MEG ENERGY

THIRD QUARTER 2016

Report to Shareholders for the period ended September 30, 2016

MEG Energy Corp. reported third quarter 2016 operating and financial results on October 27, 2016. Highlights include:

- Near-record production volumes of 83,404 barrels per day (bpd);
- Cash flow from operations of $23 million, or $0.10 per share;
- Record low non-energy operating costs of $5.32 per barrel, supporting net operating costs of $7.76 per barrel;
- Record low general and administrative expenses of $2.94 per barrel, a 21% reduction from the third quarter of 2015;
- Reduced 2016 non-energy operating cost guidance to $5.75 to $6.50 per barrel, approximately 16% below the original estimate of $6.75 to $7.75 per barrel;
- The 2016 capital program has been revised downwards to $140 million from the original budget of $328 million, while maintaining production guidance;
- Solid financial liquidity, exiting the quarter with $103 million of cash and cash equivalents and an undrawn US$2.5 billion revolving credit facility.

"Our quarterly results are a demonstration of MEG's increasing capacity to sustain the company in a challenging commodity price environment, through continued technological advancement and reductions in our overall cost base," said Bill McCaffrey, President and Chief Executive Officer. "We are seeing record low per barrel non-energy operating and general and administrative costs. These cost reductions were supported by third quarter production levels which are the second best in MEG's history."

MEG recorded production of 83,404 bpd in the third quarter of 2016, compared to production of 82,768 bpd in the third quarter of 2015. MEG expects to meet its 2016 production guidance of 80,000 to 83,000 bpd.

Related net operating costs for the third quarter were $7.76 per barrel compared to $9.10 per barrel in the third quarter of 2015. Non-energy operating costs (which exclude natural gas consumption) were $5.32 per barrel, an 11% improvement from the same period in 2015. The significant decrease in net operating costs reflects the ongoing efficiency gains from the application of eMSAGP, which is being fully deployed across the company's Phase 2 operations. Net operating costs also benefited from a decrease in the usage and cost of natural gas used to fuel the company's SAGD facilities. MEG's steam to oil ratio (SOR) averaged 2.2 during the third quarter of 2016, compared to an SOR of 2.5 for the third quarter of 2015.

High production volumes and low operating and general and administrative costs contributed to cash flow from operations of $23 million for the third quarter of 2016, despite the current commodity price environment. Cash flow from operations was relatively stable from $24 million in the third quarter of 2015.

MEG recognized an operating loss of $88 million for the third quarter of 2016, compared to an operating loss of $87 million in the same period of 2015.

At the end of the third quarter, MEG had $103 million of cash and cash equivalents on hand. At current strip prices, MEG anticipates its US$2.5 billion revolving credit facility will remain undrawn at the end of 2016.

Capital investment for the third quarter totaled $19 million, bringing total capital invested for 2016 to date to $74 million. As a result of the ongoing efficiency gains achieved through the application of eMSAGP, MEG anticipates it will achieve its sustaining and maintenance, marketing and other initiatives in 2016 with an investment of $140 million, 18% below the reduced capital investment of $170 million announced in April.

"We are continuing to make incremental reductions in costs across the business," says McCaffrey. "Our advances in technology have enabled MEG to increase production while reducing our capital and operating costs."

Forward-Looking Information and Non-GAAP Financial Measures

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

Management's Discussion and Analysis

This Management's Discussion and Analysis ("MD&A") of the financial condition and performance of MEG Energy Corp. ("MEG" or the "Corporation") for the three-month and nine-month periods ended September 30, 2016 was approved by the Corporation's Audit Committee on October 26, 2016. This MD&A should be read in conjunction with the Corporation's unaudited condensed consolidated interim financial statements and notes thereto for the three-month and nine-month periods ended September 30, 2016, the audited consolidated financial statements and notes thereto for the year ended December 31, 2015 and the 2015 annual MD&A. This MD&A and the unaudited condensed consolidated interim financial statements and comparative information have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") and are presented in thousands of Canadian dollars, except where otherwise indicated.

MD&A – Table of Contents

1. OVERVIEW

MEG is an oil sands company focused on sustainable in situ oil sands development and production in the southern Athabasca oil sands region of Alberta, Canada. MEG is actively developing enhanced oil recovery projects that utilize steam-assisted gravity drainage ("SAGD") extraction methods. MEG is not engaged in oil sands mining.

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

The Corporation has identified two commercial SAGD projects; the Christina Lake Project and the Surmont Project. The Christina Lake Project has received regulatory approval for 210,000 barrels per day ("bbls/d") of production and MEG has applied for regulatory approval for 120,000 bbls/d of production at the Surmont Project. The ultimate production rate and life of each project will be dependent on a number of factors, including the size, performance and development schedule for each expansion or phase in those projects. In addition, the Corporation holds other leases known as the "May River Regional Project" and the "Growth Properties." The Corporation is pursuing these opportunities for development and continues to consider potential regulatory applications for the May River Regional Project later in 2016. MEG has been conducting core-hole programs at the May River Regional Project with the objectives of identifying additional contingent resources, defining areas for commercial development and determining the size of potential commercial developments. The Growth Properties are in the resource definition and data gathering stage of development.

The Corporation's first two production phases at the Christina Lake Project, Phases 1 and 2, commenced production in 2008 and 2009, respectively, with a combined designed capacity of 25,000 bbls/d. In 2012, the Corporation announced the RISER initiative, which is designed to increase production from existing assets at lower capital and operating costs using a combination of proprietary reservoir technologies, redeployment of steam and facilities modifications, including debottlenecking and expansions (collectively, "RISER"). As part of the RISER initiative, the Corporation utilizes enhanced Modified Steam And Gas Push technology ("eMSAGP") to optimize reservoir operations. Phase 2B, an expansion with an initial designed capacity of 35,000 bbls/d, commenced production in the fourth quarter of 2013 and was successfully ramped up throughout 2014. Due to the successful ramp-up of Phase 2B, in combination with the success achieved from applying RISER, the Corporation achieved average production in excess of 80,000 bbls/d from the Christina Lake Project during the fourth quarter of 2014. Bitumen production averaged 71,186 bbls/d for the year ended December 31, 2014 and averaged 80,025 bbls/d for the year ended December 31, 2015.

The Corporation is currently focused on the continuing application of eMSAGP technology to optimize reservoir performance. The Corporation anticipates this strategy will allow the Corporation to increase production more efficiently and at lower capital intensity.

In addition, MEG has filed regulatory applications for the Surmont Project, which is situated along the same geological trend as the Christina Lake Project and has an anticipated designed capacity of approximately 120,000 bbls/d over multiple phases. MEG filed a regulatory application for the project in September 2012 and continues to actively work through the application process, currently engaging stakeholders as a normal part of the Alberta Energy Regulator's requirements. The proposed project is expected to use SAGD technology and include multi-well production pads, electricity and steam cogeneration and other facilities similar to MEG's current Christina Lake Project. The Surmont Project is located approximately 30 miles north of the Corporation's Christina Lake Project. This area has been extensively explored and developed for natural gas projects, and more recently for oil sands resources. Other thermal recovery projects are already operating in this area.

MEG holds a 50% interest in the Access Pipeline, a dual pipeline system that connects the Christina Lake Project to a large regional upgrading, refining, diluent supply and transportation hub in the Edmonton, Alberta area. In 2014, MEG completed an expansion of the Access Pipeline to accommodate anticipated increases in production from the Christina Lake Project as well as provide expansion capacity for future production volumes from the Surmont Project, the May River Regional Project and the Growth Properties. MEG's 50% interest of the capacity in the expanded 42-inch blend line is approximately 200,000 bbls/d of blended bitumen. The system's former 24-inch blend line was converted to diluent service during the third quarter of 2015.

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.

In addition to the Access Pipeline, MEG holds a 100% interest in the Stonefell Terminal, located near Edmonton, Alberta, with a storage and terminalling capacity of 900,000 barrels. The Stonefell Terminal is connected to local and export markets by pipeline, in addition to being pipeline connected to a third party rail-loading terminal near Bruderheim, Alberta. This combination of facilities allows for the loading of bitumen blend for transport by rail.

Effective January 1, 2016, MEG increased its transportation capacity on the Flanagan South and Seaway pipeline systems to U.S. Gulf Coast refineries. This pipeline system went into operation in late 2014.

2. OPERATIONAL AND FINANCIAL HIGHLIGHTS

The ongoing global imbalance between supply and demand for crude oil continued to significantly impact the Corporation's operating and financial results.

As a result of ongoing cost control initiatives in 2016, the Corporation has reduced non-energy operating costs per barrel by 11% compared to the third quarter of 2015 and has reduced general and administrative expense per barrel by 21% compared to the third quarter of 2015.

In early 2016, the Corporation implemented a strategic commodity risk management program to increase the predictability of the Corporation's future cash flows as governed by MEG's Risk Management Committee. During the nine months ended September 30, 2016, the Corporation entered into commodity risk management contracts to partially manage its exposure on blend sales prices and condensate purchases.

The following table summarizes selected operational and financial information of the Corporation for the periods noted. All dollar amounts are stated in Canadian dollars ($ or C$) unless otherwise noted:

	Nine months ended September 30		2016			2015				2014
($ millions, except as indicated)	**2016**	**2015**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**
Bitumen production - bbls/d	**81,065**	78,849	**83,404**	83,127	76,640	83,514	82,768	71,376	82,398	80,349
Bitumen realization - $/bbl	**24.91**	33.20	**30.98**	30.93	11.43	23.17	31.03	44.54	25.82	50.48
Net operating costs - $/bbl(1)	**7.89**	9.69	**7.76**	7.43	8.53	8.52	9.10	9.43	10.49	10.13
Non-energy operating costs - $/bbl	**5.83**	6.84	**5.32**	5.81	6.45	5.66	5.98	7.01	7.57	6.42
Cash operating netback - $/bbl(2)	**10.18**	18.01	**16.74**	16.09	(3.71)	9.05	16.41	29.64	9.83	35.56
Cash flow from (used in) operations(3)	**(102)**	94	**23**	7	(131)	(44)	24	99	(30)	134
Per share, diluted(3)	**(0.45)**	0.42	**0.10**	0.03	(0.58)	(0.20)	0.11	0.44	(0.13)	0.60
Operating earnings (loss)(3)	**(383)**	(234)	**(88)**	(98)	(197)	(140)	(87)	(23)	(124)	8
Per share, diluted(3)	**(1.70)**	(1.04)	**(0.39)**	(0.43)	(0.88)	(0.62)	(0.39)	(0.10)	(0.56)	0.04
Revenue(4)	**1,301**	1,481	**497**	513	290	445	460	555	467	615
Net earnings (loss)(5)	**(124)**	(872)	**(109)**	(146)	131	(297)	(428)	63	(508)	(150)
Per share, basic	**(0.55)**	(3.89)	**(0.48)**	(0.65)	0.58	(1.32)	(1.90)	0.28	(2.27)	(0.67)
Per share, diluted	**(0.55)**	(3.89)	**(0.48)**	(0.65)	0.58	(1.32)	(1.90)	0.28	(2.27)	(0.67)
Total cash capital investment(6)	**74**	203	**19**	20	35	54	32	90	80	324
Cash and cash equivalents	**103**	351	**103**	153	125	408	351	438	471	656
Long-term debt	**4,910**	5,024	**4,910**	4,871	4,859	5,190	5,024	4,678	4,759	4,350

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

(2) Cash operating netbacks are 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) Cash flow from (used in) operations, Operating earnings (loss) and the related per share amounts do not have standardized meanings prescribed by IFRS and therefore may not be comparable to similar measures used by other companies. For the three and nine months ended September 30, 2016 and September 30, 2015, the non-GAAP measure of cash flow from (used in) operations 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 $38.7 million and a net unrealized foreign exchange gain of $267.8 million on the Corporation's U.S. dollar denominated debt and U.S. dollar denominated cash and cash equivalents for the three and nine months ended September 30, 2016, respectively. The net losses for the three and nine months ended September 30, 2015 include net unrealized foreign exchange losses of $330.5 million and $626.3 million, respectively.

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

Bitumen Production and Steam to Oil Ratio

	Three months ended September 30		Nine months ended September 30	
	2016	**2015**	**2016**	**2015**
Bitumen production – bbls/d	**83,404**	82,768	**81,065**	78,849
Steam to oil ratio (SOR)	**2.2**	2.5	**2.3**	2.5

Bitumen Production

Bitumen production for the three months ended September 30, 2016 averaged 83,404 bbls/d compared to 82,768 bbls/d for the three months ended September 30, 2015. Bitumen production for the nine months ended September 30, 2016 averaged 81,065 bbls/d compared to 78,849 bbls/d for the nine months ended September 30, 2015. The increase in production volumes 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 2.2 for the three months ended September 30, 2016 and 2.3 for the nine months ended September 30, 2016 compared to an average SOR of 2.5 for the three and nine months ended September 30, 2015. The decrease in SOR for the three and nine months ended September 30, 2016 is due to the continued implementation of eMSAGP.

