# SECOND QUARTER 2016

**Report to Shareholders for the period ended June 30, 2016**

MEG Energy Corp. reported second quarter 2016 operating and financial results on July 28, 2016. Highlights include:

- Record first half production volumes of 79,883 barrels per day (bpd) with second quarter production of 83,127 bpd and post-maintenance production volumes above 86,000 bpd in May and June;
- Record-low quarterly net operating costs of $7.43 per barrel, supported by non-energy operating costs of $5.81 per barrel;
- Cash flow from operations of $7 million, a substantial improvement from cash flow used in operations of $131 million in the first quarter of 2016;
- Improved financial liquidity, exiting the quarter with $153 million of cash and cash equivalents and an undrawn US$2.5 billion credit facility;
- Ongoing planning of 'brownfield' growth, targeting production levels up to 110,000 to 120,000 barrels per day.

"Our quarterly results demonstrate the positive impacts of technology and innovation as we continued to advance MEG's eMSAGP technology." said Bill McCaffrey, President and Chief Executive Officer. "Our second quarter production levels have been close to record highs and we are currently seeing net operating costs of under $7.50 to produce a barrel of oil."

MEG recorded production of 83,127 bpd in the second quarter of 2016. Production levels included the impact of a planned turnaround at the company's Christina Lake facilities which continued from the first quarter into April. Volumes in the second quarter of 2016 were 16% higher than production in the second quarter of 2015.

Related net operating costs for the second quarter were a record low $7.43 per barrel compared to $9.43 per barrel in the second quarter of 2015. Non-energy operating costs (which exclude natural gas consumption) were $5.81 per barrel, a 17% 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 now being fully deployed across the company's Phase 2 operations. Net operating costs also benefited from a decrease in the cost of natural gas used to fuel the company's SAGD facilities.

With strong production volumes and low operating costs over the first half of 2016, MEG expects to meet annual production guidance of 80,000 to 83,000 bpd. While production levels remain on target, in light of the strong operating performance over the first half of 2016, the company has reduced its target non-energy operating costs to $6.00 to $7.00 per barrel from initial projections of $6.75 to $7.75 per barrel.

High production volumes and low operating costs contributed to cash flow from operations of $7 million for the second quarter of 2016, despite the current commodity price environment. Cash flow from operations decreased from $99 million in the second quarter of 2015 primarily due to a lower bitumen price realization, partially offset by an increase in bitumen sales volumes and lower operating costs. The decrease in bitumen realization is directly related to the decline of U.S. crude oil benchmark pricing.

MEG recognized an operating loss of $98 million for the second quarter of 2016, compared to an operating loss of $23 million in the same period of 2015. Comparative results are primarily impacted by the same factors affecting cash flow from operations and a $24 million increase in depletion and depreciation expense from the second quarter of 2015.

At the end of the second quarter, MEG had $153 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 second quarter totaled $20 million, bringing total capital invested year to date to $55 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. Depending on market conditions, the company now anticipates it could direct up to $30 million towards growth projects later in the year, which will leave the revised capital investment guidance of $170 million unchanged.

“We are continuing to capture efficiencies across the business that are enabling us to reduce our sustaining capital requirements,” says McCaffrey. “These incremental improvements allow us the opportunity to refocus a portion of our capital investment toward growth, while still maintaining a very conservative capital investment plan.”

**Forward-Looking Information and Non-GAAP Financial Measures**

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

MEG ENERGY

# Management's Discussion and Analysis

*This Management's Discussion and Analysis ("MD&A") of the financial condition and performance of MEG Energy Corp. ("MEG" or the "Corporation") for the three-month and six-month periods ended June 30, 2016 was approved by the Corporation's Audit Committee on July 27, 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 six-month periods ended June 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 anticipates filing regulatory applications in 2016 for the May River Regional Project. 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.

As at January 1, 2016, MEG has 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.

For a list of abbreviations that are referenced in this MD&A, please refer to the "ABBREVIATIONS" section of this MD&A.

## 2. OPERATIONAL AND FINANCIAL HIGHLIGHTS

The ongoing global imbalance between supply and demand for crude oil and the deterioration and volatility of global crude oil prices continued to significantly impact the Corporation's operating and financial results during the second quarter of 2016. The C$/bbl WTI average price for the second quarter of 2016 decreased 18% compared to the second quarter of 2015.

As a result of ongoing cost control initiatives in 2016, the Corporation has reduced non-energy operating costs per barrel by 17% compared to the second quarter of 2015 and has reduced general and administrative expenses by 23% compared to the second quarter of 2015.

The Corporation continued to implement 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 first half of 2016, the Corporation entered into commodity risk management contracts to partially manage its exposure on blend sales 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:

| | Six months ended June 30 | | 2016 | | 2015 | | | | 2014 | |
|---|---|---|---|---|---|---|---|---|---|---|
| *($ millions, except as indicated)* | **2016** | **2015** | **Q2** | **Q1** | **Q4** | **Q3** | **Q2** | **Q1** | **Q4** | **Q3** |
| Bitumen production - bbls/d | **79,883** | 76,856 | **83,127** | 76,640 | 83,514 | 82,768 | 71,376 | 82,398 | 80,349 | 76,471 |
| Bitumen realization - $/bbl | **21.56** | 34.39 | **30.93** | 11.43 | 23.17 | 31.03 | 44.54 | 25.82 | 50.48 | 65.12 |
| Net operating costs - $/bbl(1) | **7.97** | 10.01 | **7.43** | 8.53 | 8.52 | 9.10 | 9.43 | 10.49 | 10.13 | 10.31 |
| Non-energy operating costs - $/bbl | **6.12** | 7.31 | **5.81** | 6.45 | 5.66 | 5.98 | 7.01 | 7.57 | 6.42 | 7.16 |
| Cash operating netback - $/bbl(2) | **6.57** | 18.89 | **16.09** | (3.71) | 9.05 | 16.41 | 29.64 | 9.83 | 35.56 | 48.70 |
| Cash flow from (used in) operations(3) | **(124)** | 70 | **7** | (131) | (44) | 24 | 99 | (30) | 134 | 239 |
| Per share, diluted(3) | **(0.55)** | 0.31 | **0.03** | (0.58) | (0.20) | 0.11 | 0.44 | (0.13) | 0.60 | 1.06 |
| Operating earnings (loss)(3) | **(295)** | (147) | **(98)** | (197) | (140) | (87) | (23) | (124) | 8 | 87 |
| Per share, diluted(3) | **(1.31)** | (0.66) | **(0.43)** | (0.88) | (0.62) | (0.39) | (0.10) | (0.56) | 0.04 | 0.39 |
| Revenue(4) | **804** | 1,022 | **513** | 290 | 445 | 460 | 555 | 467 | 615 | 706 |
| Net earnings (loss)(5) | **(15)** | (445) | **(146)** | 131 | (297) | (428) | 63 | (508) | (150) | (101) |
| Per share, basic | **(0.07)** | (1.99) | **(0.65)** | 0.58 | (1.32) | (1.90) | 0.28 | (2.27) | (0.67) | (0.45) |
| Per share, diluted | **(0.07)** | (1.99) | **(0.65)** | 0.58 | (1.32) | (1.90) | 0.28 | (2.27) | (0.67) | (0.45) |
| Total cash capital investment(6) | **55** | 171 | **20** | 35 | 54 | 32 | 90 | 80 | 324 | 291 |
| Cash and cash equivalents | **153** | 438 | **153** | 125 | 408 | 351 | 438 | 471 | 656 | 777 |
| Long-term debt | **4,871** | 4,694 | **4,871** | 4,859 | 5,190 | 5,024 | 4,678 | 4,759 | 4,350 | 4,203 |

(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 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 six months ended June 30, 2016 and June 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 earnings (loss) in accordance with IFRS under the heading "NON-GAAP MEASURES" and discussed further in the "ADVISORY" section.*

(4) *The total of Petroleum revenue, net of royalties and Other revenue as presented on the Interim Consolidated Statement of Earnings (Loss) and Comprehensive Income (Loss).*

(5) *Includes a net unrealized foreign exchange loss of $13.8 million and a net unrealized foreign exchange gain of $306.5 million on the Corporation's U.S. dollar denominated debt and U.S. dollar denominated cash and cash equivalents for the three and six months ended June 30, 2016, respectively. The net earnings for the three months ended June 30, 2015 includes a net unrealized foreign exchange gain of $75.0 million and the net loss for the six months ended June 30, 2015 includes a net unrealized foreign exchange loss of $295.8 million.*

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

**Bitumen Production and Steam to Oil Ratio**

| | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| | **2016** | **2015** | **2016** | **2015** |
| Bitumen production – bbls/d | **83,127** | 71,376 | **79,883** | 76,856 |
| Steam to oil ratio (SOR) | **2.3** | 2.3 | **2.3** | 2.5 |

**Bitumen Production**

Bitumen production for the three months ended June 30, 2016 averaged 83,127 bbls/d compared to 71,376 bbls/d for the three months ended June 30, 2015. The increase in production volumes is primarily due to the continued implementation of RISER and efficiency gains associated with RISER at the Christina Lake Project. The implementation of the RISER initiative has improved reservoir efficiency and allowed for redeployment of steam, thereby enabling the Corporation to place additional wells into production. In addition, in the second quarter of 2015, production volumes were impacted by a major planned turnaround.

Bitumen production for the six months ended June 30, 2016 averaged 79,883 bbls/d compared to 76,856 bbls/d for the six months ended June 30, 2015. The increase in production volumes is primarily due to continued implementation of RISER at the Christina Lake Project.

**Steam to Oil Ratio**

The Corporation continues to focus on sustaining production and maintaining efficiency of current production through a lower SOR, which is an important efficiency indicator that measures the average amount of steam that is injected into the reservoir for each barrel of bitumen produced. The SOR averaged 2.3 during the three months ended June 30, 2016 and June 30, 2015. The SOR averaged 2.3 for the six months ended June 30, 2016 compared to a SOR of 2.5 for the six months ended June 30, 2015.

