or change in circumstance occurs.

Lease liabilities recognized have been estimated using a discount rate equal to the Corporation's estimated incremental borrowing rate. This rate represents the rate that the Corporation wold incur to obtain the funds necessary to purchase an asset of a similar value, with similar payment terms and security in a similar economic environment.

5. PROPERTY, PLANT AND EQUIPMENT

	Field and facilities	Transportation and storage	Corporate assets	Total
Cost				
Balance as at December 31, 2018	$ 8,880	$ 355	$ 77	$ 9,312
IFRS 16 opening balance sheet adjustment	—	17	41	58
Additions	126	11	1	138
Dispositions	(3)	—	—	(3)
Change in decommissioning liabilities	5	—	—	5
Balance as at September 30, 2019	**$ 9,008**	**$ 383**	**$ 119**	**$ 9,510**

	Field and facilities	Transportation and storage	Corporate assets	Total
Accumulated depletion and depreciation				
Balance as at December 31, 2018	$ 2,610	$ 17	$ 39	$ 2,666
Depletion and depreciation	485	102	6	593
Dispositions	(3)	—	—	(3)
Balance as at September 30, 2019	**$ 3,092**	**$ 119**	**$ 45**	**$ 3,256**
Carrying amounts				
Balance as at December 31, 2018	$ 6,270	$ 338	$ 38	$ 6,646
Balance as at September 30, 2019	**$ 5,916**	**$ 264**	**$ 74**	**$ 6,254**

On adoption of IFRS 16, the Corporation recognized right-of-use assets of $58 million in relation to corporate office lease arrangements and transportation and storage lease arrangements measured at the present value of the remaining lease payments as at December 31, 2018, and discounted using the Corporation's estimated incremental borrowing rate as of January 1, 2019. These right-of-use assets were measured at the amount equal to the lease liability on January 1, 2019. As at September 30, 2019, the carrying amount of the ROU assets, including the previously recognized finance lease under IAS 17, is $246 million.

As at September 30, 2019, property, plant and equipment was assessed for impairment and no impairment was recognized. During the second quarter of 2019, accelerated depreciation totaling $237 million was recognized on equipment, materials and engineering costs associated with greenfield expansion projects at Christina Lake which will not be pursued in the foreseeable future plus a partial upgrading technology project. Included in the cost of property, plant and equipment is $215 million of assets under construction (December 31, 2018 – $291 million).

6. EXPLORATION AND EVALUATION ASSETS

Cost	
Balance as at December 31, 2017	$ 549
Additions	3
Exploration expense	(1)
Change in decommissioning liabilities	(1)
Balance as at December 31, 2018	$ 550
Additions	1
Exploration expense	(58)
Dispositions	(3)
Balance as at September 30, 2019	**$ 490**

Exploration and evaluation assets consist of exploration projects which are pending the determination of proved or probable reserves. An assessment of existing assets was completed during the second quarter of 2019. The Corporation decided not to continue exploration and evaluation activities in its Duncan area growth properties and has included associated land lease and evaluation costs totaling $58 million as exploration expense as at September 30, 2019. During the nine months ended September 30, 2019, the Corporation sold lands with a carrying value of $3 million for proceeds of $5 million.

As at September 30, 2019, exploration and evaluation assets were assessed for impairment and no impairment was recognized.

7. OTHER ASSETS

As at	September 30, 2019	December 31, 2018
Non-current pipeline linefill[(a)]	**$ 191**	$ 194
Finance sublease receivables[(b)]	**18**	9
Intangible assets[(c)]	**9**	11
Deferred financing costs	**8**	15
Prepaid transportation costs[(d)]	**8**	—
	234	229
Less current portion	**(4)**	(8)
	$ 230	$ 221

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 2020 and 2048. As at September 30, 2019, no impairment has been recognized on these assets.