Operating Cash Flow

	Three months ended September 30		Nine months ended September 30	
($000)	**2016**	**2015**	**2016**	**2015**
Petroleum revenue – proprietary[1]	**$ 442,333**	$ 446,743	**$ 1,122,849**	$1,412,464
Diluent expense	**(200,564)**	(205,069)	**(576,857)**	(682,702)
	241,769	241,674	**545,992**	729,762
Royalties	**(3,252)**	(6,874)	**(4,720)**	(18,877)
Transportation expense	**(55,252)**	(40,176)	**(159,762)**	(111,945)
Operating expenses	**(64,796)**	(77,474)	**(185,233)**	(236,750)
Power revenue	**4,277**	6,608	**12,360**	23,798
Transportation revenue	**4,863**	4,034	**15,186**	9,920
	127,609	127,792	**223,823**	395,908
Realized gain (loss) on risk management	**3,128**	-	**(359)**	-
Operating cash flow[2]	**$ 130,737**	$ 127,792	**$ 223,464**	$ 395,908

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

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

Operating cash flow was $130.7 million for the three months ended September 30, 2016 compared to $127.8 million for the three months ended September 30, 2015. Operating cash flow increased primarily due to a decrease in operating and royalty expenses, partially offset by an increase in transportation expense. In addition, the Corporation realized a gain of $3.1 million on commodity risk management contracts in the third quarter of 2016.

Operating cash flow was $223.5 million for the nine months ended September 30, 2016 compared to $395.9 million for the nine months ended September 30, 2015. Operating cash flow decreased primarily due to lower blend sales revenue as a result of a decline in U.S. crude oil benchmark pricing, partially offset by a decrease in diluent expense. Blend sales revenue for the nine months ended September 30, 2016 was $1.1 billion compared to $1.4 billion for the nine months ended September 30, 2015. The decrease in blend sales revenue is primarily due to a 21% decrease in the average realized blend price. Diluent expense for the nine months ended September 30, 2016 was $576.9 million compared to $682.7 million for the nine months ended September 30, 2015. Diluent expense decreased primarily due to a decrease in condensate prices.

Cash Operating Netback

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

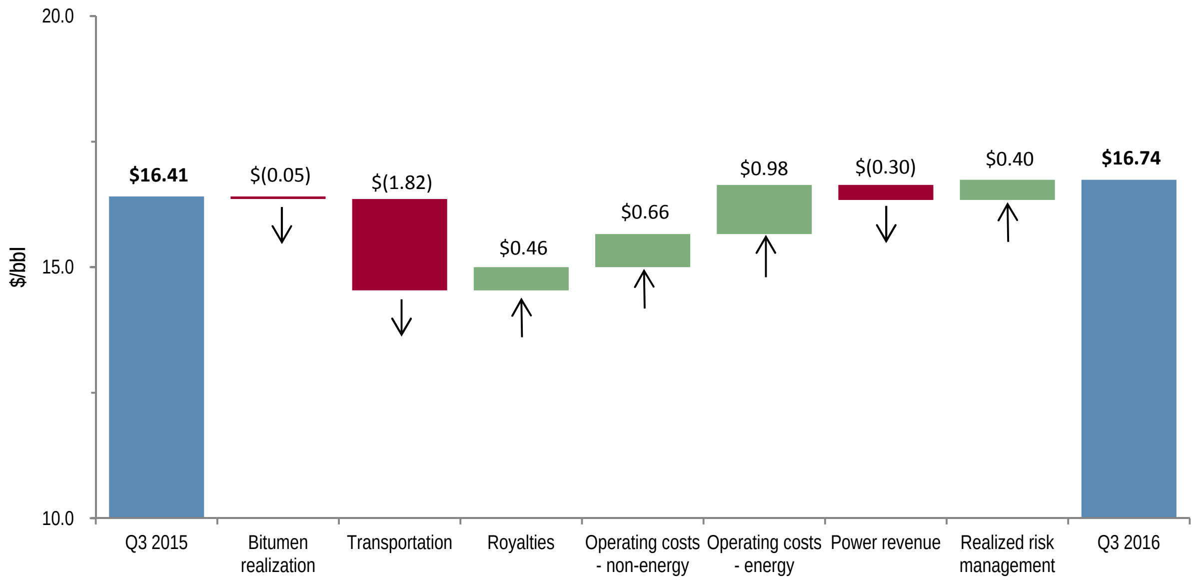
	Three months ended September 30		Nine months ended September 30	
($/bbl)	**2016**	**2015**	**2016**	**2015**
Bitumen realization[1]	**$ 30.98**	$ 31.03	**$ 24.91**	$ 33.20
Transportation[2]	**(6.46)**	(4.64)	**(6.60)**	(4.64)
Royalties	**(0.42)**	(0.88)	**(0.22)**	(0.86)
	24.10	25.51	**18.09**	27.70
Operating costs – non-energy	**(5.32)**	(5.98)	**(5.83)**	(6.84)
Operating costs – energy	**(2.99)**	(3.97)	**(2.62)**	(3.93)
Power revenue	**0.55**	0.85	**0.56**	1.08
Net operating costs	**(7.76)**	(9.10)	**(7.89)**	(9.69)
	16.34	16.41	**10.20**	18.01
Realized gain (loss) on risk management	**0.40**	-	**(0.02)**	-
Cash operating netback	**$ 16.74**	$ 16.41	**$ 10.18**	$ 18.01

(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 September 30, 2016 was $16.74 per barrel compared to $16.41 per barrel for the three months ended September 30, 2015. Cash operating netback for the nine months ended September 30, 2016 was $10.18 per barrel compared to $18.01 per barrel for the nine months ended September 30, 2015. The decrease in the cash operating netback for the nine months ended September 30, 2016 is primarily due to a decrease in bitumen realization as a result of the decline in U.S. crude oil benchmark pricing.

Cash Operating Netback – Three Months Ended September 30



Bitumen Realization

Bitumen realization represents the Corporation's realized proprietary petroleum revenue ("blend sales revenue"), net of 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 $30.98 per barrel for the three months ended September 30, 2016 compared to $31.03 per barrel for the three months ended September 30, 2015. The slight decrease in bitumen realization is primarily a result of the decline in U.S. crude oil benchmark pricing which resulted in lower blend sales revenue. This was almost completely offset by lower diluent expense.

For the three months ended September 30, 2016, the Corporation's cost of diluent was $61.68 per barrel of diluent compared to $66.51 per barrel of diluent for the three months ended September 30, 2015. The decrease in the cost of diluent is primarily a result of the decline in condensate benchmark pricing.

Transportation

The Corporation utilizes multiple facilities to transport and sell its blend to refiners throughout North America. In early 2016, the Corporation increased its transportation capacity on the Flanagan South and Seaway pipeline systems, thereby furthering the Corporation's strategy of broadening market access to world prices to improve netbacks. Such improved netbacks require additional transportation. These transportation costs averaged $6.46 per barrel for the three months ended September 30, 2016 compared to $4.64 per barrel for the three months ended September 30, 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 $0.42 per barrel during the three months ended September 30, 2016 compared to $0.88 per barrel for the three months ended September 30, 2015. The decrease in royalties for the three months ended September 30, 2016, as compared to the three months ended September 30, 2015, is primarily attributable to lower royalty rates as a result of lower 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 September 30, 2016 averaged $7.76 per barrel compared to $9.10 per barrel for the three months ended September 30, 2015. The decrease in net operating costs is attributable to a per barrel decrease in energy and non-energy operating costs, partially offset by a decrease in power revenue.

Non-energy operating costs

Non-energy operating costs averaged $5.32 per barrel for the three months ended September 30, 2016 compared to $5.98 per barrel for the three months ended September 30, 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 $2.99 per barrel for the three months ended September 30, 2016 compared to $3.97 per barrel for the three months ended September 30, 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 $2.69 per mcf during the third quarter of 2016 compared to $3.18 per mcf for the third quarter of 2015.

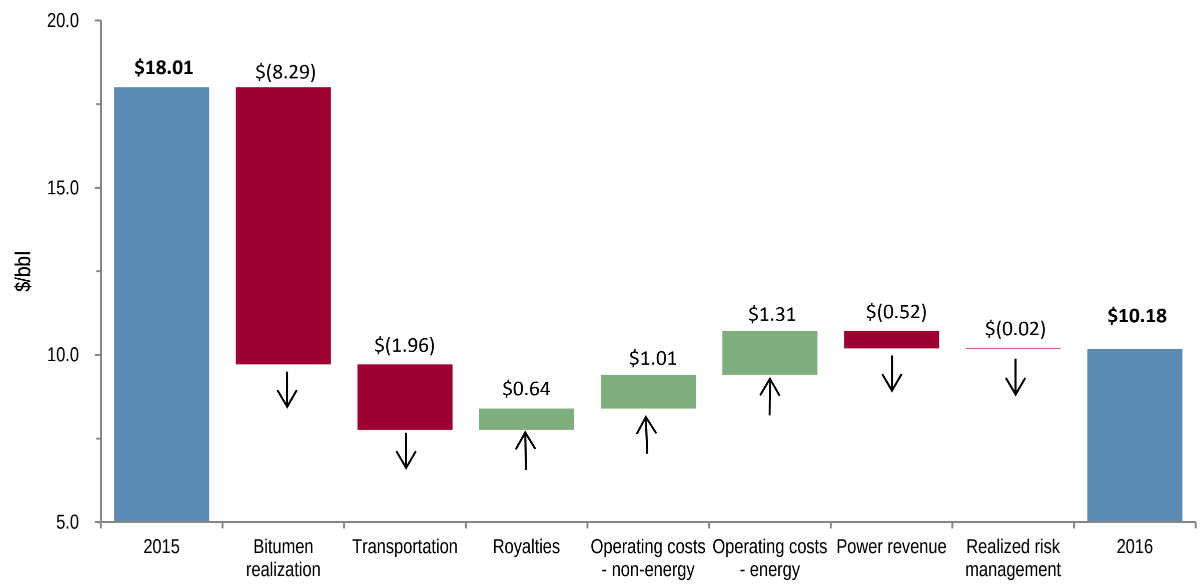
Power revenue

Power revenue averaged $0.55 per barrel for the three months ended September 30, 2016 compared to $0.85 per barrel for the three months ended September 30, 2015. The Corporation's average realized power sales price during the three months ended September 30, 2016 was $17.62 per megawatt hour compared to $25.09 per megawatt hour for the same period in 2015. The decrease in the realized power sales price is primarily due to the current surplus of power generation capacity in the province of Alberta.

Commodity Risk Management Gain

The realized gain on commodity risk management averaged $0.40 per barrel for the three months ended September 30, 2016. The Corporation initiated a commodity risk management program in 2016. Refer to the "RISK MANAGEMENT" section of this MD&A for further details.

Cash Operating Netback – Nine Months Ended September 30



Bitumen Realization

Bitumen realization averaged $24.91 per barrel for the nine months ended September 30, 2016 compared to $33.20 per barrel for the nine months ended September 30, 2015. The decrease in bitumen realization is primarily a result of the decline in U.S. crude oil benchmark pricing which resulted in lower blend sales revenue.

For the nine months ended September 30, 2016, the Corporation's cost of diluent was $58.32 per barrel of diluent compared to $69.77 per barrel of diluent for the nine months ended September 30, 2015. The decrease in the cost of diluent is primarily a result of the decline in condensate benchmark pricing.

Transportation

The Corporation utilizes multiple facilities to transport and sell its blend to refiners throughout North America. In early 2016, the Corporation increased its transportation capacity on the Flanagan South and Seaway pipeline systems, thereby furthering the Corporation's strategy of broadening market access to world prices to improve netbacks. Such improved netbacks require additional transportation. These transportation costs averaged $6.60 per barrel for the nine months ended September 30, 2016 compared to $4.64 per barrel for the nine months ended September 30, 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 $0.22 per barrel during the nine months ended September 30, 2016 compared to $0.86 per barrel for the nine months ended September 30, 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 nine months ended September 30, 2016 averaged $7.89 per barrel compared to $9.69 per barrel for the nine months ended September 30, 2015. The decrease in net operating costs is attributable to a per barrel decrease in energy and non-energy operating costs, partially offset by a decrease in power revenue.

Non-energy operating costs

Non-energy operating costs averaged $5.83 per barrel for the nine months ended September 30, 2016 compared to $6.84 per barrel for the nine months ended September 30, 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 $2.62 per barrel for the nine months ended September 30, 2016 compared to $3.93 per barrel for the nine months ended September 30, 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 $2.21 per mcf during the nine months ended September 30, 2016 compared to $3.17 per mcf for the same period in 2015.

