FOURTH QUARTER 2016

Report to Shareholders for the period ended December 31, 2016

MEG Energy Corp. reported fourth quarter and full-year 2016 operating and financial results on February 9, 2017. Highlights include:

- Quarterly production volumes of 81,780 barrels per day (bpd) contributing to record annual production of 81,245 bpd;

- Record-low per barrel net operating costs for the full year of 2016 and record-low per barrel non-energy operating costs for the full year and the quarter;

- 2016 capital spending of $137 million, lower than previous guidance of $140 million announced in October 2016 and the original budget of $328 million, while still maintaining production guidance for the full year;

- Year-end cash and cash equivalents of $156 million.

- MEG is positioned to expand its eMSAGP technology, the first step in a series of high-return projects to boost production while lowering the company's cash costs and environmental footprint.

- Subsequent to the fourth quarter, MEG Energy announced the closing of a comprehensive refinancing which has contributed to a strengthened balance sheet, and will enable an increase in production and a reduction in costs per barrel.

MEG's fourth quarter 2016 production was 81,780 bpd, compared to 83,514 bpd for the fourth quarter of 2015. Full-year 2016 production was a record 81,245 bpd, meeting targets and reflecting the ongoing efficiency gains associated with MEG's patented eMSAGP reservoir technology.

MEG established record-low per barrel net operating costs and non-energy operating costs for the full year of 2016. Net operating costs were recorded at $8.24 per barrel in the fourth quarter of 2016 with net annual operating costs of $7.99 per barrel. At $4.99 per barrel, fourth quarter non-energy operating costs supported record-low annual non-energy operating costs of $5.62 per barrel, which were well below the bottom end of the company's 2016 revised guidance and 14% lower than in 2015. Lower operating costs on both a quarterly and annual basis are primarily due to efficiency gains and a continued focus on cost management.

On January 27, 2017, MEG announced the closing of its comprehensive refinancing plan, which was first announced on January 11, 2017, and comprised of four financing transactions including the raising of $518 million in equity. The transactions have contributed to a strengthened balance sheet, and will enable an increase in production and a reduction in costs per barrel.

"The last few months have been extremely important for MEG. We have extended the runway of our debt under favorable terms, retaining the covenant lite structure. The success of our equity raise opens the door for us to refocus on growth with a fully-funded capital program driven by our technological advances and capital efficiency gains," said Bill McCaffrey, President and Chief Executive Officer. "With the expansion of our eMSAGP technology to our Phase 2B wells, we expect to exit 2017 at 86,000 to 89,000 bpd, with further production increases through 2018 into 2019."

MEG's eMSAGP expansion and upcoming Phase 2B brownfield expansion will be the first of a series of high-return projects expected to increase production, decrease cash costs and further the sustainability of the company's balance sheet. "Over the next several years, we plan to grow our production to 210,000 bpd through the addition of more of these high return, short cycle 10,000 to 20,000 bpd brownfield projects," McCaffrey said.

MEG recorded adjusted funds flow of $40.0 million for the fourth quarter of 2016 compared to adjusted funds flow of $(44.1) million for the same period in 2015. Adjusted funds flow is directly correlated to the increase in U.S. crude oil benchmark pricing during the fourth quarter of 2016, which resulted in higher blend sales revenue. Adjusted funds flow was $(61.6) million for 2016 compared to adjusted funds flow of $49.5 million for 2015.

The company recorded a fourth quarter 2016 operating loss of $72 million compared to an operating loss of $140 million for the same period in 2015. The difference in operating earnings reflects the same factors impacting adjusted funds flow.

Capital Investment and Financial Liquidity

Total cash capital investment during the fourth quarter of 2016 was $63.1 million, as compared to $54.5 million for the same period in 2015. Total cash capital investment during 2016 totalled $137.2 million as compared to $257.2 million for 2015. Capital investment in 2016 was primarily directed towards sustaining capital activities.

At the end of the fourth quarter, MEG had $156 million of cash and cash equivalents on hand. This cash on hand, together with net proceeds from MEG's $518 million equity issuance completed subsequent to year end and 2017 funds flow, is expected to fund MEG's previously announced $590 million capital budget in 2017. MEG has entered into a series of hedges designed to protect its capital program against downward movements in crude oil prices. MEG's five-year covenant-lite US$1.4 billion credit facility remains undrawn.

"We believe that the production growth expected from the first two of a series of brownfield expansions will drive our debt to EBITDA metric into the 3x to 4x range, assuming a similar operating and price environment to what we are seeing currently," McCaffrey said. "In addition, the transactions give us the added flexibility to pursue additional deleveraging alternatives which would improve our debt metrics further."

OPERATIONAL AND FINANCIAL HIGHLIGHTS

On January 27, 2017, the Corporation completed a comprehensive refinancing plan as outlined in the "Capital Resources" section of this Fourth Quarter Report.

The ongoing global imbalance between supply and demand for crude oil continued to significantly impact the Corporation's operating and financial results. The C$/bbl WTI average price for the year ended December 31, 2016 decreased 8% compared to the same period in 2015. However, during the fourth quarter of 2016, the C$/bbl WTI average price increased 17% compared to the same period in 2015.

As a result of ongoing cost control initiatives in 2016, the Corporation has reduced non-energy operating costs per barrel by 12% compared to the fourth quarter of 2015 and has reduced general and administrative expense per barrel by 13% compared to the fourth quarter of 2015.

During 2016, the Corporation implemented a strategic commodity risk management program to partially manage its exposure on blend sales prices and condensate purchases with the intent to increase the predictability of the Corporation's future cash flow as governed by the Corporation's Risk Management Committee.

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:

	Year ended December 31		2016				2015			
($ millions, except as indicated)	**2016**	**2015**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**
Bitumen production - bbls/d	**81,245**	80,025	**81,780**	83,404	83,127	76,640	83,514	82,768	71,376	82,398
Bitumen realization - $/bbl	**27.79**	30.63	**36.17**	30.98	30.93	11.43	23.17	31.03	44.54	25.82
Net operating costs - $/bbl(1)	**7.99**	9.39	**8.24**	7.76	7.43	8.53	8.52	9.10	9.43	10.49
Non-energy operating costs - $/bbl	**5.62**	6.54	**4.99**	5.32	5.81	6.45	5.66	5.98	7.01	7.57
Cash operating netback - $/bbl(2)	**13.13**	15.72	**21.73**	16.74	16.09	(3.71)	9.05	16.41	29.64	9.83
Adjusted funds flow(3)	**(62)**	49	**40**	23	7	(131)	(44)	24	99	(30)
Per share, diluted(3)	**(0.27)**	0.22	**0.18**	0.10	0.03	(0.58)	(0.20)	0.11	0.44	(0.13)
Operating loss(3)	**(455)**	(374)	**(72)**	(88)	(98)	(197)	(140)	(87)	(23)	(124)
Per share, diluted(3)	**(2.01)**	(1.67)	**(0.32)**	(0.39)	(0.43)	(0.88)	(0.62)	(0.39)	(0.10)	(0.56)
Revenue(4)	**1,866**	1,926	**566**	497	513	290	445	460	555	467
Net earnings (loss)(5)	**(429)**	(1,170)	**(305)**	(109)	(146)	131	(297)	(428)	63	(508)
Per share, basic	**(1.90)**	(5.21)	**(1.34)**	(0.48)	(0.65)	0.58	(1.32)	(1.90)	0.28	(2.27)
Per share, diluted	**(1.90)**	(5.21)	**(1.34)**	(0.48)	(0.65)	0.58	(1.32)	(1.90)	0.28	(2.27)
Total cash capital investment(6)	**137**	257	**63**	19	20	35	54	32	90	80
Cash and cash equivalents	**156**	408	**156**	103	153	125	408	351	438	471
Long-term debt(7)	**5,053**	5,190	**5,053**	4,910	4,871	4,859	5,190	5,024	4,678	4,759

(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, 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 months and years ended December 31, 2016 and December 31, 2015, the non-GAAP measure of adjusted funds flow is reconciled to net cash provided by (used in) operating activities and the non-GAAP measure of operating loss is reconciled to net 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 (Loss) and Comprehensive Income (Loss).*

(5) *Includes a net unrealized foreign exchange loss of $119.6 million and a net unrealized foreign exchange gain of $148.2 million on the Corporation's U.S. dollar denominated debt and U.S. dollar denominated cash and cash equivalents for the three months and year ended December 31, 2016, respectively. The net losses for the three months and year ended December 31, 2015 include net unrealized foreign exchange losses of $159.0 million and $785.3 million, respectively.*

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

(7) *On December 8, 2016, Fitch Ratings ("Fitch") assigned the Corporation a first-time Long-Term Issuer Default Rating of B, and assigned a rating of BB to the Corporation's covenant-lite revolving credit facility and term loan and a rating of B to the Corporation's Senior Unsecured Notes. On January 12, 2017, Fitch assigned a BB rating to the Corporation's new second lien secured notes (see the "Capital Resources" section of this MD&A). Fitch's rating outlook is negative. On January 12, 2017, Standard & Poor's Ratings Services ("S&P") assigned a BB+ rating to the Corporation's new second lien secured notes. On January 12, 2017, Moody's Investors Service ("Moody's") upgraded the Corporation's Corporate Family Rating to B3 from Caa2, the Probability of Default Rating to B3-PD from Caa2-PD and the Corporation's Senior Unsecured Notes rating to Caa2 from Caa3. Moody's Speculative Grade Liquidity Rating was raised to SGL-1 from SGL-2. Moody's also assigned a rating of Ba3 to the Corporation's covenant-lite revolving credit facility and refinanced term loan and a rating of Caa1 to the new second lien secured notes. Moody's rating outlook was changed to stable from negative.*

Bitumen Production and Steam to Oil Ratio

	Three months ended December 31		Year ended December 31	
	2016	**2015**	**2016**	**2015**
Bitumen production – bbls/d	**81,780**	83,514	**81,245**	80,025
Steam to oil ratio (SOR)	**2.3**	2.5	**2.3**	2.5

Bitumen Production

Bitumen production for the three months ended December 31, 2016 averaged 81,780 bbls/d compared to 83,514 bbls/d for the three months ended December 31, 2015. The decrease in production volumes for the three months ended December 31, 2016 is primarily due to the deferral of drilling-related capital expenditures during 2016. Bitumen production for the year ended December 31, 2016 averaged 81,245 bbls/d compared to 80,025 bbls/d for the year ended December 31, 2015. The increase in production volumes for the year ended December 31, 2016 is primarily due to the efficiency gains achieved through the continued implementation of eMSAGP at the Christina Lake Project. The implementation of eMSAGP has improved reservoir efficiency and allowed for redeployment of steam, thereby enabling the Corporation to place additional wells into production.

Steam to Oil Ratio

The Corporation continues to focus on sustaining production and maintaining efficiency of current 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 for the three months and year ended December 31, 2016 compared to an average SOR of

2.5 for the three months and year ended December 31, 2015. The decrease in SOR for the three months and year ended December 31, 2016 is due to the continued implementation of eMSAGP.

Operating Cash Flow

	Three months ended December 31		Year ended December 31	
($000)	**2016**	**2015**	**2016**	**2015**
Petroleum revenue – proprietary(1)	**$ 503,176**	$ 386,689	**$ 1,626,025**	$ 1,799,154
Diluent expense	**(231,173)**	(211,293)	**(808,030)**	(893,995)
	272,003	175,396	**817,995**	905,159
Royalties	**(3,861)**	(1,888)	**(8,581)**	(20,765)
Transportation expense	**(50,102)**	(44,437)	**(209,864)**	(156,382)
Operating expenses	**(68,525)**	(69,974)	**(253,758)**	(306,725)
Power revenue	**6,508**	5,441	**18,868**	29,239
Transportation revenue	**4,605**	3,905	**19,791**	13,824
	160,628	68,443	**384,451**	464,350
Realized gain on risk management	**2,718**	-	**2,359**	-
Operating cash flow(2)	**$ 163,346**	$ 68,443	**$ 386,810**	$ 464,350

(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 Fourth Quarter Report.*

Operating cash flow was $163.3 million for the three months ended December 31, 2016 compared to $68.4 million for the three months ended December 31, 2015. Operating cash flow increased primarily due to higher blend sales revenue as a result of an increase in U.S. crude oil benchmark pricing during the fourth quarter of 2016, partially offset by an increase in diluent and transportation expense. In addition, the Corporation realized a gain of $2.7 million on commodity risk management contracts in the fourth quarter of 2016. Blend sales revenue for the three months ended December 31, 2016 was $503.2 million compared to $386.7 million for the three months ended December 31, 2015. The increase in blend sales revenue is primarily due to a 30% increase in the average realized blend price. Diluent expense for the three months ended December 31, 2016 was $231.2 million compared to $211.3 million for the three months ended December 31, 2015, reflecting an increase in condensate prices.

Operating cash flow was $386.8 million for the year ended December 31, 2016 compared to $464.4 million for the year ended December 31, 2015. Operating cash flow decreased primarily due to lower blend sales revenue as a result of the year-over-year average decline in U.S. crude oil benchmark pricing, partially offset by a decrease in diluent expense. In addition, the Corporation realized a gain of $2.4 million on commodity risk management contracts in 2016. Blend sales revenue for the year ended December 31, 2016 was $1.6 billion compared to $1.8 billion for the year ended December 31, 2015. The decrease in blend sales revenue is primarily due to a 10% decrease in the average realized blend price. Diluent expense for the year ended December 31, 2016 was $808.0 million compared to $894.0 million for the year ended December 31, 2015, reflecting a decrease in condensate prices.

