MEG ENERGY

SECOND QUARTER 2017

Report to Shareholders for the period ended June 30, 2017

MEG Energy Corp. reported second quarter 2017 operating and financial results on July 27, 2017. Highlights include:

- Quarterly production volumes of 72,448 barrels per day (bpd), while completing planned maintenance activities;
- Net operating costs of $7.42 per barrel supported by unadjusted record low quarterly non-energy operating costs of $4.23 per barrel;
- Total cash capital investment of $158 million, primarily directed towards the eMSAGP growth initiative at Christina Lake Phase 2B which is proceeding on schedule and ahead of budget;
- Strong liquidity contributing to cash and cash equivalents of $512 million as of June 30, 2017. The company's US$1.4 billion, four-year covenant-lite revolving credit facility remains undrawn; and,
- A reduction in per barrel non-energy operating cost guidance from a range of $5.75 - $6.75 per barrel to $5.00 - $5.50 per barrel to reflect ongoing efficiency gains and a continued focus on cost management, while re-affirming annual production guidance of 80,000 to 82,000 bpd, year-end exit production guidance of 86,000 to 89,000 bpd, and 2017 capital budget guidance of $590 million.

MEG's second quarter 2017 production averaged 72,448 bpd, compared to 77,245 bpd for the first quarter of the year. Production for the second quarter was at the upper end of the forecast provided by the company in its first quarter 2017 disclosure which took into account 37 days of planned maintenance. The company remains on track to meet its 2017 average production guidance of 80,000 to 82,000 bpd.

"We had three corporate objectives for 2017 as we work to accomplish our long-term vision of continuing to strengthen our financial position while economically growing production. These objectives were completion of the comprehensive refinancing of the company's balance sheet, the active pursuit of our highly economic growth plan, and our continued focus on the further reduction of our corporate cash costs," said Bill McCaffrey, President and Chief Executive Officer. "With the successful refinancing of MEG's balance sheet in January 2017 and our annual turnaround activities behind us, our focus is now on the implementation of our highly economic Phase 2B eMSAGP growth project. Our proprietary reservoir technology which we are deploying has done more than just improve the efficiencies of our business, it has fundamentally changed the way we grow, allowing us to further lower our breakeven costs."

To date, eMSAGP has been deployed at MEG's Phase 1 and 2 wells, which represent about 25% of the company's production, and has been very successful. The Phase 2B eMSAGP project now being undertaken involves the implementation of MEG's proprietary reservoir enhancement technology to the remaining 75% of the company's production not currently under eMSAGP production. The implementation of eMSAGP has significantly improved reservoir efficiency and allowed for redeployment of steam, enabling the company to place additional wells into production. Since employing eMSAGP, the company's overall steam-oil ratio (SOR) has been reduced to 2.3, and on an eMSAGP-only basis is averaging an industry-leading range of 1.0 to 1.25.

"Given our low sustaining capital requirements and strong cash position, we remain confident that we are on track to complete the highly economic Phase 2B eMSAGP project while meaningfully lowering our corporate cash costs," said Bill. "We expect the current growth phase of 20,000 bpd production from eMSAGP to reduce our cash costs by approximately $4 to $5 per barrel when fully on stream in early 2019, meaningfully improving the ongoing sustainability of our business."

For the second quarter of 2017, net operating costs were $7.42 per barrel, compared to $8.43 per barrel in the previous quarter. Non-energy operating costs were $4.23 per barrel compared to $5.20 per barrel for the first quarter of this year. These per barrel numbers are inclusive of a $0.66 per barrel, or $4.5 million, property tax reduction related to a one-time municipal reassessment of MEG's Christina Lake facility. MEG's second quarter non-energy operating per barrel costs were a record low even excluding the reassessment, reflecting the positive results from operational efficiency gains and a continued focus on cost management.

As a result of ongoing operating cost management, including lower operations staffing and associated camp and site services costs, and continued efficiency gains over the first half of 2017, annual non- energy operating costs for 2017 are now targeted to be in the range of $5.00 - $5.50 per barrel, approximately 16% lower than the original guidance of $5.75 - $6.75 per barrel at its mid-point.

MEG realized adjusted funds flow from operations of $55 million for the second quarter of 2017 compared to adjusted funds flow from operations of $7 million for the same period in 2016. The increase in adjusted funds flow from operations was primarily due to an increase in bitumen realization driven by the increase in average crude oil benchmark pricing and narrower differentials. The company recorded a second quarter 2017 operating loss of $36 million compared to an operating loss of $79 million for the first quarter of this year.

Capital Investment and Financial Liquidity

Total cash capital investment during the second quarter of 2017 was $158 million, compared to $78 million for the first quarter of 2017. Capital investment in 2017 is primarily directed towards the company's eMSAGP production growth initiative at Christina Lake Phase 2B, which is proceeding on schedule and ahead of budget. The company expects production to increase in the third quarter, supporting year-end exit production guidance of 86,000 to 89,000 bpd.

In the second quarter of 2017, costs from the major planned turnaround of $37 million were incurred and will be depreciated on a straight-line basis over the period to the next major planned turnaround.

MEG's 2017 capital budget guidance remains at $590 million, of which approximately 55% is directed towards the Phase 2B eMSAGP growth initiative, 35% towards sustaining and turnaround costs, and the remainder towards supporting marketing, corporate and other initiatives. The company expects to fund the remainder of its 2017 capital program with a portion of the $512 million of cash on hand at June 30, 2017.

MEG has entered into a series of hedges designed to protect its capital program against downward oil price movements and mitigate volatility in cash flow. MEG has hedges in place for approximately half of its blend sales at an average floor price of US$50 WTI per barrel and for approximately 40% of its condensate purchases for the rest of 2017. MEG's four-year covenant-lite US$1.4 billion credit facility also remains undrawn.

The company is taking steps to address its financial leverage. In January 2017, MEG successfully completed a refinancing which pushed the first maturity of any of the Corporation's outstanding long-term debt obligations to 2023. The ongoing implementation of the eMSAGP growth project will grow production and associated cash flow while further de-risking the business through a reduction in its overall cash costs of $4 to $5 per barrel. In addition, taking into account the company's debt maturity profile and the ongoing commodity price environment, MEG continues to consider its options to reduce its overall amount of debt.

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.

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, 2017 was approved by the Corporation's Audit Committee on July 26, 2017. 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, 2017, the audited annual consolidated financial statements and notes thereto for the year ended December 31, 2016, the 2016 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. OVERVIEW

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 and MEG has applied for regulatory approval for 120,000 bbls/d of bitumen production at the Surmont Project. 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 "May River Regional Project" and the "Growth Properties." On February 21, 2017, the Corporation 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 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. Bitumen production at the Christina Lake Project for the year ended December 31, 2016 averaged 81,245 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 wells where the implementation of eMSAGP has already been deployed, the process has yielded steam-oil ratios in the range of 1.0 – 1.25. MEG is currently in the process of implementing the RISER initiative, and specifically eMSAGP, to Phase 2B.

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.

MEG holds a 100% interest in the Stonefell Terminal, located near Edmonton, Alberta, with a storage and terminalling capacity of 900,000 barrels. The Stonefell Terminal provides the Corporation with the ability to sell and deliver Access Western Blend ("AWB" or "blend") to a variety of markets, access multiple sources of diluent, and store both blend and diluent in periods of market and transportation disruptions or constraints. The Stonefell Terminal is directly connected by pipeline to a third party rail-loading terminal near Bruderheim, Alberta. This combination of facilities allows for the loading of bitumen blend for transport by rail.

MEG holds a 50% interest in the Access Pipeline, a dual pipeline system that connects the Christina Lake Project to a large regional upgrading, refining, diluent supply and transportation hub in the Edmonton, Alberta area.

The Corporation is taking a number of steps to address its financial leverage. In January 2017, MEG successfully completed a refinancing which pushed the first maturity of any of the Corporation's outstanding long-term debt obligations to 2023. The ongoing implementation of the eMSAGP growth project will increase future production while further reducing MEG's per barrel costs, and strengthen the Corporation's ability to deal with the current volatility in crude oil prices. In addition, the Corporation continues to consider, taking into account MEG's debt maturity profile and the ongoing price environment, other options it has available to reduce its overall amount of debt over time.

2. OPERATIONAL AND FINANCIAL HIGHLIGHTS

During the second quarter of 2017, the ongoing global imbalance between supply and demand for crude oil and the volatility of global crude oil prices continued to have an impact on the Corporation's operating and financial results. The C$/bbl WTI average price for the second quarter of 2017 increased by 11% compared to the second quarter of 2016.

Total cash capital investment for the second quarter of 2017 was $158.5 million as compared to $20.0 million for the three months ended June 30, 2016. During the three months ended, June 30, 2017, the Corporation invested approximately $68.1 million in the eMSAGP growth project at Christina Lake Phase 2B, $87.1 million in sustaining capital activities, and $3.3 million in marketing, corporate and other capital initiatives.

Sustaining capital activities during the second quarter of 2017 includes $37.1 million related to a planned 37 day turnaround at the Christina Lake Project, which was successfully completed in early June.

At June 30, 2017, the Corporation had cash and cash equivalents of $512.4 million and US$1.4 billion of undrawn capacity under the revolving credit facility. The first maturity of any of the Corporation's outstanding long-term debt obligations is in 2023. See "LIQUIDITY AND CAPITAL RESOURCES" section of this MD&A for further details.

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		2017		2016				2015	
($ millions, except as indicated)	**2017**	**2016**	**Q2**	Q1	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**
Bitumen production - bbls/d	**74,833**	79,883	**72,448**	77,245	81,780	83,404	83,127	76,640	83,514	82,768
Bitumen realization - $/bbl	**38.80**	21.56	**39.66**	37.93	36.17	30.98	30.93	11.43	23.17	31.03
Net operating costs - $/bbl(1)	**7.92**	7.97	**7.42**	8.43	8.24	7.76	7.43	8.53	8.52	9.10
Non-energy operating costs - $/bbl	**4.71**	6.12	**4.23**	5.20	4.99	5.32	5.81	6.45	5.66	5.98
Cash operating netback - $/bbl(2)	**22.66**	6.57	**22.96**	22.33	21.73	16.74	16.09	(3.71)	9.05	16.41
Adjusted funds flow from (used in) operations(3)	**98**	(124)	**55**	43	40	23	7	(131)	(44)	24
Per share, diluted(3)	**0.35**	(0.55)	**0.19**	0.16	0.18	0.10	0.03	(0.58)	(0.20)	0.11
Operating earnings (loss)(3)	**(115)**	(295)	**(36)**	(79)	(72)	(88)	(98)	(197)	(140)	(87)
Per share, diluted(3)	**(0.40)**	(1.31)	**(0.12)**	(0.29)	(0.32)	(0.39)	(0.43)	(0.88)	(0.62)	(0.39)
Revenue(4)	**1,134**	804	**574**	560	566	497	513	290	445	460
Net earnings (loss)(5)	**106**	(15)	**104**	2	(305)	(109)	(146)	131	(297)	(428)
Per share, basic	**0.37**	(0.07)	**0.36**	0.01	(1.34)	(0.48)	(0.65)	0.58	(1.32)	(1.90)
Per share, diluted	**0.37**	(0.07)	**0.35**	0.01	(1.34)	(0.48)	(0.65)	0.58	(1.32)	(1.90)
Total cash capital investment(6)	**236**	55	**158**	78	63	19	20	35	54	32
Cash and cash equivalents	**512**	153	**512**	549	156	103	153	125	408	351
Long-term debt	**4,813**	4,871	**4,813**	4,945	5,053	4,910	4,871	4,859	5,190	5,024

(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, 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. For the three and six months ended June 30, 2017 and June 30, 2016, 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 Interim Consolidated Statement of Earnings and Comprehensive Income.

(5) Includes a net unrealized foreign exchange gain of $128.0 million and $164.7 million on the Corporation's U.S. dollar denominated debt and U.S. dollar denominated cash and cash equivalents for the three and six months ended June 30, 2017, respectively. The net loss for the three and six months ended, June 30, 2016 includes a net unrealized foreign exchange loss of $13.8 million and a net unrealized foreign exchange gain of $306.5 million, respectively.

(6) Defined as total capital investment excluding dispositions, capitalized interest, capitalized cash-settled stock-based compensation and non-cash items.

3. RESULTS OF OPERATIONS

Bitumen Production and Steam-Oil Ratio

	Three months ended June 30		Six months ended June 30	
	2017	**2016**	**2017**	**2016**
Bitumen production – bbls/d	**72,448**	83,127	**74,833**	79,883
Steam-oil ratio (SOR)	**2.3**	2.3	**2.3**	2.3

Bitumen Production

Bitumen production at the Christina Lake Project for the three months ended June 30, 2017 averaged 72,448 bbls/d compared to 83,127 bbls/d for the three months ended June 30, 2016. Production for the three months ended June 30, 2017 was affected by a planned 37 day turnaround at the Christina Lake Project, which was successfully completed in early June. There were no similar activities that impacted production volumes for the three months ended June 30, 2016.

Bitumen production for the six months ended June 30, 2017 averaged 74,833 bbls/d compared to 79,883 bbl/d for the six months ended June 30, 2016. Production for the six months ended June 30, 2017 was primarily affected by preparatory work to accommodate ongoing drilling activities as well as a planned 37 day turnaround at the Christina Lake Project, which was successfully completed in early June. The 2017 turnaround had a greater impact on production volumes compared to only minor capital activities during the same period in 2016.

Steam-Oil Ratio

The Corporation continues to focus on maintaining efficiency of production through a lower SOR, which 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 SOR averaged 2.3 during the three and six months ended June 30, 2017 and June 30, 2016.