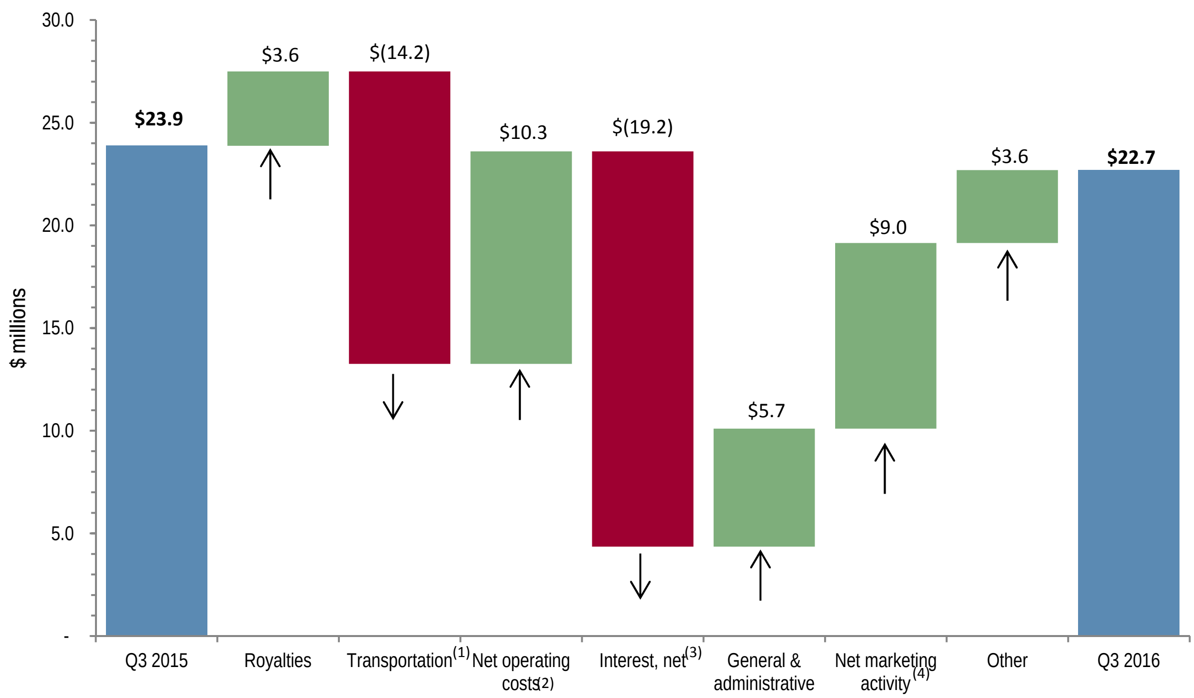
Power revenue

Power revenue averaged $0.56 per barrel for the nine months ended September 30, 2016 compared to $1.08 per barrel for the nine months ended September 30, 2015. The Corporation's average realized power sales price during the nine months ended September 30, 2016 was $17.40 per megawatt hour compared to $30.22 per megawatt hour for the same period in 2015. The decrease in the realized power sales price is primarily due to the current surplus of power generation capacity in the province of Alberta.

Commodity Risk Management Gain (Loss)

The realized loss on commodity risk management averaged $0.02 per barrel for the nine months ended September 30, 2016. Refer to the "RISK MANAGEMENT" section of this MD&A for further details.

Cash Flow From Operations – Three Months Ended September 30



(1) Defined as transportation expense less transportation revenue.

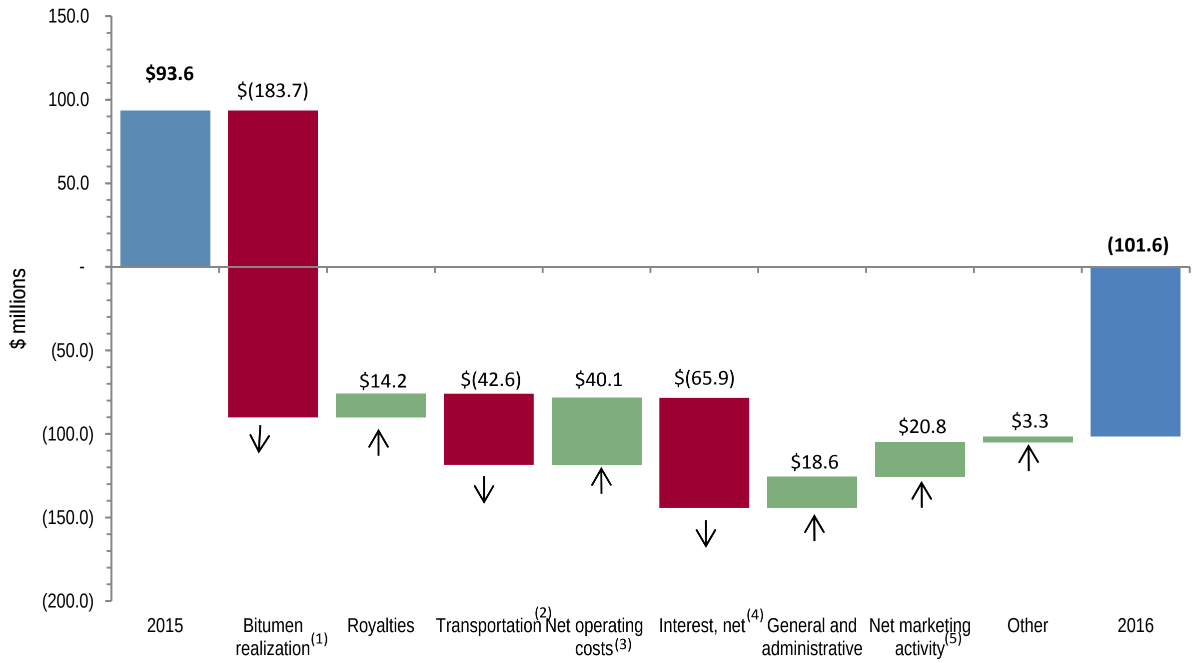
(2) Includes non-energy and energy operating costs, reduced by power revenue.

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

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

Cash flow from operations was $22.7 million for the three months ended September 30, 2016 compared to $23.9 million for the three months ended September 30, 2015. Increases in net interest expense and transportation expense were largely offset by decreases in net operating costs, net marketing activity, general and administrative expense and other expenses. 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. The decrease in net marketing activity is due to the termination of a marketing transportation contract during the fourth quarter of 2015. As a result, no expenses were recorded related to this marketing transportation contract for the three months ended September 30, 2016.

Cash Flow From (Used In) Operations – Nine Months Ended September 30



(1) Net of diluent expense.
(2) Defined as transportation expense less transportation revenue.
(3) Includes non-energy and energy operating costs, reduced by power revenue.
(4) Defined as 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 MD&A.

Cash flow used in operations was $101.6 million for the nine months ended September 30, 2016 compared to cash flow from operations of $93.6 million for the nine months ended September 30, 2015. The decrease in cash flow from operations was due to a decrease in bitumen realization and increases in net interest expense and transportation expense. These cash flow reductions were partially offset by decreases in net operating costs, net marketing activity, general and administrative expense and royalties. Cash flow from operations decreased primarily due to lower bitumen realization. The decrease in bitumen realization is directly correlated to the 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. The decrease in net marketing activity is due to the termination of a marketing transportation contract during the fourth quarter of 2015. As a result, no expenses were recorded related to this marketing transportation contract for the nine months ended September 30, 2016.

Operating Loss

Operating loss is a non-GAAP measure, as defined in the "NON-GAAP MEASURES" section of this MD&A, which the Corporation uses as a performance measure to provide comparability of financial performance between periods by excluding non-operating items. The Corporation recognized an operating loss of $87.9 million for the three months ended September 30, 2016 compared to an operating loss of $86.8 million for the three months ended September 30, 2015. The Corporation recognized an operating loss of $383.1 million for the nine months ended September 30, 2016 compared to an operating loss of $234.1 million for the nine months ended September 30, 2015. The increase in the operating loss for the nine months ended September 30, 2016 was primarily due to lower bitumen realization as a result of the decline in U.S. crude oil benchmark pricing.

Revenue

Revenue for the three months ended September 30, 2016 totalled $496.8 million compared to $459.8 million for the three months ended September 30, 2015. Revenue for the nine months ended September 30, 2016 totalled $1.3 billion compared to $1.5 billion for the nine months ended September 30, 2015. Revenue for the nine months ended September 30, 2016 decreased primarily due to a decrease in blend sales revenue as a result of the decline in U.S. crude oil benchmark pricing. Revenue represents the total of petroleum revenue, net of royalties and other revenue.

Net Loss

The Corporation recognized a net loss of $108.6 million for the three months ended September 30, 2016 compared to a net loss of $427.5 million for the three months ended September 30, 2015. The net loss for the three months ended September 30, 2016 included a net unrealized foreign exchange loss of $38.7 million on the Corporation’s U.S. dollar denominated debt and U.S. dollar denominated cash and cash equivalents which was largely offset by an unrealized gain on commodity risk management of $32.2 million. The net loss for the three months ended September 30, 2015 included a net unrealized foreign exchange loss of $330.5 million on U.S. dollar denominated debt and U.S. dollar denominated cash and cash equivalents.

The Corporation recognized a net loss of $124.0 million for the nine months ended September 30, 2016 compared to a net loss of $872.4 million for the nine months ended September 30, 2015. The net loss for the nine months ended September 30, 2016 included a net unrealized foreign exchange gain of $267.8 million on the Corporation’s U.S. dollar denominated debt and U.S. dollar denominated cash and cash equivalents. The net loss was also affected by lower bitumen realization, primarily as a result of the decline in U.S. crude oil benchmark pricing. The net loss for the nine months ended September 30, 2015 included a net unrealized foreign exchange loss of $626.3 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 September 30, 2016 totalled $19.2 million, as compared to $32.1 million for the three months ended September 30, 2015. Total cash capital investment during the nine months ended September 30, 2016 totalled $74.2 million as compared to $202.7 million for the nine months ended September 30, 2015. 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.

Capital Resources

The Corporation's cash and cash equivalents balance totalled $103.1 million as at September 30, 2016 compared to a cash and cash equivalents balance of $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$4.9 billion as at September 30, 2016 from C$5.2 billion as at December 31, 2015. All of MEG'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. The first maturity of any of the Corporation's long-term debt obligations is March 2020.

As at September 30, 2016, the Corporation's capital resources included $103.1 million of cash and cash equivalents, an additional undrawn US$2.5 billion syndicated revolving credit facility that matures November 2019, and a US$500 million guaranteed letter of credit facility that matures November 2019, under which US$295.9 million of letters of credit have been issued. Similar to the Corporation's long-term debt, the revolving credit facility is "covenant lite" in structure.

3. OUTLOOK

Summary of 2016 Guidance	Guidance February 4, 2016	Guidance July 27, 2016	Revised Guidance October 27, 2016
Capital investment - $ millions	$170	$170	$140
Bitumen production - bbls/d	80,000 – 83,000	80,000 – 83,000	80,000 – 83,000
Non-energy operating costs - $/bbl	$6.75 – $7.75	$6.00 – $7.00	$5.75 - $6.50

On February 4, 2016, the Corporation announced a 2016 capital budget of $170 million. As a result of continued focus on reducing capital spending until there is a sustained improvement in crude oil pricing, capital investment in 2016 is now anticipated to be approximately $140 million. The decrease in capital guidance is primarily due to continued efficiency gains primarily achieved through the application of eMSAGP.

The Corporation's 2016 production guidance remains unchanged at 80,000 to 83,000 bbls/d. On July 27, 2016, the Corporation announced a revision to the annual non-energy operating costs guidance to a range of $6.00 to $7.00 per barrel. As a result of continuing operating cost management and efficiency gains in 2016, annual non-energy operating costs are now targeted to be in the range of $5.75 to $6.50 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.

4. 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:

	Nine months ended September 30		2016			2015				2014
	2016	2015	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Average Commodity Prices										
Crude oil prices										
Brent (US$/bbl)	**42.91**	56.61	**46.98**	46.67	35.10	44.71	51.17	63.50	55.16	76.98
WTI (US$/bbl)	**41.34**	51.00	**44.94**	45.59	33.45	42.18	46.43	57.94	48.63	73.15
WTI (C$/bbl)	**54.69**	64.26	**58.65**	58.75	45.99	56.32	60.79	71.24	60.35	83.08
Differential – Brent:WTI (US$/bbl)	**1.57**	5.61	**2.04**	1.08	1.65	2.53	4.74	5.56	6.53	3.83
Differential – Brent:WTI (%)[1]	**3.7%**	9.9%	**4.3%**	2.3%	4.7%	5.7%	9.3%	8.8%	11.8%	5.0%
WCS (C$/bbl)	**36.59**	47.47	**41.03**	41.61	26.41	36.97	43.29	56.98	42.13	66.74
Differential – WTI:WCS (US$/bbl)	**13.68**	13.20	**13.50**	13.30	14.24	14.49	13.27	11.59	14.73	14.24
Differential – WTI:WCS (C$/bbl)	**18.10**	16.79	**17.62**	17.14	19.58	19.35	17.50	14.25	18.22	16.34
Differential – WTI:WCS (%)	**33.1%**	26.1%	**30.0%**	29.2%	42.6%	34.4%	28.8%	20.0%	30.2%	19.7%
Condensate prices										
Condensate at Edmonton (C$/bbl)	**53.45**	61.88	**56.25**	56.83	47.27	55.57	57.89	71.17	56.59	81.98
Condensate at Edmonton as % of WTI	**97.7%**	96.3%	**95.9%**	96.7%	102.8%	98.7%	95.2%	99.9%	93.8%	98.7%
Condensate at Mont Belvieu, Texas (US$/bbl)	**37.86**	46.72	**41.17**	40.37	32.03	40.76	41.27	52.89	46.01	62.47
Condensate at Mont Belvieu, Texas as % of WTI	**91.6%**	91.6%	**91.6%**	88.6%	95.8%	96.6%	88.9%	91.3%	94.6%	85.4%
Natural gas prices										
AECO (C$/mcf)	**1.89**	2.76	**2.49**	1.37	1.82	2.57	2.89	2.64	2.74	3.58
Electric power prices										
Alberta power pool (C$/MWh)	**16.93**	37.48	**17.93**	14.77	18.09	21.19	26.04	57.25	29.14	30.55
Foreign exchange rates										
C$ equivalent of 1 US$ - average	**1.3228**	1.2600	**1.3051**	1.2886	1.3748	1.3353	1.3093	1.2294	1.2411	1.1357
C$ equivalent of 1 US$ - period end	**1.3117**	1.3394	**1.3117**	1.3009	1.2971	1.3840	1.3394	1.2474	1.2683	1.1601