b. On adoption of IFRS 16, the Corporation has recognized finance sublease receivables in relation to certain sublease arrangements that were previously recognized on the consolidated balance sheet as at December 31, 2018 within the onerous contracts provision. The IFRS 16 opening balance sheet adjustment related to finance sublease receivables was $19 million as at January 1, 2019.

c. As at September 30, 2019, intangible assets consist of $9 million invested in software that is not an integral component of the related computer hardware (December 31, 2018 – $11 million). Depreciation of $2 million was recognized for the nine months ended September 30, 2019 (December 31, 2018 – $3 million). During the nine months ended September 30, 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.

d. Prepaid transportation costs related to upgrading third-party transportation infrastructure under the terms of a non-current transportation services agreement have been capitalized and are being amortized to transportation expense over the 30-year term of the agreement.

8. LONG-TERM DEBT

As at	September 30, 2019	December 31, 2018
Senior secured term loan (September 30, 2019 – nil; December 31, 2018 – US$225 million)[a]	**$ —**	$ 307
6.375% senior unsecured notes (US$800 million; due 2023)	**1,060**	1,092
7.0% senior unsecured notes (US$1 billion; due 2024)	**1,324**	1,365
6.5% senior secured second lien notes (September 30, 2019 - US$677 million; December 31, 2018 – US$750 million; due 2025)[b]	**897**	1,023
	3,281	3,787
Less unamortized deferred debt discount and debt issue costs	**(24)**	(29)
Less unamortized financial derivative liability discount	**—**	(1)
	3,257	3,757
Less current portion of senior secured term loan	**—**	(17)
	$ 3,257	$ 3,740

The U.S. dollar denominated debt was translated into Canadian dollars at the period end exchange rate of US$1 = C$1.3244 (December 31, 2018 – US$1 = C$1.3646).

a. On July 30, 2019, the Corporation repaid the outstanding senior secured term loan balance of $289 million (US $219 million).

   Concurrent with the senior secured term loan repayment, the Corporation amended and restated its revolving credit facility and the EDC Facility and extended the maturity date of each facility by 2.75 years to July 30, 2024. The maturity dates of the revolving credit facility and the EDC Facility include a feature that will 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 Corporation reduced the total available credit under the two facilities from US$1.8 billion to C$1.3 billion. The C$1.3 billion facility is now comprised of C$800 million under the revolving credit facility and C$500 million under the EDC Facility. As at September 30, 2019, the Corporation had not drawn on its revolving credit facility and had C$121 million of unutilized capacity under the EDC Facility.

   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 drawn in excess of $400 million, under the revolving credit facility 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. Following the full repayment of the outstanding senior secured term loan, the Corporation has no first lien debt outstanding and, to date, the Corporation has never drawn funds under the revolving credit facility.

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

b. During the three months ended September 30, 2019, the Corporation repurchased and extinguished a portion of its 6.5% senior secured second lien notes totaling $96 million (US$73 million). An additional $88 million (US $66 million) of principal was repurchased and extinguished on the notes subsequent to September 30, 2019.

9. PROVISIONS AND OTHER LIABILITIES

As at	September 30, 2019	December 31, 2018
Lease liabilities[(a)]	$ 288	$ 131
Decommissioning provision[(b)]	74	65
Onerous contracts provision[(c)]	—	78
Deferred lease inducements[(d)]	—	21
Other liabilities	9	16
Provisions and other liabilities	371	311
Less current portion	(29)	(17)
Non-current portion	$ 342	$ 294

a. Lease liabilities:

As at	September 30, 2019	December 31, 2018
Balance, beginning of year	$ 131	$ —
IFRS 16 opening balance sheet adjustment	160	—
Liabilities incurred	11	130
Liabilities settled	(33)	(12)
Interest expense	19	13
Balance, end of period	288	131
Less current portion	(24)	—
Non-current portion	$ 264	$ 131

On adoption of IFRS 16, the Corporation recognized lease liabilities of $160 million in relation to corporate office space and marketing storage arrangements measured at the present value of the remaining lease payments as at January 1, 2019, and discounted using the Corporation’s estimated incremental borrowing rate of 6.0% for assets over a similar term with similar security, determined in accordance with IFRS 16. The associated right-of-use assets were measured at the amount equal to the lease liabilities on January 1, 2019.

