SECOND QUARTER 2018

Report to Shareholders for the period ended June 30, 2018

MEG Energy Corp. reported second quarter 2018 operating and financial results on August 2, 2018. Highlights include:

- Quarterly production volumes of 71,325 barrels per day, while completing planned maintenance activities. With strong first half production, annual production guidance has been revised higher to 87,000 to 90,000 barrels per day (bpd), from 85,000 to 88,000 bpd;
- Record low per barrel net operating costs of $5.64, including non-energy operating costs of $5.47, which were impacted by lower sales volumes in the quarter. Annual non-energy operating cost guidance has been reduced by 5% to $4.50 to $5.00 per barrel, from $4.75 to $5.25 per barrel to reflect strong cost performance to-date;
- Adjusted funds flow from operations of $18 million, impacted by lower sales volumes due to turnaround activities, realized losses on commodity derivatives, and mark-to-market, unrealized cash-settled stock-based compensation;
- Total cash capital investment of $183 million in the quarter, primarily directed to planned turnaround activities and advancing key growth projects. The 2018 capital plan has been revised to $670 million from the previously announced $700 million, to reflect improved capital cost efficiencies and strong operational results on the Phase 2B eMSAGP implementation; and
- Cash and cash equivalents of $564 million, MEG's covenant-lite US$1.4 billion facility remains undrawn.

During the second quarter of 2018, MEG completed a large-scale turnaround at Christina Lake Phase 2B, lasting 33 days. Production in the quarter averaged 71,325 bpd, which was in-line with the second quarter of 2017, and 23% lower than the first quarter of 2018. The lower quarter-over-quarter production is the result of planned maintenance activities.

Subsequent to the quarter, MEG completed essentially all investment required for the application of eMSAGP to the Phase 2B producing assets. This led to strong production at Christina Lake during the month of July, averaging over 98,000 bpd. The Company has increased its annual production guidance to 87,000 to 90,000 bpd, and year-end exit production is anticipated to average just over 100,000 bpd.

"MEG executed the largest turnaround in its history during the second quarter. The value of our diligent approach to regular plant maintenance was demonstrated as the turnaround confirmed the overall integrity of the plant," said Harvey Doerr, Interim President and CEO. "The turnaround allowed us to tie-in and modify a number of pieces of equipment, which enable us to reliably run at higher production levels. We saw record production day rates in excess of 100,000 bpd for several days in July as new Phase 2B eMSAGP wells were brought on-stream."

MEG's blend sales realization averaged $62.32 per barrel in the second quarter of 2018, 22% higher than the first quarter of 2018. The higher blend sales realization was the result of stronger benchmark crude oil prices and tighter differentials. The Company sold approximately 32,000 bpd of blend into the U.S. Gulf Coast during the second quarter, reflecting apportionment of approximately 46% on the Enbridge Mainline system. The majority of the Company's remaining barrels were sold in Edmonton. MEG's bitumen realization averaged $47.20 per barrel in the second quarter of 2018, 34% higher than the first quarter of 2018.

"MEG's marketing strategy has been focused on diversifying our markets, intended to minimize risk and maximize the value received for our barrels. Our rail loading and strategic storage facilities have helped to mitigate the impact of apportionment, and together with our commitment on the Flanagan South and Seaway pipelines, support better price realizations," said Doerr. "However, pipeline apportionment is expected to continue to impact the industry in the short term. We continue to be supportive of Enbridge's initiative to address the nomination methodology on the Mainline system, which should have a positive impact. In the medium term, completion of the Line 3 expansion will further enhance MEG's ability to take advantage of its commitment on the Flanagan South/Seaway, which doubles to 100,000 bpd in mid-2020."

Transportation costs for the second quarter of 2018 were $8.28 per barrel, 20% higher than the second quarter of 2017, and 38% higher than the first quarter of 2018. The higher transportation expense reflects the first full quarter impact of the recent sale of the Company's 50% share in the Access Pipeline and 100% of Stonefell Terminal, as well as lower sales volumes due to the plant turnaround.

Capital and Operational Update

Total cash capital investment in the quarter was $183 million, with funds directed towards planned turnaround activities, implementation of Phase 2B eMSAGP, advancement of the eMVAPEX pilot, and continued work on the Phase 2B brownfield expansion. During the quarter, MEG invested $22 million on the Phase 2B eMSAGP implementation. All spending on the project was completed subsequent to the quarter, with total costs coming in at $340 million. The final costs were lower than both the original capital estimate of $400 million and the revised estimate of $350 million. The 2018 capital program has been reduced to $670 million from the previously announced $700 million to reflect ongoing capital cost efficiencies.

MEG's hedging philosophy over the last two years has been focused on protecting its capital program. With current cash reserves, higher commodity prices and lower anticipated levels of capital spend in 2019, the Company expects to hedge a substantially lower percentage of its barrels going forward.

As a result of a review of the Company's marketing assets, MEG has engaged TD Securities Inc. to review strategic alternatives with respect to its proprietary HI-Q® partial upgrading technology. This technology has the potential to eliminate the use of diluent for bitumen transport. MEG is seeking a third-party transaction, which will take HI-Q® to commerciality while retaining access to the technology and will not require the Company to invest additional capital.

Net operating costs for the second quarter of 2018 averaged $5.64 per barrel, which is 24% and 6% lower than the second quarter of 2017 and first quarter of 2018, respectively. The strong per barrel net operating costs were achieved despite lower bitumen sales volumes in the quarter. The ongoing reduction in net operating costs reflects efficiency gains and continued focus on cost management. Annual non-energy operating cost guidance has been reduced to $4.50 to $5.00 per barrel, from $4.75 to $5.25 per barrel, to account for strong cost performance year-to-date.

Adjusted Funds Flow

MEG realized adjusted funds flow from operations of $18 million for the second quarter of 2018, compared to $55 million in the second quarter of 2017, and $83 million in the first quarter of 2018. Higher crude oil prices in the quarter were more than offset by lower production volumes, a realized loss on commodity derivatives and mark-to-market unrealized cash-settled stock-based compensation expense. Realized losses on commodity derivatives totalled $89 million, as crude oil benchmark prices exceeded the Company's crude oil contract prices.

Mark-to-market on the unrealized portion of cash-settled stock-based compensation reduced second quarter adjusted funds flow by $14 million, or $0.05 per share. MEG's stock price increased approximately 140% from March 31, 2018 to June 30, 2018, resulting in an increase in the fair value of the cash-settled units outstanding. MEG adopted cash-settled stock-based compensation for a portion of its long-term incentive (LTI) program for 2016 and 2017, which vest over a three-year period. The Company's LTI plans are designed to align compensation to corporate performance and are linked to the Company's stock price performance.

Outlook

The search committee of the Board has identified, interviewed and subsequently shortlisted a small number of qualified candidates for the role of permanent CEO. The Board expects to make a final decision in the third quarter of 2018.

"With 100,000 bpd in reach, MEG remains firmly on-track to deliver on our Vision 20/20. As the turnaround is now behind us, and spending on Phase 2B eMSAGP is essentially complete, capital in the second half of the year will be primarily focused on the Phase 2B brownfield expansion. Given our strong cash balance of $564 million and significantly higher cash flow anticipated in the second half of 2018, we are well-positioned to internally fund our capital plans to 2020," said Doerr. "While we have realized significant improvements across our business, we continue to look for ways to further advance our technology, improve our highly competitive overall cost position and maximize the revenue we receive for our barrels."

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 section of this quarter's Management's Discussion and Analysis.

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 six month periods ended June 30, 2018 was approved by the Corporation's Audit Committee on August 1, 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 six month periods ended June 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.

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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 steam-assisted gravity drainage ("SAGD") extraction methods. 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: the Christina Lake Project, the Surmont Project and the May River Regional Project. The Christina Lake Project has received regulatory approval for 210,000 barrels per day ("bbls/d") of bitumen production. MEG has applied for regulatory approval for 120,000 bbls/d of bitumen production at the Surmont Project. 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") and redeployment of steam and 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 application of eMSAGP and cogeneration 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 steam-oil ratio of 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.

The Surmont Project has an anticipated design capacity of approximately 120,000 bbls/d over multiple phases. 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.

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

During the second quarter of 2018, the Corporation's realized sales price increased 25% compared to the same period in 2017. The average US$WTI price increased 41%, which was partially offset by widening of the WTI:WCS differential from US$11.13 per barrel in the second quarter of 2017 to US$19.27 per barrel in the second 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 significant price appreciation of WTI.

Bitumen production for the second quarter of 2018 averaged 71,325 bbls/day, reflecting the completion of a planned 33-day turnaround at the Christina Lake Project. The Corporation continues to benefit from efficiency gains achieved through the continued implementation of eMSAGP at the Christina Lake Project. As part of a two year development plan, the eMSAGP growth project is proceeding as planned. 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.

The Corporation realized a cash operating netback of $18.53 per barrel in the three months ended June 30, 2018 compared to $22.96 for the same period in 2017. Strong commodity prices increased cash operating netback by $7.54 per barrel, however this was more than offset by higher realized losses on commodity risk management contracts of $13.11 per barrel in the second quarter of 2018 compared to $1.50 per barrel for the same period in 2017. These same factors impacted adjusted funds flow from operations, which decreased to $18.4 million in the second quarter of 2018 compared to $55.1 million in the second quarter of 2017.

The Corporation realized a net loss of $178.6 million for the three months ended June 30, 2018 compared to net earnings of $104.3 million for the same period of 2017. The net loss in the second quarter of 2018 was affected by a $62.4 million net unrealized foreign exchange loss and losses on commodity risk management contracts of $150.0 million. In comparison, the net earnings in the second quarter of 2017 included a $128.0 million net unrealized foreign exchange gain and gains on commodity risk management contracts of $7.1 million.

Total cash capital investment for the second quarter of 2018 totaled $182.6 million, an increase of $24.1 million compared to the same period of 2017. Sustaining capital activities during the second quarter of 2018 included approximately $55.0 million related to a planned 33-day turnaround at the Christina Lake Project, which was completed in mid-June.

At June 30, 2018, the Corporation had cash and cash equivalents of $564.0 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:

	Six months ended June 30		2018		2017				2016	
($ millions, except as indicated)	**2018**	**2017**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**
Bitumen production - bbls/d	**82,205**	74,883	**71,325**	93,207	90,228	83,008	72,448	77,245	81,780	83,404
Bitumen realization - $/bbl	**40.67**	38.80	**47.20**	35.31	48.30	39.89	39.66	37.93	36.17	30.98
Net operating costs - $/bbl(1)	**5.82**	7.92	**5.64**	5.98	5.86	6.00	7.42	8.43	8.24	7.76
Non-energy operating costs - $/bbl	**4.96**	4.71	**5.47**	4.55	4.53	4.57	4.23	5.20	4.99	5.32
Cash operating netback - $/bbl(2)	**19.43**	22.66	**18.53**	20.16	33.83	26.84	22.96	22.33	21.73	16.74
Adjusted funds flow from operations(3)	**102**	98	**18**	83	192	83	55	43	40	23
Per share, diluted(3)	**0.34**	0.35	**0.06**	0.28	0.65	0.28	0.19	0.16	0.18	0.10
Operating earnings (loss)(3)	**(88)**	(115)	**(70)**	(18)	44	(43)	(36)	(79)	(72)	(88)
Per share, diluted(3)	**(0.30)**	(0.40)	**(0.24)**	(0.06)	0.15	(0.14)	(0.12)	(0.29)	(0.32)	(0.39)
Revenue(4)	**1,410**	1,143	**689**	721	755	576	584	560	566	497
Net earnings (loss)	**(38)**	106	**(179)**	141	(1)	84	104	2	(305)	(109)
Per share, basic	**(0.13)**	0.37	**(0.61)**	0.48	(0.00)	0.29	0.36	0.01	(1.34)	(0.48)
Per share, diluted	**(0.13)**	0.37	**(0.61)**	0.47	(0.00)	0.28	0.35	0.01	(1.34)	(0.48)
Total cash capital investment	**330**	236	**183**	148	163	103	158	78	63	19
Cash and cash equivalents	**564**	512	**564**	675	464	398	512	549	156	103
Long-term debt	**3,607**	4,813	**3,607**	3,543	4,637	4,636	4,813	4,945	5,053	4,910

(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 June 30		Six months ended June 30	
	2018	**2017**	**2018**	**2017**
Bitumen production – bbls/d	**71,325**	72,448	**82,205**	74,883
Steam-oil ratio (SOR)	**2.2**	2.3	**2.2**	2.3

Bitumen Production

Bitumen production at the Christina Lake Project averaged 71,325 bbls/d for the three months ended June 30, 2018 compared to 72,448 bbls/d for the three months ended June 30, 2017. Production was impacted during both periods by turnaround activities, with the 2018 turnaround having a greater impact on production. The 2018 turnaround was completed in mid-June.

