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 six month periods ended June 30, 2019 was approved by the Corporation's Audit Committee on July 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 six month periods ended June 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 thousands 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 900 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.

The Corporation has identified three commercial SAGD projects; the Christina Lake Project, the Surmont Project and the May River Regional Project. The Christina Lake Project has received regulatory approval for 210,000 bbls/d of production, and is currently producing with a productive capacity of approximately 100,000 bbls/d. MEG has applied for regulatory approval for approximately 120,000 bbls/d of production at the Surmont Project and anticipates receiving regulatory approval in 2019. In 2017, MEG filed regulatory applications with the Alberta Energy Regulator for the May River Regional Project. Management anticipates, consistent with the estimates contained in the GLJ Report, that the May River Regional Project can support an average of 164,000 bbls/d of bitumen production. The ultimate production rate and life of each project will be dependent on a number of factors, including the size, performance and development schedule for each expansion or phase in those projects.

MEG has invested in three major projects at its Christina Lake Project, known as Phase 1, Phase 2 and Phase 2B. Phase 1 commenced production in 2008 with an initial bitumen production design capacity of approximately 3,000 bbls/d ("Phase 1"). Phase 2 commenced production in 2009 with an initial bitumen production design capacity of approximately 22,000 bbls/d and which utilized existing central processing facilities associated with Phase 1, and primarily expanded well pad drilling and tie-ins to increase production ("Phase 2"). Together, Phase 1 and Phase 2 had an initial bitumen production design capacity of approximately 25,000 bbls/d. Phase 2B commenced production in 2013 with an initial bitumen production design capacity of approximately 35,000 bbls/d ("Phase 2B"). The combined Phase 1, Phase 2 and Phase 2B initial bitumen production design capacity was approximately 60,000 bbls/d. Supported by proprietary reservoir technologies, MEG has been able to subsequently increase overall bitumen production in excess of 100,000 bbls/d through a series of low-cost debottlenecking and expansion projects and the redeployment of steam into new well pairs. 2018 bitumen production averaged 87,731 bbls/d. 2019 annual average production is expected to be in the range of 90,000 to 92,000 bbls/d, assuming the Alberta Government mandated production curtailment program remains in place for 2019 with easing over the course of the year. If curtailments were not in place, MEG would have the ability to produce an average of approximately 100,000 bbls/d of bitumen in 2019.

On March 22, 2018 the Corporation announced that it had successfully closed the sale of the Corporation's 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. The majority of the net cash proceeds were used to repay approximately C$1.2 billion of the Corporation's senior secured term loan. As part of the transaction, MEG entered into a Transportation Services Agreement ("TSA") dedicating Christina Lake production and condensate transport to Access Pipeline for an initial term of 30 years. The Access Pipeline is a dual pipeline system that connects the Christina Lake Project to a large regional upgrading, refining, diluent supply and transportation hub in the Edmonton, Alberta area.

The transaction also included a Stonefell Lease Agreement which is a 30-year arrangement that secures the Corporation's operational control and exclusive use of 100% of the Stonefell Terminal's 900,000 barrel blend and condensate storage facility. The Stonefell Terminal is connected to local and export markets by pipeline, in addition to being pipeline connected to the Bruderheim Terminal, a crude-by-rail loading facility near Edmonton, Alberta. This combination of facilities allows for the loading of AWB for transport by rail.

MEG utilizes a network of pipeline, rail and storage facilities to optimize market access for the transport and sale of AWB to refiners throughout North America and internationally. MEG has contracted for 50,000 bbls/d (expanding to 100,000 bbls/d in mid-2020) of blend transportation capacity on the Flanagan South and Seaway pipeline systems, which provide pipeline access from Flanagan, Illinois through Cushing, Oklahoma to U.S. Gulf Coast ("USGC") refineries. At the USGC, MEG has contracted for 20,000 bbls/d of capacity on the newly extended Bayou Bridge pipeline connecting the USGC at Beaumont, Texas with the refining complex and trading hub in St. James, Louisiana which, together with storage terminals at the USGC, add operational and marketing flexibility including loading ships for export internationally. MEG is also a shipper on the Trans Mountain Expansion Project which, when in service, will provide the Corporation with 20,000 bbls/d of blend committed tidewater access to Canada's west coast. Effective January 1, 2019, MEG secured 30,000 bbls/d of blend unit train loading capacity at the Bruderheim Terminal for 3 years, with a 1-year extension option. The Corporation's marketing assets and flexibility are enhanced by exclusive use of the Stonefell Terminal. This combination of strategic marketing assets advances MEG's strategy of securing long-term, broadening and reliable market access to world oil prices for its production.

2. OPERATIONAL AND FINANCIAL HIGHLIGHTS

Bitumen production for the three months ended June 30, 2019 averaged 97,288 bbls/d compared to 71,325 bbls/d for the three months ended June 30, 2018. The increase in average production volumes was primarily due to the impact of the 33-day turnaround at the Christina Lake project in the second quarter of 2018. Commencing January 1, 2019, the Government of Alberta enacted rules to limit the production of crude oil and bitumen, however, the Corporation was able to increase its production during the second quarter of 2019 to levels near its production capability of 100,000 bbl/d through the purchase of third-party curtailment credits.

Adjusted funds flow in the second quarter of 2019 was $227 million, compared to $18 million in the second quarter of 2018. The increase in adjusted funds flow was a result of both improved bitumen realization and increased sales volumes partially offset by higher transportation and storage costs to move incremental barrels to the USGC.

The Corporation's bitumen realization averaged $62.23 per barrel in the second quarter of 2019 compared to $47.33 per barrel in the second quarter of 2018. The provincially-mandated production curtailments for the industry and increasing demand for oil in the USGC positively impacted the WTI:AWB differential at Edmonton during the second quarter of 2019 compared to the same period of 2018. Bitumen realization was also positively impacted by improved condensate benchmark pricing and a stronger U.S. dollar, partially offset by a lower WTI benchmark price.

The Corporation's sales marketing strategy is also contributing to higher realized blend sales prices. The Corporation sold 34% of its sales volumes to the USGC market in the second quarter of 2019 compared to 30% in the same period of 2018. Net of transportation and storage costs from Edmonton, blended barrels sold to the USGC market realized a US$3.50 per barrel premium to those sold in the Edmonton market during the second quarter of 2019. A US$10.09 per barrel premium was realized during the same period of 2018. The premium recognized in the second quarter of 2019 was lower than the same period of 2018 primarily due to the tighter WTI:AWB differential at Edmonton in 2019.

The Corporation recognized a net loss of $64 million in the second quarter of 2019 compared to a net loss of $179 million during the second quarter of 2018. The net loss in the second quarter of 2019 included accelerated depreciation expense, after tax, of $183 million, exploration expense, after tax, of $45 million and deferred income tax expense of $12 million, offset by an unrealized gain on commodity risk management contracts of $87 million and a $67 million unrealized foreign exchange gain. The net loss recognized in the second quarter of 2018 was affected by a $62 million unrealized foreign exchange loss and an unrealized loss on commodity risk management contracts of $61 million.

The Corporation is continuing its strategy of prioritizing balance sheet strength over growth. On July 30, 2019, the Corporation fully repaid the outstanding senior secured term loan balance of 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. Also, with provincially-mandated curtailment and continuing egress uncertainty, the Corporation has decided not to proceed with the previously announced 2019 discretionary capital budget of $75 million. Instead, 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.

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 certain non-core assets that do not contribute to the Corporation's development plan or cash flow, accelerated depreciation, after tax of $183 million and exploration expense, after tax of $45 million were recorded 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. Accelerated depreciation was also recognized on a partial upgrading technology project. In addition, the Corporation decided not to continue exploration and evaluation activities in its Duncan area growth properties for the foreseeable future and has expensed associated land lease and evaluation costs. None of these non-core assets relate to the current development plans of Christina Lake, Surmont or May River.

The two new credit facilities, senior secured term loan repayment and eventual sale or disposal of non-core assets are expected to deliver approximately $42 million of annual cost savings.

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:

	Six months ended June 30		2019		2018				2017	
($ millions, except as indicated)	**2019**	**2018**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**
Bitumen production - bbls/d	**92,228**	82,205	**97,288**	87,113	87,582	98,751	71,325	93,207	90,228	83,008
Steam-oil ratio	**2.18**	2.19	**2.16**	2.20	2.22	2.17	2.22	2.17	2.22	2.34
Bitumen sales - bbls/d	**92,486**	82,966	**95,120**	89,822	88,283	93,856	74,418	91,608	94,541	76,813
Bitumen realization - $/bbl	**56.42**	40.81	**62.23**	50.21	15.31	49.63	47.33	35.46	48.01	39.93
Net operating costs - $/bbl[(1)]	**5.39**	5.82	**4.66**	6.17	4.55	4.34	5.64	5.98	5.86	6.00
Non-energy operating costs - $/bbl	**4.86**	4.96	**4.53**	5.22	4.25	4.38	5.47	4.55	4.53	4.57
Cash operating netback - $/bbl[(2)]	**33.98**	19.57	**37.88**	29.80	7.14	24.01	18.66	20.31	33.54	26.88
Adjusted funds flow[(3)]	**378**	102	**227**	151	(38)	116	18	83	192	83
Per share, diluted[(3)]	**1.26**	0.34	**0.76**	0.50	(0.13)	0.39	0.06	0.28	0.65	0.28
Revenue[(4)]	**1,980**	1,410	**1,062**	919	520	803	689	721	755	576
Net earnings (loss)	**(111)**	(38)	**(64)**	(48)	(199)	118	(179)	141	(24)	84
Per share, basic	**(0.37)**	(0.13)	**(0.21)**	(0.16)	(0.67)	0.40	(0.61)	0.48	(0.08)	0.29
Per share, diluted	**(0.37)**	(0.13)	**(0.21)**	(0.16)	(0.67)	0.39	(0.61)	0.47	(0.08)	0.28
Total cash capital investment	**85**	330	**32**	53	144	145	183	148	163	103
Cash and cash equivalents	**399**	564	**399**	154	318	373	564	675	464	398
Long-term debt - C$	**3,582**	3,607	**3,582**	3,660	3,740	3,544	3,607	3,543	4,668	4,636
Long-term debt - US$	**2,737**	2,745	**2,737**	2,740	2,741	2,742	2,745	2,746	3,729	3,706

(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 is calculated by deducting the related diluent expense, transportation and storage, third-party curtailment credits, net operating costs, royalties and realized commodity risk management gains (losses) from petroleum revenue, net of purchased product, on a per barrel of bitumen sales volume basis.*

(3) *Adjusted funds flow and the related per share amounts are non-GAAP measures and do not have standardized meanings prescribed by IFRS and therefore may not be comparable to similar measures used by other companies. Adjusted funds flow is reconciled to net cash provided by (used in) operating activities and is discussed further under the heading "NON-GAAP MEASURES" in the "ADVISORY" section.*

(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 June 30		Six months ended June 30	
	2019	**2018**	**2019**	**2018**
Bitumen production – bbls/d	**97,288**	71,325	**92,228**	82,205
Steam-oil ratio (SOR)	**2.16**	2.22	**2.18**	2.19

Bitumen Production

Bitumen production for the three and six months ended June 30, 2019 increased 36% and 12%, respectively, compared to the same periods of 2018. The increase in average production volumes for the three and six months ended June 30, 2019 was primarily due to the impact of the 33-day turnaround at the Christina Lake project in the second quarter of 2018. There was no turnaround activity during the three and six months ended June 30, 2019 because turnaround activity was advanced to the fourth quarter of 2018 when market prices were significantly depressed.