The Corporation's minimum lease payments are as follows:

As at	September 30, 2019
Within one year	$ 48
Later than one year but not later than five years	145
Later than five years	537
Minimum lease payments	730
Amounts representing finance charges	(442)
Present value of net minimum lease payments	$ 288

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, 2019, the present value of these arrangements is $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, 2019	December 31, 2018
Balance, beginning of year	**$ 65**	$ 103
Changes in estimated future cash flows and settlement dates	**1**	(5)
Changes in discount rates	**3**	(39)
Liabilities incurred	**1**	6
Liabilities disposed	**—**	(1)
Liabilities settled	**(1)**	(5)
Accretion	**5**	6
Balance, end of period	**74**	65
Less current portion	**(5)**	(3)
Non-current portion	**$ 69**	$ 62

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 $725 million (December 31, 2018 – $719 million). The Corporation has estimated the net present value of the decommissioning obligations using a weighted average credit-adjusted risk-free rate of 13.6% (December 31, 2018 – 14.1%) and an inflation rate of 2.1% (December 31, 2018 - 2.1%). The decommissioning provision is estimated to be settled in periods up to the year 2066 (December 31, 2018 - periods up to the year 2067).

c. Onerous contracts provision:

On adoption of IFRS 16, the Corporation elected to use the practical expedient and rely on its previous assessment of whether leases were onerous under IAS 37 *Provisions, Contingent Liabilities and Contingent Assets,* immediately before initial application, as an alternative to performing an impairment review. As a result, the Corporation has adjusted the right-of-use asset by $78 million which was the amount of the onerous contracts provision recognized in the consolidated financial statements as at December 31, 2018.

d. Deferred office building lease inducements:

On adoption of IFRS 16, the Corporation recognized an opening balance sheet adjustment of $19 million related to deferred office building lease inducements.

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, 2019			Year ended December 31, 2018		
	Number of shares (thousands)		Amount	Number of shares (thousands)		Amount
Balance, beginning of year	**296,841**	**$**	**5,427**	294,104	$	5,404
Issued upon exercise of stock options	**85**		**1**	212		2
Issued upon vesting and release of RSUs and PSUs	**2,362**		**14**	2,525		21
Balance, end of period	**299,288**	**$**	**5,442**	296,841	$	5,427

11. STOCK-BASED COMPENSATION

	Three months ended September 30				Nine months ended September 30			
		2019		2018		2019		2018
Cash-settled expense (recovery) (i)	**$**	**3**	$	1	**$**	**(1)**	$	23
Equity-settled expense		**5**		6		**20**		16
Stock-based compensation	**$**	**8**	$	7	**$**	**19**	$	39

(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.

As at September 30, 2019, the Corporation has recognized a liability of $17 million relating to the fair value of cash-settled RSUs, PSUs and DSUs (December 31, 2018 – $30 million). The current portion of $15 million is included within accounts payable and accrued liabilities and $2 million is included as a non-current liability within provisions and other liabilities based on the expected payout dates of the individual awards.

A one-time charge of $10 million related to the accelerated expense of stock options, RSUs and PSUs for retirement of eligible employees was incurred during the nine months ended September 30, 2019.