Bitumen production for the six months ended June 30, 2018 averaged 82,205 bbls/d compared to 74,833 bbls/d for the six months ended June 30, 2017. The increase in average production volumes for the six months ended June 30, 2018 is primarily due to the efficiency gains achieved through the continued implementation of eMSAGP at the Christina Lake Project. 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. These increases in production were partially offset by the planned 33-day turnaround at the Christina Lake Project which had a greater impact on production volumes compared to turnaround activities in 2017.

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 six months ended June 30, 2018 compared to 2.3 for the three and six months ended June 30, 2017.

Operating Cash Flow

	Three months ended June 30		Six months ended June 30	
($000)	2018	2017	2018	2017
Petroleum revenue – proprietary(1)	**$ 624,702**	$ 502,215	**$ 1,297,592**	$ 991,603
Blend purchases(2)	**(10,862)**	(9,602)	**(59,660)**	(9,602)
Diluent expense	**(294,222)**	(225,113)	**(627,188)**	(459,512)
	319,618	267,500	**610,744**	522,489
Royalties	**(11,127)**	(5,877)	**(19,635)**	(11,568)
Transportation expense	**(60,219)**	(49,893)	**(112,195)**	(96,791)
Operating expenses	**(49,163)**	(53,871)	**(108,393)**	(116,924)
Power revenue	**10,968**	3,852	**20,924**	10,208
Transportation revenue	**4,119**	3,284	**6,729**	6,237
	214,196	164,995	**398,174**	313,651
Realized gain (loss) on commodity risk management	**(88,751)**	(10,089)	**(106,470)**	(8,577)
Operating cash flow(3)	**$ 125,445**	$ 154,906	**$ 291,704**	$ 305,074

(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 $125.4 million for the three months ended June 30, 2018 compared to $154.9 million for the three months ended June 30, 2017. Blend sales revenue for the three months ended June 30, 2018 was $122.5 million higher than the three months ended June 30, 2017. This increase was driven primarily by a 25% increase in average realized blend prices. The quarter-over-quarter increase in revenue was more than offset by an $88.8 million realized loss on commodity risk management contracts and higher diluent expense. Diluent expense for the three months ended June 30, 2018 was $69.1 million higher than the three months ended June 30, 2017, due to higher condensate benchmark prices.

Operating cash flow was $291.7 million for the six months ended June 30, 2018 compared to $305.1 million for the six months ended June 30, 2017. Blend sales revenue increased to $1.3 billion for the six months ended June 30, 2018 compared to $991.6 million for the six months ended June 30, 2017. This increase was primarily due to an 11% increase in blend sales volumes and a 14% increase in the average realized blend price. The increase in pricing was more than offset by a $106.5 million realized loss on commodity risk management contracts and higher diluent expense. Diluent expense for the six months ended June 30, 2018 was $167.7 million higher than the six months ended June 30, 2017, due to an increase in condensate volumes associated with the increase in average bitumen production, and higher condensate benchmark prices.

Cash Operating Netback

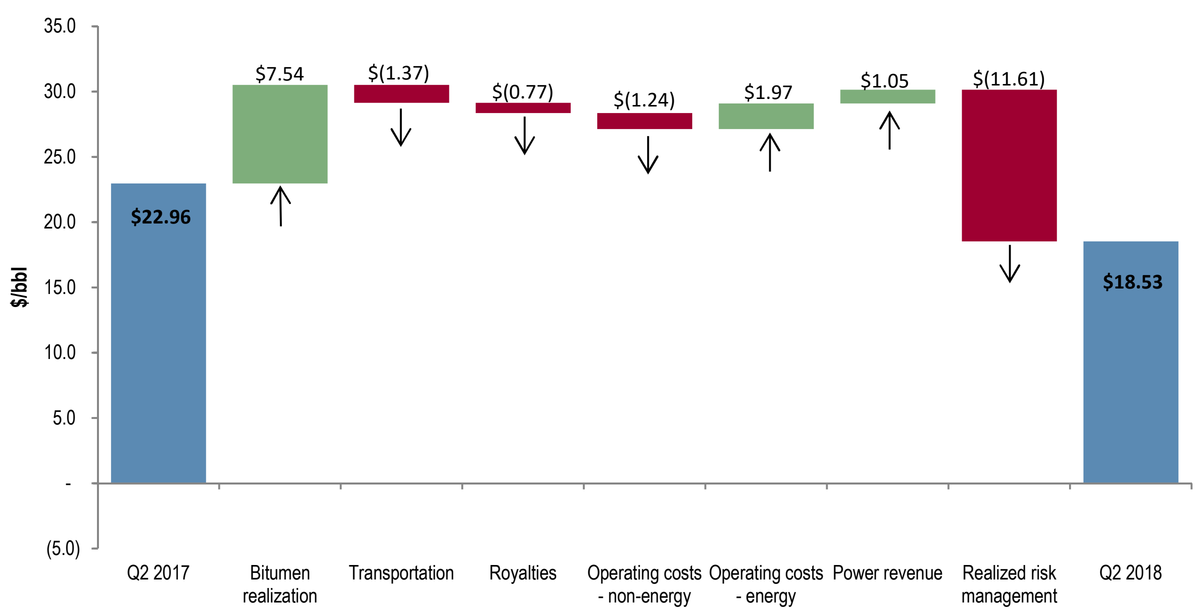
The following table summarizes the Corporation's per-unit calculation of operating cash flow, defined as cash operating netback for the periods indicated:

	Three months ended June 30		Six months ended June 30	
($/bbl)	**2018**	**2017**	**2018**	**2017**
Bitumen realization[1]	**$ 47.20**	$ 39.66	**$ 40.67**	$ 38.80
Transportation[2]	**(8.28)**	(6.91)	**(7.02)**	(6.72)
Royalties	**(1.64)**	(0.87)	**(1.31)**	(0.86)
	37.28	31.88	**32.34**	31.22
Operating costs – non-energy	**(5.47)**	(4.23)	**(4.96)**	(4.71)
Operating costs – energy	**(1.79)**	(3.76)	**(2.25)**	(3.97)
Power revenue	**1.62**	0.57	**1.39**	0.76
Net operating costs	**(5.64)**	(7.42)	**(5.82)**	(7.92)
	31.64	24.46	**26.52**	23.30
Realized gain (loss) on commodity risk management	**(13.11)**	(1.50)	**(7.09)**	(0.64)
Cash operating netback	**$ 18.53**	$ 22.96	**$ 19.43**	$ 22.66

(1) *Blend sales revenue net of diluent expense and blend purchases.*

(2) *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 June 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 $47.20 per barrel for the three months ended June 30, 2018 compared to $39.66 per barrel for the three months ended June 30, 2017. The average US$WTI price increased 41% for the three months ended June 30, 2018 compared to the same period in 2017. However, this was partially offset by the widening of the WTI:WCS differential by US$8.14 per barrel and the quarter-over-quarter increase in average condensate benchmark pricing. For the three months ended June 30, 2018, the Corporation's cost of diluent was $95.60 per barrel of diluent compared to $71.69 per barrel of diluent for the three months ended June 30, 2017.

Transportation

The Corporation utilizes multiple facilities to transport and sell its blend. Sales volumes destined for the U.S. Gulf Coast or overseas 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 June 30, 2018, transportation costs averaged $8.28 per barrel compared to $6.91 per barrel for the three months ended June 30, 2017. The increase in costs on a per barrel basis is primarily the result of incremental transportation costs incurred due to the cost of the TSA, partially offset by a lower proportion of blend sales shipped to the U.S. Gulf Coast during the second quarter of 2018 compared to the same period in 2017.

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.

The increase in royalties for the three months ended June 30, 2018, compared to the three months ended June 30, 2017 is primarily the result of higher WTI crude oil prices.

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 June 30, 2018 averaged $5.64 per barrel compared to $7.42 per barrel for the three months ended June 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, partially offset by higher non-energy operating costs.

Non-energy operating costs

Non-energy operating costs averaged $5.47 per barrel for the three months ended June 30, 2018 compared to $4.23 per barrel for the three months ended June 30, 2017. This increase is partially due to higher maintenance activity for the three months ended June 30, 2018 compared to the same period in 2017. Also, the 2017 comparative period includes a $0.66 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 $1.79 per barrel for the three months ended June 30, 2018 compared to $3.76 per barrel for the three months ended June 30, 2017. The decrease in energy operating costs is primarily attributable to lower natural gas prices. The Corporation's natural gas purchase price averaged $1.72 per mcf during the three months ended June 30, 2018 compared to $3.32 per mcf for the same period in 2017.

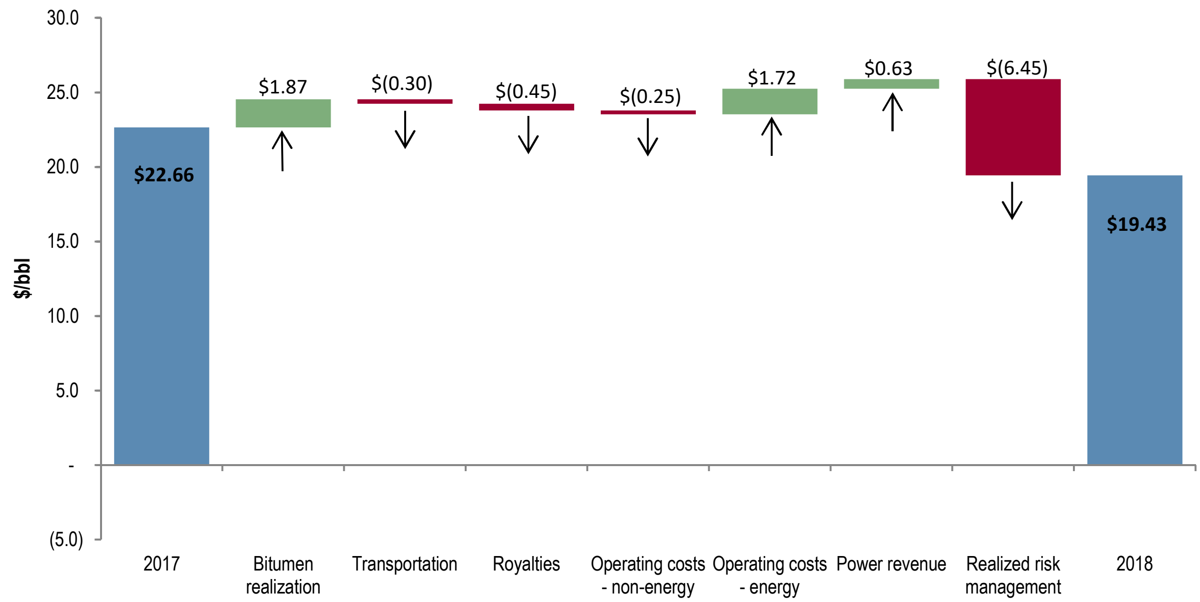
Power revenue

Power revenue averaged $1.62 per barrel for the three months ended June 30, 2018 compared to $0.57 per barrel for the three months ended June 30, 2017. The Corporation's average realized power sales price increased to $51.02 per megawatt hour in the second quarter of 2018 from $18.27 per megawatt hour for the same period in 2017.

Realized Gain or Loss on Commodity Risk Management

The realized loss on commodity risk management averaged $13.11 per barrel for the three months ended June 30, 2018 compared to $1.50 per barrel for the three months ended June 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.

Cash Operating Netback - Six Months Ended June 30



Bitumen Realization

Bitumen realization averaged $40.67 per barrel for the six months ended June 30, 2018 compared to $38.80 per barrel for the six months ended June 30, 2017. The average US$WTI price increased 30% for the six months ended June 30, 2018 compared to the same period in 2017. However, this was partially offset by the widening of the WTI:WCS differential by US$8.92 per barrel and an increase in average condensate benchmark pricing and its impact on diluent costs. For the six months ended June 30, 2018, the Corporation's cost of diluent was $89.02 per barrel of diluent compared to $71.23 per barrel of diluent for the six months ended June 30, 2017.