Cash Operating Netback

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

	Three months ended December 31		Year ended December 31	
($/bbl)	**2016**	**2015**	**2016**	**2015**
Bitumen realization[1]	**$ 36.17**	$ 23.17	**$ 27.79**	$ 30.63
Transportation[2]	**(6.05)**	(5.35)	**(6.46)**	(4.82)
Royalties	**(0.51)**	(0.25)	**(0.29)**	(0.70)
	29.61	17.57	**21.04**	25.11
Operating costs – non-energy	**(4.99)**	(5.66)	**(5.62)**	(6.54)
Operating costs – energy	**(4.12)**	(3.58)	**(3.01)**	(3.84)
Power revenue	**0.87**	0.72	**0.64**	0.99
Net operating costs	**(8.24)**	(8.52)	**(7.99)**	(9.39)
	21.37	9.05	**13.05**	15.72
Realized gain on risk management	**0.36**	-	**0.08**	-
Cash operating netback	**$ 21.73**	$ 9.05	**$ 13.13**	$ 15.72

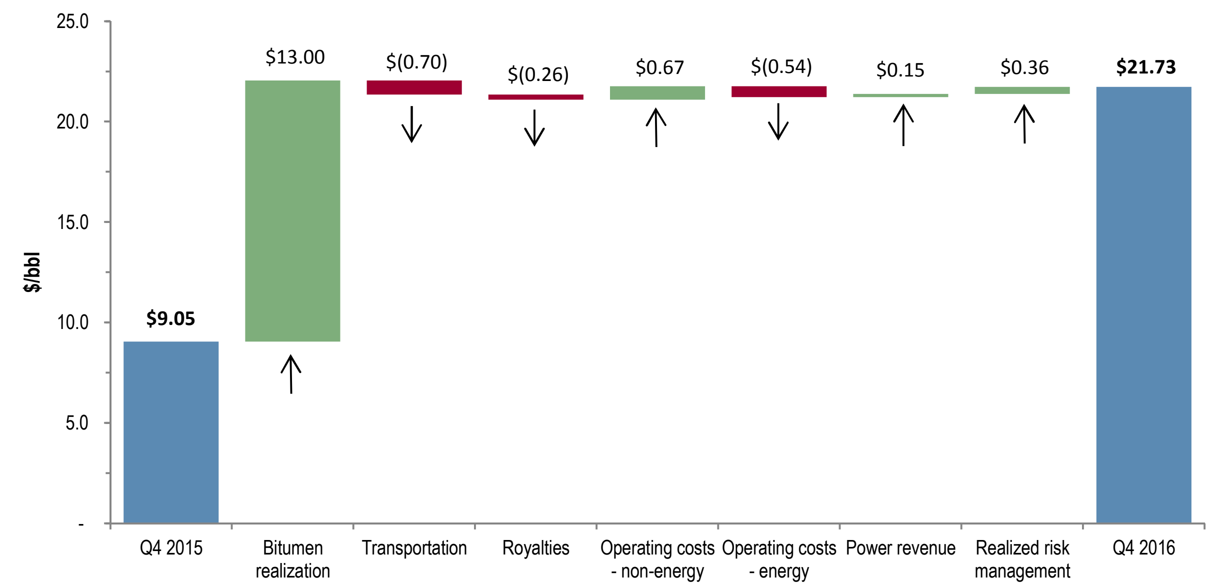
(1) Blend sales revenue net of diluent expense.

(2) Defined as transportation expense less transportation revenue. Transportation costs include 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.

Cash operating netback for the three months ended December 31, 2016 was $21.73 per barrel compared to $9.05 per barrel for the three months ended December 31, 2015. The increase in cash operating netback for the three months ended December 31, 2016 is primarily due to an increase in bitumen realization as a result of an increase in U.S. crude oil benchmark pricing during the fourth quarter of 2016.

Cash operating netback for the year ended December 31, 2016 was $13.13 per barrel compared to $15.72 per barrel for the year ended December 31, 2015. The decrease in cash operating netback for the year ended December 31, 2016 was primarily due to a decrease in bitumen realization, as a result of the year-over-year average decline in U.S. crude oil benchmark pricing and an increase in transportation expense, partially offset by a decrease in net operating costs.

Cash Operating Netback – Three Months Ended December 31



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 $36.17 per barrel for the three months ended December 31, 2016 compared to $23.17 per barrel for the three months ended December 31, 2015. The increase in bitumen realization is primarily a result of the increase in U.S. crude oil benchmark pricing during the fourth quarter of 2016 which resulted in higher blend sales revenue.

For the three months ended December 31, 2016, the Corporation's cost of diluent was $69.15 per barrel of diluent compared to $61.84 per barrel of diluent for the three months ended December 31, 2015. The increase in the cost of diluent is primarily a result of the increase in condensate benchmark pricing during the fourth quarter of 2016.

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. This improved cash operating netback requires additional transportation. Transportation costs averaged $6.05 per barrel for the three months ended December 31, 2016 compared to $5.35 per barrel for the three months ended December

31, 2015. Transportation expense increased primarily due to the cost of transporting higher blend volumes from Edmonton to the U.S. Gulf Coast via the Flanagan South and Seaway pipeline systems.

Royalties

The Corporation's royalty expense is based on price-sensitive royalty rates set by the Government of Alberta. The applicable royalty rates change dependent upon whether a project is pre-payout or post-payout, with payout being defined as the point in time when a project has generated enough net revenues to recover its cumulative costs. The royalty rate applicable to pre-payout oil sands operations starts at 1% of bitumen sales and increases for every dollar that the WTI crude oil price in Canadian dollars is priced above $55 per barrel, to a maximum of 9% when the WTI crude oil price is $120 per barrel or higher. All of the Corporation's projects are currently pre-payout.

Royalties averaged $0.51 per barrel during the three months ended December 31, 2016 compared to $0.25 per barrel for the three months ended December 31, 2015. The increase in royalties is primarily attributable to higher royalty rates as a result of higher realized 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 at the Corporation’s cogeneration facilities at the Christina Lake Project.

Net operating costs for the three months ended December 31, 2016 averaged $8.24 per barrel compared to $8.52 per barrel for the three months ended December 31, 2015. The decrease in net operating costs is attributable to a per barrel decrease in non-energy operating costs and an increase in power revenue, partially offset by an increase in energy operating costs.

Non-energy operating costs

Non-energy operating costs averaged $4.99 per barrel for the three months ended December 31, 2016 compared to $5.66 per barrel for the three months ended December 31, 2015. 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 lower materials and services costs.

Energy operating costs

Energy operating costs averaged $4.12 per barrel for the three months ended December 31, 2016 compared to $3.58 per barrel for the three months ended December 31, 2015. 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 $3.45 per mcf during the fourth quarter of 2016 compared to $2.94 per mcf for the fourth quarter of 2015. The increase in natural gas prices is primarily due to increased demand, a levelling off of production of natural gas in North America and colder weather.

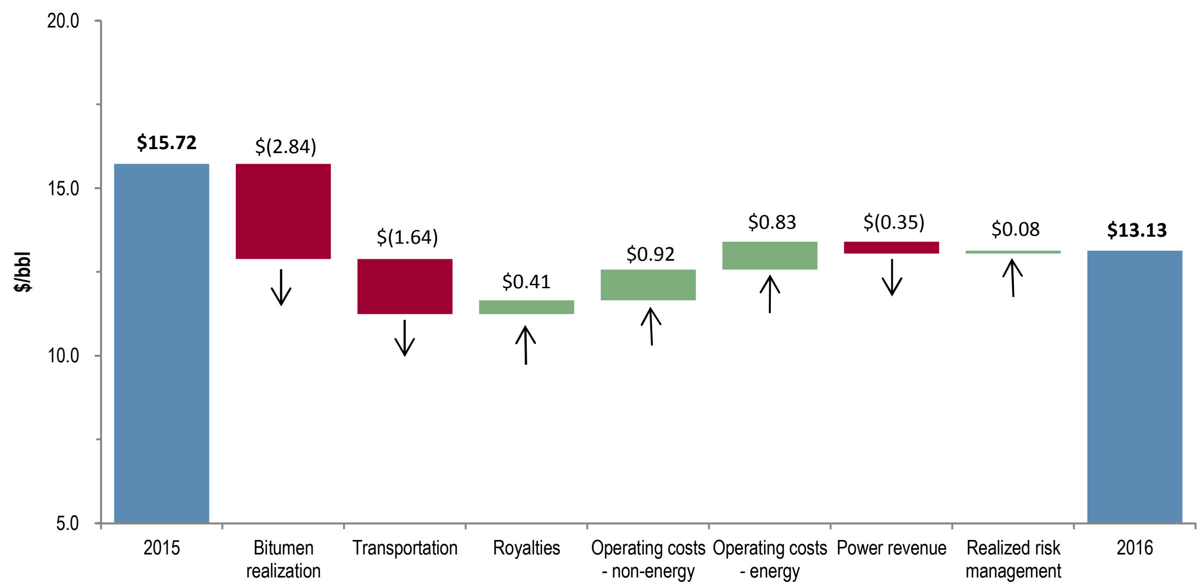
Power revenue

Power revenue averaged $0.87 per barrel for the three months ended December 31, 2016 compared to $0.72 per barrel for the three months ended December 31, 2015. The Corporation's average realized power sales price during the three months ended December 31, 2016 was $21.94 per megawatt hour compared to $19.67 per megawatt hour for the same period in 2015. The increase in the realized power sales price is primarily due to increased demand as a result of several coal plant outages in October and colder weather.

Commodity Risk Management Gain

The realized gain on commodity risk management averaged $0.36 per barrel for the three months ended December 31, 2016. The Corporation initiated a commodity risk management program in 2016. Refer to the "RISK MANAGEMENT" section of this Fourth Quarter Report for further details.

Cash Operating Netback – Year Ended December 31



Bitumen Realization

Bitumen realization averaged $27.79 per barrel for the year ended December 31, 2016 compared to $30.63 per barrel for the year ended December 31, 2015. The decrease in bitumen realization is primarily a result of the year-over-year average decline in U.S. crude oil benchmark pricing which resulted in lower blend sales revenue.

For the year ended December 31, 2016, the Corporation's cost of diluent was $61.06 per barrel of diluent compared to $67.72 per barrel of diluent for the year ended December 31, 2015. The decrease in the cost of diluent is primarily a result of the year-over-year average decline in condensate benchmark pricing.

Transportation

Transportation costs averaged $6.46 per barrel for the year ended December 31, 2016 compared to $4.82 per barrel for the year ended December 31, 2015. Transportation expense increased primarily due to the cost of transporting higher blend volumes from Edmonton to the U.S. Gulf Coast via the Flanagan South and Seaway pipeline systems.

Royalties

Royalties averaged $0.29 per barrel during the year ended December 31, 2016 compared to $0.70 per barrel for the year ended December 31, 2015. The decrease in royalties is primarily attributable to lower royalty rates as a result of lower realized prices.

Net Operating Costs

Net operating costs for the year ended December 31, 2016 averaged $7.99 per barrel compared to $9.39 per barrel for the year ended December 31, 2015. The decrease in net operating costs is attributable to a per barrel decrease in energy and non-energy operating costs and power revenue.

Non-energy operating costs

Non-energy operating costs averaged $5.62 per barrel for the year ended December 31, 2016 compared to $6.54 per barrel for the year ended December 31, 2015. 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.

Energy operating costs

Energy operating costs averaged $3.01 per barrel for the year ended December 31, 2016 compared to $3.84 per barrel for the year ended December 31, 2015. The decrease in energy operating costs on a per barrel basis is primarily attributable to the decrease in natural gas prices. The Corporation’s natural gas purchase price averaged $2.53 per mcf during the year ended December 31, 2016 compared to $3.11 per mcf for the same period in 2015.

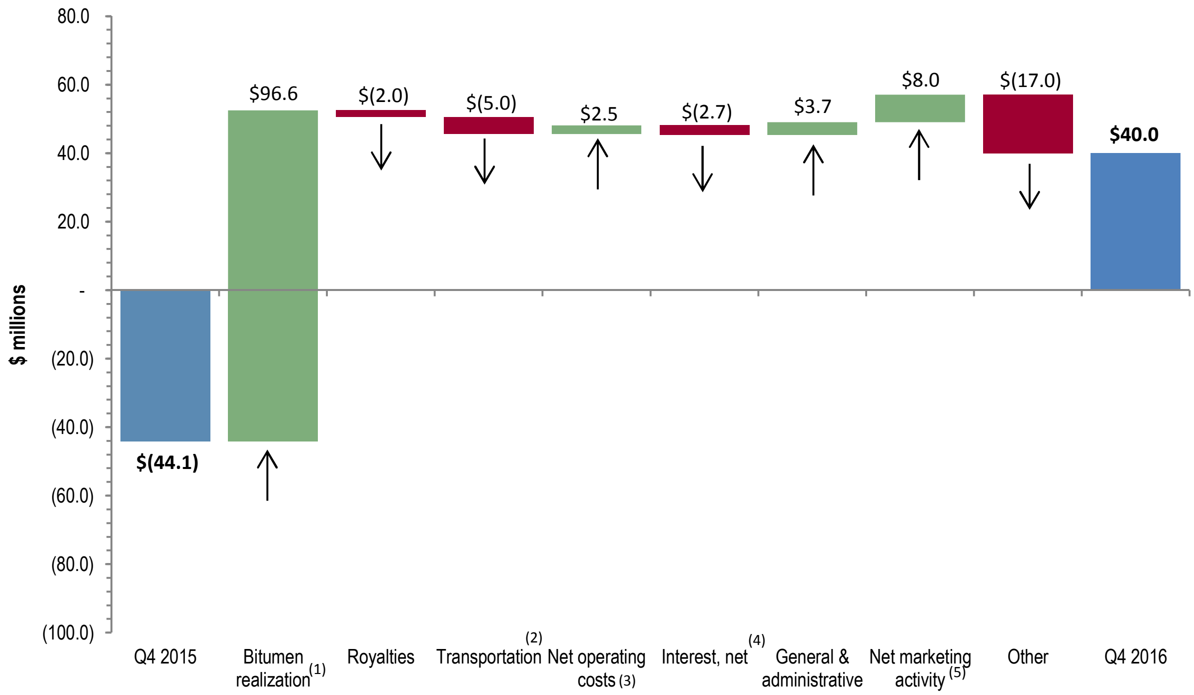
Power revenue

Power revenue averaged $0.64 per barrel for the year ended December 31, 2016 compared to $0.99 per barrel for the year ended December 31, 2015. The Corporation’s average realized power sales price during the year ended December 31, 2016 was $18.74 per megawatt hour compared to $27.48 per megawatt hour for the same period in 2015. The decrease in the realized power sales price is primarily due to the overall surplus of power generation capacity in the province of Alberta.