Operating Cash Flow

	Three months ended June 30		Six months ended June 30	
($000)	**2017**	**2016**	**2017**	**2016**
Petroleum revenue – proprietary[1]	**$ 492,613**	$ 430,119	**$ 982,001**	$ 680,516
Diluent expense	**(225,113)**	(203,428)	**(459,512)**	(376,293)
	267,500	226,691	**522,489**	304,223
Royalties	**(5,877)**	(1,965)	**(11,568)**	(1,468)
Transportation expense	**(49,893)**	(54,012)	**(96,791)**	(104,510)
Operating expenses	**(53,871)**	(57,049)	**(116,924)**	(120,437)
Power revenue	**3,852**	2,529	**10,208**	8,083
Transportation revenue	**3,284**	5,163	**6,237**	10,323
	164,995	121,357	**313,651**	96,214
Realized gain (loss) on commodity risk management	**(10,089)**	(3,487)	**(8,577)**	(3,487)
Operating cash flow[2]	**$ 154,906**	$ 117,870	**$ 305,074**	$ 92,727

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

Operating cash flow was $154.9 million for the three months ended June 30, 2017 compared to $117.9 million for the three months ended June 30, 2016. Operating cash flow increased primarily due to higher blend sales revenue as a result of the quarter-over-quarter increase in average crude oil benchmark pricing, partially offset by an increase in diluent expense. Blend sales revenue for the three months ended June 30, 2017 was $492.6 million compared to $430.1 million for the three months ended June 30, 2016. The increase in blend sales revenue is primarily due to a 24% increase in the average realized blend price. Diluent expense for the three months ended June 30, 2017 was $225.1 million compared to $203.4 million for the three months ended June 30, 2016, reflecting an increase in condensate prices.

Operating cash flow was $305.1 million for the six months ended June 30, 2017 compared to $92.7 million for the six months ended June 30, 2016. Operating cash flow increased primarily due to higher blend sales revenue as a result of the increase in average crude oil benchmark pricing, partially offset by an increase in diluent expense and royalties. Blend sales revenue for the six months ended June 30, 2017 was $982.0 million compared to $680.5 million for the six months ended June 30, 2016. The increase in blend sales revenue is primarily due to a 50% increase in the average realized blend price. Diluent expense for the six months ended June 30, 2017 was $459.5 million compared to $376.3 million for the six months ended June 30, 2016. Diluent expense increased primarily due to an increase in condensate prices.

Cash Operating Netback

The following table summarizes the Corporation's cash operating netback for the periods indicated:

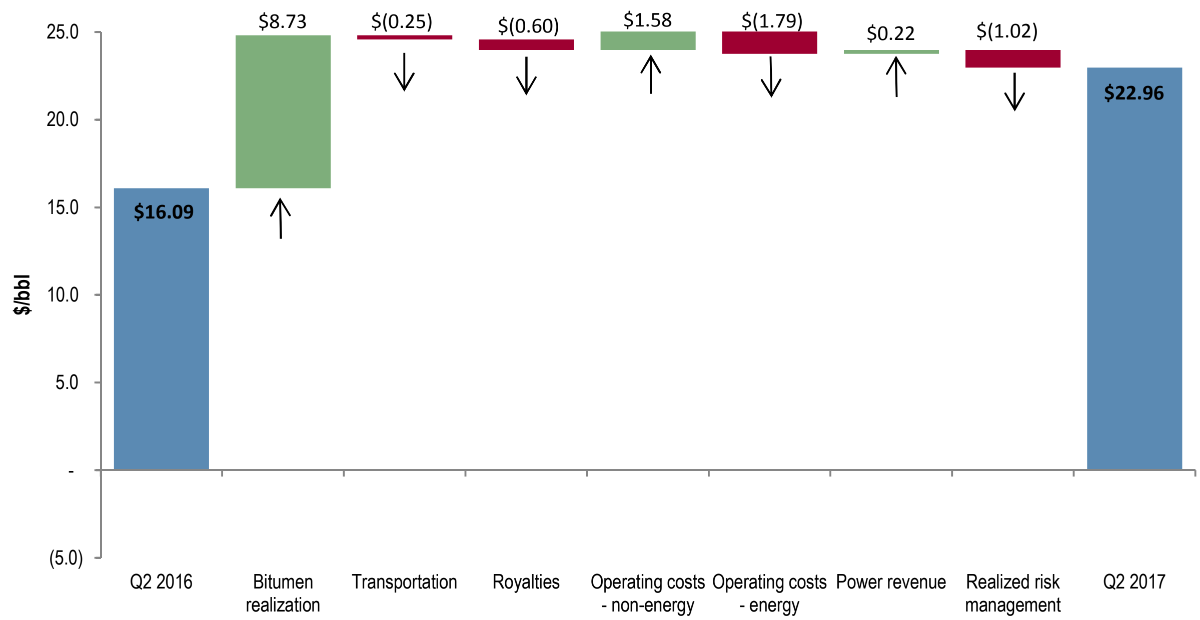
	Three months ended June 30		Six months ended June 30	
($/bbl)	**2017**	**2016**	**2017**	**2016**
Bitumen realization[1]	**$ 39.66**	$ 30.93	**$ 38.80**	$ 21.56
Transportation[2]	**(6.91)**	(6.66)	**(6.72)**	(6.67)
Royalties	**(0.87)**	(0.27)	**(0.86)**	(0.10)
	31.88	24.00	**31.22**	14.79
Operating costs – non-energy	**(4.23)**	(5.81)	**(4.71)**	(6.12)
Operating costs – energy	**(3.76)**	(1.97)	**(3.97)**	(2.42)
Power revenue	**0.57**	0.35	**0.76**	0.57
Net operating costs	**(7.42)**	(7.43)	**(7.92)**	(7.97)
	24.46	16.57	**23.30**	6.82
Realized gain (loss) on commodity risk management	**(1.50)**	(0.48)	**(0.64)**	(0.25)
Cash operating netback	**$ 22.96**	$ 16.09	**$ 22.66**	$ 6.57

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

(2) *Defined as transportation expense less transportation revenue. Transportation expense includes rail, third-party pipelines and the Stonefell Terminal costs, as well as MEG's share of the operating costs for the Access Pipeline, net of third-party recoveries on diluent transportation arrangements.*

The cash operating netback for the three months ended June 30, 2017 was $22.96 per barrel compared to $16.09 per barrel for the three months ended June 30, 2016. Cash operating netback for the six months ended June 30, 2017 was $22.66 per barrel compared to $6.57 per barrel for the six months ended June 30, 2016. The increase in the cash operating netback was primarily due to an increase in bitumen realization, as a result of the increase in average crude oil benchmark pricing.

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 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. 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 $39.66 per barrel for the three months ended June 30, 2017 compared to $30.93 per barrel for the three months ended June 30, 2016. The increase in bitumen realization is primarily a result of the quarter-over-quarter increase in average crude oil benchmark pricing, which resulted in higher blend sales revenue.

For the three months ended June 30, 2017, the Corporation's cost of diluent was $71.69 per barrel of diluent compared to $60.60 per barrel of diluent for the three months ended June 30, 2016. The increase in the cost of diluent is primarily a result of the quarter-over-quarter increase in average condensate benchmark pricing.

Transportation

The Corporation utilizes multiple facilities to transport and sell its blend to refiners throughout North America. In early 2016, the Corporation increased its transportation capacity on the Flanagan South and Seaway pipeline systems, thereby furthering the Corporation's strategy of broadening market access to world prices with the intention of improving cash operating netback. Sales volumes destined for U.S. markets require additional transportation costs and generally obtain higher sales prices. Transportation expense averaged $6.91 per barrel for the three months ended June 30, 2017 compared to $6.66 per barrel for the three months ended June 30, 2016. Transportation expense increased on a per barrel basis as a result of fixed transportation costs spread over fewer sales volumes in the second quarter of 2017 as compared to the same period in 2016.

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, 2017, compared to the three months ended June 30, 2016 is primarily the result of higher realized WTI crude oil prices.

Net Operating Costs

Net operating costs are comprised of the sum of non-energy operating costs and energy operating costs, which are reduced by power revenue. Non-energy operating costs represent production-related operating activities excluding energy operating costs. Energy operating costs represent 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, 2017 averaged $7.42 per barrel compared to $7.43 per barrel for the three months ended June 30, 2016. The slight decrease in net operating costs is comprised primarily of a per barrel decrease in non-energy operating costs, largely offset by an increase in energy operating costs.

Non-energy operating costs

Non-energy operating costs averaged $4.23 per barrel for the three months ended June 30, 2017 compared to $5.81 per barrel for the three months ended June 30, 2016. The decrease in non-energy operating costs is primarily the result of efficiency gains and a continued focus on cost management resulting in lower operations staffing and associated camp and site services costs, plus 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 $3.76 per barrel for the three months ended June 30, 2017 compared to $1.97 per barrel for the three months ended June 30, 2016. The increase in energy operating costs on a per barrel basis is primarily attributable to the increase in natural gas prices. The Corporation's natural gas purchase price averaged $3.32 per mcf during the three months ended June 30, 2017 compared to $1.67 per mcf for the three months ended June 30, 2016.

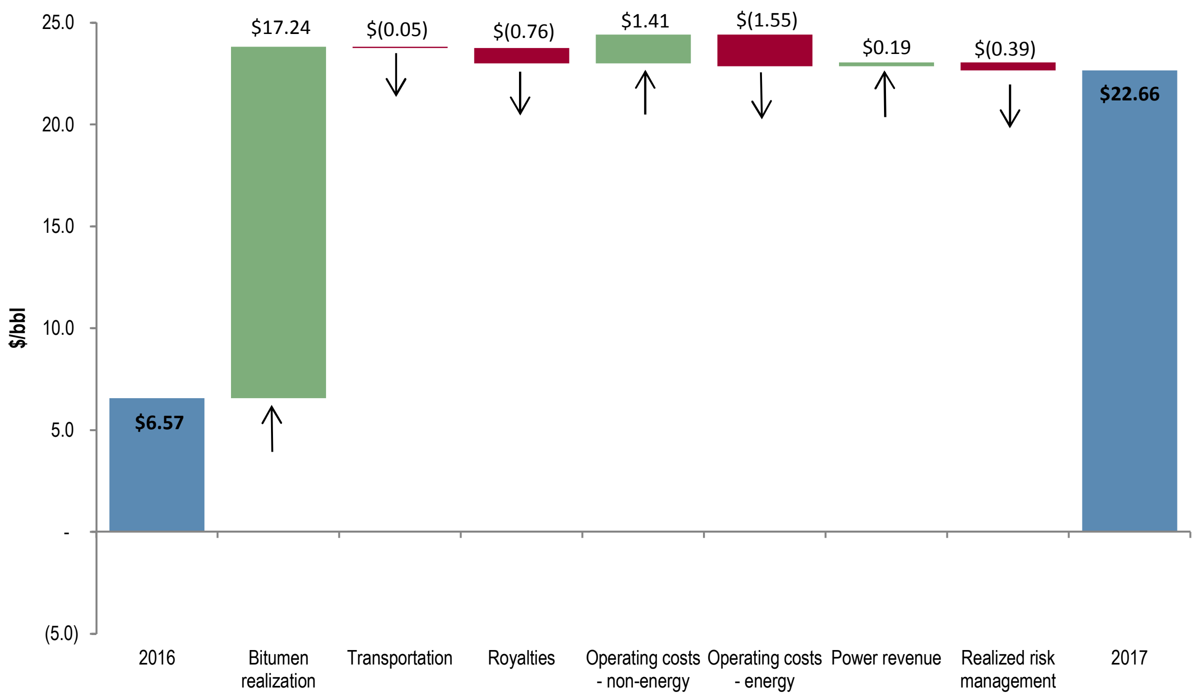
Power revenue

Power revenue averaged $0.57 per barrel for the three months ended June 30, 2017 compared to $0.35 per barrel for the three months ended June 30, 2016. The Corporation's average realized power sales price during the three months ended June 30, 2017 was $18.27 per megawatt hour compared to $13.54 per megawatt hour for the three months ended June 30, 2016.

Realized Gain (Loss) on Commodity Risk Management

The realized loss on commodity risk management averaged $1.50 per barrel for the three months ended June 30, 2017 compared to $0.48 per barrel for the three months ended June 30, 2016. This is primarily due to settlement losses on commodity risk management contracts relating to crude oil sales, partially offset by settlement gains on commodity risk management contracts relating to condensate purchases. Refer to the "Risk Management" section of this MD&A for further details.

Cash Operating Netback – Six Months Ended June 30



Bitumen Realization

Bitumen realization averaged $38.80 per barrel for the six months ended June 30, 2017 compared to $21.56 per barrel for the six months ended June 30, 2016. The increase in bitumen realization is primarily a result of the increase in average crude oil benchmark pricing, which resulted in higher blend sales revenue.

For the six months ended June 30, 2017, the Corporation's cost of diluent was $71.23 per barrel of diluent compared to $56.68 per barrel of diluent for the six months ended June 30, 2016. The increase in the cost of diluent is primarily a result of the increase in average condensate benchmark pricing.

Transportation

Transportation costs averaged $6.72 per barrel for the six months ended June 30, 2017 compared to $6.67 per barrel for the six months ended June 30, 2016. The increase is a result of fixed transportation costs spread over fewer sales volumes.

Royalties

The increase in royalties for the six months ended June 30, 2017, compared to the six months ended June 30, 2016 is primarily the result of higher realized WTI crude oil prices.

Net Operating Costs

Net operating costs for the six months ended June 30, 2017 averaged $7.92 per barrel compared to $7.97 per barrel for the six months ended June 30, 2016. The decrease in net operating costs is primarily attributable to a per barrel decrease in non-energy operating costs, offset by an increase in energy operating costs.

Non-energy operating costs

Non-energy operating costs averaged $4.71 per barrel for the six months ended June 30, 2017 compared to $6.12 per barrel for the six months ended June 30, 2016. The decrease in non-energy operating costs is primarily the result of efficiency gains and a continued focus on cost management resulting in lower operations staffing and materials and services costs, plus 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 $3.97 per barrel for the six months ended June 30, 2017 compared to $2.42 per barrel for the six months ended June 30, 2016. The increase in energy operating costs on a per barrel basis is primarily attributable to the increase in natural gas prices. The Corporation’s natural gas purchase price averaged $3.22 per mcf during the six months ended June 30, 2017 compared to $1.97 per mcf for the same period in 2016.