Transportation

During the six months ended June 30, 2018, transportation costs averaged $7.02 per barrel compared to $6.72 per barrel for the six months ended June 30, 2017. The Increase in costs on a per barrel basis is the result of incremental transportation costs incurred due to the cost of the TSA, which was entered into on March 22, 2018. The per barrel increase is partially offset by larger sales volumes for the six months ended June 30, 2018, compared to the same period in 2017.

Royalties

The increase in royalties for the six months ended June 30, 2018, compared to the six months ended June 30, 2017 is primarily the result of higher WTI crude oil prices and higher bitumen sales volumes and correspondingly higher blend sales revenue.

Net Operating Costs

Net operating costs for the six months ended June 30, 2018 averaged $5.82 per barrel compared to $7.92 per barrel for the six months ended June 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 $4.96 per barrel for the six months ended June 30, 2018 compared to $4.71 per barrel for the six months ended June 30, 2017. The 2017 comparative period includes a $0.33 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 $2.25 per barrel for the six months ended June 30, 2018 compared to $3.97 per barrel for the six months ended June 30, 2017. The decrease in energy operating costs is primarily attributable to lower natural gas prices. The Corporation’s natural gas purchase price averaged $2.10 per mcf during the six months ended June 30, 2018 compared to $3.22 per mcf for the same period in 2017.

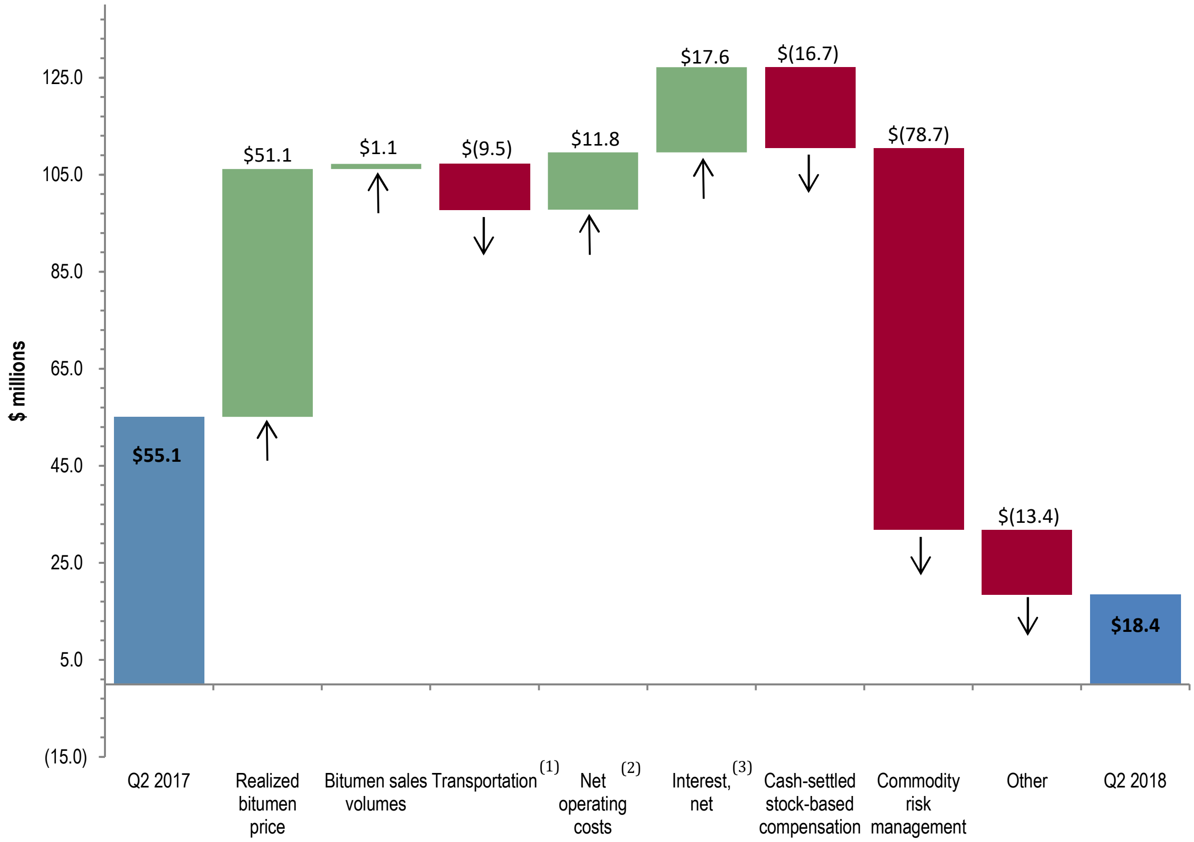
Power revenue

Power revenue averaged $1.39 per barrel for the six months ended June 30, 2018 compared to $0.76 per barrel for the six months ended June 30, 2017. The Corporation’s average realized power sales price during the six months ended June 30, 2018 was $42.23 per megawatt hour compared to $20.65 per megawatt hour for the same period in 2017.

Realized Gain or Loss on Commodity Risk Management

The realized loss on commodity risk management averaged $7.09 per barrel for the six months ended June 30, 2018 compared to $0.64 per barrel for the six months ended June 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.

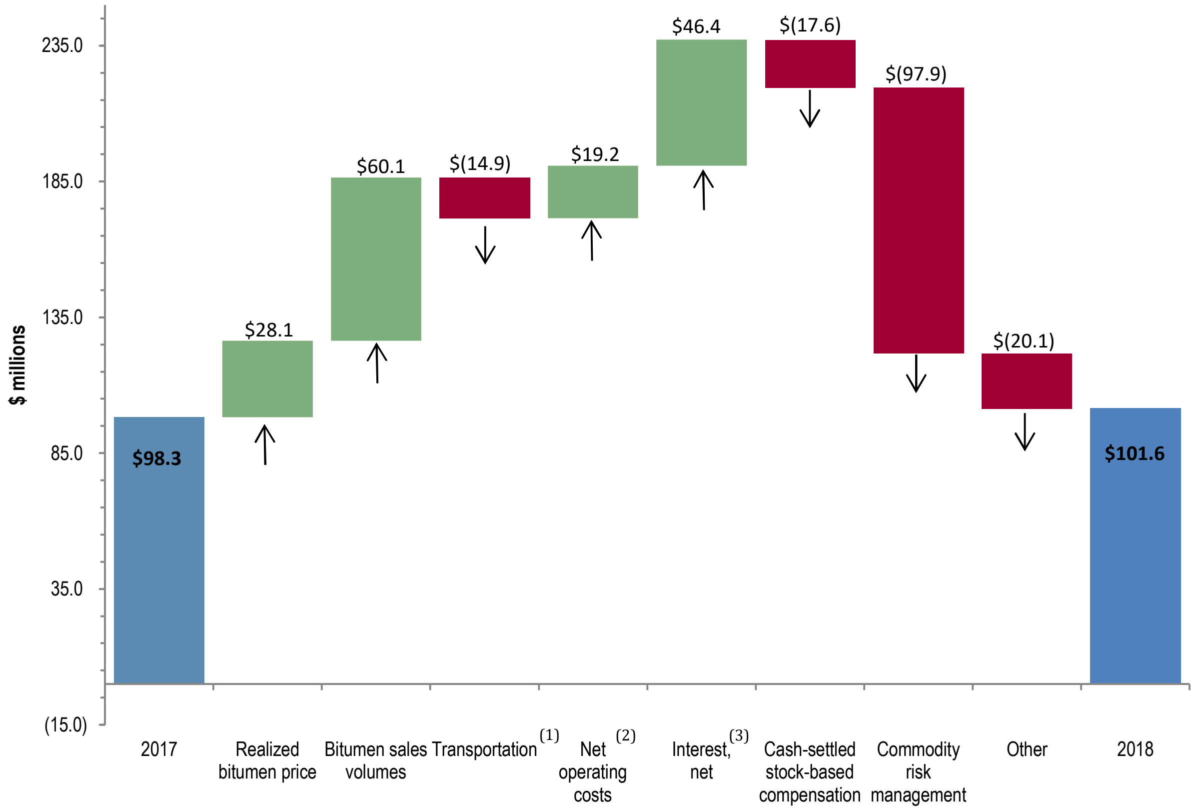
Adjusted Funds Flow From (Used In) Operations – Three Months Ended June 30



(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 June 30, 2018 was $18.4 million compared to $55.1 million for the three months ended June 30, 2017. Higher bitumen prices and lower net operating costs were more than offset by realized losses on commodity risk management contracts of $88.8 million.

Adjusted Funds Flow From (Used In) Operations – Six Months Ended June 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 $101.6 million for the six months ended June 30, 2018 from $98.3 million for the six months ended June 30, 2017. Increases to adjusted funds flow from operations were the result of higher bitumen prices and sales volumes, lower net operating costs and a reduction in net interest expense. These increases were partially offset by realized losses on commodity risk management contracts of $106.5 million.

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 $70.2 million for the three months ended June 30, 2018 compared to an operating loss of $35.7 million for the three months ended June 30, 2017. As a result of an increase in average crude oil benchmark pricing, the Corporation had higher bitumen realizations. This was more than offset by realized losses on commodity risk management contracts of $88.8 million and an increase in cash-settled stock-based compensation expense.

The Corporation recognized an operating loss of $88.2 million for the six months ended June 30, 2018 compared to an operating loss of $115.0 million for the six months ended June 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. Bitumen sales averaged 82,966 bbls/d for the six months ended June 30, 2018 compared to 74,408 bbls per day for the six months ended June 30, 2017. This was partially offset by realized losses on commodity risk management contracts of $106.5 million and an increase in cash-settled stock-based compensation expense.

	Three months ended June 30		**Six months ended June 30**	
($000)	**2018**	**2017**	**2018**	**2017**
Net earnings (loss)	**$ (178,570)**	$ 104,282	**$ (37,997)**	$ 105,870
Adjustments:				
Unrealized loss (gain) on foreign exchange[1]	**62,377**	(127,961)	**203,675**	(164,668)
Unrealized loss (gain) on derivative financial liabilities[2]	**(110)**	(1,615)	**2,866**	(3,856)
Unrealized loss (gain) on commodity risk management[3]	**61,288**	(17,224)	**119,320**	(76,823)
Realized foreign exchange loss (gain) on foreign exchange derivatives[4]	**-**	-	**(35,362)**	-
Gain on asset dispositions[5]	**-**	-	**(318,398)**	-
Onerous contracts expense	**145**	3,333	**789**	5,708
Deferred tax expense (recovery) relating to these adjustments	**(15,304)**	3,529	**(23,082)**	18,761
Operating earnings (loss)[6]	**$ (70,174)**	$ (35,656)	**$ (88,189)**	$ (115,008)

(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) *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 June 30, 2018 totaled $689.1 million compared to $583.6 million for the three months ended June 30, 2017. Revenue increased as a result of an increase in the average realized blend price.

Revenue for the six months ended June 30, 2018 totaled $1.4 billion compared to $1.1 billion for the six months ended June 30, 2017. Revenue increased primarily as a result of an increase in average realized blend price and an increase in blend sales volumes.

Net Earnings (Loss)

The Corporation recognized a net loss of $178.6 million for the three months ended June 30, 2018 compared to net earnings of $104.3 million for the three months ended June 30, 2017. The net loss for the three months ended June 30, 2018 includes an unrealized foreign exchange loss of $62.4 million as well as realized and unrealized losses on commodity risk management contracts totalling $150.0 million. In comparison, the net earnings in the second quarter of 2017 included an unrealized foreign exchange gain of $128.0 million and realized and unrealized gains on commodity risk management contracts totalling $7.1 million.

The Corporation recognized a net loss of $38.0 million for the six months ended June 30, 2018 compared to net earnings of $105.9 million for the six months ended June 30, 2017. The net loss for the six months ended June 30, 2018 was affected by a net unrealized foreign exchange loss of $203.7 million and by realized and unrealized losses on commodity risk management contracts totalling $225.8 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 six months ended June 30, 2017 included a net unrealized foreign exchange gain of $164.7 million and realized and unrealized gains on commodity risk management of $68.2 million.

Total Cash Capital Investment

Total cash capital investment for the three months ended June 30, 2018 was $182.6 million, compared to $158.5 million for the three months ended June 30, 2017. Total cash capital investment for the six months ended June 30, 2018 was $330.3 million, compared to $236.2 million for the six months ended June 30, 2017.

In the second quarter of 2018, sustaining and capital activities included approximately $55.0 million of turnaround costs.