**Operating Cash Flow**

| | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| **($000)** | **2016** | **2015** | **2016** | **2015** |
| Petroleum revenue – proprietary[1] | **$ 430,119** | $ 509,968 | **$ 680,516** | $ 965,721 |
| Diluent expense | **(203,428)** | (220,585) | **(376,293)** | (477,633) |
| | **226,691** | 289,383 | **304,223** | 488,088 |
| Royalties | **(1,965)** | (5,853) | **(1,468)** | (12,003) |
| Transportation expense | **(54,012)** | (33,107) | **(104,510)** | (71,769) |
| Operating expenses | **(57,049)** | (69,678) | **(120,437)** | (159,276) |
| Power revenue | **2,529** | 8,371 | **8,083** | 17,190 |
| Transportation revenue | **5,163** | 3,392 | **10,323** | 5,886 |
| | **121,357** | 192,508 | **96,214** | 268,116 |
| Realized loss on risk management | **(3,487)** | - | **(3,487)** | - |
| Operating cash flow[2] | **$ 117,870** | $ 192,508 | **$ 92,727** | $ 268,116 |

*(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.*

Blend sales revenue for the three months ended June 30, 2016 was $430.1 million compared to $510.0 million for the three months ended June 30, 2015. The decrease in blend sales revenue is primarily due to a 25% decrease in the average realized blend price, partially offset by a 13% increase in blend sales volumes. Diluent expense for the three months ended June 30, 2016 was $203.4 million compared to $220.6 million for the three months ended June 30, 2015. Diluent expense decreased primarily due to the decrease in condensate prices, partially offset by higher volumes of diluent required for the increased blend sales volumes. Operating cash flow decreased primarily due to lower blend sales revenue as a result of the decline of U.S. crude oil benchmark pricing, partially offset by a decrease in diluent expense.

Blend sales revenue for the six months ended June 30, 2016 was $680.5 million compared to $965.7 million for the six months ended June 30, 2015. The decrease in blend sales revenue is primarily due to a 29% decrease in the average realized blend price. Diluent expense for the six months ended June 30, 2016 was $376.3 million compared to $477.6 million for the six months ended June 30, 2015. Diluent expense decreased primarily due to the decrease in condensate prices. Operating cash flow decreased primarily due to lower blend sales revenue as a result of the decline of U.S. crude oil benchmark pricing, partially offset by a decrease in diluent expense.

## Cash Operating Netback

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

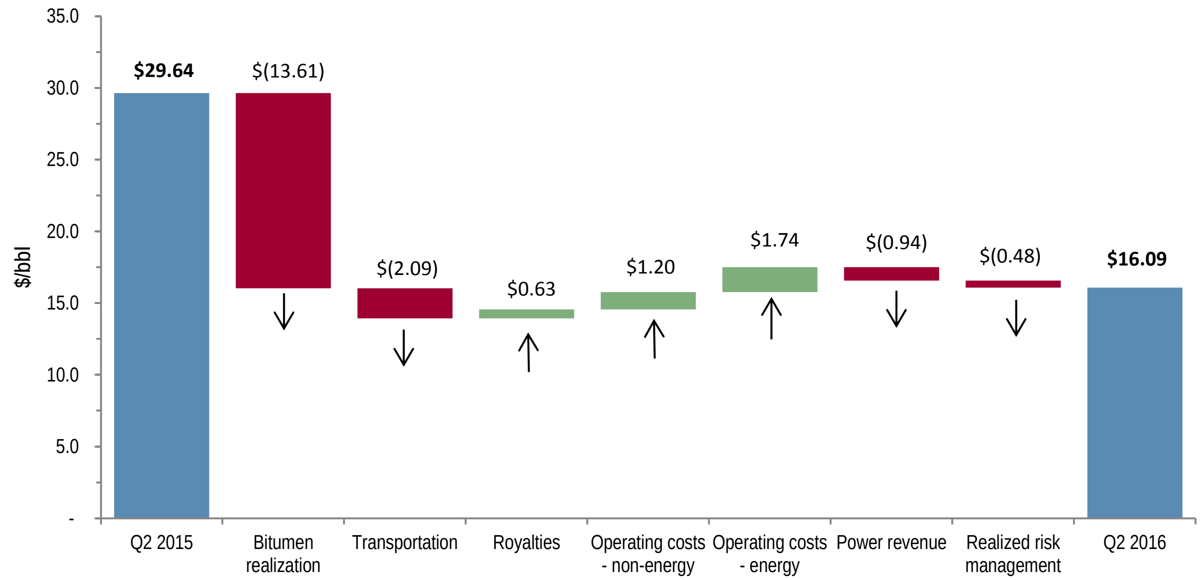
| | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| **($/bbl)** | **2016** | **2015** | **2016** | **2015** |
| Bitumen realization[1] | **$ 30.93** | $ 44.54 | **$ 21.56** | $ 34.39 |
| Transportation[2] | **(6.66)** | (4.57) | **(6.67)** | (4.64) |
| Royalties | **(0.27)** | (0.90) | **(0.10)** | (0.85) |
| | **24.00** | 39.07 | **14.79** | 28.90 |
| Operating costs – non-energy | **(5.81)** | (7.01) | **(6.12)** | (7.31) |
| Operating costs – energy | **(1.97)** | (3.71) | **(2.42)** | (3.91) |
| Power revenue | **0.35** | 1.29 | **0.57** | 1.21 |
| Net operating costs | **(7.43)** | (9.43) | **(7.97)** | (10.01) |
| Cash operating netback excluding risk management | **16.57** | 29.64 | **6.82** | 18.89 |
| Realized loss on risk management | **(0.48)** | - | **(0.25)** | - |
| Cash operating netback including risk management | **$ 16.09** | $ 29.64 | **$ 6.57** | $ 18.89 |

(1) *Blend sales 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 June 30, 2016 was $16.09 per barrel compared to $29.64 per barrel for the three months ended June 30, 2015. Cash operating netback for the six months ended June 30, 2016 was $6.57 per barrel compared to $18.89 per barrel for the six months ended June 30, 2015. The decrease in the cash operating netback is primarily due to a decrease in bitumen realization as a result of the decline of U.S. crude oil benchmark pricing.

**Cash Operating Netback – Three Months Ended June 30, 2016**




**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 the 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 $30.93 per barrel for the three months ended June 30, 2016 compared to $44.54 per barrel for the three months ended June 30, 2015. The decrease in bitumen realization is primarily a result of the decline of U.S. crude oil benchmark pricing which resulted in lower blend sales revenue.

For the three months ended June 30, 2016, the Corporation's cost of diluent was $60.60 per barrel of diluent compared to $73.86 per barrel of diluent for the three months ended June 30, 2015. The decrease in the cost of diluent is primarily a result of the decline of condensate benchmark pricing.

**Transportation**

The Corporation utilizes many 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 by 25,000 bbls/d, thereby furthering the Corporation's strategy of broadening market access to world prices to improve netbacks. Transportation costs averaged $6.66 per barrel for the three months ended June 30, 2016 compared to $4.57 per barrel for the three months ended June

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 $0.27 per barrel during the three months ended June 30, 2016 compared to $0.90 per barrel for the three months ended June 30, 2015. The decrease in royalties for the three months ended June 30, 2016, as compared to the three months ended June 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 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 June 30, 2016 averaged $7.43 per barrel compared to $9.43 per barrel for the three months ended June 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 decreased to $5.81 per barrel for the three months ended June 30, 2016 compared to $7.01 per barrel for the three months ended June 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 treating chemicals costs. The per barrel decrease is also attributable to increasing sales volumes, as these costs are now spread over a greater number of barrels.

**Energy operating costs**

Energy operating costs averaged $1.97 per barrel for the three months ended June 30, 2016 compared to $3.71 per barrel for the three months ended June 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 $1.67 per mcf during the second quarter of 2016 compared to $3.15 per mcf for the second quarter of 2015.

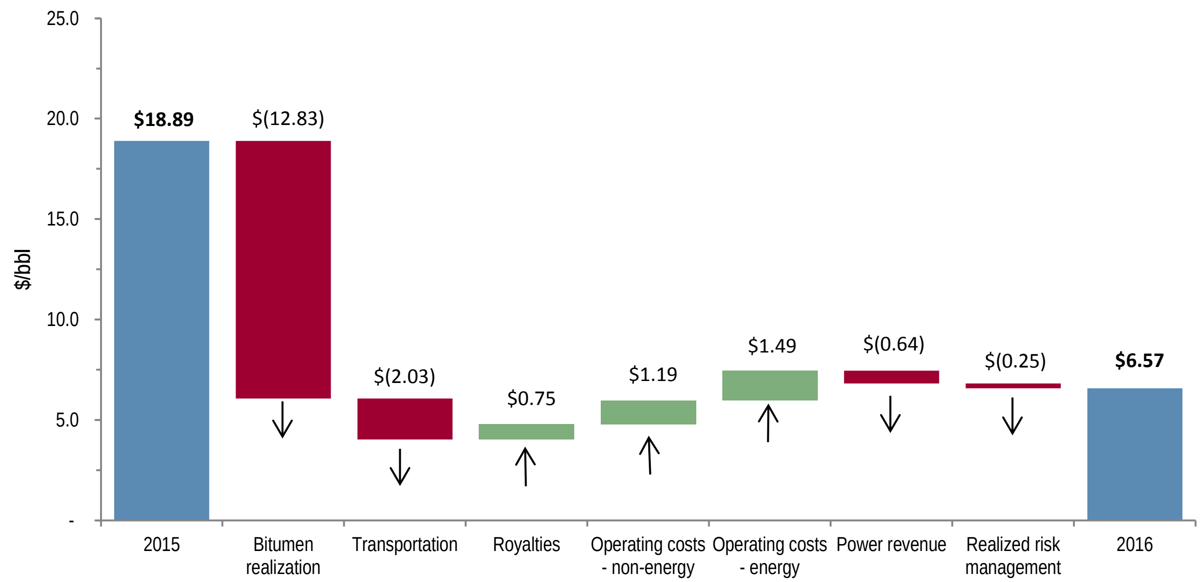
## Power revenue

Power revenue averaged $0.35 per barrel for the three months ended June 30, 2016 compared to $1.29 per barrel for the three months ended June 30, 2015. The Corporation's average realized power sales price during the three months ended June 30, 2016 was $13.54 per megawatt hour compared to $39.55 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 Loss

The realized loss on commodity risk management averaged $0.48 per barrel for the three months ended June 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 – Six Months Ended June 30, 2016




## Bitumen Realization

Bitumen realization averaged $21.56 per barrel for the six months ended June 30, 2016 compared to $34.39 per barrel for the six months ended June 30, 2015. The decrease in bitumen realization is primarily a result of the decline of U.S. crude oil benchmark pricing which resulted in lower blend sales revenue.

For the six months ended June 30, 2016, the Corporation's cost of diluent was $56.68 per barrel of diluent compared to $71.28 per barrel of diluent for the six months ended June 30, 2015. The decrease in the cost of diluent is primarily a result of the decline of condensate benchmark pricing.

**Transportation**

Transportation costs averaged $6.67 per barrel for the six months ended June 30, 2016 compared to $4.64 per barrel for the six months ended June 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 $0.10 per barrel during the six months ended June 30, 2016 compared to $0.85 per barrel for the six months ended June 30, 2015. The decrease in royalties for the six months ended June 30, 2016, as compared to the six months ended June 30, 2015, is primarily attributable to lower royalty rates as a result of lower realized prices.