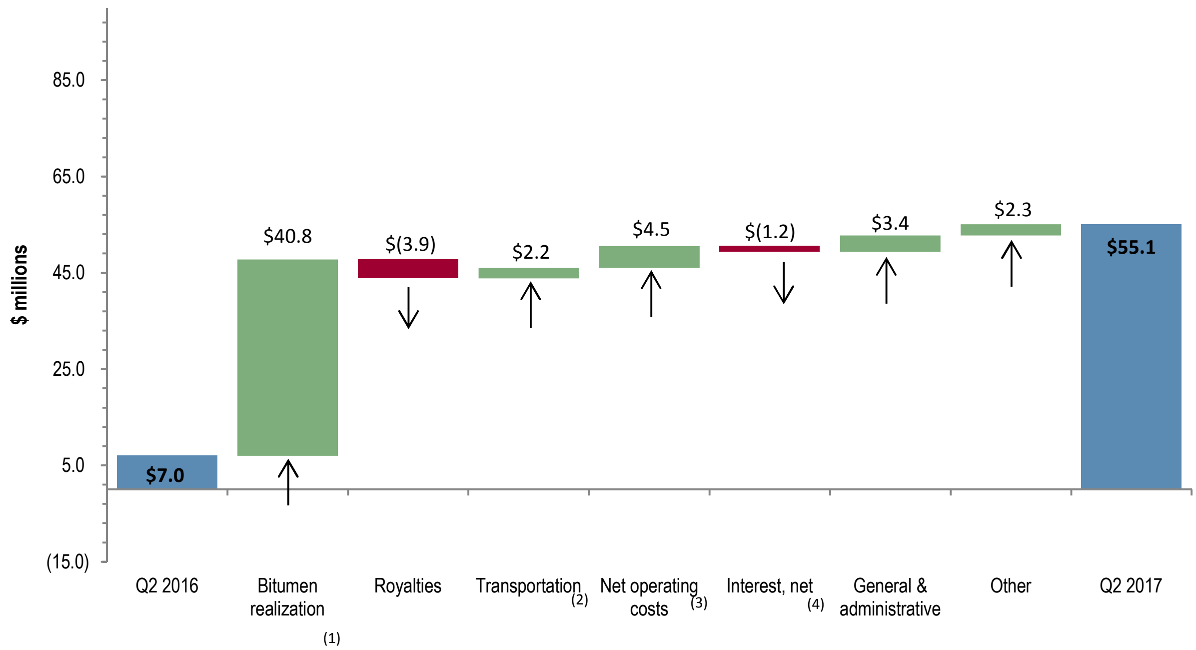
Power revenue

Power revenue averaged $0.76 per barrel for the six months ended June 30, 2017 compared to $0.57 per barrel for the six months ended June 30, 2016. The Corporation’s average realized power sales price during the six months ended June 30, 2017 was $20.65 per megawatt hour compared to $17.28 per megawatt hour for the same period in 2016.

Commodity Risk Management Gain (Loss)

The realized loss on commodity risk management averaged $0.64 per barrel for the six months ended June 30, 2017 compared to $0.25 per barrel for the six months ended June 30, 2016. This is primarily due to settlement losses on commodity risk management contracts relating to crude oil sales, partially offset by settlement gains on commodity risk management contracts relating to condensate purchases. Refer to the “RISK MANAGEMENT” section of this MD&A for further details.

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



(1) *Net of diluent expense.*

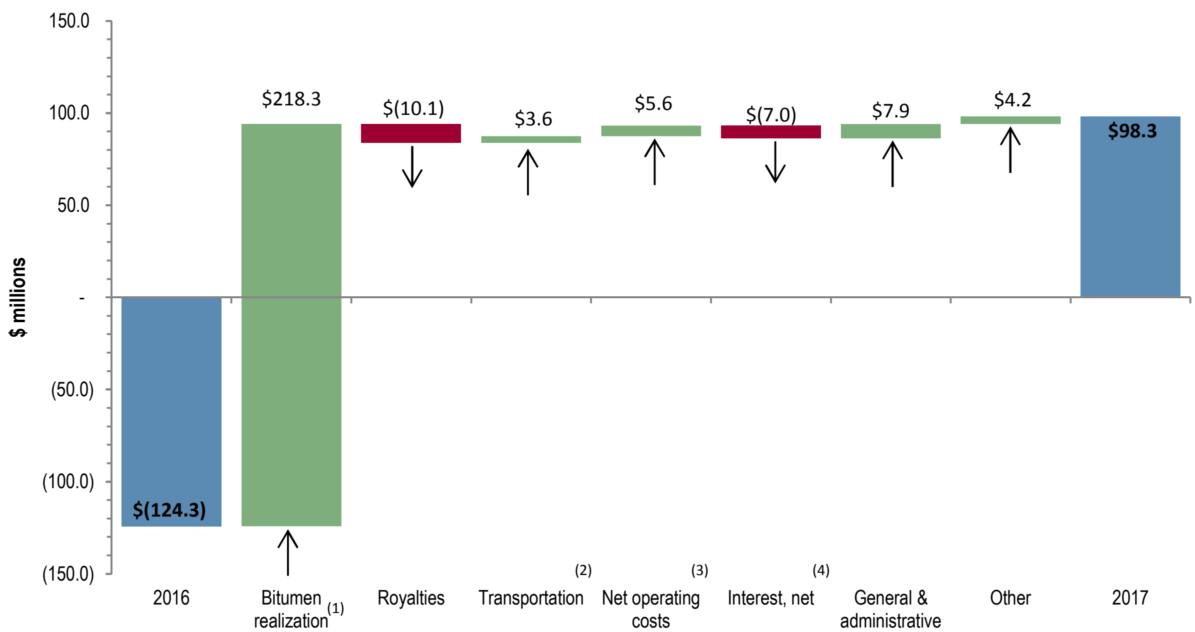
(2) *Defined as transportation expense less transportation revenue.*

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

(4) *Defined as total interest expense plus realized gain/loss on interest rate swaps 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 was $55.1 million for the three months ended June 30, 2017 compared to $7.0 million for the three months ended June 30, 2016. The increase in adjusted funds flow from operations was primarily due to an increase in bitumen realization. The increase in bitumen realization is directly correlated to the quarter-over-quarter increase in average crude oil benchmark pricing.

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



(1) Net of diluent expense.
(2) Defined as transportation expense less transportation revenue.
(3) Includes non-energy and energy operating costs, reduced by power revenue.
(4) Defined as total interest expense plus realized gain/loss on interest rate swaps less amortization of debt discount and debt issue costs.

Adjusted funds flow from operations was $98.3 million for the six months ended June 30, 2017 compared to adjusted funds flow used in operations of $(124.3) million for the six months ended June 30, 2016. The increase was primarily due to an increase in bitumen realization, which is directly correlated to the increase in average crude oil benchmark pricing.

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 $35.7 million for the three months ended June 30, 2017 compared to an operating loss of $97.9 million for the three months ended June 30, 2016. The Corporation recognized an operating loss of $115.0 million for the six months ended June 30, 2017 compared to an operating loss of $295.2 million for the six months ended June 30, 2016. The decrease in the operating loss for each of the comparative periods was primarily due to higher bitumen realization as a result of the increase in average crude oil benchmark pricing.

Revenue

Revenue represents the total of petroleum revenue, net of royalties and other revenue. Revenue for the three months ended June 30, 2017 totalled $574.0 million compared to $513.4 million for the three months ended June 30, 2016. Revenue for the six months ended June 30, 2017 totaled $1.1 billion compared to $803.7 million for the six months ended June 30, 2016. Revenue increased primarily due to an increase in blend sales revenue as a result of the increase in average crude oil benchmark pricing.

Net Earnings (Loss)

The Corporation recognized net earnings of $104.3 million for the three months ended June 30, 2017 compared to a net loss of $146.2 million for the three months ended June 30, 2016.

The net earnings for the three months ended June 30, 2017 included a net unrealized foreign exchange gain of $128.0 million on the Corporation's U.S. dollar denominated debt and U.S. dollar denominated cash and cash equivalents and an unrealized gain on commodity risk management of $17.2 million. The net loss for the three months ended June 30, 2016 included a net unrealized foreign exchange loss of $13.8 million on the Corporation's U.S. dollar denominated debt and U.S dollar denominated cash and cash equivalents and an unrealized loss on commodity risk management of $37.4 million.

The Corporation recognized net earnings of $105.9 million for the six months ended June 30, 2017 compared to a net loss of $15.3 million for the six months ended June 30, 2016.

The net earnings for the six months ended June 30, 2017 included a net unrealized foreign exchange gain of $164.7 million on the Corporation's U.S. dollar denominated debt and U.S. dollar denominated cash and cash equivalents balance and an unrealized gain on commodity risk management of $76.8 million. The net loss for the six months ended June 30, 2016 included a net unrealized foreign exchange gain of $306.5 million on the Corporation's U.S. dollar denominated debt and U.S. dollar denominated cash and cash equivalents which was partially offset by an unrealized loss on commodity risk management of $20.5 million.

Total Cash Capital Investment

Total cash capital investment during the three months ended June 30, 2017 totalled $158.5 million compared to $20.0 million for the three months ended June 30, 2016. Total cash capital investment during the six months ended June 30, 2017 totaled $236.2 million as compared to $55.0 million for the six months ended June 30, 2016. Capital investment in 2017 has primarily been directed towards the Corporation's eMSAGP production growth initiative at Christina Lake Phase 2B and sustaining capital activities.

4. OUTLOOK

Summary of 2017 Guidance	Guidance January 11, 2017	Revised Guidance July 26, 2017
Capital investment	$590 million	$590 million
Bitumen production – annual average	80,000 – 82,000 bbls/d	80,000 – 82,000 bbls/d
Bitumen production – targeted exit volume	86,000 – 89,000 bbls/d	86,000 – 89,000 bbls/d
Non-energy operating costs	$5.75 – $6.75/bbl	$5.00 – $5.50/bbl

The Corporation's 2017 capital budget remains unchanged at $590 million, of which approximately 55% is directed towards the eMSAGP growth initiative at Christina Lake Phase 2B, 35% towards sustaining and turnaround costs, and the remainder towards supporting marketing, corporate and other initiatives. The Corporation expects to fund the remaining 2017 capital program with a portion of the $512 million of cash on hand as at June 30, 2017.

The Corporation's 2017 estimated annual bitumen production volumes remain unchanged and are targeted to average 80,000 to 82,000 bbls/d with targeted exit production of 86,000 to 89,000 bbls/d.

As a result of continuing operating cost management over the first half of 2017, annual non-energy operating costs are now targeted to be in the range of $5.00 to $5.50 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		2017		2016				2015	
	2017	**2016**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**
Average Commodity Prices										
Crude oil prices										
Brent (US$/bbl)	**52.80**	40.88	**50.93**	54.66	51.13	46.98	46.67	35.10	44.71	51.17
WTI (US$/bbl)	**50.10**	39.52	**48.29**	51.91	49.29	44.94	45.59	33.45	42.18	46.43
WTI (C$/bbl)	**66.83**	52.63	**64.94**	68.68	65.75	58.65	58.75	45.99	56.32	60.79
WCS (C$/bbl)	**49.69**	34.29	**49.98**	49.39	46.65	41.03	41.61	26.41	36.97	43.29
Differential – WTI:WCS (US$/bbl)	**12.85**	13.77	**11.13**	14.58	14.32	13.50	13.30	14.24	14.49	13.27
Differential – WTI:WCS (%)	**25.6%**	34.8%	**23.0%**	28.1%	29.1%	30.0%	29.2%	42.6%	34.4%	28.8%
Condensate prices										
Condensate at Edmonton (C$/bbl)	**67.17**	52.05	**65.16**	69.17	64.49	56.25	56.83	47.27	55.57	57.89
Condensate at Edmonton as % of WTI	**100.5%**	98.9%	**100.3%**	100.7%	98.1%	95.9%	96.7%	102.8%	98.7%	95.2%
Condensate at Mont Belvieu, Texas (US$/bbl)	**45.41**	36.20	**44.77**	46.05	45.17	41.17	40.37	32.03	40.76	41.27
Condensate at Mont Belvieu, Texas as % of WTI	**90.6%**	91.6%	**92.7%**	88.7%	91.6%	91.6%	88.6%	95.8%	96.6%	88.9%
Natural gas prices										
AECO (C$/mcf)	**2.86**	1.52	**2.81**	2.91	3.31	2.49	1.37	1.82	2.57	2.89
Electric power prices										
Alberta power pool (C$/MWh)	**20.82**	16.43	**19.26**	22.38	21.97	17.93	14.77	18.09	21.19	26.04
Foreign exchange rates										
C$ equivalent of 1 US$ - average	**1.3339**	1.3317	**1.3449**	1.3230	1.3339	1.3051	1.2886	1.3748	1.3353	1.3093
C$ equivalent of 1 US$ - period end	**1.2977**	1.3009	**1.2977**	1.3322	1.3427	1.3117	1.3009	1.2971	1.3840	1.3394

Crude Oil Prices

Brent crude is the primary world price benchmark for global light sweet crude oil. The Brent benchmark price averaged US$50.93 per barrel in the second quarter of 2017 compared to US$46.67 per barrel in the second quarter of 2016. The Brent benchmark price averaged US$52.80 per barrel for the six months ended June 30, 2017 compared to US$40.88 per barrel for the six months ended June 30, 2016. 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 royalties on the Corporation's bitumen sales. The WTI price averaged US$48.29 per barrel in the second quarter of 2017 compared to US$45.59 in the second quarter of 2016. The WTI price averaged US$50.10 per barrel for the six months ended June 30, 2017 compared to US$39.52 per barrel for the six months ended June 30, 2016.

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 prices at Hardisty, Alberta. WCS typically trades at a differential below the WTI benchmark price. The WTI:WCS differential averaged US$11.13 per barrel, or 23.0%, for the second quarter of 2017, compared to US$13.30 per barrel, or 29.2% for the second quarter of 2016. The WTI:WCS differential averaged US$12.85 per barrel, or 25.6%, for the six months ended June 30, 2017 compared to US$13.77 per barrel, or 34.8%, for the six months ended June 30, 2016.

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 $65.16 per barrel, or 100.3% of WTI, for the second quarter of 2017 compared to $56.83 per barrel, or 96.7% of WTI, for the second quarter of 2016. Condensate prices, benchmarked at Edmonton, averaged $67.17 per barrel, or 100.5% of WTI, for the six months ended June 30, 2017 compared to $52.05 per barrel, or 98.9% of WTI, for the six months ended June 30, 2016.