Commodity Risk Management Gain

The realized gain on commodity risk management averaged $0.08 per barrel for the year ended December 31, 2016. Refer to the “RISK MANAGEMENT” section of this Fourth Quarter Report for further details.

Adjusted Funds Flow – Three Months Ended December 31



(1) *Net of diluent expense.*

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

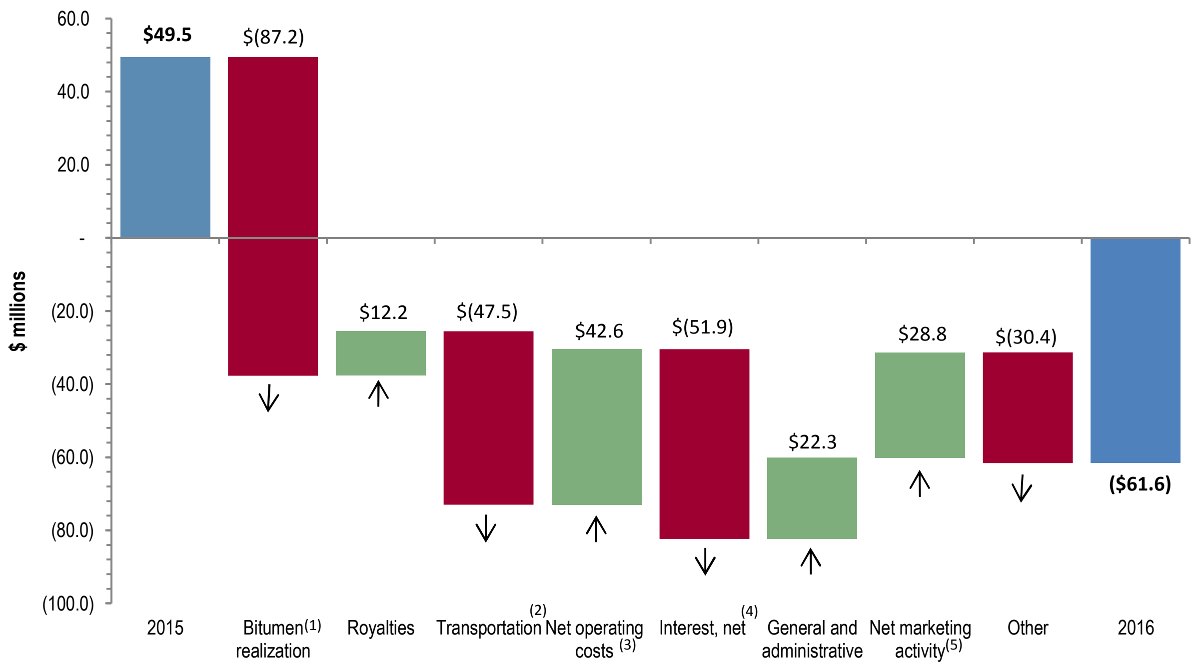
(3) *Includes non-energy and energy operating costs, reduced by power revenue.*

(4) *Defined as net interest expense in Note 16 of the Interim Consolidated Financial Statements less amortization of debt issue costs as presented on the Consolidated Statement of Cash Flow.*

(5) *A non-GAAP measure defined in the "NON-GAAP MEASURES" section of this Fourth Quarter Report.*

Adjusted funds flow was $40.0 million for the three months ended December 31, 2016 compared to adjusted funds flow of $(44.1) million for the three months ended December 31, 2015. Adjusted funds flow increased primarily due to higher bitumen realization. The increase in bitumen realization is directly correlated to the increase in U.S. crude oil benchmark pricing during the fourth quarter of 2016, which resulted in higher blend sales revenue.

Adjusted Funds Flow – Year Ended December 31



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(5) *A non-GAAP measure defined in the "NON-GAAP MEASURES" section of this Fourth Quarter Report.*

Adjusted funds flow was $(61.6) million for the year ended December 31, 2016 compared to adjusted funds flow of $49.5 million for the year ended December 31, 2015. The decrease in adjusted funds flow was due to a decrease in bitumen realization and increases in net interest expense, transportation and other. These cash flow reductions were partially offset by decreases in net operating costs, net marketing activity, general and administrative expense and royalties. Adjusted funds flow decreased primarily due to lower bitumen realization. The decrease in bitumen realization is directly correlated to the year-over-year average decline in U.S. crude oil benchmark pricing. The increase in net interest expense is primarily due to the Corporation no longer capitalizing interest in 2016 as a result of the reduction in the Corporation's 2016 capital expenditures. During the fourth quarter of 2015, there was a termination of a marketing transportation contract that impacted net marketing activity. No expenses were incurred related to marketing and storage arrangements for the year ended December 31, 2016.

Operating Loss

Operating loss is a non-GAAP measure, as defined in the "NON-GAAP MEASURES" section of this Fourth Quarter Report, 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 $72.0 million for the three months ended December 31, 2016 compared to an operating loss of $140.2 million for the three months ended December 31, 2015. The decrease in the operating loss for the three months ended December 31, 2016 was primarily due to higher bitumen realization as a result of the increase in U.S. crude oil benchmark pricing during the fourth quarter of 2016. The Corporation recognized an operating loss of $455.1 million for the year ended December 31, 2016 compared to an operating loss of $374.4 million for the year ended December 31, 2015. The increase in the operating loss for the year ended December 31, 2016 was primarily due to lower bitumen realization as a result of the year-over-year average decline in U.S. crude oil benchmark pricing.

Revenue

Revenue represents the total of petroleum revenue, net of royalties and other revenue. Revenue for the three months ended December 31, 2016 totalled $565.8 million compared to $444.5 million for the three months ended December 31, 2015. Revenue for the three months ended December 31, 2016 increased primarily due to an increase in blend sales revenue as a result of the increase in U.S. crude oil benchmark pricing during the fourth quarter of 2016. Revenue for the year ended December 31, 2016 totalled $1.87 billion compared to $1.93 billion for the year ended December 31, 2015. Revenue for the year ended December 31, 2016 decreased primarily due to a decrease in blend sales revenue as a result of the year-over-year average decline in U.S. crude oil benchmark pricing.

Net Loss

The Corporation recognized a net loss of $304.8 million for the three months ended December 31, 2016 compared to a net loss of $297.3 million for the three months ended December 31, 2015. The net loss for the three months ended December 31, 2016 included a net unrealized foreign exchange loss of $119.6 million on the Corporation's U.S. dollar denominated debt and U.S. dollar denominated cash and cash equivalents, an $80.1 million impairment charge related to the Northern Gateway pipeline, an unrealized loss on commodity risk management of $42.0 million and other expenses primarily related to onerous contracts and severance totalling $26.4 million. The net loss for the three months ended December 31, 2015 included a net unrealized foreign exchange loss of $159.0 million on U.S. dollar denominated debt and U.S. dollar denominated cash and cash equivalents and other expenses related to onerous contracts and contract cancellation expense totalling $77.5 million, partially offset by a gain of $68.2 million related to a sale of a non-core undeveloped oil sands asset.

The Corporation recognized a net loss of $428.7 million for the year ended December 31, 2016 compared to a net loss of $1.2 billion for the year ended December 31, 2015. The net loss for the year ended December 31, 2016 was affected by lower bitumen realization, primarily as a result of the year-over-year average decline in U.S. crude oil benchmark pricing. The net loss for the year ended December 31, 2016 also included an $80.1 million impairment charge related to the Northern Gateway pipeline, an unrealized loss on commodity risk management of $30.3 million and other expenses primarily related to onerous contracts and severance totalling $64.1 million. These were partially offset by a net unrealized foreign exchange gain of $148.2 million on the Corporation's U.S. dollar denominated debt and U.S. dollar denominated cash and cash equivalents. The net loss for the year ended December 31, 2015 included a net unrealized foreign exchange loss of $785.3 million on U.S. dollar denominated debt and U.S. dollar denominated cash and cash equivalents.

Total Cash Capital Investment

Total cash capital investment during the three months ended December 31, 2016 totalled $63.1 million, as compared to $54.5 million for the three months ended December 31, 2015. Total cash capital investment during the year ended December 31, 2016 totalled $137.2 million as compared to $257.2 million for the year ended December 31, 2015. Capital investment in 2016 was primarily directed towards sustaining capital activities as the Corporation had been focused on reducing capital spending until there is a sustained improvement in crude oil pricing.

Capital Resources

The Corporation's cash and cash equivalents balance totalled $156.2 million as at December 31, 2016 compared to $408.2 million as at December 31, 2015. The Corporation's cash and cash equivalents balance decreased primarily due to the use of cash for interest and principal payments and payments relating to capital investing activity.

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 decreased to C$5.1 billion as at December 31, 2016 from C$5.2 billion as at December 31, 2015.

On December 1, 2016, the Corporation filed a Canadian base shelf prospectus for common shares, debt securities, subscription receipts, warrants and units (together referred to as "Securities") in the amount of $1.5 billion. The Canadian base shelf prospectus allows for the issuance of these Securities in Canadian dollars or other currencies from time to time in one or more offerings. As at December 31, 2016, no Securities were issued under the Canadian base shelf prospectus. The Canadian base shelf prospectus expires on January 1, 2019.

On January 27, 2017, the Corporation completed 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 existing 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. It has no financial covenants and is not subject to any borrowing base redetermination;
- The US$1.2 billion term loan has been refinanced to extend its maturity date from March 2020 to December 2023. The refinanced term loan will bear interest at an annual rate of LIBOR plus 3.5% with a LIBOR floor of 1%. The term loan was issued at a price equal to 99.75% of its face value;
- The existing 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% second lien secured notes, issued at par, maturing January 2025. The existing 2021 notes will be redeemed with the proceeds from the 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 subscription receipts at a price C$7.75 per subscription receipt on a bought deal basis from a syndicate of underwriters. As part of the closing, escrow release conditions for the subscription receipt offering have been satisfied and the subscription receipts have been converted into common shares.

All of MEG's long-term debt, 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 December 2023.

OUTLOOK

Summary of 2016 Guidance	**Guidance October 27, 2016**	**Annual Results**
Cash capital investment - $ millions	$140	**$137**
Bitumen production - bbls/d	80,000 – 83,000	**81,245**
Non-energy operating costs - $/bbl	$5.75 - $6.50	**$5.62**

Cash capital investment incurred for 2016 was $137 million which was below the Corporation's most recent 2016 cash capital investment guidance of $140 million issued on October 27, 2016. Original capital guidance was issued December 4, 2015 for $328 million and reduced throughout 2016 as a result of continued focus on reducing capital spending until there was a sustained improvement in crude oil pricing.

Annual bitumen production averaged 81,245 bbls/d, consistent with the Corporation's 2016 bitumen production guidance.

As a result of continued operating cost management and efficiency gains in 2016, annual non-energy operating costs were $5.62/bbl, representing a 2% reduction from the low end of the most recent 2016 guidance issued on October 27, 2016. Original guidance issued on December 4, 2015 had non-energy operating costs targeted to be in the range of $6.75 to $7.75 per barrel.

Summary of 2017 Guidance	
Cash capital investment - $ millions	$590
Bitumen production - bbls/d	80,000 – 82,000
Bitumen exit production – bbls/d	86,000 – 89,000
Non-energy operating costs - $/bbl	$5.75 – $6.75

On January 11, 2017, the Corporation announced a 2017 capital budget of $590 million of which approximately 55% is directed towards initiation of the eMSAGP growth project 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 2017 capital program with net proceeds from the $518 million equity issuance completed on January 27, 2017, internally generated cash flow and $156 million of cash on hand as at December 31, 2016.

The Corporation's 2017 annual bitumen production volumes are targeted to be in the range of 80,000 to 82,000 bbls/d. Exit production for 2017 is targeted to be in the range of 86,000 to 89,000 bbls/d. Non-energy operating costs are targeted to be in the range of $5.75 to $6.75 per barrel.

The Corporation continues to review options available to utilize its interest in the Access Pipeline to reduce the financial leverage of the Corporation. The potential monetization of MEG's 50% interest in the Access Pipeline continues to be a priority of the Corporation.