Average production levels during the three and six months ended June 30, 2019 were impacted by provincially–mandated production curtailments. During the second quarter of 2019 the Corporation was able to increase production to levels near its production capability of 100,000 bbls/d at Christina Lake, through the purchase of third-party curtailment credits.

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 averaged 2.16 and 2.18 for the three and six months ended June 30, 2019 compared to 2.22 and 2.19 for the three and six months ended June 30, 2018.

Operating Cash Flow

	Three months ended June 30		Six months ended June 30	
($000)	**2019**	**2018**	**2019**	**2018**
Petroleum revenue, net of purchased product[1]	**$ 863,330**	$ 614,759	**$ 1,566,467**	$ 1,240,065
Diluent expense	**(324,674)**	(294,222)	**(621,924)**	(627,188)
	538,656	320,537	**944,543**	612,877
Royalties	**(17,834)**	(11,127)	**(20,829)**	(19,635)
Transportation and storage[2]	**(93,450)**	(56,100)	**(184,594)**	(105,466)
Third-party curtailment credits[3]	**(7,692)**	—	**(7,692)**	—
Operating expenses	**(54,651)**	(49,163)	**(124,065)**	(108,393)
Power revenue	**14,311**	10,968	**33,825**	20,924
	379,340	215,115	**641,188**	400,307
Realized gain (loss) on commodity risk management	**(51,393)**	(88,751)	**(72,377)**	(106,470)
Operating cash flow[4]	**$ 327,947**	$ 126,364	**$ 568,811**	$ 293,837

(1) *Petroleum revenue, net of purchased product represents the Corporation's sales ("blend sales revenue") of AWB and net sales of third-party product for marketing-related activity. AWB is comprised of bitumen produced at the Christina Lake Project blended with purchased diluent.*

(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.*

Operating cash flow was $328 million for the three months ended June 30, 2019 compared to $126 million for the three months ended June 30, 2018. Blend sales revenue increased by $249 million primarily due to a 27% increase in blend sales volumes and an 11% increase in blend sales prices. The increase in blend sales price was positively influenced by more barrels sold into the higher priced USGC market where the WTI:AWB differential narrowed by US$9.47 per barrel, combined with stronger pricing at Edmonton where the WTI:AWB differential narrowed by US$9.89 per barrel for the three months ended June 30, 2019 compared to the same period in 2018. This was partially offset by a weaker WTI benchmark price quarter over quarter. Diluent expense for the three months ended June 30, 2019 was $30 million higher than the same period of 2018 primarily due to an increase in condensate volumes required for blending purposes offset by lower condensate benchmark pricing. Transportation and storage increased on a per barrel basis for the three months ended June 30, 2019 compared to the same period of 2018 due to an increased proportion of blend volumes transported to the USGC by rail and the addition of the Bayou Bridge pipeline at the USGC which enables the Corporation to transport up to 20,000 bbls/d of oil to the eastern USGC from Beaumont, Texas delivering into St. James, Louisiana. No costs pertaining to rail deliveries to the USGC or Bayou Bridge pipeline transportation costs were incurred during the second quarter of 2018.

Operating cash flow was $569 million for the six months ended June 30, 2019 compared to $294 million for the six months ended June 30, 2018. Blend sales revenue increased by $326 million primarily due to a 14% increase in blend sales prices and an 11% increase in blend sales volumes. The increase in blend sales price was positively influenced by more barrels sold into the higher priced USGC market where the WTI:AWB differential narrowed by US$7.79 per barrel, combined with stronger pricing at Edmonton where the WTI:AWB differential narrowed by US$11.41 per barrel for the six months ended June 30, 2019 compared to the same period in 2018. This was partially offset by a weaker WTI benchmark price period over period. Diluent expense for the six months ended June 30, 2019 was $5 million lower than the same period of 2018 due to lower condensate benchmark pricing offset by an increase in condensate volumes required for blending purposes. Transportation and storage increased on a per barrel basis for the six months ended June 30, 2019 compared to the same period of 2018 due to an increased proportion of blend volumes transported to the USGC by rail, the costs associated with the TSA on Access Pipeline entered into on March 22, 2018 and the addition of the Bayou Bridge pipeline into the Corporation's market access portfolio. No costs pertaining to rail deliveries to the USGC or Bayou Bridge pipeline transportation costs were incurred during the six months ended June 30, 2018.

Cash Operating Netback

The following table summarizes the Corporation's operating cash flow per barrel of bitumen sales volume, defined as cash operating netback, for the periods indicated:

	Three months ended June 30		Six months ended June 30	
(C$ per barrel of bitumen sales)	**2019**	**2018**	**2019**	**2018**
Bitumen realization[(1)]	**$ 62.23**	$ 47.33	**$ 56.42**	$ 40.81
Transportation and storage[(2)]	**(10.80)**	(8.28)	**(11.03)**	(7.02)
Third-party curtailment credits[(3)]	**(0.89)**	—	**(0.46)**	—
Royalties	**(2.06)**	(1.64)	**(1.24)**	(1.31)
	48.48	37.41	**43.69**	32.48
Operating costs – non-energy	**(4.53)**	(5.47)	**(4.86)**	(4.96)
Operating costs – energy	**(1.78)**	(1.79)	**(2.55)**	(2.25)
Power revenue	**1.65**	1.62	**2.02**	1.39
Net operating costs	**(4.66)**	(5.64)	**(5.39)**	(5.82)
Cash operating netback excluding realized commodity risk management	**43.82**	31.77	**38.30**	26.66
Realized gain (loss) on commodity risk management	**(5.94)**	(13.11)	**(4.32)**	(7.09)
Cash operating netback[(4)]	**$ 37.88**	$ 18.66	**$ 33.98**	$ 19.57
Bitumen sales - bbls/d	**95,120**	74,418	**92,486**	82,966

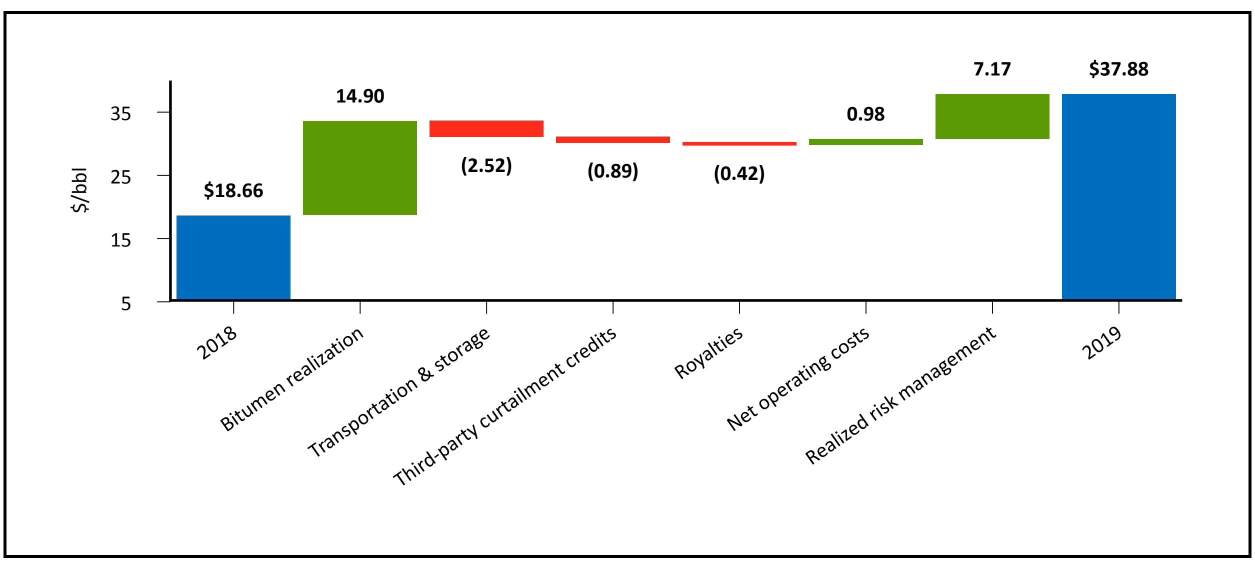
(1) *Petroleum revenue, net of purchased product ("blend sales revenue"), less diluent expense.*

(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.*

Cash Operating Netback - Three Months Ended June 30



Bitumen Realization

Bitumen realization represents the Corporation's petroleum revenue, net of purchased product ("blend sales revenue"), and diluent expense, expressed on a per barrel of bitumen basis. Blend sales revenue 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 blending is impacted by the amount of diluent required and the Corporation's cost of purchasing and transporting diluent to the production site from both Edmonton and USGC markets. Diluent expense is also impacted by Canadian and U.S. benchmark pricing, the timing of diluent inventory purchases and changes in the value of the Canadian dollar relative to the U.S. dollar. A portion of diluent expense is effectively recovered in the sales price of the blended product.

Bitumen realization averaged $62.23 per barrel for the three months ended June 30, 2019, compared to $47.33 per barrel for the three months ended June 30, 2018. The 31% increase quarter-over-quarter was due to an increase in the Corporation's realized blend sales price as a direct result of the narrowing of the WTI:AWB differential in both the Edmonton and USGC markets. The WTI:AWB differential at Edmonton narrowed by US$9.89 per barrel to a discount of US$12.32 per barrel for the three months ended June 30, 2019 from a discount of US$22.21 per barrel for the three months ended June 30, 2018. The WTI:AWB differential at the USGC narrowed by US$9.47 per barrel to a premium of US$1.64 per barrel for the three months ended June 30, 2019 from a discount of US$7.83 per barrel for the three months ended June 30, 2018. The benefit of the narrowing differentials was partially offset by the lower WTI benchmark price in the second quarter of 2019 compared to the same period in 2018. Bitumen realization was also positively impacted by the increase in blend sales volumes reaching the USGC. Approximately 34% of blend sales volumes were delivered to the USGC in the second quarter of 2019 compared to 30% in the same period of 2018. Blend sales at the USGC were sold at a premium, after transportation and storage costs, of US$3.50 per barrel compared to the Edmonton market. Refer to the Marketing Activity section of this MD&A for further details.

Also improving bitumen realization was a decrease to the Corporation's average cost of diluent during the second quarter of 2019 to $84.95 per barrel of diluent for the three months ended June 30, 2019 from $95.60 per barrel of diluent for the three months ended June 30, 2018, due to lower average condensate benchmark pricing relative to WTI. The Corporation's cost of diluent per barrel of bitumen also decreased as a result of a higher realized blend sales price, which increased the amount of diluent expense that is recovered when the blended product is sold.

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.