12. REVENUES

	Three months ended September 30		Nine months ended September 30	
	2019	2018	2019	2018
Petroleum revenue(i)	**$ 955**	$ 805	**$ 2,916**	$ 2,206
Royalties	**(13)**	(18)	**(34)**	(37)
Petroleum revenue, net of royalties	**$ 942**	$ 787	**$ 2,882**	$ 2,169
Power revenue	**$ 13**	$ 13	**$ 46**	$ 35
Transportation revenue	**3**	3	**10**	9
Other revenue	**$ 16**	$ 16	**$ 56**	$ 44
	$ 958	$ 803	**$ 2,938**	$ 2,213

(i) Petroleum revenue includes revenue related to oil products purchased from third parties for marketing-related activities. 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					
	2019			2018		
	Petroleum Revenue			Petroleum Revenue		
	Proprietary	Third-party	Total	Proprietary	Third-party	Total
Country:						
Canada	**$ 450**	**$ 52**	**$ 502**	$ 457	$ 29	$ 486
United States	**281**	**172**	**453**	319	—	319
	$ 731	**$ 224**	**$ 955**	$ 776	$ 29	$ 805

	Nine months ended September 30					
	2019			2018		
	Petroleum Revenue			Petroleum Revenue		
	Proprietary	Third-party	Total	Proprietary	Third-party	Total
Country:						
Canada	**$ 1,399**	**$ 222**	**$ 1,621**	$ 1,278	$ 83	$ 1,361
United States	**891**	**404**	**1,295**	795	50	845
	$ 2,290	**$ 626**	**$ 2,916**	$ 2,073	$ 133	$ 2,206

Other revenue recognized during the three and nine months ended September 30, 2019 and 2018 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, 2019		December 31, 2018
Petroleum revenue	**$**	**309**	$	122
Other revenue		**5**		4
Total revenue-related assets	**$**	**314**	$	126

Revenue-related receivables are typically settled within 30 days. As at September 30, 2019 and December 31, 2018, 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			
		2019		**2018**		**2019**		**2018**
Diluent expense	**$**	**268**	$	338	**$**	**890**	$	965
Transportation and storage[a]		**96**		81		**287**		193
Diluent and transportation	**$**	**364**	$	419	**$**	**1,177**	$	1,158

a. On March 22, 2018, the Corporation successfully completed the sale of its 50% interest in the Access Pipeline. Transportation expense includes incremental expenses associated with the related Transportation Services Agreement.

14. FOREIGN EXCHANGE LOSS (GAIN), NET

	Three months ended September 30				Nine months ended September 30			
		2019		**2018**		**2019**		**2018**
Unrealized foreign exchange loss (gain) on:								
Long-term debt	**$**	**41**	$	(60)	**$**	**(113)**	$	145
Other		**(3)**		2		**6**		—
Unrealized net loss (gain) on foreign exchange		**38**		(58)		**(107)**		145
Realized loss (gain) on foreign exchange		**1**		(1)		**(1)**		3
Realized loss (gain) on foreign exchange derivatives[a]		**—**		—		**—**		(35)
Foreign exchange loss (gain), net	**$**	**39**	$	(59)	**$**	**(108)**	$	113
C$ equivalent of 1 US$								
Beginning of period		**1.3091**		1.3142		**1.3646**		1.2518
End of period		**1.3244**		1.2924		**1.3244**		1.2924

a. On February 8, 2018, the Corporation entered into forward currency contracts to manage the foreign exchange risk on expected Canadian dollar denominated asset sale proceeds designated for U.S. dollar denominated long-term debt repayment. The forward currency contracts were settled on March 22, 2018, resulting in a realized gain of $35 million.

15. NET FINANCE EXPENSE

	Three months ended September 30		Nine months ended September 30	
	2019	2018	2019	2018
Interest expense on long-term debt	**$ 69**	$ 68	**$ 210**	$ 218
Interest expense on lease liabilities[a]	**6**	4	**19**	9
Interest income	**(1)**	(2)	**(4)**	(6)
Net interest expense	**74**	70	**225**	221
Accretion on provisions	**2**	2	**5**	6
Unrealized (gain) loss on derivative financial liabilities	**(1)**	—	**(1)**	2
Realized (gain) loss on interest rate swaps[b]	**—**	—	**—**	(17)
Net finance expense	**$ 75**	$ 72	**$ 229**	$ 212

a. On adoption of IFRS 16, the Corporation recognized lease liabilities of $160 million in relation to corporate office space and marketing storage arrangements. These lease liabilities will be accreted through net finance expense over the life of each lease arrangement using the Corporation's estimated incremental borrowing rate of 6.0%, which is the rate determined for assets over a similar term with similar security, and is in accordance with IFRS 16.

