THIRD QUARTER 2018

Report to Shareholders for the period ended September 30, 2018

MEG Energy Corp. reported third quarter 2018 operating and financial results on November 1, 2018. Highlights include:

- Record quarterly bitumen production volumes of 98,751 barrels per day (bpd) and low steam-oil-ratio (SOR) of 2.2. Annual production is well on-track to achieve 2018 guidance of 87,000 to 90,000 bpd;
- Record low per barrel net operating costs of $4.34, including low non-energy operating costs of $4.38 per barrel;
- Strong adjusted funds flow from operations of $116 million or $0.39 per share, including $88 million of realized net hedging losses. Adjusted funds flow from operations excluding realized net hedging losses totalled $0.68 per share;
- Total cash capital investment of $145 million in the quarter, primarily directed to advance the Phase 2B Brownfield expansion and eMVAPEX pilot;
- Cash and cash equivalents of $373 million; MEG's covenant-lite US$1.4 billion facility remains undrawn;
- Subsequent to the quarter, MEG executed a binding agreement to access 30,000 bpd of unit train rail loading capacity at the Bruderheim terminal, operated by Cenovus. The term of this agreement is for three years, with a one-year extension at MEG's option; and
- On October 17, 2018, MEG announced that its Board of Directors (the "MEG Board") unanimously rejected Husky Energy's unsolicited bid to acquire the Company and recommended MEG shareholders **NOT** tender their shares.

"The MEG of today is more robust on every measure. We are entering an exciting period of greater financial strength and flexibility, as the Company reaches a critical inflection point transforming from a net consumer of cash to a generator of significant cash flow, well in excess of future capital investment requirements. Through our world-class asset base and industry-leading technology, the Board and Management remain committed to maximizing value for our shareholders," says Derek Evans, President and Chief Executive Officer.

"The record high production and record low net operating costs per barrel in the third quarter reflects the successful application of MEG's proprietary eMSAGP technology on existing wells at Christina Lake Phase 2B. The spending on this phase of the roll-out was substantially completed during the quarter, with lower than expected total costs of $320 million or $16,000 per flowing barrel," Evans continued. "Our innovative approach to maximizing the value of our steam and achieving among the best-in-class SORs through the application of eMSAGP and eMVAPEX supports our highly efficient capital re-investment, industry-leading cost structure, and enhanced environmental performance. MEG has a pipeline of execution-ready brownfield projects with the potential to double production in the next 10 years."

Third quarter bitumen production averaged a record 98,751 bpd, a 19% increase relative to the same period in 2017. This strong production growth was achieved as new wells were brought on-stream as part of the Phase 2B eMSAGP implementation. Trending lower for the eighth consecutive quarter, net operating costs per barrel were 28% lower than the third quarter of 2017. The low per barrel net operating costs were supported by higher production volumes, low natural gas prices and strong power revenues.

Pricing and Market Access

MEG achieved strong blend sales realizations of $63.67 per barrel in the third quarter of 2018, 33% higher than the third quarter of 2017. The higher blend sales realization was the result of stronger benchmark crude oil prices, partially offset by wider WTI:WCS differentials in the period. MEG's bitumen realization averaged $49.58 per barrel, 24% higher than the third quarter of 2017.

"MEG's diversified marketing strategy allowed the Company to deliver 31% of blend sales into the premium U.S. Gulf Coast market during the third quarter, where the barrels received a pricing uplift of approximately $15 per barrel (net of transportation), relative to sales in the Edmonton market. As a result of this strategy, lower-priced post-apportionment blend sales have been limited to 13% of volumes during the third quarter," said Evans.

During the third quarter MEG doubled rail volumes to 7,800 bpd, with plans to rail approximately 15,000 bpd in the fourth quarter and up to 30,000 bpd by the end of the first quarter of 2019. Subsequent to the quarter, MEG executed a binding agreement at competitive market rates to access 30,000 bpd of unit train rail loading capacity at the Bruderheim terminal, operated by Cenovus. The term of this agreement is for three years, with a one-year extension at MEG's option. As a mechanism to clear barrels during periods of high pipeline apportionment and reduce exposure to the post-apportionment market, the use of rail enables MEG to maximize the price received on its barrels until additional egress capacity from Western Canada is secured. MEG's strategic network of North American storage facilities was also used during the third quarter to mitigate differential and apportionment exposure as MEG put barrels into storage.

Transportation costs per barrel for the third quarter of 2018 were 29% higher than the third quarter of 2017. The higher transportation costs reflect the sale of the Company's 50% share in the Access Pipeline and 100% of Stonefell Terminal, as well as higher per barrel costs associated with the increased use of rail.

"Although differentials are expected to remain challenging in the fourth quarter, we anticipate them to moderate in 2019 as Canadian rail export volumes increase significantly and PADD II refineries come back on line after what has been the largest heavy oil planned turnaround season in the last five years," added Evans. "In addition, to partially mitigate the financial impact of wider forecasted differentials, MEG plans to reduce its fourth quarter production by 4,000 to 6,000 bpd through advancing a portion of our 2019 scheduled maintenance program into November. Further, we can vary the pace of ramp-up subsequent to the turnaround depending on market conditions. We do not currently anticipate any impact to our previously announced 2018 annual guidance."

Capital Investment

Total cash capital investment in the quarter was $145 million. The largest area of spending was on the Phase 2B Brownfield expansion, with construction proceeding on-schedule and on-budget. Completion and ramp-up of the project is anticipated in the second half of 2019, bringing total expected production to 113,000 bpd by the end of 2019. Spending on the current application of eMSAGP on Phase 2B was substantially completed in the quarter. Additionally, the Company invested $14 million on the eMVAPEX pilot, including spending on the propane recycling unit, which is expected to be fully operational in the fourth quarter of this year.

Adjusted Funds Flow and Operating Loss

Adjusted funds flow from operations were $116 million in the third quarter of 2018, compared to $83 million in the third quarter of 2017. The 40% increase reflects stronger benchmark crude oil prices and higher sales volumes, partially offset by realized net losses on commodity risk management contracts totaling approximately $88 million. With current cash reserves, higher commodity prices and lower anticipated levels of capital spending in 2019, MEG expects to hedge a substantially lower percentage of barrels in 2019.

The Company recognized an operating loss of $19 million in the third quarter of 2018, compared to an operating loss of $43 million for the same period of 2017. The decrease in the operating loss is primarily the result of higher bitumen realizations, partially offset by realized losses on commodity risk management contracts.

Take-Over Offer from Husky

On October 2, 2018, Husky Energy Inc. ("Husky") made a formal offer to acquire all of the issued and outstanding common shares of MEG, at the election of each MEG shareholder, for (i) $11.00 in cash or (ii) 0.485 of a common share ("Husky Share") of Husky for each MEG common share, subject to a maximum aggregate cash consideration of $1 billion and a maximum aggregate number of Husky Shares of approximately 107 million (the "Husky Offer"). The Husky Offer must remain open until January 16, 2019 unless otherwise extended, accelerated or withdrawn in accordance with its terms. Based upon the closing price of the Husky Shares on the TSX on October 31, 2018, the current value of the Husky Offer is approximately $9.61 per MEG common share as implied by the exchange ratio.

Upon receipt of the Husky Offer, the MEG Board, operating through a Special Committee, engaged with financial and legal advisors to diligently review the Husky Offer. The MEG Board, on the recommendation of the Special Committee, has unanimously concluded that the Husky Offer significantly undervalues the Company and is not in the best interests of MEG or its shareholders. The MEG Board unanimously recommends that MEG shareholders reject the Husky Offer and not tender their common shares to the Husky Offer. No action is required to reject the Husky Offer.

The Directors' Circular, filed on October 17, 2018 by the Board, provides information for MEG shareholders about the Company's prospects and the MEG Board's analysis, deliberations and recommendations. The Directors' Circular is available at www.megenergy.com/RejectHusky and at www.sedar.com. Additional information can be found in the Investor Presentation, which is also available at www.megenergy.com/RejectHusky.

In its Directors' Circular, the Board describes the reasons for its recommendations. Among other things, the Board notes:

- MEG's stand-alone plan is worth substantially more than the value proposed to be delivered by Husky in the Husky Offer.
- The timing of the Husky Offer is opportunistic and was timed to deny MEG Shareholders the opportunity to fully evaluate the plans, and experience the value creation of MEG's new CEO, Mr. Evans.
- In addition to being financially inadequate, the form of consideration offered in the Husky Offer is disadvantageous to MEG Shareholders.
- As the Husky Offer is presently structured, Husky's existing owners are receiving the lion's share of the benefits of the combination, many of which Husky has not even acknowledged.

The Special Committee has given its financial advisor, BMO Capital Markets, a mandate to investigate alternative transactions to the Husky Offer. A data room containing confidential information about MEG has been created to help interested parties establish the true value of the Company. MEG will not be providing additional information to the market on the status of the strategic alternatives process until MEG has material developments to disclose.

Forward-Looking Information and Non-GAAP Financial Measures

This quarterly report contains forward-looking information and financial measures that are not defined by International Financial Reporting Standards ("IFRS") and should be read in conjunction with the "Forward-Looking Information" and "Non-GAAP Financial Measures" contained within the Advisory sections of this quarter's Management's Discussion and Analysis and Press Release.

MEG ENERGY

Management's Discussion and Analysis

This Management's Discussion and Analysis ("MD&A") of the financial condition and performance of MEG Energy Corp. ("MEG" or the "Corporation") for the three and nine month periods ended September 30, 2018 was approved by the Corporation's Audit Committee on October 31, 2018. This MD&A should be read in conjunction with the Corporation's unaudited interim consolidated financial statements and notes thereto for the three and nine month periods ended September 30, 2018, the audited annual consolidated financial statements and notes thereto for the year ended December 31, 2017, the 2017 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.

MD&A - Table of Contents

1. BUSINESS DESCRIPTION

MEG is an oil sands company focused on sustainable *in situ* oil sands development and production in the southern Athabasca oil sands region of Alberta, Canada. MEG is actively developing enhanced oil recovery projects that utilize well-established steam-assisted gravity drainage ("SAGD") extraction methods and the application of new MEG proprietary technologies involving the co-injection of non-condensible gas or light hydrocarbons to reduce steam requirements and enhance process efficiency and environmental performance. MEG is not engaged in oil sands mining.

MEG owns a 100% working interest in over 900 square miles of oil sands leases. For information regarding MEG's estimated reserves contained in the GLJ Petroleum Consultants Ltd. Report ("GLJ Report"), please refer to the Corporation's most recently filed Annual Information Form ("AIF"), which is available on the Corporation's website at www.megenergy.com and is also available on the SEDAR website at www.sedar.com.

The Corporation has identified three commercial SAGD projects in various stages of advancement: the Christina Lake Project, the Surmont Project and the May River Regional Project. The Christina Lake Project is under development having received regulatory approval for 210,000 barrels per day ("bbls/d") of bitumen production and is currently producing approximately 100,000 bbls/d in three initial phases.

MEG has applied for regulatory approval for approximately 123,000 bbls/d of bitumen production at the Surmont Project. The Surmont Project is located approximately 30 miles north of the Corporation's Christina Lake Project, and is situated along the same geological trend as the Christina Lake Project. The Corporation is actively pursuing regulatory approval of the Surmont Project, which is currently anticipated in late 2018 or early 2019.

On February 21, 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. In addition, the Corporation holds other leases known as the "Growth Properties." The Growth Properties are in the resource definition and data gathering stage of development.

The Corporation's first two production phases at the Christina Lake Project, Phase 1 and Phase 2, commenced production in 2008 and 2009, respectively. In 2012, the Corporation announced the RISER initiative, which is a combination of proprietary reservoir technologies, including enhanced Modified Steam And Gas Push ("eMSAGP") involving co-injection of non-condensible gas and redeployment of steam together with facilities modifications, including debottlenecking and brownfield expansions (collectively "RISER"). Phase 2B commenced production in 2013. To further enhance production, the Corporation is testing its proprietary recovery process known as enhanced Modified VAPour EXtraction ("eMVAPEX") at the Christina Lake project, which involves the targeted injection of light hydrocarbons in replacement of steam. Bitumen production at the Christina Lake Project for the year ended December 31, 2017 averaged 80,774 bbls/d. The average steam-oil ratio ("SOR"), a key measure of process efficiency, is currently approximately 2.2 for the Christina Lake project, which at this low level is among the best-in-class in the industry. The ongoing application of eMSAGP and on-site cogeneration of electricity and steam have enabled MEG to lower its greenhouse gas intensity below the *in situ* industry average calculated based on reported data to Environment Canada, the Alberta Energy Regulator and the Alberta Electric System Operator. In those specific well patterns where the implementation of eMSAGP has already been deployed, the Corporation is currently experiencing a further enhancement of the SOR to approximately 1.3. MEG is currently continuing the process of implementing the RISER initiative, and specifically eMSAGP, to Phase 2B of the Christina Lake Project.

On January 27, 2017, MEG successfully completed a refinancing which extended the first maturity of any of the Corporation's outstanding long-term debt obligations to 2023.

On March 22, 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. The majority of the net cash proceeds were used to repay approximately C$1.2 billion of MEG's senior secured term loan. In addition, the Corporation increased its 2018 capital budget to fund approximately 70% of the Corporation's

13,000 bbls/d Phase 2B brownfield expansion in 2018. As part of the transaction, MEG entered into a Transportation Services Agreement ("TSA") dedicating MEG's Christina Lake production and condensate transport to the Access Pipeline for an initial term of 30 years. The transaction also includes a Stonefell Lease Agreement which is a 30-year arrangement that secures MEG's operational control and exclusive use of 100% of the Stonefell Terminal's 900,000-barrel blend and condensate storage facility.

2. OPERATIONAL AND FINANCIAL HIGHLIGHTS

Bitumen production for the third quarter of 2018 averaged 98,751 bbls/d, the highest quarterly production average in the Corporation's history. During the third quarter of 2018, MEG substantially completed the capital requirements for eMSAGP at the Christina Lake Project. The implementation of eMSAGP has improved reservoir efficiency by reducing SORs and allowed for the redeployment of steam, thereby enabling the Corporation to place additional wells into production.

During the third quarter of 2018, the Corporation's average blend sales price increased 33% compared to the same period in 2017. The higher blend sales price is due to the 44% increase in the average US$WTI price, which was partially offset by the significant widening of the WTI:WCS differential from US$9.94 per barrel in the third quarter of 2017 to US$22.25 per barrel in the third quarter of 2018. The widening of the differential is due to ongoing pipeline capacity constraints, increasing Western Canadian heavy oil production, insufficient rail transport capacity and seasonal refinery maintenance. MEG plans to mitigate exposure to the differential through increased use of rail and inventory management. In the third quarter of 2018, approximately 31% of blend volumes were sold at the U.S. Gulf Coast, including approximately 7,800 bbls/d that were transported by rail. Blend volumes sold into the U.S. Gulf Coast market received a pricing uplift of approximately C$15 per barrel, net of transportation, relative to sales in the Edmonton market.

The Corporation recognized a cash operating netback of $23.96 per barrel in the three months ended September 30, 2018, compared to $26.84 per barrel for the three months ended September 30, 2017. The cash operating netback includes a realized net loss on commodity risk management contracts of $87.7 million for the three months ended September 30, 2018, and a realized net gain of $4.0 million for the three months ended September 30, 2017. The Corporation's cash operating netback before realized gains and losses on commodity risk management was $34.12 per barrel in the three months ended September 30, 2018, compared to $26.28 per barrel for the same period in 2017. The increase is largely the result of stronger commodity prices, coupled with approximately 31% of blend volumes being sold into the U.S. Gulf Coast, where prices were much stronger than the Edmonton market.

Adjusted funds flow from operations increased to $115.7 million in the third quarter of 2018 compared to $83.4 million in the third quarter of 2017. The increase primarily reflects higher sales prices and increased sales volumes, which were partially offset by realized losses of $87.7 million on commodity risk management contracts. MEG's hedging philosophy over the last two years has been focused on protecting a portion of its capital program. With current cash reserves and higher commodity prices, the Corporation expects to hedge a substantially lower proportion of its barrels going forward.

The Corporation recognized net earnings of $118.2 million for the three months ended September 30, 2018 compared to net earnings of $83.9 million for the three months ended September 30, 2017. Net earnings for the three months ended September 30, 2018 included a net foreign exchange gain of $59.1 million and a gain on commodity risk management contracts of $20.2 million. In comparison, net earnings in the third quarter of 2017 included a net foreign exchange gain of $178.4 million and a loss on commodity risk management contracts of $53.5 million.

Total cash capital investment for the third quarter of 2018 was $144.5 million, an increase of $41.3 million compared to the same period of 2017, primarily as a result of increased investment in Phase 2B growth capital and sustaining capital activities at the Christina Lake Project.

At September 30, 2018 , the Corporation had cash and cash equivalents of $372.6 million and US$1.4 billion of undrawn capacity under the revolving credit facility.

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:

	Nine months ended September 30		2018			2017				2016
($ millions, except as indicated)	**2018**	**2017**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**
Bitumen production - bbls/d	**87,781**	77,588	**98,751**	71,325	93,207	90,228	83,008	72,448	77,245	81,780
Bitumen realization - $/bbl	**43.92**	39.17	**49.58**	47.20	35.31	48.30	39.89	39.66	37.93	36.17
Net operating costs - $/bbl(1)	**5.28**	7.26	**4.34**	5.64	5.98	5.86	6.00	7.42	8.43	8.24
Non-energy operating costs - $/bbl	**4.75**	4.66	**4.38**	5.47	4.55	4.53	4.57	4.23	5.20	4.99
Cash operating netback - $/bbl(2)	**21.09**	24.09	**23.96**	18.53	20.16	33.83	26.84	22.96	22.33	21.73
Adjusted funds flow from operations(3)	**217**	182	**116**	18	83	192	83	55	43	40
Per share, diluted(3)	**0.73**	0.63	**0.39**	0.06	0.28	0.65	0.28	0.19	0.16	0.18
Operating earnings (loss)(3)	**(107)**	(158)	**(19)**	(70)	(18)	44	(43)	(36)	(79)	(72)
Per share, diluted(3)	**(0.36)**	(0.55)	**(0.06)**	(0.24)	(0.06)	0.15	(0.14)	(0.12)	(0.29)	(0.32)
Revenue(4)	**2,213**	1,720	**803**	689	721	755	576	584	560	566
Net earnings (loss)	**80**	190	**118**	(179)	141	(1)	84	104	2	(305)
Per share, basic	**0.27**	0.66	**0.40**	(0.61)	0.48	0.00	0.29	0.36	0.01	(1.34)
Per share, diluted	**0.27**	0.66	**0.39**	(0.61)	0.47	0.00	0.28	0.35	0.01	(1.34)
Total cash capital investment	**475**	339	**145**	183	148	163	103	158	78	63
Cash and cash equivalents	**373**	398	**373**	564	675	464	398	512	549	156
Long-term debt	**3,544**	4,636	**3,544**	3,607	3,543	4,668	4,636	4,813	4,945	5,053

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

(2) *Cash operating netback is calculated by deducting the related diluent expense, blend purchases, transportation, operating expenses, royalties and realized commodity risk management gains (losses) from proprietary blend revenues and power revenues, on a per barrel of bitumen sales volume basis.*

(3) *Adjusted funds flow from (used in) operations, operating earnings (loss) and the related per share amounts do not have standardized meanings prescribed by IFRS and therefore may not be comparable to similar measures used by other companies. The non-GAAP measure of adjusted funds flow from (used in) operations is reconciled to net cash provided by (used in) operating activities and the non-GAAP measure of operating earnings (loss) is reconciled to net earnings (loss) in accordance with IFRS under the heading "NON-GAAP MEASURES" and discussed further 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. Prior quarters have been revised as applicable to reflect the new presentation.*

3. RESULTS OF OPERATIONS

Bitumen Production and Steam-Oil Ratio

	Three months ended September 30		Nine months ended September 30	
	2018	**2017**	**2018**	**2017**
Bitumen production – bbls/d	**98,751**	83,008	**87,781**	77,588
Steam-oil ratio (SOR)	**2.2**	2.3	**2.2**	2.3

Bitumen Production

Bitumen production at the Christina Lake Project averaged 98,751 bbls/d for the three months ended September 30, 2018, the highest quarterly production average in the Corporation's history. This compares to 83,008 bbls/d for the three months ended September 30, 2017. The increase in average production volumes for the three months ended September 30, 2018 is primarily due to the efficiency gains achieved through the continued implementation of eMSAGP at the Christina Lake Project, with capital spending on eMSAGP having been substantially completed in the third quarter of 2018. The implementation of eMSAGP has improved reservoir efficiency and allowed for the redeployment of steam, thereby enabling the Corporation to place additional wells into production. Production for the same period in 2017 was negatively affected by weather events at the Christina Lake Project.

Bitumen production for the nine months ended September 30, 2018 averaged 87,781 bbls/d compared to 77,588 bbls/d for the nine months ended September 30, 2017. The increase in average production volumes for the nine months ended September 30, 2018 is primarily due to the efficiency gains achieved through the continued implementation of eMSAGP at the Christina Lake Project. Production during both periods was impacted by turnaround activities, with the 2018 turnaround having a greater impact on production.