**Net Operating Costs**

Net operating costs for the six months ended June 30, 2016 averaged $7.97 per barrel compared to $10.01 per barrel for the six months ended June 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 decreased to $6.12 per barrel for the six months ended June 30, 2016 compared to $7.31 per barrel for the six months ended June 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 $2.42 per barrel for the six months ended June 30, 2016 compared to $3.91 per barrel for the six months ended June 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 $1.97 per mcf during the first half 2016 compared to $3.17 per mcf for the first half of 2015.

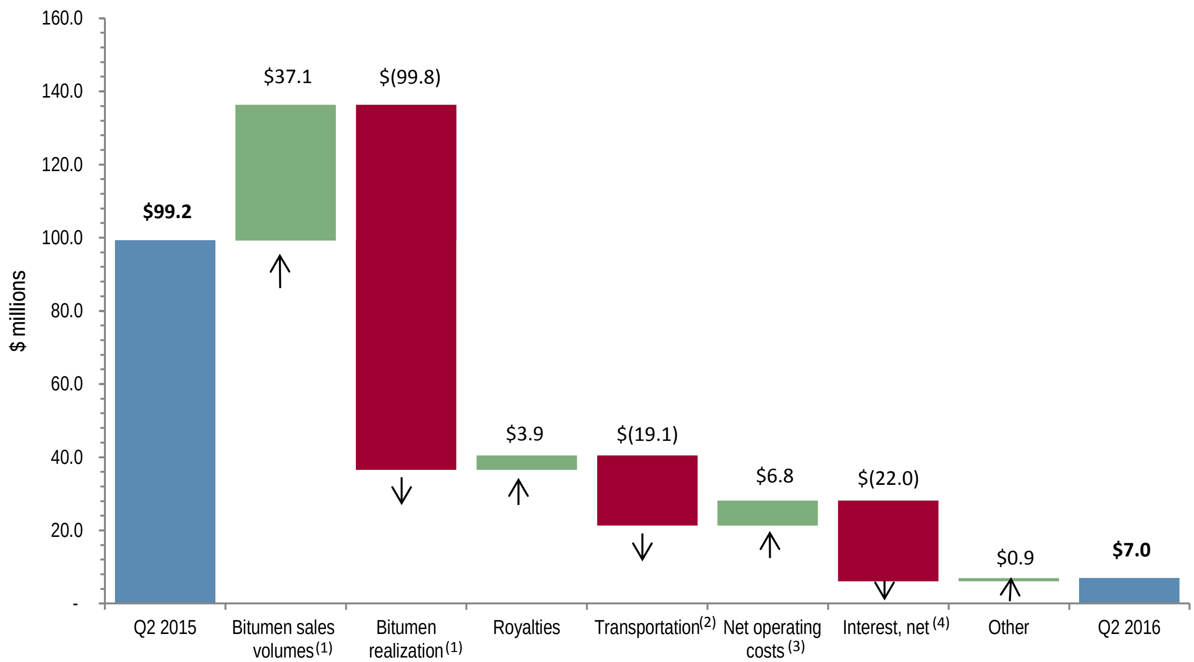
**Power revenue**

Power revenue averaged $0.57 per barrel for the six months ended June 30, 2016 compared to $1.21 per barrel for the six months ended June 30, 2015. The Corporation's average realized power sales price during the six months ended June 30, 2016 was $17.28 per megawatt hour compared to $32.79 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 Loss

The realized loss on commodity risk management averaged $0.25 per barrel for the six months ended June 30, 2016. Refer to the "RISK MANAGEMENT" section of this MD&A for further details.

## Cash Flow From Operations – Three Months Ended June 30, 2016




*(1) Net of diluent.*

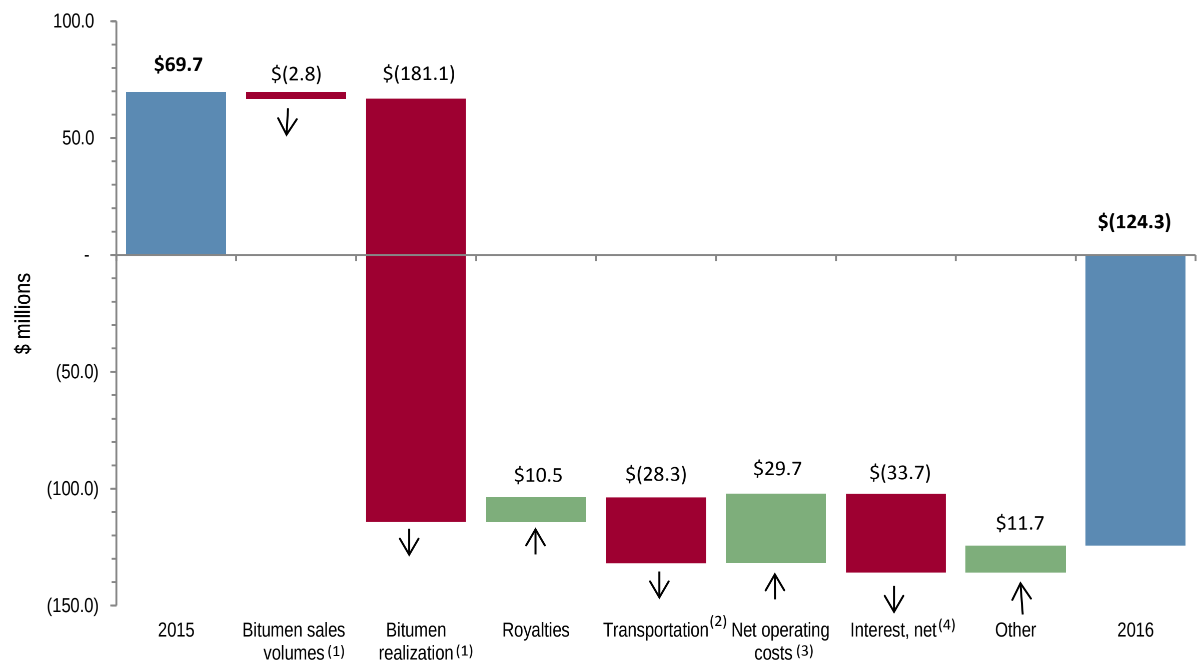
*(2) Defined as transportation expense less transportation revenue.*

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

*(4) Includes cash interest expense, net of capitalized interest, and realized gain/loss on interest rate swaps less interest income.*

Cash flow from operations was $7.0 million for the three months ended June 30, 2016 compared to cash flow from operations of $99.2 million for the three months ended June 30, 2015. Cash flow from operations decreased primarily due to lower bitumen realization, partially offset by an increase in bitumen sales volumes. The decrease in bitumen realization is directly correlated to the decline of U.S. crude oil benchmark pricing.

**Cash Flow Used In Operations – Six Months Ended June 30, 2016**




(1) *Net of diluent.*

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

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

(4) *Includes cash interest expense, net of capitalized interest, and realized gain/loss on interest rate swaps less interest income.*

Cash flow used in operations was $124.3 million for the six months ended June 30, 2016 compared to cash flow from operations of $69.7 million for the six months ended June 30, 2015. Cash flow used in operations increased primarily due to lower bitumen realization. The decrease in bitumen realization is directly correlated to the decline of U.S. crude oil benchmark pricing.

**Operating Loss**

The Corporation recognized an operating loss of $97.9 million for the three months ended June 30, 2016 compared to an operating loss of $23.0 million for the three months ended June 30, 2015. The Corporation recognized an operating loss of $295.2 million for the six months ended June 30, 2016 compared to an operating loss of $147.4 million for the six months ended June 30, 2015. The increase in the operating loss was primarily due to lower bitumen realization as a result of the decline of U.S. crude oil benchmark pricing.

**Revenue**

Revenue for the three months ended June 30, 2016 totalled $513.4 million compared to $554.6 million for the three months ended June 30, 2015. Revenue for the six months ended June 30, 2016 totalled $803.7 million compared to $1.0 billion for the six months ended June 30, 2015. Revenue decreased primarily due to a decrease in blend sales revenue as a result of the decline of U.S. crude oil benchmark pricing. Revenue represents the total of petroleum revenue, net of royalties and other revenue.

**Net Earnings (Loss)**

The Corporation recognized a net loss of $146.2 million for the three months ended June 30, 2016 compared to net earnings of $63.4 million for the three months ended June 30, 2015. The net loss for the three months ended June 30, 2016 included an unrealized loss on commodity risk management of $37.4 million and a net unrealized foreign exchange loss of $13.8 million on the Corporation's U.S. dollar denominated debt and U.S. dollar denominated cash and cash equivalents. The net loss was also affected by lower bitumen realization, primarily as a result of the decline of U.S. crude oil benchmark pricing. Net earnings for the three months ended June 30, 2015 included a net unrealized foreign exchange gain of $75.0 million on U.S. dollar denominated debt and U.S. dollar denominated cash and cash equivalents.

The Corporation recognized a net loss of $15.3 million for the six months ended June 30, 2016 compared to a net loss of $444.9 million for the six months ended June 30, 2015. The net loss for the six months ended June 30, 2016 included a net unrealized foreign exchange gain of $306.5 million on the Corporation's U.S. dollar denominated debt and U.S. dollar denominated cash and cash equivalents. The net loss was also affected by lower bitumen realization, primarily as a result of the decline of U.S. crude oil benchmark pricing. The net loss for the six months ended June 30, 2015 included a net unrealized foreign exchange loss of $295.8 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 June 30, 2016 totalled $20.0 million, as compared to $90.5 million for the three months ended June 30, 2015. Total cash capital investment during the six months ended June 30, 2016 totalled $55.0 million as compared to $170.6 million for the six months ended June 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 $152.7 million as at June 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 semi-annual and quarterly 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 June 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 June 30, 2016, the Corporation's capital resources included $152.7 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$307.6 million of letters of credit have been issued under the facility with Export Development Canada (“EDC”). Similar to the Corporation’s long-term debt, the revolving credit facility is “covenant lite” in structure.

## 3. OUTLOOK

| Summary of 2016 Guidance | Initial Guidance December 4, 2015 | Guidance February 4, 2016 | Revised Guidance July 27, 2016 |
|---|---|---|---|
| Capital investment - $ millions | $328 | $170 | $170 |
| 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 | $6.75 – $7.75 | $6.00 – $7.00 |

In December 2015, the Corporation announced a 2016 capital budget of $328 million. On February 4, 2016, the Corporation reduced the 2016 capital budget to $170 million. As a result of efficiency gains achieved through the application of eMSAGP, which is now fully deployed across the Corporation’s Phase 2 operations, the Corporation anticipates that capital investment directed towards sustaining and maintenance, marketing and other initiatives in 2016 will be approximately $140 million. Depending on market conditions, the Corporation now anticipates directing approximately $30 million towards growth projects. This will leave the Corporation’s capital investment guidance of $170 million unchanged.