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 has been revised to $670 million from the previously announced $700 million, to reflect improved capital cost efficiencies and strong operational results through the continued implementation of eMSAGP at the Christina Lake Project. The Corporation expects to fund the remaining 2018 capital program with internally generated cash flow and existing cash.

The Corporation's 2018 exit bitumen production volumes remain unchanged and are targeted to be in the range of 95,000 – 100,000 bbls/d. Average annual bitumen production volumes guidance has been increased to 87,000 – 90,000 bbls/d from 85,000 – 88,000 bbls/d. The revised guidance is due to efficiency gains achieved through the continued implementation of eMSAGP at the Christina Lake Project. The operational guidance takes into account the major turnaround at the Corporation's Christina Lake Phase 2B facility which took place in the second quarter of 2018.

The Corporation's non-energy cost guidance has been reduced to $4.50 – $5.00 per barrel, reflecting ongoing efficiency gains and a continued focus on cost management. The new guidance is 5% lower than the initial guidance of $4.75 – $5.25 per barrel.

5. BUSINESS ENVIRONMENT

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

	Six months ended June 30		2018		2017				2016	
	2018	**2017**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**
Average Commodity Prices										
Crude oil prices										
Brent (US$/bbl)	**71.04**	52.80	**74.90**	67.18	61.54	52.18	50.93	54.66	51.13	46.98
WTI (US$/bbl)	**65.37**	50.10	**67.88**	62.87	55.40	48.21	48.29	51.91	49.29	44.94
WTI (C$/bbl)	**83.55**	66.83	**87.64**	79.54	70.45	60.38	64.94	68.68	65.75	58.65
WCS (C$/bbl)	**55.73**	49.69	**62.76**	48.82	54.86	47.93	49.98	49.39	46.65	41.03
Differential – WTI:WCS (US$/bbl)	**21.77**	12.85	**19.27**	24.28	12.26	9.94	11.13	14.58	14.32	13.50
Differential – WTI:WCS (%)	**33.3%**	25.6%	**28.4%**	38.6%	22.1%	20.6%	23.0%	28.1%	29.1%	30.0%
Condensate prices										
Condensate at Edmonton (C$/bbl)	**84.28**	67.17	**88.84**	79.72	73.72	59.59	65.16	69.17	64.49	56.25
Condensate at Edmonton as % of WTI	**100.9%**	100.5%	**101.4%**	100.2%	104.6%	98.7%	100.3%	100.7%	98.1%	95.9%
Condensate at Mont Belvieu, Texas (US$/bbl)	**61.83**	45.41	**64.40**	59.27	55.35	46.37	44.77	46.05	45.17	41.17
Condensate at Mont Belvieu, Texas as % of WTI	**94.6%**	90.6%	**94.9%**	94.3%	99.9%	96.2%	92.7%	88.7%	91.6%	91.6%
Natural gas prices										
AECO (C$/mcf)	**1.76**	2.86	**1.26**	2.26	1.84	1.58	2.81	2.91	3.31	2.49
Electric power prices										
Alberta power pool (C$/MWh)	**45.36**	20.82	**55.92**	34.81	22.49	24.55	19.26	22.38	21.97	17.93
Foreign exchange rates										
C$ equivalent of 1 US$ - average	**1.2781**	1.3339	**1.2911**	1.2651	1.2717	1.2524	1.3449	1.3230	1.3339	1.3051
C$ equivalent of 1 US$ - period end	**1.3142**	1.2977	**1.3142**	1.2901	1.2518	1.2510	1.2977	1.3322	1.3427	1.3117

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$67.88 per barrel for the three months ended June 30, 2018 compared to US$48.29 per barrel for the three months ended June 30, 2017. The WTI price averaged US$65.37 per barrel for the six months ended June 30, 2018 compared to US$50.10 per barrel for the six months ended June 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$19.27 per barrel, or 28.4% of WTI, for the three months ended June 30, 2018 compared to US$11.13 per barrel, or 23.0% of WTI, for the three months ended June 30, 2017. The WTI:WCS differential averaged US$21.77 per barrel, or 33.3% of WTI, for the six months ended June 30, 2018 compared to US$12.85 per barrel, or 25.6% of WTI, for the six months ended June 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 accompanied with delays in initiating expansions of export pipelines and delays affecting the ramp up of major rail carriers' capacity.

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 $88.84 per barrel, or 101.4% of WTI, for the three months ended June 30, 2018 compared to $65.16 per barrel, or 100.3% of WTI, for the three months ended June 30, 2017. Condensate prices, benchmarked at Edmonton, averaged $84.28 per barrel, or 100.9% of WTI, for the six months ended June 30, 2018 compared to $67.17 per barrel, or 100.5% of WTI, for the six months ended June 30, 2017.

Condensate prices, benchmarked at Mont Belvieu, Texas, averaged US$64.40 per barrel, or 94.9% of WTI, for the three months ended June 30, 2018 compared to US$44.77 per barrel, or 92.7% of WTI, for the three months ended June 30, 2017. Condensate prices, benchmarked at Mont Belvieu, Texas, averaged US$61.83 per barrel, or 94.6% of WTI, for the six months ended June 30, 2018 compared to US$45.41 per barrel, or 90.6% of WTI, for the six months ended June 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 $1.26 per mcf for the three months ended June 30, 2018 compared to $2.81 per mcf for the three months ended June 30, 2017. The AECO natural gas price averaged $1.76 per mcf for the six months ended June 30, 2018 compared to $2.86 per mcf for the six months ended June 30, 2017. The AECO natural gas price has decreased in each of the comparative periods as a result of increased natural gas production levels and continued maintenance on the Nova Gas Transmission system (NGTL), limiting transport capacity.

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 $55.92 per megawatt hour for the three months ended June 30, 2018 compared to $19.26 per megawatt hour for the three months ended June 30, 2017. The Alberta power pool price averaged $45.36 per megawatt hour for the six months ended June 30, 2018 compared to $20.82 per megawatt hour for the six months ended June 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 along with the retirement and suspension of older coal-fired plants.

Foreign Exchange Rates

Changes in the value of the Canadian dollar relative to the U.S. dollar have an impact on the Corporation's blend sales revenue and diluent expense, as blend sales prices and diluent expense are determined by reference to U.S. benchmarks. Changes in the value of the Canadian dollar relative to the U.S. dollar also have an impact on principal and interest payments on the Corporation's U.S. dollar denominated debt. A decrease in the value of the Canadian dollar compared to the U.S. dollar has a positive impact on blend sales revenue and a negative impact on diluent expense and principal and interest payments. Conversely, an increase in the value of the Canadian dollar has a negative impact on blend sales revenue and a positive impact on diluent expense and principal and interest payments.

The Corporation recognizes net unrealized foreign exchange gains and losses on the translation of U.S. dollar denominated debt and U.S. dollar denominated cash and cash equivalents at each reporting date. As at June 30, 2018, the Canadian dollar, at a rate of 1.3142, had decreased in value by approximately 5% 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

	Three months ended June 30		Six months ended June 30	
($000)	**2018**	**2017**	**2018**	**2017**
Petroleum revenue – third party	**$ 60,463**	$ 80,161	**$ 104,106**	$ 146,934
Third party purchased product	**(59,544)**	(79,642)	**(101,973)**	(145,184)
Net marketing activity(1)	**$ 919**	$ 519	**$ 2,133**	$ 1,750

(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

	Three months ended June 30		Six months ended June 30	
($000)	**2018**	**2017**	**2018**	**2017**
Depletion and depreciation expense	**$ 104,350**	$ 111,605	**$ 215,249**	$ 228,484
Depletion and depreciation expense per barrel of production	**$ 16.08**	$ 16.93	**$ 14.47**	$ 16.87

Depletion and depreciation expense decreased for each of the comparative three and six 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. 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.

($000)	Three months ended June 30					
	2018			2017		
	Realized	Unrealized	Total	Realized	Unrealized	Total
Crude oil contracts(1)	**$ (88,960)**	**$ (56,440)**	**$ (145,400)**	$ (18,909)	$ 28,541	$ 9,632
Condensate contracts(2)	**209**	**(4,848)**	**(4,639)**	8,820	(11,317)	(2,497)
Commodity risk management gain (loss)	**$ (88,751)**	**$ (61,288)**	**$ (150,039)**	$ (10,089)	$ 17,224	$ 7,135

The Corporation realized a net loss on commodity risk management contracts of $88.8 million for the three months ended June 30, 2018, primarily due to net settlement losses on contracts relating to crude oil sales. This compares to a realized net loss of $10.1 million for the three months ended June 30, 2017. WTI fixed price contracts were priced at approximately US$55 per barrel, and settled at approximately US$68 per barrel for the three months ended June 30, 2018. These realized losses were partially offset by gains on WTI:WCS fixed differential contracts that were priced at approximately US$15 per barrel, and settled at approximately US$19 per barrel.

The Corporation recognized an unrealized loss on commodity risk management contracts of $61.3 million for the three months ended June 30, 2018, reflecting unrealized losses on crude oil contracts and condensate purchase contracts. Crude oil benchmark forward prices increased over the quarter, resulting in unrealized losses on the Corporation's WTI fixed price contracts and collars. The $61.3 million unrealized loss in the second quarter of 2018 compares to a $17.2 million unrealized gain for the same period in 2017. Refer to the "Risk Management" section of this MD&A for further details.

($000)	Six months ended June 30					
	2018			2017		
	Realized	Unrealized	Total	Realized	Unrealized	Total
Crude oil contracts(1)	**$ (106,679)**	**$ (114,859)**	**$ (221,538)**	$ (22,803)	$ 90,231	$ 67,428
Condensate contracts(2)	**209**	**(4,461)**	**(4,252)**	14,226	(13,408)	818
Commodity risk management gain (loss)	**$ (106,470)**	**$ (119,320)**	**$ (225,790)**	$ (8,577)	$ 76,823	$ 68,246

(1) Includes WTI fixed price, WTI collars and WCS fixed differential contracts.
(2) Relates to condensate purchase contracts that effectively fix condensate prices at Mont Belvieu, Texas.

The Corporation realized a net loss on commodity risk management contracts of $106.5 million for the six months ended June 30, 2018, primarily due to net settlement losses on contracts relating to crude oil sales. This compares to a realized net loss of $8.6 million for the six months ended June 30, 2017. WTI fixed price contracts were priced at approximately US$55 per barrel, and settled at approximately US$65 per barrel for the six months ended June 30, 2018. These realized losses were partially offset by gains on WTI:WCS fixed differential contracts that were priced at approximately US$14 per barrel, and settled at approximately US$22 per barrel.

The Corporation recognized an unrealized loss on commodity risk management contracts of $119.3 million for the six months ended June 30, 2018, reflecting unrealized losses on crude oil contracts and condensate purchase contracts. Crude oil benchmark forward prices increased over the period, resulting in unrealized losses on the Corporation's WTI fixed price contracts and collars. These unrealized losses were partially offset by gains on the WTI:WCS fixed differential contracts, as differentials widened. The $119.3 million unrealized loss for the six months ended June 30, 2018 compares to a $76.8 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 June 30		Six months ended June 30	
($000)	**2018**	**2017**	**2018**	**2017**
General and administrative expense	**$ 19,152**	$ 20,939	**$ 40,875**	$ 44,161
General and administrative expense per barrel of production	**$ 2.95**	$ 3.18	**$ 2.75**	$ 3.26

General and administrative expense for the three months ended June 30, 2018 was $2.95 per barrel, compared to $3.18 per barrel for the three months ended June 30, 2017. The per barrel expense was impacted during both periods by turnaround activities which resulted in lower production.

General and administrative expense per barrel decreased 16% for the six months ended June 30, 2018 to $2.75, from $3.26 for the six months ended June 30, 2017. The decrease in per barrel costs was primarily due to increased production.

Stock-based Compensation

	Three months ended June 30		Six months ended June 30	
($000)	**2018**	**2017**	**2018**	**2017**
Cash-settled expense (recovery)	**$ 21,340**	$ (2,272)	**$ 21,049**	$ (3,495)
Equity-settled expense	**3,999**	4,763	**10,128**	8,273
Stock-based compensation	**$ 25,339**	$ 2,491	**$ 31,177**	$ 4,778

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 June 30, 2018 was $25.3 million compared to $2.5 million for the three months ended June 30, 2017. Stock-based compensation expense for the six months ended June 30, 2018 was $31.2 million compared to $4.8 million for the six months ended June 30, 2017. The increase in each of the comparative three and six month periods was primarily a result of an increase in the fair value of the cash-settled units due to the significant increase in the Corporation’s common share price. As at June 30, 2018, the Corporation’s share price had increased by approximately 113% compared to its value as at December 31, 2017.