During the three months ended June 30, 2019, transportation and storage costs averaged $10.80 per barrel of bitumen sales compared to $8.28 per barrel of bitumen sales for the three months ended June 30, 2018. The increase in costs on a per barrel basis is primarily the result of increased blend volumes transported by rail to the USGC, plus the addition of the Bayou Bridge pipeline transportation cost which enables the Corporation to access the eastern USGC market.

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.

The Corporation incurred costs to purchase third-party curtailment credits of $0.89 per barrel for the three months ended June 30, 2019. Curtailment was not in place during the three months ended June 30, 2018 therefore the Corporation did not incur any costs related to the purchase of third-party curtailment credits. 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.

Royalties averaged $2.06 per barrel for the three months ended June 30, 2019, compared to $1.64 per barrel for the three months ended June 30, 2018. The increase in royalties per barrel is primarily the result of an increase in the Corporation's revenue for royalty purposes compared to the same period of 2018.

Net Operating Costs

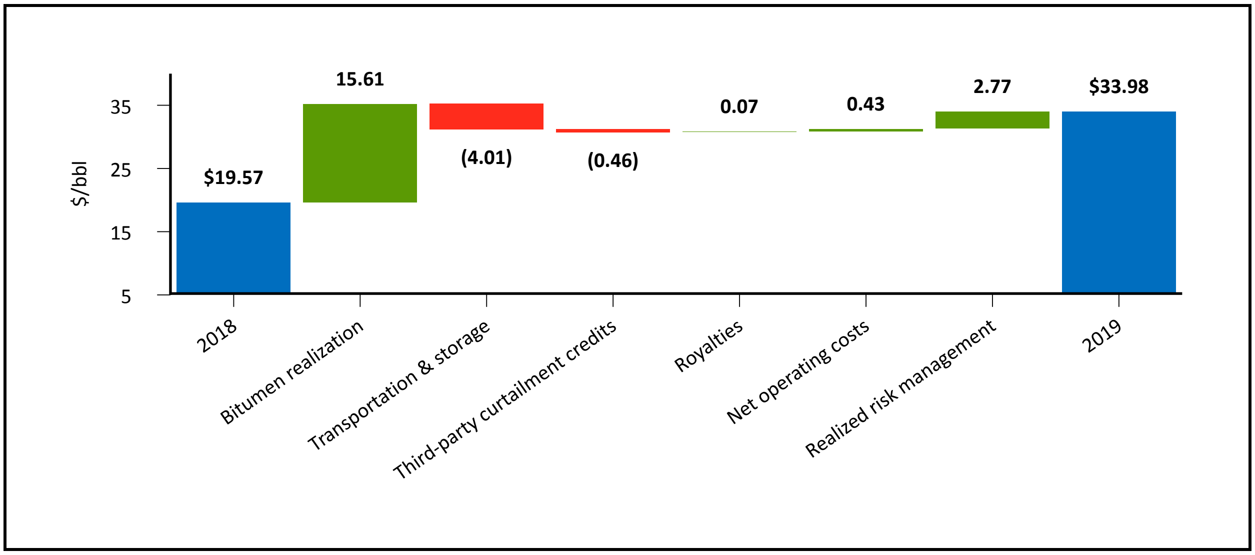
Net operating costs are comprised of the sum of non-energy operating costs and energy operating costs, reduced by power revenue. Non-energy operating costs relate to production-related operating activities and energy operating costs reflect the cost of natural gas used for fuel to generate steam and 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.

Net operating costs for the three months ended June 30, 2019 averaged $4.66 per barrel compared to $5.64 per barrel for the three months ended June 30, 2018. The decrease in net operating costs is primarily due to lower non-energy operating costs per barrel as a result of increased sales volumes during the three months ended June 30, 2019 compared to the same period of 2018. Energy operating costs and power revenues both increased, however, on a per barrel basis, these variable inputs remained relatively consistent quarter over quarter.

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. The realized loss on commodity risk management averaged $5.94 per barrel for the three months ended June 30, 2019 compared to a realized loss of $13.11 per barrel for the three months ended June 30, 2018. Realized losses were recognized in both periods due to the settlement of losses on commodity risk management contracts 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.

Cash Operating Netback - Six Months Ended June 30



Bitumen Realization

Bitumen realization averaged $56.42 per barrel for the six months ended June 30, 2019, compared to $40.81 per barrel for the six months ended June 30, 2018. The 38% increase period-over-period was due to an increase in the Corporation's realized blend sales price as a direct result of the narrowing of the WTI:AWB differential in both Edmonton and USGC markets. The WTI:AWB differential at Edmonton narrowed by US$11.41 per barrel to a discount of US$13.42 per barrel for the six months ended June 30, 2019 from a discount of US$24.83 per barrel for the six months ended June 30, 2018. The WTI:AWB differential at the USGC narrowed by US$7.79 per barrel to a premium of US$0.38 per barrel for the six months ended June 30, 2019 from a discount of US$7.41 per barrel for the six months ended June 30, 2018. The benefit of the narrowing differentials was partially offset by the lower WTI benchmark price during the six months ended June 30, 2019 compared to the same period in 2018. Bitumen realization was also positively impacted by the increase in blend sales volumes reaching the USGC. Approximately 33% of blend sales volumes were delivered to the USGC during the six months ended June 30, 2019 compared to 27% in the same period of 2018. Blend sales at the USGC were sold at a premium, after transportation and storage costs, of US$3.66 per barrel compared to the Edmonton market. Refer to the Marketing Activity section of this MD&A for further details.

Also improving bitumen realization was a decrease to the Corporation's average cost of diluent during the six months ended June 30, 2019 to $81.28 per barrel of diluent from $89.02 per barrel of diluent for the six months ended June 30, 2018, due to lower average condensate benchmark pricing relative to WTI. The Corporation's cost of diluent per barrel of bitumen also decreased as a result of a higher realized blend sales price, which increased the amount of diluent expense that is recovered when the blended product is sold.

Transportation and storage

During the six months ended June 30, 2019, transportation and storage costs averaged $11.03 per barrel of bitumen compared to $7.02 per barrel of bitumen for the six months ended June 30, 2018. The increase in costs on a per barrel basis is the result of increased blend volumes transported by rail to the USGC, the incremental transportation costs associated with the TSA and the addition of the Bayou Bridge pipeline transportation cost which enables the Corporation to access the eastern USGC market.

Third-party curtailment credits

The Corporation incurred costs to purchase third-party curtailment credits of $0.46 per barrel for the six months ended June 30, 2019. Curtailment was not in place during the six months ended June 30, 2018 therefore the Corporation did not incur any costs related to the purchase of third-party curtailment credits. Subject to financial and operational considerations, the Corporation may continue to purchase third-party curtailment credits, if and when they become available.

Royalties

Royalties averaged $1.24 per barrel for the six months ended June 30, 2019, compared to $1.31 per barrel for the six months ended June 30, 2018. The decrease in royalties per barrel, compared to the same period 2018, is primarily due to a recovery related to prior year royalty adjustments.

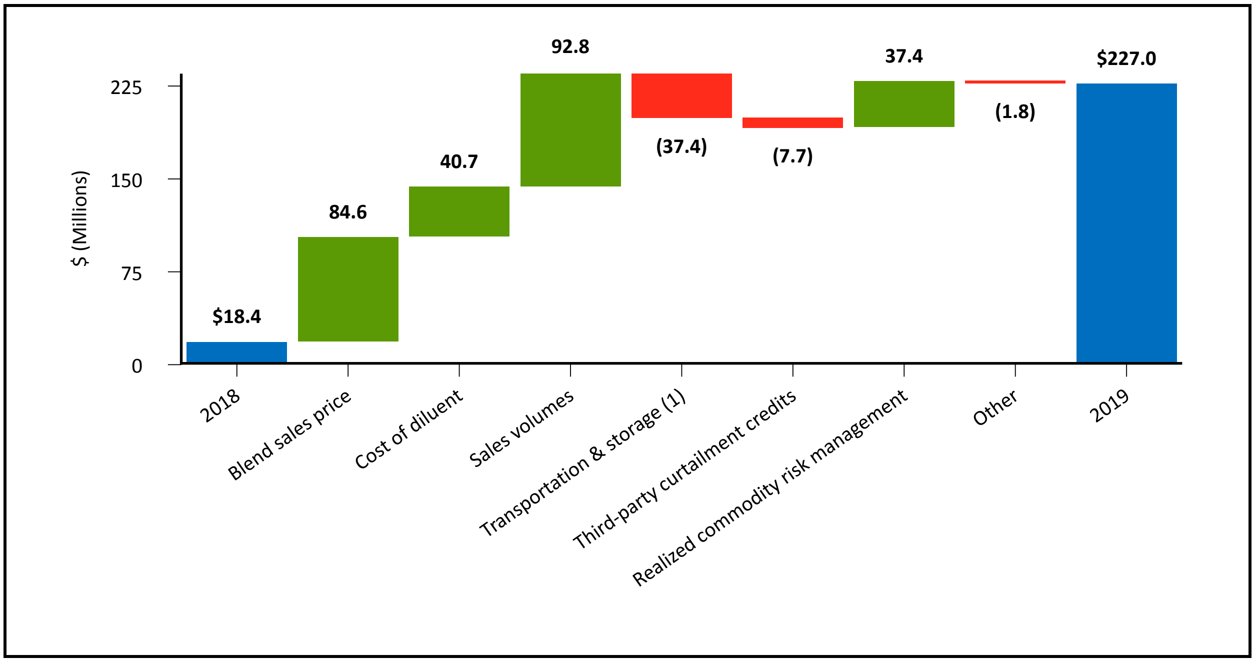
Net Operating Costs

Net operating costs for the six months ended June 30, 2019 averaged $5.39 per barrel compared to $5.82 per barrel for the six months ended June 30, 2018. The decrease in net operating costs per barrel is primarily the result of an increase in power revenue, partially offset by an increase in energy operating costs. The Corporation's average realized power sales price during the six months ended June 30, 2019 was $63.32 per megawatt hour compared to $42.23 per megawatt hour in the same period of 2018. The Corporation’s natural gas purchase price averaged $2.35 per mcf during the six months ended June 30, 2019 compared to $2.10 per mcf in the same period of 2018.

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. The realized loss on commodity risk management averaged $4.32 per barrel for the six months ended June 30, 2019 compared to a realized loss of $7.09 per barrel for the six months ended June 30, 2018. Realized losses were recognized in both periods due to the settlement of losses on commodity risk management contracts 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.