The Corporation’s 2016 production guidance remains unchanged at 80,000 to 83,000 bbls/d. As a result of continuing operating cost management over the first half of 2016, annual non-energy operating costs are now targeted to be in the range of $6.00 to $7.00 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:

| | Six months ended June 30 | | 2016 | | 2015 | | | | 2014 | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2016 | 2015 | Q2 | Q1 | Q4 | Q3 | Q2 | Q1 | Q4 | Q3 |
| **Average Commodity Prices** | | | | | | | | | | |
| **Crude oil prices** | | | | | | | | | | |
| Brent (US$/bbl) | **40.88** | 59.33 | **46.67** | 35.10 | 44.71 | 51.17 | 63.50 | 55.16 | 76.98 | 103.39 |
| WTI (US$/bbl) | **39.52** | 53.29 | **45.59** | 33.45 | 42.18 | 46.43 | 57.94 | 48.63 | 73.15 | 97.16 |
| WTI (C$/bbl) | **52.63** | 65.83 | **58.75** | 45.99 | 56.32 | 60.79 | 71.24 | 60.35 | 83.08 | 105.84 |
| Differential – Brent:WTI (US$/bbl) | **1.36** | 6.04 | **1.08** | 1.65 | 2.53 | 4.74 | 5.56 | 6.53 | 3.83 | 6.23 |
| Differential – Brent:WTI (%) | **3.3%** | 10.2% | **2.3%** | 4.7% | 5.7% | 9.3% | 8.8% | 11.8% | 5.0% | 6.0% |
| WCS (C$/bbl) | **34.29** | 49.56 | **41.61** | 26.41 | 36.97 | 43.29 | 56.98 | 42.13 | 66.74 | 83.82 |
| Differential – WTI:WCS (C$/bbl) | **18.34** | 16.28 | **17.14** | 19.58 | 19.35 | 17.50 | 14.25 | 18.22 | 16.34 | 22.02 |
| Differential – WTI:WCS (%) | **34.8%** | 24.7% | **29.2%** | 42.6% | 34.4% | 28.8% | 20.0% | 30.2% | 19.7% | 20.8% |
| **Condensate prices** | | | | | | | | | | |
| Condensate at Edmonton (C$/bbl) | **52.05** | 63.88 | **56.83** | 47.27 | 55.57 | 57.89 | 71.17 | 56.59 | 81.98 | 101.72 |
| Condensate at Edmonton as % of WTI | **98.9%** | 97.0% | **96.7%** | 102.8% | 98.7% | 95.2% | 99.9% | 93.8% | 98.7% | 96.1% |
| Condensate at Mont Belvieu, Texas (US$/bbl) | **36.20** | 49.45 | **40.37** | 32.03 | 40.76 | 41.27 | 52.89 | 46.01 | 62.47 | 88.49 |
| Condensate at Mont Belvieu, Texas as % of WTI | **91.6%** | 92.8% | **88.6%** | 95.8% | 96.6% | 88.9% | 91.3% | 94.6% | 85.4% | 91.1% |
| **Natural gas prices** | | | | | | | | | | |
| AECO (C$/mcf) | **1.52** | 2.69 | **1.37** | 1.82 | 2.57 | 2.89 | 2.64 | 2.74 | 3.58 | 4.00 |
| **Electric power prices** | | | | | | | | | | |
| Alberta power pool (C$/MWh) | **16.43** | 43.20 | **14.77** | 18.09 | 21.19 | 26.04 | 57.25 | 29.14 | 30.55 | 63.91 |
| **Foreign exchange rates** | | | | | | | | | | |
| C$ equivalent of 1 US$ - average | **1.3317** | 1.2353 | **1.2886** | 1.3748 | 1.3353 | 1.3093 | 1.2294 | 1.2411 | 1.1357 | 1.0893 |
| C$ equivalent of 1 US$ - period end | **1.3009** | 1.2474 | **1.3009** | 1.2971 | 1.3840 | 1.3394 | 1.2474 | 1.2683 | 1.1601 | 1.1208 |

### Crude Oil Pricing

Brent crude is the primary world price benchmark for global light sweet crude oil. The Brent benchmark price averaged US$46.67 per barrel in the second quarter of 2016 compared to US$63.50 per barrel for the second quarter of 2015. The Brent benchmark price averaged US$40.88 per barrel for the six months ended June 30, 2016 compared to US$59.33 per barrel for the six months ended June 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$45.59 per barrel in the second quarter of 2016 compared to US$57.94 per barrel for the second quarter of 2015. The WTI price averaged US$39.52 per barrel for the six months ended June 30, 2016 compared to US$53.29 per barrel for the six months ended June 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 $17.14 per barrel, or 29.2%, for the second quarter of 2016, compared to $14.25 per barrel, or 20.0%, for the second quarter of 2015. The WTI:WCS differential averaged $18.34 per barrel, or 34.8%, for the first half of 2016 compared to $16.28 per barrel, or 24.7%, for the first half of 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 $56.83 per barrel, or 96.7% as a percentage of WTI, for the second quarter of 2016 compared to $71.17 per barrel, or 99.9% as a percentage of WTI, for the second quarter of 2015. Condensate prices, benchmarked at Edmonton, averaged $52.05 per barrel, or 98.9% as a percentage of WTI, for the first half of 2016 compared to $63.88 per barrel, or 97.0% as a percentage of WTI, for the first half of 2015.

Condensate prices, benchmarked at Mont Belvieu, Texas, averaged US$40.37 per barrel, or 88.6% as a percentage of WTI, for the second quarter of 2016 compared to US$52.89 per barrel, or 91.3% as a percentage of WTI, for the second quarter of 2015. Condensate prices, benchmarked at Mont Belvieu, Texas, averaged US$36.20 per barrel, or 91.6% as a percentage of WTI, for the first half of 2016 compared to US$49.45 per barrel, or 92.8% as a percentage of WTI, for the first half of 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 $1.37 per mcf for the second quarter of 2016 compared to $2.64 per mcf for the second quarter of 2015. The AECO natural gas price averaged $1.52 per mcf for the six months ended June 30, 2016 compared to $2.69 per mcf for the six months ended June 30, 2015. The North American natural gas market continues to be oversupplied, resulting in lower prices.

**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 $14.77 per megawatt hour for the second quarter of 2016 compared to $57.25 per megawatt hour for the second quarter of 2015. Average power prices for the second quarter of 2015 were positively affected by several plant outages late in the second quarter of 2015. The Alberta power pool price averaged $16.43 per megawatt hour for the six months ended June 30, 2016 compared to $43.20 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 cost of diluent, as blend sales prices and cost of diluent 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 cost of diluent 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 cost of diluent and principal and interest payments.

The Corporation recognizes net unrealized foreign exchange gains and losses on the translation of U.S. dollar denominated debt and U.S. dollar denominated cash and cash equivalents at each reporting date. As at June 30, 2016, the Canadian dollar, at a rate of 1.3009, had increased in value by approximately 6% against the U.S. dollar compared to its value as at December 31, 2015, when the rate was 1.3840. As at June 30, 2016, the Canadian dollar had weakened in value by approximately 4% from June 30, 2015, when the rate was 1.2474.

## 5. OTHER OPERATING RESULTS

**Net Marketing Activity**

| | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| **($000)** | **2016** | **2015** | **2016** | **2015** |
| Petroleum revenue – third party | **$ 77,509** | $ 38,769 | **$ 106,239** | $ 44,848 |
| Purchased product and storage: | | | | |
| Purchased product | **(74,671)** | (37,145) | **(103,481)** | (43,187) |
| Marketing and storage arrangements | **-** | (4,592) | **-** | (10,657) |
| | **(74,671)** | (41,737) | **(103,481)** | (53,844) |
| Net marketing activity[1] | **$ 2,838** | $ (2,968) | **$ 2,758** | $ (8,996) |

(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 barge, 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 optimize the returns on these 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 six months ended June 30, 2016.

**Depletion and Depreciation**

| | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| **($000)** | **2016** | **2015** | **2016** | **2015** |
| Depletion and depreciation expense | **$ 127,352** | $ 102,912 | **$ 244,345** | $ 218,483 |
| Depletion and depreciation expense per barrel of production | **$ 16.84** | $ 15.84 | **$ 16.81** | $ 15.71 |

Depletion and depreciation expense for the three months ended June 30, 2016 totalled $127.4 million compared to $102.9 million for the three months ended June 30, 2015. Depletion and depreciation expense was $16.84 per barrel for the three months ended June 30, 2016 compared to $15.84 per barrel for the three months ended June 30, 2015. The increase in the depletion and depreciation expense per barrel was primarily due to an increase in the estimate of future development costs associated with the Corporation's proved reserves and an increase in depreciable costs.

Depletion and depreciation expense for the six months ended June 30, 2016 totalled $244.3 million compared to $218.5 million for the six months ended June 30, 2015. Depletion and depreciation expense was $16.81 per barrel for the six months ended June 30, 2016 compared to $15.71 per barrel for the six months ended June 30, 2015. The increase in the depletion and depreciation expense per barrel was primarily due to an increase in the estimate of future development costs associated with the Corporation's proved reserves and an increase in depreciable costs.

**Commodity Risk Management Loss (Gain)**

| | Three months ended June 30 | | | | | |
|---|---|---|---|---|---|---|
| **($000)** | **2016** | | | **2015** | | |
| | **Realized** | **Unrealized** | **Total** | **Realized** | **Unrealized** | **Total** |
| Crude oil contracts | **$ 5,304** | **$ 17,698** | **$ 23,002** | $ - | $ - | $ - |
| Condensate contracts[(1)] | **(1,817)** | **19,736** | **17,919** | - | - | - |
| Commodity risk management loss | **$ 3,487** | **$ 37,434** | **$ 40,921** | $ - | $ - | $ - |

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

During the three and six months ended June 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 loss on commodity risk management contracts of $37.4 million and a realized loss on commodity risk management contracts of $3.5 million for the three months ended June 30, 2016.

| | Six months ended June 30 | | | | | |
|---|---|---|---|---|---|---|
| **($000)** | **2016** | | | **2015** | | |
| | **Realized** | **Unrealized** | **Total** | **Realized** | **Unrealized** | **Total** |
| Crude oil contracts | **$ 5,304** | **$ 18,289** | **$ 23,593** | $ - | $ - | $ - |
| Condensate contracts[1] | **(1,817)** | **2,182** | **365** | - | - | - |
| Commodity risk management loss | **$ 3,487** | **$ 20,471** | **$ 23,958** | $ - | $ - | $ - |

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

The Corporation recognized an unrealized loss on commodity risk management contracts of $20.5 million and a realized loss on commodity risk management contracts of $3.5 million for the six months ended June 30, 2016. Refer to the "RISK MANAGEMENT" section of this MD&A for further details.