Condensate prices, benchmarked at Mont Belvieu, Texas, averaged US$44.77 per barrel , or 92.7% of WTI, for the second quarter of 2017 compared to US$40.37 per barrel, or 88.6% of WTI, for the second quarter of 2016. Condensate prices, benchmarked at Mont Belvieu, Texas, averaged US$45.41 per barrel, or 90.6% of WTI, for the six months ended June 30, 2017 compared to US$36.20 per barrel, or 91.6% of WTI, for the six months ended June 30, 2016.

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 $2.81 per mcf for the second quarter of 2017 compared to $1.37 per mcf for the second quarter of 2016. The AECO natural gas price averaged $2.86 per mcf for the six months ended June 30, 2017 compared to $1.52 per mcf for the six months ended June 30, 2016. The increase in natural gas price is due to lower natural gas production, an increase in exports and increasing natural gas demand in the power sector.

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 $19.26 per megawatt hour for the second quarter of 2017 compared to $14.77 per megawatt hour for the second quarter of 2016. The Alberta power pool price averaged $20.82 per megawatt hour for the six months ended June 30, 2017 compared to $16.43 per megawatt hour for the six months ended June 30, 2016. The Alberta power pool price has settled in the $14 per megawatt hour to $24 per megawatt hour range since late 2015, primarily due to an overall surplus of power generation capacity in the province.

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, 2017, the Canadian dollar, at a rate of 1.2977, had increased in value by approximately 3% against the U.S. dollar compared to its value as at December 31, 2016, when the rate was 1.3427. As at June 30, 2016, the Canadian dollar, at a rate of 1.3009, had increased in value by approximately 6% against the U.S. dollar compared to its value as at December 31, 2015, when the rate was 1.3840.

6. OTHER OPERATING RESULTS

Net Marketing Activity

	Three months ended June 30		Six months ended June 30	
($000)	2017	2016	2017	2016
Petroleum revenue – third party	**$ 80,161**	$ 77,509	**$ 146,934**	$ 106,239
Purchased product and storage	**(79,642)**	(74,671)	**(145,184)**	(103,481)
Net marketing activity[1]	**$ 519**	$ 2,838	**$ 1,750**	$ 2,758

(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	
($000)	2017	2016	2017	2016
Depletion and depreciation expense	**$ 111,605**	$ 127,352	**$ 228,484**	$ 244,345
Depletion and depreciation expense per barrel of production	**$ 16.93**	$ 16.84	**$ 16.87**	$ 16.81

Depletion and depreciation expense for the three months ended June 30, 2017 totalled $111.6 million compared to $127.4 million for the three months ended June 30, 2016. Depletion and depreciation expense for the six months ended June 30, 2017 totalled $228.5 million compared to $244.3 million for the six months ended June 30, 2016. The decrease in the depletion and depreciation expense was primarily due to the decrease in production.

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.

	Three months ended June 30					
($000)	**2017**			**2016**		
	Realized	**Unrealized**	**Total**	**Realized**	**Unrealized**	**Total**
Crude oil contracts[1]	**$(18,909)**	**$ 28,541**	**$ 9,632**	$ (5,304)	$ (17,698)	$(23,002)
Condensate contracts[2]	**8,820**	**(11,317)**	**(2,497)**	1,817	(19,736)	(17,919)
Commodity risk management gain (loss)	**$(10,089)**	**$ 17,224**	**$ 7,135**	$ (3,487)	$ (37,434)	$(40,921)

The Corporation recognized an unrealized gain on commodity risk management contracts of $17.2 million for the three months ended June 30, 2017 compared to an unrealized loss on commodity risk management contracts of $37.4 million for the three months ended June 30, 2016.

The Corporation realized a loss on commodity risk management contracts of $10.1 million for the three months ended June 30, 2017 compared to a loss of $3.5 million for the three months ended June 30, 2016. Refer to the "Risk Management" section of this MD&A for further details.

	Six months ended June 30					
($000)	**2017**			**2016**		
	Realized	**Unrealized**	**Total**	**Realized**	**Unrealized**	**Total**
Crude oil contracts[1]	**$ (22,803)**	**$ 90,231**	**$ 67,428**	$ (5,304)	$ (18,289)	$(23,593)
Condensate contracts[2]	**14,226**	**(13,408)**	**818**	1,817	(2,182)	(365)
Commodity risk management gain (loss)	**$ (8,577)**	**$ 76,823**	**$ 68,246**	$ (3,487)	$ (20,471)	$(23,958)

(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 as a percentage of WTI (US$/bbl).*

The Corporation recognized an unrealized gain on commodity risk management contracts of $76.8 million for the six months ended June 30, 2017 compared to an unrealized loss on commodity risk management contracts of $20.5 million for the six months ended June 30, 2016.

The Corporation realized a loss on commodity risk management contracts of $8.6 million for the six months ended June 30, 2017 compared to a loss of $3.5 million for the six months ended June 30, 2016. 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	
($000)	2017	2016	2017	2016
General and administrative expense	**$ 20,939**	$ 24,368	**$ 44,161**	$ 52,084
General and administrative expense per barrel of production	**$ 3.18**	$ 3.22	**$ 3.26**	$ 3.58

General and administrative expense for the three months ended June 30, 2017 was $20.9 million compared to $24.4 million for the three months ended June 30, 2016. General and administrative expense was $3.18 per barrel for the three months ended June 30, 2017 compared to $3.22 per barrel for the three months ended June 30, 2016. General and administrative expense for the six months ended June 30, 2017 was $44.2 million compared to $52.1 million for the six months ended June 30, 2016. General and administrative expense was $3.26 per barrel for the six months ended June 30, 2017 compared to $3.58 per barrel for the six months ended June 30, 2016. General and administrative expense decreased primarily due to workforce reductions and the Corporation's continued focus on cost management.

Stock-based Compensation

	Three months ended June 30		Six months ended June 30	
($000)	2017	2016	2017	2016
Cash-settled expense (recovery)	**$ (2,272)**	$ 1,450	**$ (3,495)**	$ 1,450
Equity-settled expense	**4,763**	9,069	**8,273**	21,961
Stock-based compensation	**$ 2,491**	$ 10,519	**$ 4,778**	$ 23,411

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 and PSUs under a cash-settled Restricted Share Unit Plan. RSUs generally vest over a three year period while PSUs 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. Upon vesting of the RSUs and PSUs, the participants of the cash-settled RSU plan will receive a cash payment based on the fair value of the underlying share units at the vesting date. The 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. 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, 2017 was $2.5 million compared to $10.5 million for the three months ended June 30, 2016. Stock-based compensation expense for the six months ended June 30, 2017 was $4.8 million compared to $23.4 million for the six months ended June 30, 2016. The decrease is primarily due to a decrease in equity-settled share-based compensation costs as a result of fewer equity-settled compensation awards issued in 2016. The cash-settled share-based compensation recovery is primarily the result of a decrease in the Corporation's common share price during the three and six months ended June 30, 2017.

Research and Development

	Three months ended June 30		Six months ended June 30	
($000)	**2017**	**2016**	**2017**	**2016**
Research and development expense	**$ 1,166**	$ 1,717	**$ 2,106**	$ 3,095

Research and development expenditures related to the Corporation's research of crude quality improvement and related technologies have been expensed. Research and development expenditures were $1.2 million for the three months ended June 30, 2017 compared to $1.7 million for the three months ended June 30, 2016. Research and development expenditures were $2.1 million for the six months ended June 30, 2017 compared to $3.1 million for the six months ended June 30, 2016.

Foreign Exchange Loss (Gain), Net

	Three months ended June 30		Six months ended June 30	
($000)	**2017**	**2016**	**2017**	**2016**
Unrealized foreign exchange loss (gain) on:				
Long-term debt	**$ (130,390)**	$ 14,416	**$ (170,148)**	$ (315,677)
Other	**2,429**	(627)	**5,480**	9,185
Unrealized net loss (gain) on foreign exchange	**(127,961)**	13,789	**(164,668)**	(306,492)
Realized loss (gain) on foreign exchange	**(3,042)**	808	**(5,355)**	(4,858)
Foreign exchange loss (gain), net	**$ (131,003)**	$ 14,597	**$ (170,023)**	$ (311,350)
C$ equivalent of 1 US$				
Beginning of period	**1.3322**	1.2971	**1.3427**	1.3840
End of period	**1.2977**	1.3009	**1.2977**	1.3009

The Corporation recognized a net foreign exchange gain of $131.0 million for the three months ended June 30, 2017 compared to a net foreign exchange loss of $14.6 million for the three months ended June 30, 2016. The net foreign exchange gain in 2017 is primarily due to the translation of the U.S. dollar denominated debt as a result of the strengthening of the Canadian dollar compared to the U.S. dollar during the three months ended June 30, 2017.

The Corporation recognized a net foreign exchange gain of $170.0 million for the six months ended June 30, 2017 compared to a net foreign exchange gain of $311.4 million for the six months ended June 30, 2016. The net foreign exchange gains are primarily due to the translation of the U.S. dollar denominated debt as a result of the strengthening of the Canadian dollar compared to the U.S. dollar during each respective six month period.

Net Finance Expense

	Three months ended June 30		Six months ended June 30	
($000)	**2017**	**2016**	**2017**	**2016**
Total interest expense	**$ 85,162**	$ 80,758	**$ 178,436**	$ 164,673
Accretion on provisions	**1,825**	1,820	**3,681**	3,514
Unrealized loss (gain) on derivative financial liabilities[1]	**(1,615)**	516	**(3,856)**	6,005
Realized loss on interest rate swaps	**-**	1,471	**-**	3,040
Net finance expense	**$ 85,372**	$ 84,565	**$ 178,261**	$ 177,232
Average effective interest rate[2]	**6.1%**	5.8%	**6.0%**	5.8%

(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.*

Total interest expense for the three months ended June 30, 2017 was $4.4 million higher than the comparative 2016 period, primarily due to higher average effective interest rates. Total interest expense for the six months ended June 30, 2017 was $178.4 million compared to $164.7 million for the six months ended June 30, 2016. This increase was due to higher effective interest rates and the incremental interest expense associated with carrying both the now repaid US$750 million aggregate principal amount of 6.5% Senior Unsecured Notes and the new 6.5% Senior Secured Second Lien Notes for a period of 49 days. Given the reduction in the early redemption premium threshold between closing and March 15, 2017, the economic cost of carrying interest on these notes for an incremental 49 days was less than the cost of redeeming the notes prior to March 15, 2017. The 6.5% Senior Unsecured Notes were repaid on March 15, 2017 with the proceeds from the Senior Secured Second Lien Notes. This issuance and repayment of notes was part of the Corporation's comprehensive refinancing plan which is further described in the "LIQUIDITY AND CAPITAL RESOURCES" section of this MD&A.

Unrealized gains and losses on derivative liabilities includes unrealized gains and losses related to the change in fair value of the interest rate floor associated with the Corporation's senior secured term loan, and for the three and six months ended June 30, 2016, the change in fair value of the Corporation's interest rate swap contracts. The Corporation recognized an unrealized gain on derivative financial liabilities of $1.6 million for the three months ended June 30, 2017 compared to an unrealized loss of $0.5 million for the three months ended June 30, 2016. The Corporation recognized an unrealized gain on derivative financial liabilities of $3.9 million for the six months ended June 30, 2017 compared to an unrealized loss of $6.0 million for the six months ended June 30, 2016.

The Corporation's interest rate swap contracts expired on September 30, 2016. The Corporation realized a loss on the interest rate swaps of $1.5 million and $3.0 million for the three and six months ended June 30, 2016, respectively.

Other Expenses

	Three months ended June 30		Six months ended June 30	
($000)	**2017**	**2016**	**2017**	**2016**
Onerous contracts	**$ 3,333**	$ 9,055	**$ 5,708**	$ 13,426
Severance and other	**3,468**	6,179	**3,468**	6,179
Other expenses	**$ 6,801**	$ 15,234	**$ 9,176**	$ 19,605

The Corporation recognized other expenses of $6.8 million for the three months ended June 30, 2017 compared to $15.2 million for the three months ended June 30, 2016. The Corporation recognized other expenses of $9.2 million for the six months ended June 30, 2017 compared to $19.6 million for the six months ended June 30, 2016.

The Corporation recognized onerous contracts expense of $3.3 million for the three months ended June 30, 2017 compared to $9.1 million for the three months ended June 30, 2016. The Corporation recognized onerous contracts expense of $5.7 million for the six months ended June 30, 2017 compared to $13.4 million for the six months ended June 30, 2016. 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	
($000)	**2017**	**2016**	**2017**	**2016**
Current income tax expense (recovery)	**$ 115**	$ 97	**$ (169)**	$ 614
Deferred income tax expense (recovery)	**(28,156)**	(48,804)	**(17,177)**	(117,960)
Income tax expense (recovery)	**$ (28,041)**	$ (48,707)	**$ (17,346)**	$ (117,346)

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, 2017, the Corporation had approximately $8.4 billion of available tax pools.

For the six months ended June 30, 2017, the Corporation recognized a current income tax recovery of $0.4 million related to the refundable Alberta tax credit on Scientific Research and Experimental Development expenditures.

The Corporation recognized a deferred income tax recovery of $28.2 million for the three months ended June 30, 2017 compared to a deferred income tax recovery of $48.8 million for the three months ended June 30, 2016. The Corporation recognized a deferred income tax recovery of $17.2 million for the six months ended June 30, 2017 and a deferred income tax recovery of $118.0 million for the six months ended June 30, 2016.

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

- 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, 2017, the non-taxable net gain was $65.2 million compared to a non-taxable loss of $7.2 million for the three months ended June 30, 2016. For the six months ended June 30, 2017, the non-taxable gain was $85.1 million compared to a non-taxable gain of $157.8 million for the six months ended June 30, 2016.

- 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, 2017 was $4.8 million compared to $9.1 million for the three months ended June 30, 2016. Stock-based compensation expense for equity-settled plans for the six months ended June 30, 2017 was $8.3 million compared to $22.0 million for the three months ended June 30, 2016.

As at June 30, 2017, the Corporation has recognized a deferred income tax asset of $143.9 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, 2017, the Corporation had not recognized the tax benefit related to $532.5 million of realized and unrealized taxable capital foreign exchange losses.