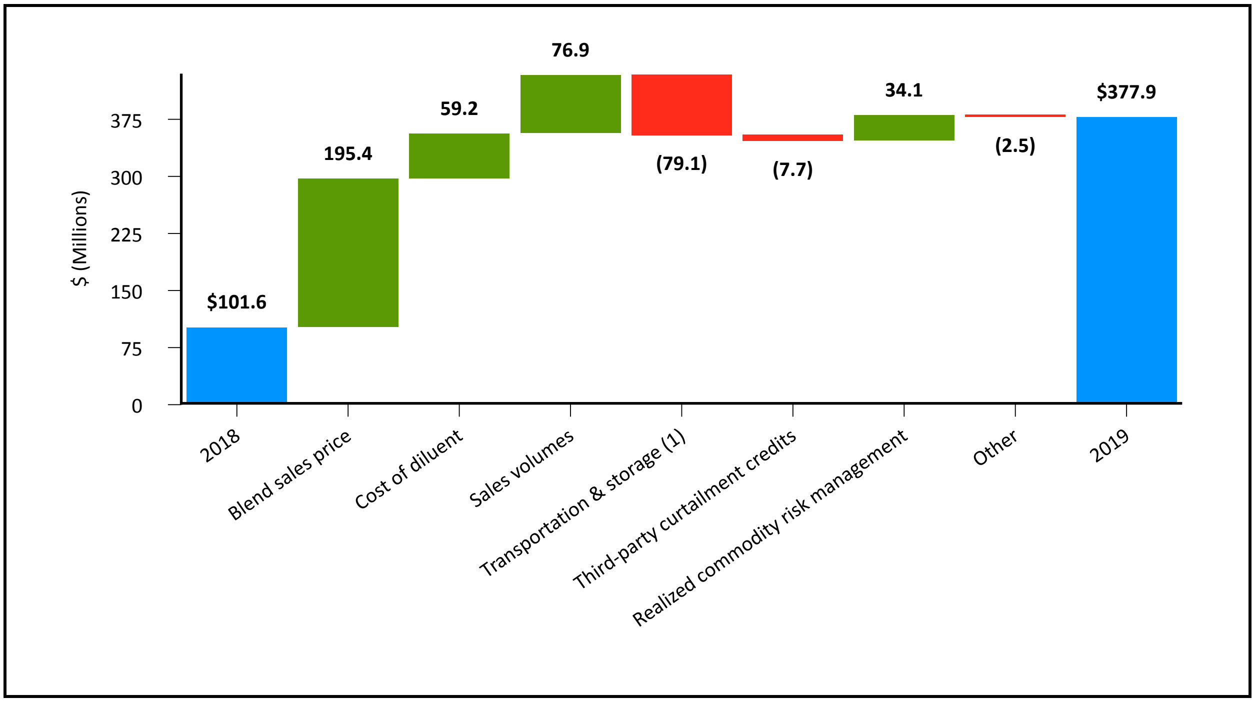
Adjusted Funds Flow - Three Months Ended June 30



(1) 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, net of third-party recoveries on diluent transportation arrangements.

Adjusted funds flow is a non-GAAP measure, as defined in the "NON-GAAP MEASURES" section of this MD&A, which is used by the Corporation to analyze operating performance and liquidity. Adjusted funds flow increased significantly in the second quarter of 2019 to $227 million from $18 million in the second quarter of 2018. The increase in adjusted funds flow was primarily the result of an increase in sales volumes, an increase in the Corporation's realized blend sales price due to narrowing differentials at both Edmonton and the USGC and a decrease in the cost of diluent. These items were partially offset by higher costs associated with transportation and storage.

Adjusted Funds Flow - Six Months Ended June 30



(1) 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, net of third-party recoveries on diluent transportation arrangements.

Adjusted funds flow increased significantly during the six months ended June 30, 2019 to $378 million from $102 million during the same period of 2018. The increase in adjusted funds flow was primarily the result of increased blend sales price due to improved differentials at both Edmonton and the USGC, combined with the Corporation's marketing activity directed at optimizing access to premium markets. An increase in blend sales volumes and a decrease in the cost of diluent also had a positive impact on adjusted funds flow for the six months ended June 30, 2019. These items were partially offset by higher costs associated with transportation and storage.

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 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 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.

The following table summarizes 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:

	Three months ended June 30, 2019				
	Edmonton (US$/bbl)		USGC (US$/bbl)		
(US$ per barrel of blend sales)	Pipeline	Rail	Pipeline	Rail	TOTAL (US$/bbl)
WTI	$ 59.82	$ 59.82	$ 59.82	$ 59.82	$ 59.82
Differential - WTI:AWB at sales point	(13.29)	(10.87)	1.48	(0.78)	(8.10)
Blend sales price	46.53	48.95	61.30	59.04	51.72
Transportation and storage[1]	(1.65)	(3.86)	(10.28)	(26.02)	(5.60)
Transportation and storage from Christina Lake to Edmonton[2]	1.65	1.65	1.65	1.65	1.65
Blend sales price, net of transportation & storage at Edmonton	$ 46.53	$ 46.74	$ 52.67	$ 34.67	$ 47.77

	Edmonton (US$/bbl)	USGC (US$/bbl)	USGC premium (US$/bbl)
Average blend sales price by location	$ 46.98	$ 60.97	$ 13.99
Transportation and storage[1]	(2.04)	(12.53)	(10.49)
Transportation and storage from Christina Lake to Edmonton[2]	1.65	1.65	—
Blend sales price, net of transportation & storage at Edmonton	$ 46.59	$ 50.09	$ 3.50

	Pipeline	Rail	Pipeline	Rail	TOTAL
Total blend sales - bbls/d	73,822	16,783	39,855	6,660	137,120
% of total sales	54%	12%	29%	5%	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, was C$10.80 per barrel for the three months ended June 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 1.3376.*

	Three months ended June 30, 2018				
	Edmonton (US$/bbl)		USGC (US$/bbl)		
(US$ per barrel of blend sales)	Pipeline	Rail	Pipeline	Rail	TOTAL (US$/bbl)
WTI	$ 67.88	$ 67.88	$ 67.88	—	$ 67.88
Differential - WTI:AWB at sales point	(24.70)	(26.45)	(7.02)	—	(19.54)
Blend sales price	43.18	41.43	60.86	—	48.34
Transportation and storage[1]	(1.61)	(8.45)	(9.76)	—	(4.41)
Transportation and storage from Christina Lake to Edmonton[2]	1.61	1.61	1.61	—	1.61
Blend sales price, net of transportation & storage at Edmonton	$ 43.18	$ 34.59	$ 52.71	—	$ 45.54

	Edmonton (US$/bbl)	USGC (US$/bbl)	USGC premium (US$/bbl)
Average blend sales price by location	$ 43.08	$ 60.86	$ 17.78
Transportation and storage[1]	(2.07)	(9.76)	(7.69)
Transportation and storage from Christina Lake to Edmonton[2]	1.61	1.61	—
Blend sales price, net of transportation & storage at Edmonton	$ 42.62	$ 52.71	$ 10.09

	Pipeline	Rail	Pipeline	Rail	TOTAL
Total blend sales - bbls/d	72,031	4,173	32,033	—	108,237
% of total sales	67%	4%	30%	—	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, was C$8.28 per barrel for the three months ended June 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 1.2911.*

(US$ per barrel of blend sales)	Six months ended June 30, 2019 Edmonton (US$/bbl) Pipeline	Edmonton (US$/bbl) Rail	USGC (US$/bbl) Pipeline	USGC (US$/bbl) Rail	TOTAL (US$/bbl)
WTI	$ 57.36	$ 57.36	$ 57.36	$ 57.36	$ 57.36
Differential - WTI:AWB at sales point	(14.60)	(10.18)	1.19	(2.31)	(9.20)
Blend sales price	42.76	47.18	58.55	55.05	48.16
Transportation and storage(1)	(1.72)	(4.14)	(10.58)	(24.50)	(5.68)
Transportation and storage from Christina Lake to Edmonton(2)	1.72	1.72	1.72	1.72	1.72
Blend sales price, net of transportation & storage at Edmonton	$ 42.76	$ 44.76	$ 49.69	$ 32.27	$ 44.20

	Edmonton (US$/bbl)	USGC (US$/bbl)	USGC premium (US$/bbl)
Average blend sales price by location	$ 43.41	$ 57.94	$ 14.53
Transportation and storage(1)	(2.11)	(12.98)	(10.87)
Transportation and storage from Christina Lake to Edmonton(2)	1.72	1.72	—
Blend sales price, net of transportation & storage at Edmonton	$ 43.02	$ 46.68	$ 3.66

	Pipeline	Rail	Pipeline	Rail	TOTAL
Total blend sales - bbls/d	77,269	13,459	36,434	7,600	134,762
% of total sales	57%	10%	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, was C$11.03 per barrel for the six months ended June 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 1.3335.*

(US$ per barrel of blend sales)	Six months ended June 30, 2018 Edmonton (US$/bbl) Pipeline	Edmonton (US$/bbl) Rail	USGC (US$/bbl) Pipeline	USGC (US$/bbl) Rail	TOTAL (US$/bbl)
WTI	$ 65.37	$ 65.37	$ 65.37	—	$ 65.37
Differential - WTI:AWB at sales point	(26.92)	(25.04)	(6.86)	—	(21.39)
Blend sales price	38.45	40.33	58.51	—	43.98
Transportation and storage(1)	(1.09)	(8.40)	(9.44)	—	(3.74)
Transportation and storage from Christina Lake to Edmonton(2)	1.09	1.09	1.09	—	1.09
Blend sales price, net of transportation & storage at Edmonton	$ 38.45	$ 33.02	$ 50.16	—	$ 41.33

	Edmonton (US$/bbl)	USGC (US$/bbl)	USGC premium (US$/bbl)
Average blend sales price by location	$ 38.54	$ 58.51	$ 19.97
Transportation and storage(1)	(1.46)	(9.44)	(7.98)
Transportation and storage from Christina Lake to Edmonton(2)	1.09	1.09	—
Blend sales price, net of transportation & storage at Edmonton	$ 38.17	$ 50.16	$ 11.99

	Pipeline	Rail	Pipeline	Rail	TOTAL
Total blend sales - bbls/d	84,286	4,427	33,179	—	121,892
% of total sales	69%	4%	27%	—	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, was C$7.02 per barrel for the six months ended June 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 1.2781.*

Blend sales for the three months ended June 30, 2019 averaged 137,120 bbls/d compared to 108,237 bbls/d for the three months ended June 30, 2018. During the second quarter of 2019, the Corporation's sales volumes transported by rail averaged 23,443 bbls/d, 28% of which were delivered to the USGC, compared to 4,173 bbls/d of total sales volumes transported by rail for the same period in 2018, of which none were delivered to the USGC.

Blend sales for the six months ended June 30, 2019 averaged 134,762 bbls/d compared to 121,892 bbls/d for the six months ended June 30, 2018. During the six months ended June 30, 2019, the Corporation's sales volumes transported by rail averaged 21,059 bbls/d, 36% of which were delivered to the USGC, compared to 4,427 bbls/d of total sales volumes transported by rail for the same period in 2018, of which none were delivered to the USGC.

Although WTI:WCS differentials at Edmonton narrowed significantly, primarily due to the provincially-mandated curtailment, during the three and six months ended June 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 41% during the three and six months ended June 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 six months ended June 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$3.50 per barrel and US$3.66 per barrel premium to those sold at Edmonton for the three and six months ended June 30, 2019. This compares to a US$10.09 per barrel and US $11.99 per barrel premium at the USGC compared to Edmonton for the three and six months ended June 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 six months ended June 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 six months ended June 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. The Corporation anticipates normalized delivered rail costs to the USGC in the range of US$17-19 per barrel of blend once the change out is complete and the Bruderheim terminal is fully utilized.