### General and Administrative

| | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| **($000)** | **2016** | **2015** | **2016** | **2015** |
| General and administrative expense | **$ 24,368** | $ 31,596 | **$ 52,084** | $ 64,902 |
| General and administrative expense per barrel of production | **$ 3.22** | $ 4.86 | **$ 3.58** | $ 4.67 |

General and administrative expense for the three months ended June 30, 2016 was $24.4 million compared to $31.6 million for the three months ended June 30, 2015. General and administrative expense was $3.22 per barrel for the three months ended June 30, 2016 compared to $4.86 per barrel for the three months ended June 30, 2015. General and administrative expense for the six months ended June 30, 2016 was $52.1 million compared to $64.9 million for the six months ended June 30, 2015. General and administrative expense was $3.58 per barrel for the six months ended June 30, 2016 compared to $4.67 per barrel for the six months ended June 30, 2015. General and administrative expense was lower due to the Corporation's continued focus on cost management in all areas of the business.

**Stock-based Compensation Expense**

| | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| ($000) | 2016 | 2015 | 2016 | 2015 |
| Cash-settled | $ 1,450 | $ - | $ 1,450 | $ - |
| Equity-settled | 9,069 | 12,286 | 21,961 | 24,816 |
| Stock-based compensation expense | $ 10,519 | $ 12,286 | $ 23,411 | $ 24,816 |

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 June 30, 2016 was $10.5 million compared to $12.3 million for the three months ended June 30, 2015. Stock-based compensation expense was lower during the second quarter of 2016 compared to the second quarter of 2015 primarily due to forfeitures on previously issued equity-settled plans. Stock-based compensation expense for the six months ended June 30, 2016 was $23.4 million compared to $24.8 million for the six months ended June 30, 2015.

**Research and Development**

| | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| ($000) | 2016 | 2015 | 2016 | 2015 |
| Research and development expense | $ 1,717 | $ 1,619 | $ 3,095 | $ 2,791 |

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 $1.7 million for the three months ended June 30, 2016 compared to $1.6 million for the three months ended June 30, 2015. Research and development expenditures were $3.1 million for the six months ended June 30, 2016 compared to $2.8 million for the six months ended June 30, 2015.

**Foreign Exchange Loss (Gain), Net**

| | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| ($000) | 2016 | 2015 | 2016 | 2015 |
| Unrealized foreign exchange loss (gain) on: | | | | |
| Long-term debt | **$ 14,416** | $ (79,622) | **$ (315,677)** | $ 332,784 |
| US$ denominated cash, cash equivalents and other | **(627)** | 4,596 | **9,185** | (36,961) |
| Unrealized net loss (gain) on foreign exchange | **13,789** | (75,026) | **(306,492)** | 295,823 |
| Realized loss (gain) on foreign exchange | **808** | 938 | **(4,858)** | 8,168 |
| Foreign exchange loss (gain), net | **$ 14,597** | $ (74,088) | **$ (311,350)** | $ 303,991 |

| | | | | |
|---|---|---|---|---|
| C$ equivalent of 1 US$ | | | | |
| Beginning of period | **1.2971** | 1.2683 | **1.3840** | 1.1601 |
| End of period | **1.3009** | 1.2474 | **1.3009** | 1.2474 |

The Corporation recognized a net foreign exchange loss of $14.6 million for the three months ended June 30, 2016 compared to a net foreign exchange gain of $74.1 million for the three months ended June 30, 2015. The net foreign exchange loss is primarily due to the translation of the U.S. dollar denominated debt as a result of moderate weakening of the Canadian dollar compared to the U.S. dollar during the three months ended June 30, 2016. During the three months ended June 30, 2015, the Canadian dollar strengthened in value by approximately 2%.

The Corporation recognized a net foreign exchange gain of $311.4 million for the six months ended June 30, 2016 compared to a net foreign exchange loss of $304.0 million for the six months ended June 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 6% during the six months ended June 30, 2016. During the six months ended June 30, 2015, the Canadian dollar weakened in value by approximately 8%.

**Net Finance Expense**

| | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| **($000)** | **2016** | **2015** | **2016** | **2015** |
| Total interest expense | **$ 80,758** | $ 75,550 | **$ 164,673** | $ 151,276 |
| Less capitalized interest | **-** | (16,485) | **-** | (32,488) |
| Net interest expense | **80,758** | 59,065 | **164,673** | 118,788 |
| Accretion on provisions | **1,820** | 1,244 | **3,514** | 2,556 |
| Unrealized loss (gain) on derivative financial liabilities | **516** | (7,738) | **6,005** | (4,207) |
| Realized loss on interest rate swaps | **1,471** | 1,404 | **3,040** | 2,805 |
| Net finance expense | **$ 84,565** | $ 53,975 | **$ 177,232** | $ 119,942 |
| | | | | |
| Average effective interest rate[1] | **5.8%** | 5.8% | **5.8%** | 5.8% |

(1) *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 June 30, 2016 was $80.8 million compared to $75.6 million for the three months ended June 30, 2015. Total interest expense, before capitalization, for the six months ended June 30, 2016 was $164.7 million compared to $151.3 million for the six months ended June 30, 2015. Total interest expense for the three and six months ended June 30, 2016 was higher 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 budget and expenditures, the Corporation did not capitalize interest during the three and six months ended June 30, 2016. During the three and six months ended June 30, 2015, the Corporation capitalized $16.5 million and $32.5 million of interest, respectively.

The Corporation recognized an unrealized loss on derivative financial liabilities of $0.5 million for the three months ended June 30, 2016 compared to an unrealized gain of $7.7 million for the three months ended June 30, 2015. The Corporation recognized an unrealized loss on derivative financial liabilities of $6.0 million for the six months ended June 30, 2016 compared to an unrealized gain of $4.2 million for the six months ended June 30, 2015. These unrealized losses and 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 swap contracts of $1.5 million for the three months ended June 30, 2016 compared to a realized loss of $1.4 million for the three months ended June 30, 2015. The Corporation realized a loss on the interest swap contracts of $3.0 million for the six months ended June 30, 2016 compared to a realized loss of $2.8 million for the six months ended June 30, 2015.

**Other Expenses (Recoveries)**

| | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| ($000) | 2016 | 2015 | 2016 | 2015 |
| Onerous contracts | **$ 9,055** | $ - | **$ 13,426** | $ - |
| Contract cancellation recovery | **-** | (5,880) | **-** | (5,880) |
| Severance and other | **6,179** | - | **6,179** | - |
| Other expenses (recoveries) | **$ 15,234** | $ (5,880) | **$ 19,605** | $ (5,880) |

The Corporation recognized other expenses of $15.2 million for the three months and $19.6 million for the six months ended June 30, 2016 compared to a recovery of $5.9 million for the three and six months ended June 30, 2015.

For the three months ended June 30, 2016, an onerous contract expense of $9.1 million was recognized primarily related to the continued reduction of the Corporation's capital program for 2016 and its impact on a camp construction contract and changes in estimated future cash flows related to the onerous office lease provision. For the six months ended June 30, 2016, the Corporation recognized an onerous contracts expense of $13.4 million which includes the camp construction contract, the changes in estimated future cash flows related to the onerous office lease provision and an onerous operating lease expense related to a drilling contract recorded in the first quarter of 2016.

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

During the three months ended June 30, 2015, the Corporation recognized a $5.9 million recovery of project cancellation costs.

**Income Tax Expense (Recovery)**

| | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| ($000) | 2016 | 2015 | 2016 | 2015 |
| Current income tax expense (recovery) | **$ 97** | $ (800) | **$ 614** | $ (800) |
| Deferred income tax expense (recovery) | **(48,804)** | 5,256 | **(117,960)** | (22,518) |
| Income tax expense (recovery) | **$ (48,707)** | $ 4,456 | **$ (117,346)** | $ (23,318) |

The Corporation recognized a current income tax expense of $0.1 million for the three months ended June 30, 2016 and $0.6 million for the six months ended June 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 second quarter of 2015, the Corporation recognized a current income tax recovery of $0.8 million relating to the refundable Alberta tax credit on Scientific Research and Experimental Development expenditures.

The Corporation recognized a deferred income tax recovery of $48.8 million for the three months ended June 30, 2016 compared to a deferred income tax expense of $5.3 million for the three months ended June 30, 2015. The Corporation recognized a deferred income tax recovery of $118.0 million for the six months ended June 30, 2016 compared to a deferred income tax recovery of $22.5 million for the six months ended June 30, 2015.

During the second quarter of 2015, the Government of Alberta enacted an increase in the Alberta corporate income tax rate from 10% to 12%. 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 June 30, 2016, the non-taxable loss was $7.2 million compared to a non-taxable gain of $39.8 million for the three months ended June 30, 2015. For the six months ended June 30, 2016, the non-taxable gain was $157.8 million compared to a non-taxable loss of $166.4 million for the six months ended June 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 June 30, 2016 was $9.1 million compared to $12.3 million for the three months ended June 30, 2015. Stock-based compensation expense for equity-settled plans for the six months ended June 30, 2016 was $22.0 million compared to $24.8 million for the three months ended June 30, 2015.

- During the six months ended June 30, 2016, a deferred tax recovery of $1.9 million was recognized relating to a tax deduction available for the fair market value of vested RSUs. During the six months ended June 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 June 30, 2016, the Corporation had approximately $8.0 billion of available tax pools and $219.5 million of capital investment in respect of incomplete projects which will increase available tax pools upon completion of the projects.

As at June 30, 2016, the Corporation has recognized a deferred income tax asset of $30.5 million as estimated future taxable income is expected to be sufficient to realize the deferred income tax asset.

As at June 30, 2016, the Corporation had not recognized the tax benefit related to $539.3 million of unrealized taxable capital foreign exchange losses.

## 6. CAPITAL INVESTING

| | **Three months ended June 30** | | **Six months ended June 30** | |
|---|---|---|---|---|
| **($000)** | **2016** | **2015** | **2016** | **2015** |
| Total cash capital investment | **$ 19,990** | $ 90,465 | **$ 54,965** | $ 170,566 |
| Capitalized interest | **-** | 16,485 | **-** | 32,488 |
| | **$ 19,990** | $ 106,950 | **$ 54,965** | $ 203,054 |

Total cash capital investment for the three months ended June 30, 2016 was $20.0 million, as compared to $90.5 million for the three months ended June 30, 2015. Total cash capital investment for the six months ended June 30, 2016 was $55.0 million as compared to $170.6 million for the six months ended June 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 budget and expenditures, the Corporation did not capitalize interest during the three and six months ended June 30, 2016. During the three and six months ended June 30, 2015, the Corporation capitalized $16.5 million and $32.5 million of interest, respectively.