7. NET CAPITAL INVESTMENT

	Three months ended June 30		Six months ended June 30	
($000)	**2017**	**2016**	**2017**	**2016**
Total cash capital investment	**$ 158,474**	$ 19,990	**$ 236,244**	$ 54,965
Capitalized cash-settled stock-based compensation	**(916)**	-	**(830)**	-
	$ 157,558	$ 19,990	**$ 235,414**	$ 54,965

Total cash capital investment for the three months ended June 30, 2017 was $158.5 million, compared to $20.0 million for the three months ended June 30, 2016. Total cash capital investment for the six months ended June 30, 2017 was $236.2 million as compared to $55.0 million for the six months ended June 30, 2016. During the first six months of 2017, the Corporation invested $100.8 million in the eMSAGP growth project at Christina Lake Phase 2B, $116.8 million in sustaining capital activities, and $18.6 million in marketing, corporate and other capital initiatives. Capital investment in the three and six months ended June 30, 2016 was primarily directed towards sustaining capital activities.

In the second quarter of 2017, turnaround costs of $37.1 million were incurred and will be depreciated on a straight-line basis over the period to the next turnaround.

In June 2016, the Corporation began capitalizing the cost related to a new cash-settled stock-based compensation plan for employees directly involved in capital investing activities.

8. LIQUIDITY AND CAPITAL RESOURCES

($000)	June 30, 2017	December 31, 2016
Cash and cash equivalents	**$ 512,424**	$ 156,230
Senior secured term loan (June 30, 2017 – US$1.232 billion; due 2023; December 31, 2016 – US$1.236 billion)	**1,598,653**	1,658,906
US$1.4 billion revolver (due 2021)	**-**	-
6.5% senior secured second lien notes (US$750.0 million; due 2025)	**973,275**	-
6.5% senior unsecured notes (US$750.0 million; due 2021)	**-**	1,007,025
6.375% senior unsecured notes (US$800.0 million; due 2023)	**1,038,160**	1,074,160
7.0% senior unsecured notes (US$1.0 billion; due 2024)	**1,297,700**	1,342,700
Total debt(1)	**$ 4,907,788**	$ 5,082,791

(1) Total debt does not have a standardized meaning prescribed by IFRS and therefore may not be comparable to similar measures used by other companies. The Corporation uses this non-GAAP measure to analyze leverage and liquidity. Total debt plus the debt redemption premium less current portion of the senior secured term loan, unamortized financial derivative liability discount and unamortized deferred debt discount and debt issue costs is equal to long-term debt as reported in the Corporation's interim consolidated financial statements as at June 30, 2017 and the Corporation's consolidated financial statements as at December 31, 2016. 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 $512.4 million as at June 30, 2017 compared to $156.2 million as at December 31, 2016. The Corporation's cash and cash equivalents balance increased primarily due to net equity issuance proceeds of $496.3 million received pursuant to the comprehensive refinancing that closed on January 27, 2017.

All of the Corporation's long-term debt is denominated in U.S. dollars. As a result of the increase in the value of the Canadian dollar relative to the U.S. dollar, long-term debt as presented on the Consolidated Balance Sheet, decreased to C$4.8 billion as at June 30, 2017 from C$5.1 billion as at December 31, 2016.

On January 27, 2017, the Corporation closed a comprehensive refinancing plan by way of the Corporation's Canadian base shelf prospectus dated December 1, 2016. The plan was comprised of the following four transactions:

- An extension of the maturity date on substantially all of the commitments under the Corporation's undrawn covenant-lite revolving credit facility from November 2019 to November 2021. The commitment amount of the five-year facility has been reduced from US$2.5 billion to US$1.4 billion. The revolving credit facility has no financial maintenance covenants and is not subject to any borrowing base redetermination;
- The US$1.2 billion term loan has been refinanced and its maturity date has been extended from March 2020 to December 2023. The refinanced term loan bears interest at an annual rate of LIBOR plus 3.5% with a LIBOR floor of 1%;
- The US$750 million aggregate principal amount of 6.5% Senior Unsecured Notes, with a maturity date of March 2021, have been refinanced and replaced with new 6.5% Senior Secured Second Lien Notes, maturing January 2025. The existing 2021 notes were redeemed with the proceeds from the Senior Secured Second Lien Notes on March 15, 2017; and

- The Corporation raised C$518 million of equity, before underwriting fees and expenses, in the form of 66,815,000 common shares at a price of $7.75 per common share on a bought deal basis from a syndicate of underwriters.

In addition to the transactions noted above, on February 15, 2017, the Corporation extended the maturity date on its five-year letter of credit facility, guaranteed by EDC, from November 2019 to November 2021. The guaranteed letter of credit facility has been reduced from US$500 million to US$440 million. As at June 30, 2017, US$302 million of letters of credit have been issued. Letters of credit under this facility do not consume capacity of the revolving credit facility.

All of MEG's long-term debt, the revolving credit facility and the EDC 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 outstanding:

As at June 30, 2017	Volumes (bbls/d) [1]	Term	Average Price (US$/bbl) [1]
Fixed Price:			
WTI Fixed Price	24,100	Jul 1, 2017 – Dec 31, 2017	$55.07
WTI:WCS Fixed Differential	50,000	Jul 1, 2017 – Sep 30, 2017	$(15.16)
WTI:WCS Fixed Differential	54,600	Oct 1, 2017 – Dec 31, 2017	$(15.14)
WTI:WCS Fixed Differential	4,000	Jan 1, 2018 – Mar 31, 2018	$(14.35)
Collars:			
WTI Collars	30,500	Jul 1, 2017 – Dec 31, 2017	$47.87 – $58.57
WTI Collars	6,000	Jan 1, 2018 – Mar 31, 2018	$50.00 – $56.81

The Corporation has entered into the following commodity risk management contracts relating to crude oil sales subsequent to June 30, 2017 up to the date of July 26, 2017:

Subsequent to June 30, 2017	Volumes (bbls/d) [1]	Term	Average Price (US$/bbl) [1]
Fixed Price:			
WTI:WCS Fixed Differential	6,000	Jan 1, 2018 – Mar 31, 2018	$(13.80)
WTI:WCS Fixed Differential	2,000	Apr 1, 2018 – Jun 30, 2018	$(13.90)

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

The Corporation enters into commodity risk management contracts that effectively fix the average condensate prices at Mont Belvieu, Texas as a percentage of WTI. The Corporation had the following commodity risk management contracts relating to condensate purchases outstanding:

As at June 30, 2017	Volumes (bbls/d)	Term	Average % of WTI
Mont Belvieu fixed % of WTI	15,150	Jul 1, 2017 – Dec 31, 2017	82.9

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. The Corporation did not have any outstanding interest rate swap contracts as at June 30, 2017. During the three and six months ended June 30, 2016, the Corporation had interest rate swap contracts in place to effectively fix the interest rate at approximately 4.4% on US$748.0 million of the senior secured term loan. These interest rate swap contracts expired on September 30, 2016.

Cash Flow Summary

	Three months ended June 30		Six months ended June 30	
($000)	**2017**	**2016**	**2017**	**2016**
Net cash provided by (used in):				
Operating activities	**$ 63,612**	$ 64,587	**$ 109,418**	$ (156,084)
Investing activities	**(92,400)**	(33,030)	**(156,336)**	(80,592)
Financing activities	**(4,520)**	(4,222)	**409,080**	(8,435)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency	**(3,249)**	816	**(5,968)**	(10,391)
Change in cash and cash equivalents	**$ (36,557)**	$ 28,151	**$ 356,194**	$ (255,502)

Cash Flow – Operating Activities

Net cash provided by operating activities totalled $63.6 million for the three months ended June 30, 2017, which was substantially consistent with net cash provided by operating activities of $64.6 million for the three months ended June 30, 2016.

Net cash provided by operating activities totalled $109.4 million for the six months ended June 30, 2017 compared to net cash used in operating activities of ($156.1) million for the six months ended June 30, 2016. This increase in cash flows is primarily due to higher bitumen realization, primarily as a result of the increase in average crude oil benchmark pricing.

Cash Flow – Investing Activities

Net cash used in investing activities was $92.4 million for the three months ended June 30, 2017 compared to $33.0 million for the three months ended June 30, 2016. The increase in net cash used in investing activities is primarily due to increased capital spending activity directed toward the eMSAGP growth initiative at Christina Lake Phase 2B and sustaining and turnaround costs.

Net cash used in investing activities was $156.3 million for the six months ended June 30, 2017 compared to $80.6 million for the six months ended June 30, 2016. The increase in net cash used in investing activities is primarily due to increased capital spending activity directed toward the eMSAGP growth initiative at Christina Lake Phase 2B and sustaining and turnaround costs.

Cash Flow – Financing Activities

Net cash used in financing activities was $4.5 million for the three months ended June 30, 2017 compared to $4.2 million for the three months ended June 30, 2016. Net cash used in financing activities includes quarterly debt repayments of US$3.1 million.

Net cash provided by financing activities was $409.1 million for the six months ended June 30, 2017 compared to net cash used in financing activities of $8.4 million for the six months ended June 30, 2016. Net cash provided by financing activities increased primarily 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 that closed on January 27, 2017.

9. SHARES OUTSTANDING

As at June 30, 2017, the Corporation had the following share capital instruments outstanding or exercisable:

(000)	Outstanding
Common shares	**294,047**
Convertible securities	
Stock options[(1)]	**9,544**
Equity-settled RSUs and PSUs	**6,403**

(1) 6.8 million stock options were exercisable as at June 30, 2017.

On January 27, 2017, the Corporation issued 66.8 million common shares at a price $7.75 per common share.

As at July 19, 2017, the Corporation had 294.0 million common shares, 9.5 million stock options and 6.4 million equity-settled restricted share units and equity-settled performance share units outstanding, and 6.8 million stock options exercisable.

10. CONTRACTUAL OBLIGATIONS AND COMMITMENTS

The information presented in the table below reflects management's estimate of the contractual maturities of the Corporation's obligations. 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)	2017	2018	2019	2020	2021	Thereafter
Long-term debt[(1)]	$ 8,013	$ 16,027	$ 16,027	$ 16,027	$ 16,027	$ 4,835,667
Interest on long-term debt[(1)]	146,096	291,653	290,931	290,211	289,490	607,392
Decommissioning obligation[(2)]	738	6,252	7,059	5,916	2,957	817,070
Transportation and storage[(3)]	89,661	199,220	198,187	249,160	307,309	3,947,125
Office lease rentals[(4)]	16,226	32,091	32,121	33,037	33,435	230,483
Diluent purchases[(5)]	164,748	116,558	19,988	20,043	19,988	36,636
Other commitments[(6)]	11,894	14,056	9,989	11,998	11,240	73,535
Total	**$ 437,376**	**$ 675,857**	**$ 574,302**	**$ 626,392**	**$ 680,446**	**$10,547,908**

(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, 2017.

(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 2017 to 2042, including various pipeline commitments which are awaiting regulatory approval.

(4) This represents the future gross lease commitments for the Corporation's corporate offices.

(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.

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 purchased product and storage arrangements. Petroleum revenue – third party is disclosed in Note 12 in the Notes to the Interim Consolidated Financial Statements and purchased product and storage is presented as a line item on the Consolidated Statement of Earnings and Comprehensive Income.

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, net change in other liabilities, 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	
($000)	**2017**	**2016**	**2017**	**2016**
Net cash provided by (used in) operating activities	**$ 63,612**	$ 64,587	**$ 109,418**	$ (156,084)
Net change in non-cash operating working capital items	**(14,024)**	(56,923)	**(22,211)**	30,917
Funds flow from (used in) operations	**49,588**	7,664	**87,207**	(125,167)
Adjustments:				
Net change in other liabilities	**-**	(1,451)	**-**	(1,451)
Payments on onerous contracts	**5,468**	717	**9,602**	1,346
Decommissioning expenditures	**39**	34	**1,461**	996
Adjusted funds flow from (used in) operations	**$ 55,095**	$ 6,964	**$ 98,270**	$ (124,276)

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, 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, in the table below.

	Three months ended June 30		**Six months ended June 30**	
($000)	**2017**	**2016**	**2017**	**2016**
Net earnings (loss)	**$ 104,282**	$ (146,165)	**$ 105,870**	$ (15,336)
Adjustments:				
Unrealized net loss (gain) on foreign exchange[1]	**(127,961)**	13,789	**(164,668)**	(306,492)
Unrealized loss (gain) on derivative financial liabilities[2]	**(1,615)**	516	**(3,856)**	6,005
Unrealized loss (gain) on commodity risk management[3]	**(17,224)**	37,434	**(76,823)**	20,471
Onerous contracts expense[4]	**3,333**	9,055	**5,708**	13,426
Deferred tax expense (recovery) relating to these adjustments	**3,529**	(12,523)	**18,761**	(13,254)
Operating earnings (loss)	**$ (35,656)**	$ (97,894)	**$ (115,008)**	$ (295,180)

(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) *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.*

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, transportation, field operating costs, 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, 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, excluding the debt redemption premium, 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.

($000)	June 30, 2017	December 31, 2016
Long-term debt	**$ 4,813,092**	$ 5,053,239
Adjustments:		
Debt redemption premium	**-**	(21,812)
Current portion of senior secured term loan	**16,027**	17,455
Unamortized financial derivative liability discount	**19,433**	11,143
Unamortized deferred debt discount and debt issue costs	**59,236**	22,766
Total debt	**$ 4,907,788**	$ 5,082,791

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 Corporation's 2016 annual MD&A.

13. NEW ACCOUNTING STANDARDS

The Corporation has adopted the following revised standards effective January 1, 2017:

IAS 7, Statement of Cash Flows, has been amended by the IASB as part of its disclosure initiative to require additional disclosure for changes in liabilities arising from financing activities. This includes changes arising from cash flows and non-cash changes. Additional disclosures for changes in liabilities arising from financing activities has been included in Note 19 to the Corporation's consolidated financial statements. As allowed by IAS 7, comparative information has not been presented.

IAS 12, Income Taxes, has been amended to clarify the recognition of deferred tax assets relating to unrealized losses. The adoption of this revision did not have an impact on the Corporation's consolidated financial statements.

Accounting standards issued but not yet applied

The IASB has issued the following standards which are not yet effective:

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. 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.

In July 2014, the IASB issued IFRS 9 Financial Instruments, which is intended to replace 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. IFRS 9 is effective for annual periods beginning on or after January 1, 2018, with early adoption permitted. IFRS 9 will be adopted by the Corporation on January 1, 2018, and the Corporation is currently assessing and evaluating the impact of the standard on the consolidated financial statements.