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 2.2 for the three and nine months ended September 30, 2018 compared to 2.3 for the three and nine months ended September 30, 2017.

Operating Cash Flow

	Three months ended September 30		Nine months ended September 30	
($000)	2018	2017	2018	2017
Petroleum revenue – proprietary[(1)]	**$ 775,964**	$ 506,151	**$ 2,073,556**	$ 1,497,754
Blend purchases[(2)]	**(9,937)**	(30,367)	**(69,597)**	(39,969)
Diluent expense	**(337,941)**	(193,897)	**(965,129)**	(653,409)
	428,086	281,887	**1,038,830**	804,376
Royalties	**(17,333)**	(3,745)	**(36,968)**	(15,313)
Transportation expense	**(81,128)**	(52,994)	**(193,323)**	(149,785)
Operating expenses	**(50,721)**	(48,222)	**(159,114)**	(165,146)
Power revenue	**13,332**	5,896	**34,256**	16,104
Transportation revenue	**2,470**	2,963	**9,199**	9,200
	294,706	185,785	**692,880**	499,436
Realized gain (loss) on commodity risk management	**(87,728)**	3,976	**(194,198)**	(4,601)
Operating cash flow[(3)]	**$ 206,978**	$ 189,761	**$ 498,682**	$ 494,835

(1) *Proprietary petroleum revenue represents MEG's revenue ("blend sales revenue") from its heavy crude oil blend known as Access Western Blend ("AWB" or "blend"). Blend is comprised of bitumen produced at the Christina Lake Project blended with purchased diluent.*

(2) *Effective January 1, 2018, blend purchases are presented on a gross basis as they represent separate performance obligations, as discussed in the "NEW ACCOUNTING STANDARDS" section of this MD&A.*

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

Operating cash flow was $207.0 million for the three months ended September 30, 2018 compared to $189.8 million for the three months ended September 30, 2017. The realized loss on commodity risk management of $87.7 million had a significant impact on operating cash flow. Before commodity risk management, operating cash flow increased by $108.9 million in the third quarter of 2018 compared to the same quarter of 2017. This is the result of a $269.8 million increase in blend sales revenue, partially offset by a $144.0 million increase in diluent expense. The increase in sales revenue was driven primarily by a 33% increase in the average blend sales price and a 15% increase in blend sales volumes. Diluent expense increased due to incremental condensate volumes required for blending purposes, as well as higher condensate benchmark prices.

Operating cash flow was $498.7 million for the nine months ended September 30, 2018 compared to $494.8 million for the nine months ended September 30, 2017. The realized loss on commodity risk management of $194.2 million had a significant impact on operating cash flow. Before the losses on commodity risk management, operating cash flow increased $193.4 million as a result of higher blend sales revenue, partially offset by higher diluent expense. The increase in blend sales revenue was primarily due to a 20% increase in the average blend sales price and a 15% increase in blend sales volumes. Diluent expense increased due to incremental condensate volumes required for blending purposes, as well as higher condensate benchmark prices.

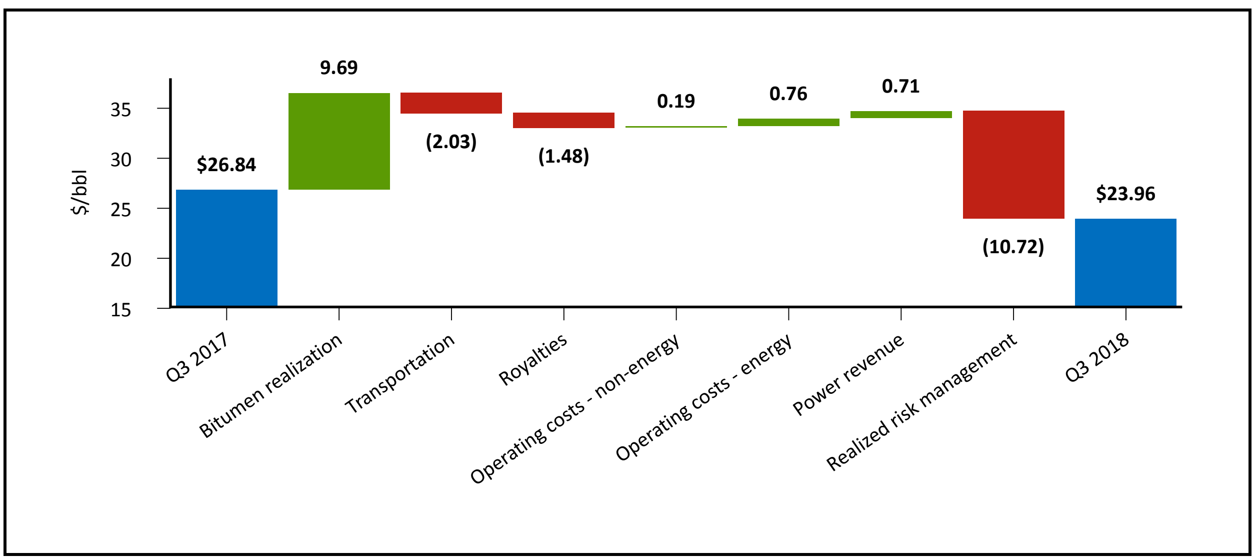
Cash Operating Netback

The following table summarizes the Corporation's per-unit calculation of operating cash flow, defined as cash operating netback, for the periods indicated:

	Three months ended September 30		Nine months ended September 30	
($/bbl)	**2018**	**2017**	**2018**	**2017**
Blend sales price[1]	**$ 63.67**	$ 47.93	**$ 58.80**	$ 48.84
Bitumen realization[2]	**$ 49.58**	$ 39.89	**$ 43.92**	$ 39.17
Transportation[3]	**(9.11)**	(7.08)	**(7.78)**	(6.85)
Royalties	**(2.01)**	(0.53)	**(1.56)**	(0.75)
	38.46	32.28	**34.58**	31.57
Operating costs – non-energy	**(4.38)**	(4.57)	**(4.75)**	(4.66)
Operating costs – energy	**(1.50)**	(2.26)	**(1.98)**	(3.38)
Power revenue	**1.54**	0.83	**1.45**	0.78
Net operating costs	**(4.34)**	(6.00)	**(5.28)**	(7.26)
Cash operating netback excluding realized commodity risk management	**34.12**	26.28	**29.30**	24.31
Realized gain (loss) on commodity risk management	**(10.16)**	0.56	**(8.21)**	(0.22)
Cash operating netback	**$ 23.96**	$ 26.84	**$ 21.09**	$ 24.09

(1) *Blend sales revenue on a per barrel of blend sales volume basis.*
(2) *Blend sales revenue net of blend purchases and diluent expense.*
(3) *Defined as transportation expense less transportation revenue. Transportation includes pipeline, rail and storage costs, net of third-party recoveries on diluent transportation arrangements.*

Cash Operating Netback - Three Months Ended September 30



Bitumen Realization

Bitumen realization represents the Corporation's realized proprietary petroleum revenue ("blend sales revenue"), net of blend purchases and diluent expense, expressed on a per barrel basis. Blend sales revenue represents MEG's revenue from its heavy crude oil blend known as Access Western Blend ("AWB" or "blend"). 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. A portion of diluent expense is effectively recovered in the sales price of the blended product. 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.

Bitumen realization averaged $49.58 per barrel for the three months ended September 30, 2018, compared to $39.89 for the three months ended September 30, 2017. The Corporation's average blend sales price increased 33%, to $63.67 per barrel in the third quarter of 2018 compared to $47.93 per barrel for the same period in 2017. The higher blend sales price was the result of stronger benchmark crude oil prices and higher sales prices at the U.S. Gulf coast, where approximately 31% of blend sales volumes were delivered, of which approximately 7,800 bbls/d were transported by rail. This was partially offset by the significant widening of the WTI:WCS differential by US$12.31 per barrel and an increase in average condensate benchmark pricing. For the three months ended September 30, 2018, the Corporation's cost of diluent was $99.37 per barrel of diluent compared to $68.46 per barrel of diluent for the three months ended September 30, 2017.

Transportation

The Corporation utilizes a network of pipelines, rail and storage facilities to optimize market access. Sales volumes destined for the U.S. Gulf Coast require additional transportation costs, but generally obtain higher sales prices.

On March 22, 2018, the Corporation successfully completed the sale of its 50% interest in the Access Pipeline and its 100% interest in the Stonefell Terminal. As part of the transaction, MEG entered into a Transportation Services Agreement ("TSA") dedicating MEG's Christina Lake production and condensate transport to the Access Pipeline for an initial term of 30 years.

During the three months ended September 30, 2018, transportation costs averaged $9.11 per barrel compared to $7.08 per barrel for the three months ended September 30, 2017. The increase in costs on a per barrel basis is primarily the result of incremental transportation costs associated with the TSA and additional costs associated with increased volumes transported by rail to the U.S. Gulf Coast.

Royalties

The Corporation's royalty expense is based on price-sensitive royalty rates set by the Government of Alberta. The applicable royalty rates change depending on whether a project is pre-payout or post-payout, with payout being defined as the point in time when a project has generated enough cumulative net revenues to recover its cumulative costs. The royalty rate applicable to pre-payout oil sands operations 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. All of the Corporation's projects are currently pre-payout.

Royalties averaged $2.01 per barrel during the three months ended September 30, 2018 compared to $0.53 per barrel for the three months ended September 30, 2017. The increase in royalties is primarily the result of higher WTI crude oil prices and higher sales volumes and revenue.

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. Energy operating costs reflect the cost of natural gas for the production of steam and power at the Corporation's facilities. Power revenue is the sale of surplus power generated by the Corporation's cogeneration facilities at the Christina Lake Project.

Net operating costs for the three months ended September 30, 2018 averaged $4.34 per barrel compared to $6.00 per barrel for the three months ended September 30, 2017. The decrease in net operating costs is primarily the result of a per barrel decrease in energy operating costs and an increase in per barrel power revenue.

Non-energy operating costs

Non-energy operating costs averaged $4.38 per barrel for the three months ended September 30, 2018 compared to $4.57 per barrel for the three months ended September 30, 2017. Additional production-related costs were more than offset by higher sales volumes for the three months ended September 30, 2018 compared to the same period in 2017.

Energy operating costs

Energy operating costs averaged $1.50 per barrel for the three months ended September 30, 2018 compared to $2.26 per barrel for the three months ended September 30, 2017. The decrease in energy operating costs is primarily attributable to lower natural gas prices. The Corporation's natural gas purchase price averaged $1.48 per mcf during the three months ended September 30, 2018 compared to $1.94 per mcf for the same period in 2017.

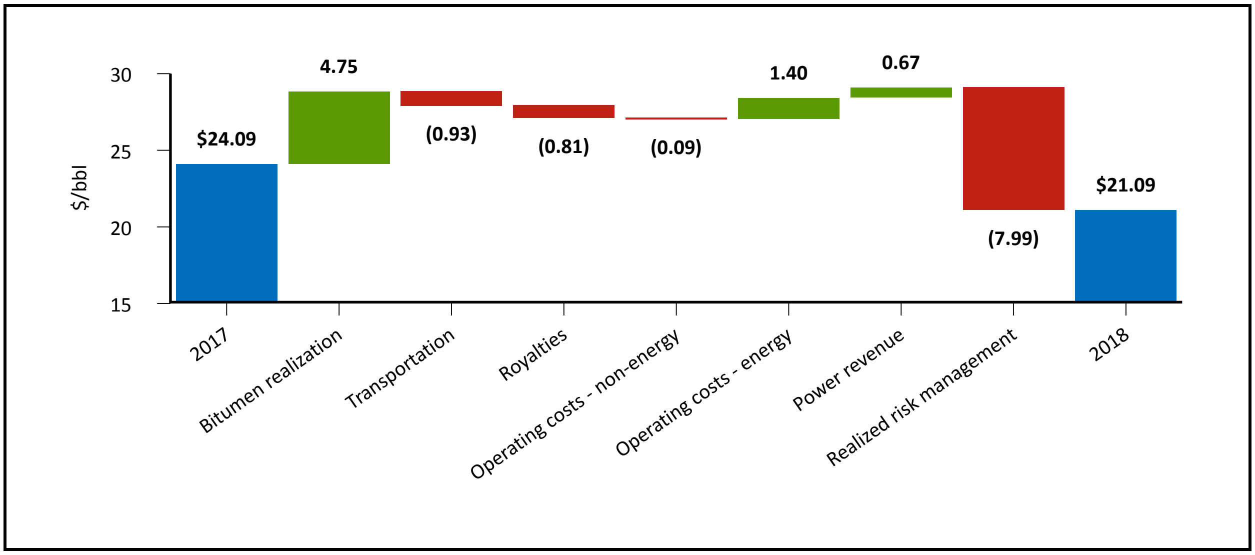
Power revenue

Power revenue averaged $1.54 per barrel for the three months ended September 30, 2018 compared to $0.83 per barrel for the three months ended September 30, 2017 . The Corporation's average realized power sales price increased to $51.53 per megawatt hour in the third quarter of 2018 from $23.29 per megawatt hour for the same period in 2017. The higher average realized price is attributable to Alberta power pool prices increasing due to the introduction of a higher carbon tax levy at the beginning of 2018 and the retirement and suspension of older coal-fired power plants in the province of Alberta.

Realized Gain or Loss on Commodity Risk Management

The Corporation has entered into financial commodity risk management contracts to protect a portion of its capital program. The realized loss on commodity risk management averaged $10.16 per barrel for the three months ended September 30, 2018 compared to a realized gain on commodity risk management of $0.56 per barrel for the three months ended September 30, 2017. The realized loss is primarily due to settlement 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 - Nine Months Ended September 30



Bitumen Realization

Bitumen realization averaged $43.92 per barrel for the nine months ended September 30, 2018, compared to $39.17 per barrel for the nine months ended September 30, 2017. The Corporation's average blend sales price increased 20%, to $58.80 per barrel for the nine months ended September 30, 2018 compared to $48.84 per barrel for the same period in 2017. The higher blend sales price was the result of stronger benchmark crude oil prices and higher sales prices at the U.S. Gulf coast, where approximately 29% of blend sales volumes were delivered. This was partially offset by the significant widening of the WTI:WCS differential by US$10.05 per barrel and an increase in average condensate benchmark pricing. For the nine months ended September 30, 2018, the Corporation's cost of diluent was $92.37 per barrel of diluent compared to $70.39 per barrel of diluent for the nine months ended September 30, 2017.

Transportation

During the nine months ended September 30, 2018, transportation costs averaged $7.78 per barrel compared to $6.85 per barrel for the nine months ended September 30, 2017. The increase in costs on a per barrel basis is primarily the result of incremental transportation costs associated with the TSA, which was entered into on March 22, 2018. The per barrel increase is partially offset by larger sales volumes for the nine months ended September 30, 2018, compared to the same period in 2017.

Royalties

Royalties averaged $1.56 per barrel for the nine months ended September 30, 2018, compared to $0.75 per barrel for the nine months ended September 30, 2017. The increase in royalties is primarily the result of higher WTI crude oil prices and higher sales volumes and revenue.

Net Operating Costs

Net operating costs for the nine months ended September 30, 2018 averaged $5.28 per barrel compared to $7.26 per barrel for the nine months ended September 30, 2017. The decrease in net operating costs is primarily the result of a per barrel decrease in energy operating costs and an increase in per barrel power revenue.

Non-energy operating costs

Non-energy operating costs averaged $4.75 per barrel for the nine months ended September 30, 2018, compared to $4.66 per barrel for the nine months ended September 30, 2017. Additional production-related costs were largely offset by higher sales volumes for the nine months ended September 30, 2018 compared to the same period in 2017. In addition, the 2017 comparative period includes a $0.22 per barrel, or $4.5 million reduction of property taxes related to a one-time municipal reassessment of its Christina Lake facility.

Energy operating costs

Energy operating costs averaged $1.98 per barrel for the nine months ended September 30, 2018 compared to $3.38 per barrel for the nine months ended September 30, 2017. The decrease in energy operating costs is primarily attributable to lower natural gas prices. The Corporation's natural gas purchase price averaged $1.88 per mcf during the nine months ended September 30, 2018 compared to $2.79 per mcf for the same period in 2017.

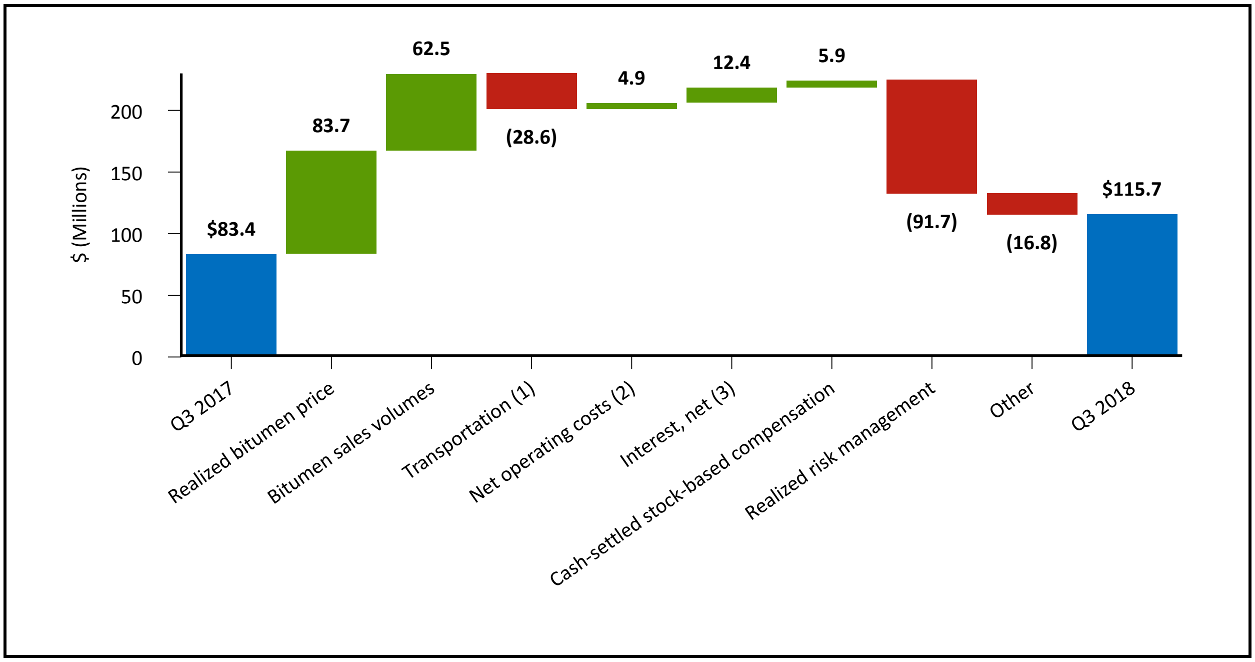
Power revenue

Power revenue averaged $1.45 per barrel for the nine months ended September 30, 2018 compared to $0.78 per barrel for the nine months ended September 30, 2017. The Corporation's average realized power sales price during the nine months ended September 30, 2018 was $45.42 per megawatt hour compared to $21.54 per megawatt hour for the same period in 2017. The higher average realized price is attributable to Alberta power pool prices increasing due to the introduction of a higher carbon tax levy at the beginning of 2018 and the retirement and suspension of older coal-fired power plants in the province of Alberta.

Realized Gain or Loss on Commodity Risk Management

The Corporation has entered into financial commodity risk management contracts to protect a portion of its capital program. The realized loss on commodity risk management averaged $8.21 per barrel for the nine months ended September 30, 2018 compared to a realized loss of $0.22 per barrel for the nine months ended September 30, 2017. This is primarily due to settlement 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 From Operations – Three Months Ended September 30



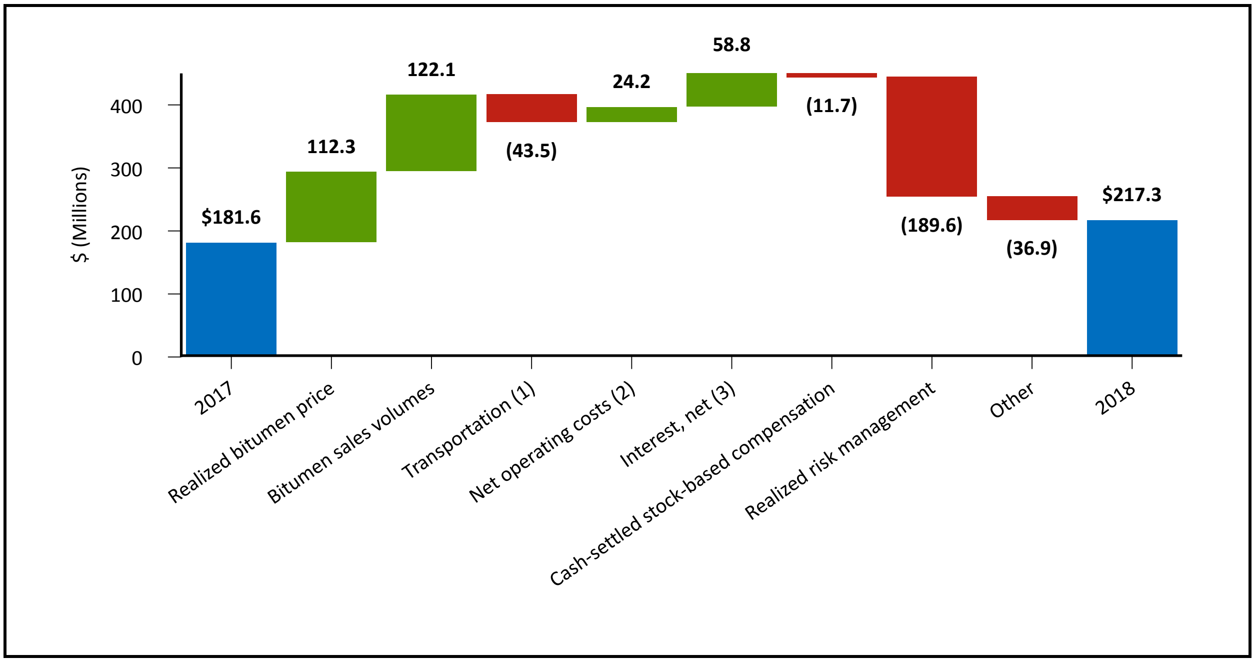
(1) *Defined as transportation expense less transportation revenue.*

(2) *Includes non-energy and energy operating costs, reduced by power revenue.*

(3) *Defined as net interest expense plus realized gain/loss on interest rate swaps less interest expense on finance leases less amortization of debt discount and debt issue costs.*

Adjusted funds flow from (used in) operations 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 from operations for the three months ended September 30, 2018 was $115.7 million compared to $83.4 million for the three months ended September 30, 2017. The increase in adjusted funds flow from operations was primarily the result of higher blend prices and sales volumes, partially offset by realized losses on commodity risk management contracts.