## 7. LIQUIDITY AND CAPITAL RESOURCES

| ($000) | June 30, 2016 | December 31, 2015 |
|---|---|---|
| Cash and cash equivalents | **$ 152,711** | $ 408,213 |
| | | |
| Senior secured term loan (June 30, 2016 – US$1.242 billion; December 31, 2015 – US$1.249 billion; due 2020) | **1,615,718** | 1,727,924 |
| US$2.5 billion revolver (due 2019) | **-** | - |
| 6.5% senior unsecured notes (US$750.0 million; due 2021) | **975,675** | 1,038,000 |
| 6.375% senior unsecured notes (US$800.0 million; due 2023) | **1,040,720** | 1,107,200 |
| 7.0% senior unsecured notes (US$1.0 billion; due 2024) | **1,300,900** | 1,384,000 |
| Total debt(1),(2) | **$ 4,933,013** | $ 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 June 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 June 30, 2016, the Corporation's available capital resources included $152.7 million of cash and cash equivalents and an undrawn US$2.5 billion syndicated revolving credit facility. The Corporation also has a US$500 million guaranteed letter of credit facility, under which US$307.6 million of letters of credit have been issued.

The US$2.5 billion revolving credit facility remains undrawn as at June 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 installments of US$3.25 million. The Corporation has a five-year US$500 million letter of credit facility guaranteed by EDC 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**

| | **Three months ended June 30** | | **Six months ended June 30** | |
|---|---|---|---|---|
| **($000)** | **2016** | **2015** | **2016** | **2015** |
| Net cash provided by (used in): | | | | |
| Operating activities | **$ 64,587** | $ 121,761 | **$ (156,084)** | $ 104,819 |
| Investing activities | **(33,030)** | (148,492) | **(80,592)** | (354,302) |
| Financing activities | **(4,222)** | (4,024) | **(8,435)** | (8,148) |
| Effect of exchange rate changes on cash and cash equivalents held in foreign currency | **816** | (1,785) | **(10,391)** | 39,772 |
| Change in cash and cash equivalents | **$ 28,151** | $ (32,540) | **$ (255,502)** | $ (217,859) |

**Cash Flow – Operating Activities**

Net cash provided by operating activities totalled $64.6 million for the three months ended June 30, 2016 compared to net cash provided by operating activities of $121.8 million for the three months ended June 30, 2015. The decrease in cash flow from operating activities is primarily due to lower bitumen realization as a result of the decline of U.S. crude oil benchmark pricing. Net cash provided by operating activities for the second quarter of 2016 included an increase in the net change in non-cash working capital of $56.9 million, primarily due to the timing of interest payments.

Net cash used in operating activities totalled $156.1 million for the six months ended June 30, 2016 compared to net cash provided by operating activities of $104.8 million for the six months ended June 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 of U.S. crude oil benchmark pricing.

**Cash Flow – Investing Activities**

Net cash used in investing activities for the three months ended June 30, 2016 primarily consisted of $20.0 million in capital investment (refer to the "CAPITAL INVESTING" section of this MD&A for further details) and a $13.2 million decrease in the net change in non-cash investing working capital.

Net cash used in investing activities for the three months ended June 30, 2015 primarily consisted of $107.0 million in capital investment and a $39.0 million use of cash related to the net change in non-cash investing working capital.

Net cash used in investing activities for the six months ended June 30, 2016 primarily consisted of $55.0 million in capital investment (refer to the “CAPITAL INVESTING” section of this MD&A for further details) and a $24.5 million use of cash related to the net change in non-cash investing working capital.

Net cash used in investing activities for the six months ended June 30, 2015 primarily consisted of $203.1 million in capital investment and a $150.7 million use of cash related to the net change in non-cash investing working capital, primarily relating to the settlement of accounts payable related to 2014 capital investment activity.

**Cash Flow – Financing Activities**

Net cash used in financing activities for the three months ended June 30, 2016 consisted of $4.2 million of debt principal repayment. Net cash used in financing activities for the three months ended June 30, 2015 consisted of $4.0 million of debt principal repayment.

Net cash used in financing activities for the six months ended June 30, 2016 consisted of $8.4 million of debt principal repayment. Net cash used in financing activities for the six months ended June 30, 2015 consisted of $8.1 million of debt principal repayment.

## 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 the fluctuation of global crude oil markets, 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 crude oil sales contracts that remain outstanding as at June 30, 2016:

| As at June 30, 2016 | Volumes (bbls/d) | Term | Average Price (US$/bbl) |
|---|---|---|---|
| Fixed Price: | | | |
| WTI Fixed Price | 18,663 | Jul 1, 2016 – Sep 30, 2016 | $45.22 |
| WTI Fixed Price | 12,000 | Oct 1, 2016 – Dec 31, 2016 | $48.06 |
| WCS Differential | 48,660 | Jul 1, 2016 – Sep 30, 2016 | $(13.74) |
| WCS Differential | 1,000 | Oct 1, 2016 – Dec 31, 2016 | $(14.90) |
| Collars: | | | |
| WTI Collars | 30,000 | Jul 1, 2016 – Sep 30, 2016 | $44.61 – $51.25 |
| WTI Collars | 19,000 | Oct 1, 2016 – Dec 31, 2016 | $44.99 – $53.68 |

The Corporation has entered into condensate purchase contracts that effectively fix the average percentage differentials of condensate prices at Mont Belvieu, Texas to a percentage of WTI (US$/bbl). The following condensate purchase contracts remain outstanding as at June 30, 2016:

| As at June 30, 2016 | Volumes (bbls/d) | Term | Average % of WTI |
|---|---|---|---|
| Mont Belvieu fixed % of WTI | 9,250 | Jul 1, 2016 – Sep 30, 2016 | 84.2% |
| Mont Belvieu fixed % of WTI | 12,750 | Oct 1, 2016 – Dec 31, 2016 | 83.7% |
| Mont Belvieu fixed % of WTI | 15,150 | Jan 1, 2017 – Dec 31, 2017 | 82.9% |

**Interest Rate Risk Management**

The Corporation is exposed to interest rate cash flow risk on its floating rate long-term debt and periodically enters into interest rate swap contracts to manage its floating to fixed interest rate mix on long-term debt. The Corporation has entered into interest rate swap contracts to effectively fix the interest rate at approximately 4.4% on US$748.0 million of the US$1.242 billion senior secured term loan until September 30, 2016.

## 9. SHARES OUTSTANDING

As at June 30, 2016, the Corporation had the following share capital instruments outstanding and exercisable:

| | Outstanding |
|---|---|
| Common shares | 226,356,944 |
| Convertible securities | |
| Stock options[1] | 10,550,886 |
| Equity-settled RSUs and PSUs | 1,797,608 |

*(1) 6,961,651 stock options were exercisable as at June 30, 2016.*

As at July 18, 2016, the Corporation had 226,356,944 common shares, 10,496,311 stock options and 1,791,344 equity-settled restricted share units and equity-settled performance share units outstanding and 6,921,447 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 | 2017 | 2018 | 2019 | 2020 | Thereafter |
|---|---|---|---|---|---|---|
| Long-term debt[1] | $ 8,456 | $ 16,912 | $ 16,912 | $ 16,912 | $ 1,556,527 | $ 3,317,294 |
| Interest on long-term debt[1] | 140,629 | 280,784 | 280,149 | 279,515 | 235,440 | 447,388 |
| Decommissioning obligation[2] | 743 | 2,180 | 2,420 | 2,420 | 2,420 | 793,701 |
| Transportation and storage[3] | 85,598 | 180,353 | 196,440 | 187,018 | 225,644 | 3,202,273 |
| Office lease rentals[4] | 7,797 | 34,137 | 32,700 | 32,729 | 33,619 | 268,259 |
| Diluent purchases[5] | 101,196 | 46,250 | 19,943 | 19,943 | 19,997 | 56,498 |
| Other commitments[6] | 22,948 | 21,835 | 8,779 | 10,796 | 11,432 | 80,340 |
| **Total** | **$ 367,367** | **$ 582,451** | **$ 557,343** | **$ 549,333** | **$ 2,085,079** | **$ 8,165,753** |

*(1) This represents the scheduled principal repayments of the senior secured credit facility and the senior unsecured notes and associated interest payments based on interest and foreign exchange rates in effect on June 30, 2016.*

*(2) This represents the undiscounted future obligations associated with the decommissioning of the Corporation's crude oil, transportation and storage assets.*

*(3) This represents transportation and storage commitments from 2016 to 2040, including various pipeline commitments which are awaiting regulatory approval.*

*(4) This represents the future commitments for the Calgary Corporate office.*

*(5) This represents the future commitments associated with the Corporation's diluent purchases.*

*(6) This represents the future commitments associated with the Corporation's capital program and other operating and maintenance commitments.*

## 11. NON-GAAP MEASURES

Certain financial measures in this MD&A including: net marketing activity, 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 June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| **($000)** | **2016** | **2015** | **2016** | **2015** |
| Net cash provided by (used in) operating activities | **$ 64,587** | $ 121,761 | **$ (156,084)** | $ 104,819 |
| Add (deduct): | | | | |
| Net change in non-cash operating working capital items | **(56,923)** | (16,993) | **30,917** | (30,481) |
| Net change in other liabilities | **(734)** | - | **(105)** | - |
| Contract cancellation recovery | **-** | (5,880) | **-** | (5,880) |
| Decommissioning expenditures | **34** | 355 | **996** | 1,251 |
| Cash flow from (used in) operations | **$ 6,964** | $ 99,243 | **$ (124,276)** | $ 69,709 |

**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 earnings (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 earnings (loss)", the nearest IFRS measure, in the table below.

| | **Three months ended June 30** | | **Six months ended June 30** | |
|---|---|---|---|---|
| **($000)** | **2016** | **2015** | **2016** | **2015** |
| Net earnings (loss) | **$ (146,165)** | $ 63,414 | **$ (15,336)** | $ (444,893) |
| Add (deduct): | | | | |
| Unrealized net loss (gain) on foreign exchange(1) | **13,789** | (75,026) | **(306,492)** | 295,823 |
| Unrealized loss (gain) on derivative financial instruments(2) | **516** | (7,738) | **6,005** | (4,207) |
| Unrealized loss on risk management(3) | **37,434** | - | **20,471** | - |
| Contract cancellation recovery | **-** | (5,880) | **-** | (5,880) |
| Onerous contracts(4) | **9,055** | - | **13,426** | - |
| Deferred tax expense (recovery) relating to these adjustments | **(12,523)** | 2,280 | **(13,254)** | 11,786 |
| Operating loss | **$ (97,894)** | $ (22,950) | **$ (295,180)** | $ (147,371) |

*(1) Unrealized net foreign exchange 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 the second quarter of 2016, an onerous contracts expense was recognized primarily related to the reduction of the Corporation's capital program for 2016 and its impact on a camp construction contract and changes in estimated future cash flows related to the onerous office lease provision. During the six months ended June 30, 2016, onerous contracts expenses included expenses related to the camp construction contract and a drilling contract.*

**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 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 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 six months ended June 30, 2016 and June 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 June 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. Payments of these leases are included as an expense as incurred over the lease term. No asset or liability value had been assigned to these leases as at June 30, 2016 and December 31, 2015.