In May 2014, the IASB issued IFRS 15 Revenue From Contracts With Customers, which will replace 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 new standard is effective for annual periods beginning on or after January 1, 2018, with early adoption permitted. IFRS 15 will be adopted by the Corporation on January 1, 2018. The Corporation is currently assessing and evaluating the terms of its sales contracts with customers to determine the impact, if any, that the standard will have on the consolidated financial statements. The Corporation anticipates there will be additional enhanced disclosures.

In June 2016, the IASB issued amendments to IFRS 2 Share-based Payment, relating to classification and measurement of particular share-based payment transactions. The amendments are effective for periods beginning on or after January 1, 2018. The Corporation is currently assessing the impact of the adoption of these amendments on the Corporation's consolidated financial statements.

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.

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
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, 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; 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.

A full version of MEG's Second Quarter 2017 Report to Shareholders, including unaudited financial statements, is available at www.megenergy.com/investors and at www.sedar.com.

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

	2017		2016				2015	
Unaudited	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**
FINANCIAL ($000 unless specified)								
Net earnings (loss)(1)	**104,282**	1,588	(304,758)	(108,632)	(146,165)	130,829	(297,275)	(427,503)
Per share, diluted	**0.35**	0.01	(1.34)	(0.48)	(0.65)	0.58	(1.32)	(1.90)
Operating earnings (loss)	**(35,656)**	(79,354)	(71,989)	(87,929)	(97,894)	(197,286)	(140,234)	(86,769)
Per share, diluted	**(0.12)**	(0.29)	(0.32)	(0.39)	(0.43)	(0.88)	(0.62)	(0.39)
Adjusted funds flow from (used in) operations	**55,095**	43,175	39,967	22,702	6,964	(131,240)	(44,130)	23,877
Per share, diluted	**0.19**	0.16	0.18	0.10	0.03	(0.58)	(0.20)	0.11
Cash capital investment(2)	**158,474**	77,770	63,077	19,203	19,990	34,975	54,473	32,139
Cash and cash equivalents	**512,424**	548,981	156,230	103,136	152,711	124,560	408,213	350,736
Working capital	**445,463**	537,427	96,442	163,038	128,586	183,649	363,038	366,725
Long-term debt	**4,813,092**	4,944,741	5,053,239	4,909,711	4,871,182	4,859,099	5,190,363	5,023,976
Shareholders' equity	**3,898,054**	3,792,818	3,286,776	3,577,557	3,679,372	3,812,566	3,677,867	3,956,689
BUSINESS ENVIRONMENT								
WTI (US$/bbl)	**48.29**	51.91	49.29	44.94	45.59	33.45	42.18	46.43
C$ equivalent of 1US$ - average	**1.3449**	1.3230	1.3339	1.3051	1.2886	1.3748	1.3353	1.3093
Differential – WTI:WCS (C$/bbl)	**14.97**	19.29	19.10	17.62	17.14	19.58	19.35	17.50
Differential – WTI:WCS (%)	**23.0%**	28.1%	29.1%	30.0%	29.2%	42.6%	34.4%	28.8%
Natural gas – AECO ($/mcf)	**2.81**	2.91	3.31	2.49	1.37	1.82	2.57	2.89
OPERATIONAL ($/bbl unless specified)								
Bitumen production – bbls/d	**72,448**	77,245	81,780	83,404	83,127	76,640	83,514	82,768
Bitumen sales – bbls/d	**74,116**	74,703	81,746	84,817	80,548	74,529	82,282	84,651
Steam-oil ratio (SOR)	**2.3**	2.4	2.3	2.2	2.3	2.4	2.5	2.5
Bitumen realization	**39.66**	37.93	36.17	30.98	30.93	11.43	23.17	31.03
Transportation – net	**(6.91)**	(6.54)	(6.05)	(6.46)	(6.66)	(6.68)	(5.35)	(4.64)
Royalties	**(0.87)**	(0.85)	(0.51)	(0.42)	(0.27)	0.07	(0.25)	(0.88)
Operating costs – non-energy	**(4.23)**	(5.20)	(4.99)	(5.32)	(5.81)	(6.45)	(5.66)	(5.98)
Operating costs – energy	**(3.76)**	(4.18)	(4.12)	(2.99)	(1.97)	(2.90)	(3.58)	(3.97)
Power revenue	**0.57**	0.95	0.87	0.55	0.35	0.82	0.72	0.85
Realized gain (loss) on commodity risk management	**(1.50)**	0.22	0.36	0.40	(0.48)	-	-	-
Cash operating netback	**22.96**	22.33	21.73	16.74	16.09	(3.71)	9.05	16.41
Power sales price (C$/MWh)	**18.27**	22.42	21.94	17.62	13.54	19.77	19.67	25.09
Power sales (MW/h)	**97**	131	134	110	86	129	125	119
Depletion and depreciation rate per bbl of production	**16.93**	16.81	16.81	16.81	16.84	16.78	16.55	15.99
COMMON SHARES								
Shares outstanding, end of period (000)	**294,047**	293,282	226,467	226,415	226,357	224,997	224,997	224,942
Volume traded (000)	**98,795**	123,445	114,776	112,720	157,056	182,199	76,631	73,099
Common share price ($)								
High	**7.27**	9.83	9.79	6.90	7.86	8.26	13.15	20.36
Low	**3.63**	5.84	5.11	4.72	5.21	3.46	7.33	7.87
Close (end of period)	**3.81**	6.74	9.23	5.93	6.84	6.55	8.02	8.24

(1) *Includes net unrealized foreign exchange gains and losses on translation of U.S. dollar denominated debt and U.S. dollar denominated cash and cash equivalents.*

(2) *Defined as total capital investment excluding dispositions, capitalized interest, capitalized cash-settled stock-based compensation and non-cash items.*

Interim Consolidated Financial Statements

Consolidated Balance Sheet

(Unaudited, expressed in thousands of Canadian dollars)

As at	Note	June 30, 2017	December 31, 2016
Assets			
Current assets			
Cash and cash equivalents	19	**$ 512,424**	$ 156,230
Trade receivables and other		**205,637**	236,989
Inventories		**64,884**	66,394
Commodity risk management	21	**47,162**	-
		830,107	459,613
Non-current assets			
Property, plant and equipment	4	**7,680,565**	7,639,434
Exploration and evaluation assets	5	**549,141**	547,752
Other intangible assets	6	**14,213**	16,111
Other assets	7	**145,919**	137,370
Deferred income tax asset	18	**143,923**	120,944
Total assets		**$ 9,363,868**	$ 8,921,224
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities		**$ 341,429**	$ 292,340
Current portion of long-term debt	8	**16,027**	17,455
Current portion of provisions and other liabilities	9	**26,536**	23,063
Commodity risk management	21	**652**	30,313
		384,644	363,171
Non-current liabilities			
Long-term debt	8	**4,813,092**	5,053,239
Provisions and other liabilities	9	**268,078**	218,038
Total liabilities		**5,465,814**	5,634,448
Shareholders' equity			
Share capital	10	**5,402,594**	4,878,607
Contributed surplus		**155,841**	168,253
Deficit		**(1,689,197)**	(1,795,067)
Accumulated other comprehensive income		**28,816**	34,983
Total shareholders' equity		**3,898,054**	3,286,776
Total liabilities and shareholders' equity		**$ 9,363,868**	$ 8,921,224

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	2017	2016	2017	2016
Revenues					
Petroleum revenue, net of royalties	12	**$ 566,897**	$ 505,663	**$ 1,117,367**	$ 785,287
Other revenue	13	**7,136**	7,692	**16,445**	18,406
		574,033	513,355	**1,133,812**	803,693
Expenses					
Diluent and transportation	14	**275,006**	257,440	**556,303**	480,803
Operating expenses		**53,871**	57,049	**116,924**	120,437
Purchased product and storage		**79,642**	74,671	**145,184**	103,481
Depletion and depreciation	4,6	**111,605**	127,352	**228,484**	244,345
General and administrative		**20,939**	24,368	**44,161**	52,084
Stock-based compensation	11	**2,491**	10,519	**4,778**	23,411
Research and development		**1,166**	1,717	**2,106**	3,095
Interest and other income		**(963)**	(206)	**(1,820)**	(726)
Commodity risk management loss (gain)	21	**(7,135)**	40,921	**(68,246)**	23,958
Foreign exchange loss (gain), net	15	**(131,003)**	14,597	**(170,023)**	(311,350)
Net finance expense	16	**85,372**	84,565	**178,261**	177,232
Other expenses	17	**6,801**	15,234	**9,176**	19,605
Earnings (loss) before income taxes		**76,241**	(194,872)	**88,524**	(132,682)
Income tax expense (recovery)	18	**(28,041)**	(48,707)	**(17,346)**	(117,346)
Net earnings (loss)		**104,282**	(146,165)	**105,870**	(15,336)
Other comprehensive income (loss), net of tax					
Items that may be reclassified to profit or loss:					
Foreign currency translation adjustment		**(4,710)**	2,267	**(6,167)**	(8,714)
Comprehensive income (loss) for the period		**$ 99,572**	$ (143,898)	**$ 99,703**	$ (24,050)
Net earnings (loss) per common share					
Basic	20	**$ 0.36**	$ (0.65)	**$ 0.37**	$ (0.07)
Diluted	20	**$ 0.35**	$ (0.65)	**$ 0.37**	$ (0.07)

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, 2016		**$4,878,607**	**$ 168,253**	**$(1,795,067)**	**$ 34,983**	**$ 3,286,776**
Shares issued	10	**517,816**	**-**	**-**	**-**	**517,816**
Share issue costs, net of tax	10	**(15,698)**	**-**	**-**	**-**	**(15,698)**
Stock-based compensation		**-**	**9,457**	**-**	**-**	**9,457**
RSUs vested and released	10	**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**
Balance as at December 31, 2015		$4,836,800	$ 171,835	$(1,366,341)	$ 35,573	$ 3,677,867
Stock-based compensation		-	25,555	-	-	25,555
RSUs vested and released		39,038	(39,038)	-	-	-
Comprehensive income (loss)		-	-	(15,336)	(8,714)	(24,050)
Balance as at June 30, 2016		$4,875,838	$ 158,352	$(1,381,677)	$ 26,859	$ 3,679,372

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	**2017**	**2016**	**2017**	**2016**
Cash provided by (used in):					
Operating activities					
Net earnings (loss)		**$ 104,282**	$ (146,165)	**$ 105,870**	$ (15,336)
Adjustments for:					
Depletion and depreciation	4,6	**111,605**	127,352	**228,484**	244,345
Stock-based compensation	11	**4,763**	9,069	**8,273**	21,961
Unrealized loss (gain) on foreign exchange	15	**(127,961)**	13,789	**(164,668)**	(306,492)
Unrealized loss (gain) on derivative financial liabilities	16	**(1,615)**	516	**(3,856)**	6,005
Unrealized loss (gain) on risk management	21	**(17,224)**	37,434	**(76,823)**	20,471
Onerous contracts	17	**3,333**	9,055	**5,708**	13,426
Deferred income tax expense (recovery)	18	**(28,156)**	(48,804)	**(17,177)**	(117,960)
Amortization of debt discount and debt issue costs	7,8	**4,728**	3,029	**9,754**	6,032
Other		**1,340**	1,689	**2,705**	3,272
Decommissioning expenditures	9	**(39)**	(34)	**(1,461)**	(996)
Payments on onerous contracts	9	**(5,468)**	(717)	**(9,602)**	(1,346)
Net change in other liabilities		**-**	1,451	**-**	1,451
Net change in non-cash working capital items	19	**14,024**	56,923	**22,211**	(30,917)
Net cash provided by (used in) operating activities		**63,612**	64,587	**109,418**	(156,084)
Investing activities					
Capital investments:					
Property, plant and equipment	4	**(157,067)**	(17,214)	**(234,708)**	(51,223)
Exploration and evaluation	5	**(479)**	(721)	**(692)**	(981)
Other intangible assets	6	**(12)**	(2,055)	**(14)**	(2,761)
Other	9	**6,298**	153	**16,933**	(1,086)
Net change in non-cash working capital items	19	**58,860**	(13,193)	**62,145**	(24,541)
Net cash used in investing activities		**(92,400)**	(33,030)	**(156,336)**	(80,592)
Financing activities					
Issue of shares, net of issue costs	10	**-**	-	**496,312**	-
Redemption of senior unsecured notes	19	**-**	-	**(1,008,825)**	-
Issue of senior secured second lien notes	19	**-**	-	**1,008,825**	-
Payment on term loan	19	**(4,200)**	(4,222)	**(4,855)**	(8,435)
Refinancing costs	19	**(320)**	-	**(82,377)**	-
Net cash provided by (used in) financing activities		**(4,520)**	(4,222)	**409,080**	(8,435)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency		**(3,249)**	816	**(5,968)**	(10,391)
Change in cash and cash equivalents		**(36,557)**	28,151	**356,194**	(255,502)
Cash and cash equivalents, beginning of period		**548,981**	124,560	**156,230**	408,213
Cash and cash equivalents, end of period		**$ 512,424**	$ 152,711	**$ 512,424**	$ 152,711

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. The Corporation also holds a 50% interest in the Access Pipeline, a dual pipeline to transport diluent north from the Edmonton area to the Athabasca oil sands area and a blend of bitumen and diluent south from the Christina Lake Project into the Edmonton area. In addition to the Access Pipeline, the Corporation owns the Stonefell Terminal, located near Edmonton, Alberta, which offers 900,000 barrels of terminalling and storage capacity. The Stonefell Terminal is connected to the Access Pipeline and is also connected by pipeline to a third-party rail-loading terminal. The corporate office is located at 600 – 3rd Avenue SW, Calgary, Alberta, Canada.

2. BASIS OF PRESENTATION

The unaudited interim consolidated financial statements ("interim consolidated financial statements") were prepared using the same accounting policies and methods as those used in the Corporation's audited consolidated financial statements for the year ended December 31, 2016. 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"), have 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, 2016. These interim consolidated financial statements should be read in conjunction with the Corporation's audited consolidated financial statements for the year ended December 31, 2016.

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 July 26, 2017.