BUSINESS ENVIRONMENT

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

	Year ended December 31		2016				2015			
	2016	2015	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Average Commodity Prices										
Crude oil prices										
Brent (US$/bbl)	**44.97**	53.62	**51.13**	46.98	46.67	35.10	44.71	51.17	63.50	55.16
WTI (US$/bbl)	**43.33**	48.80	**49.29**	44.94	45.59	33.45	42.18	46.43	57.94	48.63
WTI (C$/bbl)	**57.44**	62.40	**65.75**	58.65	58.75	45.99	56.32	60.79	71.24	60.35
Differential – Brent:WTI (US$/bbl)	**1.64**	4.82	**1.84**	2.04	1.08	1.65	2.53	4.74	5.56	6.53
Differential – Brent:WTI (%)[1]	**3.6%**	9.0%	**3.6%**	4.3%	2.3%	4.7%	5.7%	9.3%	8.8%	11.8%
WCS (C$/bbl)	**39.09**	45.12	**46.65**	41.03	41.61	26.41	36.97	43.29	56.98	42.13
Differential – WTI:WCS (US$/bbl)	**13.84**	13.52	**14.32**	13.50	13.30	14.24	14.49	13.27	11.59	14.73
Differential – WTI:WCS (C$/bbl)	**18.35**	17.29	**19.10**	17.62	17.14	19.58	19.35	17.50	14.25	18.22
Differential – WTI:WCS (%)	**31.9%**	27.7%	**29.1%**	30.0%	29.2%	42.6%	34.4%	28.8%	20.0%	30.2%
Condensate prices										
Condensate at Edmonton (C$/bbl)	**56.21**	60.30	**64.49**	56.25	56.83	47.27	55.57	57.89	71.17	56.59
Condensate at Edmonton as % of WTI	**97.9%**	96.6%	**98.1%**	95.9%	96.7%	102.8%	98.7%	95.2%	99.9%	93.8%
Condensate at Mont Belvieu, Texas (US$/bbl)	**39.68**	45.23	**45.17**	41.17	40.37	32.03	40.76	41.27	52.89	46.01
Condensate at Mont Belvieu, Texas as % of WTI	**91.6%**	92.7%	**91.6%**	91.6%	88.6%	95.8%	96.6%	88.9%	91.3%	94.6%
Natural gas prices										
AECO (C$/mcf)	**2.25**	2.71	**3.31**	2.49	1.37	1.82	2.57	2.89	2.64	2.74
Electric power prices										
Alberta power pool (C$/MWh)	**18.19**	33.40	**21.97**	17.93	14.77	18.09	21.19	26.04	57.25	29.14
Foreign exchange rates										
C$ equivalent of 1 US$ - average	**1.3256**	1.2788	**1.3339**	1.3051	1.2886	1.3748	1.3353	1.3093	1.2294	1.2411
C$ equivalent of 1 US$ - period end	**1.3427**	1.3840	**1.3427**	1.3117	1.3009	1.2971	1.3840	1.3394	1.2474	1.2683

Crude Oil Pricing

Brent crude is the primary world price benchmark for global light sweet crude oil. The Brent benchmark price averaged US$51.13 per barrel in the fourth quarter of 2016 compared to US$44.71 per barrel for the fourth quarter of 2015. The Brent benchmark price averaged US$44.97 per barrel for the year ended December 31, 2016 compared to US$53.62 per barrel for the year ended December 31, 2015. Recent announcements arising out of a meeting between OPEC ("Organization of the Petroleum Exporting Countries") and non-OPEC counterparties, held the latter part of the fourth quarter of 2016, resulted in a slight increase in late fourth quarter prices.

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$49.29 per barrel in the fourth quarter of 2016 compared to US$42.18 per barrel for the fourth quarter of 2015. The WTI price averaged US$43.33 per barrel for the year ended December 31, 2016 compared to US$48.80 per barrel for the year ended December 31, 2015. Recent announcements arising out of a meeting between OPEC and non-OPEC counterparties, held the latter part of the fourth quarter of 2016, resulted in a slight increase in late fourth quarter prices.

The WCS benchmark reflects North American prices at Hardisty, Alberta. WCS is a blend of heavy oils, consisting of heavy conventional crude oils and bitumen, blended with sweet synthetic, light crude oil or condensate. WCS typically trades at a differential below the WTI benchmark price. The WTI:WCS differential averaged US$14.32 per barrel, or 29.1%, for the fourth quarter of 2016, compared to US$14.49 per barrel, or 34.4%, for the fourth quarter of 2015. The WTI:WCS differential averaged US$13.84 per barrel, or 31.9%, for the year ended December 31, 2016 compared to US$13.52 per barrel, or 27.7%, for the year ended December 31, 2015.

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 $64.49 per barrel, or 98.1% of WTI, for the fourth quarter of 2016 compared to $55.57 per barrel, or 98.7% of WTI, for the fourth quarter of 2015. Condensate prices, benchmarked at Edmonton, averaged $56.21 per barrel, or 97.9% of WTI, for the year ended December 31, 2016 compared to $60.30 per barrel, or 96.6% of WTI, for the year ended December 31, 2015.

Condensate prices, benchmarked at Mont Belvieu, Texas, averaged US$45.17 per barrel, or 91.6% of WTI, for the fourth quarter of 2016 compared to US$40.76 per barrel, or 96.6% of WTI, for the fourth quarter of 2015. Condensate prices, benchmarked at Mont Belvieu, Texas, averaged US$39.68 per barrel, or 91.6% of WTI, for the year ended December 31, 2016 compared to US$45.23 per barrel, or 92.7% of WTI, for the year ended December 31, 2015.

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 $3.31 per mcf for the fourth quarter of 2016 compared to $2.57 per mcf for the fourth quarter of 2015. The AECO natural gas price averaged $2.25 per mcf for the year ended December 31, 2016 compared to $2.71 per mcf for the year ended December 31, 2015. Natural gas market prices have increased during the fourth quarter of 2016 due to increased demand combined with a levelling off of production of natural gas in North America and colder weather.

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 $21.97 per megawatt hour for the fourth quarter of 2016 compared to $21.19 per megawatt hour for the fourth quarter of 2015. Average power prices for the fourth quarter of 2016 were positively affected by several coal plant outages in October and colder weather. The Alberta power pool price averaged $18.19 per megawatt hour for the year ended December 31, 2016 compared to $33.40 per megawatt hour for the same period in 2015. The decline in the Alberta power pool price is 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. 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 December 31, 2016, the Canadian dollar, at a rate of 1.3427, had increased in value by approximately 3% against the U.S. dollar compared to its value as at December 31, 2015, when the rate was 1.3840.

OTHER OPERATING RESULTS

Net Marketing Activity

	Three months ended December 31		Year ended December 31	
($000)	**2016**	**2015**	**2016**	**2015**
Petroleum revenue – third party	**$ 50,952**	$ 50,361	**$ 205,790**	$ 104,464
Purchased product and storage:				
Purchased product	**(50,497)**	(50,339)	**(202,135)**	101,928)
Marketing and storage arrangements	**-**	(7,580)	**-**	(27,687)
	(50,497)	(57,919)	**(202,135)**	(129,615)
Net marketing activity(1)	**$ 455**	$ (7,558)	**$ 3,655**	$ (25,151)

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

Net marketing activity includes the Corporation's activities toward enhancing its ability to transport proprietary crude oil products to a wider range of markets in Canada, the United States and on tidewater. Accordingly, the Corporation has entered into marketing arrangements for rail, pipelines, transportation commitments and product storage arrangements. The intent of these arrangements is to maximize the value of all barrels sold into the marketplace. In the event that the Corporation is not utilizing these arrangements for proprietary purposes, MEG 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.

During the fourth quarter of 2015, the Corporation recognized a contract cancellation expense of $18.8 million primarily due to the termination of a marketing transportation contract. No expenses were incurred related to marketing and storage arrangements for the three months and year ended December 31, 2016.

Depletion and Depreciation

	Three months ended December 31		Year ended December 31	
($000)	**2016**	**2015**	**2016**	**2015**
Depletion and depreciation expense	**$ 126,471**	$ 127,153	**$ 499,811**	$ 467,422
Depletion and depreciation expense per barrel of production	**$ 16.81**	$ 16.55	**$ 16.81**	$ 16.00

Depletion and depreciation expense for the three months ended December 31, 2016 totalled $126.5 million compared to $127.2 million for the three months ended December 31, 2015. Depletion and depreciation expense was $16.81 per barrel for the three months ended December 31, 2016 compared to $16.55 per barrel for the three months ended December 31, 2015. The increase in the depletion and depreciation expense per barrel was primarily due to an increase in depreciable costs.

Depletion and depreciation expense for the year ended December 31, 2016 totalled $499.8 million compared to $467.4 million for the year ended December 31, 2015. Depletion and depreciation expense was $16.81 per barrel for the year ended December 31, 2016 compared to $16.00 per barrel for the year ended December 31, 2015. The increase in the depletion and depreciation expense per barrel was primarily due to an increase in the estimated future development costs associated with the Corporation's proved reserves and an increase in depreciable costs for the year ended December 31, 2016 compared to the year ended December 31, 2015.

Impairment

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 6, 2016 directive from the Government of Canada to the National Energy Board ("NEB") to dismiss the project application. On June 18, 2014, Northern Gateway received certificates from the NEB permitting the construction of the oil pipeline subject to conditions. On June 30, 2016, the Federal Court of Appeal ("FCA") quashed these certificates on the basis that the Crown's Phase IV Aboriginal consultation process was inadequate. The FCA held that the hearing leading to the approved permits and the consultation conducted by Northern Gateway was properly done. On November 29, 2016, the Federal Government, rather than conducting further consultation with Aboriginal communities, announced that it would instruct the NEB to dismiss the application and on December 6, 2016, the NEB formalized this dismissal. As a result, the Corporation fully impaired its investment and has recognized an impairment charge of $80.1 million.

Commodity Risk Management Gain (Loss)

During the three months and year ended December 31, 2016, the Corporation entered into commodity risk management contracts. The Corporation has not designated any of its commodity risk management contracts as hedges for accounting purposes. All 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 commodity risk management contracts are the result of contract settlements during the period. 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.

	Three months ended December 31			Year ended December 31		
	2016			2016		
($000)	Realized	Unrealized	Total	Realized	Unrealized	Total
Crude oil contracts[1]	$ (4,071)	$ (40,293)	$ (44,364)	$ (9,888)	$ (59,404)	$ (69,292)
Condensate contracts[2]	6,789	(1,756)	5,033	12,247	29,091	41,338
Commodity risk management gain (loss)	$ 2,718	$ (42,049)	$ (39,331)	$ 2,359	$ (30,313)	$ (27,954)

(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 loss on commodity risk management contracts of $42.0 million and a realized gain on commodity risk management contracts of $2.7 million for the three months ended December 31, 2016.

The Corporation recognized an unrealized loss on commodity risk management contracts of $30.3 million and a realized gain on commodity risk management contracts of $2.4 million for the year ended December 31, 2016. Refer to the “RISK MANAGEMENT” section of this Fourth Quarter Report for further details.

During 2015, the Corporation did not enter into any commodity risk management contracts.

General and Administrative

	Three months ended December 31		Year ended December 31	
($000)	2016	2015	2016	2015
General and administrative expense	$ 21,570	$ 25,281	$ 96,241	$ 118,518
General and administrative expense per barrel of production	$ 2.87	$ 3.29	$ 3.24	$ 4.06

General and administrative expense for the three months ended December 31, 2016 was $21.6 million compared to $25.3 million for the three months ended December 31, 2015. General and administrative expense was $2.87 per barrel for the three months ended December 31, 2016 compared to $3.29 per barrel for the three months ended December 31, 2015. General and administrative expense for the year ended December 31, 2016 was $96.2 million compared to $118.5 million for the year ended December 31, 2015. General and administrative expense was $3.24 per barrel for the year ended December 31, 2016 compared to $4.06 per barrel for the year ended December 31, 2015. General and administrative expense decreased primarily due to a reduction in staffing and the Corporation’s continued focus on cost management in all areas of the business.

Stock-based Compensation

	Three months ended December 31		Year ended December 31	
($000)	**2016**	**2015**	**2016**	**2015**
Cash-settled	**$ 10,859**	$ -	**$ 16,354**	$ -
Equity-settled	**5,650**	12,039	**33,588**	50,105
Stock-based compensation expense	**$ 16,509**	$ 12,039	**$ 49,942**	$ 50,105

The fair value of compensation associated with the granting of stock options, restricted share units ("RSUs"), performance share units ("PSUs") and directors 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.

In June 2016, the Corporation granted RSUs and PSUs under a new 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 estimated vesting and 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 December 31, 2016 was $16.5 million compared to $12.0 million for the three months ended December 31, 2015. Stock-based compensation expense for the year ended December 31, 2016 was $49.9 million compared to $50.1 million for the year ended December 31, 2015.

Research and Development

	Three months ended December 31		Year ended December 31	
($000)	**2016**	**2015**	**2016**	**2015**
Research and development expense	**$ 1,139**	$ 2,467	**$ 5,499**	$ 7,497

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 $1.1 million for the three months ended December 31, 2016 compared to $2.5 million for the three months ended December 31, 2015. Research and development expenditures were $5.5 million for the year ended December 31, 2016 compared to $7.5 million for the year ended December 31, 2015.

Foreign Exchange Loss (Gain), Net

	Three months ended December 31		Year ended December 31	
($000)	2016	2015	2016	2015
Unrealized foreign exchange loss (gain) on:				
Long-term debt	**$ 117,451**	$ 169,572	**$ (157,272)**	$ 852,422
Other	**2,159**	(10,563)	**9,119**	(67,112)
Unrealized net loss (gain) on foreign exchange	**119,610**	159,009	**(148,153)**	785,310
Realized loss (gain) on foreign exchange	**611**	3,348	**(3,242)**	16,429
Foreign exchange loss (gain), net	**$ 120,221**	$ 162,357	**$ (151,395)**	$ 801,739
C$ equivalent of 1 US$				
Beginning of period	**1.3117**	1.3394	**1.3840**	1.1601
End of period	**1.3427**	1.3840	**1.3427**	1.3840

The Corporation recognized a net foreign exchange loss of $120.2 million for the three months ended December 31, 2016 compared to a net foreign exchange loss of $162.4 million for the three months ended December 31, 2015. The net foreign exchange loss is primarily due to the translation of the U.S. dollar denominated debt as the Canadian dollar weakened compared to the U.S. dollar by approximately 2% during the three months ended December 31, 2016. During the three months ended December 31, 2015, the Canadian dollar weakened in value by approximately 3%.

The Corporation recognized a net foreign exchange gain of $151.4 million for the year ended December 31, 2016 compared to a net foreign exchange loss of $801.7 million for the year ended December 31, 2015. The net foreign exchange gain is primarily due to the translation of the U.S. dollar denominated debt as a result of strengthening of the Canadian dollar compared to the U.S. dollar by approximately 3% during the year ended December 31, 2016. During the year ended December 31, 2015, the Canadian dollar weakened in value by approximately 19%.