Research and Development

	Three months ended June 30		Six months ended June 30	
($000)	2018	2017	2018	2017
Research and development expense	$ 1,425	$ 1,166	$ 2,413	$ 2,106

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 June 30		Six months ended June 30	
($000)	2018	2017	2018	2017
Unrealized foreign exchange gain (loss) on:				
Long-term debt	$ (67,028)	$ 130,390	$ (205,812)	$ 170,148
Other	4,651	(2,429)	2,137	(5,480)
Unrealized net gain (loss) on foreign exchange	(62,377)	127,961	(203,675)	164,668
Realized gain (loss) on foreign exchange	(1,641)	3,042	(3,651)	5,355
Realized gain (loss) on foreign exchange derivatives	-	-	35,362	-
Foreign exchange gain (loss), net	$ (64,018)	$ 131,003	$ (171,964)	$ 170,023
C$ equivalent of 1 US$				
Beginning of period	1.2901	1.3322	1.2518	1.3427
End of period	1.3142	1.2977	1.3142	1.2977

The net foreign exchange gains and losses are primarily due to the translation of the U.S. dollar denominated debt as a result of the strengthening or weakening of the Canadian dollar compared to the U.S. dollar during each period. For the three months ended June 30, 2018 the Canadian dollar weakened by 2% resulting in an unrealized foreign exchange loss on translation of the U.S dollar denominated debt of $67.0 million. For the three months ended June 30, 2017 the Canadian dollar strengthened by 3% resulting in an unrealized foreign exchange gain on translation of the U.S. dollar denominated debt of $130.4 million.

For the six months ended June 30, 2018 the Canadian dollar weakened by 5%, resulting in an unrealized foreign exchange loss on translation of the U.S. dollar denominated debt of $205.8 million. For the six months ended June 30, 2017 the Canadian dollar strengthened by 3% resulting in an unrealized foreign exchange gain on translation of the U.S. dollar denominated debt of $170.1 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 for the six months ended June 30, 2018.

Net Finance Expense

	Three months ended June 30				Six months ended June 30			
($000)		**2018**		**2017**		**2018**		**2017**
Interest expense on long-term debt	**$**	**67,558**	$	85,162	**$**	**149,982**	$	178,436
Interest expense on finance leases		**4,108**		-		**4,549**		-
Interest income		**(2,277)**		(963)		**(4,017)**		(1,769)
Net interest expense		**69,389**		84,199		**150,514**		176,667
Accretion on provisions		**1,810**		1,825		**3,720**		3,681
Unrealized loss (gain) on derivative financial liabilities(1)		**(110)**		(1,615)		**2,866**		(3,856)
Realized loss (gain) on interest rate swaps		**-**		-		**(17,312)**		-
Net finance expense	**$**	**71,089**	$	84,409	**$**	**139,788**	$	176,492
Average effective interest rate(2)		**6.6%**		6.1%		**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 June 30, 2018 was $17.6 million lower than the comparative 2017 period. Interest expense on long-term debt for the six months ended June 30, 2018 was $150.0 million compared to $178.4 million for the six months ended June 30, 2017. The decrease in the three and six months ended June 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 successfully completed 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 for the six months ended June 30, 2018.

Other Expenses

	Three months ended June 30				Six months ended June 30			
($000)		**2018**		**2017**		**2018**		**2017**
Onerous contracts	**$**	**145**	$	3,333	**$**	**789**	$	5,708
Severance and other		**2,801**		3,468		**2,988**		3,417
Other expenses	**$**	**2,946**	$	6,801	**$**	**3,777**	$	9,125

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.

Income Tax Expense (Recovery)

	Three months ended June 30		Six months ended June 30	
($000)	**2018**	**2017**	**2018**	**2017**
Current income tax expense (recovery)	**$ 79**	$ 115	**$ 195**	$ (169)
Deferred income tax expense (recovery)	**(44,752)**	(28,156)	**(74,526)**	(17,177)
Income tax expense (recovery)	**$ (44,673)**	$ (28,041)	**$ (74,331)**	$ (17,346)

The Corporation recognizes current income taxes associated with its operations in the United States. The Corporation's Canadian operations are not currently taxable. As at June 30, 2018, the Corporation had approximately $7.5 billion of available Canadian tax pools.

The Corporation recognized a current income tax expense of $0.2 million for the six months ended June 30, 2018 and a current income tax recovery of $0.2 million for the six months ended June 30, 2017. The 2018 expense of $0.2 million is related to United States income tax associated with operations in the United States. The 2017 recovery is comprised of $0.4 million related to the refundable Alberta tax credit on Scientific Research and Experimental Development expenditures, partially offset by an expense of $0.1 million related to United States income tax associated with its operations in the United States.

The Corporation recognized a deferred income tax recovery of $44.8 million for the three months ended June 30, 2018 and a deferred income tax recovery of $28.2 million for the three months ended June 30, 2017. The Corporation recognized a deferred income tax recovery of $74.5 million for the six months ended June 30, 2018 and a deferred income tax recovery of $17.2 million for the six months ended June 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 six months ended June 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 June 30, 2018, the non-taxable net loss was $33.5 million compared to a non-taxable net gain of $65.2 million for the three months ended June 30, 2017. For the six months ended June 30, 2018, the non-taxable loss was $102.9 million compared to a non-taxable gain of $85.1 million for the six months ended June 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 June 30, 2018 was $4.0 million compared to $4.8 million for the three months ended June 30, 2017. Stock-based compensation expense for equity-settled plans for the six months ended June 30, 2018 was $10.1 million compared to $8.3 million for the six months ended June 30, 2017.

As at June 30, 2018, the Corporation has recognized a deferred income tax asset of $261.4 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 June 30, 2018, the Corporation had not recognized the tax benefit related to $365.8 million of realized and unrealized taxable foreign exchange losses.

7. NET CAPITAL INVESTMENT

	Three months ended June 30		Six months ended June 30	
($000)	**2018**	**2017**	**2018**	**2017**
eMSAGP growth capital	**$ 22,307**	$ 67,873	**$ 69,050**	$ 100,758
eMVAPEX growth capital	**18,367**	1,381	**42,628**	7,298
Phase 2B brownfield expansion	**26,270**	-	**44,080**	-
Growth capital	**66,944**	69,254	**155,758**	108,056
Sustaining and maintenance	**108,868**	87,101	**161,356**	116,791
Field infrastructure, corporate and other	**6,755**	2,119	**13,192**	11,397
Total cash capital investment	**182,567**	158,474	**330,306**	236,244
Capitalized cash-settled stock-based compensation	**8,260**	(916)	**8,135**	(830)
	$ 190,827	$ 157,558	**$ 338,441**	$ 235,414

Total cash capital investment for the three months ended June 30, 2018 was $182.6 million, compared to $158.5 million for the three months ended June 30, 2017. The increase in capital investment for the three months ended June 30, 2018 was primarily related to sustaining capital activities, which included approximately $55.0 million of turnaround costs. In comparison, for the three months ended June 30, 2017, sustaining capital activities included approximately $37.1 million in turnaround costs.

Total cash capital investment for the six months ended June 30, 2018 was $330.3 million, compared to $236.2 million for the six months ended June 30, 2017. The increase in capital investment for the six months ended June 30, 2018 was primarily related to increased spending on the eMVAPEX and Phase 2B brownfield growth projects, which are proceeding on schedule. Sustaining capital activities had increased investment and included approximately $55.0 million of turnaround costs that were incurred in the second quarter of 2018. In comparison, for the six months ended June 30, 2017, sustaining capital activities included approximately $37.1 million in turnaround costs.

8. LIQUIDITY AND CAPITAL RESOURCES

($000)	**June 30, 2018**	**December 31, 2017**
Cash and cash equivalents	**$ 563,969**	$ 463,531
Senior secured term loan (June 30, 2018 – US$231.6 million; due 2023; December 31, 2017 – US$1.226 billion)	**304,319**	1,534,378
6.5% senior secured second lien notes (US$750.0 million; due 2025)	**985,650**	938,850
6.375% senior unsecured notes (US$800.0 million; due 2023)	**1,051,360**	1,001,440
7.0% senior unsecured notes (US$1.0 billion; due 2024)	**1,314,200**	1,251,800
US$1.4 billion revolving credit facility (due 2021)	**-**	-
Total debt[1]	**$ 3,655,529**	$ 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 totalled $564.0 million as at June 30, 2018 compared to $463.5 million as at December 31, 2017. As at June 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 June 30, 2018, the Corporation had US$118.1 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$3.7 billion as at June 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$0.2 billion of unrealized foreign exchange losses on translation of the 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.

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

As at June 30, 2018	**Volumes (bbls/d)[(1)]**	**Term**	**Average Price (US$/bbl)[(1)]**
Crude Oil Sales Contracts			
Fixed Price:			
WTI Fixed Price	29,000	Jul 1, 2018 – Dec 31, 2018	$54.16
WTI Fixed Price	5,000	Jan 1, 2019 – Jun 30, 2019	$65.30
WTI:WCS Fixed Differential	39,500	Jul 1, 2018 – Dec 31, 2018	$(16.05)
WTI:WCS Fixed Differential	3,000	Jan 1, 2019 – Dec 31, 2019	$(21.97)
Collars:			
WTI Collars	32,500	Jul 1, 2018 – Dec 31, 2018	$46.64 – $54.52
Options:			
Purchased WTI Calls	8,000	Jul 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 Differential	5,750	Jul 1, 2018 – Dec 31, 2018	$(5.47)
Fixed Percentage:			
Mont Belvieu Fixed % of WTI	2,000	Jul 1, 2018 – Sep 30, 2018	93.3% of WTI

The Corporation entered into the following commodity risk management contracts relating to crude oil sales subsequent to June 30, 2018 up to the date of August 1, 2018:

Subsequent to June 30, 2018	**Volumes (bbls/d)[(1)]**	**Term**	**Average Price (US$/bbl)[(1)]**
Fixed Price:			
WTI:WCS Fixed Differential	5,000	Jan 1, 2019 – Dec 31, 2019	$(23.50)

(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 successfully completed the sale of its 50% interest in the Access Pipeline and its 100% interest in the Stonefell Terminal. A majority of the net cash proceeds were used to repay approximately C$1.2 billion of the Corporation's senior secured term loan. As a result, the Corporation terminated its interest rate swap contract and realized a gain of $17.3 million for the six months ended June 30, 2018. The Corporation does not have any outstanding interest rate swap contracts as at June 30, 2018.

Cash Flow Summary

	Three months ended June 30		Six months ended June 30	
($000)	**2018**	**2017**	**2018**	**2017**
Net cash provided by (used in):				
Operating activities	**$ 65,243**	$ 63,612	**$ 183,269**	$ 109,418
Investing activities	**(178,156)**	(92,400)	**1,189,846**	(156,336)
Financing activities	**(3,150)**	(4,520)	**(1,275,925)**	409,080
Effect of exchange rate changes on cash and cash equivalents held in foreign currency	**4,916**	(3,249)	**3,248**	(5,968)
Change in cash and cash equivalents	**$ (111,147)**	$ (36,557)	**$ 100,438**	$ 356,194

Cash Flow – Operating Activities

Net cash provided by operating activities totalled $65.2 million for the three months ended June 30, 2018 compared to $63.6 million for the three months ended June 30, 2017. Blend sales revenue for the three months ended June 30, 2018 was higher as a result of an increase in average realized blend price. 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 the increase in average diluent benchmark pricing.

Net cash provided by operating activities totalled $183.3 million for the six months ended June 30, 2018 compared to $109.4 million for the six months ended June 30, 2017. This increase in cash flows is primarily due to higher blend sales revenue, primarily as a result of an increase in average realized blend 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 $178.2 million for the three months ended June 30, 2018 compared to $92.4 million for the three months ended June 30, 2017. The increase in net cash used in investing activities is primarily due to increased capital spending activity directed toward growth initiatives at Christina Lake Phase 2B and sustaining capital activities which include costs associated with the planned turnaround at the Christina Lake Project.

Net cash provided by investing activities was $1.2 billion for the six months ended June 30, 2018 compared to net cash used in investing activities of $156.3 million for the six months ended June 30, 2017. The increase in cash flows is due to 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 spending activity.