Adjusted Funds Flow From Operations – Nine Months Ended September 30



(1) *Defined as transportation expense less transportation revenue.*

(2) *Includes non-energy and energy operating costs, reduced by power revenue.*

(3) *Defined as net interest expense plus realized gain/loss on interest rate swaps less interest expense on finance leases less amortization of debt discount and debt issue costs.*

Adjusted funds flow from operations increased to $217.3 million for the nine months ended September 30, 2018 from $181.6 million for the nine months ended September 30, 2017. The increase in adjusted funds flow from operations was primarily the result of significantly higher sales volumes and blend prices partially offset by a significant increase in realized losses on commodity risk management contracts.

Operating Earnings (Loss)

Operating earnings (loss) is a non-GAAP measure, as defined in the "NON-GAAP MEASURES" section of this MD&A, which the Corporation uses as a performance measure to provide comparability of financial performance between periods by excluding non-operating items. The Corporation recognized an operating loss of $19.0 million for the three months ended September 30, 2018 compared to an operating loss of $42.6 million for the three months ended September 30, 2017. The decrease in the operating loss is primarily the result of higher bitumen realizations, partially offset by realized losses on commodity risk management contracts.

The Corporation recognized an operating loss $107.2 million for the nine months ended September 30, 2018 compared to an operating loss of $157.6 million for the nine months ended September 30, 2017. The decrease in the operating loss was due to higher bitumen realization as a result of the increase in average crude oil benchmark pricing along with higher bitumen sales volumes, partially offset by an increase in realized losses on commodity risk management contracts.

($000)	Three months ended September 30 2018	Three months ended September 30 2017	Nine months ended September 30 2018	Nine months ended September 30 2017
Net earnings (loss)	**$ 118,160**	$ 83,885	**$ 80,163**	$ 189,755
Adjustments:				
Unrealized loss (gain) on foreign exchange(1)	**(58,253)**	(180,448)	**145,422**	(345,116)
Unrealized loss (gain) on derivative financial liabilities(2)	**(192)**	(3,490)	**2,674**	(7,346)
Unrealized loss (gain) on commodity risk management(3)	**(107,949)**	57,470	**11,371**	(19,353)
Realized foreign exchange loss (gain) on foreign exchange derivatives(4)	**—**	—	**(35,362)**	—
Gain on asset dispositions(5)	**—**	—	**(318,398)**	—
Contract cancellation expense(6)	**—**	18,765	**—**	18,765
Onerous contracts expense	**897**	(27)	**1,686**	5,681
Insurance proceeds	**—**	(183)	**—**	(183)
Deferred tax expense (recovery) relating to these adjustments	**28,326**	(18,543)	**5,244**	218
Operating earnings (loss)(7)	**$ (19,011)**	$ (42,571)	**$ (107,200)**	$ (157,579)

(1) *Unrealized net foreign exchange gains and losses result from the translation of U.S. dollar denominated long-term debt and cash and cash equivalents using period-end exchange rates.*

(2) *Unrealized gains and losses on derivative financial liabilities result from the interest rate floor on the Corporation's long-term debt and interest rate swaps entered into to effectively fix a portion of its variable rate long-term debt.*

(3) *Unrealized gains or losses on commodity risk management contracts represent the change in the mark-to-market position of the unsettled commodity risk management contracts during the period.*

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

(5) *A gain related to the sale of the Corporation's 50% interest in the Access Pipeline.*

(6) *During the third quarter of 2017, the Corporation recognized a contract cancellation expense of $18.8 million relating to the termination of a long-term marketing transportation contract that had not yet commenced.*

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

Revenue

Revenue represents the total of petroleum revenue, net of royalties and other revenue. Revenue for the three months ended September 30, 2018 totaled $803.2 million compared to $576.3 million for the three months ended September 30, 2017. Revenue increased as a result of an increase in the average blend sales price and an increase in blend sales volumes.

Revenue for the nine months ended September 30, 2018 totaled $2.2 billion compared to $1.7 billion for the nine months ended September 30, 2017. Revenue increased as a result of an increase in the average blend sales price and an increase in blend sales volumes.

Net Earnings (Loss)

The Corporation recognized net earnings of $118.2 million for the three months ended September 30, 2018 compared to net earnings of $83.9 million for the three months ended September 30, 2017. Net earnings for the three months ended September 30, 2018 included a net foreign exchange gain of $59.1 million and a gain on commodity risk management contracts of $20.2 million . In comparison, net earnings in the third quarter of 2017 included a net foreign exchange gain of $178.4 million and a loss on commodity risk management contracts of $53.5 million.

The Corporation recognized net earnings of $80.2 million for the nine months ended September 30, 2018 compared to net earnings of $189.8 million for the nine months ended September 30, 2017. Net earnings for the nine months ended September 30, 2018 was affected by a net foreign exchange loss of $112.9 million and a loss on commodity risk management contracts of $205.6 million. This was offset by a gain on asset dispositions of $318.4 million relating to the sale of the Corporation's 50% interest in the Access Pipeline. In comparison, the net earnings for the nine months ended September 30, 2017 included a net foreign exchange gain of $348.4 million and a gain on commodity risk management contracts of $14.8 million.

Total Cash Capital Investment

Total cash capital investment for the three months ended September 30, 2018 was $144.5 million, compared to $103.2 million for the three months ended September 30, 2017. Total cash capital investment for the nine months ended September 30, 2018 was $474.8 million, compared to $339.4 million for the nine months ended September 30, 2017.

Capital investment in 2018 has primarily been directed towards the Corporation's growth and sustaining capital initiatives at Christina Lake Phase 2B.

4. OUTLOOK

Summary of 2018 Guidance	Guidance February 8, 2018	Revised Guidance August 1, 2018
Total cash capital investment	$700 million	$670 million
Bitumen production – annual average (bbls/d)	85,000 – 88,000	87,000 – 90,000
Bitumen production – targeted exit volume (bbls/d)	95,000 – 100,000	95,000 – 100,000
Non-energy operating costs ($/bbl)	$4.75 – $5.25	$4.50 – $5.00

The Corporation's 2018 capital guidance remains unchanged from the August 1, 2018 revised guidance of $670 million. The Corporation continues to benefit from improved capital cost efficiencies and strong operational results through the continued implementation of eMSAGP at the Christina Lake Project and expects to fund the remaining 2018 capital program with internally generated cash flow and existing cash.

The Corporation's 2018 average annual bitumen production volumes and non-energy operating costs remain unchanged from the August 1, 2018 revised guidance. Guidance takes into account the advancement of a portion of the Corporation's 2019 scheduled maintenance program to the fourth quarter of 2018, which is anticipated to reduce fourth quarter production by 4,000 – 6,000 bbls/d. Bitumen production volumes remain targeted to be in the range of 87,000 – 90,000 bbls/d, with exit bitumen production volumes of 95,000 – 100,000 bbls/d. Non-energy operating costs remain targeted to average $4.50 – $5.00 per barrel.

5. BUSINESS ENVIRONMENT

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

	Nine months ended September 30		2018			2017				2016
	2018	**2017**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**
Average Commodity Prices										
Crude oil prices										
Brent (US$/bbl)	**72.68**	52.59	**75.97**	74.90	67.18	61.54	52.18	50.93	54.66	51.13
WTI (US$/bbl)	**66.75**	49.47	**69.50**	67.88	62.87	55.40	48.21	48.29	51.91	49.29
WTI (C$/bbl)	**85.96**	64.64	**90.84**	87.64	79.54	70.45	60.38	64.94	68.68	65.75
WCS (C$/bbl)	**57.72**	49.12	**61.76**	62.76	48.82	54.86	47.93	49.98	49.39	46.65
Differential – WTI:WCS (US$/bbl)	**21.93**	11.88	**22.25**	19.27	24.28	12.26	9.94	11.13	14.58	14.32
Differential – WTI:WCS (%)	**32.9%**	24.0%	**32.0%**	28.4%	38.6%	22.1%	20.6%	23.0%	28.1%	29.1%
Condensate prices										
Condensate at Edmonton (C$/bbl)	**85.30**	64.64	**87.35**	88.84	79.72	73.72	59.59	65.16	69.17	64.49
Condensate at Edmonton as % of WTI	**99.2%**	100.0%	**96.2%**	101.4%	100.2%	104.6%	98.7%	100.3%	100.7%	98.1%
Condensate at Mont Belvieu, Texas (US$/bbl)	**62.73**	45.73	**64.53**	64.40	59.27	55.35	46.37	44.77	46.05	45.17
Condensate at Mont Belvieu, Texas as % of WTI	**94.0%**	92.4%	**92.8%**	94.9%	94.3%	99.9%	96.2%	92.7%	88.7%	91.6%
Natural gas prices										
AECO (C$/mcf)	**1.59**	2.44	**1.28**	1.26	2.26	1.84	1.58	2.81	2.91	3.31
Electric power prices										
Alberta power pool (C$/MWh)	**48.39**	22.06	**54.46**	55.92	34.81	22.49	24.55	19.26	22.38	21.97
Foreign exchange rates										
C$ equivalent of 1 US$ - average	**1.2877**	1.3067	**1.3070**	1.2911	1.2651	1.2717	1.2524	1.3449	1.3230	1.3339
C$ equivalent of 1 US$ - period end	**1.2924**	1.2510	**1.2924**	1.3142	1.2901	1.2518	1.2510	1.2977	1.3322	1.3427

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$69.50 per barrel for the three months ended September 30, 2018 compared to US$48.21 per barrel for the three months ended September 30, 2017. The WTI price averaged US$66.75 per barrel for the nine months ended September 30, 2018 compared to US$49.47 per barrel for the nine months ended September 30, 2017.

WCS is a blend of heavy oils, consisting of heavy conventional crude oils and bitumen, blended with sweet synthetic, light crude oil or condensate. The WCS benchmark reflects North American heavy oil prices at Hardisty, Alberta. WCS typically trades at a differential below the WTI benchmark price. The WTI:WCS differential averaged US$22.25 per barrel, or 32.0% of WTI, for the three months ended September 30, 2018 compared to US$9.94 per barrel, or 20.6% of WTI, for the three months ended September 30, 2017. The WTI:WCS differential averaged US$21.93 per barrel, or 32.9% of WTI, for the nine months ended September 30, 2018 compared to US$11.88 per barrel, or 24.0% of WTI, for the nine months ended September 30, 2017. The WTI:WCS differential has widened as a result of increased apportionment on pipelines that has been caused by increased heavy oil production combined with a lack of export pipeline capacity. Delays affecting the ramp up of major rail carriers' capacity and seasonal refinery maintenance have also contributed to a material widening of the WTI:WCS differential.

Condensate Prices

In order to facilitate pipeline transportation, MEG uses condensate sourced throughout North America as diluent for blending with the Corporation's bitumen. Condensate prices, benchmarked at Edmonton, averaged $87.35 per barrel, or 96.2% of WTI, for the three months ended September 30, 2018 compared to $59.59 per barrel, or 98.7% of WTI, for the three months ended September 30, 2017. Condensate prices, benchmarked at Edmonton, averaged $85.30 per barrel, or 99.2% of WTI, for the nine months ended September 30, 2018 compared to $64.64 per barrel, or 100.0% of WTI, for the nine months ended September 30, 2017.

Condensate prices, benchmarked at Mont Belvieu, Texas, averaged US$64.53 per barrel, or 92.8% of WTI, for the three months ended September 30, 2018 compared to US$46.37 per barrel, or 96.2% of WTI, for the three months ended September 30, 2017 . Condensate prices, benchmarked at Mont Belvieu, Texas, averaged US$62.73 per barrel, or 94.0% of WTI, for the nine months ended September 30, 2018 compared to US$45.73 per barrel, or 92.4% of WTI, for the nine months ended September 30, 2017.

Natural Gas Prices

Natural gas is a primary energy input cost for the Corporation, as it is used as fuel to generate steam for the SAGD process and to create electricity from the Corporation's cogeneration facilities. The AECO natural gas price averaged $1.28 per mcf for the three months ended September 30, 2018 compared to $1.58 per mcf for the three months ended September 30, 2017. The AECO natural gas price averaged $1.59 per mcf for the nine months ended September 30, 2018 compared to $2.44 per mcf for the nine months ended September 30, 2017. The AECO natural gas price has decreased in each of the comparative periods as a result of increased natural gas production in Alberta, coupled with continued pipeline constraints.

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 $54.46 per megawatt hour for the three months ended September 30, 2018 compared to $24.55 per megawatt hour for the three months ended September 30, 2017. The Alberta power pool price averaged $48.39 per megawatt hour for the nine months ended September 30, 2018 compared to $22.06 per megawatt hour for the nine months ended September 30, 2017. Alberta power pool prices have increased for each of the comparative periods due to the introduction of a higher carbon tax levy at the beginning of 2018 and the retirement and suspension of older coal-fired power plants in the province of Alberta.

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 September 30, 2018, the Canadian dollar, at a rate of 1.2924, had decreased in value by approximately 3% against the U.S. dollar compared to its value as at December 31, 2017, when the rate was 1.2518.

6. OTHER OPERATING RESULTS

Net Marketing Activity

($000)	Three months ended September 30 2018	2017	Nine months ended September 30 2018	2017
Petroleum revenue – third party	**$ 28,751**	$ 64,994	**$ 132,857**	$ 211,928
Third party purchased product	**(28,329)**	(64,738)	**(130,302)**	(209,922)
Net marketing activity(1)	**$ 422**	$ 256	**$ 2,555**	$ 2,006

(1) *Net marketing activity is a non-GAAP measure as defined in the "NON-GAAP MEASURES" section.*

The Corporation has entered into marketing arrangements for rail and pipeline transportation commitments and product storage arrangements to enhance its ability to transport proprietary crude oil products to a wider range of markets in Canada, the United States and on tidewater. In the event that the Corporation is not utilizing these arrangements for proprietary purposes, the Corporation purchases and sells third-party crude oil and related products and enters into transactions to generate revenues to offset the costs of such marketing and storage arrangements.

Depletion and Depreciation

($000)	Three months ended September 30 2018	2017	Nine months ended September 30 2018	2017
Depletion and depreciation expense	**$ 125,834**	$ 128,754	**$ 341,083**	$ 357,238
Depletion and depreciation expense per barrel of production	**$ 13.85**	$ 16.86	**$ 14.23**	$ 16.87

Depletion and depreciation expense per barrel decreased for each of the comparative three and nine month periods, primarily due to a significant reduction in estimated future development costs associated with the Corporation's proved reserves. Future development costs are derived from the Corporation's independent reserve report and are a key element of the rate determination. The decrease in future development costs is primarily related to the Corporation's future growth strategy, which anticipates reduced capital requirements to produce the reserves.

Commodity Risk Management Gain (Loss)

The Corporation has entered into financial commodity risk management contracts to protect a portion of its capital program. The Corporation has not designated any of its commodity risk management contracts as hedges for accounting purposes. All financial commodity risk management contracts have been recorded at fair value, with all changes in fair value recognized through net earnings (loss). Realized gains or losses on financial commodity risk management contracts are the result of contract settlements during the period. Unrealized gains or losses on financial commodity risk management contracts represent the change in the mark-to-market position of the unsettled commodity risk management contracts during the period.

	Three months ended September 30					
($000)	2018			2017		
	Realized	Unrealized	Total	Realized	Unrealized	Total
Crude oil contracts[1]	**$ (84,865)**	**$ 102,074**	**$ 17,209**	$ (7,182)	$ (55,300)	$ (62,482)
Condensate contracts[2]	**(2,863)**	**5,875**	**3,012**	11,158	(2,170)	8,988
Commodity risk management gain (loss)	**$ (87,728)**	**$ 107,949**	**$ 20,221**	$ 3,976	$ (57,470)	$ (53,494)

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

(2) *Relates to condensate purchase contracts that effectively fix condensate prices as a percentage of WTI at Mont Belvieu, Texas.*

The Corporation realized a net loss on commodity risk management contracts of $87.7 million for the three months ended September 30, 2018, due to net settlement losses on contracts primarily relating to crude oil sales. This compares to a realized net gain of $4.0 million for the three months ended September 30, 2017. WTI fixed price contracts were priced at approximately US$55 per barrel and settled, on average, at approximately US$70 per barrel for the three months ended September 30, 2018, resulting in realized losses. These were partially offset by gains on WTI:WCS fixed differential contracts which were priced at approximately US$16 per barrel and settled, on average, at approximately US$22 per barrel.

The Corporation recognized an unrealized gain on commodity risk management contracts of $107.9 million for the three months ended September 30, 2018, primarily reflecting the third quarter settlement of losses on crude oil contracts, as well as widening WTI:WCS forward differentials, which generated unrealized gains on the Corporation's WTI:WCS fixed differential contracts. These gains were partially offset by unrealized losses on the WTI fixed price contracts and collars as crude oil benchmark forward prices increased over the quarter. The $107.9 million unrealized gain in the third quarter of 2018 compares to a $57.5 million unrealized loss for the same period in 2017. Refer to the “Risk Management” section of this MD&A for further details.

	Nine months ended September 30					
($000)	2018			2017		
	Realized	Unrealized	Total	Realized	Unrealized	Total
Crude oil contracts[1]	**$ (191,545)**	**$ (12,785)**	**$ (204,330)**	$ (29,984)	$ 34,931	$ 4,947
Condensate contracts[2]	**(2,653)**	**1,414**	**(1,239)**	25,383	(15,578)	9,805
Commodity risk management gain (loss)	**$ (194,198)**	**$ (11,371)**	**$ (205,569)**	$ (4,601)	$ 19,353	$ 14,752

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

(2) *Relates to condensate purchase contracts that effectively fix condensate prices as a percentage of WTI at Mont Belvieu, Texas.*

The Corporation realized a net loss on commodity risk management contracts of $194.2 million for the nine months ended September 30, 2018, primarily due to net settlement losses on contracts relating to crude oil sales. This compares to a realized net loss of $4.6 million for the nine months ended September 30, 2017 . WTI fixed price contracts were priced at approximately US$55 per barrel and settled, on average, at approximately US$67 per barrel during the nine months ended September 30, 2018. These realized losses were partially offset by gains on WTI:WCS fixed differential contracts which were priced at approximately US$15 per barrel and settled, on average, at approximately US$22 per barrel.

The Corporation recognized an unrealized net loss on commodity risk management contracts of $11.4 million for the nine months ended September 30, 2018, reflecting net unrealized losses on crude oil contracts partially offset by unrealized gains on condensate purchase contracts. Losses on crude oil contracts were the result of crude oil benchmark forward prices increasing over the period, resulting in unrealized losses on the Corporation’s WTI fixed price contracts and collars, partially offset by widening WTI:WCS forward differentials, which resulted in gains on WTI:WCS fixed differential contracts. The $11.4 million unrealized loss for the nine months ended September 30, 2018 compares to a $19.4 million unrealized gain for the same period in 2017. Refer to the “Risk Management” section of this MD&A for further details.

General and Administrative

	Three months ended September 30		Nine months ended September 30	
($000)	**2018**	**2017**	**2018**	**2017**
General and administrative expense	**$ 21,360**	$ 19,321	**$ 62,235**	$ 63,482
General and administrative expense per barrel of production	**$ 2.35**	$ 2.53	**$ 2.60**	$ 3.00

General and administrative expense per barrel decreased 7% for the three months ended September 30, 2018 to $2.35 per barrel, from $2.53 per barrel for the three months ended September 30, 2017. General and administrative expense per barrel decreased 13% for the nine months ended September 30, 2018 to $2.60 per barrel, from $3.00 per barrel for the nine months ended September 30, 2017. The per barrel decrease in each comparative period was primarily due to increased production.