b. In the third quarter of 2017, the Corporation entered into an interest rate swap contract to effectively fix the interest rate on US$650 million of its US$1.2 billion senior secured term loan at approximately 5.3%. In conjunction with the partial repayment of the senior secured term loan on March 27, 2018, the interest rate swap was terminated and a realized gain of $17 million was recognized.

16. INCOME TAX

On June 28, 2019, the Government of Alberta enacted legislation which will reduce the corporate tax rate from 12% to 8% by January 1, 2022. A one-time deferred income tax expense of $33 million related to the Alberta tax rate reduction was recognized during the nine months ended September 30, 2019. As at September 30, 2019, the Corporation has recognized a deferred tax asset of $251 million (December 31, 2018 - $237 million). Future taxable income is expected to be sufficient to realize the deferred tax asset.

17. SUPPLEMENTAL CASH FLOW DISCLOSURES

	Three months ended September 30		Nine months ended September 30	
	2019	**2018**	**2019**	**2018**
Cash provided by (used in):				
Trade receivables and other	**$ 62**	$ (60)	**$ (122)**	$ 2
Inventories	**6**	(2)	**6**	(11)
Accounts payable and accrued liabilities	**(77)**	(89)	**(95)**	(54)
	$ (9)	$ (151)	**$ (211)**	$ (63)
Changes in non-cash working capital relating to:				
Operating	**$ (17)**	$ (108)	**$ (162)**	$ (48)
Investing	**8**	(43)	**(49)**	(15)
	$ (9)	$ (151)	**$ (211)**	$ (63)
Cash and cash equivalents:[(a)]				
Cash	**$ 154**	$ 239	**$ 154**	$ 239
Cash equivalents	**—**	134	**—**	134
	$ 154	$ 373	**$ 154**	$ 373
Cash interest paid	**$ 115**	$ 115	**$ 237**	$ 248

a. As at September 30, 2019, C$62 million of the Corporation's total cash and cash equivalents balance was held in U.S. dollars (September 30, 2018 – C$156 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$1.3244 (September 30, 2018 – US $1 = C$1.2924).

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, 2018	$ —	$ 131	$ 3,757
Cash changes:			
Receipts on leased assets	(1)	—	—
Payments on lease liabilities	—	(33)	—
Repayment of long-term debt	—	—	(393)
Non-cash changes:			
IFRS 16 opening balance sheet adjustment	19	160	—
Lease liabilities incurred	—	11	—
Interest expense on lease liabilities	—	19	—
Unrealized (gain) loss on foreign exchange	—	—	(113)
Other	—	—	6
Balance as at September 30, 2019	**$ 18**	**$ 288**	**$ 3,257**

(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	
	2019	**2018**	**2019**	**2018**
Net earnings (loss)	**$ 24**	$ 118	**$ (87)**	$ 80
Weighted average common shares outstanding	**300**	297	**298**	295
Dilutive effect of stock options, RSUs and PSUs	**3**	3	**—**	4
Weighted average common shares outstanding – diluted (millions)	**303**	300	**298**	299
Net earnings (loss) per share, basic	**$ 0.08**	$ 0.40	**$ (0.29)**	$ 0.27
Net earnings (loss) per share, diluted	**$ 0.08**	$ 0.39	**$ (0.29)**	$ 0.27

a. Weighted average common shares outstanding for the three months ended September 30, 2019 includes 381,014 PSUs not yet released (three months ended September 30, 2018 - nil).

b. For the nine months ended September 30, 2019, there was no dilutive effect of stock options, RSUs and PSUs due to the Corporation incurring a net loss. If the Corporation had recognized net earnings during the nine months ended September 30, 2019, the dilutive effect of stock options, RSUs and PSUs would have been three million weighted average common shares.