Cash Flow – Financing Activities

Net cash used in financing activities was $3.2 million for the three months ended June 30, 2018 compared to $4.5 million for the three months ended June 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 six months ended June 30, 2018 compared to net cash provided by financing activities of $409.1 million for the six months ended June 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 six months ended June 30, 2017 was due to $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 June 30, 2018, the Corporation had the following share capital instruments outstanding or exercisable:

(000)	Units
Common shares	**296,751**
Convertible securities	
Stock options[(1)]	**8,595**
Equity-settled RSUs and PSUs	**6,622**

(1) *7.0 million stock options were exercisable as at June 30, 2018.*

As at July 30, 2018, the Corporation had 296.8 million common shares, 8.5 million stock options and 6.6 million equity-settled restricted share units and equity-settled performance share units outstanding, and 6.9 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 June 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)]	$ 8,115	$ 16,230	$ 16,230	$ 16,230	$ 16,230	$ 3,582,494	$ 3,655,529
Interest on long-term debt[(1)]	120,098	239,408	238,498	237,590	236,681	266,739	1,339,014
Decommissioning obligation[(2)]	3,015	9,811	7,435	8,614	8,614	757,938	795,427
Transportation and storage[(3)]	142,329	302,352	326,419	433,923	443,660	6,639,287	8,287,970
Finance leases[(4)]	6,525	15,817	15,975	16,135	16,296	470,127	540,875
Office lease rentals	13,989	22,635	21,214	20,949	20,128	152,617	251,532
Diluent purchases[(5)]	332,297	402,494	20,595	20,538	20,538	17,108	813,570
Other commitments[(6)]	13,145	13,648	11,079	9,377	8,422	54,298	109,969
Total	**$ 639,513**	**$1,022,395**	**$ 657,445**	**$ 763,356**	**$ 770,569**	**$ 11,940,608**	**$ 15,793,886**

(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 June 30, 2018.*

(2) *This represents the undiscounted future obligations associated with the decommissioning of the Corporation’s crude oil, transportation and storage 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 $4.9 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 $1.5 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 June 30		Six months ended June 30	
($000)	2018	2017	2018	2017
Net cash provided by (used in) operating activities	**$ 65,243**	$ 63,612	**$ 183,269**	$ 109,418
Net change in non-cash operating working capital items	**(51,836)**	(14,024)	**(59,972)**	(22,211)
Funds flow from (used in) operations	**13,407**	49,588	**123,297**	87,207
Adjustments:				
Realized gain on foreign exchange derivatives[1]	**-**	-	**(35,362)**	-
Payments on onerous contracts	**4,236**	5,468	**10,244**	9,602
Decommissioning expenditures	**750**	39	**3,371**	1,461
Adjusted funds flow from (used in) operations	**$ 18,393**	$ 55,095	**$ 101,550**	$ 98,270

(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.

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, gain on asset dispositions, onerous contracts expense, 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.

($000)	June 30, 2018	December 31, 2017
Long-term debt	**$ 3,606,765**	$ 4,668,267
Adjustments:		
Current portion of senior secured term loan	**16,230**	15,460
Unamortized financial derivative liability discount	**1,399**	4,242
Unamortized deferred debt discount and debt issue costs	**31,135**	38,499
Total debt	**$ 3,655,529**	$ 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, which 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 accounting requirements for lessors is substantially unchanged and a lessor will continue to classify leases as either finance leases or operating leases, but disclosure requirements are enhanced. 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. The standard is expected to increase the Corporation's assets and liabilities, increase depletion and depreciation expense, increase net finance expense, reduce general and administrative expense, and reduce transportation expense.

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; and anticipated sources of funding for operations and capital investments. 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

For information regarding MEG's estimated reserves, 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. 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.

20. QUARTERLY SUMMARIES

	2018		2017				2016	
Unaudited	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**
FINANCIAL **($000 unless specified)**								
Net earnings (loss)	**(178,570)**	140,573	(23,779)	83,885	104,282	1,588	(304,758)	(108,632)
Per share, diluted	**(0.61)**	0.47	(0.08)	0.28	0.35	0.01	(1.34)	(0.48)
Operating earnings (loss)	**(70,174)**	(18,015)	44,055	(42,571)	(35,656)	(79,354)	(71,989)	(87,929)
Per share, diluted	**(0.24)**	(0.06)	0.15	(0.14)	(0.12)	(0.29)	(0.32)	(0.39)
Adjusted funds flow from operations	**18,393**	83,157	192,178	83,352	55,095	43,175	39,967	22,702
Per share, diluted	**0.06**	0.28	0.65	0.28	0.19	0.16	0.18	0.10
Cash capital investment	**182,567**	147,739	163,337	103,173	158,474	77,770	63,077	19,203
Cash and cash equivalents	**563,969**	675,116	463,531	397,598	512,424	548,981	156,230	103,136
Working capital	**211,045**	445,792	313,025	350,067	445,463	537,427	96,442	163,038
Long-term debt	**3,606,765**	3,542,763	4,668,267	4,635,740	4,813,092	4,944,741	5,053,239	4,909,711
Shareholders' equity	**3,945,782**	4,112,531	3,964,113	3,981,750	3,898,054	3,792,818	3,286,776	3,577,557
BUSINESS ENVIRONMENT								
WTI (US$/bbl)	**67.88**	62.87	55.40	48.21	48.29	51.91	49.29	44.94
C$ equivalent of 1US$ - average	**1.2911**	1.2651	1.2717	1.2524	1.3449	1.3230	1.3339	1.3051
Differential – WTI:WCS (C$/bbl)	**24.88**	30.72	15.59	12.45	14.97	19.29	19.10	17.62
Differential – WTI:WCS (%)	**28.4%**	38.6%	22.1%	20.6%	23.0%	28.1%	29.1%	30.0%
Natural gas – AECO ($/mcf)	**1.26**	2.26	1.84	1.58	2.81	2.91	3.31	2.49
OPERATIONAL **($/bbl unless specified)**								
Bitumen production – bbls/d	**71,325**	93,207	90,228	83,008	72,448	77,245	81,780	83,404
Bitumen sales – bbls/d	**74,418**	91,608	94,541	76,813	74,116	74,703	81,746	84,817
Steam-oil ratio (SOR)	**2.2**	2.2	2.2	2.3	2.3	2.4	2.3	2.2
Bitumen realization	**47.20**	35.31	48.30	39.89	39.66	37.93	36.17	30.98
Transportation – net	**(8.28)**	(5.99)	(7.00)	(7.08)	(6.91)	(6.54)	(6.05)	(6.46)
Royalties	**(1.64)**	(1.03)	(0.84)	(0.53)	(0.87)	(0.85)	(0.51)	(0.42)
Operating costs – non-energy	**(5.47)**	(4.55)	(4.53)	(4.57)	(4.23)	(5.20)	(4.99)	(5.32)
Operating costs – energy	**(1.79)**	(2.64)	(2.03)	(2.26)	(3.76)	(4.18)	(4.12)	(2.99)
Power revenue	**1.62**	1.21	0.70	0.83	0.57	0.95	0.87	0.55
Realized gain (loss) on commodity risk management	**(13.11)**	(2.15)	(0.77)	0.56	(1.50)	0.22	0.36	0.40
Cash operating netback	**18.53**	20.16	33.83	26.84	22.96	22.33	21.73	16.74
Power sales price (C$/MWh)	**51.02**	35.50	21.37	23.29	18.27	22.42	21.94	17.62
Power sales (MW/h)	**98**	130	129	115	97	131	134	110
Depletion and depreciation rate per bbl of production	**16.08**	13.22	14.26	16.86	16.93	16.81	16.81	16.81
COMMON SHARES								
Shares outstanding, end of period (000)	**296,751**	294,105	294,104	294,079	294,047	293,282	226,467	226,415
Volume traded (000)	**166,016**	89,721	76,531	70,216	98,795	123,445	114,776	112,720
Common share price ($)								
High	**11.24**	6.43	6.82	5.79	7.27	9.83	9.79	6.90
Low	**4.49**	4.28	4.54	3.28	3.63	5.84	5.11	4.72
Close (end of period)	**10.96**	4.55	5.14	5.49	3.81	6.74	9.23	5.93

Interim Consolidated Financial Statements

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

As at	Note	June 30, 2018	December 31, 2017
Assets			
Current assets			
Cash and cash equivalents	19	**$ 563,969**	$ 463,531
Trade receivables and other		**231,106**	289,104
Inventories		**95,306**	85,850
		890,381	838,485
Non-current assets			
Property, plant and equipment	5	**6,604,060**	7,634,399
Exploration and evaluation assets	6	**548,688**	548,828
Intangible assets	7	**11,593**	13,037
Other assets	8	**208,941**	145,732
Commodity risk management	21	**206**	-
Deferred income tax asset	18	**261,420**	182,871
Total assets		**$ 8,525,289**	$ 9,363,352
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities		**$ 450,591**	$ 413,905
Current portion of long-term debt	9	**16,230**	15,460
Current portion of provisions and other liabilities	10	**26,534**	27,446
Commodity risk management	21	**185,981**	68,649
		679,336	525,460
Non-current liabilities			
Long-term debt	9	**3,606,765**	4,668,267
Provisions and other liabilities	10	**293,406**	205,512
Total liabilities		**4,579,507**	5,399,239
Shareholders' equity			
Share capital	11	**5,426,279**	5,403,978
Contributed surplus		**157,209**	166,636
Deficit		**(1,669,454)**	(1,629,091)
Accumulated other comprehensive income		**31,748**	22,590
Total shareholders' equity		**3,945,782**	3,964,113
Total liabilities and shareholders' equity		**$ 8,525,289**	$ 9,363,352

Commitments and contingencies (Note 23)

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 June 30		Six months ended June 30	
	Note	2018	2017 Revised (Note 3)	2018	2017 Revised (Note 3)
Revenues					
Petroleum revenue, net of royalties	3,13	**$ 674,038**	$ 576,499	**$1,382,063**	$ 1,126,969
Other revenue	3,13	**15,087**	7,136	**27,653**	16,445
		689,125	583,635	**1,409,716**	1,143,414
Expenses					
Diluent and transportation	14	**354,441**	275,006	**739,383**	556,303
Operating expenses		**49,163**	53,871	**108,393**	116,924
Purchased product and storage	3,15	**70,406**	89,244	**161,633**	154,786
Depletion and depreciation	5,7	**104,350**	111,605	**215,249**	228,484
General and administrative		**19,152**	20,939	**40,875**	44,161
Stock-based compensation	12	**25,339**	2,491	**31,177**	4,778
Research and development		**1,425**	1,166	**2,413**	2,106
Net finance expense	17	**71,089**	84,409	**139,788**	176,492
Other expenses		**2,946**	6,801	**3,777**	9,125
Gain on asset dispositions	5	**-**	-	**(318,398)**	-
Commodity risk management loss (gain)	21	**150,039**	(7,135)	**225,790**	(68,246)
Foreign exchange loss (gain), net	16	**64,018**	(131,003)	**171,964**	(170,023)
Earnings (loss) before income taxes		**(223,243)**	76,241	**(112,328)**	88,524
Income tax expense (recovery)	18	**(44,673)**	(28,041)	**(74,331)**	(17,346)
Net earnings (loss)		**(178,570)**	104,282	**(37,997)**	105,870
Other comprehensive income (loss), net of tax					
Items that may be reclassified to profit or loss:					
Foreign currency translation adjustment		**3,457**	(4,710)	**9,158**	(6,167)
Comprehensive income (loss) for the period		**$(175,113)**	$ 99,572	**$ (28,839)**	$ 99,703
Net earnings (loss) per common share					
Basic	20	**$ (0.61)**	$ 0.36	**$ (0.13)**	$ 0.37
Diluted	20	**$ (0.61)**	$ 0.35	**$ (0.13)**	$ 0.37

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		**-**	**12,049**	**-**	**-**	**12,049**
Stock options exercised	11	**1,223**	**(398)**	**-**	**-**	**825**
RSUs vested and released	11	**21,078**	**(21,078)**	**2,293**	**-**	**2,293**
Comprehensive income (loss)		**-**	**-**	**(37,997)**	**9,158**	**(28,839)**
Balance as at June 30, 2018		**$ 5,426,279**	**$ 157,209**	**$ (1,669,454)**	**$ 31,748**	**$ 3,945,782**
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		-	9,457	-	-	9,457
RSUs vested and released		21,869	(21,869)	-	-	-
Comprehensive income (loss)		-	-	105,870	(6,167)	99,703
Balance as at June 30, 2017		$ 5,402,594	$ 155,841	$ (1,689,197)	$ 28,816	$ 3,898,054