Stock-based Compensation

	Three months ended September 30		Nine months ended September 30	
($000)	**2018**	**2017**	**2018**	**2017**
Cash-settled expense (recovery)	**$ 1,134**	$ 7,054	**$ 22,183**	$ 3,559
Equity-settled expense	**6,771**	5,491	**16,899**	13,764
Stock-based compensation	**$ 7,905**	$ 12,545	**$ 39,082**	$ 17,323

The fair value of compensation associated with the granting of stock options, restricted share units ("RSUs"), performance share units ("PSUs") and deferred share units (“DSUs”) to officers, directors, employees and consultants is recognized by the Corporation as stock-based compensation expense. Fair values for equity-settled plans are determined using the Black-Scholes option pricing model.

The Corporation also grants RSUs, PSUs and DSUs under cash-settled plans. The cash-settled RSUs, PSUs and DSUs are accounted for as liability instruments and are measured at fair value based on the market value of the Corporation’s common shares at each period end. Fluctuations in the fair value are recognized within stock-based compensation expense or capitalized to property, plant and equipment during the period in which they occur.

Stock-based compensation expense for the three months ended September 30, 2018 was $7.9 million compared to $12.5 million for the three months ended September 30, 2017. For the three months ended September 30, 2017, the cash-settled stock-based compensation expense reflects an increase in the fair value of the cash-settled units due to the increase in the Corporation's common share price during the third quarter of 2017.

Stock-based compensation expense for the nine months ended September 30, 2018 was $39.1 million compared to $17.3 million for the nine months ended September 30, 2017. The increase was primarily a result of an increase in the fair value of the cash-settled units due to a 56% increase in the Corporation’s common share price from December 31, 2017 to September 30, 2018.

Research and Development

	Three months ended September 30		Nine months ended September 30	
($000)	**2018**	**2017**	**2018**	**2017**
Research and development expense	$ **1,693**	1,299	$ **4,106**	3,405

Research and development expenditures relate to the Corporation's research of crude quality improvement and related technologies.

Foreign Exchange Gain (Loss), Net

	Three months ended September 30		Nine months ended September 30	
($000)	**2018**	**2017**	**2018**	**2017**
Unrealized foreign exchange gain (loss) on:				
Long-term debt	$ **60,601**	176,586	$ **(145,211)**	346,734
Other	**(2,348)**	3,862	**(211)**	(1,618)
Unrealized net gain (loss) on foreign exchange	**58,253**	180,448	**(145,422)**	345,116
Realized gain (loss) on foreign exchange	**818**	(2,064)	**(2,833)**	3,291
Realized gain (loss) on foreign exchange derivatives	**—**	—	**35,362**	—
Foreign exchange gain (loss), net	$ **59,071**	$ 178,384	$ **(112,893)**	$ 348,407
C$ equivalent of 1 US$				
Beginning of period	**1.3142**	1.2977	**1.2518**	1.3427
End of period	**1.2924**	1.2510	**1.2924**	1.2510

Net foreign exchange gains and losses are primarily due to the translation of U.S. dollar denominated debt as a result of the strengthening or weakening of the Canadian dollar compared to the U.S. dollar during each period. For the three months ended September 30, 2018 the Canadian dollar strengthened by 2% resulting in an unrealized foreign exchange gain on translation of U.S dollar denominated debt of $60.6 million. For the three months ended September 30, 2017 the Canadian dollar strengthened by 4%, resulting in an unrealized foreign exchange gain on translation of U.S. dollar denominated debt of $176.6 million.

For the nine months ended September 30, 2018, the Canadian dollar weakened by 3%, resulting in an unrealized foreign exchange loss on translation of U.S. dollar denominated debt of $145.2 million. For the nine months ended September 30, 2017 the Canadian dollar strengthened by 7%, resulting in an unrealized foreign exchange gain on translation of U.S. dollar denominated debt of $346.7 million.

On March 22, 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. A majority of the net cash proceeds were used to repay approximately C$1.2 billion of MEG's senior secured term loan. Upon entering into the sale agreement on February 8, 2018, 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 $35.4 million.

Net Finance Expense

		Three months ended September 30		Nine months ended September 30
($000)	2018	2017	2018	2017
Interest expense on long-term debt	$ 68,039	$ 80,860	$ 218,021	$ 259,296
Interest expense on finance leases	4,115	—	8,664	—
Interest income	(1,907)	(968)	(5,924)	(2,736)
Net interest expense	70,247	79,892	220,761	256,560
Accretion on provisions	1,888	1,994	5,608	5,675
Unrealized loss (gain) on derivative financial liabilities[(1)]	(192)	(3,490)	2,674	(7,346)
Realized loss (gain) on interest rate swaps	—	21	(17,312)	21
Net finance expense	$ 71,943	$ 78,417	$ 211,731	$ 254,910
Average effective interest rate[(2)]	6.6%	6.0%	6.4%	6.0%

(1) Derivative financial liabilities include the 1% interest rate floor and interest rate swaps.

(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 interest rate swaps.

Interest expense on long-term debt for the three months ended September 30, 2018 was $68.0 million compared to $80.9 million for the 2017 period. Interest expense on long-term debt for the nine months ended September 30, 2018 was $218.0 million compared to $259.3 million for the nine months ended September 30, 2017. The interest expense decrease in the three and nine months ended September 30, 2018 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 its senior secured term loan, and realized a gain of $17.3 million.

Other Expenses

		Three months ended September 30		Nine months ended September 30
($000)	2018	2017	2018	2017
Severance and other	$ 1,929	$ 1,320	$ 4,917	$ 4,736
Onerous contracts expense (recovery)	897	(27)	1,686	5,681
Contract cancellation expense	—	18,765	—	18,765
Other expenses	$ 2,826	$ 20,058	$ 6,603	$ 29,182

Onerous contracts expense primarily includes changes in estimated future cash flow sublease recoveries related to the onerous office lease provision for the Corporation's office building lease contracts.

During the third quarter of 2017, the Corporation recognized contract cancellation expense of $18.8 million relating to the termination of a long-term marketing transportation contract that had not yet commenced.

Income Tax Expense (Recovery)

	Three months ended September 30		Nine months ended September 30	
($000)	**2018**	**2017**	**2018**	**2017**
Current income tax expense (recovery)	**$ 117**	$ (257)	**$ 312**	$ (426)
Deferred income tax expense (recovery)	**23,604**	(33,091)	**(50,922)**	(50,268)
Income tax expense (recovery)	**$ 23,721**	$ (33,348)	**$ (50,610)**	$ (50,694)

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 September 30, 2018, the Corporation had approximately $7.6 billion of available Canadian tax pools.

The Corporation recognized a current income tax expense of $0.3 million for the nine months ended September 30, 2018 and a current income tax recovery of $0.4 million for the nine months ended September 30, 2017. The 2018 expense of $0.3 million is related to United States income tax associated with operations in the United States. The 2017 recovery is comprised of $0.8 million related to the refundable Alberta tax credit on Scientific Research and Experimental Development expenditures, partially offset by an expense of $0.4 million related to United States income tax associated with its operations in the United States.

The Corporation recognized a deferred income tax expense of $23.6 million for the three months ended September 30, 2018 and a deferred income tax recovery of $33.1 million for the three months ended September 30, 2017. The Corporation recognized a deferred income tax recovery of $50.9 million for the nine months ended September 30, 2018 and a deferred income tax recovery of $50.3 million for the nine months ended September 30, 2017.

The Corporation's effective tax rate on earnings is impacted by permanent differences. The significant permanent differences are:

- The permanent difference due to capital gains arising on the disposition of the Access Pipeline and the Stonefell Terminal, and gains on foreign exchange derivatives. For the nine months ended September 30, 2018, capital gains of $365.6 million were sheltered by capital loss carry forwards not previously recognized.

- 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 September 30, 2018, the non-taxable net gain was $30.3 million compared to a non-taxable net gain of $88.3 million for the three months ended September 30, 2017. For the nine months ended September 30, 2018, the non-taxable loss was $72.6 million compared to a non-taxable gain of $173.4 million for the nine months ended September 30, 2017.

- 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 September 30, 2018 was $6.8 million compared to $5.5 million for the three months ended September 30, 2017. Stock-based compensation expense for equity-settled plans for the nine months ended September 30, 2018 was $16.9 million compared to $13.8 million for the nine months ended September 30, 2017.

As at September 30, 2018, the Corporation has recognized a deferred income tax asset of $237.8 million on the Consolidated Balance Sheet, as estimated future taxable income is expected to be sufficient to realize the deferred income tax asset.

As at September 30, 2018, the Corporation had not recognized the tax benefit related to $335.5 million of realized and unrealized taxable foreign exchange losses.

7. NET CAPITAL INVESTMENT

	Three months ended September 30		Nine months ended September 30	
($000)	2018	2017	2018	2017
eMSAGP growth capital	**$ 15,288**	$ 49,407	**$ 84,338**	$ 150,165
eMVAPEX growth capital	**14,370**	3,899	**56,998**	11,197
Phase 2B brownfield expansion	**57,281**	—	**101,361**	—
Growth capital	**86,939**	53,306	**242,697**	161,362
Sustaining and maintenance	**47,167**	23,246	**208,523**	140,037
Field infrastructure, corporate and other	**10,402**	26,621	**23,594**	38,018
Total cash capital investment	**144,508**	103,173	**474,814**	339,417
Capitalized cash-settled stock-based compensation	**(4,710)**	571	**3,425**	(259)
	$ 139,798	$ 103,744	**$ 478,239**	$ 339,158

Total cash capital investment for the three months ended September 30, 2018 was $144.5 million, compared to $103.2 million for the three months ended September 30, 2017. Total cash capital investment for the nine months ended September 30, 2018 was $474.8 million, compared to $339.4 million for the nine months ended September 30, 2017. The increase in capital investment for the three and nine months ended September 30, 2018 was primarily related to increased spending on the eMVAPEX and Phase 2B brownfield growth projects, which are proceeding on schedule. Investment in sustaining capital activities for the nine months ended September 30, 2018 included approximately $56.0 million of turnaround costs that were primarily incurred in the second quarter of 2018. In comparison, for the nine months ended September 30, 2017, sustaining capital activities included approximately $37.1 million in turnaround costs.

8. LIQUIDITY AND CAPITAL RESOURCES

($000)	September 30, 2018	December 31, 2017
Cash and cash equivalents	**$ 372,550**	$ 463,531
Senior secured term loan (September 30, 2018 – US$228.5 million; due 2023; December 31, 2017 – US$1.226 billion)	**295,281**	1,534,378
6.5% senior secured second lien notes (US$750.0 million; due 2025)	**969,300**	938,850
6.375% senior unsecured notes (US$800.0 million; due 2023)	**1,033,920**	1,001,440
7.0% senior unsecured notes (US$1.0 billion; due 2024)	**1,292,400**	1,251,800
US$1.4 billion revolving credit facility (due 2021)	**—**	—
Total debt(1)	**$ 3,590,901**	$ 4,726,468

(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

The Corporation's cash and cash equivalents balance totaled $372.6 million as at September 30, 2018 compared to $463.5 million as at December 31, 2017 . As at September 30, 2018 , no amount has been drawn under the Corporation's US$1.4 billion revolving credit facility.

The Corporation’s letter of credit facility, guaranteed by Export Development Canada, has a limit of US$440 million. Letters of credit under this facility do not consume capacity of the revolving credit facility. As at September 30, 2018, the Corporation had US$115.7 million of unutilized capacity under this facility.

On March 22, 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. A majority of the net cash proceeds were used to repay approximately C$1.2 billion of MEG's senior secured term loan. Total debt decreased to C$3.6 billion as at September 30, 2018 from C$4.7 billion as at December 31, 2017 as a result of the C$1.2 billion repayment, partially offset by C$0.1 billion of unrealized foreign exchange losses on translation of U.S dollar denominated debt.

The senior secured term loan, revolving credit facility, letter of credit facility and second lien notes are secured by substantially all the assets of the Corporation. All of MEG’s long-term debt, the revolving credit facility and the letter of credit facility are “covenant-lite” in structure, meaning they are free of any financial maintenance covenants and are not dependent on, nor calculated from, the Corporation’s crude oil reserves. The first maturity of any of the Corporation’s outstanding long-term debt obligations is in 2023.

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 commodity prices and market conditions 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 with the intent of increasing the predictability of the Corporation’s future cash flow. MEG’s commodity risk management program is governed by a Risk Management Committee that follows guidelines and limits approved by the Board of Directors. The Corporation does not use financial derivatives for speculative purposes.

To mitigate the Corporation’s exposure to fluctuations in crude oil prices, the Corporation periodically enters into financial commodity risk management contracts to partially manage its exposure on blend sales and condensate purchases. MEG's hedging philosophy over the last two years has been focused on protecting a portion of its capital program. With current cash reserves and higher commodity prices, the Corporation expects to hedge a substantially lower proportion of its barrels going forward.

The Corporation had the following financial commodity risk management contracts relating to crude oil sales and condensate purchases outstanding as at September 30, 2018:

As at September 30, 2018	Volumes (bbls/d)[1]	Term	Average Price (US$/bbl)[1]
Crude Oil Sales Contracts			
Fixed Price:			
WTI[ii] Fixed Price	29,000	Oct 1, 2018 – Dec 31, 2018	$54.16
WTI Fixed Price	19,060	Jan 1, 2019 – Dec 31, 2019	$66.53
WTI:WCS[iii] Fixed Differential	37,000	Oct 1, 2018 – Dec 31, 2018	$(16.50)
WTI:WCS Fixed Differential	28,000	Jan 1, 2019 – Dec 31, 2019	$(23.73)
WTI:WCS Fixed Differential	5,000	Jan 1, 2020 – Dec 31, 2020	$(23.19)
Collars:			
WTI Collars	32,500	Oct 1, 2018 – Dec 31, 2018	$46.64 – $54.52
Options:			
Purchased WTI Calls	8,000	Oct 1, 2018 – Dec 31, 2018	$82.00
Purchased WTI Puts	1,000	Jan 1, 2019 – Mar 31, 2019	$55.00
Condensate Purchase Contracts			
Fixed Price:			
WTI:Mont Belvieu Fixed Premium	5,000	Oct 1, 2018 – Dec 31, 2018	$4.96
Fixed Percentage:			
Mont Belvieu Fixed % of WTI	3,750	Jan 1, 2019 – Dec 31, 2019	95.2% of WTI
Mont Belvieu Fixed % of WTI	6,500	Jan 1, 2020 – Dec 31, 2020	93.9% of WTI

The Corporation entered into the following commodity risk management contracts relating to crude oil sales between October 1, 2018 and October 30, 2018:

Subsequent to September 30, 2018	Volumes (bbls/d)[1]	Term	Average Prices (US$/bbl)[1]
Crude Oil Sales Contracts			
Fixed Price:			
WTI Fixed Price	2,055	Jan 1, 2019 – Dec 31, 2019	$74.45
WTI:WCS Fixed Differential	3,000	Jan 1, 2019 – Dec 31, 2019	$(29.35)
Condensate Purchase Contracts			
Fixed Percentage:			
Mont Belvieu Fixed % of WTI	5,000	Jan 1, 2019 – Dec 31, 2019	91.0% of WTI
Mont Belvieu Fixed % of WTI	1,250	Jan 1, 2020 – Dec 31, 2020	89.1% of WTI

(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.

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. The Corporation does not have any outstanding interest rate swap contracts as at September 30, 2018.

Cash Flow Summary

	Three months ended September 30		Nine months ended September 30	
($000)	**2018**	**2017**	**2018**	**2017**
Net cash provided by (used in):				
Operating activities	**$ 3,409**	$ 7,979	**$ 186,678**	$ 117,397
Investing activities	**(188,398)**	(122,288)	**1,001,448**	(278,624)
Financing activities	**(3,799)**	(3,892)	**(1,279,724)**	405,188
Effect of exchange rate changes on cash and cash equivalents held in foreign currency	**(2,631)**	3,375	**617**	(2,593)
Change in cash and cash equivalents	**$ (191,419)**	$ (114,826)	**$ (90,981)**	$ 241,368

Cash Flow – Operating Activities

Net cash provided by operating activities totaled $3.4 million for the three months ended September 30, 2018 compared to $8.0 million for the three months ended September 30, 2017. Blend sales revenue for the three months ended September 30, 2018 was higher as a result of an increase in the average blend sales price and an increase in blend sales volumes. This was partially offset by realized losses on commodity risk management contracts, and an increase in diluent expense, due to an increase in condensate volumes, reflecting the increase in average bitumen production, and higher condensate benchmark prices.

Net cash provided by operating activities totaled $186.7 million for the nine months ended September 30, 2018 compared to $117.4 million for the nine months ended September 30, 2017. This increase in cash flows is primarily due to higher blend sales revenue, primarily as a result of an increase in the average blend sales price and an increase in blend sales volumes. This was partially offset by realized losses on commodity risk management contracts, an increase in cash-settled stock-based compensation expense and an increase in diluent expense, due to an increase in condensate volumes, reflecting the increase in average bitumen production, and higher condensate benchmark prices.

Cash Flow – Investing Activities

Net cash used in investing activities was $188.4 million for the three months ended September 30, 2018 compared to $122.3 million for the three months ended September 30, 2017. The increase in net cash used in investing activities is primarily due to increased capital spending activity directed toward growth initiatives and sustaining capital activities at the Christina Lake Project.

Net cash provided by investing activities was $1.0 billion for the nine months ended September 30, 2018 compared to net cash used in investing activities of $278.6 million for the nine months ended September 30, 2017. The increase in investing activity cash flows is due to the receipt of 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, which closed in the first quarter of 2018, partially offset by increased capital investing activity.

Cash Flow – Financing Activities

Net cash used in financing activities was $3.8 million for the three months ended September 30, 2018 compared to $3.9 million for the three months ended September 30, 2017. Net cash used in financing activities includes quarterly debt repayments of US$3.1 million.

Net cash used in financing activities was $1.3 billion for the nine months ended September 30, 2018 compared to net cash provided by financing activities of $405.2 million for the nine months ended September 30, 2017. Net cash used in financing activities 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. Net cash provided by financing activities for the nine months ended September 30, 2017 included $496.3 million of net equity issuance proceeds, partially offset by costs of $82.4 million paid as part of the comprehensive refinancing plan.

9. SHARES OUTSTANDING

As at September 30, 2018, the Corporation had the following share capital instruments outstanding or exercisable:

(000)	**Units**
Common shares	**296,813**
Convertible securities	
Stock options[(1)]	**8,682**
Equity-settled RSUs and PSUs	**6,722**

(1) 6.8 million stock options were exercisable as at September 30, 2018.

As at October 29, 2018, the Corporation had 296.8 million common shares, 8.6 million stock options and 6.6 million equity-settled restricted share units and equity-settled performance share units outstanding, and 6.7 million stock options exercisable.

10. CONTRACTUAL OBLIGATIONS, COMMITMENTS AND CONTINGENCIES

(a) Contractual Obligations and Commitments

The information presented in the table below reflects management's estimate of the contractual maturities of the Corporation's obligations as at September 30, 2018. 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 repayments or redemptions.

($000)		2018		2019		2020		2021		2022		Thereafter		Total
Long-term debt[1]	$	3,990	$	15,961	$	15,961	$	15,961	$	15,961	$	3,523,067	$	3,590,901
Interest on long-term debt[1]		58,965		235,380		234,488		233,597		232,707		262,269		1,257,406
Decommissioning obligation[2]		2,563		9,811		7,585		7,585		7,585		776,319		811,448
Transportation and storage[3]		71,073		299,844		340,800		387,425		437,618		6,640,968		8,177,728
Finance leases[4]		3,915		15,817		15,975		16,135		16,296		470,127		538,265
Office lease rentals		6,893		23,296		21,382		21,117		20,281		152,544		245,513
Diluent purchases[5]		217,300		444,183		20,463		20,407		20,407		16,996		739,756
Other commitments[6]		18,374		14,113		11,270		9,536		8,570		55,519		117,382
Total	**$**	**383,073**	**$**	**1,058,405**	**$**	**667,924**	**$**	**711,763**	**$**	**759,425**	**$**	**11,897,809**	**$**	**15,478,399**

(1) *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 September 30, 2018.*
(2) *This represents the undiscounted future obligations primarily associated with the decommissioning of the Corporation's crude oil assets.*
(3) *This represents transportation and storage commitments from 2018 to 2048, including the Access Pipeline TSA, and various pipeline commitments which are awaiting regulatory approval and are not yet in service.*
(4) *This represents the future finance lease payments related to the Stonefell Lease Agreement.*
(5) *This represents the future commitments associated with the Corporation's diluent purchases.*
(6) *This represents the future commitments associated with the Corporation's capital program, and other operating and maintenance commitments.*

Commitments for various transportation and storage arrangements increased $4.8 billion from December 31, 2017 primarily due to the Corporation's sale of its 50% interest in the Access Pipeline and the resulting TSA to transport blend production and condensate on the Access Pipeline for an initial term of 30 years. Long-term debt and interest on long-term debt decreased $1.6 billion from December 31, 2017 primarily due to the partial repayment of the Corporation's senior secured term loan.