3. CHANGE IN ACCOUNTING POLICIES

New accounting standards

The Corporation has adopted the following revised standards effective January 1, 2017:

IAS 7, Statement of Cash Flows, has been amended by the IASB as part of its disclosure initiative to require additional disclosure for changes in liabilities arising from financing activities. This includes changes arising from cash flows and non-cash changes. Additional disclosures for changes in liabilities arising from financing activities has been included in Note 19. As allowed by IAS 7, comparative information has not been presented.

IAS 12, Income Taxes, has been amended to clarify the recognition of deferred tax assets relating to unrealized losses. The adoption of this revision did not have an 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. 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.

In July 2014, the IASB issued IFRS 9 Financial Instruments, which is intended to replace 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. IFRS 9 is effective for annual periods beginning on or after January 1, 2018, with early adoption permitted. IFRS 9 will be adopted by the Corporation on January 1, 2018, and the Corporation is currently assessing and evaluating the impact of the standard on the consolidated financial statements.

In May 2014, the IASB issued IFRS 15 Revenue From Contracts With Customers, which will replace 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 new standard is effective for annual periods beginning on or after January 1, 2018, with early adoption permitted. IFRS 15 will be adopted by the Corporation on January 1, 2018. The Corporation is currently assessing and evaluating the terms of its sales contracts with customers to determine the impact, if any, that the standard will have on the consolidated financial statements. The Corporation anticipates there will be additional enhanced disclosures.

In June 2016, the IASB issued amendments to IFRS 2 Share-based Payment, relating to classification and measurement of particular share-based payment transactions. The amendments are effective for periods beginning on or after January 1, 2018. The Corporation is currently assessing the impact of the adoption of these amendments on the Corporation's consolidated financial statements.

4. 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	216,695	2,501	16,495	235,691
Change in decommissioning liabilities	30,919	1,093	-	32,012
Balance as at June 30, 2017	**$ 8,125,623**	**$ 1,613,712**	**$ 72,478**	**$ 9,811,813**
Accumulated depletion and depreciation				
Balance as at December 31, 2016	$ 1,766,709	$ 110,833	$ 27,134	$ 1,904,676
Depletion and depreciation	209,062	14,885	2,625	226,572
Balance as at June 30, 2017	**$ 1,975,771**	**$ 125,718**	**$ 29,759**	**$ 2,131,248**
Carrying amounts				
Balance as at December 31, 2016	$ 6,111,300	$ 1,499,285	$ 28,849	$ 7,639,434
Balance as at June 30, 2017	**$ 6,149,852**	**$ 1,487,994**	**$ 42,719**	**$ 7,680,565**

As at June 30, 2017, $507.1 million of assets under construction were included within property, plant and equipment (December 31, 2016 – $547.9 million). Assets under construction are not subject to depletion and depreciation. As at June 30, 2017, no impairment has been recognized on property, plant and equipment.

5. EXPLORATION AND EVALUATION ASSETS

Cost	
Balance as at December 31, 2016	$ 547,752
Additions	692
Change in decommissioning liabilities	697
Balance as at June 30, 2017	**$ 549,141**

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, 2017, no impairment has been recognized on exploration and evaluation assets.

6. OTHER INTANGIBLE ASSETS

Cost		
Balance as at December 31, 2016	$	112,921
Additions		14
Balance as at June 30, 2017	**$**	**112,935**

Accumulated depreciation		
Balance as at December 31, 2016	$	96,810
Depreciation		1,912
Balance as at June 30, 2017	**$**	**98,722**

Carrying amounts		
Balance as at December 31, 2016	$	16,111
Balance as at June 30, 2017	**$**	**14,213**

As at June 30, 2017, other intangible assets consist of $14.2 million invested in software that is not an integral component of the related computer hardware (December 31, 2016 – $16.1 million). As at June 30, 2017, no impairment has been recognized on these assets.

At December 31, 2016, the Corporation evaluated its investment in the right to participate in the Northern Gateway pipeline for impairment in relation to the December 2016 directive from the Government of Canada to the National Energy Board to dismiss the project application. As a result, the Corporation fully impaired its investment in the Northern Gateway pipeline in the fourth quarter of 2016 and recognized an impairment charge of $80.1 million.

7. OTHER ASSETS

As at		June 30, 2017		December 31, 2016
Long-term pipeline linefill[(a)]	**$**	**126,094**	$	129,733
Deferred financing costs[(b)]		**28,478**		12,001
		154,572		141,734
Less current portion of deferred financing costs		**(8,653)**		(4,364)
	$	**145,919**	$	137,370

(a) The Corporation has entered into agreements to transport diluent and bitumen blend on third-party owned pipelines and is required to supply linefill for these pipelines. As the pipelines are owned by third parties, the linefill is not considered to be a component of the Corporation's property, plant and equipment. The linefill is classified as a long-term asset as these transportation contracts extend beyond 2024. As at June 30, 2017, no impairment has been recognized on these assets.

(b) During the six months ended June 30, 2017, the Corporation recognized deferred financing costs on modifications to its revolving credit facility and guaranteed letter of credit facility of $17.5 million and $2.9 million, respectively (Note 8).

8. LONG-TERM DEBT

As at	June 30, 2017	December 31, 2016
Senior secured term loan (June 30, 2017 – US$1.232 billion; due 2023; December 31, 2016 – US$1.236 billion)[(a)]	**$ 1,598,653**	$ 1,658,906
6.5% senior secured second lien notes (US$750.0 million; due 2025)[(b)]	**973,275**	-
6.5% senior unsecured notes (US$750.0 million; due 2021)[(c)]	**-**	1,007,025
6.375% senior unsecured notes (US$800.0 million; due 2023)	**1,038,160**	1,074,160
7.0% senior unsecured notes (US$1.0 billion; due 2024)	**1,297,700**	1,342,700
	4,907,788	5,082,791
Less unamortized financial derivative liability discount	**(19,433)**	(11,143)
Less unamortized deferred debt discount and debt issue costs[(a)(b)]	**(59,236)**	(22,766)
Debt redemption premium[(c)]	**-**	21,812
	4,829,119	5,070,694
Less current portion of senior secured term loan	**(16,027)**	(17,455)
	$ 4,813,092	$ 5,053,239

The U.S. dollar denominated debt was translated into Canadian dollars at the period end exchange rate of US$1 = C$1.2977 (December 31, 2016 – US$1 = C$1.3427).

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) Effective January 27, 2017, the Corporation refinanced and extended the maturity date of its US$1.2 billion term loan from March 2020 to December 2023. The term loan bears interest at an annual rate based on either U.S. Prime or LIBOR, at the Corporation's option, plus a credit spread of 2.5% or 3.5%, respectively. The term loan also has a U.S. Prime Rate floor of 2.0% and a LIBOR floor of 1.0%. The term loan is to be repaid in quarterly installment payments of US$3.1 million, with the balance due on December 31, 2023. The term loan was issued at a price equal to 99.75% of its face value. The Corporation has deferred the debt discount and the associated debt issue costs of $22.0 million and is amortizing these costs over the life of the loan utilizing the effective interest method.

    Effective January 27, 2017, the Corporation extended the maturity date on substantially all of its commitments under the Corporation's covenant-lite revolving credit facility from November 2019 to November 2021. The commitment amount of the five-year facility has been reduced from US$2.5 billion to US$1.4 billion. As at June 30, 2017, no amount has been drawn under the revolving credit facility.

    On February 15, 2017, the Corporation extended the maturity date on the Corporation's five-year letter of credit facility, guaranteed by Export Development Canada, from November 2019 to November 2021. The guaranteed letter of credit facility has been reduced from US$500 million to US$440 million. Letters of credit under this facility do not consume capacity of the revolving credit facility. As at June 30, 2017, letters of credit of US$302.1 million had been issued under this facility.

    The amendments to the term loan, revolving credit facility and guaranteed letter of credit facility were not considered to be new financial liabilities, as no substantial modifications arose between the existing and amended agreements. As a result, no profit or loss was recognized when the terms of the financial liabilities were amended.

(b) Effective January 27, 2017, the Corporation issued US$750 million in aggregate principal amount of 6.5% Senior Secured Second Lien Notes, with a maturity date of January 2025. Interest is paid semi-annually in January and July. No principal payments are required until 2025. The Corporation has deferred the associated debt issue costs of $18.1 million and is amortizing these costs over the life of the notes utilizing the effective interest method.

(c) On March 15, 2017, the Corporation redeemed the previously outstanding US$750 million aggregate principal amount of 6.5% Senior Unsecured Notes due 2021, utilizing the proceeds received from the issuance of the US$750 million, 6.5% Senior Secured Second Lien Notes, which were held in escrow subject to the redemption. The 2.166% debt redemption premium of $21.8 million and associated remaining unamortized deferred debt issue costs of $7.0 million were recognized as debt extinguishment expense in the fourth quarter of 2016.

9. PROVISIONS AND OTHER LIABILITIES

As at	June 30, 2017	December 31, 2016
Decommissioning provision[(a)]	**$ 168,548**	$ 133,924
Onerous contracts provision[(b)]	96,571	100,159
Derivative financial liabilities[(c)]	**10,285**	3,714
Deferred lease inducements[(d)]	**19,210**	3,304
Provisions and other liabilities	**294,614**	241,101
Less current portion	**(26,536)**	(23,063)
Non-current portion	**$ 268,078**	$ 218,038

(a) 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, 2017	December 31, 2016
Balance, beginning of year	**$ 133,924**	$ 130,381
Changes in estimated future cash flows	**1,102**	(91)
Changes in discount rates and settlement dates	**19,779**	(6,117)
Liabilities incurred	**11,828**	4,123
Liabilities settled	**(1,461)**	(1,290)
Accretion	**3,376**	6,918
Balance, end of period	**168,548**	133,924
Less current portion	**(6,268)**	(3,097)
Non-current portion	**$ 162,280**	$ 130,827

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 Corporation has estimated the net present value of the decommissioning obligations using a weighted average credit-adjusted risk-free rate of 7.1% (December 31, 2016 – 8.2%). The decommissioning provision is estimated to be settled in periods up to the year 2067 (December 31, 2016 – periods up to the year 2066).

(b) Onerous contracts provision:

As at	June 30, 2017	December 31, 2016
Balance, beginning of year	$ 100,159	$ 58,178
Changes in estimated future cash flows	5,708	40,499
Changes in discount rates	-	(1,478)
Liabilities incurred	-	8,845
Liabilities settled	(9,602)	(6,116)
Accretion	306	231
Balance, end of period	96,571	100,159
Less current portion	(18,605)	(18,930)
Non-current portion	$ 77,966	$ 81,229

As at June 30, 2017, the Corporation has recognized a provision of $96.6 million related to onerous operating lease contracts (December 31, 2016 – $100.2 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. These cash flows have been discounted using a risk-free discount rate of 1.4% (December 31, 2016 – 1.3%). This estimate may vary as a result of changes in estimated recoveries.

(c) Derivative financial liabilities:

As at	June 30, 2017	December 31, 2016
1% interest rate floor	$ 10,285	$ 3,714
Less current portion	(34)	(517)
Non-current portion	$ 10,251	$ 3,197

(d) Deferred lease inducements:

During the six months ended June 30, 2017, the Corporation recognized a $16.9 million deferred liability associated with a tenant improvement allowance related to its corporate office lease.

10. SHARE CAPITAL

Authorized:

Unlimited number of common shares
Unlimited number of preferred shares

Changes in issued common shares are as follows:

	Six months ended June 30, 2017			Year ended December 31, 2016		
	Number of shares		**Amount**	**Number of shares**		**Amount**
Balance, beginning of year	**226,467,107**	**$**	**4,878,607**	224,996,989	$	4,836,800
Shares issued	**66,815,000**		**517,816**	-		-
Share issue costs net of tax	**-**		**(15,698)**	-		-
Issued upon vesting and release of RSUs and PSUs	**765,262**		**21,869**	1,470,118		41,807
Balance, end of period	**294,047,369**	**$**	**5,402,594**	226,467,107	$	4,878,607

On January 27, 2017, the Corporation issued 66,815,000 common shares at a price of $7.75 per share for gross proceeds of $517.8 million.

11. 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 Restricted Share Unit Plan generally vest over a three-year period. PSUs granted under the cash-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.

Upon vesting of the RSUs and PSUs, the participants of the cash-settled RSU plan will receive a cash payment based on the fair value of the underlying share units at the vesting date. The 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. 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.

RSUs and PSUs outstanding:

Six months ended June 30, 2017	
Outstanding, beginning of year	**6,013,010**
Granted	**1,454,659**
Vested and released	**(1,438,390)**
Forfeited	**(618,350)**
Outstanding, end of period	**5,410,929**

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, 2017, there were 284,871 DSUs outstanding (December 31, 2016 – 163,954 DSUs outstanding).

As at June 30, 2017, the Corporation has recognized a liability of $6.9 million relating to the fair value of RSUs, PSUs and DSUs (December 31, 2016 – $19.2 million).

(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, 2017	Stock options	Weighted average exercise price
Outstanding, beginning of year	**9,281,186**	**$ 27.45**
Granted	**1,211,880**	**4.57**
Forfeited	**(853,885)**	**27.34**
Expired	**(94,750)**	**32.11**
Outstanding, end of period	**9,544,431**	**$ 24.50**

ii. Restricted share units and performance share units:

RSUs granted under the equity-settled Restricted Share Unit Plan generally vest annually 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.

Upon vesting of the RSUs and PSUs, the holder receives the right to a cash payment equal to the fair market value of the Corporation's common shares calculated at the date of such payment or, at the election of the Corporation, its equivalent in fully-paid common shares. The Corporation does not intend to make cash payments under the equity-settled RSU plan.

RSUs and PSUs outstanding:

Six months ended June 30, 2017	
Outstanding, beginning of year	**1,655,606**
Granted	**5,693,406**
Vested and released	**(765,262)**
Forfeited	**(180,286)**
Outstanding, end of period	**6,403,464**

(c) Stock-based compensation

	Three months ended June 30		Six months ended June 30	
	2017	**2016**	**2017**	**2016**
Cash-settled expense (recovery)[(i)]	**$ (2,272)**	$ 1,450	**$ (3,495)**	$ 1,450
Equity-settled expense	**4,763**	9,069	**8,273**	21,961
Stock-based compensation	**$ 2,491**	$ 10,519	**$ 4,778**	$ 23,411

(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. Fluctuations in the fair value are recognized during the period in which they occur.