Revenue

Revenue represents the total of petroleum revenue, net of royalties and other revenue. Revenue for the three months ended June 30, 2019 totaled $1.1 billion compared to $689 million for the three months ended June 30, 2018. Revenue for the six months ended June 30, 2019 totaled $2.0 billion compared to $1.4 billion for the six months ended June 30, 2018. Revenue increased as a result of the increase in the average blend sales price and increased blend sales volumes.

Net Earnings (Loss)

The Corporation recognized a net loss of $64 million for the three months ended June 30, 2019 compared to a net loss of $179 million for the three months ended June 30, 2018. The net loss for the three months ended June 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 a deferred tax expense of $12 million, offset by an $87 million unrealized gain on commodity risk management contracts and a $67 million unrealized foreign exchange gain. The net loss for the three months ended June 30, 2018 included unrealized losses on commodity risk management contracts of $61 million and an unrealized foreign exchange loss of $62 million.

The Corporation recognized a net loss of $111 million for the six months ended June 30, 2019 compared to a net loss of $38 million for the six months ended June 30, 2018. The net loss for the six months ended June 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 $122 million offset by an unrealized foreign exchange gain of $145 million. The net loss for the six months ended June 30, 2018 was affected by a net unrealized foreign exchange loss of $204 million and unrealized losses on commodity risk management contracts totaling $119 million.

Capital Investment

	Three months ended June 30		Six months ended June 30	
($000)	**2019**	**2018**	**2019**	**2018**
Sustaining and maintenance	**17,350**	$ 108,868	**$ 37,280**	$ 161,356
Phase 2B brownfield expansion	**9,338**	26,270	**25,600**	44,080
eMSAGP	**—**	22,307	**—**	69,050
eMVAPEX	**4,065**	18,367	**10,758**	42,628
Field infrastructure, corporate and other	**1,106**	6,755	**11,514**	13,192
Total cash capital investment	**31,859**	182,567	**85,152**	330,306
Capitalized cash-settled stock-based compensation	**746**	8,260	**337**	8,135
	$ 32,605	$ 190,827	**$ 85,489**	$ 338,441

Total cash capital investment was $32 million for the three months ended June 30, 2019 and $85 million for the six months ended June 30, 2019, compared to $183 million for the three months ended June 30, 2018 and $330 million for the six months ended June 30, 2018. The decrease in capital spending reflects the Corporation's disciplined 2019 capital budget of $200 million. Capital investment in the three and six months ended June 30, 2019 was primarily directed towards sustaining and maintenance activities as well as completing work already underway on the Phase 2B Brownfield expansion.

4. OUTLOOK

Summary of 2019 Guidance	**Guidance January 22, 2019**
Total cash capital investment	$200 million
Bitumen production – annual average (bbls/d)	90,000 – 92,000
Non-energy operating costs ($/bbl)	$4.75 – $5.25
General and administrative expense ($/bbl)	$1.95 – $2.05

During the second quarter of 2019 the Corporation was able to increase production to levels near its production capability of 100,000 bbls/d at Christina Lake, through the purchase of third-party curtailment credits, which positively impacted the Corporation's results for the three and six months ended June 30, 2019. Second quarter production results may not be indicative of performance during the second half of 2019 due to the uncertainty of the Corporation's ability to continue purchasing third-party curtailment credits. Subject to financial and operational considerations, the Corporation may continue to purchase third-party curtailment credits, if and when they become available, from other upstream producers who choose to sell some of their allocations under the current Alberta–wide curtailment.

The Corporation continues to target 2019 production volumes in the range of 90,000 - 92,000 bbls/d, non-energy operating costs in the range of $4.75 - $5.25 per barrel and general and administrative expense 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, but eases over the course of the year.

The Corporation is continuing its strategy of prioritizing balance sheet strength over growth. With provincially-mandated curtailment and continuing egress uncertainty, the Corporation has decided not to proceed with the previously announced discretionary capital budget of $75 million. Instead, 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 budget of $200 million remains unchanged and is primarily designed with the intentions of sustaining production capability at 100,000 bbls/d and expanding oil treating capacity at the Corporation's central facility to 120,000 bbls/d.

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:

	Six months ended June 30		2019		2018				2017	
	2019	2018	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Average Commodity Prices										
Crude oil prices										
Brent (US$/bbl)	66.11	71.04	68.32	63.90	68.08	75.97	74.90	67.18	61.54	52.18
WTI (US$/bbl)	57.36	65.37	59.82	54.90	58.81	69.50	67.88	62.87	55.40	48.21
Differential – WTI:WCS – Edmonton (US$/bbl)	(11.48)	(21.77)	(10.67)	(12.29)	(39.43)	(22.25)	(19.27)	(24.28)	(12.26)	(9.94)
Differential – WCS:AWB – Edmonton (US$/bbl)	(1.94)	(3.06)	(1.65)	(2.21)	(5.17)	(3.44)	(2.94)	(3.17)	(2.30)	(1.89)
AWB – Edmonton (US$/bbl)	43.94	40.54	47.50	40.40	14.21	43.81	45.67	35.42	40.84	36.38
Differential – WTI:AWB – U.S. Gulf Coast (US$/bbl)	0.38	(7.41)	1.64	(0.89)	(6.25)	(5.63)	(7.83)	(7.00)	(5.48)	(6.61)
AWB – U.S. Gulf Coast (US$/bbl)	57.74	57.96	61.46	54.01	52.56	63.87	60.05	55.87	49.92	41.60
Condensate prices										
Condensate at Edmonton (C$/bbl)	**71.00**	84.28	**74.76**	67.25	59.63	87.35	88.84	79.72	73.72	59.59
Condensate at Edmonton as % of WTI	**92.8%**	100.9%	**93.4%**	92.1%	76.7%	96.2%	101.4%	100.2%	104.6%	98.7%
Condensate at Mont Belvieu, Texas (US$/bbl)	**49.27**	61.83	**50.22**	48.31	51.21	64.53	64.40	59.27	55.35	46.37
Condensate at Mont Belvieu, Texas as % of WTI	**85.9%**	94.6%	**84.0%**	88.0%	87.1%	92.8%	94.9%	94.3%	99.9%	96.2%
Natural gas prices										
AECO (C$/mcf)	**1.99**	1.76	**1.12**	2.86	1.70	1.28	1.26	2.26	1.84	1.58
Electric power prices										
Alberta power pool (C$/MWh)	**63.55**	45.36	**56.37**	70.73	55.57	54.46	55.92	34.81	22.49	24.55
Foreign exchange rates										
C$ equivalent of 1 US$ – average	**1.3335**	1.2781	**1.3376**	1.3293	1.3215	1.3070	1.2911	1.2651	1.2717	1.2524
C$ equivalent of 1 US$ – period end	**1.3091**	1.3142	**1.3091**	1.3360	1.3646	1.2924	1.3142	1.2901	1.2518	1.2510

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. The WTI price averaged US$59.82 per barrel for the three months ended June 30, 2019 compared to US$67.88 per barrel for the three months ended June 30, 2018. The WTI price averaged US$57.36 per barrel for the six months ended June 30, 2019 compared to US $65.37 per barrel for the six months ended June 30, 2018.

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 WTI:WCS differential at Edmonton averaged US$10.67 per barrel, for the three months ended June 30, 2019 compared to US$19.27 per barrel for the three months ended June 30, 2018. The WTI:WCS differential at Edmonton averaged US$11.48 per barrel, for the six months ended June 30, 2019 compared to US$21.77 per barrel for the six months ended June 30, 2018.

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 six months ended June 30, 2019 compared to the fourth quarter of 2018.

Condensate Prices

In order to facilitate pipeline transportation of bitumen, the Corporation uses condensate sourced at both Edmonton and the USGC as diluent for blending with the Corporation's bitumen. The Corporation's committed diluent purchases at the USGC reference benchmark pricing at Mont Belvieu, Texas.

Condensate prices, benchmarked at Edmonton, averaged $74.76 per barrel, or 93.4% of WTI, for the three months ended June 30, 2019 compared to $88.84 per barrel, or 101.4% of WTI, for the three months ended June 30, 2018. Condensate prices, benchmarked at Edmonton, averaged $71.00 per barrel, or 92.8% of WTI, for the six months ended June 30, 2019 compared to $84.28 per barrel, or 100.9% of WTI, for the six months ended June 30, 2018.

Condensate prices, benchmarked at Mont Belvieu, Texas, averaged US$50.22 per barrel, or 84.0% of WTI, for the three months ended June 30, 2019 compared to US$64.40 per barrel, or 94.9% of WTI, for the three months ended June 30, 2018. Condensate prices, benchmarked at Mont Belvieu, Texas, averaged US$49.27 per barrel, or 85.9% of WTI, for the six months ended June 30, 2019 compared to US$61.83 per barrel, or 94.6% of WTI, for the six months ended June 30, 2018. Condensate sourced from Mont Belvieu, Texas is subject to transportation costs of approximately US$2.50 per barrel of condensate from Mont Belvieu to the Edmonton area.

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 averaged $1.12 per mcf for the three months ended June 30, 2019 compared to $1.26 per mcf for the three months ended June 30, 2018. The AECO natural gas price decreased as a result of continued pipeline constraints, lack of demand growth and robust production in the Western Canadian Sedimentary Basin. The AECO natural gas price averaged $1.99 per mcf for the six months ended June 30, 2019 compared to $1.76 per mcf for the six months ended June 30, 2018.

Electric Power Prices

Electric power prices impact the price that the Corporation receives on the sale of surplus power from the Corporation's cogeneration facilities. The Alberta power pool price averaged $56.37 per megawatt hour for the three months ended June 30, 2019 compared to $55.92 per megawatt hour for the three months ended June 30, 2018. The Alberta power pool price averaged $63.55 per megawatt hour for the six months ended June 30, 2019 compared to $45.36 per megawatt hour for the six months ended June 30, 2018.

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 revenue 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. A decrease in the value of the Canadian dollar compared to the U.S. dollar has a positive impact on blend sales revenue and a negative impact on diluent expense and principal and interest payments. Conversely, an increase in the value of the Canadian dollar has a negative impact on blend sales revenue and a positive impact on diluent expense and principal and interest payments.

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 June 30, 2019, the Canadian dollar, at a rate of 1.3091 per U.S. dollar, had increased in value by approximately 4% against the U.S. dollar compared to its value as at December 31, 2018, when the rate was 1.3646.

6. OTHER OPERATING RESULTS

Depletion and Depreciation

	Three months ended June 30		Six months ended June 30	
($000)	**2019**	**2018**	**2019**	**2018**
Depletion and depreciation expense	**$ 364,923**	$ 104,350	**$ 480,030**	$ 215,249
Depletion and depreciation expense per barrel of production	**$ 41.22**	$ 16.08	**$ 28.76**	$ 14.47

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 certain 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 $26.78 per barrel and $14.20 per barrel for the three and six months ended June 30, 2019, respectively. 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 per barrel, excluding the accelerated depreciation expense, was $14.44 per barrel for the three months ended June 30, 2019 and $14.55 per barrel for the six months ended June 30, 2019. The decrease from the same periods of 2018 is primarily due to increased bitumen production volumes, partially offset by a decrease in future development costs associated with the Corporation's depletable assets.