Net Finance Expense

	Three months ended December 31		Year ended December 31	
($000)	2016	2015	2016	2015
Total interest expense	$ 82,469	$ 81,888	$ 328,335	$ 313,411
Less capitalized interest	-	(5,970)	-	(56,449)
Net interest expense	82,469	75,918	328,335	256,962
Debt extinguishment expense	28,845	-	28,845	-
Accretion on provisions	1,840	1,616	7,150	5,663
Unrealized gain on derivative financial liabilities(1)	(7,146)	(15,890)	(12,508)	(13,289)
Realized loss on interest rate swaps	-	1,541	4,548	5,858
Net finance expense	$ 106,008	$ 63,185	$ 356,370	$ 255,194
Average effective interest rate(2)	5.7%	5.8%	5.8%	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 and senior unsecured notes outstanding, including the impact of interest rate swaps.*

Total interest expense, before capitalization, for the three months ended December 31, 2016 was $82.5 million compared to $81.9 million for the three months ended December 31, 2015. Total interest expense, before capitalization, for the year ended December 31, 2016 was $328.3 million compared to $313.4 million for the year ended December 31, 2015. Total interest expense for the year ended December 31, 2016 was higher than the comparative 2015 period due to a weaker average Canadian dollar and its impact on U.S. dollar denominated interest expense.

The Corporation capitalizes interest associated with qualifying assets. As a result of the reduction in the Corporation's 2016 capital expenditures, the Corporation did not capitalize interest during the three months and year ended December 31, 2016. During the three months and year ended December 31, 2015, the Corporation capitalized $6.0 million and $56.5 million of interest, respectively.

At December 31, 2016, the Corporation recognized $28.8 million of debt extinguishment expense associated with the planned redemption of the 6.5% Senior Unsecured Notes on March 15, 2017, under the comprehensive refinancing plan completed on January 27, 2017, as described in the "Capital Resources" section of this Fourth Quarter Report. The debt extinguishment expense is comprised of a redemption premium of $21.8 million and the associated remaining unamortized deferred debt issue costs of $7.0 million.

Unrealized gain on derivative liabilities includes unrealized gains related to the change in fair value of the interest rate floor associated with the Corporation's senior secured term loan and the change in fair value of the Corporation's interest rate swap contracts. The Corporation recognized an unrealized gain on derivative financial liabilities of $7.2 million for the three months ended December 31, 2016 compared to an unrealized gain of $15.9 million for the three months ended December 31, 2015. The Corporation recognized an unrealized gain on derivative financial liabilities of $12.5 million for the year ended December 31, 2016 compared to an unrealized gain of $13.3 million for the year ended December 31, 2015.

The Corporation’s interest rate swap contracts expired on September 30, 2016. During the three months ended December 31, 2015, the Corporation had a realized loss of $1.5 million on interest rate swaps. The Corporation realized a loss on the interest rate swaps of $4.5 million for the year ended December 31, 2016 compared to a realized loss of $5.9 million for the year ended December 31, 2015.

Other Expenses

	Three months ended December 31		Year ended December 31	
($000)	**2016**	**2015**	**2016**	**2015**
Onerous contracts	**$ 16,383**	$ 58,719	**$ 47,866**	$ 58,719
Severance and other	**10,063**	-	**16,242**	-
Contract cancellation expense	**-**	18,759	**-**	12,879
Other expenses	**$ 26,446**	$ 77,478	**$ 64,108**	$ 71,598

The Corporation recognized other expenses of $26.5 million for the three months ended December 31, 2016 compared to $77.5 million for the three months ended December 31, 2015. The Corporation recognized other expenses of $64.1 million for the year ended December 31, 2016 compared to $71.6 million for the year ended December 31, 2015.

For the three months ended December 31, 2016, an onerous contracts expense of $16.4 million was recognized primarily due to a decrease in estimated future cash flow recoveries related to the onerous office lease provision. For the year ended December 31, 2016, the Corporation recognized an onerous contracts expense of $47.9 million primarily due to a decrease in estimated future cash flow recoveries related to the onerous office lease provision. During the fourth quarter of 2015, the Corporation recognized $58.7 million relating to certain onerous Calgary office building lease contracts, determined as the difference between future lease obligations and estimated sublease recoveries.

During the three months ended December 31, 2016, severance and other expenses of $10.1 million were incurred. During the year ended December 31, 2016, severance and other expenses of $16.2 million were incurred.

For the three months and the year ended December 31, 2015, the Corporation recognized contract cancellation expense of $18.8 million and $12.9 million, respectively, primarily relating to the termination of a marketing transportation contract, partially offset by a recovery of project cancellation costs recorded in the second quarter of 2015.

Income Tax Recovery

	Three months ended December 31		Year ended December 31	
($000)	2016	2015	2016	2015
Current income tax expense (recovery)	$ 202	$ -	$ 919	$ (1,200)
Deferred income tax recovery	(67,620)	(42,935)	(208,413)	(90,733)
Income tax recovery	$ (67,418)	$ (42,935)	$ (207,494)	$ (91,933)

The Corporation recognized a current income tax expense of $0.2 million for the three months ended December 31, 2016. During the three months ended December 31, 2015, the Corporation did not recognize a current income tax expense (recovery). The Corporation recognized a current income tax expense of $0.9 million for the year ended December 31, 2016 relating to U.S. income tax associated with its operations in the United States. The Corporation's Canadian operations are not currently taxable. During the year ended December 31, 2015, the Corporation recognized a current income tax recovery of $1.2 million which was related to the refundable Alberta tax credit on Scientific Research and Experimental Development expenditures.

The Corporation recognized a deferred income tax recovery of $67.6 million for the three months ended December 31, 2016 compared to a deferred income tax recovery of $42.9 million for the three months ended December 31, 2015. The Corporation recognized a deferred income tax recovery of $208.4 million for the year ended December 31, 2016 compared to a deferred income tax recovery of $90.7 million for the year ended December 31, 2015.

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 unrealized foreign exchange gains and losses arising on the translation of the U.S. dollar denominated debt. For the three months ended December 31, 2016, the non-taxable loss was $58.7 million compared to a non-taxable loss of $84.8 million for the three months ended December 31, 2015. For the year ended December 31, 2016, the non-taxable gain was $78.6 million compared to a non-taxable loss of $426.2 million for the year ended December 31, 2015.

- 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 December 31, 2016 was $5.7 million compared to $12.0 million for the three months ended December 31, 2015. Stock-based compensation expense for equity-settled plans for the year ended December 31, 2016 was $33.6 million compared to $50.1 million for the year ended December 31, 2015.

- During the year ended December 31, 2016, a deferred tax recovery of $2.1 million was recognized relating to a tax deduction available for the fair market value of vested RSUs. During the year ended December 31, 2015, a deferred tax recovery of $5.5 million was recognized relating to a tax deduction available for the fair market value of vested RSUs.

As at December 31, 2016, the Corporation had approximately $8.0 billion of available tax pools and $219.6 million of capital investment in respect of incomplete projects which will increase available tax pools upon completion of the projects.

As at December 31, 2016, the Corporation has recognized a deferred income tax asset of $120.9 million, as estimated future taxable income is expected to be sufficient to realize the deferred income tax asset.

As at December 31, 2016, the Corporation had not recognized the tax benefit related to $617.5 million of unrealized taxable capital foreign exchange losses.

NET CAPITAL INVESTMENT

	Three months ended December 31		Year ended December 31	
($000)	**2016**	**2015**	**2016**	**2015**
Total cash capital investment	**$ 63,077**	$ 54,473	**$ 137,245**	$ 257,178
Capitalized cash-settled stock-based compensation	**1,772**	-	**2,491**	-
Capitalized interest	**-**	5,970	**-**	56,449
	64,849	60,443	**139,736**	$ 313,627
Dispositions	**-**	(41,827)	**-**	(41,827)
Net capital investment	**$ 64,849**	$ 18,616	**$ 139,736**	$ 271,800

Total cash capital investment for the three months ended December 31, 2016 was $63.1 million, compared to $54.5 million for the three months ended December 31, 2015. Total cash capital investment for the year ended December 31, 2016 was $137.2 million, compared to $257.2 million for the year ended December 31, 2015. Total capital investment in 2016 was primarily directed towards sustaining capital activities, as the Corporation has been focused on reducing capital spending until there is a sustained improvement in crude oil pricing.

During 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. During the three months and year ended December 31, 2016, the Corporation capitalized $1.8 million and $2.5 million of cash-settled stock-based compensation, respectively.

The Corporation capitalizes interest associated with qualifying assets. As a result of the reduction in the Corporation's 2016 capital expenditures, the Corporation did not capitalize interest during the three months and year ended December 31, 2016. During the three months and year ended December 31, 2015, the Corporation capitalized $6.0 million and $56.4 million of interest, respectively.

During the fourth quarter of 2015, the Corporation divested of a non-core undeveloped oil sands asset for proceeds of $110.0 million.

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. During 2016, the Corporation implemented a strategic commodity risk management program through the use of derivative financial instruments with the intent to increase 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 commodity risk management contracts to partially manage its exposure on blend sales and condensate purchases. The Corporation had the following commodity risk management contracts relating to crude oil sales outstanding:

As at December 31, 2016	Volumes (bbls/d)	Term	Average Price (US$/bbl)
Fixed Price:			
WTI Fixed Price	3,500	Jan 1, 2017 – Jun 30, 2017	$52.54
WTI Fixed Price	13,100	Jul 1, 2017 – Dec 31, 2017	$55.19
WCS Fixed Differential	18,000	Jan 1, 2017 – Jun 30, 2017	$(14.94)
Collars:			
WTI Collars	49,250	Jan 1, 2017 – Mar 31, 2017	$45.69 – $54.76
WTI Collars	47,250	Apr 1, 2017 – Jun 30, 2017	$45.71 – $54.61
WTI Collars	28,000	Jul 1, 2017 – Dec 31, 2017	$47.68 – $58.53

The Corporation has entered into the following commodity risk management contracts relating to crude oil sales subsequent to December 31, 2016.

Subsequent to December 31, 2016	Volumes (bbls/d)	Term	Average Price (US$/bbl)
Fixed Price:			
WTI Fixed Price	6,000	Mar 1, 2017 – Jun 30, 2017	$54.82
WTI Fixed Price	3,000	Jul 1, 2017 – Dec 31, 2017	$55.13
WCS Fixed Differential	21,810	Feb 1, 2017 – Jun 30, 2017	$(15.19)
WCS Fixed Differential	18,000	Jul 1, 2017 – Dec 31, 2017	$(15.76)
Collars:			
WTI Collars	2,500	Jul 1, 2017 – Dec 31, 2017	$50.00 – $59.00

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

As at December 31, 2016	Volumes (bbls/d)	Term	Average % of WTI
Mont Belvieu fixed % of WTI	15,150	Jan 1, 2017 – Dec 31, 2017	82.9%

Interest Rate Risk Management

During 2015 and during the first nine months of 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 $1.236 billion senior secured term loan. These interest rate swap contracts expired on September 30, 2016.

NON-GAAP MEASURES

Certain financial measures in this Fourth Quarter Report including: net marketing activity, funds flow, adjusted funds flow, operating loss and operating cash flow 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 related marketing 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 (Loss) and Comprehensive Income (Loss).

Funds Flow and Adjusted Funds Flow

Prior to the fourth quarter of 2016, the Corporation reported cash flow from (used in) operations as a non-GAAP measure. Beginning in the fourth quarter of 2016, the Corporation changed the label of this non-GAAP measure to "funds flow" and "adjusted funds flow". The Corporation believes that this labelling and presentation better distinguishes these measures from the IFRS measurement "net cash provided by (used in) operating activities".

Funds flow and adjusted funds flow, previously referred to as cash flow from (used in) operations, are non-GAAP measures utilized by the Corporation to analyze operating performance and liquidity. Funds flow excludes the net change in non-cash operating working capital while the IFRS measurement "net cash provided by (used in) operating activities" includes these items. Adjusted funds flow excludes the net change in non-cash operating working capital, net change in other liabilities, contract cancellation expense and decommissioning expenditures while the IFRS measurement "net cash provided by (used in) operating activities" includes these items. Funds flow and adjusted funds flow are not intended to represent net cash provided by (used in) operating activities calculated in accordance with IFRS. Funds flow and adjusted funds flow are reconciled to net cash provided by (used in) operating activities in the table below.

	Three months ended December 31		Year ended December 31	
($000)	**2016**	**2015**	**2016**	**2015**
Net cash provided by (used in) operating activities	**$ 82,621**	$ 12,515	**$ (94,074)**	$ 112,158
Net change in non-cash operating working capital items	**(43,636)**	(76,388)	**25,061**	(77,991)
Funds flow	**38,985**	(63,873)	**(69,013)**	34,167
Adjustments:				
Net change in other liabilities	**787**	541	**6,116**	541
Contract cancellation expense	**-**	18,759	**-**	12,879
Decommissioning expenditures	**195**	443	**1,290**	1,873
Adjusted funds flow	**$ 39,967**	$ (44,130)	**$ (61,607)**	$ 49,460

Operating Loss

Operating 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 loss is defined as net loss as reported, excluding unrealized foreign exchange gains and losses, unrealized gains and losses on derivative financial instruments, impairment charges, gains and losses on disposition of assets, unrealized gains and losses on risk management, debt extinguishment expense, contract cancellation expense, onerous contracts, insurance proceeds and the respective deferred tax impact on these adjustments. Operating loss is reconciled to "Net loss", the nearest IFRS measure, in the table below.