Crude Oil Pricing

Brent crude is the primary world price benchmark for global light sweet crude oil. The Brent benchmark price averaged US$46.98 per barrel in the third quarter of 2016 compared to US$51.17 per barrel for the third quarter of 2015. The Brent benchmark price averaged US$42.91 per barrel for the nine months ended September 30, 2016 compared to US$56.61 per barrel for the nine months ended September 30, 2015. The global supply of crude oil is currently greater than demand, which has resulted in a decrease in 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$44.94 per barrel in the third quarter of 2016 compared to US$46.43 per barrel for the third quarter of 2015. The WTI price averaged US$41.34 per barrel for the nine months ended September 30, 2016 compared to US$51.00 per barrel for the nine months ended September 30, 2015. The global supply of crude oil is currently greater than demand, which has resulted in a decrease in 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$13.50 per barrel, or 30.0%, for the third quarter of 2016, compared to US$13.27 per barrel, or 28.8%, for the third quarter of 2015. The WTI:WCS differential averaged US$13.68 per barrel, or 33.1%, for the nine months ended September 30, 2016 compared to US$13.20 per barrel, or 26.1%, for the nine months ended September 30, 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 $56.25 per barrel, or 95.9% of WTI, for the third quarter of 2016 compared to $57.89 per barrel, or 95.2% of WTI, for the third quarter of 2015. Condensate prices, benchmarked at Edmonton, averaged $53.45 per barrel, or 97.7% of WTI, for the nine months ended September 30, 2016 compared to $61.88 per barrel, or 96.3% of WTI, for the nine months ended September 30, 2015.

Condensate prices, benchmarked at Mont Belvieu, Texas, averaged US$41.17 per barrel, or 91.6% of WTI, for the third quarter of 2016 compared to US$41.27 per barrel, or 88.9% of WTI, for the third quarter of 2015. Condensate prices, benchmarked at Mont Belvieu, Texas, averaged US$37.86 per barrel, or 91.6% of WTI, for the nine months ended September 30, 2016 compared to US$46.72 per barrel, or 91.6% of WTI, for the nine months ended September 30, 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 $2.49 per mcf for the third quarter of 2016 compared to $2.89 per mcf for the third quarter of 2015. The AECO natural gas price averaged $1.89 per mcf for the nine months ended September 30, 2016 compared to $2.76 per mcf for the nine months ended September 30, 2015. Natural gas market prices have recently improved due to factors such as below average storage injections and a levelling off of production of natural gas in North America.

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 $17.93 per megawatt hour for the third quarter of 2016 compared to $26.04 per megawatt hour for the third quarter of 2015. Average power prices for the third quarter of 2015 were positively affected by several plant outages late in the third quarter of 2015. The Alberta power pool price averaged $16.93 per megawatt hour for the nine months ended September 30, 2016 compared to $37.48 per megawatt hour for the same period in 2015. The decline in the Alberta power pool price is primarily due to a 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 the 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 the diluent expense and principal and interest payments.

The Corporation recognizes net unrealized foreign exchange gains and losses on the translation of U.S. dollar denominated debt and U.S. dollar denominated cash and cash equivalents at each reporting date. As at September 30, 2016, the Canadian dollar, at a rate of 1.3117, had increased in value by approximately 5% against the U.S. dollar compared to its value as at December 31, 2015, when the rate was 1.3840. As at September 30, 2016, the Canadian dollar had increased in value by approximately 2% from September 30, 2015, when the rate was 1.3394.

5. OTHER OPERATING RESULTS

Net Marketing Activity

	Three months ended September 30		Nine months ended September 30	
($000)	**2016**	**2015**	**2016**	**2015**
Petroleum revenue – third party	**$ 48,599**	$ 9,255	**$ 154,838**	$ 54,103
Purchased product and storage:				
Purchased product	**(48,157)**	(8,402)	**(151,638)**	(51,589)
Marketing and storage arrangements	**-**	(9,450)	**-**	(20,107)
	(48,157)	(17,852)	**(151,638)**	(71,696)
Net marketing activity[1]	**$ 442**	$ (8,597)	**$ 3,200**	$ (17,593)

(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. As a result, no expenses were recorded related to marketing and storage arrangements for the three and nine months ended September 30, 2016.

Depletion and Depreciation

	Three months ended September 30		Nine months ended September 30	
($000)	2016	2015	2016	2015
Depletion and depreciation expense	**$ 128,995**	$ 121,786	**$ 373,340**	$ 340,269
Depletion and depreciation expense per barrel of production	**$ 16.81**	$ 15.99	**$ 16.81**	$ 15.81

Depletion and depreciation expense for the three months ended September 30, 2016 totalled $129.0 million compared to $121.8 million for the three months ended September 30, 2015. Depletion and depreciation expense was $16.81 per barrel for the three months ended September 30, 2016 compared to $15.99 per barrel for the three months ended September 30, 2015. The increase in the depletion and depreciation expense per barrel was primarily due to an increase in estimated future development costs associated with the Corporation's proved reserves and an increase in depreciable costs.

Depletion and depreciation expense for the nine months ended September 30, 2016 totalled $373.3 million compared to $340.3 million for the nine months ended September 30, 2015. Depletion and depreciation expense was $16.81 per barrel for the nine months ended September 30, 2016 compared to $15.81 per barrel for the nine months ended September 30, 2015. The increase in the depletion and depreciation expense per barrel was primarily due to an increase in estimated future development costs associated with the Corporation's proved reserves and an increase in depreciable costs.

Commodity Risk Management Gain (Loss)

	Three months ended September 30					
	2016			2015		
($000)	Realized	Unrealized	Total	Realized	Unrealized	Total
Condensate contracts[1]	**$ 3,640**	**$ 33,027**	**$ 36,667**	$ -	$ -	$ -
Crude oil contracts[2]	**(512)**	**(820)**	**(1,332)**	-	-	-
Commodity risk management gain (loss)	**$ 3,128**	**$ 32,207**	**$ 35,335**	$ -	$ -	$ -

(1) *Relates to condensate purchase contracts that effectively fix condensate prices at Mont Belvieu, Texas as a percentage of WTI (US$/bbl).*

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

During the three and nine months ended September 30, 2016, the Corporation entered into commodity risk management contracts. The Corporation has not designated any of its commodity risk management contracts as accounting hedges. 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.

The Corporation recognized an unrealized gain on commodity risk management contracts of $32.2 million and a realized gain on commodity risk management contracts of $3.1 million for the three months ended September 30, 2016.

Nine months ended September 30						
	2016			2015		
($000)	Realized	Unrealized	Total	Realized	Unrealized	Total
Condensate contracts[1]	$ 5,457	$ 30,846	$ 36,303	$ -	$ -	$ -
Crude oil contracts[2]	(5,816)	(19,110)	(24,926)	-	-	-
Commodity risk management gain (loss)	$ (359)	$ 11,736	$ 11,377	$ -	$ -	$ -

(1) *Relates to condensate purchase contracts that effectively fix condensate prices at Mont Belvieu, Texas as a percentage of WTI (US$/bbl).*

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

The Corporation recognized an unrealized gain on commodity risk management contracts of $11.7 million and a realized loss on commodity risk management contracts of $0.4 million for the nine months ended September 30, 2016. Refer to the "RISK MANAGEMENT" section of this MD&A for further details.

General and Administrative

	Three months ended September 30		Nine months ended September 30	
($000)	2016	2015	2016	2015
General and administrative expense	$ 22,587	$ 28,335	$ 74,671	$ 93,237
General and administrative expense per barrel of production	$ 2.94	$ 3.72	$ 3.36	$ 4.33

General and administrative expense for the three months ended September 30, 2016 was $22.6 million compared to $28.3 million for the three months ended September 30, 2015. General and administrative expense was $2.94 per barrel for the three months ended September 30, 2016 compared to $3.72 per barrel for the three months ended September 30, 2015. General and administrative expense for the nine months ended September 30, 2016 was $74.7 million compared to $93.2 million for the nine months ended September 30, 2015. General and administrative expense was $3.36 per barrel for the nine months ended September 30, 2016 compared to $4.33 per barrel for the nine months ended September 30, 2015. General and administrative expense was lower 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 September 30		Nine months ended September 30	
($000)	2016	2015	2016	2015
Cash-settled	$ 4,045	$ -	$ 5,495	$ -
Equity-settled	5,977	13,250	27,938	38,066
Stock-based compensation expense	$ 10,022	$ 13,250	$ 33,433	$ 38,066

The fair value of compensation associated with the granting of stock options, restricted share units ("RSUs") and performance share units ("PSUs") to directors, officers, 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 issued RSUs and PSUs under a new cash-settled plan. Upon vesting of the RSUs, the participants of the RSU plan will receive a cash payment based on the fair value of the underlying share units at the vesting date. PSUs become eligible to vest if the Corporation satisfies the performance criteria identified by the Corporation's Board of Directors within a target range. 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 in the period they occur.

Stock-based compensation expense for the three months ended September 30, 2016 was $10.0 million compared to $13.3 million for the three months ended September 30, 2015. Stock-based compensation expense for the nine months ended September 30, 2016 was $33.4 million compared to $38.1 million for the nine months ended September 30, 2015. Stock-based compensation expense was lower during the three and nine months ended September 30, 2016, compared to same periods in 2015, primarily due to lower costs associated with new awards and forfeitures.

Research and Development

	Three months ended September 30		Nine months ended September 30	
($000)	**2016**	**2015**	**2016**	**2015**
Research and development expense	**$ 1,265**	$ 2,239	**$ 4,360**	$ 5,030

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 $1.3 million for the three months ended September 30, 2016 compared to $2.2 million for the three months ended September 30, 2015. Research and development expenditures were $4.4 million for the nine months ended September 30, 2016 compared to $5.0 million for the nine months ended September 30, 2015.

Foreign Exchange Loss (Gain), Net

	Three months ended September 30		Nine months ended September 30	
($000)	**2016**	**2015**	**2016**	**2015**
Unrealized foreign exchange loss (gain) on:				
Long-term debt	**$ 40,954**	$ 350,066	**$ (274,723)**	$ 682,850
US$ denominated cash and cash equivalents	**(2,225)**	(19,588)	**6,960**	(56,549)
Unrealized net loss (gain) on foreign exchange	**38,729**	330,478	**(267,763)**	626,301
Realized loss (gain) on foreign exchange	**1,005**	4,913	**(3,853)**	13,081
Foreign exchange loss (gain), net	**$ 39,734**	$ 335,391	**$ (271,616)**	$ 639,382
C$ equivalent of 1 US$				
Beginning of period	**1.3009**	1.2474	**1.3840**	1.1601
End of period	**1.3117**	1.3394	**1.3117**	1.3394

The Corporation recognized a net foreign exchange loss of $39.7 million for the three months ended September 30, 2016 compared to a net foreign exchange loss of $335.4 million for the three months ended September 30, 2015. The net foreign exchange loss is primarily due to the translation of the U.S. dollar denominated debt as a result of slight weakening of the Canadian dollar compared to the U.S. dollar during the three months ended September 30, 2016. During the three months ended September 30, 2015, the Canadian dollar weakened in value by approximately 7%.

The Corporation recognized a net foreign exchange gain of $271.6 million for the nine months ended September 30, 2016 compared to a net foreign exchange loss of $639.4 million for the nine months ended September 30, 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 5% during the nine months ended September 30, 2016. During the nine months ended September 30, 2015, the Canadian dollar weakened in value by approximately 15%.

Net Finance Expense

	Three months ended September 30		Nine months ended September 30	
($000)	**2016**	**2015**	**2016**	**2015**
Total interest expense	**$ 81,194**	$ 80,248	**$ 245,866**	$ 231,524
Less capitalized interest	**-**	(17,991)	**-**	(50,479)
Net interest expense	**81,194**	62,257	**245,866**	181,045
Accretion on provisions	**1,796**	1,491	**5,310**	4,047
Unrealized loss (gain) on derivative financial liabilities(1)	**(11,367)**	6,807	**(5,362)**	2,600
Realized loss on interest rate swaps	**1,507**	1,512	**4,548**	4,317
Net finance expense	**$ 73,130**	$ 72,068	**$ 250,362**	$ 192,010
Average effective interest rate(2)	**5.8%**	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 September 30, 2016 was $81.2 million compared to $80.2 million for the three months ended September 30, 2015. Total interest expense, before capitalization, for the nine months ended September 30, 2016 was $245.9 million compared to $231.5 million for the nine months ended September 30, 2015. Total interest expense for the three and nine months ended September 30, 2016 was higher than the comparative 2015 periods 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 and nine months ended September 30, 2016. During the three and nine months ended September 30, 2015, the Corporation capitalized $18.0 million and $50.5 million of interest, respectively.