Commodity Risk Management Gain (Loss)

The Corporation has entered 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 June 30					
($000)	**2019**			**2018**		
	Realized	**Unrealized**	**Total**	**Realized**	**Unrealized**	**Total**
Crude oil contracts[1]	**$ (44,327)**	**$ 90,714**	**$ 46,387**	$ (88,960)	$ (56,440)	$ (145,400)
Condensate contracts[2]	**(7,066)**	**(3,471)**	**(10,537)**	209	(4,848)	(4,639)
Commodity risk management gain (loss)	**$ (51,393)**	**$ 87,243**	**$ 35,850**	$ (88,751)	$ (61,288)	$ (150,039)

(1) *Includes WTI fixed price, 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 realized a net loss on commodity risk management contracts of $51 million for the three months ended June 30, 2019, primarily due to net settlement losses on crude oil contracts. This compares to a realized net loss of $89 million for the three months ended June 30, 2018. WTI:WCS fixed differential contracts, which fixed the differential at approximately US$22 per barrel, settled, on average, at approximately US$11 per barrel. Condensate contracts, which fixed the price of condensate at approximately 91% of WTI, settled, on average, at 84% of WTI. The realized losses from the settlement of these contracts were partially offset by gains on WTI fixed price contracts, which fixed prices at approximately US$65 per barrel, and settled, on average, at approximately US$60 per barrel.

The Corporation recognized an unrealized net gain on commodity risk management contracts of $87 million for the three months ended June 30, 2019, primarily reflecting unrealized gains on crude oil contracts. This compares to an unrealized loss of $61 million for the three months ended June 30, 2018. The $91 million unrealized gain on crude oil contracts reflects decreasing crude oil benchmark forward prices, resulting in unrealized gains on the Corporation's WTI fixed price contracts, combined with settlement of WTI:WCS forward differential contracts during the period resulting in unrealized gains. In addition, forward prices for condensate decreased relative to WTI, resulting in an offsetting $3 million unrealized loss on the Corporation's condensate contracts. Refer to the "Risk Management" section of this MD&A for further details.

	Six months ended June 30					
($000)	**2019**			**2018**		
	Realized	**Unrealized**	**Total**	**Realized**	**Unrealized**	**Total**
Crude oil contracts[1]	**$ (62,630)**	**$ (111,639)**	**$ (174,269)**	$ (106,679)	$ (114,859)	$ (221,538)
Condensate contracts[2]	**(9,747)**	**(10,114)**	**(19,861)**	209	(4,461)	(4,252)
Commodity risk management gain (loss)	**$ (72,377)**	**$ (121,753)**	**$ (194,130)**	$ (106,470)	$ (119,320)	$ (225,790)

(1) *Includes WTI fixed price, 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 realized a net loss on commodity risk management contracts of $72 million for the six months ended June 30, 2019, primarily due to net settlement losses on crude oil contracts. This compares to a realized net loss of $106 million for the six months ended June 30, 2018. WTI:WCS fixed differential contracts, which fixed the differential at approximately US$22 per barrel, settled, on average, at approximately US$11 per barrel. Condensate contracts, which fixed the price of condensate at approximately 91% of WTI, settled, on average, at 86% of WTI. The realized losses from the settlement of these contracts were partially offset by gains on WTI fixed price contracts, which fixed prices at approximately US$66 per barrel, and settled, on average, at approximately US$57 per barrel.

The Corporation recognized an unrealized net loss on commodity risk management contracts of $122 million for the six months ended June 30, 2019, primarily reflecting unrealized losses on crude oil contracts. This compares to an unrealized loss of $119 million for the six months ended June 30, 2018. The $112 million unrealized loss on crude oil contracts reflects settlement of realized losses during the period, increasing crude oil benchmark forward prices, resulting in unrealized losses on the Corporation's WTI fixed price contracts and narrowing WTI:WCS forward differentials since December 31, 2018, resulting in unrealized losses on WTI:WCS fixed differential contracts. In addition, forward prices for condensate decreased relative to WTI, resulting in a $10 million unrealized loss on the Corporation's condensate contracts. Refer to the "Risk Management" section of this MD&A for further details.

General and Administrative

	Three months ended June 30		Six months ended June 30	
($000)	**2019**	**2018**	**2019**	**2018**
General and administrative expense	**$ 16,043**	$ 19,152	**$ 33,810**	$ 40,875
General and administrative expense per barrel of production	**$ 1.81**	$ 2.95	**$ 2.03**	$ 2.75

General and administrative expense per barrel decreased 39% for the three months ended June 30, 2019 to $1.81 per barrel, from $2.95 per barrel for the three months ended June 30, 2018. General and administrative expense per barrel decreased 26% for the six months ended June 30, 2019 to $2.03 per barrel, from $2.75 per barrel for the six months ended June 30, 2018. The per barrel decrease in each of the comparative three and six month periods was primarily due to spreading fixed costs over higher production volumes. In addition, a reduction of staffing levels in February 2019 is reducing overall general and administrative costs. Based on the current production guidance which incorporates the provincially-mandated curtailment, and as the full impact of the staff cost reduction is captured, the Corporation anticipates annual 2019 general and administrative expense to average $1.95 - $2.05 per barrel.

Stock-based Compensation

	Three months ended June 30		Six months ended June 30	
($000)	**2019**	**2018**	**2019**	**2018**
Cash-settled expense (recovery)	**$ 4,998**	$ 21,340	**$ (4,440)**	$ 21,049
Equity-settled expense	**11,351**	3,999	**15,645**	10,128
Stock-based compensation	**$ 16,349**	$ 25,339	**$ 11,205**	$ 31,177

Stock-based compensation expense for the three months ended June 30, 2019 was $16 million compared to $25 million for the three months ended June 30, 2018. Stock-based compensation expense for the six months ended June 30, 2019 was $11 million compared to stock-based compensation expense of $31 million for the six months ended June 30, 2018. For the three and six months ended June 30, 2018, the Corporation's share price increased significantly, which increased the fair value and expense of cash-settled units in those periods. In contrast, the Corporation's share price decreased in the six months ended June 30, 2019 and remained steady during the three months ended June 30, 2019. Also impacting the increase in stock-based compensation for the three and six months ended June 30, 2019 was a one-time expense of $10 million related to the accelerated vesting of units for retirement eligible employees.

Foreign Exchange Gain (Loss), Net

	Three months ended June 30		Six months ended June 30	
($000)	**2019**	**2018**	**2019**	**2018**
Unrealized foreign exchange gain (loss) on:				
Long-term debt	**$ 74,460**	$ (67,028)	**$ 153,745**	$ (205,812)
Other	**(6,961)**	4,651	**(9,228)**	2,137
Unrealized net gain (loss) on foreign exchange	**67,499**	(62,377)	**144,517**	(203,675)
Realized gain (loss) on foreign exchange	**1,878**	(1,641)	**2,958**	(3,651)
Realized gain (loss) on foreign exchange derivatives	**—**	—	**—**	35,362
Foreign exchange gain (loss), net	**$ 69,377**	$ (64,018)	**$ 147,475**	$ (171,964)
C$ equivalent of 1 US$				
Beginning of period	**1.3360**	1.2901	**1.3646**	1.2518
End of period	**1.3091**	1.3142	**1.3091**	1.3142

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 June 30, 2019, the Canadian dollar strengthened by 2%, resulting in an unrealized foreign exchange gain on translation of U.S. dollar denominated debt of $67 million. For the three months ended June 30, 2018, the Canadian dollar weakened by 2%, resulting in an unrealized foreign exchange loss on translation of U.S. dollar denominated debt of $62 million.

For the six months ended June 30, 2019, the Canadian dollar strengthened by 4%, resulting in an unrealized foreign exchange gain on translation of U.S. dollar denominated debt of $145 million. For the six months ended June 30, 2018, the Canadian dollar weakened by 5%, resulting in an unrealized foreign exchange loss on translation of U.S. dollar denominated debt of $204 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

	Three months ended June 30		Six months ended June 30	
($000)	**2019**	**2018**	**2019**	**2018**
Interest expense on long-term debt	**$ 69,237**	$ 67,558	**$ 140,961**	$ 149,982
Interest expense on lease liabilities	**6,616**	4,108	**13,119**	4,549
Interest income	**(1,682)**	(2,277)	**(3,007)**	(4,017)
Net interest expense	**74,171**	69,389	**151,073**	150,514
Accretion on provisions	**1,736**	1,810	**3,401**	3,720
Unrealized loss (gain) on derivative financial liabilities[(1)]	**562**	(110)	**309**	2,866
Realized loss (gain) on interest rate swaps	**—**	—	**—**	(17,312)
Net finance expense	**$ 76,469**	$ 71,089	**$ 154,783**	$ 139,788
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 the U.S. dollar denominated senior secured term loan, senior secured second lien notes, and senior unsecured notes outstanding, including the impact of the interest rate swap.*

Interest expense on long-term debt for the three months ended June 30, 2019 was $69 million compared to $68 million for the three months ended June 30, 2018. Interest expense on long-term debt for the six months ended June 30, 2019 was $141 million compared to $150 million for the six months ended June 30, 2018. The interest expense decrease for the six months ended June 30, 2019 was primarily due to the repayment of approximately C$1.2 billion of the Corporation's senior secured term loan in the first quarter of 2018 from a portion of the proceeds from the sale of the Corporation's 50% interest in the Access Pipeline and its 100% interest in the Stonefell Terminal. As a result of the repayment, the Corporation terminated its existing interest rate swap contract, which effectively fixed the interest rate on a portion of its senior secured term loan, and realized a gain of $17 million for the six months ended June 30, 2018.

Other Expenses

	Three months ended June 30		Six months ended June 30	
($000)	**2019**	**2018**	**2019**	**2018**
Severance and other	**$ 4,481**	$ 2,801	**$ 11,464**	$ 2,988
Onerous contracts expense	**—**	145	**—**	789
Other expenses	**$ 4,481**	$ 2,946	**$ 11,464**	$ 3,777

The Corporation recognized other expenses of $4 million for the three months ended June 30, 2019 compared to $3 million for the three months ended June 30, 2018. The Corporation recognized other expenses of $11 million for the six months ended June 30, 2019 compared to $4 million for the six months ended June 30, 2018. The increase in each of the comparative three and six month periods was primarily due to severance costs related to the Corporation reducing its staffing levels to align with a lower level of capital spending and improving overall cost efficiencies.

Income Tax Expense (Recovery)

	Three months ended June 30		Six months ended June 30	
($000)	**2019**	**2018**	**2019**	**2018**
Current income tax expense (recovery)	**$ (153)**	$ 79	**$ 90**	$ 195
Deferred income tax expense (recovery)	**$ 11,960**	$ (44,752)	**(33,709)**	(74,526)
Income tax expense (recovery)	**$ 11,807**	$ (44,673)	**$ (33,619)**	$ (74,331)

The Corporation recognizes current income taxes associated with its operations in the United States. The Corporation's Canadian operations are not currently taxable. As at June 30, 2019, the Corporation had approximately $7.4 billion of available Canadian tax pools.