## 15. NEW ACCOUNTING STANDARDS

There were no new accounting standards adopted during the six months ended June 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. The Corporation is currently assessing the impact of the adoption of these amendments 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. The Corporation is currently assessing the impact of the adoption of these amendments 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** | **Q2** | **Q1** | **Q4** | **Q3** | **Q2** | **Q1** | **Q4** | **Q3** |
| **FINANCIAL ($000 unless specified)** | | | | | | | | |
| Net earnings (loss)[1] | **(146,165)** | 130,829 | (297,275) | (427,503) | 63,414 | (508,307) | (150,076) | (100,975) |
| Per share, diluted | **(0.65)** | 0.58 | (1.32) | (1.90) | 0.28 | (2.27) | (0.67) | (0.45) |
| Operating earnings (loss) | **(97,894)** | (197,286) | (140,234) | (86,769) | (22,950) | (124,421) | 8,084 | 87,471 |
| Per share, diluted | **(0.43)** | (0.88) | (0.62) | (0.39) | (0.10) | (0.56) | 0.04 | 0.39 |
| Cash flow from (used in) operations | **6,964** | (131,240) | (44,130) | 23,877 | 99,243 | (29,534) | 134,099 | 238,659 |
| Per share, diluted | **0.03** | (0.58) | (0.20) | 0.11 | 0.44 | (0.13) | 0.60 | 1.06 |
| Cash capital investment[2] | **19,990** | 34,975 | 54,473 | 32,139 | 90,465 | 80,101 | 323,970 | 291,309 |
| Cash and cash equivalents | **152,711** | 124,560 | 408,213 | 350,736 | 438,238 | 470,778 | 656,097 | 776,522 |
| Working capital | **128,586** | 183,649 | 363,038 | 366,725 | 374,766 | 386,130 | 525,534 | 747,928 |
| Long-term debt | **4,871,182** | 4,859,099 | 5,190,363 | 5,023,976 | 4,677,577 | 4,759,102 | 4,350,421 | 4,202,966 |
| Shareholders' equity | **3,679,372** | 3,812,566 | 3,677,867 | 3,956,689 | 4,358,078 | 4,279,873 | 4,768,235 | 4,894,444 |
| **BUSINESS ENVIRONMENT** | | | | | | | | |
| WTI (US$/bbl) | **45.59** | 33.45 | 42.18 | 46.43 | 57.94 | 48.63 | 73.15 | 97.16 |
| C$ equivalent of 1US$ - average | **1.2886** | 1.3748 | 1.3353 | 1.3093 | 1.2294 | 1.2411 | 1.1357 | 1.0893 |
| Differential – WTI:WCS ($/bbl) | **17.14** | 19.58 | 19.35 | 17.50 | 14.25 | 18.22 | 16.34 | 22.02 |
| Differential – WTI:WCS (%) | **29.2%** | 42.6% | 34.4% | 28.8% | 20.0% | 30.2% | 19.7% | 20.8% |
| Natural gas – AECO ($/mcf) | **1.37** | 1.82 | 2.57 | 2.89 | 2.64 | 2.74 | 3.58 | 4.00 |
| **OPERATIONAL ($/bbl unless specified)** | | | | | | | | |
| Bitumen production – bbls/d | **83,127** | 76,640 | 83,514 | 82,768 | 71,376 | 82,398 | 80,349 | 76,471 |
| Bitumen sales – bbls/d | **80,548** | 74,529 | 82,282 | 84,651 | 71,401 | 85,519 | 70,116 | 69,757 |
| Steam to oil ratio (SOR) | **2.3** | 2.4 | 2.5 | 2.5 | 2.3 | 2.6 | 2.5 | 2.5 |
| Bitumen realization | **30.93** | 11.43 | 23.17 | 31.03 | 44.54 | 25.82 | 50.48 | 65.12 |
| Transportation – net | **(6.66)** | (6.68) | (5.35) | (4.64) | (4.57) | (4.70) | (1.82) | (1.09) |
| Royalties | **(0.27)** | 0.07 | (0.25) | (0.88) | (0.90) | (0.80) | (2.97) | (5.02) |
| Operating costs – non-energy | **(5.81)** | (6.45) | (5.66) | (5.98) | (7.01) | (7.57) | (6.42) | (7.16) |
| Operating costs – energy | **(1.97)** | (2.90) | (3.58) | (3.97) | (3.71) | (4.07) | (5.16) | (5.58) |
| Power revenue | **0.35** | 0.82 | 0.72 | 0.85 | 1.29 | 1.15 | 1.45 | 2.43 |
| Realized risk management loss | **(0.48)** | - | - | - | - | - | - | - |
| Cash operating netback | **16.09** | (3.71) | 9.05 | 16.41 | 29.64 | 9.83 | 35.56 | 48.70 |
| Power sales price (C$/MWh) | **13.54** | 19.77 | 19.67 | 25.09 | 39.55 | 28.21 | 31.67 | 59.07 |
| Power sales (MW/h) | **86** | 129 | 125 | 119 | 97 | 145 | 134 | 119 |
| Depletion and depreciation rate per bbl of production | **16.84** | 16.78 | 16.55 | 15.99 | 15.84 | 15.58 | 13.63 | 13.92 |
| **COMMON SHARES** | | | | | | | | |
| Shares outstanding, end of period (000) | **226,357** | 224,997 | 224,997 | 224,942 | 224,881 | 223,847 | 223,847 | 223,794 |
| Volume traded (000) | **157,056** | 182,199 | 76,631 | 73,099 | 40,929 | 57,657 | 94,588 | 30,649 |
| Common share price ($) | | | | | | | | |
| High | **7.86** | 8.26 | 13.15 | 20.36 | 25.20 | 24.31 | 34.69 | 40.75 |
| Low | **5.21** | 3.46 | 7.33 | 7.87 | 17.56 | 14.84 | 13.30 | 34.00 |
| Close (end of period) | **6.84** | 6.55 | 8.02 | 8.24 | 20.40 | 20.46 | 19.55 | 34.38 |

(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 | June 30, 2016 | December 31, 2015 |
|---|---|---|---|
| **Assets** | | | |
| Current assets | | | |
| Cash and cash equivalents | 19 | $ **152,711** | $ 408,213 |
| Trade receivables and other | | **206,191** | 150,042 |
| Inventories | | **73,150** | 53,079 |
| | | **432,052** | 611,334 |
| Non-current assets | | | |
| Property, plant and equipment | 4 | **7,826,124** | 8,011,760 |
| Exploration and evaluation assets | 5 | **547,653** | 546,421 |
| Other intangible assets | 6 | **84,467** | 84,142 |
| Other assets | 7 | **138,921** | 146,612 |
| Deferred income tax asset | 18 | **30,506** | - |
| **Total assets** | | **$ 9,059,723** | $ 9,400,269 |
| **Liabilities** | | | |
| Current liabilities | | | |
| Accounts payable and accrued liabilities | | $ **241,548** | $ 217,991 |
| Current portion of long-term debt | 8 | **16,912** | 17,992 |
| Current portion of provisions and other liabilities | 9 | **26,230** | 12,313 |
| Commodity risk management | 21 | **18,776** | - |
| | | **303,466** | 248,296 |
| Non-current liabilities | | | |
| Long-term debt | 8 | **4,871,182** | 5,190,363 |
| Provisions and other liabilities | 9 | **204,008** | 196,274 |
| Deferred income tax liability | 18 | **-** | 87,469 |
| Commodity risk management | 21 | **1,695** | - |
| Total liabilities | | **5,380,351** | 5,722,402 |
| **Shareholders' equity** | | | |
| Share capital | 10 | **4,875,838** | 4,836,800 |
| Contributed surplus | 10 | **158,352** | 171,835 |
| Deficit | | **(1,381,677)** | (1,366,341) |
| Accumulated other comprehensive income | | **26,859** | 35,573 |
| Total shareholders' equity | | **3,679,372** | 3,677,867 |
| **Total liabilities and shareholders' equity** | | **$ 9,059,723** | $ 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 June 30 | | Six months ended June 30 | |
|---|---|---|---|---|---|
| | **Note** | **2016** | **2015** | **2016** | **2015** |
| **Revenues** | | | | | |
| Petroleum revenue, net of royalties | 12 | **$ 505,663** | $ 542,884 | **$ 785,287** | $ 998,566 |
| Other revenue | 13 | **7,692** | 11,763 | **18,406** | 23,076 |
| | | **513,355** | 554,647 | **803,693** | 1,021,642 |
| **Expenses** | | | | | |
| Diluent and transportation | 14 | **257,440** | 253,692 | **480,803** | 549,402 |
| Operating expenses | | **57,049** | 69,678 | **120,437** | 159,276 |
| Purchased product and storage | | **74,671** | 41,737 | **103,481** | 53,844 |
| Depletion and depreciation | 4,6 | **127,352** | 102,912 | **244,345** | 218,483 |
| Commodity risk management loss | 21 | **40,921** | - | **23,958** | - |
| General and administrative | | **24,368** | 31,596 | **52,084** | 64,902 |
| Stock-based compensation | 11 | **10,519** | 12,286 | **23,411** | 24,816 |
| Research and development | | **1,717** | 1,619 | **3,095** | 2,791 |
| Interest and other income | | **(206)** | (750) | **(726)** | (1,714) |
| Foreign exchange loss (gain), net | 15 | **14,597** | (74,088) | **(311,350)** | 303,991 |
| Net finance expense | 16 | **84,565** | 53,975 | **177,232** | 119,942 |
| Other expenses (recoveries) | 17 | **15,234** | (5,880) | **19,605** | (5,880) |
| Earnings (loss) before income taxes | | **(194,872)** | 67,870 | **(132,682)** | (468,211) |
| Income tax expense (recovery) | 18 | **(48,707)** | 4,456 | **(117,346)** | (23,318) |
| Net earnings (loss) | | **(146,165)** | 63,414 | **(15,336)** | (444,893) |
| Other comprehensive income (loss), net of tax | | | | | |
| Items that may be reclassified to profit or loss: | | | | | |
| Foreign currency translation adjustment | | **2,267** | 401 | **(8,714)** | 6,239 |
| Comprehensive income (loss) for the period | | **$ (143,898)** | $ 63,815 | **$ (24,050)** | $ (438,654) |

| | | | | | |
|---|---|---|---|---|---|
| Net earnings (loss) per common share | | | | | |
| Basic | 20 | **$ (0.65)** | $ 0.28 | **$ (0.07)** | $ (1.99) |
| Diluted | 20 | **$ (0.65)** | $ 0.28 | **$ (0.07)** | $ (1.99) |