($000)	Three months ended December 31 2016	2015	Year ended December 31 2016	2015
Net loss	**$ (304,758)**	$ (297,275)	**(428,726)**	$(1,169,671)
Adjustments:				
Unrealized net loss (gain) on foreign exchange[1]	**119,610**	159,009	**(148,153)**	785,310
Unrealized loss (gain) on derivative financial instruments[2]	**(7,146)**	(15,890)	**(12,508)**	(13,289)
Impairment charge	**80,072**	-	**80,072**	-
Gain on disposition of assets[3]	**-**	(68,192)	**-**	(68,192)
Unrealized loss on risk management[4]	**42,049**	-	**30,313**	-
Debt extinguishment expense[5]	**28,845**	-	**28,845**	-
Contract cancellation expense	**-**	18,759	**-**	12,879
Onerous contracts[6]	**16,383**	58,719	**47,866**	58,719
Insurance proceeds[7]	**(4,391)**	-	**(4,391)**	-
Deferred tax expense (recovery) relating to these adjustments	**(42,653)**	4,636	**(48,416)**	19,870
Operating loss	**$ (71,989)**	$ (140,234)	**(455,098)**	$ (374,374)

(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 instruments 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) *A gain related to the sale of a non-core undeveloped oil sands asset in the fourth quarter of 2015.*

(4) *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.*

(5) *At December 31, 2016, the Corporation recognized $28.8 million of debt extinguishment expense associated with the planned redemption of the 6.5% Senior Unsecured Notes on March 15, 2017, under the comprehensive refinancing plan completed on January 27, 2017.*

(6) *During 2016, onerous contracts expenses were recognized primarily due to changes in estimated future cash flows related to the onerous office lease provision.*

(7) *Includes insurance proceeds related to the small fire that occurred during the first quarter of 2016, which caused damage to the Sulphur Recovery Unit at the Corporation's Christina Lake facility.*

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.

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
eMSAGP	enhanced Modified Steam And Gas Push
GAAP	Generally Accepted Accounting Principles
IFRS	International Financial Reporting Standards
LIBOR	London Interbank Offered Rate
OPEC	Organization of the Petroleum Exporting Countries
PSU	Performance share units
RSU	Restricted share units
SAGD	Steam-Assisted Gravity Drainage
SOR	Steam to 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

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; and the operational risks and delays in the development, exploration, production, and the capacities and performance associated with MEG's projects.

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.

Non-GAAP Financial Measures

Certain financial measures in this Fourth Quarter Report do not have a standardized meaning as prescribed by IFRS including: net marketing activity, funds flow, adjusted funds flow, operating loss and operating cash flow. 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 Fourth Quarter Report.

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.

QUARTERLY SUMMARIES

	2016				2015			
Unaudited	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**
FINANCIAL ($000 unless specified)								
Net earnings (loss)[(1)]	**(304,758)**	(108,632)	(146,165)	130,829	(297,275)	(427,503)	63,414	(508,307)
Per share, diluted	**(1.34)**	(0.48)	(0.65)	0.58	(1.32)	(1.90)	0.28	(2.27)
Operating loss	**(71,989)**	(87,929)	(97,894)	(197,286)	(140,234)	(86,769)	(22,950)	(124,421)
Per share, diluted	**(0.32)**	(0.39)	(0.43)	(0.88)	(0.62)	(0.39)	(0.10)	(0.56)
Adjusted funds flow	**39,967**	22,702	6,964	(131,240)	(44,130)	23,877	99,243	(29,534)
Per share, diluted	**0.18**	0.10	0.03	(0.58)	(0.20)	0.11	0.44	(0.13)
Cash capital investment[(2)]	**63,077**	19,203	19,990	34,975	54,473	32,139	90,465	80,101
Cash and cash equivalents	**156,230**	103,136	152,711	124,560	408,213	350,736	438,238	470,778
Working capital	**96,442**	163,038	128,586	183,649	363,038	366,725	374,766	386,130
Long-term debt	**5,053,239**	4,909,711	4,871,182	4,859,099	5,190,363	5,023,976	4,677,577	4,759,102
Shareholders' equity	**3,286,776**	3,577,557	3,679,372	3,812,566	3,677,867	3,956,689	4,358,078	4,279,873
BUSINESS ENVIRONMENT								
WTI (US$/bbl)	**49.29**	44.94	45.59	33.45	42.18	46.43	57.94	48.63
C$ equivalent of 1US$ - average	**1.3339**	1.3051	1.2886	1.3748	1.3353	1.3093	1.2294	1.2411
Differential – WTI:WCS ($/bbl)	**19.10**	17.62	17.14	19.58	19.35	17.50	14.25	18.22
Differential – WTI:WCS (%)	**29.1%**	30.0%	29.2%	42.6%	34.4%	28.8%	20.0%	30.2%
Natural gas – AECO ($/mcf)	**3.31**	2.49	1.37	1.82	2.57	2.89	2.64	2.74
OPERATIONAL ($/bbl unless specified)								
Bitumen production – bbls/d	**81,780**	83,404	83,127	76,640	83,514	82,768	71,376	82,398
Bitumen sales – bbls/d	**81,746**	84,817	80,548	74,529	82,282	84,651	71,401	85,519
Steam to oil ratio (SOR)	**2.3**	2.2	2.3	2.4	2.5	2.5	2.3	2.6
Bitumen realization	**36.17**	30.98	30.93	11.43	23.17	31.03	44.54	25.82
Transportation – net	**(6.05)**	(6.46)	(6.66)	(6.68)	(5.35)	(4.64)	(4.57)	(4.70)
Royalties	**(0.51)**	(0.42)	(0.27)	0.07	(0.25)	(0.88)	(0.90)	(0.80)
Operating costs – non-energy	**(4.99)**	(5.32)	(5.81)	(6.45)	(5.66)	(5.98)	(7.01)	(7.57)
Operating costs – energy	**(4.12)**	(2.99)	(1.97)	(2.90)	(3.58)	(3.97)	(3.71)	(4.07)
Power revenue	**0.87**	0.55	0.35	0.82	0.72	0.85	1.29	1.15
Realized risk management gain (loss)	**0.36**	0.40	(0.48)	-	-	-	-	-
Cash operating netback	**21.73**	16.74	16.09	(3.71)	9.05	16.41	29.64	9.83
Power sales price (C$/MWh)	**21.94**	17.62	13.54	19.77	19.67	25.09	39.55	28.21
Power sales (MW/h)	**134**	110	86	129	125	119	97	145
Depletion and depreciation rate per bbl of production	**16.81**	16.81	16.84	16.78	16.55	15.99	15.84	15.58
COMMON SHARES								
Shares outstanding, end of period (000)	**226,467**	226,415	226,357	224,997	224,997	224,942	224,881	223,847
Volume traded (000)	**114,776**	112,720	157,056	182,199	76,631	73,099	40,929	57,657
Common share price ($)								
High	**9.79**	6.90	7.86	8.26	13.15	20.36	25.20	24.31
Low	**5.11**	4.72	5.21	3.46	7.33	7.87	17.56	14.84
Close (end of period)	**9.23**	5.93	6.84	6.55	8.02	8.24	20.40	20.46

(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 December 31	Note	2016	2015
Assets			
Current assets			
Cash and cash equivalents	19	**$ 156,230**	$ 408,213
Trade receivables and other		**236,989**	150,042
Inventories		**66,394**	53,079
		459,613	611,334
Non-current assets			
Property, plant and equipment	4	**7,639,434**	8,011,760
Exploration and evaluation assets	5	**547,752**	546,421
Other intangible assets	6	**16,111**	84,142
Other assets	7	**137,370**	146,612
Deferred income tax asset	18	**120,944**	-
Total assets		**$ 8,921,224**	$ 9,400,269
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities		**$ 292,340**	$ 217,991
Current portion of long-term debt	8	**17,455**	17,992
Current portion of provisions and other liabilities	9	**23,063**	12,313
Commodity risk management	21	**30,313**	-
		363,171	248,296
Non-current liabilities			
Long-term debt	8	**5,053,239**	5,190,363
Provisions and other liabilities	9	**218,038**	196,274
Deferred income tax liability	18	**-**	87,469
Total liabilities		**5,634,448**	5,722,402
Shareholders' equity			
Share capital	10	**4,878,607**	4,836,800
Contributed surplus		**168,253**	171,835
Deficit		**(1,795,067)**	(1,366,341)
Accumulated other comprehensive income		**34,983**	35,573
Total shareholders' equity		**3,286,776**	3,677,867
Total liabilities and shareholders' equity		**$ 8,921,224**	$ 9,400,269

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 December 31		Year ended December 31	
	Note	**2016**	**2015**	**2016**	**2015**
Revenues					
Petroleum revenue, net of royalties	12	**$ 550,267**	$ 435,162	**$ 1,823,234**	$ 1,882,853
Other revenue	13	**15,504**	9,346	**43,050**	43,063
		565,771	444,508	**1,866,284**	1,925,916
Expenses					
Diluent and transportation	14	**281,275**	255,730	**1,017,894**	1,050,377
Operating expenses		**68,525**	69,974	**253,758**	306,725
Purchased product and storage		**50,497**	57,920	**202,135**	129,615
Depletion and depreciation	4,6	**126,471**	127,153	**499,811**	467,422
Impairment charge	6	**80,072**	-	**80,072**	-
Exploration expense	5	**-**	-	**1,248**	-
General and administrative		**21,570**	25,281	**96,241**	118,518
Stock-based compensation	11	**16,509**	12,039	**49,942**	50,105
Research and development		**1,139**	2,467	**5,499**	7,497
Gain on disposition of assets	5	**-**	(68,192)	**-**	(68,192)
Interest and other income		**(117)**	(674)	**(1,133)**	(3,078)
Commodity risk management loss	21	**39,331**	-	**27,954**	-
Foreign exchange loss (gain), net	15	**120,221**	162,357	**(151,395)**	801,739
Net finance expense	16	**106,008**	63,185	**356,370**	255,194
Other expenses	17	**26,446**	77,478	**64,108**	71,598
Loss before income taxes		**(372,176)**	(340,210)	**(636,220)**	(1,261,604)
Income tax recovery	18	**(67,418)**	(42,935)	**(207,494)**	(91,933)
Net loss		**(304,758)**	(297,275)	**(428,726)**	(1,169,671)
Other comprehensive income (loss), net of tax					
Items that may be reclassified to profit or loss:					
Foreign currency translation adjustment		**7,727**	4,814	**(590)**	22,358
Comprehensive loss for the period		**$ (297,031)**	$ (292,461)	**$ (429,316)**	$ (1,147,313)
Net loss per common share					
Basic	20	**$ (1.34)**	$ (1.32)	**$ (1.90)**	$ (5.21)
Diluted	20	**$ (1.34)**	$ (1.32)	**$ (1.90)**	$ (5.21)

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, 2015		**$4,836,800**	**$ 171,835**	**$(1,366,341)**	**$ 35,573**	**$ 3,677,867**
Stock-based compensation	11	**-**	**38,225**	**-**	**-**	**38,225**
RSUs vested and released	10	**41,807**	**(41,807)**	**-**	**-**	**-**
Comprehensive loss		**-**	**-**	**(428,726)**	**(590)**	**(429,316)**
Balance as at December 31, 2016		**$4,878,607**	**$ 168,253**	**$(1,795,067)**	**$ 34,983**	**$ 3,286,776**
Balance as at December 31, 2014		$4,797,853	$ 153,837	$ (196,670)	$ 13,215	$ 4,768,235
Stock-based compensation		-	56,945	-	-	56,945
RSUs vested and released		38,947	(38,947)	-	-	-
Comprehensive income (loss)		-	-	(1,169,671)	22,358	(1,147,313)
Balance as at December 31, 2015		$4,836,800	$ 171,835	$(1,366,341)	$ 35,573	$ 3,677,867

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 December 31		Year ended December 31	
	Note	2016	2015	2016	2015
Cash provided by (used in):					
Operating activities					
Net loss		**$ (304,758)**	$ (297,275)	**$ (428,726)**	$(1,169,671)
Adjustments for:					
Depletion and depreciation	4,6	**126,471**	127,153	**499,811**	467,422
Impairment charge	6	**80,072**	-	**80,072**	-
Exploration expense	5	**-**	-	**1,248**	-
Stock-based compensation	11	**5,650**	12,039	**33,588**	50,105
Gain on disposition of assets	5	**-**	(68,192)	**-**	(68,192)
Unrealized loss (gain) on foreign exchange	15	**119,610**	159,009	**(148,153)**	785,310
Unrealized gain on derivative financial liabilities	16	**(7,146)**	(15,890)	**(12,508)**	(13,289)
Unrealized loss on risk management	21	**42,049**	-	**30,313**	-
Onerous contracts	17	**16,383**	58,719	**47,866**	58,719
Deferred income tax recovery	18	**(67,620)**	(42,935)	**(208,413)**	(90,733)
Amortization of debt issue costs	7,8	**3,090**	2,998	**12,192**	11,795
Debt extinguishment expense	8,16	**28,845**	-	**28,845**	-
Other		**(2,679)**	1,485	**2,258**	5,115
Decommissioning expenditures	9	**(195)**	(443)	**(1,290)**	(1,873)
Net change in other liabilities		**(787)**	(541)	**(6,116)**	(541)
Net change in non-cash working capital items	19	**43,636**	76,388	**(25,061)**	77,991
Net cash provided by (used in) operating activities		**82,621**	12,515	**(94,074)**	112,158
Investing activities					
Capital investments:					
Property, plant and equipment	4	**(51,145)**	(58,976)	**(120,828)**	(305,670)
Exploration and evaluation	5	**(414)**	(136)	**(2,265)**	(1,458)
Other intangible assets	6	**(13,290)**	(1,331)	**(16,643)**	(6,498)
Proceeds on disposition of assets	5,7	**3,247**	110,015	**3,247**	110,015
Other		**3,012**	(339)	**2,775**	(930)
Net change in non-cash working capital items	19	**34,906**	(10,830)	**2,603**	(212,455)
Net cash provided by (used in) investing activities		**(23,684)**	38,403	**(131,111)**	(416,996)
Financing activities					
Repayment of long-term debt	8	**(4,364)**	(4,512)	**(17,062)**	(17,020)
Net cash provided by (used in) financing activities		**(4,364)**	(4,512)	**(17,062)**	(17,020)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency		**(1,479)**	11,071	**(9,736)**	73,974
Change in cash and cash equivalents		**53,094**	57,477	**(251,983)**	(247,884)
Cash and cash equivalents, beginning of period		**103,136**	350,736	**408,213**	656,097
Cash and cash equivalents, end of period		**$ 156,230**	$ 408,213	**$ 156,230**	$ 408,213

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 address of the Corporation’s registered office is 520 - 3rd Avenue S.W., 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, 2015. 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, 2015. These interim consolidated financial statements should be read in conjunction with the Corporation’s audited consolidated financial statements for the year ended December 31, 2015.