(b) Contingencies

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

The Corporation is the defendant to a statement of claim originally filed in 2014 in relation to legacy issues involving a unit train transloading facility in Alberta. The claim was amended in the fourth quarter of 2017 asserting a significant increase to damages claimed. The Corporation continues to view this three year old claim, and the recent amendments, as without merit and will defend against all such claims.

11. NON-GAAP MEASURES

Certain financial measures in this MD&A including: net marketing activity, funds flow from (used in) operations, adjusted funds flow from (used in) operations, operating earnings (loss), operating cash flow 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.

Net Marketing Activity

Net marketing activity is a non-GAAP measure which the Corporation uses to analyze the returns on the sale of third-party crude oil and related products through various marketing and storage arrangements. Net marketing activity represents the Corporation's third-party petroleum sales less the cost of third-party purchased product. Petroleum revenue – third party is disclosed in Note 13 and purchased product and storage – third party is presented in Note 15 to the Consolidated Financial Statements.

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

Funds flow from (used in) operations and adjusted funds flow from (used in) operations 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 from (used in) operations 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 from (used in) operations 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 from (used in) operations are reconciled to net cash provided by (used in) operating activities in the table below.

	Three months ended September 30		Nine months ended September 30	
($000)	**2018**	**2017**	**2018**	**2017**
Net cash provided by (used in) operating activities	**$ 3,409**	$ 7,979	**$ 186,678**	$ 117,397
Net change in non-cash operating working capital items	**107,549**	51,133	**47,577**	28,922
Funds flow from (used in) operations	**110,958**	59,112	**234,255**	146,319
Adjustments:				
Realized gain on foreign exchange derivatives (1)	**—**	—	**(35,362)**	—
Contract cancellation expense (2)	**—**	18,765	**—**	18,765
Payments on onerous contracts	**4,332**	5,089	**14,576**	14,691
Decommissioning expenditures	**452**	386	**3,823**	1,847
Adjusted funds flow from (used in) operations	**$ 115,742**	$ 83,352	**$ 217,292**	$ 181,622

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

(2) *During the third quarter of 2017, the Corporation recognized a contract cancellation expense of $18.8 million relating to the termination of a long-term marketing transportation contract that had not yet commenced.*

Operating Earnings (Loss)

Operating earnings (loss) is a non-GAAP measure which the Corporation uses as a performance measure to provide comparability of financial performance between periods by excluding non-operating items. Operating earnings (loss) is defined as net earnings (loss) as reported, excluding unrealized foreign exchange gains and losses, unrealized gains and losses on derivative financial instruments, unrealized gains and losses on commodity risk management, realized gains and losses on foreign exchange derivatives not considered part of ordinary continuing operating results, gain on asset dispositions, contract cancellation expense, onerous contracts expense, insurance proceeds and the respective deferred tax impact on these adjustments. Operating earnings (loss) is reconciled to "Net earnings (loss)", the nearest IFRS measure.

Operating Cash Flow

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, 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, 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.

($000)	September 30, 2018	December 31, 2017
Long-term debt	**$ 3,543,587**	$ 4,668,267
Adjustments:		
Current portion of senior secured term loan	**15,961**	15,460
Unamortized financial derivative liability discount	**1,333**	4,242
Unamortized deferred debt discount and debt issue costs	**30,020**	38,499
Total debt	**$ 3,590,901**	$ 4,726,468

12. 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 2017 annual MD&A. Additional estimates, assumptions and judgments are detailed in the Corporation's unaudited interim consolidated financial statements.

Sale and leaseback accounting

On March 22, 2018, the Corporation sold its 100% interest in the Stonefell Terminal. Management applied judgment to determine that the sale of the Stonefell Terminal and the subsequent lease of the terminal should be accounted for as a sale and leaseback transaction that resulted in a finance lease.

Determining the measurement of a finance lease asset and obligation is a complex process that involves estimates, assumptions and judgments to determine the fair value of leased assets, and estimates on timing and amount of expected future cash flows and discount rates. Any future changes to the estimated discount rate will not impact the carrying values of the finance lease asset and obligation. The leased asset will be subject to property, plant and equipment impairment reviews and assessments at subsequent reporting periods.

13. NEW ACCOUNTING STANDARDS

The Corporation has adopted the following revised standards effective January 1, 2018:

IFRS 15 Revenue From Contracts With Customers

The IASB issued IFRS 15 *Revenue From Contracts With Customers*, which is effective January 1, 2018 and replaces IAS 11 *Construction Contracts* and IAS 18 *Revenue* and the related interpretations on revenue recognition. IFRS 15 provides a comprehensive revenue recognition and measurement framework that applies to all contracts with customers. The Corporation adopted IFRS 15 retrospectively as required by the standard on January 1, 2018, and applied a practical expedient whereby completed contracts prior to January 1, 2017 were not assessed. The adoption of this standard did not have a material impact on the Corporation's consolidated financial statements. The main changes are explained below.

(a) Significant Accounting Policies

Revenues

The Corporation earns revenue primarily from the sale of crude oil, with other revenue earned from excess power generation, and from transportation fees charged to third parties.

i. Petroleum revenue recognition

The Corporation sells proprietary and purchased crude oil and natural gas under contracts of varying terms of up to one year to customers at prevailing market prices, whereby delivery takes place throughout the contract period. In most cases, consideration is due when title has transferred and is generally collected in the month following the month of delivery.

The Corporation evaluates its arrangements with third parties to determine if the Corporation acts as the principal or as an agent. In making this evaluation, management considers if the Corporation obtains control of the product delivered. If the Corporation acts in the capacity of an agent rather than as a principal in a transaction, then the revenue is recognized on a net-basis, only reflecting the fee, if any, realized by the Corporation from the transaction.

Revenues associated with the sales of proprietary and purchased crude oil owned by the Corporation are recognized at a point in time when control of goods have transferred, which is generally when title passes from the Corporation to the customer. Revenues are recorded net of crown royalties. Crown royalties are recognized at the time of production.

Revenue is allocated to each performance obligation on the basis of its standalone selling price and measured at the transaction price, which is the fair value of the consideration and represents amounts receivable for goods or services provided in the normal course of business. The price is allocated to each unit in the series as each unit is substantially the same and depicts the same pattern of transfer to the customer.

ii. Other revenue recognition

Revenue from power generated in excess of the Corporation's internal requirements is recognized upon delivery from the plant gate, at which point, control is transferred to the customer on the power grid. Revenues are earned at prevailing market prices for each megawatt hour produced.

Fees charged to customers for the use of pipelines and facilities are recognized in the period when the products are delivered and the services are provided.

iii. Asset dispositions

Property, plant and equipment assets are derecognized upon disposal or when no future economic benefits are expected to arise from the continued use of the asset. Any gain or loss arising from derecognition of the asset is determined as the difference between the net disposal proceeds, if any, and the carrying amount of the asset, and is recognized in net earnings or loss, unless the disposition is part of a sale and leaseback. The amount of consideration to be included in the gain or loss arising from derecognition is determined by the transaction contract.

Dispositions of property, plant and equipment occur on the date the acquiror obtains control of the asset.

(b) Impact from change in accounting policy

Under IFRS 15, revenues from the purchase and sale of proprietary crude oil are recognized on a gross basis as separate performance obligations. In conjunction with the transition to IFRS 15, the presentation of petroleum revenue, net of royalties and purchased product and storage will change, with no impact on earnings (loss) before income tax, net earnings (loss), comprehensive income (loss), or net cash provided by (used in) operating activities.

The quarterly impact of these changes in 2017 was as follows:

	Q1 2017	Q2 2017	Q3 2017	Q4 2017	Total
Petroleum revenue – proprietary, as previously reported	$ 489,388	$ 492,613	$ 475,784	$ 710,817	$ 2,168,602
Blend purchases	—	9,602	30,367	6	$ 39,975
Adjusted petroleum revenue – proprietary	**$ 489,388**	**$ 502,215**	**$ 506,151**	**$ 710,823**	**$ 2,208,577**
Purchased product and storage as previously reported	$ 65,542	$ 79,642	$ 64,738	$ 40,759	$ 250,681
Blend purchases	—	9,602	30,367	6	39,975
Adjusted purchased product and storage	**$ 65,542**	**$ 89,244**	**$ 95,105**	**$ 40,765**	**$ 290,656**

Enhanced required disclosures are provided in Notes 13 and 15 of the Corporation's consolidated financial statements.

IFRS 9 Financial Instruments

The IASB issued IFRS 9 *Financial Instruments*, which is effective January 1, 2018 and replaces IAS 39 *Financial Instruments: Recognition and Measurement*. IFRS 9 uses a single approach to determine whether a financial asset is measured at amortized cost or fair value, replacing the multiple rules in IAS 39. The accounting treatment of financial liabilities in IFRS 9 is essentially unchanged from IAS 39, except for financial liabilities designated at fair value through profit or loss, whereby an entity can recognize the portion of the change in fair value related to the change in the entity's own credit risk through other comprehensive income rather than net earnings. The standard also introduces a new expected credit loss impairment model for financial assets. In addition, IFRS 9 incorporates new hedge accounting requirements that more closely aligns with risk management activities. An amendment to IFRS 9 requires debt modifications to be discounted at the original effective interest rate of the debt rather than a revised effective interest rate as was required under IAS 39. The adoption of this standard did not have a material impact on the Corporation's consolidated financial statements.

(a) Significant Accounting Policies

Financial Instruments

Financial assets and liabilities are recognized when the Corporation becomes a party to the contractual provisions of the instrument. A financial asset or liability is measured initially at fair value plus, for an item not measured at Fair Value Through Profit or Loss (“FVTPL”), transaction costs that are directly attributable to its acquisition or issuance.

Derivative financial instruments are recognized at fair value. Transaction costs are expensed in the consolidated statement of earnings (loss) and comprehensive income (loss). Gains and losses arising from changes in fair value are recognized in net earnings (loss) in the period in which they arise.

Financial assets and liabilities at FVTPL are classified as current except where an unconditional right to defer payment beyond 12 months exists. Derivative financial instruments are included on the balance sheet as either an asset or liability and are classified as current or non-current based on the contractual terms specific to the instrument.

Financial assets and liabilities are offset and the net amount is reported on the balance sheet when there is a legally enforceable right to offset the recognized amounts and there is an intention to settle on a net basis, or realize the asset and settle the liability simultaneously.

Derivative financial instruments are included in FVTPL unless they are designated for hedge accounting. The Corporation may periodically use derivative financial instruments to manage commodity price, foreign currency and interest rate exposures. The Corporation’s commodity risk management contracts and interest rate swap contract have been classified as FVTPL.

i. Financial assets

At initial recognition, a financial asset is classified as measured at: amortized cost, FVTPL or Fair Value Through OCI (“FVTOCI”) depending on the business model and contractual cash flows of the instrument.

Financial assets are derecognized when the rights to receive cash flows from the assets have expired or have been transferred and the Corporation has transferred substantially all risks and rewards of ownership. A substantial modification to the terms of an existing financial asset results in the derecognition of the financial asset and the recognition of a new financial asset at fair value. In the event that the modification to the terms of an existing financial asset do not result in a substantial difference in the contractual cash flows the gross carrying amount of the financial asset is recalculated and the difference resulting from the adjustment in the gross carrying amount is recognized in earnings or loss.

ii. Financial liabilities

Financial liabilities are measured at amortized cost or FVTPL. Financial liabilities at amortized cost include accounts payable and accrued liabilities and long-term debt. Accounts payable and accrued liabilities are initially recognized at the amount required to be paid less any required discount to reduce the payables to fair value. Long-term debt is recognized initially at fair value, net of any transaction costs incurred, and subsequently at amortized cost using the effective interest method.

Financial liabilities are derecognized when the liability is extinguished. A substantial modification of the terms of an existing financial liability is recorded as an extinguishment of the original financial liability and the recognition of a new financial liability. The difference between the carrying amount of a financial liability extinguished and the consideration paid is recognized in earnings or loss. If the modification is not treated as an extinguishment, any costs or fees incurred to third parties adjust the carrying amount of the liability and are amortized over the remaining term of the modified liability at the original effective interest rate. Payments that represent compensation for the change in cash flows of a liability are expensed as part of the gain or loss on modification.

iii. Impairments

Financial Assets

Loss allowances are measured at an amount equal to the lifetime expected credit losses on the asset. Expected credit losses are a probability-weighted estimate of credit losses and are measured as the present value of all cash shortfalls for financial assets that are not credit-impaired at the reporting date and as the difference between the gross carrying amount and the present value of estimated future cash flows for financial assets that are credit-impaired at the reporting date. Loss allowances for expected credit losses for financial assets measured at amortized cost are presented in the statement of financial position as a deduction from the gross carrying amount of the asset.

(b) Impact from change in accounting policy

The classification of certain financial instruments was impacted by the adoption of IFRS 9. Trade receivables and other are measured at amortized cost under IFRS 9 as the Corporation holds the receivables with the sole intention of collecting contractual cash flows. There were no significant changes to the closing impairment allowance for financial assets determined in accordance with IAS 39 and the expected credit loss allowance determined in accordance with IFRS 9 as at January 1, 2018.

The amendment to IFRS 9 that requires debt modification to be discounted at the original effective interest rate of the debt rather than a revised effective interest rate, as was required under IAS 39, required the Corporation to revise the opening deficit as follows:

		As at January 1, 2018
Increase to net finance expense[(i)]	$	6,381
Tax effect		(1,722)
Increase to opening deficit	$	4,659

(i) The increase to net finance expense was the result of a decrease in the unamortized financial derivative liability discount and debt issue costs which resulted in an increase in the carrying value of long-term debt as at January 1, 2018.

IFRS 2 Share-based Payment

The IASB issued amendments to IFRS 2 *Share-based Payment*, effective January 1, 2018 relating to classification and measurement of particular share-based payment transactions. The adoption of this revision did not have a material impact on the Corporation's consolidated financial statements.

Accounting standards issued but not yet applied

In January 2016, the IASB issued IFRS 16 *Leases*, which will replace IAS 17 *Leases*. Under IFRS 16, a single recognition and measurement model will apply for lessees, which will require recognition of lease assets and lease obligations 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 standard is effective for annual periods beginning on or after January 1, 2019, with early adoption permitted if IFRS 15 has been adopted. The standard may be applied retrospectively or using a modified retrospective approach.

IFRS 16 will be adopted by the Corporation on 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 retained earnings and deficit on transition date and the standard is prospectively applied. The Corporation is currently assessing and evaluating the impact of the standard on the consolidated financial statements. The Corporation anticipates there will be a material impact on the consolidated financial statements and additional new disclosures.

On adoption, the standard is expected to increase the Corporation's assets and liabilities with the recognition of right-of-use ("ROU") assets and corresponding lease liabilities based on the principles of the new standard. The lease liabilities will be measured at the present value of the remaining lease payments, discounted using the Corporation's incremental borrowing rate as at January 1, 2019. The corresponding ROU assets will be measured at the amount equal to the lease liability on January 1, 2019. As a result, there will be an increase to depletion and depreciation expense on ROU 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 will remain unchanged upon transition to IFRS 16.

Lessors

The 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. However, as an intermediate lessor, on adoption of IFRS 16, the Corporation will reassess 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 will be accounted for as a new finance lease entered into on January 1, 2019.

14. RISK FACTORS

The Corporation's primary focus is on the ongoing development and operation of its oil sands 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.

In an effort to reduce the amount of sulphur oxide emanating from ships, the International Maritime Organization ("IMO") has amended the Marine Fuel Oil Sulphur Specifications to set a limit for sulphur in fuel oil used by ships of 0.5 weight percent, from the current limit of 3.5 weight percent, effective January 1, 2020. Refineries worldwide currently blend around three million barrels per day of high sulphur Residual Fuel Oil ("RFO") with lighter oil to make bunker fuel oil for the shipping industry. The majority of MEG's crude is processed by complex refineries which yield little RFO. However, after 2020, the availability of complex refining capacity may become scarce as high sulphur residuum crudes move away from simple refineries and compete for capacity at complex refineries. The IMO sulphur specification amendment has the potential to adversely impact MEG's crude marketing and may contribute to widening of the light to heavy crude oil differential, impacting pricing for heavier crude oils including bitumen.

15. DISCLOSURE CONTROLS AND PROCEDURES

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

16. INTERNAL CONTROLS OVER FINANCIAL REPORTING

The CEO and CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting to provide reasonable assurance regarding the reliability of the Corporation's financial reporting and the preparation of financial statements for external purposes in accordance with IFRS.

The CEO and CFO are required to cause the Corporation to disclose any change in the Corporation's internal controls over financial reporting that occurred during the most recent interim period that has materially affected, or is reasonably likely to materially affect, the Corporation's internal controls over financial reporting. No changes in internal controls over financial reporting were identified during such period that have materially affected, or are reasonably likely to materially affect, the Corporation's internal controls over financial reporting.

It should be noted that a control system, including the Corporation's disclosure and internal controls and procedures, no matter how well conceived, can provide only reasonable, but not absolute, assurance that the objectives of the control system will be met and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud. In reaching a reasonable level of assurance, management necessarily is required to apply its judgment in evaluating the cost/benefit relationship of possible controls and procedures.

17. ABBREVIATIONS

The following provides a summary of common abbreviations used in this document:

Financial and Business Environment

AECO	Alberta natural gas price reference location
AIF	Annual Information Form
AWB	Access Western Blend
$ or C$	Canadian dollars
DSU	Deferred share units
EDC	Export Development Canada
eMSAGP	enhanced Modified Steam And Gas Push
eMVAPEX	enhanced Modified VAPour EXtraction
GAAP	Generally Accepted Accounting Principles
IFRS	International Financial Reporting Standards
LIBOR	London Interbank Offered Rate
MD&A	Management's Discussion and Analysis
PSU	Performance share units
RSU	Restricted share units
SAGD	Steam-Assisted Gravity Drainage
SOR	Steam-oil ratio
U.S.	United States
US$	United States dollars
WCS	Western Canadian Select
WTI	West Texas Intermediate

Measurement

bbl	barrel
bbls/d	barrels per day
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
MW	megawatts
MW/h	megawatts per hour

18. ADVISORY

Forward-Looking Information

This document may contain forward-looking information 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; 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 MEG 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 MEG's future phases and the expansion and/or operation of MEG's projects; risks and uncertainties related to the timing of completion, commissioning, and start-up, of MEG's future phases, expansions and projects; the operational risks and delays in the development, exploration, production, and the capacities and performance associated with MEG's projects; and uncertainties arising in connection with any future disposition of assets.

Although MEG 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 MEG's most recently filed Annual Information Form ("AIF"), along with MEG's other public disclosure documents. Copies of the AIF and MEG'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 MEG 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 oil sands development and production in the southern Athabasca oil sands region of Alberta, Canada. MEG is actively developing enhanced oil recovery projects that utilize SAGD extraction methods. MEG's common shares are listed on the Toronto Stock Exchange under the symbol "MEG."

Estimates of Reserves and Resources

For information regarding MEG's estimated reserves and resources, please refer to MEG's AIF.

Non-GAAP Financial Measures

Certain financial measures in this MD&A do not have a standardized meaning as prescribed by IFRS including: net marketing activity, funds flow from (used in) operations, adjusted funds flow from (used in) operations, operating earnings (loss), operating cash flow 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 MEG's ability to generate funds and to finance its operations as well as profitability measures specific to the oil sands industry. The definition and reconciliation of each non-GAAP measure is presented in the "NON-GAAP MEASURES" section of this MD&A.

19. OFFER TO ACQUIRE ALL OUTSTANDING COMMON SHARES OF MEG ENERGY CORP.

On September 30, 2018, Husky Energy Inc. issued a Press Release announcing a proposal to acquire all of the outstanding Common Shares of MEG Energy Corp. On October 2, 2018, this proposal was formalized and Husky Energy Inc. issued an Offer to Purchase and Bid Circular. MEG Energy Corp. responded through a Press Release and Directors' Circular issued on October 17, 2018. For further information, please refer to MEG's website at www.megenergy.com and also to the SEDAR website at www.sedar.com.

20. ADDITIONAL INFORMATION

Additional information relating to the Corporation, including its AIF, is available on MEG's website at www.megenergy.com and is also available on SEDAR at www.sedar.com.