The Corporation recognized a current income tax recovery of $0.2 million for the three months ended June 30, 2019 and a current income tax expense of $0.1 million for the three months ended June 30, 2018. The 2019 current tax recovery of $0.2 million comprises $0.4 million of a refundable Alberta tax credit on Scientific Research and Experimental Development, partially offset by $0.2 million of tax expense related to operations in the United States. The Corporation recognized a current income tax expense of $0.1 million for the six months ended June 30, 2019 and a current income tax expense of $0.2 million for the six months ended June 30, 2018 primarily related to its operations in the United States.

The Corporation recognized a deferred income tax expense of $12 million for the three months ended June 30, 2019 and a deferred income tax recovery of $45 million for the three months ended June 30, 2018. The Corporation recognized a deferred income tax recovery of $34 million for the six months ended June 30, 2019 and a deferred income tax recovery of $75 million for the six months ended June 30, 2018.

The Corporation's effective tax rate on earnings is impacted by the following significant differences:

- The permanent difference due to the non-taxable portion of realized and unrealized foreign exchange gains and losses arising on the translation of the U.S. dollar denominated debt. For the three months ended June 30, 2019, the non-taxable gain was $37 million compared to a non-taxable loss of $34 million for the three months ended June 30, 2018.

- Non-taxable stock-based compensation expense for equity-settled plans is a permanent difference. Stock-based compensation expense for equity-settled plans for the three months ended June 30, 2019 was $11 million compared to $4 million for the three months ended June 30, 2018.

- During the three months ended June 30, 2019, the Government of Alberta enacted legislation to reduce the corporate tax rate from 12% to 8% by January 1, 2022. As a result, the Corporation recognized a one-time deferred income tax expense of $34 million associated with the rate reduction, as the rate change reduced the value of the Corporation's deferred tax asset as at June 30, 2019.

As at June 30, 2019, the Corporation recognized a deferred income tax asset of $266 million. Estimated future taxable income is expected to be sufficient to realize the deferred income tax asset.

As at June 30, 2019, the Corporation had not recognized the tax benefit related to $358 million of realized and unrealized taxable foreign exchange losses.

7. LIQUIDITY AND CAPITAL RESOURCES

($000)	June 30, 2019	December 31, 2018
Cash and cash equivalents	**$ 399,212**	$ 317,704
First Lien:		
Senior secured term loan (June 30, 2019 – US$219.2 million; due 2023; December 31, 2018 – US$225.4 million)	**286,971**	307,552
US$1.4 billion revolving credit facility (due 2021)	**—**	—
Second Lien:		
6.5% senior secured second lien notes (US$750.0 million; due 2025)	**981,825**	1,023,413
Unsecured:		
6.375% senior unsecured notes (US$800.0 million; due 2023)	**1,047,280**	1,091,640
7.0% senior unsecured notes (US$1.0 billion; due 2024)	**1,309,100**	1,364,550
Total debt(1)	**$ 3,625,176**	$ 3,787,155

(1) The non-GAAP measure of total debt is reconciled to long-term debt in accordance with IFRS under the heading "NON-GAAP MEASURES" and discussed further in the "ADVISORY" section.

Capital Resources

As at June 30, 2019, all of the Corporation's long-term debt was denominated in U.S. dollars. Total debt decreased by C$162 million to C$3.6 billion as at June 30, 2019 from C$3.8 billion as at December 31, 2018, primarily as a result of the increase in value of the Canadian dollar relative to the U.S. dollar.

The Corporation's cash and cash equivalents balance was $399 million as at June 30, 2019 compared to $318 million as at December 31, 2018. As at June 30, 2019, no amount had been drawn under the Corporation's US$1.4 billion revolving credit facility.

As at June 30, 2019, the Corporation's letter of credit facility, guaranteed by Export Development Canada ("EDC Facility"), had a limit of US$440 million. Letters of credit under this facility do not consume capacity of the revolving credit facility. As at June 30, 2019, the Corporation had US$170.0 million of unutilized capacity under this facility.

On July 30, 2019, the Corporation repaid the outstanding senior secured term loan balance of US$219 million. The Corporation expects to continue to repay outstanding indebtedness as free cash flow becomes available. Interest savings resulting from the repayment of the senior secured term loan are expected to be approximately C$18 million annually.

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. The reduction of the total available credit is expected to reduce fees going forward by approximately C$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 50%. If drawn in excess of 50%, or $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.

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.

The objectives of the Corporation's investment guidelines for surplus cash are to ensure preservation of capital and to maintain adequate liquidity to meet the Corporation’s cash flow requirements. The Corporation only places surplus cash investments with counterparties that have a short term credit rating of R-1 (high) or equivalent. The Corporation has experienced no material loss or lack of access to its cash in operating accounts, invested cash or cash equivalents. However, the Corporation can provide no assurance that access to its invested cash and cash equivalents will not be impacted by adverse conditions in the financial markets. While the Corporation monitors the cash balances in its operating and investment accounts according to its investment practices and adjusts the cash balances as appropriate, these cash balances could be impacted if the underlying financial institutions or corporations fail or are subject to other adverse conditions in the financial markets.

Risk Management

Commodity Price Risk Management

Fluctuations in market conditions and commodity prices can impact the Corporation’s financial performance, operating results, cash flows, expansion and growth opportunities, access to funding and the cost of borrowing. 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's commodity risk management program is approved by the Board of Directors annually and is governed by a Risk Management Committee that follows the approved guidelines and limits. The Corporation does not use financial derivatives for speculative purposes.

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 June 30, 2019:

As at June 30, 2019	Volumes (bbls/d)[1]	Term	Average Price (US$/bbl)[1]
Crude Oil Sales Contracts			
WTI Fixed Price	44,146	Jul 1, 2019 - Dec 31, 2019	$63.01
WTI Fixed Price	16,989	Jan 1, 2020 - Dec 31, 2020	$59.56
WTI:WCS Fixed Differential	57,050	Jul 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	Jul 1, 2019 - Dec 31, 2019	$(7.56)
WTI:Mont Belvieu Fixed Differential	7,250	Jan 1, 2020 - Dec 31, 2020	$(7.63)
Mont Belvieu Fixed % of WTI	9,750	Jul 1, 2019 - Dec 31, 2019	92.2 %
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 operating cash flow, 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 June 30, 2019:

Commodity	Sensitivity Range	Increase	Decrease
Crude oil commodity price	± US$1.00 per bbl applied to WTI contracts	**$ (18,702)**	**$ 18,702**
Crude oil differential price[1]	± US$1.00 per bbl applied to WTI:WCS differential contracts	**$ 21,887**	**$ (21,887)**

(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 June 30, 2019:

As at June 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	13,386	Jul 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	35.8	Jul 1, 2019 - Dec 31, 2019	$58.67
Gas Purchases Contracts	**(Mcf/d)**		**(C$/Mcf)**
Fixed Price Gas Purchases	29,778	Jul 1, 2019 - Dec 31, 2019	$1.66
Propane Purchases Contracts	**(M^3/d)**		**(C$/$M^3$)**
Fixed Price Propane Purchases	158	Jul 1, 2019 - Dec 31, 2019	$134.12

(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 July 1, 2019 and July 30, 2019:

Subsequent to June 30, 2019	Volumes (bbls/d)[1]	Term	Average Prices (US$/bbl)[1]
Crude Oil Sales Contracts			
WTI Fixed Price	5,322	Jul 1, 2019 - Sep 30, 2019	$58.14
WTI Fixed Price	10,054	Oct 1, 2019 - Dec 31, 2019	$60.00
WTI:WCS Fixed Differential	2,000	Sep 1, 2019 - Sep 30, 2019	$(16.85)

(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.*

Interest Rate Risk Management

The Corporation is exposed to interest rate cash flow risk on its floating rate long-term debt and periodically enters into interest rate swap contracts to manage its floating to fixed interest rate mix. In the third quarter of 2017, the Corporation entered into an interest rate swap contract to effectively fix the interest rate at approximately 5.3% on US$650 million of its US$1.2 billion senior secured term loan. In the first quarter of 2018, the Corporation completed the sale of its 50% interest in the Access Pipeline and its 100% interest in the Stonefell Terminal. A majority of the net cash proceeds were used to repay approximately C$1.2 billion of the Corporation's senior secured term loan. As a result, the Corporation terminated its interest rate swap contract and realized a gain of $17.3 million for the six months ended June 30, 2018. The Corporation did not have any outstanding interest rate swap contracts as at June 30, 2019 and June 30, 2018.

Cash Flow Summary

	Three months ended June 30		Six months ended June 30	
($000)	**2019**	**2018**	**2019**	**2018**
Net cash provided by (used in):				
Operating activities	**$ 301,941**	$ 65,243	**$ 232,212**	$ 183,269
Investing activities	**(40,452)**	(178,156)	**(124,090)**	1,189,846
Financing activities	**(9,281)**	(3,150)	**(16,832)**	(1,275,925)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency	**(7,076)**	4,916	**(9,782)**	3,248
Change in cash and cash equivalents	**$ 245,132**	$ (111,147)	**$ 81,508**	$ 100,438

Cash Flow – Operating Activities

Net cash provided by operating activities totaled $302 million for the three months ended June 30, 2019 compared to $65 million for the three months ended June 30, 2018. Net cash provided by operating activities totaled $232 million for the six months ended June 30, 2019 compared to $183 million for the six months ended June 30, 2018. The increases in net cash provided by operating activities for the three and six months ended June 30, 2019 are primarily due to higher blend sales revenue, as a result of the increase in average realized blend price combined with an increase in blend sales volumes.

Cash Flow – Investing Activities

Net cash used in investing activities was $40 million for the three months ended June 30, 2019 compared to $178 million for the three months ended June 30, 2018. The decrease in net cash used in investing activities is primarily due to reduced capital spending activity during the second quarter of 2019 as well as the receipt of cash proceeds of

$5 million, related to the sale of exploration and evaluation assets, which contributes to the decrease in net cash use. This compares to the second quarter of 2018 when there was an increase in capital spending activity directed toward growth initiatives at Christina Lake Phase 2B and sustaining capital activities which included costs associated with the planned turnaround at the Christina Lake project.

Net cash used in investing activities was $124 million for the six months ended June 30, 2019 compared to net cash provided by investing activities of $1 billion for the six months ended June 30, 2018. Net cash used in investing activities for the six months ended June 30, 2019 reflects reduced capital spending activity, offset by 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, offset by increased capital spending activity.

Cash Flow – Financing Activities

Net cash used in financing activities was $9 million for the three months ended June 30, 2019 compared to net cash used in financing activities of $3 million for the three months ended June 30, 2018. Net cash used in financing activities for the three months ended June 30, 2019 included a quarterly debt repayment of $4 million 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 June 30, 2018 included a quarterly debt repayment of $4 million.