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 June 30		Six months ended June 30	
	Note	**2018**	**2017**	**2018**	**2017**
Cash provided by (used in):					
Operating activities					
Net earnings (loss)		**$ (178,570)**	$ 104,282	**$ (37,997)**	$ 105,870
Adjustments for:					
Depletion and depreciation	5,7	**104,350**	111,605	**215,249**	228,484
Stock-based compensation	12	**3,999**	4,763	**10,128**	8,273
Unrealized loss (gain) on foreign exchange	16	**62,377**	(127,961)	**203,675**	(164,668)
Unrealized loss (gain) on derivative financial liabilities	17	**(110)**	(1,615)	**2,866**	(3,856)
Unrealized loss (gain) on commodity risk management	21	**61,288**	(17,224)	**119,320**	(76,823)
Onerous contracts expense		**145**	3,333	**789**	5,708
Deferred income tax expense (recovery)	18	**(44,752)**	(28,156)	**(74,526)**	(17,177)
Amortization of debt discount and debt issue costs	8,9	**3,407**	4,728	**8,135**	9,754
Gain on asset dispositions	5	**-**	-	**(318,398)**	-
Other		**(674)**	1,340	**738**	2,705
Decommissioning expenditures	10	**(750)**	(39)	**(3,371)**	(1,461)
Payments on onerous contracts	10	**(4,236)**	(5,468)	**(10,244)**	(9,602)
Net change in other liabilities		**6,933**	-	**6,933**	-
Net change in non-cash working capital items	19	**51,836**	14,024	**59,972**	22,211
Net cash provided by (used in) operating activities		**65,243**	63,612	**183,269**	109,418
Investing activities					
Capital investments:					
Property, plant and equipment	5	**(190,531)**	(157,067)	**(337,785)**	(234,708)
Exploration and evaluation	6	**(119)**	(479)	**(557)**	(692)
Intangible assets	7	**(177)**	(12)	**(99)**	(14)
Net proceeds on dispositions	5	**-**	-	**1,502,869**	-
Other		**(2,077)**	6,298	**(2,734)**	16,933
Net change in non-cash working capital items	19	**14,748**	58,860	**28,152**	62,145
Net cash provided by (used in) investing activities		**(178,156)**	(92,400)	**1,189,846**	(156,336)
Financing activities					
Issue of shares, net of issue costs	11	**825**	-	**825**	496,312
Redemption of senior unsecured notes		**-**	-	**-**	(1,008,825)
Issue of senior secured second lien notes		**-**	-	**-**	1,008,825
Payments on term loan	19	**(3,975)**	(4,200)	**(1,276,750)**	(4,855)
Refinancing costs		**-**	(320)	**-**	(82,377)
Net cash provided by (used in) financing activities		**(3,150)**	(4,520)	**(1,275,925)**	409,080
Effect of exchange rate changes on cash and cash equivalents held in foreign currency		**4,916**	(3,249)	**3,248**	(5,968)
Change in cash and cash equivalents		**(111,147)**	(36,557)	**100,438**	356,194
Cash and cash equivalents, beginning of period		**675,116**	548,981	**463,531**	156,230
Cash and cash equivalents, end of period		**$ 563,969**	$ 512,424	**$ 563,969**	$ 512,424

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 August 1, 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, which 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.

<u>Financial Assets</u>

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 accounting requirements for lessors is substantially unchanged and a lessor will continue to classify leases as either finance leases or operating leases, but disclosure requirements are enhanced. 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. The standard is expected to increase the Corporation's assets and liabilities, increase depletion and depreciation expense, increase net finance expense, reduce general and administrative expense, and reduce transportation expense.

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	334,812	200,677	252	535,741
Transfers to other assets (Note 8)	-	(67,318)	-	(67,318)
Dispositions	-	(1,396,864)	-	(1,396,864)
Change in decommissioning liabilities	(33,851)	(328)	-	(34,179)
Balance as at June 30, 2018	**$ 8,599,051**	**$ 354,008**	**$ 76,700**	**$ 9,029,759**

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	191,709	18,748	3,249	213,706
Dispositions	-	(145,987)	-	(145,987)
Balance as at June 30, 2018	**$ 2,375,957**	**$ 13,395**	**$ 36,347**	**$ 2,425,699**
Carrying amounts				
Balance as at December 31, 2017	$ 6,113,842	$ 1,477,207	$ 43,350	$ 7,634,399
Balance as at June 30, 2018	**$ 6,223,094**	**$ 340,613**	**$ 40,353**	**$ 6,604,060**

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 $194.1 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 June 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 $234.4 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		557
Change in decommissioning liabilities		(697)
Balance as at June 30, 2018	**$**	**548,688**

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 June 30, 2018, these assets were assessed for impairment within the aggregation of all of the Corporation's CGU's 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		99
Balance as at June 30, 2018	**$**	**113,554**

Accumulated depreciation		
Balance as at December 31, 2016	$	96,810
Depreciation		3,608
Balance as at December 31, 2017	$	100,418
Depreciation		1,543
Balance as at June 30, 2018	**$**	**101,961**

Carrying amounts		
Balance as at December 31, 2017	$	13,037
Balance as at June 30, 2018	**$**	**11,593**

As at June 30, 2018, intangible assets consist of $11.6 million invested in software that is not an integral component of the related computer hardware (December 31, 2017 – $13.0 million). As at June 30, 2018, no impairment has been recognized on these assets.

8. OTHER ASSETS

As at	June 30, 2018	December 31, 2017
Long-term pipeline linefill[(a)]	**$ 195,291**	$ 122,657
Deferred financing costs	**19,825**	24,134
Prepaid transportation costs[(b)]	**2,478**	-
Interest rate swap[(c)]	**-**	8,067
	217,594	154,858
Less current portion	**(8,653)**	(9,126)
	$ 208,941	$ 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 June 30, 2018, no impairment has been recognized on these assets.

(b) In the second quarter of 2018, the Corporation invested $2.5 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	June 30, 2018	December 31, 2017
Senior secured term loan (June 30, 2018 – US$231.6 million; due 2023; December 31, 2017 – US$1.226 billion)[(a)]	**$ 304,319**	$ 1,534,378
6.5% senior secured second lien notes (US$750.0 million; due 2025)	**985,650**	938,850
6.375% senior unsecured notes (US$800.0 million; due 2023)	**1,051,360**	1,001,440
7.0% senior unsecured notes (US$1.0 billion; due 2024)	**1,314,200**	1,251,800
	3,655,529	4,726,468
Less unamortized financial derivative liability discount	**(1,399)**	(4,242)
Less unamortized deferred debt discount and debt issue costs	**(31,135)**	(38,499)
	3,622,995	4,683,727
Less current portion of senior secured term loan	**(16,230)**	(15,460)
	$ 3,606,765	$ 4,668,267

The U.S. dollar denominated debt was translated into Canadian dollars at the period end exchange rate of US$1 = C$1.3142 (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 June 30, 2018, the senior secured credit facilities are comprised of a US$231.6 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 June 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 June 30, 2018, the Corporation has US$118.1 million of unutilized capacity under this facility.

10. PROVISIONS AND OTHER LIABILITIES

As at	June 30, 2018	December 31, 2017
Finance leases[a]	**$ 130,659**	$ -
Onerous contracts provision[b]	**83,142**	92,157
Decommissioning provision[c]	**66,636**	102,530
Deferred lease inducements[d]	**21,886**	22,854
Other long-term liabilities	**17,617**	15,417
Provisions and other liabilities	**319,940**	232,958
Less current portion	**(26,534)**	(27,446)
Non-current portion	**$ 293,406**	$ 205,512

(a) Finance leases:

As at	June 30, 2018	December 31, 2017
Balance, beginning of year	**$ -**	$ -
Liabilities incurred	**130,446**	-
Liabilities settled	**(4,336)**	-
Interest expense	**4,549**	-
Balance, end of period	**$ 130,659**	$ -

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 30-year lease term is $540.8 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	June 30, 2018
Within one year	**$ 14,409**
Later than one year but not later than five years	**64,476**
Later than five years	**461,889**
Minimum lease payments	**540,774**
Amounts representing finance charges	**(410,115)**
Present value of net minimum lease payments	**$ 130,659**

(b) Onerous contracts provision:

As at	June 30, 2018	December 31, 2017
Balance, beginning of year	**$ 92,157**	$ 100,159
Changes in estimated future cash flows	**1,381**	13,337
Changes in discount rates	**(592)**	(2,507)
Liabilities settled	**(10,244)**	(19,569)
Accretion	**440**	737
Balance, end of period	**83,142**	92,157
Less current portion	**(14,760)**	(19,047)
Non-current portion	**$ 68,382**	$ 73,110

As at June 30, 2018, the Corporation has recognized a provision of $83.1 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 $93.7 million (December 31, 2017 – $102.1 million). These cash flows have been discounted using a risk-free discount rate of 1.9% (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	June 30, 2018	December 31, 2017
Balance, beginning of year	**$ 102,530**	$ 133,924
Changes in estimated future cash flows and settlement dates	**2,008**	(36,314)
Changes in discount rates	**(39,723)**	(19,602)
Liabilities incurred	**2,888**	19,902
Liabilities disposed	**(976)**	-
Liabilities settled	**(3,371)**	(2,403)
Accretion	**3,280**	7,023
Balance, end of period	**66,636**	102,530
Less current portion	**(9,843)**	(6,386)
Non-current portion	**$ 56,793**	$ 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 $795.4 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 14.1% (December 31, 2017 – 9.5%).

(d) Deferred lease inducements:

Deferred lease inducements of $21.9 million will be amortized and recognized as a reduction to general and administrative expense 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:

	Six months ended June 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	**143**	**1,223**	-	-
Issued upon vesting and release of RSUs and PSUs	**2,504**	**21,078**	822	23,253
Balance, end of period	**296,751**	**$5,426,279**	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:

Six months ended June 30, 2018	(thousands)
Outstanding, beginning of year	5,310
Granted	467
Vested and released	(1,376)
Forfeited	(81)
Outstanding, end of period	4,320

ii. Deferred share units outstanding:

The Deferred Share Unit Plan allows for the granting of DSUs to directors of the Corporation. As at June 30, 2018, there were 356,275 DSUs outstanding (December 31, 2017 – 284,871 DSUs outstanding).

As at June 30, 2018, the Corporation has recognized a liability of $30.9 million relating to the fair value of cash-settled RSUs, PSUs and DSUs (December 31, 2017 – $14.3 million). The current portion of $24.0 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.

Six months ended June 30, 2018	Stock options (thousands)	Weighted average exercise price
Outstanding, beginning of year	8,896	$ 23.81
Granted	445	9.63
Exercised	(143)	5.77
Forfeited	(95)	25.85
Expired	(508)	51.06
Outstanding, end of period	8,595	$ 21.74

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:

Six months ended June 30, 2018	(thousands)
Outstanding, beginning of year	**6,307**
Granted	**3,060**
Vested and released	**(2,504)**
Forfeited	**(241)**
Outstanding, end of period	**6,622**

(c) Stock-based compensation

	Three months ended June 30		Six months ended June 30	
	2018	**2017**	**2018**	**2017**
Cash-settled expense (recovery)[(i)]	**$ 21,340**	$ (2,272)	**$ 21,049**	$ (3,495)
Equity-settled expense	**3,999**	4,763	**10,128**	8,273
Stock-based compensation	**$ 25,339**	$ 2,491	**$ 31,177**	$ 4,778

(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 June 30		Six months ended June 30	
	2018	**2017 Revised (Note 3)**	**2018**	**2017 Revised (Note 3)**
Petroleum revenue[(i)]:				
Proprietary	**$ 624,702**	$ 502,215	**$ 1,297,592**	$ 991,603
Third-party	**60,463**	80,161	**104,106**	146,934
Petroleum revenue	**685,165**	582,376	**1,401,698**	1,138,537
Royalties	**(11,127)**	(5,877)	**(19,635)**	(11,568)
Petroleum revenue, net of royalties	**$ 674,038**	$ 576,499	**$ 1,382,063**	$ 1,126,969
Power revenue	**$ 10,968**	$ 3,852	**$ 20,924**	$ 10,208
Transportation revenue	**4,119**	3,284	**6,729**	6,237
Other revenue	**$ 15,087**	$ 7,136	**$ 27,653**	$ 16,445
	$ 689,125	$ 583,635	**$ 1,409,716**	$ 1,143,414