21. QUARTERLY SUMMARIES

	2018			2017				2016
Unaudited	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**
FINANCIAL ($000 unless specified)								
Net earnings (loss)	**118,160**	(178,570)	140,573	(23,779)	83,885	104,282	1,588	(304,758)
Per share, diluted	**0.39**	(0.61)	0.47	(0.08)	0.28	0.35	0.01	(1.34)
Operating earnings (loss)	**(19,011)**	(70,174)	(18,015)	44,055	(42,571)	(35,656)	(79,354)	(71,989)
Per share, diluted	**(0.06)**	(0.24)	(0.06)	0.15	(0.14)	(0.12)	(0.29)	(0.32)
Adjusted funds flow from operations	**115,742**	18,393	83,157	192,178	83,352	55,095	43,175	39,967
Per share, diluted	**0.39**	0.06	0.28	0.65	0.28	0.19	0.16	0.18
Cash capital investment	**144,508**	182,567	147,739	163,337	103,173	158,474	77,770	63,077
Cash and cash equivalents	**372,550**	563,969	675,116	463,531	397,598	512,424	548,981	156,230
Working capital	**274,344**	211,045	445,792	313,025	350,067	445,463	537,427	96,442
Long-term debt	**3,543,587**	3,606,765	3,542,763	4,668,267	4,635,740	4,813,092	4,944,741	5,053,239
Shareholders' equity	**4,068,048**	3,945,782	4,112,531	3,964,113	3,981,750	3,898,054	3,792,818	3,286,776
BUSINESS ENVIRONMENT								
WTI (US$/bbl)	**69.50**	67.88	62.87	55.40	48.21	48.29	51.91	49.29
C$ equivalent of 1US$ - average	**1.3070**	1.2911	1.2651	1.2717	1.2524	1.3449	1.3230	1.3339
Differential – WTI:WCS (C$/bbl)	**29.08**	24.88	30.72	15.59	12.45	14.97	19.29	19.10
Differential – WTI:WCS (%)	**32.0%**	28.4%	38.6%	22.1%	20.6%	23.0%	28.1%	29.1%
Natural gas – AECO ($/mcf)	**1.28**	1.26	2.26	1.84	1.58	2.81	2.91	3.31
OPERATIONAL ($/bbl unless specified)								
Blend sales - proprietary – bbls/d	**132,461**	109,984	145,189	135,533	114,789	110,695	111,489	118,086
Blend sales price	**63.67**	62.42	51.50	57.01	47.93	49.86	48.77	46.32
Bitumen production – bbls/d	**98,751**	71,325	93,207	90,228	83,008	72,448	77,245	81,780
Bitumen sales – bbls/d	**93,856**	74,418	91,608	94,541	76,813	74,116	74,703	81,746
Steam-oil ratio (SOR)	**2.2**	2.2	2.2	2.2	2.3	2.3	2.4	2.3
Bitumen realization	**49.58**	47.20	35.31	48.30	39.89	39.66	37.93	36.17
Transportation – net	**(9.11)**	(8.28)	(5.99)	(7.00)	(7.08)	(6.91)	(6.54)	(6.05)
Royalties	**(2.01)**	(1.64)	(1.03)	(0.84)	(0.53)	(0.87)	(0.85)	(0.51)
Operating costs – non-energy	**(4.38)**	(5.47)	(4.55)	(4.53)	(4.57)	(4.23)	(5.20)	(4.99)
Operating costs – energy	**(1.50)**	(1.79)	(2.64)	(2.03)	(2.26)	(3.76)	(4.18)	(4.12)
Power revenue	**1.54**	1.62	1.21	0.70	0.83	0.57	0.95	0.87
Realized gain (loss) on commodity risk management	**(10.16)**	(13.11)	(2.15)	(0.77)	0.56	(1.50)	0.22	0.36
Cash operating netback	**23.96**	18.53	20.16	33.83	26.84	22.96	22.33	21.73
Power sales price (C$/MWh)	**51.53**	51.02	35.50	21.37	23.29	18.27	22.42	21.94
Power sales (MW/h)	**117**	98	130	129	115	97	131	134
Depletion and depreciation rate per bbl of production	**13.85**	16.08	13.22	14.26	16.86	16.93	16.81	16.81
COMMON SHARES								
Shares outstanding, end of period (000)	**296,813**	296,751	294,105	294,104	294,079	294,047	293,282	226,467
Volume traded (000)	**128,363**	166,016	89,721	76,531	70,216	98,795	123,445	114,776
Common share price ($)								
High	**11.51**	11.24	6.43	6.82	5.79	7.27	9.83	9.79
Low	**6.78**	4.49	4.28	4.54	3.28	3.63	5.84	5.11
Close (end of period)	**8.03**	10.96	4.55	5.14	5.49	3.81	6.74	9.23

Interim Consolidated Financial Statements

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

As at	Note	September 30, 2018	December 31, 2017
Assets			
Current assets			
Cash and cash equivalents	20	$ 372,550	$ 463,531
Trade receivables and other		289,742	289,104
Inventories		100,016	85,850
Commodity risk management	22	3,498	—
		765,806	838,485
Non-current assets			
Property, plant and equipment	5	6,616,536	7,634,399
Exploration and evaluation assets	6	548,631	548,828
Intangible assets	7	11,104	13,037
Other assets	8	210,189	145,732
Commodity risk management	22	8,117	—
Deferred income tax asset	19	237,813	182,871
Total assets		$ 8,398,196	$ 9,363,352
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities		$ 361,219	$ 413,905
Current portion of long-term debt	9	15,961	15,460
Current portion of provisions and other liabilities	10	26,311	27,446
Commodity risk management	22	87,971	68,649
		491,462	525,460
Non-current liabilities			
Long-term debt	9	3,543,587	4,668,267
Provisions and other liabilities	10	292,645	205,512
Commodity risk management	22	2,454	—
Total liabilities		4,330,148	5,399,239
Shareholders' equity			
Share capital	11	5,426,753	5,403,978
Contributed surplus		163,861	166,636
Deficit		(1,551,293)	(1,629,091)
Accumulated other comprehensive income		28,727	22,590
Total shareholders' equity		4,068,048	3,964,113
Total liabilities and shareholders' equity		$ 8,398,196	$ 9,363,352

Commitments and contingencies (Note 24)

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

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

		Three months ended September 30		Nine months ended September 30	
	Note	2018	2017 Revised (Note 3)	2018	2017 Revised (Note 3)
Revenues					
Petroleum revenue, net of royalties	3,13	**$ 787,382**	$ 567,400	**$ 2,169,445**	$ 1,694,369
Other revenue	3,13	**15,802**	8,859	**43,455**	25,304
		803,184	576,259	**2,212,900**	1,719,673
Expenses					
Diluent and transportation	14	**419,069**	246,891	**1,158,452**	803,194
Operating expenses		**50,721**	48,222	**159,114**	165,146
Purchased product and storage	3,15	**38,266**	95,105	**199,899**	249,891
Depletion and depreciation	5,7	**125,834**	128,754	**341,083**	357,238
General and administrative		**21,360**	19,321	**62,235**	63,482
Stock-based compensation	12	**7,905**	12,545	**39,082**	17,323
Research and development		**1,693**	1,299	**4,106**	3,405
Net finance expense	17	**71,943**	78,417	**211,731**	254,910
Exploration expense		**978**	—	**978**	—
Other expenses	18	**2,826**	20,058	**6,603**	29,182
Gain on asset dispositions	5	**—**	—	**(318,398)**	—
Commodity risk management loss (gain)	22	**(20,221)**	53,494	**205,569**	(14,752)
Foreign exchange loss (gain), net	16	**(59,071)**	(178,384)	**112,893**	(348,407)
Earnings (loss) before income taxes		**141,881**	50,537	**29,553**	139,061
Income tax expense (recovery)	19	**23,721**	(33,348)	**(50,610)**	(50,694)
Net earnings (loss)		**118,160**	83,885	**80,163**	189,755
Other comprehensive income (loss), net of tax					
Items that may be reclassified to profit or loss:					
Foreign currency translation adjustment		**(3,021)**	(6,352)	**6,137**	(12,519)
Comprehensive income (loss) for the period		**$ 115,139**	$ 77,533	**$ 86,300**	$ 177,236
Net earnings (loss) per common share					
Basic	21	**$ 0.40**	$ 0.29	**$ 0.27**	$ 0.66
Diluted	21	**$ 0.39**	$ 0.28	**$ 0.27**	$ 0.66

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

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

	Note	Share Capital	Contributed Surplus	Deficit	Accumulated Other Comprehensive Income	Total Shareholders' Equity
Balance as at December 31, 2017		**$5,403,978**	**$ 166,636**	**$(1,629,091)**	**$ 22,590**	**$ 3,964,113**
IFRS 9 opening deficit adjustment	3	**—**	**—**	**(4,659)**	**—**	**(4,659)**
Stock-based compensation		**—**	**18,946**	**—**	**—**	**18,946**
Stock options exercised	11	**1,560**	**(506)**	**—**	**—**	**1,054**
RSUs vested and released	11	**21,215**	**(21,215)**	**2,294**	**—**	**2,294**
Comprehensive income (loss)		**—**	**—**	**80,163**	**6,137**	**86,300**
Balance as at September 30, 2018		**$5,426,753**	**$ 163,861**	**$(1,551,293)**	**$ 28,727**	**$ 4,068,048**
Balance as at December 31, 2016		$4,878,607	$ 168,253	$(1,795,067)	$ 34,983	$ 3,286,776
Shares issued		517,816	—	—	—	517,816
Share issue costs, net of tax		(15,698)	—	—	—	(15,698)
Stock-based compensation		—	15,620	—	—	15,620
RSUs vested and released		22,855	(22,855)	—	—	—
Comprehensive income (loss)		—	—	189,755	(12,519)	177,236
Balance as at September 30, 2017		$5,403,580	$ 161,018	$(1,605,312)	$ 22,464	$ 3,981,750

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

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

		Three months ended September 30		Nine months ended September 30	
	Note	2018	2017	2018	2017
Cash provided by (used in):					
Operating activities					
Net earnings (loss)		**$ 118,160**	$ 83,885	**$ 80,163**	$ 189,755
Adjustments for:					
Depletion and depreciation	5,7	**125,834**	128,754	**341,083**	357,238
Exploration expense		**978**	—	**978**	—
Stock-based compensation	12	**6,771**	5,491	**16,899**	13,764
Unrealized loss (gain) on foreign exchange	16	**(58,253)**	(180,448)	**145,422**	(345,116)
Unrealized loss (gain) on derivative financial liabilities	17	**(192)**	(3,490)	**2,674**	(7,346)
Unrealized loss (gain) on commodity risk management	22	**(107,949)**	57,470	**11,371**	(19,353)
Onerous contracts expense	18	**897**	(27)	**1,686**	5,681
Deferred income tax expense (recovery)	19	**23,604**	(33,091)	**(50,922)**	(50,268)
Amortization of debt discount and debt issue costs	8,9	**3,354**	4,721	**11,489**	14,475
Gain on asset dispositions	5	**—**	—	**(318,398)**	—
Other		**2,589**	1,322	**3,327**	4,027
Decommissioning expenditures	10	**(452)**	(386)	**(3,823)**	(1,847)
Payments on onerous contracts	10	**(4,332)**	(5,089)	**(14,576)**	(14,691)
Net change in other liabilities		**(51)**	—	**6,882**	—
Net change in non-cash working capital items	20	**(107,549)**	(51,133)	**(47,577)**	(28,922)
Net cash provided by (used in) operating activities		**3,409**	7,979	**186,678**	117,397
Investing activities					
Capital investments:					
Property, plant and equipment	5	**(138,635)**	(108,050)	**(476,420)**	(342,758)
Exploration and evaluation	6	**(939)**	(560)	**(1,496)**	(1,252)
Intangible assets	7	**(224)**	(115)	**(323)**	(129)
Net proceeds on dispositions	5	**—**	4,981	**1,502,869**	4,981
Other		**(5,154)**	4,940	**(7,888)**	21,873
Net change in non-cash working capital items	20	**(43,446)**	(23,484)	**(15,294)**	38,661
Net cash provided by (used in) investing activities		**(188,398)**	(122,288)	**1,001,448**	(278,624)
Financing activities					
Issue of shares, net of issue costs	11	**229**	—	**1,054**	496,312
Redemption of senior unsecured notes		**—**	—	**—**	(1,008,825)
Issue of senior secured second lien notes		**—**	—	**—**	1,008,825
Payments on term loan	20	**(4,028)**	(3,892)	**(1,280,778)**	(8,747)
Refinancing costs		**—**	—	**—**	(82,377)
Net cash provided by (used in) financing activities		**(3,799)**	(3,892)	**(1,279,724)**	405,188
Effect of exchange rate changes on cash and cash equivalents held in foreign currency		**(2,631)**	3,375	**617**	(2,593)
Change in cash and cash equivalents		**(191,419)**	(114,826)	**(90,981)**	241,368
Cash and cash equivalents, beginning of period		**563,969**	512,424	**463,531**	156,230
Cash and cash equivalents, end of period		**$ 372,550**	$ 397,598	**$ 372,550**	$ 397,598

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

1. CORPORATE INFORMATION

MEG Energy Corp. (the "Corporation") was incorporated under the *Alberta Business Corporations Act* on March 9, 1999. The Corporation's shares trade on the Toronto Stock Exchange ("TSX") under the symbol "MEG". The Corporation owns a 100% interest in over 900 square miles of oil sands leases in the southern Athabasca oil sands region of northern Alberta and is primarily engaged in a steam assisted gravity drainage oil sands development at its 80 section Christina Lake Project.

In the first quarter of 2018, the Corporation successfully completed the sale of its 50% interest in the Access Pipeline and its 100% interest in the Stonefell Terminal for cash proceeds of $1.52 billion and other consideration of $90 million (Note 5).

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

2. BASIS OF PRESENTATION

The unaudited interim consolidated financial statements ("interim consolidated financial statements") were prepared using the same accounting policies and methods as those used in the Corporation's audited consolidated financial statements for the year ended December 31, 2017, except as described in Note 3. The interim consolidated financial statements are in compliance with International Accounting Standard 34, Interim Financial Reporting ("IAS 34"). Accordingly, certain information and footnote disclosure normally included in annual financial statements prepared in accordance with International Financial Reporting Standards ("IFRS"), as issued by the International Accounting Standards Board ("IASB"), has been omitted or condensed. The preparation of interim consolidated financial statements in accordance with IAS 34 requires the use of certain critical accounting estimates. It also requires management to exercise judgment in applying the Corporation's accounting policies. The areas involving a higher degree of judgment or complexity, or areas where assumptions and estimates are significant to the consolidated financial statements, have been set out in Note 4 of the Corporation's audited consolidated financial statements for the year ended December 31, 2017 and in Note 4 of these interim consolidated financial statements. These interim consolidated financial statements should be read in conjunction with the Corporation's audited consolidated financial statements for the year ended December 31, 2017.

These interim consolidated financial statements are presented in Canadian dollars ($ or C$), which is the Corporation's functional currency. The Corporation's operations are aggregated into one operating segment for reporting, consistent with the internal reporting provided to the chief operating decision-maker of the Corporation.

These interim consolidated financial statements were approved by the Corporation's Audit Committee on October 31, 2018.

3. CHANGE IN ACCOUNTING POLICIES

New accounting standards

(a) IFRS 15 *Revenue From Contracts With Customers*

The IASB issued IFRS 15 *Revenue From Contracts With Customers*, which is effective January 1, 2018 and replaces IAS 11 *Construction Contracts* and IAS 18 *Revenue* and the related interpretations on revenue recognition. IFRS 15 provides a comprehensive revenue recognition and measurement framework that applies to all contracts with customers. The Corporation adopted IFRS 15 retrospectively as required by the standard on January 1, 2018, and applied a practical expedient whereby completed contracts prior to January

1, 2017 were not assessed. The adoption of this standard did not have a material impact on the Corporation's consolidated financial statements. The main changes are explained below.

i. Significant Accounting Policies

Revenues

The Corporation earns revenue primarily from the sale of crude oil, with other revenue earned from excess power generation, and from transportation fees charged to third parties.

(1) Petroleum revenue recognition

The Corporation sells proprietary and purchased crude oil and natural gas under contracts of varying terms of up to one year to customers at prevailing market prices, whereby delivery takes place throughout the contract period. In most cases, consideration is due when title has transferred and is generally collected in the month following the month of delivery.

The Corporation evaluates its arrangements with third parties to determine if the Corporation acts as the principal or as an agent. In making this evaluation, management considers if the Corporation obtains control of the product delivered. If the Corporation acts in the capacity of an agent rather than as a principal in a transaction, then the revenue is recognized on a net-basis, only reflecting the fee, if any, realized by the Corporation from the transaction.

Revenues associated with the sales of proprietary and purchased crude oil owned by the Corporation are recognized at a point in time when control of goods have transferred, which is generally when title passes from the Corporation to the customer. Revenues are recorded net of crown royalties. Crown royalties are recognized at the time of production.

Revenue is allocated to each performance obligation on the basis of its standalone selling price and measured at the transaction price, which is the fair value of the consideration and represents amounts receivable for goods or services provided in the normal course of business. The price is allocated to each unit in the series as each unit is substantially the same and depicts the same pattern of transfer to the customer.

(2) Other revenue recognition

Revenue from power generated in excess of the Corporation's internal requirements is recognized upon delivery from the plant gate, at which point, control is transferred to the customer on the power grid. Revenues are earned at prevailing market prices for each megawatt hour produced.

Fees charged to customers for the use of pipelines and facilities are recognized in the period when the products are delivered and the services are provided.

(3) Asset dispositions

Property, plant and equipment assets are derecognized upon disposal or when no future economic benefits are expected to arise from the continued use of the asset. Any gain or loss arising from derecognition of the asset is determined as the difference between the net disposal proceeds, if any, and the carrying amount of the asset, and is recognized in net earnings or loss, unless the disposition is part of a sale and leaseback. The amount of consideration to be included in the gain or loss arising from derecognition is determined by the transaction contract.

Dispositions of property, plant and equipment occur on the date the acquiror obtains control of the asset.

ii. Impact from change in accounting policy

Under IFRS 15, revenues from the purchase and sale of proprietary crude oil are recognized on a gross basis as separate performance obligations. In conjunction with the transition to IFRS 15, the presentation of petroleum revenue, net of royalties and purchased product and storage will change, with no impact on earnings (loss) before income tax, net earnings (loss), comprehensive income (loss), or net cash provided by (used in) operating activities.

The quarterly impact of these changes in 2017 was as follows:

	Q1 2017	Q2 2017	Q3 2017	Q4 2017	Total
Petroleum revenue – proprietary, as previously reported	$ 489,388	$ 492,613	$ 475,784	$ 710,817	$ 2,168,602
Blend purchases	—	9,602	30,367	6	39,975
Adjusted petroleum revenue – proprietary	**$ 489,388**	**$ 502,215**	**$ 506,151**	**$ 710,823**	**$ 2,208,577**
Purchased product and storage as previously reported	$ 65,542	$ 79,642	$ 64,738	$ 40,759	$ 250,681
Blend purchases	—	9,602	30,367	6	39,975
Adjusted purchased product and storage	**$ 65,542**	**$ 89,244**	**$ 95,105**	**$ 40,765**	**$ 290,656**

Enhanced required disclosures are provided in Notes 13 and 15.

(b) IFRS 9 *Financial Instruments*

The IASB issued IFRS 9 *Financial Instruments*, which is effective January 1, 2018 and replaces IAS 39 *Financial Instruments: Recognition and Measurement*. IFRS 9 uses a single approach to determine whether a financial asset is measured at amortized cost or fair value, replacing the multiple rules in IAS 39. The accounting treatment of financial liabilities in IFRS 9 is essentially unchanged from IAS 39, except for financial liabilities designated at fair value through profit or loss, whereby an entity can recognize the portion of the change in fair value related to the change in the entity's own credit risk through other comprehensive income rather than net earnings. The standard also introduces a new expected credit loss impairment model for financial assets. In addition, IFRS 9 incorporates new hedge accounting requirements that more closely aligns with risk management activities. An amendment to IFRS 9 requires debt modifications to be discounted at the original effective interest rate of the debt rather than a revised effective interest rate as was required under IAS 39. The adoption of this standard did not have a material impact on the Corporation's consolidated financial statements.

i. Significant Accounting Policies

Financial Instruments

Financial assets and liabilities are recognized when the Corporation becomes a party to the contractual provisions of the instrument. A financial asset or liability is measured initially at fair value plus, for an item not measured at Fair Value Through Profit or Loss ("FVTPL"), transaction costs that are directly attributable to its acquisition or issuance.

Derivative financial instruments are recognized at fair value. Transaction costs are expensed in the consolidated statement of earnings (loss) and comprehensive income (loss). Gains and losses arising from changes in fair value are recognized in net earnings (loss) in the period in which they arise.

Financial assets and liabilities at FVTPL are classified as current except where an unconditional right to defer payment beyond 12 months exists. Derivative financial instruments are included on the balance sheet as either an asset or liability and are classified as current or non-current based on the contractual terms specific to the instrument.

Financial assets and liabilities are offset and the net amount is reported on the balance sheet when there is a legally enforceable right to offset the recognized amounts and there is an intention to settle on a net basis, or realize the asset and settle the liability simultaneously.

Derivative financial instruments are included in FVTPL unless they are designated for hedge accounting. The Corporation may periodically use derivative financial instruments to manage commodity price, foreign currency and interest rate exposures. The Corporation's commodity risk management contracts and interest rate swap contract have been classified as FVTPL.

Financial Assets

At initial recognition, a financial asset is classified as measured at: amortized cost, FVTPL or Fair Value Through OCI ("FVTOCI") depending on the business model and contractual cash flows of the instrument.

Financial assets are derecognized when the rights to receive cash flows from the assets have expired or have been transferred and the Corporation has transferred substantially all risks and rewards of ownership. A substantial modification to the terms of an existing financial asset results in the derecognition of the financial asset and the recognition of a new financial asset at fair value. In the event that the modification to the terms of an existing financial asset do not result in a substantial difference in the contractual cash flows the gross carrying amount of the financial asset is recalculated and the difference resulting from the adjustment in the gross carrying amount is recognized in earnings or loss.