The Corporation recognized an unrealized gain on derivative financial liabilities of $11.4 million for the three months ended September 30, 2016 compared to an unrealized loss of $6.8 million for the three months ended September 30, 2015. The Corporation recognized an unrealized gain on derivative financial liabilities of $5.4 million for the nine months ended September 30, 2016 compared to an unrealized loss of $2.6 million for the nine months ended September 30, 2015. These unrealized gains relate 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 realized a loss on the interest rate swaps of $1.5 million for the three months ended September 30, 2016 compared to a realized loss of $1.5 million for the three months ended September 30, 2015. The Corporation realized a loss on the interest rate swaps of $4.5 million for the nine months ended September 30, 2016 compared to a realized loss of $4.3 million for the nine months ended September 30, 2015. The interest rate swaps expired on September 30, 2016.

Other Expenses (Recoveries)

	Three months ended September 30		Nine months ended September 30	
($000)	**2016**	**2015**	**2016**	**2015**
Onerous contracts	**$ 18,057**	$ -	**$ 31,483**	$ -
Contract cancellation recovery	**-**	-	**-**	(5,880)
Severance and other	**-**	-	**6,179**	-
Other expenses (recoveries)	**$ 18,057**	$ -	**$ 37,662**	$ (5,880)

The Corporation recognized other expenses of $18.1 million for the three months ended September 30, 2016 and $37.7 million for the nine months ended September 30, 2016 compared to a recovery of $5.9 million for the nine months ended September 30, 2015.

For the three months ended September 30, 2016, an onerous contract expense of $18.1 million was recognized primarily related to a decrease in estimated future cash flow recoveries related to the onerous office lease provision. For the nine months ended September 30, 2016, the Corporation recognized an onerous contracts expense of $31.5 million primarily due to a decrease in estimated future cash flow recoveries related to the onerous office lease provision.

During the nine months ended September 30, 2016, severance and other expenses of $6.2 million were incurred.

Income Tax Expense (Recovery)

	Three months ended September 30		Nine months ended September 30	
($000)	**2016**	**2015**	**2016**	**2015**
Current income tax expense (recovery)	**$ 103**	$ (400)	**$ 717**	$ (1,200)
Deferred income tax recovery	**(22,833)**	(25,280)	**(140,793)**	(47,798)
Income tax recovery	**$ (22,730)**	$ (25,680)	**$ (140,076)**	$ (48,998)

The Corporation recognized a current income tax expense of $0.1 million for the three months ended September 30, 2016 and $0.7 million for the nine months ended September 30, 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 three and nine months ended September 30, 2015, the Corporation recognized current income tax recoveries of $0.4 million and $1.2 million, respectively, which are related to the refundable Alberta tax credit on Scientific Research and Experimental Development expenditures.

The Corporation recognized a deferred income tax recovery of $22.8 million for the three months ended September 30, 2016 compared to a deferred income tax recovery of $25.3 million for the three months ended September 30, 2015. The Corporation recognized a deferred income tax recovery of $140.8 million for the nine months ended September 30, 2016 compared to a deferred income tax recovery of $47.8 million for the nine months ended September 30, 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 September 30, 2016, the non-taxable loss was $20.5 million compared to a non-taxable loss of $175.0 million for the three months ended September 30, 2015. For the nine months ended September 30, 2016, the non-taxable gain was $137.4 million compared to a non-taxable loss of $341.4 million for the nine months ended September 30, 2015.

- Non-taxable stock-based compensation expense is a permanent difference. Stock-based compensation expense for equity-settled plans for the three months ended September 30, 2016 was $6.0 million compared to $13.3 million for the three months ended September 30, 2015. Stock-based compensation expense for equity-settled plans for the nine months ended September 30, 2016 was $27.9 million compared to $38.1 million for the three months ended September 30, 2015.

- During the nine months ended September 30, 2016, a deferred tax recovery of $2.0 million was recognized relating to a tax deduction available for the fair market value of vested RSUs. During the nine months ended September 30, 2015, a deferred tax recovery of $5.4 million was recognized relating to a tax deduction available for the fair market value of vested RSUs.

As at September 30, 2016, the Corporation had approximately $8.0 billion of available tax pools and $219.7 million of capital investment in respect of incomplete projects which will increase available tax pools upon completion of the projects.

As at September 30, 2016, the Corporation has recognized a deferred income tax asset of $53.3 million, as estimated future taxable income is expected to be sufficient to realize the deferred income tax asset.

As at September 30, 2016, the Corporation had not recognized the tax benefit related to $559.3 million of unrealized taxable capital foreign exchange losses.

6. CAPITAL INVESTING

	Three months ended September 30		Nine months ended September 30	
($000)	2016	2015	2016	2015
Total cash capital investment	$ 19,203	$ 32,139	$ 74,168	$ 202,705
Capitalized interest	-	17,991	-	50,479
	$ 19,203	$ 50,130	$ 74,168	$ 253,184

Total cash capital investment for the three months ended September 30, 2016 was $19.2 million, compared to $32.1 million for the three months ended September 30, 2015. Total cash capital investment for the nine months ended September 30, 2016 was $74.2 million, compared to $202.7 million for the nine months ended September 30, 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.

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 and nine months ended September 30, 2016. During the three and nine months ended September 30, 2015, the Corporation capitalized $18.0 million and $50.5 million of interest, respectively.

7. LIQUIDITY AND CAPITAL RESOURCES

($000)	September 30, 2016	December 31, 2015
Cash and cash equivalents	$ 103,136	$ 408,213
Senior secured term loan (September 30, 2016 – US$1.239 billion; December 31, 2015 – US$1.249 billion; due 2020)	1,624,868	1,727,924
US$2.5 billion revolver (due 2019)	-	-
6.5% senior unsecured notes (US$750.0 million; due 2021)	983,775	1,038,000
6.375% senior unsecured notes (US$800.0 million; due 2023)	1,049,360	1,107,200
7.0% senior unsecured notes (US$1.0 billion; due 2024)	1,311,700	1,384,000
Total debt[(1),(2)]	$ 4,969,703	$ 5,257,124

(1) Total debt does not have a standardized meaning prescribed by IFRS and therefore may not be comparable to similar measures used by other companies. The Corporation uses this non-GAAP measure to analyze leverage and liquidity. Total debt less the current portion of the senior secured term loan, unamortized financial derivative liability discount and unamortized deferred debt issue costs is equal to long-term debt as reported in the Corporation's interim consolidated financial statements as at September 30, 2016 and the Corporation's consolidated financial statements as at December 31, 2015.

(2) On February 3, 2016, Moody's Investors Service ("Moody's") downgraded the Corporation's Corporate Family Rating (CFR) to Caa2 from B1, Probability of Default Rating to Caa2-PD from B1-PD, secured bank credit facility rating to B3 from Ba2 and senior unsecured notes rating to Caa3 from B2. The Speculative Grade Liquidity Rating was lowered to SGL-2 from SGL-1. The rating outlook is negative. The Corporation's senior secured term loan and senior unsecured notes do not include any provision that would require any changes in payment schedules or terminations as a result of a credit downgrade.

Capital Resources

As at September 30, 2016, the Corporation's available capital resources included $103.1 million of cash and cash equivalents and an undrawn US$2.5 billion syndicated revolving credit facility (“revolver”). The Corporation also has a US$500 million guaranteed letter of credit facility, under which US$295.9 million of letters of credit have been issued.

The US$2.5 billion revolver remains undrawn as at September 30, 2016. All of MEG’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. The first maturity of any of the Corporation’s long-term debt obligations is March 2020. The term loan has quarterly principal installments of US$3.25 million. The Corporation has a five-year US$500 million letter of credit facility that matures in November 2019.

Management believes its current capital resources and its ability to manage cash flow and working capital levels will allow the Corporation to meet its current and future obligations, to make scheduled principal and interest payments, and to fund the other needs of the business for at least the next 12 months. However, no assurance can be given that this will be the case or that future sources of capital will not be necessary. The Corporation's cash flow and the development of projects are dependent on factors discussed in the "RISK FACTORS" section of this MD&A.

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

Cash Flow Summary

($000)	Three months ended September 30 2016	Three months ended September 30 2015	Nine months ended September 30 2016	Nine months ended September 30 2015
Net cash provided by (used in):				
Operating activities	**$ (19,894)**	$ (5,188)	**$ (175,978)**	$ 99,631
Investing activities	**(27,552)**	(101,085)	**(108,144)**	(455,387)
Financing activities	**(4,263)**	(4,359)	**(12,698)**	(12,507)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency	**2,134**	23,130	**(8,257)**	62,902
Change in cash and cash equivalents	**$ (49,575)**	$ (87,502)	**$ (305,077)**	$ (305,361)

Cash Flow – Operating Activities

Net cash used in operating activities totalled $19.9 million for the three months ended September 30, 2016 compared to net cash used in operating activities of $5.2 million for the three months ended September 30, 2015. Net cash used in operating activities increased due to the decline in U.S. crude oil benchmark pricing.

Net cash used in operating activities totalled $176.0 million for the nine months ended September 30, 2016 compared to net cash provided by operating activities of $99.6 million for the nine months ended September 30, 2015. The decrease in cash flow from operating activities is primarily due to lower bitumen realization, particularly in the first quarter of 2016, primarily as a result of the decline in U.S. crude oil benchmark pricing as well as the use of cash for quarterly interest and principal payments.

Cash Flow – Investing Activities

Net cash used in investing activities was $27.6 million for the three months ended September 30, 2016 compared to $101.1 million for the three months ended September 30, 2015. The decrease in net cash used in investing activities is primarily due to a reduction of the Corporation’s capital program in 2016.

Net cash used in investing activities was $108.1 million for the nine months ended September 30, 2016 compared to $455.4 million for the nine months ended September 30, 2015. The decrease in net cash used in investing activities is primarily due to a reduction of the Corporation’s capital program in 2016.

Cash Flow – Financing Activities

Net cash used in financing activities was $4.3 million for the three months ended September 30, 2016 compared to $4.4 million for the three months ended September 30, 2015. Net cash used in financing activities includes quarterly debt principal repayments of US$3.25 million.

Net cash used in financing activities was $12.7 million for the nine months ended September 30, 2016 compared to $12.5 million for the nine months ended September 30, 2015. Net cash used in financing activities includes debt principal payments of US$9.75 million for each of the nine-month periods.

8. 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. MEG has implemented a strategic commodity risk management program through the use of derivative financial instruments to increase the predictability of the Corporation's 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 has the following commodity risk management contracts relating to crude oil sales outstanding:

As at September 30, 2016	Volumes (bbls/d)	Term	Average Price (US$/bbl)
Fixed Price:			
WTI Fixed Price	24,000	Oct 1, 2016 – Dec 31, 2016	$48.25
WCS Fixed Differential	30,587	Oct 1, 2016 – Dec 31, 2016	$(14.64)
WCS Fixed Differential	15,000	Jan 1, 2017 – Jun 30, 2017	$(14.74)
Collars:			
WTI Collars	19,000	Oct 1, 2016 – Dec 31, 2016	$44.99 – $53.68
WTI Collars	29,500	Jan 1, 2017 – Jun 30, 2017	$45.00 – $51.92
WTI Collars	7,000	Jul 1, 2017 – Dec 31, 2017	$45.00 – $56.72

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

As at September 30, 2016	Volumes (bbls/d)	Term	Average % of WTI
Mont Belvieu fixed % of WTI	14,750	Oct 1, 2016 – Dec 31, 2016	84.0%
Mont Belvieu fixed % of WTI	15,150	Jan 1, 2017 – Dec 31, 2017	82.9%

Interest Rate Risk Management

During 2015 and 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 US$1.239 billion senior secured term loan. These interest rate swap contracts expired on September 30, 2016.

9. SHARES OUTSTANDING

As at September 30, 2016, the Corporation had the following share capital instruments outstanding or exercisable:

	Outstanding
Common shares	226,415,112
Convertible securities	
Stock options[1]	9,755,987
Equity-settled RSUs and PSUs	1,724,636

(1) 6,244,876 stock options were exercisable as at September 30, 2016.

As at October 18, 2016, the Corporation had 226,415,112 common shares, 9,470,964 stock options and 1,723,488 equity-settled restricted share units and equity-settled performance share units outstanding and 5,968,602 stock options exercisable.

10. CONTRACTUAL OBLIGATIONS AND COMMITMENTS

The information presented in the table below reflects management's estimate of the contractual maturities of the Corporation's obligations. These maturities may differ significantly from the actual maturities of these obligations. In particular, debt under the senior secured credit facilities may be retired earlier due to mandatory repayments.