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 February 8, 2017.

3. CHANGE IN ACCOUNTING POLICIES

New accounting standards

There were no new accounting standards adopted during the year ended December 31, 2016.

Accounting standards issued but not yet applied

On January 19, 2016, the IASB issued amendments to IAS 12, Income Taxes, relating to the recognition of deferred tax assets for unrealized losses. The amendments are effective for annual periods beginning on or after January 1, 2017, with early adoption permitted. Amendments to IAS 12 will be applied on a retrospective basis by the Corporation on January 1, 2017. The adoption of this amended standard is not expected to have a material impact on the Corporation's consolidated financial statements.

On January 29, 2016, the IASB issued amendments to IAS 7, Statement of Cash Flows, as part of its disclosure initiative. The amendments require an entity to disclose changes in liabilities arising from financing activities. The amendments are effective for annual periods beginning on or after January 1, 2017, with early adoption permitted. Amendments to IAS 7 will be applied by the Corporation on January 1, 2017. The adoption of this amended standard will have required disclosure impacts that enable users of financial statements to evaluate changes in liabilities arising from financing activities on the Corporation's consolidated financial statements.

On June 20, 2016, the IASB issued amendments to IFRS 2, 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.

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 and the Corporation is currently assessing and evaluating the impact of the standard on the consolidated financial statements.

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 and the Corporation is currently assessing and evaluating the impact of the standard on the consolidated financial statements.

4. PROPERTY, PLANT AND EQUIPMENT

	Crude oil	Transportation and storage	Corporate assets	Total
Cost				
Balance as at December 31, 2014	$ 7,539,369	$ 1,560,314	$ 47,117	$ 9,146,800
Additions	254,586	54,515	3,959	313,060
Change in decommissioning liabilities	(25,711)	(2,344)	-	(28,055)
Transfer to other assets (Note 7)	-	(6,938)	-	(6,938)
Balance as at December 31, 2015	$ 7,768,244	$ 1,605,547	$ 51,076	$ 9,424,867
Additions	115,832	4,544	4,907	125,283
Derecognition	(3,641)	-	-	(3,641)
Change in decommissioning liabilities	(2,426)	27	-	(2,399)
Balance as at December 31, 2016	**$ 7,878,009**	**$ 1,610,118**	**$ 55,983**	**$ 9,544,110**
Accumulated depletion and depreciation				
Balance as at December 31, 2014	$ 883,723	$ 51,113	$ 16,474	$ 951,310
Depletion and depreciation	426,946	29,227	5,624	461,797
Balance as at December 31, 2015	$ 1,310,669	$ 80,340	$ 22,098	$ 1,413,107
Depletion and depreciation	459,681	30,493	5,036	495,210
Derecognition	(3,641)	-	-	(3,641)
Balance as at December 31, 2016	**$ 1,766,709**	**$ 110,833**	**$ 27,134**	**$ 1,904,676**
Carrying amounts				
Balance as at December 31, 2015	$ 6,457,575	$ 1,525,207	$ 28,978	$ 8,011,760
Balance as at December 31, 2016	**$ 6,111,300**	**$ 1,499,285**	**$ 28,849**	**$ 7,639,434**

As at December 31, 2016, $547.9 million of assets under construction were included within property, plant and equipment (December 31, 2015 - $663.8 million). Assets under construction are not subject to depletion and depreciation. As at December 31, 2016, no impairment has been recognized on property, plant and equipment as the net present value of future cash flows exceeded the carrying value of the respective CGUs.

5. EXPLORATION AND EVALUATION ASSETS

Cost		
Balance as at December 31, 2014	$	588,526
Additions		1,458
Dispositions		(41,827)
Change in decommissioning liabilities		(1,736)
Balance as at December 31, 2015	$	546,421
Additions		2,265
Exploration expense		(1,248)
Change in decommissioning liabilities		314
Balance as at December 31, 2016	**$**	**547,752**

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. If it is determined that the project is not technically feasible and commercially viable or if the Corporation decides not to continue the exploration and evaluation activity, the unrecoverable accumulated costs are expensed as exploration expense. As at December 31, 2016, these assets were assessed for impairment within the aggregation of all of the Corporation's CGUs and no impairment has been recognized on exploration and evaluation assets.

In the fourth quarter of 2015, the Corporation completed a sale of a non-core undeveloped oil sands asset to an unrelated third party for gross proceeds of $110.0 million, resulting in a gain of $68.2 million.

6. OTHER INTANGIBLE ASSETS

Cost		
Balance as at December 31, 2014	$	89,780
Additions		6,498
Balance as at December 31, 2015	$	96,278
Additions		16,643
Balance as at December 31, 2016	**$**	**112,921**

Accumulated depreciation		
Balance as at December 31, 2014	$	6,690
Depreciation		5,446
Balance as at December 31, 2015	$	12,136
Impairment		80,072
Depreciation		4,602
Balance as at December 31, 2016	**$**	**96,810**

Carrying amounts		
Balance as at December 31, 2015	$	84,142
Balance as at December 31, 2016	**$**	**16,111**

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 6, 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 and has recognized an impairment charge of $80.1 million.

As at December 31, 2016, other intangible assets consist of $16.1 million invested in software that is not an integral component of the related computer hardware. As at December 31, 2015, these assets included $63.6 million invested to maintain the right to participate in the Northern Gateway pipeline project and $20.5 million invested in software that is not an integral component of the related computer hardware.

7. OTHER ASSETS

As at December 31		**2016**		**2015**
Long-term pipeline linefill[a]	**$**	**129,733**	$	131,141
Deferred financing costs		**12,001**		16,366
U.S. auction rate securities[b]		**-**		3,470
		141,734		150,977
Less current portion of deferred financing costs		**(4,364)**		(4,365)
	$	**137,370**	$	146,612

(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 these 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 the year 2024. As at December 31, 2016, no impairment has been recognized on these assets.

(b) In the fourth quarter of 2016, the Corporation disposed of these securities for proceeds of $3.2 million.

8. LONG-TERM DEBT

As at December 31		2016		2015
Senior secured term loan (December 31, 2016 – US$1.236 billion; December 31, 2015 – US$1.249 billion; due 2020)	**$**	**1,658,906**	$	1,727,924
6.5% senior unsecured notes (US$750 million; due 2021)		**1,007,025**		1,038,000
6.375% senior unsecured notes (US$800 million; due 2023)		**1,074,160**		1,107,200
7.0% senior unsecured notes (US$1.0 billion; due 2024)		**1,342,700**		1,384,000
		5,082,791		5,257,124
Debt redemption premium		**21,812**		-
Less current portion of senior secured term loan		**(17,455)**		(17,992)
Less unamortized financial derivative liability discount		**(11,143)**		(14,377)
Less unamortized deferred debt issue costs		**(22,766)**		(34,392)
	$	**5,053,239**	$	5,190,363

The U.S. dollar denominated debt was translated into Canadian dollars at the period end exchange rate of US$1 = C$1.3427 (December 31, 2015 - US$1 = C$1.3840).

The 6.5% senior unsecured notes have a prepayment option, and under IFRS, the Corporation is required to make an estimate at each reporting date of the likelihood of the prepayment option being exercised. At December 31, 2016, it was determined that it was probable that the prepayment option would be exercised. As such, the Corporation recognized the 2.166% premium that will be payable on the planned redemption of these notes on March 15, 2017, under the comprehensive refinancing plan completed on January 27, 2017 (note 25). The debt redemption premium of $21.8 million and the associated remaining unamortized deferred debt issue costs of $7.0 million have been recognized as debt extinguishment expense.

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.

9. PROVISIONS AND OTHER LIABILITIES

As at December 31		2016		2015
Decommissioning provision[a]	**$**	**133,924**	$	130,381
Onerous contracts provision[b]		**100,159**		58,178
Derivative financial liabilities[c]		**3,714**		16,223
Deferred lease inducements		**3,304**		3,805
Provisions and other liabilities		**241,101**		208,587
Less current portion		**(23,063)**		(12,313)
Non-current portion	**$**	**218,038**	$	196,274

(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 December 31		**2016**		**2015**
Balance, beginning of year	**$**	**130,381**	$	156,382
Changes in estimated future cash flows		**(91)**		14,076
Changes in discount rates and settlement dates		**(6,117)**		(48,933)
Liabilities incurred		**4,123**		5,066
Liabilities settled		**(1,290)**		(1,873)
Accretion		**6,918**		5,663
Balance, end of year		**133,924**		130,381
Less current portion		**(3,097)**		(1,485)
Non-current portion	**$**	**130,827**	$	128,896

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 8.2% (December 31, 2015 – 8.3%). The decommissioning provision is estimated to be settled in periods up to the year 2066 (December 31, 2015 – periods up to the year 2064).

(b) Onerous contracts provision:

As at December 31		**2016**		**2015**
Balance, beginning of year	**$**	**58,178**	$	-
Changes in estimated future cash flows		**40,499**		-
Changes in discount rates		**(1,478)**		-
Liabilities incurred		**8,845**		58,719
Liabilities settled		**(6,116)**		(541)
Accretion		**231**		-
Balance, end of year		**100,159**		58,178
Less current portion		**(18,930)**		(1,993)
Non-current portion	**$**	**81,229**	$	56,185

As at December 31, 2016, the Corporation has recognized a total provision of $100.2 million related to certain onerous operating lease contracts (December 31, 2015 – $58.2 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 1.3% (December 31, 2015 – 1.0%). This estimate may vary as a result of changes in estimated recoveries.

(c) Derivative financial liabilities:

As at December 31		2016		2015
1% interest rate floor	**$**	**3,714**	$	11,740
Interest rate swaps (Note 21)		**-**		4,483
Derivative financial liabilities		**3,714**		16,223
Less current portion		**(517)**		(8,316)
Non-current portion	**$**	**3,197**	$	7,907

10. SHARE CAPITAL

Authorized:

Unlimited number of common shares
Unlimited number of preferred shares

Changes in issued common shares are as follows:

Year ended December 31	2016			2015		
	Number of shares		Amount	Number of shares		Amount
Balance, beginning of year	**224,996,989**	**$**	**4,836,800**	223,846,891	$	4,797,853
Issued upon vesting and release of RSUs and PSUs	**1,470,118**		**41,807**	1,150,098		38,947
Balance, end of year	**226,467,107**	**$**	**4,878,607**	224,996,989	$	4,836,800

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:

In June 2016, the Corporation granted RSUs and PSUs under a new 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. As at December 31, 2016, the Corporation has recognized a liability of $19.2 million relating to the fair value of RSUs, PSUs and DSUs.

RSUs and PSUs outstanding:

Year ended December 31, 2016	
Outstanding, beginning of year	-
Granted	**6,132,701**
Forfeited	**(119,691)**
Outstanding, end of year	**6,013,010**

ii. Deferred share units outstanding:

The Deferred Share Unit Plan allows for the granting of Deferred Share Units ("DSUs") to directors of the Corporation. As at December 31, 2016, there were 163,954 DSUs outstanding (December 31, 2015 – 47,696 DSUs outstanding).

(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.

Year ended December 31, 2016	**Stock options**	**Weighted average exercise price**
Outstanding, beginning of year	**9,925,313**	**$ 29.94**
Granted	**1,214,300**	**6.52**
Forfeited	**(851,422)**	**30.73**
Expired	**(1,007,005)**	**24.00**
Outstanding, end of year	**9,281,186**	**$ 27.45**

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.

RSU and PSU grants made prior to June 2016 are captured under the equity-settled plan, whereby upon vesting, 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:

Year ended December 31, 2016	
Outstanding, beginning of year	**3,280,112**
Granted	**-**
Vested and released	**(1,470,118)**
Forfeited	**(154,388)**
Outstanding, end of year	**1,655,606**

(c) Stock-based Compensation

	Three months ended December 31		Year ended December 31	
	2016	**2015**	**2016**	**2015**
Cash-settled	**$ 10,859**	$ -	**$ 16,354**	$ -
Equity-settled	**5,650**	12,039	**33,588**	50,105
Stock-based compensation expense	**$ 16,509**	$ 12,039	**$ 49,942**	$ 50,105

12. PETROLEUM REVENUE, NET OF ROYALTIES

	Three months ended December 31		Year ended December 31	
	2016	**2015**	**2016**	**2015**
Petroleum revenue:				
Proprietary	**$ 503,176**	$ 386,689	**$ 1,626,025**	$ 1,799,154
Third-party[(a)]	**50,952**	50,361	**205,790**	104,464
Petroleum revenue	**$ 554,128**	$ 437,050	**$ 1,831,815**	$ 1,903,618
Royalties	**(3,861)**	(1,888)	**(8,581)**	(20,765)
Petroleum revenue, net of royalties	**$ 550,267**	$ 435,162	**$ 1,823,234**	$ 1,882,853

(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 December 31		Year ended December 31	
	2016	**2015**	**2016**	**2015**
Power revenue	**$ 6,508**	$ 5,441	**$ 18,868**	$ 29,239
Transportation revenue	**4,605**	3,905	**19,791**	13,824
Insurance proceeds[a]	**4,391**	-	**4,391**	-
Other revenue	**$ 15,504**	$ 9,346	**$ 43,050**	$ 43,063

(a) Includes insurance proceeds related to the small fire that occurred during the first quarter of 2016, which caused damage to the Sulphur Recovery Unit at the Corporation's Christina Lake facility.