Financial Liabilities

Financial liabilities are measured at amortized cost or FVTPL. Financial liabilities at amortized cost include accounts payable and accrued liabilities and long-term debt. Accounts payable and accrued liabilities are initially recognized at the amount required to be paid less any required discount to reduce the payables to fair value. Long-term debt is recognized initially at fair value, net of any transaction costs incurred, and subsequently at amortized cost using the effective interest method.

Financial liabilities are derecognized when the liability is extinguished. A substantial modification of the terms of an existing financial liability is recorded as an extinguishment of the original financial liability and the recognition of a new financial liability. The difference between the carrying amount of a financial liability extinguished and the consideration paid is recognized in earnings or loss. If the modification is not treated as an extinguishment, any costs or fees incurred to third parties adjust the carrying amount of the liability and are amortized over the remaining term of the modified liability at the original effective interest rate. Payments that represent compensation for the change in cash flows of a liability are expensed as part of the gain or loss on modification.

Impairments

Financial assets

Loss allowances are measured at an amount equal to the lifetime expected credit losses on the asset. Expected credit losses are a probability-weighted estimate of credit losses and are measured as the present value of all cash shortfalls for financial assets that are not credit-impaired at the reporting date and as the difference between the gross carrying amount and the present value of estimated future cash flows for financial assets that are credit-impaired at the reporting date. Loss allowances for expected credit losses for financial assets measured at amortized cost are presented in the statement of financial position as a deduction from the gross carrying amount of the asset.

ii. Impact from change in accounting policy

The classification of certain financial instruments was impacted by the adoption of IFRS 9. Trade receivables and other are measured at amortized cost under IFRS 9 as the Corporation holds the receivables with the sole intention of collecting contractual cash flows. There were no significant changes to the closing impairment allowance for financial assets determined in accordance with IAS 39 and the expected credit loss allowance determined in accordance with IFRS 9 as at January 1, 2018.

The amendment to IFRS 9 that requires debt modification to be discounted at the original effective interest rate of the debt rather than a revised effective interest rate, as was required under IAS 39, required the Corporation to revise the opening deficit as follows:

		As at January 1, 2018
Increase to net finance expense[(i)]	$	6,381
Tax effect		(1,722)
Increase to opening deficit	**$**	**4,659**

(i) The increase to net finance expense was the result of a decrease in the unamortized financial derivative liability discount and debt issue costs which resulted in an increase in the carrying value of long-term debt as at January 1, 2018.

(c) IFRS 2 *Share-based Payment*

The IASB issued amendments to IFRS 2 *Share-based Payment*, effective January 1, 2018 relating to classification and measurement of particular share-based payment transactions. The adoption of this revision did not have a material impact on the Corporation's consolidated financial statements.

Accounting standards issued but not yet applied

In January 2016, the IASB issued IFRS 16 *Leases*, which will replace IAS 17 *Leases*. Under IFRS 16, a single recognition and measurement model will apply for lessees, which will require recognition of lease assets and lease obligations 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 standard is effective for annual periods beginning on or after January 1, 2019, with early adoption permitted if IFRS 15 has been adopted. The standard may be applied retrospectively or using a modified retrospective approach.

IFRS 16 will be adopted by the Corporation on 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 retained earnings and deficit on transition date and the standard is prospectively applied. The Corporation is currently assessing and evaluating the impact of the standard on the consolidated financial statements. The Corporation anticipates there will be a material impact on the consolidated financial statements and additional new disclosures.

On adoption, the standard is expected to increase the Corporation's assets and liabilities with the recognition of right-of-use ("ROU") assets and corresponding lease liabilities based on the principles of the new standard. The lease liabilities will be measured at the present value of the remaining lease payments, discounted using the Corporation's incremental borrowing rate as at January 1, 2019. The corresponding ROU assets will be measured at the amount equal to the lease liability on January 1, 2019. As a result, there will be an increase to depletion and depreciation expense on ROU 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 will remain unchanged upon transition to IFRS 16.

Lessors

The 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. However, as an intermediate lessor, on adoption of IFRS 16, the Corporation will reassess 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 will be accounted for as a new finance lease entered into on January 1, 2019.

4. SIGNIFICANT ACCOUNTING ESTIMATES, ASSUMPTIONS AND JUDGMENTS

The same accounting estimates, assumptions and judgments were used in the unaudited interim consolidated financial statements as were used in the Corporation's audited consolidated financial statements. Additional estimates, assumptions and judgments for 2018 are outlined below:

(a) Sale and leaseback accounting

During the first quarter of 2018, the Corporation sold its 100% interest in the Stonefell Terminal and management determined that the sale of the Stonefell Terminal and the subsequent lease of the terminal should be accounted for as a sale and leaseback transaction that resulted in a finance lease.

Determining the measurement of a finance lease asset and obligation is a complex process that involves estimates, assumptions and judgments to determine the fair value of leased assets, and estimates on timing and amount of expected future cash flows and discount rates. Any future changes to the estimated discount rate will not impact the carrying values of the finance lease asset and obligation. The leased asset will be subject to property, plant and equipment impairment reviews at subsequent reporting periods.

5. PROPERTY, PLANT AND EQUIPMENT

	Crude oil	Transportation and storage	Corporate assets	Total
Cost				
Balance as at December 31, 2016	$ 7,878,009	$ 1,610,118	$ 55,983	$ 9,544,110
Additions	478,782	8,645	20,465	507,892
Dispositions	(24,102)	—	—	(24,102)
Change in decommissioning liabilities	(34,599)	(922)	—	(35,521)
Balance as at December 31, 2017	$ 8,298,090	$ 1,617,841	$ 76,448	$ 9,992,379
Additions	473,311	200,855	355	674,521
Transfers to other assets (Note 8)	—	(67,318)	—	(67,318)
Dispositions	—	(1,396,864)	—	(1,396,864)
Change in decommissioning liabilities	(32,119)	(342)	—	(32,461)
Balance as at September 30, 2018	**$ 8,739,282**	**$ 354,172**	**$ 76,803**	**$ 9,170,257**
Accumulated depletion and depreciation				
Balance as at December 31, 2016	$ 1,766,709	$ 110,833	$ 27,134	$ 1,904,676
Depletion and depreciation	436,271	29,801	5,964	472,036
Dispositions	(18,732)	—	—	(18,732)
Balance as at December 31, 2017	$ 2,184,248	$ 140,634	$ 33,098	$ 2,357,980
Depletion and depreciation	316,418	20,585	4,820	341,823
Dispositions	—	(146,082)	—	(146,082)
Balance as at September 30, 2018	**$ 2,500,666**	**$ 15,137**	**$ 37,918**	**$ 2,553,721**
Carrying amounts				
Balance as at December 31, 2017	$ 6,113,842	$ 1,477,207	$ 43,350	$ 7,634,399
Balance as at September 30, 2018	**$ 6,238,616**	**$ 339,035**	**$ 38,885**	**$ 6,616,536**

During the first quarter of 2018, the Corporation successfully completed the sale of its 50% interest in the Access Pipeline and its 100% interest in the Stonefell Terminal for proceeds of $1.50 billion (net of transaction costs of $18.5 million). As a result of the transaction, the Corporation recognized a gain of $318.4 million on the sale of its 50% interest in the Access Pipeline. The sale of its 100% interest in the Stonefell Terminal has been accounted for as a sale and leaseback transaction that results in a finance lease (Note 10(a)). The $192.4 million net book value of the leased asset is included in transportation and storage assets within property, plant and equipment. The Stonefell Lease Agreement is a 30-year arrangement that secures the Corporation’s operational control and exclusive use of 100% of Stonefell Terminal’s 900,000 barrel blend and condensate facility.

As at September 30, 2018, property, plant and equipment was assessed for impairment and no impairment was recognized. Included in the cost of property, plant and equipment is $260.8 million of assets under construction (December 31, 2017 – $459.7 million).

6. EXPLORATION AND EVALUATION ASSETS

Cost		
Balance as at December 31, 2016	$	547,752
Additions		1,569
Change in decommissioning liabilities		(493)
Balance as at December 31, 2017	$	548,828
Additions		1,496
Dispositions		(978)
Change in decommissioning liabilities		(715)
Balance as at September 30, 2018	**$**	**548,631**

Exploration and evaluation assets consist of exploration projects which are pending the determination of proved or probable reserves. These assets are not subject to depletion, as they are in the exploration and evaluation stage, but are reviewed on a quarterly basis for any indication of impairment. As at September 30, 2018, these assets were assessed for impairment and no impairment has been recognized on exploration and evaluation assets.

7. INTANGIBLE ASSETS

Cost		
Balance as at December 31, 2016	$	112,921
Additions		534
Balance as at December 31, 2017	$	113,455
Additions		323
Balance as at September 30, 2018	**$**	**113,778**

Accumulated depreciation		
Balance as at December 31, 2016	$	96,810
Depreciation		3,608
Balance as at December 31, 2017	$	100,418
Depreciation		2,256
Balance as at September 30, 2018	**$**	**102,674**

Carrying amounts		
Balance as at December 31, 2017	$	13,037
Balance as at September 30, 2018	**$**	**11,104**

As at September 30, 2018, intangible assets consist of $11.1 million invested in software that is not an integral component of the related computer hardware (December 31, 2017 – $13.0 million). As at September 30, 2018, no impairment has been recognized on these assets.

8. OTHER ASSETS

As at	September 30, 2018	December 31, 2017
Long-term pipeline linefill[(a)]	$ 193,309	$ 122,657
Deferred financing costs	17,653	24,134
Prepaid transportation costs[(b)]	7,880	—
Interest rate swap[(c)]	—	8,067
	218,842	154,858
Less current portion	(8,653)	(9,126)
	$ 210,189	$ 145,732

(a) Long-term pipeline linefill on third party owned pipelines is classified as a long-term asset as these transportation contracts expire between the years 2025 and 2048. As a result of the sale of the Corporation's 50% interest in Access Pipeline and its 100% interest in the Stonefell Terminal in the first quarter of 2018, $67.3 million of the associated pipeline linefill was transferred from property, plant and equipment to other assets. As at September 30, 2018, no impairment has been recognized on these assets.

(b) During the nine months ended September 30, 2018, the Corporation invested $7.9 million to upgrade third-party transportation infrastructure under the terms of a long-term transportation services agreement. The prepaid expenditures have been capitalized and will be amortized to transportation expense over the 30-year term of the agreement, once the transportation infrastructure is available for use.

(c) In the third quarter of 2017, the Corporation entered into an interest rate swap contract to effectively fix the interest rate on US$650.0 million of its US$1.2 billion senior secured term loan at approximately 5.3%. In conjunction with the March 2018 partial repayment of the senior secured term loan, the interest rate swap was terminated and a realized gain of $17.3 million was recognized (Note 17).

9. LONG-TERM DEBT

As at	September 30, 2018	December 31, 2017
Senior secured term loan (September 30, 2018 – US$228.5 million; due 2023; December 31, 2017 – US$1.226 billion)[(a)]	$ 295,281	$ 1,534,378
6.5% senior secured second lien notes (US$750.0 million; due 2025)	969,300	938,850
6.375% senior unsecured notes (US$800.0 million; due 2023)	1,033,920	1,001,440
7.0% senior unsecured notes (US$1.0 billion; due 2024)	1,292,400	1,251,800
	3,590,901	4,726,468
Less unamortized financial derivative liability discount	(1,333)	(4,242)
Less unamortized deferred debt discount and debt issue costs	(30,020)	(38,499)
	3,559,548	4,683,727
Less current portion of senior secured term loan	(15,961)	(15,460)
	$ 3,543,587	$ 4,668,267

The U.S. dollar denominated debt was translated into Canadian dollars at the period end exchange rate of US$1 = C$1.2924 (December 31, 2017 – US$1 = C$1.2518).

All of the Corporation's long-term debt is "covenant-lite" in structure, meaning it is free of any financial maintenance covenants and is not dependent on, nor calculated from, the Corporation's crude oil reserves.

(a) During the first quarter of 2018, subsequent to the sale of assets, a majority of the net cash proceeds were used to repay approximately $1.2 billion of the senior secured term loan (Note 5).

As at September 30, 2018, the senior secured credit facilities are comprised of a US$228.5 million term loan and a US$1.4 billion revolving credit facility. The senior secured term loan, credit facilities and second lien notes are secured by substantially all the assets of the Corporation. As at September 30, 2018, no amount has been drawn under the US$1.4 billion revolving credit facility.

The Corporation's letter of credit facility, guaranteed by Export Development Canada, has a limit of US$440 million. Letters of credit under this facility do not consume capacity of the revolving credit facility. As at September 30, 2018, the Corporation has US$115.7 million of unutilized capacity under this facility.

10. PROVISIONS AND OTHER LIABILITIES

As at	September 30, 2018	December 31, 2017
Finance leases[a]	$ **130,858**	$ —
Onerous contracts provision[b]	**79,934**	92,157
Decommissioning provision[c]	**69,544**	102,530
Deferred lease inducements[d]	**21,409**	22,854
Other long-term liabilities	**17,211**	15,417
Provisions and other liabilities	**318,956**	232,958
Less current portion	**(26,311)**	(27,446)
Non-current portion	$ **292,645**	$ 205,512

(a) Finance leases:

As at	September 30, 2018	December 31, 2017
Balance, beginning of year	$ **—**	$ —
Liabilities incurred	**130,446**	—
Liabilities settled	**(8,251)**	—
Interest expense	**8,663**	—
Balance, end of period	$ **130,858**	$ —

During the first quarter of 2018, the Corporation successfully completed the sale of its 100% interest in the Stonefell Terminal. Concurrently, the Corporation entered into a Stonefell Lease Agreement, which is a 30-year arrangement that secures the Corporation's operational control and use of 100% of the Stonefell Terminal. The sale of the Stonefell Terminal and the Stonefell Lease Agreement are accounted for as a sale and leaseback transaction that results in a finance lease. The lease payments are escalated at 1% per year and the Corporation is entitled to unlimited renewal terms. The total undiscounted amount of the estimated future cash flows to settle the lease obligations over the remaining lease term is $538.2 million. At the time the Corporation entered into the lease agreement, the Corporation estimated the net present value of the lease obligations using an estimated incremental borrowing rate of 13.5%.

The Corporation's minimum lease payments are as follows:

As at	September 30, 2018
Within one year	$ **15,741**
Later than one year but not later than five years	**64,638**
Later than five years	**457,785**
Minimum lease payments	**538,164**
Amounts representing finance charges	**(407,306)**
Present value of net minimum lease payments	$ **130,858**

(b) Onerous contracts provision:

As at	September 30, 2018	December 31, 2017
Balance, beginning of year	$ **92,157**	$ 100,159
Changes in estimated future cash flows	**2,688**	13,337
Changes in discount rates	**(1,002)**	(2,507)
Liabilities settled	**(14,576)**	(19,569)
Accretion	**667**	737
Balance, end of period	**79,934**	92,157
Less current portion	**(14,562)**	(19,047)
Non-current portion	$ **65,372**	$ 73,110

As at September 30, 2018, the Corporation has recognized a provision of $79.9 million related to onerous operating lease contracts (December 31, 2017 – $92.2 million). The provision represents the present value of the difference between the minimum future payments that the Corporation is obligated to make under the non-cancellable onerous operating lease contracts and estimated recoveries. The total undiscounted amount of the estimated future cash flows to settle the onerous contracts obligations is $90.5 million (December 31, 2017 – $102.1 million). These cash flows have been discounted using a risk-free discount rate of 2.2% (December 31, 2017 – 1.8%). This estimate may vary as a result of changes in estimated recoveries.

(c) Decommissioning provision:

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

As at	September 30, 2018	December 31, 2017
Balance, beginning of year	**$ 102,530**	$ 133,924
Changes in estimated future cash flows and settlement dates	**2,758**	(36,314)
Changes in discount rates	**(41,850)**	(19,602)
Liabilities incurred	**5,964**	19,902
Liabilities disposed	**(976)**	—
Liabilities settled	**(3,823)**	(2,403)
Accretion	**4,941**	7,023
Balance, end of period	**69,544**	102,530
Less current portion	**(9,827)**	(6,386)
Non-current portion	**$ 59,717**	$ 96,144

The decommissioning provision represents the present value of the estimated future costs for the reclamation and abandonment of the Corporation's property, plant and equipment and exploration and evaluation assets. The total undiscounted amount of the estimated future cash flows to settle the decommissioning obligations is $811.4 million (December 31, 2017 – $859.1 million). The Corporation has estimated the net present value of the decommissioning obligations using a weighted average credit-adjusted risk-free rate of 14.4% (December 31, 2017 – 9.5%).

(d) Deferred lease inducements:

Deferred lease inducements of $21.4 million will be amortized over the respective terms of the Corporation's office leases.

11. SHARE CAPITAL

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

Changes in issued common shares are as follows:

	Nine months ended September 30, 2018		Year ended December 31, 2017	
	Number of shares (thousands)	Amount	Number of shares (thousands)	Amount
Balance, beginning of year	**294,104**	**$ 5,403,978**	226,467	$ 4,878,607
Shares issued	**—**	**—**	66,815	517,816
Share issue costs net of tax	**—**	**—**	—	(15,698)
Issued upon exercise of stock options	**184**	**1,560**	—	—
Issued upon vesting and release of RSUs and PSUs	**2,525**	**21,215**	822	23,253
Balance, end of period	**296,813**	**$ 5,426,753**	294,104	$ 5,403,978

12. STOCK-BASED COMPENSATION

The Corporation has a number of stock-based compensation plans which include stock options, restricted share units ("RSUs"), performance share units ("PSUs") and deferred share units ("DSUs"). Further detail on each of these plans is outlined below.

(a) Cash-settled plans

i. Restricted share units and performance share units:

RSUs granted under the cash-settled RSU plan generally vest annually in thirds over a three-year period. PSUs granted under the cash-settled RSU plan generally vest on the third anniversary of the grant date, provided that the Corporation satisfies certain performance criteria identified by the Corporation's Board of Directors within a target range and which are set and measured annually. The stock-based compensation expense for PSUs is determined based on an estimate of the final number of PSU awards that eventually vest based on the performance multiplier and the performance criteria.

Cash-settled RSUs and PSUs outstanding:

Nine months ended September 30, 2018	**(thousands)**
Outstanding, beginning of year	**5,310**
Granted	**467**
Vested and released	**(1,397)**
Forfeited	**(117)**
Outstanding, end of period	**4,263**

ii. Deferred share units outstanding:

The Deferred Share Unit Plan allows for the granting of DSUs to directors of the Corporation. As at September 30, 2018, there were 342,775 DSUs outstanding (December 31, 2017 – 284,871 DSUs outstanding).

As at September 30, 2018, the Corporation has recognized a liability of $27.1 million relating to the fair value of cash-settled RSUs, PSUs and DSUs (December 31, 2017 – $14.3 million). The current portion of $20.2 million is included within accounts payable and accrued liabilities and $6.9 million is included as a long-term liability within provisions and other liabilities based on the expected payout dates of the individual awards.

(b) Equity-settled plans

i. Stock options outstanding:

The Corporation's Stock Option Plan allows for the granting of stock options to directors, officers, employees and consultants of the Corporation. Stock options granted are generally fully exercisable after three years and expire seven years after the grant date.

Nine months ended September 30, 2018	Stock options (thousands)		Weighted average exercise price
Outstanding, beginning of year	**8,896**	**$**	**23.81**
Granted	**798**		**9.03**
Exercised	**(184)**		**5.74**
Forfeited	**(317)**		**25.77**
Expired	**(511)**		**51.05**
Outstanding, end of period	**8,682**	**$**	**21.16**

ii. Restricted share units and performance share units:

RSUs granted under the equity-settled Restricted Share Unit Plan generally vest annually in thirds over a three-year period. PSUs granted under the equity-settled Restricted Share Unit Plan generally vest on the third anniversary of the grant date, provided that the Corporation satisfies certain performance criteria identified by the Corporation's Board of Directors within a target range and which are set and measured annually.

Equity-settled RSUs and PSUs outstanding:

Nine months ended September 30, 2018	(thousands)
Outstanding, beginning of year	**6,307**
Granted	**3,274**
Vested and released	**(2,525)**
Forfeited	**(334)**
Outstanding, end of period	**6,722**

(c) Stock-based compensation

	Three months ended September 30		Nine months ended September 30	
	2018	**2017**	**2018**	**2017**
Cash-settled expense [(i)]	**$ 1,134**	$ 7,054	**$ 22,183**	$ 3,559
Equity-settled expense	**6,771**	5,491	**16,899**	13,764
Stock-based compensation	**$ 7,905**	$ 12,545	**$ 39,082**	$ 17,323

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

13. REVENUES

	Three months ended September 30		Nine months ended September 30	
	2018	2017 Revised (Note 3)	2018	2017 Revised (Note 3)
Petroleum revenue:				
Proprietary	**$ 775,964**	$ 506,151	**$ 2,073,556**	$ 1,497,754
Third-party[(i)]	**28,751**	64,994	**132,857**	211,928
Petroleum revenue	**804,715**	571,145	**2,206,413**	1,709,682
Royalties	**(17,333)**	(3,745)	**(36,968)**	(15,313)
Petroleum revenue, net of royalties	**$ 787,382**	$ 567,400	**$ 2,169,445**	$ 1,694,369
Power revenue	**$ 13,332**	$ 5,896	**$ 34,256**	$ 16,104
Transportation revenue	**2,470**	2,963	**9,199**	9,200
Other revenue	**$ 15,802**	$ 8,859	**$ 43,455**	$ 25,304
	$ 803,184	$ 576,259	**$ 2,212,900**	$ 1,719,673

(i) The Corporation purchases crude oil products from third-parties for marketing-related activities. These purchases and associated storage charges are included in the consolidated statement of earnings (loss) and comprehensive income (loss) under the caption "Purchased product and storage".