($000)	2016[1]	2017	2018	2019	2020	Thereafter
Long-term debt[2]	$ 4,263	$ 17,052	$ 17,052	$ 17,052	$ 1,569,449	$ 3,344,835
Interest on long-term debt[2]	70,878	283,115	282,475	281,836	237,395	451,103
Decommissioning obligation[3]	371	483	2,648	2,657	1,774	793,638
Transportation and storage[4]	43,017	180,914	197,878	188,401	227,348	3,217,659
Office lease rentals[5]	3,695	33,934	32,496	32,526	33,442	269,411
Diluent purchases[6]	69,074	58,281	20,246	20,246	20,302	57,355
Other commitments[7]	12,285	23,819	8,811	10,822	11,453	80,543
Total	**$203,583**	**$ 597,598**	**$ 561,606**	**$ 553,540**	**$ 2,101,163**	**$ 8,214,544**

(1) Represents the commitments remaining for the period October 1 to December 31, 2016.
(2) This represents the scheduled principal repayments of the senior secured term loan and the senior unsecured notes and associated interest payments based on interest and foreign exchange rates in effect on September 30, 2016.
(3) This represents the undiscounted future obligations associated with the decommissioning of the Corporation's crude oil, transportation and storage assets.
(4) This represents transportation and storage commitments from 2016 to 2040, including various pipeline commitments which are awaiting regulatory approval.
(5) This represents the future commitments for the Calgary Corporate office.
(6) This represents the future commitments associated with the Corporation's diluent purchases.
(7) This represents the future commitments associated with the Corporation's capital program and other operating and maintenance commitments.

11. NON-GAAP MEASURES

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

Cash Flow From (Used In) Operations

Cash flow from (used in) operations is a non-GAAP measure utilized by the Corporation to analyze operating performance and liquidity. Cash flow from (used in) operations excludes the net change in non-cash operating working capital, net change in other liabilities, contract cancellation recovery and decommissioning expenditures, while the IFRS measurement "net cash provided by (used in) operating activities" includes these items. Cash flow from (used in) operations is reconciled to net cash provided by (used in) operating activities in the table below.

	Three months ended September 30		Nine months ended September 30	
($000)	**2016**	**2015**	**2016**	**2015**
Net cash provided by (used in) operating activities	**$ (19,894)**	$ (5,188)	**$ (175,978)**	$ 99,631
Adjustments:				
Net change in non-cash operating working capital items	**45,492**	28,887	**76,409**	(1,594)
Net change in other liabilities	**(2,995)**	-	**(3,100)**	-
Contract cancellation recovery	**-**	-	**-**	(5,880)
Decommissioning expenditures	**99**	178	**1,095**	1,429
Cash flow from (used in) operations	**$ 22,702**	$ 23,877	**$ (101,574)**	$ 93,586

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, unrealized gains and losses on risk management, contract cancellation recovery, onerous contracts and the respective deferred tax impact of these adjustments. Operating loss is reconciled to "net loss", the nearest IFRS measure, in the table below.

	Three months ended September 30		Nine months ended September 30	
($000)	**2016**	**2015**	**2016**	**2015**
Net loss	**$ (108,632)**	$ (427,503)	**$ (123,968)**	$ (872,396)
Adjustments:				
Unrealized net loss (gain) on foreign exchange[1]	**38,729**	330,478	**(267,763)**	626,301
Unrealized loss (gain) on derivative financial instruments[2]	**(11,367)**	6,807	**(5,362)**	2,600
Unrealized gain on risk management[3]	**(32,207)**	-	**(11,736)**	-
Contract cancellation recovery	**-**	-	**-**	(5,880)
Onerous contracts expense[4]	**18,057**	-	**31,483**	-
Deferred tax expense (recovery) relating to these adjustments	**7,491**	3,449	**(5,763)**	15,235
Operating loss	**$ (87,929)**	$ (86,769)	**$ (383,109)**	$ (234,140)

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

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

Operating Cash Flow

Operating cash flow is a non-GAAP measure widely used in the oil and gas industry as a supplemental measure of the Corporation’s efficiency and its ability to fund future capital investments. 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 production revenues 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 revenues and power revenues, on a per barrel of bitumen sales volume basis.

12. CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The Corporation's critical accounting estimates are those estimates having a significant impact on the Corporation's financial position and operations and that require management to make judgments, assumptions and estimates in the application of IFRS. Judgments, assumptions and estimates are based on historical experience and other factors that management believes to be reasonable under current conditions. As events occur and additional information is obtained, these judgments, assumptions and estimates may be subject to change.

For a detailed discussion regarding the Corporation's critical accounting policies and estimates, please refer to the Corporation's 2015 annual MD&A.

13. TRANSACTIONS WITH RELATED PARTIES

The Corporation did not enter into any related party transactions during the three and nine months ended September 30, 2016 and September 30, 2015, other than compensation of key management personnel. The Corporation considers directors and executive officers of the Corporation as key management personnel.

14. OFF-BALANCE SHEET ARRANGEMENTS

As at September 30, 2016 and December 31, 2015, the Corporation did not have any off-balance sheet arrangements. The Corporation has certain operating or rental lease agreements, as disclosed in the Contractual Obligations and Commitments section of this MD&A, which are entered into in the normal course of operations.

15. NEW ACCOUNTING STANDARDS

There were no new accounting standards adopted during the nine months ended September 30, 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.

A description of additional accounting standards that are anticipated to be adopted by the Corporation in future periods is provided within Note 3 of the Corporation's audited consolidated financial statements for the year ended December 31, 2015.

16. RISK FACTORS

The Corporation's primary focus is on the ongoing development and operation of its oil sands assets. In developing and operating these assets, the Corporation is and will be subject to many risks, including the risks which have been categorized and described in the Corporation’s MD&A for the year ended December 31, 2015. Further information regarding the risk factors which may affect the Corporation is contained in the most recently filed Annual Information Form (“AIF”), which is available on the Corporation’s website at www.megenergy.com and is also available on the SEDAR website at www.sedar.com.

17. DISCLOSURE CONTROLS AND PROCEDURES

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

18. INTERNAL CONTROLS OVER FINANCIAL REPORTING

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

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

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

19. 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
eMSAGP	enhanced Modified Steam And Gas Push
GAAP	Generally Accepted Accounting Principles
IFRS	International Financial Reporting Standards
LIBOR	London Interbank Offered Rate
MD&A	Management's Discussion and Analysis
PSU	Performance share units
RSU	Restricted share units
SAGD	Steam-Assisted Gravity Drainage
SOR	Steam 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

20. 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; the anticipated reductions in operating costs as a result of optimization and scalability of certain operations; and the 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, 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, the securing of adequate supplies and access to markets and transportation infrastructure; the availability of capacity on the electricity transmission grid; the uncertainty of reserve and resource estimates; the uncertainty of 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.

Estimates of Reserves

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

Non-GAAP Financial Measures

Certain financial measures in this MD&A do not have a standardized meaning as prescribed by IFRS including: net marketing activity, cash flow from (used in) operations, 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 MD&A.

21. 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.

22. QUARTERLY SUMMARIES

	2016			2015				2014
Unaudited	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**
FINANCIAL ($000 unless specified)								
Net earnings (loss)[1]	**(108,632)**	(146,165)	130,829	(297,275)	(427,503)	63,414	(508,307)	(150,076)
Per share, diluted	**(0.48)**	(0.65)	0.58	(1.32)	(1.90)	0.28	(2.27)	(0.67)
Operating earnings (loss)	**(87,929)**	(97,894)	(197,286)	(140,234)	(86,769)	(22,950)	(124,421)	8,084
Per share, diluted	**(0.39)**	(0.43)	(0.88)	(0.62)	(0.39)	(0.10)	(0.56)	0.04
Cash flow from (used in) operations	**22,702**	6,964	(131,240)	(44,130)	23,877	99,243	(29,534)	134,099
Per share, diluted	**0.10**	0.03	(0.58)	(0.20)	0.11	0.44	(0.13)	0.60
Cash capital investment[2]	**19,203**	19,990	34,975	54,473	32,139	90,465	80,101	323,970
Cash and cash equivalents	**103,136**	152,711	124,560	408,213	350,736	438,238	470,778	656,097
Working capital	**163,038**	128,586	183,649	363,038	366,725	374,766	386,130	525,534
Long-term debt	**4,909,711**	4,871,182	4,859,099	5,190,363	5,023,976	4,677,577	4,759,102	4,350,421
Shareholders' equity	**3,577,557**	3,679,372	3,812,566	3,677,867	3,956,689	4,358,078	4,279,873	4,768,235
BUSINESS ENVIRONMENT								
WTI (US$/bbl)	**44.94**	45.59	33.45	42.18	46.43	57.94	48.63	73.15
C$ equivalent of 1US$ - average	**1.3051**	1.2886	1.3748	1.3353	1.3093	1.2294	1.2411	1.1357
Differential – WTI:WCS ($/bbl)	**17.62**	17.14	19.58	19.35	17.50	14.25	18.22	16.34
Differential – WTI:WCS (%)	**30.0%**	29.2%	42.6%	34.4%	28.8%	20.0%	30.2%	19.7%
Natural gas – AECO ($/mcf)	**2.49**	1.37	1.82	2.57	2.89	2.64	2.74	3.58
OPERATIONAL ($/bbl unless specified)								
Bitumen production – bbls/d	**83,404**	83,127	76,640	83,514	82,768	71,376	82,398	80,349
Bitumen sales – bbls/d	**84,817**	80,548	74,529	82,282	84,651	71,401	85,519	70,116
Steam to oil ratio (SOR)	**2.2**	2.3	2.4	2.5	2.5	2.3	2.6	2.5
Bitumen realization	**30.98**	30.93	11.43	23.17	31.03	44.54	25.82	50.48
Transportation – net	**(6.46)**	(6.66)	(6.68)	(5.35)	(4.64)	(4.57)	(4.70)	(1.82)
Royalties	**(0.42)**	(0.27)	0.07	(0.25)	(0.88)	(0.90)	(0.80)	(2.97)
Operating costs – non-energy	**(5.32)**	(5.81)	(6.45)	(5.66)	(5.98)	(7.01)	(7.57)	(6.42)
Operating costs – energy	**(2.99)**	(1.97)	(2.90)	(3.58)	(3.97)	(3.71)	(4.07)	(5.16)
Power revenue	**0.55**	0.35	0.82	0.72	0.85	1.29	1.15	1.45
Realized risk management gain (loss)	**0.40**	(0.48)	-	-	-	-	-	-
Cash operating netback	**16.74**	16.09	(3.71)	9.05	16.41	29.64	9.83	35.56
Power sales price (C$/MWh)	**17.62**	13.54	19.77	19.67	25.09	39.55	28.21	31.67
Power sales (MW/h)	**110**	86	129	125	119	97	145	134
Depletion and depreciation rate per bbl of production	**16.81**	16.84	16.78	16.55	15.99	15.84	15.58	13.63
COMMON SHARES								
Shares outstanding, end of period (000)	**226,415**	226,357	224,997	224,997	224,942	224,881	223,847	223,847
Volume traded (000)	**112,720**	157,056	182,199	76,631	73,099	40,929	57,657	94,588
Common share price ($)								
High	**6.90**	7.86	8.26	13.15	20.36	25.20	24.31	34.69
Low	**4.72**	5.21	3.46	7.33	7.87	17.56	14.84	13.30
Close (end of period)	**5.93**	6.84	6.55	8.02	8.24	20.40	20.46	19.55

(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 and non-cash items.

Interim Consolidated Financial Statements

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

As at	Note	September 30, 2016	December 31, 2015
Assets			
Current assets			
Cash and cash equivalents	19	**$ 103,136**	$ 408,213
Trade receivables and other		**207,018**	150,042
Inventories		**68,093**	53,079
Commodity risk management	21	**10,841**	-
		389,088	611,334
Non-current assets			
Property, plant and equipment	4	**7,721,629**	8,011,760
Exploration and evaluation assets	5	**547,425**	546,421
Other intangible assets	6	**83,942**	84,142
Other assets	7	**138,561**	146,612
Deferred income tax asset	18	**53,324**	-
Commodity risk management	21	**4,705**	-
Total assets		**$ 8,938,674**	$ 9,400,269
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities		**$ 183,735**	$ 217,991
Current portion of long-term debt	8	**17,052**	17,992
Current portion of provisions and other liabilities	9	**21,453**	12,313
Commodity risk management	21	**3,810**	-
		226,050	248,296
Non-current liabilities			
Long-term debt	8	**4,909,711**	5,190,363
Provisions and other liabilities	9	**225,356**	196,274
Deferred income tax liability	18	**-**	87,469
Total liabilities		**5,361,117**	5,722,402
Shareholders' equity			
Share capital	10	**4,877,420**	4,836,800
Contributed surplus	10	**163,190**	171,835
Deficit		**(1,490,309)**	(1,366,341)
Accumulated other comprehensive income		**27,256**	35,573
Total shareholders' equity		**3,577,557**	3,677,867
Total liabilities and shareholders' equity		**$ 8,938,674**	$ 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 September 30		Nine months ended September 30	
	Note	2016	2015	2016	2015
Revenues					
Petroleum revenue, net of royalties	12	**$ 487,680**	$ 449,124	**$ 1,272,967**	$ 1,447,690
Other revenue	13	**9,140**	10,642	**27,546**	33,718
		496,820	459,766	**1,300,513**	1,481,408
Expenses					
Diluent and transportation	14	**255,816**	245,245	**736,619**	794,647
Operating expenses		**64,796**	77,474	**185,233**	236,750
Purchased product and storage		**48,157**	17,852	**151,638**	71,696
Depletion and depreciation	4,6	**128,995**	121,786	**373,340**	340,269
Exploration expense	5	**1,248**	-	**1,248**	-
General and administrative		**22,587**	28,335	**74,671**	93,237
Stock-based compensation	11	**10,022**	13,250	**33,433**	38,066
Research and development		**1,265**	2,239	**4,360**	5,030
Interest and other income		**(290)**	(691)	**(1,016)**	(2,405)
Commodity risk management gain	21	**(35,335)**	-	**(11,377)**	-
Foreign exchange loss (gain), net	15	**39,734**	335,391	**(271,616)**	639,382
Net finance expense	16	**73,130**	72,068	**250,362**	192,010
Other expenses (recoveries)	17	**18,057**	-	**37,662**	(5,880)
Loss before income taxes		**(131,362)**	(453,183)	**(264,044)**	(921,394)
Income tax recovery	18	**(22,730)**	(25,680)	**(140,076)**	(48,998)
Net loss		**(108,632)**	(427,503)	**(123,968)**	(872,396)
Other comprehensive income (loss), net of tax					
Items that may be reclassified to profit or loss:					
Foreign currency translation adjustment		**397**	11,305	**(8,317)**	17,544
Comprehensive loss for the period		**$ (108,235)**	$ (416,198)	**$ (132,285)**	$ (854,852)