14. DILUENT AND TRANSPORTATION

	Three months ended December 31		Year ended December 31	
	2016	**2015**	**2016**	**2015**
Diluent expense	**$ 231,173**	$ 211,293	**$ 808,030**	$ 893,995
Transportation expense	**50,102**	44,437	**209,864**	156,382
Diluent and transportation	**$ 281,275**	$ 255,730	**$ 1,017,894**	$ 1,050,377

15. FOREIGN EXCHANGE LOSS (GAIN), NET

	Three months ended December 31		Year ended December 31	
	2016	**2015**	**2016**	**2015**
Unrealized foreign exchange loss (gain) on:				
Long-term debt	**$ 117,451**	$ 169,572	**$ (157,272)**	$ 852,422
Other	**2,159**	(10,563)	**9,119**	(67,112)
Unrealized net loss (gain) on foreign exchange	**119,610**	159,009	**(148,153)**	785,310
Realized loss (gain) on foreign exchange	**611**	3,348	**(3,242)**	16,429
Foreign exchange loss (gain), net	**$ 120,221**	$ 162,357	**$ (151,395)**	$ 801,739

C$ equivalent of 1 US$				
Beginning of period	**1.3117**	1.3394	**1.3840**	1.1601
End of period	**1.3427**	1.3840	**1.3427**	1.3840

16. NET FINANCE EXPENSE

	Three months ended December 31		Year ended December 31	
	2016	**2015**	**2016**	**2015**
Total interest expense	**$ 82,469**	$ 81,888	**$ 328,335**	$ 313,411
Less capitalized interest	**-**	(5,970)	**-**	(56,449)
Net interest expense	**82,469**	75,918	**328,335**	256,962
Debt extinguishment expense[(a)]	**28,845**	-	**28,845**	-
Accretion on provisions	**1,840**	1,616	**7,150**	5,663
Unrealized gain on derivative financial liabilities	**(7,146)**	(15,890)	**(12,508)**	(13,289)
Realized loss on interest rate swaps	**-**	1,541	**4,548**	5,858
Net finance expense	**$ 106,008**	$ 63,185	**$ 356,370**	$ 255,194

(a) At December 31, 2016, the Corporation recognized $28.8 million of debt extinguishment expense associated with the planned redemption of the 6.5% Senior Unsecured Notes on March 15, 2017, under the comprehensive refinancing plan completed on January 27, 2017 (note 25). The debt extinguishment expense is comprised of a redemption premium of $21.8 million and the associated remaining unamortized deferred debt issue costs of $7.0 million.

17. OTHER EXPENSES

	Three months ended December 31		Year ended December 31	
	2016	**2015**	**2016**	**2015**
Onerous contracts	**$ 16,383**	$ 58,719	**$ 47,866**	$ 58,719
Severance and other	**10,063**	-	**16,242**	-
Contract cancellation	**-**	18,759	**-**	12,879
Other expenses	**$ 26,446**	$ 77,478	**$ 64,108**	$ 71,598

18. INCOME TAX RECOVERY

	Three months ended December 31		Year ended December 31	
	2016	**2015**	**2016**	**2015**
Current income tax expense (recovery)	**$ 202**	$ -	**$ 919**	$ (1,200)
Deferred income tax recovery	**(67,620)**	(42,935)	**(208,413)**	(90,733)
Income tax recovery	**$ (67,418)**	$ (42,935)	**$ (207,494)**	$ (91,933)

Based on the Corporation’s independently evaluated reserve report, the Corporation has recognized a deferred tax asset. 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 December 31		Year ended December 31	
	2016	2015	**2016**	2015
Cash provided by (used in):				
Trade receivables and other	**$ (25,435)**	$ 20,593	**$ (83,601)**	$ 46,852
Inventories	**1,915**	17,669	**(13,524)**	47,492
Accounts payable and accrued liabilities	**102,062**	27,296	**74,667**	(228,808)
	$ 78,542	$ 65,558	**$ (22,458)**	$ (134,464)
Changes in non-cash working capital relating to:				
Operating	**$ 43,636**	$ 76,388	**$ (25,061)**	$ 77,991
Investing	**34,906**	(10,830)	**2,603**	(212,455)
	$ 78,542	$ 65,558	**$ (22,458)**	$ (134,464)
Cash and cash equivalents:[(a)]				
Cash	**$ 156,230**	$ 222,341	**$ 156,230**	$ 222,341
Cash equivalents	**-**	185,872	**-**	185,872
	$ 156,230	$ 408,213	**$ 156,230**	$ 408,213
Cash interest paid	**$ 15,766**	$ 16,655	**$ 286,983**	$ 267,347

(a) As at December 31, 2016, C$102.8 million of the Corporation's total cash and cash equivalents balance was held in U.S. dollars (December 31, 2015 - C$277.1 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$1.3427 (December 31, 2015 - US$1 = C$1.3840).

20. NET LOSS PER COMMON SHARE

	Three months ended December 31		Year ended December 31	
	2016	2015	**2016**	2015
Net loss	**$ (304,758)**	$ (297,275)	**$ (428,726)**	$(1,169,671)
Weighted average common shares outstanding[(a)]	**226,617,057**	225,102,632	**225,982,724**	224,579,249
Dilutive effect of stock options, RSUs and PSUs[(b)]	**-**	-	**-**	-
Weighted average common shares outstanding – diluted	**226,617,057**	225,102,632	**225,982,724**	224,579,249
Net loss per share, basic	**$ (1.34)**	$ (1.32)	**$ (1.90)**	$ (5.21)
Net loss per share, diluted	**$ (1.34)**	$ (1.32)	**$ (1.90)**	$ (5.21)

(a) Weighted average common shares outstanding for the year ended December 31, 2016 includes 184,425 PSUs not yet released (year ended December 31, 2015 – 141,929 PSUs).

(b) For the three months and year ended December 31, 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 year ended December 31, 2016, the dilutive effect of stock options, RSUs and PSUs would have been 46,293 (three months ended December 31, 2015 – 321,530) and 122,500 (year ended December 31, 2015 – 564,201) 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, U.S. auction rate securities ("ARS") included within other assets, 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 December 31, 2016, commodity risk management contracts and the 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 ARS, long-term debt, derivative financial liabilities, commodity risk management contracts and debt redemption premium liability:

As at December 31, 2016	Carrying amount	Fair value measurements using Level 1	Level 2	Level 3
Recurring measurements:				
Financial liabilities				
Long-term debt[1] (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**	**$ -**

As at December 31, 2015	Carrying amount	Fair value measurements using Level 1	Level 2	Level 3
Recurring measurements:				
Financial assets				
ARS (Note 7)	$ 3,470	$ -	$ 3,470	$ -
Financial liabilities				
Long-term debt[1] (Note 8)	$5,257,124	$ -	$ 3,999,317	$ -
Derivative financial liabilities (Note 9)	$ 16,223	$ -	$ 16,223	$ -

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

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

As at December 31, 2016, 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 values of the ARS and long-term debt are derived using quoted prices in an inactive market from a third-party independent broker.

The fair value of commodity risk management contracts and the 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 December 31, 2016, 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:

In 2016, the Corporation entered into derivative financial instruments to manage commodity price risk. The use of these 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. Commodity risk management contracts are measured at fair value, with gains and losses on re-measurement included in the consolidated statement of earnings (loss) and comprehensive income (loss) in the period in which they arise.

The Corporation has the following commodity risk management contracts relating to crude oil sales outstanding as at December 31, 2016:

As at December 31, 2016	**Volumes (bbls/d)**	**Term**	**Average Price (US$/bbl)**
Fixed Price:			
WTI[1] Fixed Price	3,500	Jan 1, 2017 – Jun 30, 2017	$52.54
WTI Fixed Price	13,100	Jul 1, 2017 – Dec 31, 2017	$55.19
WCS[2] Fixed Differential	18,000	Jan 1, 2017 – Jun 30, 2017	$(14.94)
Collars:			
WTI Collars	49,250	Jan 1, 2017 – Mar 31, 2017	$45.69 – $54.76
WTI Collars	47,250	Apr 1, 2017 – Jun 30, 2017	$45.71 – $54.61
WTI Collars	28,000	Jul 1, 2017 – Dec 31, 2017	$47.68 – $58.53

(1) West Texas Intermediate ("WTI") crude oil
(2) Western Canadian Select ("WCS") crude oil blend

The Corporation has entered into the following commodity risk management contracts relating to crude oil sales subsequent to December 31, 2016. As a result, these contracts are not reflected in the Corporation's Interim Consolidated Financial Statements:

Subsequent to December 31, 2016	**Volumes (bbls/d)**	**Term**	**Average Price (US$/bbl)**
Fixed Price:			
WTI[1] Fixed Price	6,000	Mar 1, 2017 – Jun 30, 2017	$54.82
WTI Fixed Price	3,000	Jul 1, 2017 – Dec 31, 2017	$55.13
WCS[2] Fixed Differential	21,810	Feb 1, 2017 – Jun 30, 2017	$(15.19)
WCS Fixed Differential	18,000	Jul 1, 2017 – Dec 31, 2017	$(15.76)
Collars:			
WTI Collars	2,500	Jul 1, 2017 – Dec 31, 2017	$50.00 – $59.00

(1) West Texas Intermediate ("WTI") crude oil
(2) Western Canadian Select ("WCS") crude oil blend

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

As at December 31, 2016	**Volumes (bbls/d)**	**Term**	**Average % of WTI**
Mont Belvieu fixed % of WTI	15,150	Jan 1, 2017 – Dec 31, 2017	82.9%

The Corporation's 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 commodity risk management positions:

As at	**December 31, 2016**		
	Asset	**Liability**	**Net**
Gross amount	$ -	**$ (165,740)**	**$ (165,740)**
Amount offset	-	**135,427**	**135,427**
Net amount	**$ -**	**$ (30,313)**	**$ (30,313)**

As at December 31, 2015 the Corporation did not have any commodity risk management contracts outstanding.

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

December 31, 2016	Three months ended	Year ended
Realized gain on commodity risk management	$ (2,718)	$ (2,359)
Unrealized loss on commodity risk management	42,049	30,313
Commodity risk management loss	$ 39,331	$ 27,954

As at December 31, 2015 the Corporation did not have any commodity risk management contracts outstanding.

The following table summarizes the sensitivity of the earnings before income tax impact of fluctuating commodity prices on the Corporation's open commodity risk management positions in place as at December 31, 2016:

Commodity	Sensitivity Range	Increase	Decrease
Crude oil commodity price	± US$1.00 per bbl applied to WTI contracts	$ (11,707)	$ 9,523
Crude oil differential price[1]	± US$1.00 per bbl applied to WCS differential contracts	$ 4,375	$ (4,375)
Condensate percentage	± 1% in condensate price as a percentage of US$ WTI price per bbl applied to condensate contracts	$ 3,203	$ (3,203)

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

(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 (loss) and comprehensive income (loss) in the period in which they arise. As at December 31, 2016, the Corporation does not have any outstanding interest rate swap contracts.

22. GEOGRAPHICAL DISCLOSURE

As at December 31, 2016, the Corporation had non-current assets related to operations in the United States of $109.2 million (December 31, 2015 - $111.1 million). For the three months and year ended December 31, 2016, petroleum revenue related to operations in the United States were $195.1 million and $664.2 million respectively (three months and year ended December 31, 2015 - $121.2 million and $541.5 million, respectively).

23. COMMITMENTS AND CONTINGENCIES

(a) Commitments

The Corporation had the following commitments as at December 31, 2016:

	2017	2018	2019	2020	2021	Thereafter
Transportation and storage	$ 178,632	$ 202,913	$ 192,853	$ 232,719	$ 270,293	$ 2,997,998
Office lease rentals	33,640	32,198	32,228	33,144	39,010	226,074
Diluent purchases	189,721	20,725	20,725	20,782	20,725	37,986
Other operating commitments	17,827	8,440	11,657	12,354	11,552	74,077
Capital commitments	17,496	-	-	-	-	-
Commitments	**$ 437,316**	**$ 264,276**	**$ 257,463**	**$ 298,999**	**$ 341,580**	**$ 3,336,135**

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.

24. CAPITAL DISCLOSURES

On December 1, 2016, the Corporation filed a Canadian base shelf prospectus for common shares, debt securities, subscription receipts, warrants and units (together referred to as "Securities") in the amount of $1.5 billion. The Canadian base shelf prospectus allows for the issuance of these Securities in Canadian dollars or other currencies from time to time in one or more offerings. As at December 31, 2016, no Securities were issued under the Canadian base shelf prospectus. The Canadian base shelf prospectus expires on January 1, 2019.

25. SUBSEQUENT EVENTS

On January 27, 2017, the Corporation completed 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 existing 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. It has no financial covenants and is not subject to any borrowing base redetermination;

- The US$1.2 billion term loan has been refinanced to extend its maturity date from March 2020 to December 2023. The refinanced term loan will bear interest at an annual rate of LIBOR plus 3.5% with a LIBOR floor of 1%. The term loan was issued at a price equal to 99.75% of its face value;

- The existing 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% second lien secured notes, issued at par, maturing January 2025. The existing 2021 notes will be redeemed with the proceeds from the 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 subscription receipts at a price C$7.75 per subscription receipt on a bought deal basis from a syndicate of underwriters. As part of the closing, escrow release conditions for the subscription receipt offering have been satisfied and the subscription receipts have been converted into common shares.