(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 June 30					
	2018			2017		
	Petroleum Revenue			Petroleum Revenue		
	Proprietary	**Third-party**	**Total**	**Proprietary**	**Third-party**	**Total**
Country:						
Canada	**$ 391,388**	**$ 13,642**	**$ 405,030**	$ 311,566	$ 37,386	$ 348,952
United States	**233,314**	**46,821**	**280,135**	190,649	42,775	233,424
	$ 624,702	**$ 60,463**	**$ 685,165**	$ 502,215	$ 80,161	$ 582,376

	Six months ended June 30					
	2018			2017		
	Petroleum Revenue			Petroleum Revenue		
	Proprietary	**Third-party**	**Total**	**Proprietary**	**Third-party**	**Total**
Country:						
Canada	**$ 820,710**	**$ 54,671**	**$ 875,381**	$ 626,262	$ 74,249	$ 700,511
United States	**476,882**	**49,435**	**526,317**	365,341	72,685	438,026
	$ 1,297,592	**$ 104,106**	**$ 1,401,698**	$ 991,603	$ 146,934	$ 1,138,537

Other revenue recognized during the three and six months ended June 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	**June 30, 2018**	**December 31, 2017**
Petroleum revenue	**$ 193,054**	$ 244,330
Other revenue	**4,066**	2,960
Total revenue-related assets	**$ 197,120**	$ 247,290

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

14. DILUENT AND TRANSPORTATION

	Three months ended June 30		Six months ended June 30	
	2018	**2017**	**2018**	**2017**
Diluent expense	**$ 294,222**	$ 225,113	**$ 627,188**	$ 459,512
Transportation expense	**60,219**	49,893	**112,195**	96,791
Diluent and transportation	**$ 354,441**	$ 275,006	**$ 739,383**	$ 556,303

15. PURCHASED PRODUCT AND STORAGE

	Three months ended June 30		Six months ended June 30	
	2018	2017 Revised (Note 3)	2018	2017 Revised (Note 3)
Third-party purchased product	**$ 59,544**	$ 79,642	**$ 101,973**	$ 145,184
Blend purchases	**10,862**	9,602	**59,660**	9,602
Purchased product and storage	**$ 70,406**	$ 89,244	**$ 161,633**	$ 154,786

16. FOREIGN EXCHANGE LOSS (GAIN), NET

	Three months ended June 30		Six months ended June 30	
	2018	2017	2018	2017
Unrealized foreign exchange loss (gain) on:				
Long-term debt	**$ 67,028**	$ (130,390)	**$ 205,812**	$ (170,148)
Other	**(4,651)**	2,429	**(2,137)**	5,480
Unrealized net loss (gain) on foreign exchange	**62,377**	(127,961)	**203,675**	(164,668)
Realized loss (gain) on foreign exchange	**1,641**	(3,042)	**3,651**	(5,355)
Realized loss (gain) on foreign exchange derivatives[(a)]	**-**	-	**(35,362)**	-
Foreign exchange loss (gain), net	**$ 64,018**	$ (131,003)	**$ 171,964**	$ (170,023)

C$ equivalent of 1 US$				
Beginning of period	**1.2901**	1.3322	**1.2518**	1.3427
End of period	**1.3142**	1.2977	**1.3142**	1.2977

(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 June 30		Six months ended June 30	
	2018	2017	2018	2017
Interest expense on long-term debt	**$ 67,558**	$ 85,162	**$ 149,982**	$ 178,436
Interest expense on finance leases	**4,108**	-	**4,549**	-
Interest income	**(2,277)**	(963)	**(4,017)**	(1,769)
Net interest expense	**69,389**	84,199	**150,514**	176,667
Accretion on provisions	**1,810**	1,825	**3,720**	3,681
Unrealized loss (gain) on derivative financial liabilities	**(110)**	(1,615)	**2,866**	(3,856)
Realized loss (gain) on interest rate swaps[(a)]	**-**	-	**(17,312)**	-
Net finance expense	**$ 71,089**	$ 84,409	**$ 139,788**	$ 176,492

(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. INCOME TAX EXPENSE (RECOVERY)

	Three months ended June 30		Six months ended June 30	
	2018	2017	**2018**	2017
Current income tax expense (recovery)	**$ 79**	$ 115	**$ 195**	$ (169)
Deferred income tax expense (recovery)	**(44,752)**	(28,156)	**(74,526)**	(17,177)
Income tax expense (recovery)	**$ (44,673)**	$ (28,041)	**$ (74,331)**	$ (17,346)

The Corporation has recognized a deferred tax asset of $261.4 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.

19. SUPPLEMENTAL CASH FLOW DISCLOSURES

	Three months ended June 30		Six months ended June 30	
	2018	2017	**2018**	2017
Cash provided by (used in):				
Trade receivables and other	**$ 70,740**	$ 12	**$ 61,795**	$ 32,746
Inventories	**9,490**	12,431	**(8,825)**	606
Accounts payable and accrued liabilities	**(13,646)**	60,441	**35,154**	51,004
	$ 66,584	$ 72,884	**$ 88,124**	$ 84,356
Changes in non-cash working capital relating to:				
Operating	**$ 51,836**	$ 14,024	**$ 59,972**	$ 22,211
Investing	**14,748**	58,860	**28,152**	62,145
	$ 66,584	$ 72,884	**$ 88,124**	$ 84,356
Cash and cash equivalents:[(a)]				
Cash	**$ 278,204**	$ 264,932	**$ 278,204**	$ 264,932
Cash equivalents	**285,765**	247,492	**285,765**	247,492
	$ 563,969	$ 512,424	**$ 563,969**	$ 512,424
Cash interest paid	**$ 4,485**	$ 24,009	**$ 132,277**	$ 139,993

(a) As at June 30, 2018, C$274.2 million of the Corporation's total cash and cash equivalents balance was held in U.S. dollars (June 30, 2017 – C$98.7 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$1.3142 (June 30, 2017 – US$1 = C$1.2977).

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	(1,276,750)
Non-cash changes:	
Unrealized loss (gain) on foreign exchange	205,812
Amortization of financial derivative liability discount	750
Amortization of deferred debt discount and debt issue costs	3,075
IFRS 9 adjustment to deferred debt discount and debt issue costs (Note 3)	6,381
Balance as at June 30, 2018	**$ 3,622,995**

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

20. NET EARNINGS (LOSS) PER COMMON SHARE

	Three months ended June 30		Six months ended June 30	
	2018	**2017**	**2018**	**2017**
Net earnings (loss)	**$ (178,570)**	$ 104,282	**$ (37,997)**	$ 105,870
Weighted average common shares outstanding[a] (thousands)	**295,075**	293,704	**294,662**	283,988
Dilutive effect of stock options, RSUs and PSUs[b] (thousands)	**-**	348	**-**	367
Weighted average common shares outstanding – diluted (thousands)	**295,075**	294,052	**294,662**	284,355
Net earnings (loss) per share, basic	**$ (0.61)**	$ 0.36	**$ (0.13)**	$ 0.37
Net earnings (loss) per share, diluted	**$ (0.61)**	$ 0.35	**$ (0.13)**	$ 0.37

(a) Weighted average common shares outstanding for the six months ended June 30, 2017 included 139,863 PSUs eligible to vest but not yet released.

(b) For the three months and six months ended June 30, 2018, there was no dilutive effect of stock options, RSUs and PSUs due to the Corporation incurring a net loss. If the Corporation had recognized net earnings during the three months and six months ended June 30, 2018, the dilutive effect of stock options, RSUs and PSUs would have been 4.6 million and 4.1 million weighted average common shares, respectively.

21. 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 June 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 June 30, 2018	**Carrying amount**	**Level 1**	**Level 2**	**Level 3**
Recurring measurements:				
Financial assets				
Commodity risk management contracts	**$ 206**	**$ -**	**$ 206**	**$ -**
Financial liabilities				
Long-term debt(i) (Note 9)	**$ 3,655,529**	**$ -**	**$ 3,473,102**	**$ -**
Finance leases (Note 10)	**$ 130,659**	**$ -**	**$ -**	**$ 130,659**
Derivative financial liabilities (Note 10)	**$ 827**	**$ -**	**$ 827**	**$ -**
Commodity risk management contracts	**$ 185,981**	**$ -**	**$ 185,981**	**$ -**

		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 (Note 10)	$ 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 June 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.

(b) 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 June 30, 2018:

As at June 30, 2018	Volumes (bbls/d)[(i)]	Term	Average Price (US$/bbl)[(i)]
Crude Oil Sales Contracts			
Fixed Price:			
WTI[(ii)] Fixed Price	29,000	Jul 1, 2018 – Dec 31, 2018	$54.16
WTI Fixed Price	5,000	Jan 1, 2019 – Jun 30, 2019	$65.30
WTI:WCS[(iii)] Fixed Differential	39,500	Jul 1, 2018 – Dec 31, 2018	$(16.05)
WTI:WCS Fixed Differential	3,000	Jan 1, 2019 – Dec 31, 2019	$(21.97)
Collars:			
WTI Collars	32,500	Jul 1, 2018 – Dec 31, 2018	$46.64 – $54.52
Options:			
Purchased WTI Calls	8,000	Jul 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 Differential	5,750	Jul 1, 2018 – Dec 31, 2018	$(5.47)
Fixed Percentage:			
Mont Belvieu Fixed % of WTI	2,000	Jul 1, 2018 – Sep 30, 2018	93.3% 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	June 30, 2018			December 31, 2017		
	Asset	**Liability**	**Net**	**Asset**	**Liability**	**Net**
Gross amount	**$ 206**	**$ (254,741)**	**$ (254,535)**	$ -	$ (184,175)	$ (184,175)
Amount offset	**-**	**68,760**	**68,760**	-	115,526	115,526
Net amount	**$ 206**	**$ (185,981)**	**$ (185,775)**	$ -	$ (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 June 30:

As at June 30	2018	2017
Fair value of contracts, beginning of year	**$ (68,649)**	$ (30,313)
Fair value of contracts realized	**106,470**	8,577
Change in fair value of contracts	**(225,790)**	68,246
Unamortized premiums on put and call options	**2,194**	-
Fair value of contracts, end of period	**$ (185,775)**	$ 46,510

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

	Three months ended June 30		Six months ended June 30	
	2018	**2017**	**2018**	**2017**
Realized loss (gain) on commodity risk management	**$ 88,751**	$ 10,089	**$ 106,470**	$ 8,577
Unrealized loss (gain) on commodity risk management	**61,288**	(17,224)	**119,320**	(76,823)
Commodity risk management loss (gain)	**$ 150,039**	$ (7,135)	**$ 225,790**	$ (68,246)

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 June 30, 2018:

Commodity	Sensitivity Range	Increase	Decrease
Crude oil commodity price	± US$1.00 per bbl applied to WTI contracts	$ (17,249)	$ 17,249
Crude oil differential price (i)	± US$1.00 per bbl applied to WCS differential contracts	$ 10,977	$ (10,977)

(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 June 30, 2018. As a result, this contract is not reflected in the Corporation's Interim Consolidated Financial Statements:

Subsequent to June 30, 2018	Volumes (bbls/d)	Term	Average Prices (US$/bbl)
Fixed Price:			
WTI:WCS Fixed Differential	5,000	Jan 1, 2019 – Dec 31, 2019	$(23.50)

(c) 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.

(d) 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).

22. GEOGRAPHICAL DISCLOSURE

As at June 30, 2018, the Corporation had non-current assets related to operations in the United States of $104.6 million (December 31, 2017 – $101.7 million). For the three and six months ended June 30, 2018, petroleum revenue related to operations in the United States was $280.1 million and $526.3 million (three and six months ended June 30, 2017 – $233.4 million and $438.0 million).

23. 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 June 30, 2018:

	2018	2019	2020	2021	2022	Thereafter	Total
Transportation and storage[i]	$ 142,329	$ 302,352	$ 326,419	$ 433,923	$ 443,660	$ 6,639,287	$ 8,287,970
Office lease rentals[ii]	5,431	10,863	11,286	11,286	11,286	107,667	157,819
Diluent purchases	332,297	402,494	20,595	20,538	20,538	17,108	813,570
Other operating commitments	6,576	13,648	11,079	9,377	8,422	54,298	103,400
Capital commitments	6,569	-	-	-	-	-	6,569
Commitments	**$ 493,202**	**$ 729,357**	**$ 369,379**	**$ 475,124**	**$ 483,906**	**$ 6,818,360**	**$ 9,369,328**

(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.