12. PETROLEUM REVENUE, NET OF ROYALTIES

	Three months ended June 30		Six months ended June 30	
	2017	**2016**	**2017**	**2016**
Petroleum revenue:				
Proprietary	**$ 492,613**	$ 430,119	**$ 982,001**	$ 680,516
Third-party[(a)]	**80,161**	77,509	**146,934**	106,239
Petroleum revenue	**572,774**	507,628	**1,128,935**	$ 786,755
Royalties	**(5,877)**	(1,965)	**(11,568)**	(1,468)
Petroleum revenue, net of royalties	**$ 566,897**	$ 505,663	**$ 1,117,367**	$ 785,287

(a) 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".

13. OTHER REVENUE

	Three months ended June 30		Six months ended June 30	
	2017	**2016**	**2017**	**2016**
Power revenue	**$ 3,852**	$ 2,529	**$ 10,208**	$ 8,083
Transportation revenue	**3,284**	5,163	**6,237**	10,323
Other revenue	**$ 7,136**	$ 7,692	**$ 16,445**	$ 18,406

14. DILUENT AND TRANSPORTATION

	Three months ended June 30		Six months ended June 30	
	2017	2016	**2017**	2016
Diluent expense	**$ 225,113**	$ 203,428	**$ 459,512**	$ 376,293
Transportation expense	**49,893**	54,012	**96,791**	104,510
Diluent and transportation	**$ 275,006**	$ 257,440	**$ 556,303**	$ 480,803

15. FOREIGN EXCHANGE LOSS (GAIN), NET

	Three months ended June 30		Six months ended June 30	
	2017	2016	**2017**	2016
Unrealized foreign exchange loss (gain) on:				
Long-term debt	**$ (130,390)**	$ 14,416	**$ (170,148)**	$ (315,677)
Other	**2,429**	(627)	**5,480**	9,185
Unrealized net loss (gain) on foreign exchange	**(127,961)**	13,789	**(164,668)**	(306,492)
Realized loss (gain) on foreign exchange	**(3,042)**	808	**(5,355)**	(4,858)
Foreign exchange loss (gain), net	**$ (131,003)**	$ 14,597	**$ (170,023)**	$ (311,350)

C$ equivalent of 1 US$				
Beginning of period	**1.3322**	1.2971	**1.3427**	1.3840
End of period	**1.2977**	1.3009	**1.2977**	1.3009

16. NET FINANCE EXPENSE

	Three months ended June 30		Six months ended June 30	
	2017	2016	**2017**	2016
Total interest expense	**$ 85,162**	$ 80,758	**$ 178,436**	$ 164,673
Accretion on provisions	**1,825**	1,820	**3,681**	3,514
Unrealized loss (gain) on derivative financial liabilities	**(1,615)**	516	**(3,856)**	6,005
Realized loss (gain) on interest rate swaps	**-**	1,471	**-**	3,040
Net finance expense	**$ 85,372**	$ 84,565	**$ 178,261**	$ 177,232

17. OTHER EXPENSES

	Three months ended June 30		Six months ended June 30	
	2017	2016	**2017**	2016
Onerous contracts	**$ 3,333**	$ 9,055	**$ 5,708**	$ 13,426
Severance and other	**3,468**	6,179	**3,468**	6,179
Other expenses	**$ 6,801**	$ 15,234	**$ 9,176**	$ 19,605

18. INCOME TAX EXPENSE (RECOVERY)

	Three months ended June 30		Six months ended June 30	
	2017	2016	2017	2016
Current income tax expense (recovery)	$ 115	$ 97	$ (169)	$ 614
Deferred income tax expense (recovery)	(28,156)	(48,804)	(17,177)	(117,960)
Income tax expense (recovery)	$ (28,041)	$ (48,707)	$ (17,346)	$ (117,346)

Based on the Corporation's independently evaluated reserve report, the Corporation has recognized a deferred tax asset of $143.9 million (December 31, 2016 – $120.9 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	
	2017	2016	2017	2016
Cash provided by (used in):				
Trade receivables and other	$ 12	$ (61,796)	$ 32,746	$ (59,290)
Inventories	12,431	11,174	606	(20,217)
Accounts payable and accrued liabilities	60,441	94,352	51,004	24,049
	$ 72,884	$ 43,730	$ 84,356	$ (55,458)
Changes in non-cash working capital relating to:				
Operating	$ 14,024	$ 56,923	$ 22,211	$ (30,917)
Investing	58,860	(13,193)	62,145	(24,541)
	$ 72,884	$ 43,730	$ 84,356	$ (55,458)
Cash and cash equivalents:[a]				
Cash	$ 264,932	$ 152,711	$ 264,932	$ 152,711
Cash equivalents	247,492	-	247,492	-
	$ 512,424	$ 152,711	$ 512,424	$ 152,711
Cash interest paid	$ 24,009	$ 15,335	$ 139,993	$ 144,347

(a) As at June 30, 2017, C$98.7 million of the Corporation's total cash and cash equivalents balance was held in U.S. dollars (June 30, 2016 – C$91.6 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$1.2977 (June 30, 2016 – US$1 = C$1.3009).

The following table reconciles liabilities to cash flows arising from financing activities:

	Long-term debt [i]
Balance as at December 31, 2016	$ 5,070,694
Cash changes:	
Debt refinancing costs[a]	(61,930)
Redemption of senior unsecured notes	(1,008,825)
Issue of senior secured second lien notes	1,008,825
Payment on term loan	(4,855)
Non-cash changes:	
Unrealized loss (gain) on foreign exchange	(170,148)
Change in fair value of financial derivative liability	(10,426)
Amortization of financial derivative liability discount	2,135
Amortization of deferred debt discount and debt issue costs	3,649
Balance as at June 30, 2017	**$ 4,829,119**

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

(a) During the six months ended June 30, 2017, debt refinancing costs of $82.4 million were paid, including $61.9 million for the refinancing and maturity extension of the Corporation's US$1.2 billion term loan and replacement of the Corporation's US$750 million Senior Unsecured Notes with US$750 million Senior Secured Second Lien Notes (Note 8). Refinancing costs related to amendments and extensions to the revolving credit facility and to the guaranteed letter of credit facility of $17.5 million and $2.9 million respectively, have been recognized as a component of other assets (Note 7).

20. NET EARNINGS (LOSS) PER COMMON SHARE

	Three months ended June 30		Six months ended June 30	
	2017	**2016**	**2017**	**2016**
Net earnings (loss)	**$ 104,282**	$ (146,165)	**$ 105,870**	$ (15,336)
Weighted average common shares outstanding[a]	**293,704,126**	225,601,265	**283,988,250**	225,370,092
Dilutive effect of stock options, RSUs and PSUs[b]	**347,816**	-	**367,180**	-
Weighted average common shares outstanding – diluted	**294,051,942**	225,601,265	**284,355,430**	225,370,092
Net earnings (loss) per share, basic	**$ 0.36**	$ (0.65)	**$ 0.37**	$ (0.07)
Net earnings (loss) per share, diluted	**$ 0.35**	$ (0.65)	**$ 0.37**	$ (0.07)

(a) Weighted average common shares outstanding for the six months ended June 30, 2017 includes 139,863 PSUs not yet released (six months ended June 30, 2016 – 184,425 PSUs).

(b) For the three months and six months ended June 30, 2016, 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, 2016, the dilutive effect of stock options, RSUs and PSUs would have been 443,816 and 407,726 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, accounts payable and accrued liabilities, derivative financial liabilities included within provisions and other liabilities, long-term debt and debt redemption premium liability included within long-term debt. As at June 30, 2017, commodity risk management contracts and derivative financial liabilities were classified as held-for-trading financial instruments; cash and cash equivalents and trade receivables and other were classified as loans and receivables; and accounts payable and accrued liabilities were classified as other financial liabilities. Long-term debt was 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, derivative financial liabilities, commodity risk management contracts and debt redemption premium liability:

		Fair value measurements using		
As at June 30, 2017	**Carrying amount**	**Level 1**	**Level 2**	**Level 3**
Recurring measurements:				
Financial assets				
Commodity risk management contracts	$ 47,162	$ -	$ 47,162	$ -
Financial liabilities				
Long-term debt[(i)] (Note 8)	$ 4,907,788	$ -	$ 4,339,535	$ -
Derivative financial liabilities (Note 9)	$ 10,285	$ -	$ 10,285	$ -
Commodity risk management contracts	$ 652	$ -	$ 652	$ -

		Fair value measurements using		
As at December 31, 2016	**Carrying amount**	**Level 1**	**Level 2**	**Level 3**
Recurring measurements:				
Financial liabilities				
Long-term debt[(i)] (Note 8)	$ 5,082,791	$ -	$ 4,768,344	$ -
Derivative financial liabilities (Note 9)	$ 3,714	$ -	$ 3,714	$ -
Commodity risk management contracts	$ 30,313	$ -	$ 30,313	$ -
Debt redemption premium (Note 8)	$ 21,812	$ -	$ 21,812	$ -

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

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

As at June 30, 2017, 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 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.

As at June 30, 2017, the Corporation did not have any financial instruments measured at Level 3 fair value. 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 has the following financial commodity risk management contracts relating to crude oil sales outstanding as at June 30, 2017:

As at June 30, 2017	**Volumes (bbls/d)**[(i)]	**Term**	**Average Price (US$/bbl)**[(i)]
Fixed Price:			
WTI[(ii)] Fixed Price	24,100	Jul 1, 2017 – Dec 31, 2017	$55.07
WTI:WCS[(iii)] Fixed Differential	50,000	Jul 1, 2017 – Sep 30, 2017	$(15.16)
WTI:WCS Fixed Differential	54,600	Oct 1, 2017 – Dec 31, 2017	$(15.14)
WTI:WCS Fixed Differential	4,000	Jan 1, 2018 – Mar 31, 2018	$(14.35)
Collars:			
WTI Collars	30,500	Jul 1, 2017 – Dec 31, 2017	$47.87 – $58.57
WTI Collars	6,000	Jan 1, 2018 – Mar 31, 2018	$50.00 – $56.81

The Corporation has entered into the following financial commodity risk management contracts relating to crude oil sales subsequent to June 30, 2017. As a result, these contracts are not reflected in the Corporation’s Interim Consolidated Financial Statements:

Subsequent to June 30, 2017	**Volumes (bbls/d)**[(i)]	**Term**	**Average Price (US$/bbl)**[(i)]
Fixed Price:			
WTI:WCS[(iii)] Fixed Differential	6,000	Jan 1, 2018 – Mar 31, 2018	$(13.80)
WTI:WCS[(iii)] Fixed Differential	2,000	Apr 1, 2018 – Jun 30, 2018	$(13.90)

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

(ii) West Texas Intermediate (“WTI”) crude oil

(iii) Western Canadian Select (“WCS”) crude oil blend

The Corporation has the following financial commodity risk management contracts relating to condensate purchases outstanding:

As at June 30, 2017	Volumes (bbls/d)	Term	Average % of WTI
Mont Belvieu fixed % of WTI	15,150	Jul 1, 2017 – Dec 31, 2017	82.9%

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, 2017			December 31, 2016		
	Asset	**Liability**	**Net**	**Asset**	**Liability**	**Net**
Gross amount	**$ 79,938**	**$ (24,876)**	**$ 55,062**	$ -	$ (165,740)	$ (165,740)
Amount offset	**(32,776)**	**24,224**	**(8,552)**	-	135,427	135,427
Net amount	**$ 47,162**	**$ (652)**	**$ 46,510**	$ -	$ (30,313)	$ (30,313)

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, 2017	June 30, 2016
Fair value of contracts, beginning of year	**$ (30,313)**	$ -
Fair value of contracts realized during the period	**8,577**	3,487
Change in fair value of contracts during the period	**68,246**	(23,958)
Fair value of contracts, end of period	**$ 46,510**	$ (20,471)

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

	Three months ended June 30		Six months ended June 30	
	2017	**2016**	**2017**	**2016**
Realized loss (gain) on commodity risk management	**$ 10,089**	$ 3,487	**$ 8,577**	$ 3,487
Unrealized loss (gain) on commodity risk management	**(17,224)**	37,434	**(76,823)**	20,471
Commodity risk management loss (gain)	**$ (7,135)**	$ 40,921	**$ (68,246)**	$ 23,958

The following table summarizes the 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, 2017:

Commodity	Sensitivity Range	Increase	Decrease
Crude oil commodity price	± US$5.00 per bbl applied to WTI contracts	$ (39,513)	$ 68,722
Crude oil differential price[(i)]	± US$1.00 per bbl applied to WCS differential contracts	$ 12,961	$ (12,961)
Condensate percentage	± 1% in condensate price as a percentage of US$ WTI price per bbl applied to condensate contracts	$ 1,561	$ (1,561)

(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.

(c) 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. Interest rate swaps are classified as derivative financial liabilities and measured at fair value, with gains and losses on re-measurement included in the statement of consolidated earnings and comprehensive income in the period in which they arise. The Corporation did not have any outstanding interest rate swap contracts as at June 30, 2017.

22. GEOGRAPHICAL DISCLOSURE

As at June 30, 2017, the Corporation had non-current assets related to operations in the United States of $109.9 million (December 31, 2016 – $109.2 million). For the three and six months ended June 30, 2017, petroleum revenue related to operations in the United States was $233.4 million and $438.0 million respectively (three and six months ended June 30, 2016 – $181.7 million and $278.0 million, respectively).

23. COMMITMENTS AND CONTINGENCIES

(a) Commitments

The Corporation had the following commitments as at June 30, 2017:

	2017	2018	2019	2020	2021	Thereafter
Transportation and storage	$ 89,661	$ 199,220	$ 198,187	$ 249,160	$ 307,309	$ 3,947,125
Office lease rentals	16,226	32,091	32,121	33,037	33,435	230,483
Diluent purchases	164,748	116,558	19,988	20,043	19,988	36,636
Other operating commitments	8,574	14,056	9,989	11,998	11,240	73,535
Capital commitments	3,320	-	-	-	-	-
Commitments	**$ 282,529**	**$ 361,925**	**$ 260,285**	**$ 314,238**	**$ 371,972**	**$ 4,287,779**

The Corporation's commitments have been presented on a gross basis. A portion of these committed amounts have been recognized on the balance sheet within provisions and other liabilities (Note 9(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.