Net loss per common share					
Basic	20	**$ (0.48)**	$ (1.90)	**$ (0.55)**	$ (3.89)
Diluted	20	**$ (0.48)**	$ (1.90)	**$ (0.55)**	$ (3.89)

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	10	**-**	**31,975**	**-**	**-**	**31,975**
RSUs vested and released	10	**40,620**	**(40,620)**	**-**	**-**	**-**
Comprehensive loss		**-**	**-**	**(123,968)**	**(8,317)**	**(132,285)**
Balance as at September 30, 2016		**$4,877,420**	**$ 163,190**	**$(1,490,309)**	**$ 27,256**	**$ 3,577,557**
Balance as at December 31, 2014		$4,797,853	$ 153,837	$ (196,670)	$ 13,215	$ 4,768,235
Stock-based compensation		-	43,306	-	-	43,306
RSUs vested and released		37,631	(37,631)	-	-	-
Comprehensive income (loss)		-	-	(872,396)	17,544	(854,852)
Balance as at September 30, 2015		$4,835,484	$ 159,512	$(1,069,066)	$ 30,759	$ 3,956,689

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

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

		Three months ended September 30		Nine months ended September 30	
	Note	**2016**	**2015**	**2016**	**2015**
Cash provided by (used in):					
Operating activities					
Net loss		**$ (108,632)**	$ (427,503)	**$ (123,968)**	$ (872,396)
Adjustments for:					
Depletion and depreciation	4,6	**128,995**	121,786	**373,340**	340,269
Exploration expense	5	**1,248**	-	**1,248**	-
Stock-based compensation	11	**5,977**	13,250	**27,938**	38,066
Unrealized loss (gain) on foreign exchange	15	**38,729**	330,478	**(267,763)**	626,301
Unrealized loss (gain) on derivative financial liabilities	16	**(11,367)**	6,807	**(5,362)**	2,600
Unrealized gain on risk management	21	**(32,207)**	-	**(11,736)**	-
Onerous contracts	17	**18,057**	-	**31,483**	-
Deferred income tax recovery	18	**(22,833)**	(25,280)	**(140,793)**	(47,798)
Amortization of debt issue costs	7,8	**3,070**	2,979	**9,102**	8,797
Other		**1,665**	1,360	**4,937**	3,627
Decommissioning expenditures	9	**(99)**	(178)	**(1,095)**	(1,429)
Net change in other liabilities		**2,995**	-	**3,100**	-
Net change in non-cash working capital items	19	**(45,492)**	(28,887)	**(76,409)**	1,594
Net cash provided by (used in) operating activities		**(19,894)**	(5,188)	**(175,978)**	99,631
Investing activities					
Capital investments:					
Property, plant and equipment	4	**(17,741)**	(49,505)	**(68,964)**	(246,695)
Exploration and evaluation	5	**(870)**	(464)	**(1,851)**	(1,322)
Other intangible assets	6	**(592)**	(161)	**(3,353)**	(5,167)
Other		**130**	(1)	**(956)**	(578)
Net change in non-cash working capital items	19	**(8,479)**	(50,954)	**(33,020)**	(201,625)
Net cash provided by (used in) investing activities		**(27,552)**	(101,085)	**(108,144)**	(455,387)
Financing activities					
Repayment of long-term debt	8	**(4,263)**	(4,359)	**(12,698)**	(12,507)
Net cash provided by (used in) financing activities		**(4,263)**	(4,359)	**(12,698)**	(12,507)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency		**2,134**	23,130	**(8,257)**	62,902
Change in cash and cash equivalents		**(49,575)**	(87,502)	**(305,077)**	(305,361)
Cash and cash equivalents, beginning of period		**152,711**	438,238	**408,213**	656,097
Cash and cash equivalents, end of period		**$ 103,136**	$ 350,736	**$ 103,136**	$ 350,736

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 is using a staged approach to development. The Corporation also holds a 50% interest in the Access Pipeline, a dual pipeline to transport diluent north from the Edmonton area to the Athabasca oil sands area and a blend of bitumen and diluent south from the Christina Lake Project into the Edmonton area. In addition to the Access Pipeline, the Corporation owns the Stonefell Terminal, located near Edmonton, Alberta, which offers 900,000 barrels of terminalling and storage capacity. The Stonefell Terminal is connected to the Access Pipeline and is also connected by pipeline to a third-party rail-loading terminal. The corporate office is located at 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 October 26, 2016.

3. CHANGE IN ACCOUNTING POLICIES

New accounting standards

There were no new accounting standards adopted during the nine months ended September 30, 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.

A description of additional accounting standards that are anticipated to be adopted by the Corporation in future periods is provided within Note 3 of the Corporation's audited consolidated financial statements for the year ended December 31, 2015.

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	69,803	2,595	1,005	73,403
Change in decommissioning liabilities	5,995	259	-	6,254
Balance as at September 30, 2016	**$ 7,844,042**	**$ 1,608,401**	**$ 52,081**	**$ 9,504,524**
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	342,900	23,059	3,829	369,788
Balance as at September 30, 2016	**$ 1,653,569**	**$ 103,399**	**$ 25,927**	**$ 1,782,895**
Carrying amounts				
Balance as at December 31, 2015	$ 6,457,575	$ 1,525,207	$ 28,978	$ 8,011,760
Balance as at September 30, 2016	**$ 6,190,473**	**$ 1,505,002**	**$ 26,154**	**$ 7,721,629**

As at September 30, 2016, $659.3 million of assets under construction were included within property, plant and equipment (December 31, 2015 - $727.7 million). Assets under construction are not subject to depletion and depreciation. As at September 30, 2016, no impairment has been recognized on property, plant and equipment.

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	1,851
Exploration expense	(1,248)
Change in decommissioning liabilities	401
Balance as at September 30, 2016	**$ 547,425**

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 September 30, 2016, no impairment has been recognized on exploration and evaluation assets.

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		3,353
Balance as at September 30, 2016	**$**	**99,631**

Accumulated depreciation		
Balance as at December 31, 2014	$	6,690
Depreciation		5,446
Balance as at December 31, 2015	$	12,136
Depreciation		3,553
Balance as at September 30, 2016	**$**	**15,689**

Carrying amounts		
Balance as at December 31, 2015	$	84,142
Balance as at September 30, 2016	**$**	**83,942**

As at September 30, 2016, other intangible assets include $66.8 million invested to maintain the right to participate in a potential pipeline project and $17.1 million invested in software that is not an integral component of the related computer hardware (December 31, 2015 - $63.6 million and $20.5 million, respectively). As at September 30, 2016, no impairment has been recognized on other intangible assets.

7. OTHER ASSETS

As at		**September 30, 2016**		**December 31, 2015**
Long-term pipeline linefill[(a)]	**$**	**126,543**	$	131,141
Deferred financing costs		**13,093**		16,366
U.S. auction rate securities		**3,290**		3,470
		142,926		150,977
Less current portion of deferred financing costs		**(4,365)**		(4,365)
	$	**138,561**	$	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 September 30, 2016, no impairment has been recognized on these assets.

8. LONG-TERM DEBT

As at	September 30, 2016	December 31, 2015
Senior secured term loan (September 30, 2016 – US$1.239 billion; December 31, 2015 – US$1.249 billion; due 2020)	**$ 1,624,868**	$ 1,727,924
6.5% senior unsecured notes (US$750 million; due 2021)	**983,775**	1,038,000
6.375% senior unsecured notes (US$800 million; due 2023)	**1,049,360**	1,107,200
7.0% senior unsecured notes (US$1.0 billion; due 2024)	**1,311,700**	1,384,000
	4,969,703	5,257,124
Less current portion of senior secured term loan	**(17,052)**	(17,992)
Less unamortized financial derivative liability discount	**(11,964)**	(14,377)
Less unamortized deferred debt issue costs	**(30,976)**	(34,392)
	$ 4,909,711	$ 5,190,363

The U.S. dollar denominated debt was translated into Canadian dollars at the period end exchange rate of US$1 = C$1.3117 (December 31, 2015 - US$1 = C$1.3840).

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. The first maturity of any of the Corporation's long-term debt obligations is March 2020.

9. PROVISIONS AND OTHER LIABILITIES

As at	September 30, 2016	December 31, 2015
Decommissioning provision[a]	**$ 141,080**	$ 130,381
Onerous contracts provision[b]	**85,220**	58,178
Derivative financial liabilities[c]	**10,860**	16,223
Stock-based compensation liability (Note 11)	**6,214**	-
Deferred lease inducements	**3,435**	3,805
Provisions and other liabilities	**246,809**	208,587
Less current portion	**(21,453)**	(12,313)
Non-current portion	**$ 225,356**	$ 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		September 30, 2016		December 31, 2015
Balance, beginning of year	**$**	**130,381**	$	156,382
Changes in estimated future cash flows		**89**		18,679
Changes in discount rates and settlement dates		**4,603**		(53,536)
Liabilities incurred		**1,963**		5,066
Liabilities settled		**(1,095)**		(1,873)
Accretion		**5,139**		5,663
Balance, end of period		**141,080**		130,381
Less current portion		**(733)**		(1,485)
Non-current portion	**$**	**140,347**	$	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 credit-adjusted risk-free rate of 8.3% (December 31, 2015 – 8.3%). The decommissioning provision is estimated to be settled in periods up to the year 2061 (December 31, 2015 – periods up to the year 2064).

(b) Onerous contracts provision:

As at September 30, 2016, the Corporation had recognized a total provision of $85.2 million related to certain onerous operating lease contracts (December 31, 2015 – $58.2 million). The increase in the provision primarily represents changes in estimates relating to office building lease contracts. 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 0.7% (December 31, 2015 – 1.0%). This estimate may vary as a result of changes in estimated recoveries.

(c) Derivative financial liabilities:

As at		September 30, 2016		December 31, 2015
1% interest rate floor	**$**	**10,860**	$	11,740
Interest rate swaps (Note 21)		**-**		4,483
Derivative financial liabilities		**10,860**		16,223
Less current portion		**(2,355)**		(8,316)
Non-current portion	**$**	**8,505**	$	7,907

10. SHARE CAPITAL AND CONTRIBUTED SURPLUS

(a) Share capital:

Authorized:

Unlimited number of common shares
Unlimited number of preferred shares

Changes in issued common shares are as follows:

	Nine months ended September 30, 2016		Year ended December 31, 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	**1,418,123**	**40,620**	1,150,098	38,947
Balance, end of period	**226,415,112**	**$ 4,877,420**	224,996,989	$ 4,836,800

(b) Contributed surplus:

Nine months ended September 30, 2016	
Balance, beginning of year	**$ 171,835**
Stock-based compensation - expensed	**27,938**
Stock-based compensation - capitalized	**4,037**
RSUs vested and released	**(40,620)**
Balance, end of period	**$ 163,190**

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) Stock options outstanding:

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

Nine months ended September 30, 2016	Stock options	Weighted average exercise price
Outstanding, beginning of year	**9,925,313**	**$ 29.94**
Granted	**1,214,300**	**6.52**
Forfeited	**(426,621)**	**28.67**
Expired	**(957,005)**	**24.00**
Outstanding, end of period	**9,755,987**	**$ 27.66**

(b) Restricted share units and performance share units:

RSUs granted under the Restricted Share Unit Plan generally vest annually over a three year period. PSUs granted under the Restricted Share Unit Plan generally vest on the third anniversary of the grant date, provided that certain performance criteria have been satisfied.

In June 2016, the Corporation issued RSUs and PSUs under a new cash-settled plan. Upon vesting of the RSUs, the participants of the RSU plan will receive a cash payment based on the fair value of the underlying share units at the vesting date. PSUs become eligible to vest if the Corporation satisfies certain performance criteria identified by the Corporation's Board of Directors within a target range. 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 in the period in which they occur. As at September 30, 2016, the Corporation recognized a liability of $6.2 million relating to the fair value of RSUs and PSUs, of which $3.0 million was recorded as a current liability.

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.