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, commodity risk management contracts, accounts payable and accrued liabilities, derivative financial liabilities included within provisions and other liabilities and long-term debt.

a. Fair values:

The carrying value of cash and cash equivalents, trade receivables and other and accounts payable and accrued liabilities included on the consolidated balance sheet approximate the fair value 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, 2019**		**December 31, 2018**	
	Carrying amount	**Fair value**	**Carrying amount**	**Fair value**
Recurring measurements:				
Financial assets				
Commodity risk management contracts	**$ 18**	**$ 18**	$ 123	$ 123
Financial liabilities				
Long-term debt[(i)] (Note 8)	**$ 3,281**	**$ 3,240**	$ 3,787	$ 3,707
Derivative financial liabilities	**—**	**—**	$ 1	$ 1
Commodity risk management contracts	**$ 37**	**$ 37**	$ 30	$ 30

(i) Includes the current and non-current portions.

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 of commodity risk management contracts and derivative financial liabilities are 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. Commodity price risk management:

The Corporation enters into derivative financial instruments to manage commodity price risk. Financial commodity 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 had the following financial commodity risk management contracts relating to crude oil sales and condensate purchases outstanding as at September 30, 2019:

As at September 30, 2019	Volumes (bbls/d)(i)	Term	Average Price (US$/bbl)(i)
Crude Oil Sales Contracts			
WTI(ii) Fixed Price	71,418	Oct 1, 2019 - Dec 31, 2019	$61.00
WTI Fixed Price	19,052	Jan 1, 2020 - Dec 31, 2020	$59.41
WTI:WCS(iii) Fixed Differential	57,050	Oct 1, 2019 - Dec 31, 2019	$(21.15)
WTI: WCS Fixed Differential	17,000	Jan 1, 2020 - Dec 31, 2020	$(22.18)
Condensate Purchase Contracts			
WTI:Mont Belvieu Fixed Differential	5,250	Oct 1, 2019 - Dec 31, 2019	$(7.56)
WTI:Mont Belvieu Fixed Differential	7,250	Jan 1, 2020 - Dec 31, 2020	$(7.63)
WTI:Mont Belvieu Fixed Differential	3,000	Jan 1, 2021 - Dec 31, 2021	$(10.55)
WTI:Mont Belvieu Fixed % of WTI	9,750	Oct 1, 2019 - Dec 31, 2019	92.2 %
WTI:Mont Belvieu Fixed % of WTI	7,750	Jan 1, 2020 - Dec 31, 2020	93.1 %

(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's financial commodity 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 commodity risk management positions:

As at	September 30, 2019			December 31, 2018		
	Asset	Liability	Net	Asset	Liability	Net
Gross amount	**$ 64**	**$ (101)**	**$ (37)**	$ 303	$ (66)	$ 237
Amount offset	**(46)**	**64**	**18**	(180)	36	(144)
Net amount	**$ 18**	**$ (37)**	**$ (19)**	$ 123	$ (30)	$ 93
Current portion	**$ 14**	**$ (31)**	**$ (17)**	$ 123	$ (6)	$ 117
Non-current portion	**4**	**(6)**	**(2)**	—	(24)	(24)
Net amount	**$ 18**	**$ (37)**	**$ (19)**	$ 123	$ (30)	$ 93

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

As at September 30		2019		2018
Fair value of contracts, beginning of year	$	93	$	(69)
Fair value of contracts realized		109		194
Change in fair value of contracts		(221)		(206)
Amortized premiums on put options		—		1
Fair value of contracts, end of period	**$**	**(19)**	$	(80)