(a) Disaggregation of revenue from contracts with customers

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

	Three months ended September 30					
	2018			2017		
	Petroleum Revenue			Petroleum Revenue		
	Proprietary	Third-party	Total	Proprietary	Third-party	Total
Country:						
Canada	**$ 457,092**	**$ 28,751**	**$ 485,843**	$ 280,585	$ 41,924	$ 322,509
United States	**318,872**	**—**	**318,872**	225,566	23,070	248,636
	$ 775,964	**$ 28,751**	**$ 804,715**	$ 506,151	$ 64,994	$ 571,145

	Nine months ended September 30					
	2018			2017		
	Petroleum Revenue			Petroleum Revenue		
	Proprietary	Third-party	Total	Proprietary	Third-party	Total
Country:						
Canada	**$ 1,277,802**	**$ 83,422**	**$ 1,361,224**	$ 906,847	$ 116,173	$ 1,023,020
United States	**795,754**	**49,435**	**845,189**	590,907	95,755	686,662
	$ 2,073,556	**$ 132,857**	**$ 2,206,413**	$ 1,497,754	$ 211,928	$ 1,709,682

Other revenue recognized during the three and nine months ended September 30, 2018 and 2017 is attributed to Canada.

(b) Revenue-related assets

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

As at		September 30, 2018		December 31, 2017
Petroleum revenue	**$**	**242,288**	$	244,330
Other revenue		**3,204**		2,960
Total revenue-related assets	**$**	**245,492**	$	247,290

Accrued receivables are typically settled within 30 days. As at September 30, 2018 and December 31, 2017, no impairment has been recognized on revenue-related receivables.

14. DILUENT AND TRANSPORTATION

		Three months ended September 30				Nine months ended September 30		
		2018		**2017**		**2018**		**2017**
Diluent expense	**$**	**337,941**	$	193,897	**$**	**965,129**	$	653,409
Transportation expense[a]		**81,128**		52,994		**193,323**		149,785
Diluent and transportation	**$**	**419,069**	$	246,891	**$**	**1,158,452**	$	803,194

(a) On March 22, 2018, the Corporation successfully completed the sale of its 50% interest in the Access Pipeline. Transportation expense includes incremental expenses associated with the related Transportation Services Agreement from March 22, 2018 through September 30, 2018.

15. PURCHASED PRODUCT AND STORAGE

		Three months ended September 30				Nine months ended September 30		
		2018		**2017 Revised (Note 3)**		**2018**		**2017 Revised (Note 3)**
Third-party purchased product	**$**	**28,329**	$	64,738	**$**	**130,302**	$	209,922
Blend purchases		**9,937**		30,367		**69,597**		39,969
Purchased product and storage	**$**	**38,266**	$	95,105	**$**	**199,899**	$	249,891

16. FOREIGN EXCHANGE LOSS (GAIN), NET

	Three months ended September 30		Nine months ended September 30	
	2018	2017	**2018**	2017
Unrealized foreign exchange loss (gain) on:				
Long-term debt	**$ (60,601)**	$ (176,586)	**$ 145,211**	$ (346,734)
Other	**2,348**	(3,862)	**211**	1,618
Unrealized net loss (gain) on foreign exchange	**(58,253)**	(180,448)	**145,422**	(345,116)
Realized loss (gain) on foreign exchange	**(818)**	2,064	**2,833**	(3,291)
Realized loss (gain) on foreign exchange derivatives[a]	**—**	—	**(35,362)**	—
Foreign exchange loss (gain), net	**$ (59,071)**	$ (178,384)	**$ 112,893**	$ (348,407)

C$ equivalent of 1 US$				
Beginning of period	**1.3142**	1.2977	**1.2518**	1.3427
End of period	**1.2924**	1.2510	**1.2924**	1.2510

(a) On February 8, 2018, the Corporation entered into forward currency contracts to manage the foreign exchange risk on expected Canadian dollar denominated asset sale proceeds designated for U.S. dollar denominated long-term debt repayment. The forward currency contracts were settled on March 22, 2018, resulting in a realized gain of $35.4 million.

17. NET FINANCE EXPENSE

	Three months ended September 30		Nine months ended September 30	
	2018	2017	**2018**	2017
Interest expense on long-term debt	**$ 68,039**	$ 80,860	**$ 218,021**	$ 259,296
Interest expense on finance leases	**4,115**	—	**8,664**	—
Interest income	**(1,907)**	(968)	**(5,924)**	(2,736)
Net interest expense	**70,247**	79,892	**220,761**	256,560
Accretion on provisions	**1,888**	1,994	**5,608**	5,675
Unrealized loss (gain) on derivative financial liabilities	**(192)**	(3,490)	**2,674**	(7,346)
Realized loss (gain) on interest rate swaps[a]	**—**	21	**(17,312)**	21
Net finance expense	**$ 71,943**	$ 78,417	**$ 211,731**	$ 254,910

(a) In the third quarter of 2017, the Corporation entered into an interest rate swap contract to effectively fix the interest rate on US$650.0 million of its US$1.2 billion senior secured term loan at approximately 5.3%. In conjunction with the partial repayment of the senior secured term loan on March 27, 2018, the interest rate swap was terminated and a realized gain of $17.3 million was recognized.

18. OTHER EXPENSES

	Three months ended September 30		Nine months ended September 30	
	2018	**2017**	**2018**	**2017**
Severance and other	**$ 1,929**	$ 1,320	**$ 4,917**	$ 4,736
Onerous contracts expense (recovery)[(a)]	**897**	(27)	**1,686**	5,681
Contract cancellation expense[(b)]	**—**	18,765	**—**	18,765
Other expenses	**$ 2,826**	$ 20,058	**$ 6,603**	$ 29,182

(a) Onerous contracts expense primarily includes changes in estimated future cash flow sublease recoveries related to the onerous office lease provision for the Corporation's office building lease contracts.

(b) During the third quarter of 2017, the Corporation recognized an $18.8 million contract cancellation expense relating to the termination of a long-term marketing transportation contract that had not yet commenced.

19. INCOME TAX EXPENSE (RECOVERY)

	Three months ended September 30		Nine months ended September 30	
	2018	**2017**	**2018**	**2017**
Current income tax expense (recovery)	**$ 117**	$ (257)	**$ 312**	$ (426)
Deferred income tax expense (recovery)	**23,604**	(33,091)	**(50,922)**	(50,268)
Income tax expense (recovery)	**$ 23,721**	$ (33,348)	**$ (50,610)**	$ (50,694)

The Corporation has recognized a deferred tax asset of $237.8 million (December 31, 2017 – $182.9 million). Future taxable income is expected to be sufficient to realize the deferred tax asset. The deferred tax asset is reviewed at each balance sheet date to assess whether it is probable that the related tax benefit will be realized.

20. SUPPLEMENTAL CASH FLOW DISCLOSURES

	Three months ended September 30		Nine months ended September 30	
	2018	2017	**2018**	2017
Cash provided by (used in):				
Trade receivables and other	**$ (60,146)**	$ (22,371)	**$ 1,649**	$ 10,375
Inventories	**(2,011)**	(30,249)	**(10,836)**	(29,643)
Accounts payable and accrued liabilities	**(88,838)**	(21,997)	**(53,684)**	29,007
	$ (150,995)	$ (74,617)	**$ (62,871)**	$ 9,739
Changes in non-cash working capital relating to:				
Operating	**$ (107,549)**	$ (51,133)	**$ (47,577)**	$ (28,922)
Investing	**(43,446)**	(23,484)	**(15,294)**	38,661
	$ (150,995)	$ (74,617)	**$ (62,871)**	$ 9,739
Cash and cash equivalents:(a)				
Cash	**$ 238,825**	$ 247,044	**$ 238,825**	$ 247,044
Cash equivalents	**133,725**	150,554	**133,725**	150,554
	$ 372,550	$ 397,598	**$ 372,550**	$ 397,598
Cash interest paid	**$ 115,402**	$ 135,553	**$ 247,679**	$ 275,546

(a) As at September 30, 2018, C$156.0 million of the Corporation's total cash and cash equivalents balance was held in U.S. dollars (September 30, 2017 – C$50.0 million). The U.S. dollar cash and cash equivalents balance has been translated into Canadian dollars at the period end exchange rate of US$1 = C$1.2924 (September 30, 2017 – US$1 = C$1.2510).

The following table reconciles long-term debt to cash flows arising from financing activities:

	Long-term debt (i)
Balance as at December 31, 2017	$ 4,683,727
Cash changes:	
Payments on term loan	(1,280,778)
Non-cash changes:	
Unrealized loss (gain) on foreign exchange	145,211
Amortization of financial derivative liability discount	816
Amortization of deferred debt discount and debt issue costs	4,191
IFRS 9 adjustment to deferred debt discount and debt issue costs (Note 3)	6,381
Balance as at September 30, 2018	**$ 3,559,548**

(i) Long-term debt, including the current portion of long-term debt.

21. NET EARNINGS (LOSS) PER COMMON SHARE

	Three months ended September 30		Nine months ended September 30	
	2018	2017	**2018**	2017
Net earnings (loss)	**$ 118,160**	$ 83,885	**$ 80,163**	$ 189,755
Weighted average common shares outstanding (thousands)	**296,771**	294,198	**295,373**	287,429
Dilutive effect of stock options, RSUs and PSUs (thousands)	**3,358**	1,271	**3,759**	128
Weighted average common shares outstanding – diluted (thousands)	**300,129**	295,469	**299,132**	287,557
Net earnings (loss) per share, basic	**$ 0.40**	$ 0.29	**$ 0.27**	$ 0.66
Net earnings (loss) per share, diluted	**$ 0.39**	$ 0.28	**$ 0.27**	$ 0.66

22. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The financial instruments recognized on the consolidated balance sheet are comprised of cash and cash equivalents, trade receivables and other, commodity risk management contracts, the interest rate swap included within other assets, accounts payable and accrued liabilities, finance leases and derivative financial liabilities included within provisions and other liabilities and long-term debt. As at September 30, 2018, commodity risk management contracts were classified as fair value through profit and loss; cash and cash equivalents, trade receivables and other, accounts payable and accrued liabilities, finance leases and long-term debt were carried at amortized cost.

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

(a) Fair value measurement of long-term debt, finance leases, derivative financial liabilities, derivative financial assets and commodity risk management contracts:

		Fair value measurements using		
As at September 30, 2018	**Carrying amount**	**Level 1**	**Level 2**	**Level 3**
Recurring measurements:				
Financial assets				
Commodity risk management contracts	**$ 11,615**	**$ —**	**$ 11,615**	**$ —**
Financial liabilities				
Long-term debt[i] (Note 9)	**$ 3,590,901**	**$ —**	**$ 3,654,031**	**$ —**
Finance leases (Note 10)	**$ 130,858**	**$ —**	**$ —**	**$ 130,858**
Derivative financial liabilities	**$ 635**	**$ —**	**$ 635**	**$ —**
Commodity risk management contracts	**$ 90,425**	**$ —**	**$ 90,425**	**$ —**

		Fair value measurements using		
As at December 31, 2017	**Carrying amount**	**Level 1**	**Level 2**	**Level 3**
Recurring measurements:				
Financial assets				
Interest rate swap (Note 8)	$ 8,067	$ —	$ 8,067	$ —
Financial liabilities				
Long-term debt[i] (Note 9)	$ 4,726,468	$ —	$ 4,415,238	$ —
Derivative financial liabilities	$ 6,028	$ —	$ 6,028	$ —
Commodity risk management contracts	$ 68,649	$ —	$ 68,649	$ —

(i) Includes the current and long-term portions.

Level 1 fair value measurements are based on unadjusted quoted market prices.

As at September 30, 2018, the Corporation did not have any financial instruments measured at Level 1 fair value.

Level 2 fair value measurements are based on valuation models and techniques where the significant inputs are derived from quoted prices or indices.

The estimated fair value of long-term debt is derived using quoted prices in an inactive market from a third-party independent broker.

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

Level 3 fair value measurements are based on unobservable information.

The estimated fair value of finance leases is based on recently observed transactions, or calculated by discounting the expected future contractual cash flows using a discount rate based on either contractual terms or market rates for instruments of similar maturity and credit risk.

The Corporation recognizes transfers into and transfers out of fair value hierarchy levels as of the date of the event or change in circumstances that caused the transfer.

(a) Commodity price risk management:

The Corporation enters into derivative financial instruments to manage commodity price risk. The use of the financial commodity risk management contracts is governed by a Risk Management Committee that follows guidelines and limits approved by the Board of Directors. The Corporation does not use financial derivatives for speculative purposes. Financial commodity risk management contracts are measured at fair value, with gains and losses on re-measurement included in the consolidated statement of earnings and comprehensive income in the period in which they arise.

The Corporation had the following financial commodity risk management contracts relating to crude oil sales and condensate purchases outstanding as at September 30, 2018:

As at September 30, 2018	Volumes (bbls/d)(i)	Term	Average Price (US$/bbl)(i)
Crude Oil Sales Contracts			
Fixed Price:			
WTI(ii) Fixed Price	29,000	Oct 1, 2018 – Dec 31, 2018	$54.16
WTI Fixed Price	19,060	Jan 1, 2019 – Dec 31, 2019	$66.53
WTI:WCS(iii) Fixed Differential	37,000	Oct 1, 2018 – Dec 31, 2018	$(16.50)
WTI:WCS Fixed Differential	28,000	Jan 1, 2019 – Dec 31, 2019	$(23.73)
WTI:WCS Fixed Differential	5,000	Jan 1, 2020 – Dec 31, 2020	$(23.19)
Collars:			
WTI Collars	32,500	Oct 1, 2018 – Dec 31, 2018	$46.64 – $54.52
Options:			
Purchased WTI Calls	8,000	Oct 1, 2018 – Dec 31, 2018	$82.00
Purchased WTI Puts	1,000	Jan 1, 2019 – Mar 31, 2019	$55.00
Condensate Purchase Contracts			
Fixed Price:			
WTI:Mont Belvieu Fixed Premium	5,000	Oct 1, 2018 – Dec 31, 2018	$4.96
Fixed Percentage:			
Mont Belvieu Fixed % of WTI	3,750	Jan 1, 2019 – Dec 31, 2019	95.2% of WTI
Mont Belvieu Fixed % of WTI	6,500	Jan 1, 2020 – Dec 31, 2020	93.9% of WTI

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

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

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

As at	September 30, 2018			December 31, 2017		
	Asset	Liability	Net	Asset	Liability	Net
Gross amount	**$ 17,541**	**$ (202,752)**	**$ (185,211)**	$ —	$ (184,175)	$ (184,175)
Amount offset	**(5,926)**	**112,327**	**106,401**	—	115,526	115,526
Net amount	**$ 11,615**	**$ (90,425)**	**$ (78,810)**	$ —	$ (68,649)	$ (68,649)
Current portion	**$ 3,498**	**$ (87,971)**	**$ (84,473)**	$ —	$ (68,649)	$ (68,649)
Non-current portion	**8,117**	**(2,454)**	**5,663**	—	—	—
Net amount	**$ 11,615**	**$ (90,425)**	**$ (78,810)**	$ —	$ (68,649)	$ (68,649)

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

As at September 30	2018	2017
Fair value of contracts, beginning of year	$ (68,649)	$ (30,313)
Fair value of contracts realized	194,198	4,601
Change in fair value of contracts	(205,569)	14,752
Unamortized premiums on put and call options	1,210	—
Fair value of contracts, end of period	**$ (78,810)**	$ (10,960)

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

	Three months ended September 30		Nine months ended September 30	
	2018	2017	2018	2017
Realized loss (gain) on commodity risk management	**$ 87,728**	$ (3,976)	**$ 194,198**	$ 4,601
Unrealized loss (gain) on commodity risk management	**(107,949)**	57,470	**11,371**	(19,353)
Commodity risk management loss (gain)	**$ (20,221)**	$ 53,494	**$ 205,569**	$ (14,752)

The following table summarizes the significant sensitivity of the earnings before income tax impact of fluctuating commodity prices on the Corporation's open financial commodity risk management positions in place as at September 30, 2018:

Commodity	Sensitivity Range	Increase	Decrease
Crude oil commodity price	± US$1.00 per bbl applied to WTI contracts	$ (16,304)	$ 16,304
Crude oil differential price [(i)]	± US$1.00 per bbl applied to WCS differential contracts	$ 19,973	$ (19,973)

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

The Corporation entered into the following financial commodity risk management contract relating to crude oil sales subsequent to September 30, 2018. As a result, this contract is not reflected in the Corporation's Interim Consolidated Financial Statements:

Subsequent to September 30, 2018	**Volumes (bbls/d)**	**Term**	**Average Prices (US$/bbl)**
Crude Oil Sales Contracts			
Fixed Price:			
WTI Fixed Price	2,055	Jan 1, 2019 – Dec 31, 2019	$74.45
WTI:WCS Fixed Differential	3,000	Jan 1, 2019 – Dec 31, 2019	$(29.35)
Condensate Purchase Contracts			
Fixed Percentage:			
Mont Belvieu Fixed % of WTI	5,000	Jan 1, 2019 – Dec 31, 2019	91.0% of WTI
Mont Belvieu Fixed % of WTI	1,250	Jan 1, 2020 – Dec 31, 2020	89.1% of WTI

(a) Credit risk management:

The Corporation applies the simplified approach to providing for expected credit losses prescribed by IFRS 9, which permits the use of the lifetime expected loss provision for all trade receivables. The Corporation uses a combination of historical and forward looking information to determine the appropriate loss allowance provisions. Credit risk exposure is mitigated through the use of credit policies governing the Corporation's credit portfolio and with credit practices that limit transactions according to the counterparties' credit quality. A substantial portion of accounts receivable are with investment grade customers in the energy industry and are subject to normal industry credit risk. The Corporation has experienced no material loss in relation to trade receivables.

(b) 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 on long-term debt. In the third quarter of 2017, the Corporation entered into an interest rate swap contract to effectively fix the interest rate on US$650.0 million of the US$1.2 billion senior secured term loan at approximately 5.3%. Interest rate swaps are classified as derivative financial assets and liabilities and measured at fair value, with gains and losses on re-measurement included as a component of net finance expense in the period in which they arise. In conjunction with the partial repayment of the senior secured term loan on March 27, 2018, the interest rate swap was terminated and a realized gain of $17.3 million was recognized (Note 17).

23. GEOGRAPHICAL DISCLOSURE

As at September 30, 2018, the Corporation had non-current assets related to operations in the United States of $98.9 million (December 31, 2017 – $101.7 million). For the three and nine months ended September 30, 2018, petroleum revenue related to operations in the United States was $318.9 million and $845.2 million, respectively (three and nine months ended September 30, 2017 – $248.6 million and $686.7 million, respectively).

24. COMMITMENTS AND CONTINGENCIES

(a) Commitments

The Corporation's commitments are enforceable and legally binding obligations to make payments in the future for goods and services. These items exclude amounts recorded on the consolidated balance sheet. The Corporation had the following commitments as at September 30, 2018:

	2018	2019	2020	2021	2022	Thereafter	Total
Transportation and storage[i]	$ 71,073	$ 299,844	$ 340,800	$ 387,425	$ 437,618	$ 6,640,968	$ 8,177,728
Office lease rentals[ii]	2,716	10,855	11,278	11,278	11,278	107,592	154,997
Diluent purchases	217,300	444,183	20,463	20,407	20,407	16,996	739,756
Other operating commitments	3,141	14,113	11,270	9,536	8,570	55,519	102,149
Capital commitments	15,233	—	—	—	—	—	15,233
Commitments	**$ 309,463**	**$ 768,995**	**$ 383,811**	**$ 428,646**	**$ 477,873**	**$ 6,821,075**	**$ 9,189,863**

(i) This represents transportation and storage commitments from 2018 to 2048, including the Access Pipeline TSA, and various pipeline commitments which are awaiting regulatory approval and are not yet in service. Excludes finance leases recognized on the consolidated balance sheet (Note 10(a)).

(ii) Excludes amounts for which an onerous contracts provision has been recognized on the consolidated balance sheet (Note 10(b)).

(b) Contingencies

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

The Corporation is the defendant to a statement of claim originally filed in 2014 in relation to legacy issues involving a unit train transloading facility in Alberta. The claim was amended in the fourth quarter of 2017 asserting a significant increase to damages claimed. The Corporation continues to view this three year old claim, and the recent amendments, as without merit and will defend against all such claims.