Net cash used in financing activities was $17 million for the six months ended June 30, 2019 compared to net cash used in financing activities of $1 billion for the six months ended June 30, 2018. Net cash used in financing activities for the six months ended June 30, 2019 included quarterly debt repayments of $8 million and payments on leased liabilities of $9 million, which have been reclassified from operating activities following the adoption of IFRS 16. Net cash used in financing activities for the six months ended June 30, 2018 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 June 30, 2019, the Corporation had the following share capital instruments outstanding or exercisable:

(000)	Units
Common shares	**299,207**
Convertible securities	
Stock options[1]	**7,700**
Equity-settled RSUs and PSUs	**6,635**

(1) *6.2 million stock options were exercisable as at June 30, 2019.*

As at July 26, 2019, the Corporation had 299.2 million common shares, 7.7 million stock options and 6.6 million equity-settled restricted share units and equity-settled performance share units outstanding, and 6.2 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 June 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.

($000)		2019		2020		2021		2022		2023		Thereafter		Total
Transportation and storage(1)	$	173,024	$	376,437	$	416,112	$	421,408	$	439,021	$	6,260,994	$	8,086,996
Long-term debt(2)		8,084		16,167		16,167		16,167		1,277,665		2,290,926		3,625,176
Interest on long-term debt(2)		126,170		238,180		237,234		236,289		173,079		92,046		1,102,998
Decommissioning obligation(3)		2,005		5,325		2,391		3,085		3,085		714,122		730,013
Diluent purchases		194,531		122,040		20,671		20,671		17,216		—		375,129
Office lease rentals		13,225		21,879		21,614		20,778		18,160		135,544		231,200
Other commitments(4)		9,008		14,711		11,081		9,211		9,222		49,574		102,807
Total	**$**	**526,047**	**$**	**794,739**	**$**	**725,270**	**$**	**727,609**	**$**	**1,937,448**	**$**	**9,543,206**	**$**	**14,254,319**

(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 term loan, the senior secured second lien notes, the senior unsecured notes, and associated interest payments based on interest and foreign exchange rates in effect on June 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, and the recent amendments, 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

Certain financial measures in this MD&A including: funds flow from (used in) operations, adjusted funds flow, operating cash flow, cash operating netback and total debt 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.

Funds Flow From (Used in) Operations and Adjusted Funds Flow

Funds flow from (used in) operations and adjusted funds flow are non-GAAP measures utilized by the Corporation to analyze operating performance and liquidity. Funds flow from (used in) operations excludes the net change in non-cash operating working capital while the IFRS measurement "net cash provided by (used in) operating activities" includes these items. Adjusted funds flow excludes the net change in non-cash operating working capital, realized gain on foreign exchange derivatives not considered part of ordinary continuing operating results, payments on onerous contracts and decommissioning expenditures, while the IFRS measurement "net cash provided by (used in) operating activities" includes these items. Funds flow from (used in) operations and adjusted funds flow are not intended to represent net cash provided by (used in) operating activities calculated in accordance with IFRS. Funds flow from (used in) operations and adjusted funds flow are reconciled to net cash provided by (used in) operating activities in the table below.

	Three months ended June 30		Six months ended June 30	
($000)	2019	2018	2019	2018
Net cash provided by (used in) operating activities	$ 301,941	$ 65,243	$ 232,212	$ 183,269
Net change in non-cash operating working capital items	(75,044)	(51,836)	145,243	(59,972)
Funds flow from (used in) operations	226,897	13,407	377,455	123,297
Adjustments:				
Realized gain on foreign exchange derivatives[1]	—	—	—	(35,362)
Payments on onerous contracts	—	4,236	—	10,244
Decommissioning expenditures	65	750	441	3,371
Adjusted funds flow	$ 226,962	$ 18,393	$ 377,896	$ 101,550

(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.

Operating Cash Flow and Cash Operating Netback

Operating cash flow 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 investments. The Corporation's operating cash flow is calculated by deducting the related diluent expense, blend purchases, transportation and storage, third-party curtailment credits, operating expenses, royalties and realized commodity risk management gains or losses from proprietary blend sales revenue and power revenue. The per-unit calculation of operating cash flow, defined as cash operating netback, is calculated by deducting the related diluent expense, blend purchases, transportation and storage, third-party curtailment credits, operating expenses, royalties and realized commodity risk management gains or losses from proprietary blend revenue and power revenue, on a per barrel of bitumen sales volume basis.

Total Debt

Total debt is a non-GAAP measure which is used by the Corporation to analyze leverage and liquidity. The Corporation's total debt is defined as long-term debt as reported, the current portion of the senior secured term loan, the unamortized financial derivative liability discount, and the unamortized deferred debt discount and debt issue costs. Total debt is reconciled to long-term debt in the table below.

($000)	June 30, 2019	December 31, 2018
Long-term debt	$ 3,582,428	$ 3,740,150
Adjustments:		
Current portion of senior secured term loan	16,167	16,852
Unamortized financial derivative liability discount	—	1,267
Unamortized deferred debt discount and debt issue costs	26,581	28,886
Total debt	$ 3,625,176	$ 3,787,155

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	$ 6,645,224		$ 17,418	$ 41,607	$ 6,704,249
Other assets	210,628	19,164			229,792
Deferred income tax asset	236,578	(5,174)		773	232,177
Liabilities					
Provisions and other liabilities	(293,817)		(17,418)	(44,469)	(355,704)
Shareholders' Equity					
Deficit	1,750,653	(13,990)		2,089	1,738,752
	$ 8,549,266	**$ —**	**$ —**	**$ —**	**$ 8,549,266**

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, 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 investments; 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 investments; 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; outlook for regulatory approval timelines for the Surmont Project; 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; 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 disposition 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 Annual Information Form ("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 focused on sustainable in situ thermal oil development and production in the southern Athabasca region of Alberta, Canada. The Corporation is actively developing enhanced thermal oil recovery projects that utilize SAGD extraction methods. 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 including: funds flow from (used in) operations, adjusted funds flow, operating cash flow, cash operating netback and total debt. As such, these measures are considered non-GAAP financial 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. These measures are 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 each 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	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**
FINANCIAL ($000 unless specified)								
Net earnings (loss)	**(63,693)**	(47,528)	(199,360)	118,160	(178,570)	140,573	(23,779)	83,885
Per share, diluted	**(0.21)**	(0.16)	(0.67)	0.39	(0.61)	0.47	(0.08)	0.28
Adjusted funds flow	**226,962**	150,898	(37,562)	115,742	18,393	83,157	192,178	83,352
Per share, diluted	**0.76**	0.50	(0.13)	0.39	0.06	0.28	0.65	0.28
Cash capital investment	**31,859**	53,293	144,006	144,508	182,567	147,739	163,337	103,173
Cash and cash equivalents	**399,212**	154,080	317,704	372,550	563,969	675,116	463,531	397,598
Working capital	**416,375**	174,528	289,755	274,344	211,045	445,792	313,025	350,067
Long-term debt	**3,582,428**	3,659,547	3,740,150	3,543,587	3,606,765	3,542,763	4,668,267	4,635,740
Shareholders' equity	**3,795,390**	3,850,502	3,885,538	4,068,048	3,945,782	4,112,531	3,964,113	3,981,750
BUSINESS ENVIRONMENT								
WTI (US$/bbl)	**59.82**	54.90	58.81	69.50	67.88	62.87	55.40	48.21
Differential – WTI:WCS – Edmonton (US$/bbl)	**(10.67)**	(12.29)	(39.43)	(22.25)	(19.27)	(24.28)	(12.26)	(9.94)
Differential – WCS:AWB – Edmonton (US$/bbl)	**(1.65)**	(2.21)	(5.17)	(3.44)	(2.94)	(3.17)	(2.30)	(1.89)
AWB – Edmonton (US$/bbl)	**47.50**	40.40	14.21	43.81	45.67	35.42	40.84	36.38
Differential – WTI:AWB – U.S. Gulf Coast (US$/bbl)	**1.64**	(0.89)	(6.25)	(5.63)	(7.83)	(7.00)	(5.48)	(6.61)
AWB – U.S. Gulf Coast (US$/bbl)	**61.46**	54.01	52.56	63.87	60.05	55.87	49.92	41.60
C$ equivalent of 1US$ – average	**1.3376**	1.3293	1.3215	1.3070	1.2911	1.2651	1.2717	1.2524
Natural gas – AECO ($/mcf)	**1.12**	2.86	1.70	1.28	1.26	2.26	1.84	1.58
OPERATIONAL ($/bbl unless specified)								
Blend sales, net of purchased product – bbls/d	**137,120**	132,377	126,750	130,823	108,237	135,701	135,533	107,600
Diluent usage – bbls/d	**(42,000)**	(42,555)	(38,467)	(36,967)	(33,819)	(44,093)	(40,992)	(30,787)
Bitumen sales – bbls/d	**95,120**	89,822	88,283	93,856	74,418	91,608	94,541	76,813
Bitumen production – bbls/d	**97,288**	87,113	87,582	98,751	71,325	93,207	90,228	83,008
Steam-oil ratio (SOR)	**2.2**	2.2	2.2	2.2	2.2	2.2	2.2	2.3
Blend sales price	**69.19**	59.02	37.76	63.68	62.41	51.20	56.81	48.09
Bitumen realization	**62.23**	50.21	15.31	49.63	47.33	35.46	48.01	39.93
Transportation and storage – net	**(10.80)**	(11.27)	(10.28)	(9.11)	(8.28)	(5.99)	(7.00)	(7.08)
Third-party curtailment credits	**(0.89)**	—	—	—	—	—	—	—
Royalties	**(2.06)**	(0.37)	(0.15)	(2.01)	(1.64)	(1.03)	(0.84)	(0.53)
Operating costs – non-energy	**(4.53)**	(5.22)	(4.25)	(4.38)	(5.47)	(4.55)	(4.53)	(4.57)
Operating costs – energy	**(1.78)**	(3.36)	(1.98)	(1.50)	(1.79)	(2.64)	(2.03)	(2.26)
Power revenue	**1.65**	2.41	1.68	1.54	1.62	1.21	0.70	0.83
Realized gain (loss) on commodity risk management	**(5.94)**	(2.60)	6.81	(10.16)	(13.11)	(2.15)	(0.77)	0.56
Cash operating netback	**37.88**	29.80	7.14	24.01	18.66	20.31	33.54	26.88
Power sales price (C$/MWh)	**55.33**	70.83	55.38	51.53	51.02	35.50	21.37	23.29
Power sales (MW/h)	**118**	128	111	117	98	130	129	115
Depletion and depreciation rate per bbl of production	**41.22**	14.68	13.79	13.85	16.08	13.22	14.26	16.86
COMMON SHARES								
Shares outstanding, end of period (000)	**299,207**	296,857	296,841	296,813	296,751	294,105	294,104	294,079
Volume traded (000)	**163,295**	191,935	151,873	128,363	166,016	89,721	76,531	70,216
Common share price ($)								
High	**6.79**	8.62	11.70	11.51	11.24	6.43	6.82	5.79
Low	**4.06**	4.75	7.25	6.78	4.49	4.28	4.54	3.28
Close (end of period)	**5.02**	5.10	7.71	8.03	10.96	4.55	5.14	5.49

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.

Cash capital investment has decreased consistently from 2017 to 2019. The decrease in capital spending, particularly in the first two quarters of 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.