RSUs and PSUs outstanding:

Nine months ended September 30, 2016	Cash-settled	Equity-settled
Outstanding, beginning of year	**-**	**3,280,112**
Granted	**6,099,920**	**-**
Vested and released	**-**	**(1,418,123)**
Forfeited	**(60,722)**	**(137,353)**
Outstanding, end of period	**6,039,198**	**1,724,636**

(c) 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 September 30, 2016, there were 163,954 DSUs outstanding (December 31, 2015 – 47,696 DSUs outstanding).

(d) Stock-based compensation:

	Three months ended September 30		Nine months ended September 30	
	2016	**2015**	**2016**	**2015**
Cash-settled	**$ 4,045**	$ -	**$ 5,495**	$ -
Equity-settled	**5,977**	13,250	**27,938**	38,066
Stock-based compensation expense	**$ 10,022**	$ 13,250	**$ 33,433**	$ 38,066

12. PETROLEUM REVENUE, NET OF ROYALTIES

	Three months ended September 30		Nine months ended September 30	
	2016	**2015**	**2016**	**2015**
Petroleum revenue:				
Proprietary	**$ 442,333**	$ 446,743	**$ 1,122,849**	$ 1,412,464
Third-party[(a)]	**48,599**	9,255	**154,838**	54,103
Petroleum revenue	**$ 490,932**	$ 455,998	**$ 1,277,687**	$ 1,466,567
Royalties	**(3,252)**	(6,874)	**(4,720)**	(18,877)
Petroleum revenue, net of royalties	**$ 487,680**	$ 449,124	**$ 1,272,967**	$ 1,447,690

(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 September 30		Nine months ended September 30	
	2016	2015	**2016**	2015
Power revenue	**$ 4,277**	$ 6,608	**$ 12,360**	$ 23,798
Transportation revenue	**4,863**	4,034	**15,186**	9,920
Other revenue	**$ 9,140**	$ 10,642	**$ 27,546**	$ 33,718

14. DILUENT AND TRANSPORTATION

	Three months ended September 30		Nine months ended September 30	
	2016	2015	**2016**	2015
Diluent expense	**$ 200,564**	$ 205,069	**$ 576,857**	$ 682,702
Transportation expense	**55,252**	40,176	**159,762**	111,945
Diluent and transportation	**$ 255,816**	$ 245,245	**$ 736,619**	$ 794,647

15. FOREIGN EXCHANGE LOSS (GAIN), NET

	Three months ended September 30		Nine months ended September 30	
	2016	2015	**2016**	2015
Unrealized foreign exchange loss (gain) on:				
Long-term debt	**$ 40,954**	$ 350,066	**$ (274,723)**	$ 682,850
US$ denominated cash and cash equivalents	**(2,225)**	(19,588)	**6,960**	(56,549)
Unrealized net loss (gain) on foreign exchange	**38,729**	330,478	**(267,763)**	626,301
Realized loss (gain) on foreign exchange	**1,005**	4,913	**(3,853)**	13,081
Foreign exchange loss (gain), net	**$ 39,734**	$ 335,391	**$ (271,616)**	$ 639,382

16. NET FINANCE EXPENSE

	Three months ended September 30		Nine months ended September 30	
	2016	**2015**	**2016**	**2015**
Total interest expense	**$ 81,194**	$ 80,248	**$ 245,866**	$ 231,524
Less capitalized interest	**-**	(17,991)	**-**	(50,479)
Net interest expense	**81,194**	62,257	**245,866**	181,045
Accretion on provisions	**1,796**	1,491	**5,310**	4,047
Unrealized loss (gain) on derivative financial liabilities	**(11,367)**	6,807	**(5,362)**	2,600
Realized loss on interest rate swaps	**1,507**	1,512	**4,548**	4,317
Net finance expense	**$ 73,130**	$ 72,068	**$ 250,362**	$ 192,010

17. OTHER EXPENSES (RECOVERIES)

	Three months ended September 30		Nine months ended September 30	
	2016	**2015**	**2016**	**2015**
Onerous contracts	**$ 18,057**	$ -	**$ 31,483**	$ -
Contract cancellation recoveries	**-**	-	**-**	(5,880)
Severance and other	**-**	-	**6,179**	-
Other expenses (recoveries)	**$ 18,057**	$ -	**$ 37,662**	$ (5,880)

18. INCOME TAX EXPENSE (RECOVERY)

	Three months ended September 30		Nine months ended September 30	
	2016	**2015**	**2016**	**2015**
Current income tax expense (recovery)	**$ 103**	$ (400)	**$ 717**	$ (1,200)
Deferred income tax recovery	**(22,833)**	(25,280)	**(140,793)**	(47,798)
Income tax recovery	**$ (22,730)**	$ (25,680)	**$ (140,076)**	$ (48,998)

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 September 30		Nine months ended September 30	
	2016	2015	**2016**	2015
Cash provided by (used in):				
Trade receivables and other	**$ (2,596)**	$ 38,486	**$ (61,886)**	$ 7,801
Inventories	**4,778**	2,546	**(15,439)**	29,813
Accounts payable and accrued liabilities	**(56,153)**	(120,873)	**(32,104)**	(237,645)
	$ (53,971)	$ (79,841)	**$ (109,429)**	$ (200,031)
Changes in non-cash working capital relating to:				
Operating	**$ (45,492)**	$ (28,887)	**$ (76,409)**	$ 1,594
Investing	**(8,479)**	(50,954)	**(33,020)**	(201,625)
	$ (53,971)	$ (79,841)	**$ (109,429)**	$ (200,031)
Cash and cash equivalents:[(a)]				
Cash	**$ 93,114**	$ 254,202	**$ 93,114**	$ 254,202
Cash equivalents	**10,022**	96,534	**10,022**	96,534
	$ 103,136	$ 350,736	**$ 103,136**	$ 350,736
Cash interest paid	**$ 126,869**	$ 128,300	**$ 271,216**	$ 266,122

(a) As at September 30, 2016, C$65.3 million of the Corporation's total cash and cash equivalents balance was held in U.S. dollars (September 30, 2015 - C$217.6 million). The U.S. dollar cash and cash equivalents balance has been translated into Canadian dollars at the period end exchange rate of US$1 = C$1.3117 (September 30, 2015 - US$1 = C$1.3394).

20. NET LOSS PER COMMON SHARE

	Three months ended September 30		Nine months ended September 30	
	2016	2015	**2016**	2015
Net loss	**$ (108,632)**	$ (427,503)	**$ (123,968)**	$ (872,396)
Weighted average common shares outstanding[(a)]	**226,560,337**	225,042,674	**225,769,736**	224,402,871
Dilutive effect of stock options, RSUs and PSUs[(b)]	**-**	-	**-**	-
Weighted average common shares outstanding – diluted	**226,560,337**	225,042,674	**225,769,736**	224,402,871
Net loss per share, basic	**$ (0.48)**	$ (1.90)	**$ (0.55)**	$ (3.89)
Net loss per share, diluted	**$ (0.48)**	$ (1.90)	**$ (0.55)**	$ (3.89)

(a) Weighted average common shares outstanding for the nine months ended September 30, 2016 includes 184,425 PSUs not yet released (nine months ended September 30, 2015 – 141,929 PSUs).

(b) For the three and nine months ended September 30, 2016, there was no dilutive effect of stock options, RSUs and PSUs due to the Corporation incurring a net loss. If the Corporation had recognized net earnings during the three and nine month periods ended September 30, 2016, the dilutive effect of stock options, RSUs and PSUs would have been 36,815 (three months ended September 30, 2015 – 282,562) and 209,940 (nine months ended September 30, 2015 – 652,742) 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 and long-term debt. As at September 30, 2016, the ARS, 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, commodity risk management contracts, long-term debt and derivative financial liabilities:

		Fair value measurements using		
As at September 30, 2016	**Carrying amount**	**Level 1**	**Level 2**	**Level 3**
Recurring measurements:				
Financial assets				
ARS (Note 7)	**$ 3,290**	**$ -**	**$ 3,290**	**$ -**
Commodity risk management contracts	**15,546**	**-**	**15,546**	**-**
Financial liabilities				
Long-term debt[(1)] (Note 8)	**4,969,703**	**-**	**4,203,236**	**-**
Derivative financial liabilities (Note 9)	**10,860**	**-**	**10,860**	**-**
Commodity risk management contracts	**3,810**	**-**	**3,810**	**-**

		Fair value measurements using		
As at December 31, 2015	**Carrying amount**	**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 September 30, 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 September 30, 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 is subject to 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 September 30, 2016:

As at September 30, 2016	**Volumes (bbls/d)**	**Term**	**Average Price (US$/bbl)**
Fixed Price:			
WTI Fixed Price[1]	24,000	Oct 1, 2016 – Dec 31, 2016	$48.25
WCS Fixed Differential[2]	30,587	Oct 1, 2016 – Dec 31, 2016	$(14.64)
WCS Fixed Differential	15,000	Jan 1, 2017 – Jun 30, 2017	$(14.74)
Collars:			
WTI Collars	19,000	Oct 1, 2016 – Dec 31, 2016	$44.99 – $53.68
WTI Collars	29,500	Jan 1, 2017 – Jun 30, 2017	$45.00 – $51.92
WTI Collars	7,000	Jul 1, 2017 – Dec 31, 2017	$45.00 – $56.72

(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 September 30, 2016. As a result, these contracts are not reflected in the Corporation's Interim Consolidated Financial Statements:

Subsequent to September 30, 2016	**Volumes (bbls/d)**	**Term**	**Average Price (US$/bbl)**
Fixed Price:			
WTI Fixed Price	3,000	Nov 1, 2016 – Dec 31, 2016	$49.60
WTI Fixed Price	3,000	Jan 1, 2017 – Jun 30, 2017	$52.00
Collars:			
WTI Collars	7,000	Jan 1, 2017 – Mar 31, 2017	$45.00 – $59.18
WTI Collars	5,000	Apr 1, 2017 – Jun 30, 2017	$45.00 – $59.51

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

As at September 30, 2016	Volumes (bbls/d)	Term	Average % of WTI
Mont Belvieu fixed % of WTI	14,750	Oct 1, 2016 – Dec 31, 2016	84.0%
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 offsetting commodity risk management positions:

As at	September 30, 2016			December 31, 2015		
	Asset	**Liability**	**Net**	**Asset**	**Liability**	**Net**
Gross amount	**$ 104,862**	**$ (20,513)**	**$ 84,349**	$	$ -	$ -
Amount offset	**(89,316)**	**16,703**	**(72,613)**	-	-	-
Net amount	**$ 15,546**	**$ (3,810)**	**$ 11,736**	$	$ -	$ -

The following table summarizes the unrealized commodity risk management positions by contract type:

As at	September 30, 2016			December 31, 2015		
	Asset	**Liability**	**Net**	**Asset**	**Liability**	**Net**
Condensate contracts[1]	**$ 29,084**	**$ 1,762**	**$ 30,846**	$	$ -	$ -
Crude oil contracts [2]	**(13,538)**	**(5,572)**	**(19,110)**	-	-	-
Total fair value	**$ 15,546**	**$ (3,810)**	**$ 11,736**	$	$ -	$ -

(1) *Relates to condensate purchase contracts that effectively fix condensate prices at Mont Belvieu, Texas as a percentage of WTI (US$/bbl).*

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

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

	Three months ended September 30		Nine months ended September 30	
	2016	**2015**	**2016**	**2015**
Realized loss (gain) on commodity risk management	**$ (3,128)**	$ -	**$ 359**	$ -
Unrealized gain on commodity risk management	**(32,207)**	-	**(11,736)**	-
Commodity risk management gain	**$ (35,335)**	$ -	**$ (11,377)**	$ -

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

Commodity	Sensitivity Range	Increase	Decrease
Crude oil commodity price	± US$1.00 per bbl applied to WTI contracts	$ (5,807)	$ 2,208
Crude oil differential price[1]	± US$1.00 per bbl applied to WCS differential contracts	$ 5,529	$ (5,529)
Condensate percentage	± 1% in condensate price as a percentage of US$ WTI price per bbl applied to condensate contracts	$ 2,940	$ (2,940)

(1) The WCS differential is expressed as a discount to WTI, therefore, 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 September 30, 2016, the Corporation does not have any outstanding interest rate swap contracts.

22. GEOGRAPHICAL DISCLOSURE

As at September 30, 2016, the Corporation had non-current assets related to operations in the United States of $106.1 million (December 31, 2015 - $111.1 million). For the three and nine months ended September 30, 2016, petroleum revenue related to operations in the United States were $191.1 million and $469.1 million respectively (three and nine months ended September 30, 2015 - $141.9 million and $420.3 million, respectively).

23. COMMITMENTS AND CONTINGENCIES

(a) Commitments

The Corporation had the following commitments as at September 30, 2016:

	2016[1]	2017	2018	2019	2020	Thereafter
Transportation and storage	$ 43,017	$ 180,914	$ 197,878	$ 188,401	$ 227,348	$ 3,217,659
Office lease rentals	3,695	33,934	32,496	32,526	33,442	269,411
Diluent purchases	69,074	58,281	20,246	20,246	20,302	57,355
Other operating commitments	4,634	16,133	8,811	10,822	11,453	80,543
Capital commitments	7,652	7,686	-	-	-	-
Commitments	**$ 128,072**	**$ 296,948**	**$ 259,431**	**$ 251,995**	**$ 292,545**	**$ 3,624,968**

(1) *Represents the commitments remaining for the period October 1 – December 31,2016.*

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.