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

	Three months ended September 30				Nine months ended September 30			
		2019		**2018**		**2019**		**2018**
Realized loss (gain) on commodity risk management	**$**	**37**	$	88	**$**	**109**	$	194
Unrealized loss (gain) on commodity risk management		**(10)**		(108)		**112**		12
Commodity risk management loss (gain)	**$**	**27**	$	(20)	**$**	**221**	$	206

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, 2019:

Commodity	Sensitivity Range		Increase		Decrease
Crude oil commodity price	± US$1.00 per bbl applied to WTI contracts	**$**	**(18)**	**$**	**18**
Crude oil differential price (i)	± US$1.00 per bbl applied to WTI:WCS differential contracts	**$**	**15**	**$**	**(15)**

(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.

The Corporation entered into the following financial commodity risk management contracts relating to crude oil sales and condensate purchases subsequent to September 30, 2019. As a result, these contracts are not reflected in the Corporation's Consolidated Financial Statements:

Subsequent to September 30, 2019	Volumes (bbls/d)(i)	Term	Average Prices (US$/bbl)(i)
Crude Oil Sales Contracts			
WTI Fixed Price	15,000	Jan 1, 2020 - Jan 31, 2020	$56.24
Condensate Purchase Contracts			
WTI:Mont Belvieu Fixed Differential	2,000	Jan 1, 2021 - Dec 31, 2021	$(10.26)

(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.*

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 it has sufficient capital resources to allow the Corporation to meet its liquidity requirements for the forseeable future. Debt repayment and sustaining capital expenditure activities are anticipated to be funded by the Corporation's adjusted funds flow and cash on hand.

The Corporation's debt matures beyond 2022 and the Corporation has a C$800 million revolving credit facility, as well as a C$500 million letter of credit facility, guaranteed by Export Development Canada.

The following table summarizes the Corporation's net debt:

As at	Note	September 30, 2019	December 31, 2018
Non-current portion of long-term debt	8	**$ 3,257**	$ 3,740
Current portion of long-term debt	8	**—**	17
Cash and cash equivalents		**(154)**	(318)
Net debt		**$ 3,103**	$ 3,439

Net debt is an important measure used by management to analyze leverage and liquidity. Net debt decreased to $3.1 billion at September 30, 2019 from $3.4 billion at December 31, 2018. The decrease is mainly due to the senior secured term loan repayments of $289 million (US$219 million) and $96 million (US$73 million) repurchase and extinguishment of a portion of the 6.5% senior secured second lien notes during the three months ended September 30, 2019.

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

		Three months ended September 30		Nine months ended September 30	
	Note	2019	2018	2019	2018
Net cash provided by (used in) operating activities		**$ 174**	$ 3	**$ 406**	$ 186
Net change in non-cash operating working capital items		**17**	108	**162**	48
Funds flow from (used in) operations		**191**	111	**568**	234
Adjustments:					
Realized gain on foreign exchange derivatives(i)	14	**—**	—	**—**	(35)
Payments on onerous contracts	9	**—**	4	**—**	14
Decommissioning expenditures	9	**1**	1	**1**	4
Adjusted funds flow		**$ 192**	$ 116	**$ 569**	$ 217

(i) A gain related to the settlement of forward currency contracts to manage the foreign exchange risk on Canadian dollar denominated proceeds related to the sale of assets designated for U.S. dollar denominated long-term debt repayment.

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 and other items 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, 2019:

	2019	2020	2021	2022	2023	Thereafter	Total
Transportation and storage[i]	$ 86	$ 376	$ 429	$ 436	$ 456	$ 6,299	$ 8,082
Diluent purchases	101	115	21	21	18	—	276
Other operating commitments	4	15	11	9	9	48	96
Variable office lease costs	1	5	5	5	5	36	57
Capital commitments	4	—	—	—	—	—	4
Commitments	**$ 196**	**$ 511**	**$ 466**	**$ 471**	**$ 488**	**$ 6,383**	**$ 8,515**

(i) This represents transportation and storage commitments from 2019 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.