*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 | **-** | **25,555** | **-** | **-** | **25,555** |
| RSUs vested and released | 10 | **39,038** | **(39,038)** | **-** | **-** | **-** |
| Comprehensive loss | | **-** | **-** | **(15,336)** | **(8,714)** | **(24,050)** |
| **Balance as at June 30, 2016** | | **$ 4,875,838** | **$ 158,352** | **$(1,381,677)** | **$ 26,859** | **$ 3,679,372** |
| | | | | | | |
| Balance as at December 31, 2014 | | $ 4,797,853 | $ 153,837 | $ (196,670) | $ 13,215 | $ 4,768,235 |
| Stock-based compensation | | - | 28,497 | - | - | 28,497 |
| RSUs vested and released | | 35,401 | (35,401) | - | - | - |
| Comprehensive income (loss) | | - | - | (444,893) | 6,239 | (438,654) |
| Balance as at June 30, 2015 | | $ 4,833,254 | $ 146,933 | $ (641,563) | $ 19,454 | $ 4,358,078 |

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

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

| | | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|---|
| | **Note** | **2016** | **2015** | **2016** | **2015** |
| **Cash provided by (used in):** | | | | | |
| Operating activities | | | | | |
| Net earnings (loss) | | **$ (146,165)** | $ 63,414 | **$ (15,336)** | $ (444,893) |
| Adjustments for: | | | | | |
| Depletion and depreciation | 4,6 | **127,352** | 102,912 | **244,345** | 218,483 |
| Stock-based compensation | 11 | **9,069** | 12,286 | **21,961** | 24,816 |
| Unrealized loss (gain) on foreign exchange | 15 | **13,789** | (75,026) | **(306,492)** | 295,823 |
| Unrealized loss (gain) on derivative financial liabilities | 16 | **516** | (7,738) | **6,005** | (4,207) |
| Unrealized loss on risk management | 21 | **37,434** | - | **20,471** | - |
| Onerous contracts | 17 | **9,055** | - | **13,426** | - |
| Deferred income tax expense (recovery) | 18 | **(48,804)** | 5,256 | **(117,960)** | (22,518) |
| Amortization of debt issue costs | 7,8 | **3,029** | 2,933 | **6,032** | 5,818 |
| Other | | **1,689** | 1,086 | **3,272** | 2,267 |
| Decommissioning expenditures | 9 | **(34)** | (355) | **(996)** | (1,251) |
| Net change in other liabilities | | **734** | - | **105** | - |
| Net change in non-cash working capital items | 19 | **56,923** | 16,993 | **(30,917)** | 30,481 |
| **Net cash provided by (used in) operating activities** | | **64,587** | 121,761 | **(156,084)** | 104,819 |
| Investing activities | | | | | |
| Capital investments: | | | | | |
| Property, plant and equipment | 4 | **(17,214)** | (105,600) | **(51,223)** | (197,190) |
| Exploration and evaluation | 5 | **(721)** | (611) | **(981)** | (858) |
| Other intangible assets | 6 | **(2,055)** | (739) | **(2,761)** | (5,006) |
| Other | | **153** | (2,518) | **(1,086)** | (577) |
| Net change in non-cash working capital items | 19 | **(13,193)** | (39,024) | **(24,541)** | (150,671) |
| **Net cash provided by (used in) investing activities** | | **(33,030)** | (148,492) | **(80,592)** | (354,302) |
| Financing activities | | | | | |
| Repayment of long-term debt | 8 | **(4,222)** | (4,024) | **(8,435)** | (8,148) |
| **Net cash provided by (used in) financing activities** | | **(4,222)** | (4,024) | **(8,435)** | (8,148) |
| **Effect of exchange rate changes on cash and cash equivalents held in foreign currency** | | **816** | (1,785) | **(10,391)** | 39,772 |
| Change in cash and cash equivalents | | **28,151** | (32,540) | **(255,502)** | (217,859) |
| Cash and cash equivalents, beginning of period | | **124,560** | 470,778 | **408,213** | 656,097 |
| Cash and cash equivalents, end of period | | **$ 152,711** | $ 438,238 | **$ 152,711** | $ 438,238 |

*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 July 27, 2016.

## 3. CHANGE IN ACCOUNTING POLICIES

### New accounting standards

There were no new accounting standards adopted during the six months ended June 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. The Corporation is currently assessing the impact of the adoption of these amendments 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. The Corporation is currently assessing the impact of the adoption of these amendments 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 | 52,665 | 1,053 | 1,053 | 54,771 |
| Change in decommissioning liabilities | 1,528 | (25) | - | 1,503 |
| **Balance as at June 30, 2016** | **$ 7,822,437** | **$ 1,606,575** | **$ 52,129** | **$ 9,481,141** |
| **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 | 223,643 | 15,677 | 2,590 | 241,910 |
| **Balance as at June 30, 2016** | **$ 1,534,312** | **$ 96,017** | **$ 24,688** | **$ 1,655,017** |

| | Crude oil | Transportation and storage | Corporate assets | Total |
|---|---|---|---|---|
| **Carrying amounts** | | | | |
| Balance as at December 31, 2015 | $ 6,457,575 | $ 1,525,207 | $ 28,978 | $ 8,011,760 |
| **Balance as at June 30, 2016** | **$ 6,288,125** | **$ 1,510,558** | **$ 27,441** | **$ 7,826,124** |

As at June 30, 2016, $659.1 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 June 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 | 981 |
| Change in decommissioning liabilities | 251 |
| **Balance as at June 30, 2016** | **$ 547,653** |

Exploration and evaluation assets consist of exploration projects which are pending the determination of proved or probable reserves. These assets are not subject to depletion, as they are in the exploration and evaluation stage, but are reviewed on a quarterly basis for any indication of impairment. As at June 30, 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 | | 2,761 |
| **Balance as at June 30, 2016** | **$** | **99,039** |

| **Accumulated depreciation** | | |
|---|---|---|
| Balance as at December 31, 2014 | $ | 6,690 |
| Depreciation | | 5,446 |
| Balance as at December 31, 2015 | $ | 12,136 |
| Depreciation | | 2,436 |
| **Balance as at June 30, 2016** | **$** | **14,572** |

| **Carrying amounts** | | |
|---|---|---|
| Balance as at December 31, 2015 | $ | 84,142 |
| **Balance as at June 30, 2016** | **$** | **84,467** |

As at June 30, 2016, other intangible assets include $66.3 million invested to maintain the right to participate in a potential pipeline project and $18.2 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 June 30, 2016, no impairment has been recognized on other intangible assets.

## 7. OTHER ASSETS

| **As at** | | **June 30, 2016** | | **December 31, 2015** |
|---|---|---|---|---|
| Long-term pipeline linefill[(a)] | **$** | **125,837** | $ | 131,141 |
| Deferred financing costs | | **14,184** | | 16,366 |
| U.S. auction rate securities | | **3,264** | | 3,470 |
| | | **143,285** | | 150,977 |
| Less current portion of deferred financing costs | | **(4,364)** | | (4,365) |
| | **$** | **138,921** | $ | 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 June 30, 2016, no impairment has been recognized on these assets.

## 8. LONG-TERM DEBT

| As at | | June 30, 2016 | | December 31, 2015 |
|---|---|---|---|---|
| Senior secured term loan (June 30, 2016 – US$1.242 billion; December 31, 2015 – US$1.249 billion; due 2020) | **$** | **1,615,718** | $ | 1,727,924 |
| 6.5% senior unsecured notes (US$750 million; due 2021) | | **975,675** | | 1,038,000 |
| 6.375% senior unsecured notes (US$800 million; due 2023) | | **1,040,720** | | 1,107,200 |
| 7.0% senior unsecured notes (US$1.0 billion; due 2024) | | **1,300,900** | | 1,384,000 |
| | | **4,933,013** | | 5,257,124 |
| Less current portion of senior secured term loan | | **(16,912)** | | (17,992) |
| Less unamortized financial derivative liability discount | | **(12,780)** | | (14,377) |
| Less unamortized deferred debt issue costs | | **(32,139)** | | (34,392) |
| | **$** | **4,871,182** | $ | 5,190,363 |

The U.S. dollar denominated debt was translated into Canadian dollars at the period end exchange rate of US$1 = C$1.3009 (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 | | June 30, 2016 | | December 31, 2015 |
|---|---|---|---|---|
| Decommissioning provision[(a)] | **$** | **134,533** | $ | 130,381 |
| Onerous contracts provision[(b)] | | **68,161** | | 58,178 |
| Derivative financial liabilities[(c)] | | **22,227** | | 16,223 |
| Deferred lease inducements | | **3,564** | | 3,805 |
| Stock-based compensation liability | | **1,753** | | - |
| Provisions and other liabilities | | **230,238** | | 208,587 |
| Less current portion | | **(26,230)** | | (12,313) |
| Non-current portion | **$** | **204,008** | $ | 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 | | June 30, 2016 | | December 31, 2015 |
|---|---|---|---|---|
| Balance, beginning of year | **$** | **130,381** | $ | 156,382 |
| Changes in estimated future cash flows | | **123** | | 14,076 |
| Changes in discount rates | | **7** | | (48,933) |
| Liabilities incurred | | **1,624** | | 5,066 |
| Liabilities settled | | **(996)** | | (1,873) |
| Accretion | | **3,394** | | 5,663 |
| Balance, end of period | | **134,533** | | 130,381 |
| Less current portion | | **(1,833)** | | (1,485) |
| Non-current portion | **$** | **132,700** | $ | 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 8.8% (December 31, 2015 – 8.3%).

(b) Onerous contracts provision:

As at June 30, 2016, the Corporation had recognized a total provision of $68.2 million related to certain onerous operating lease contracts (Note 16) (December 31, 2015 – $58.2 million). The increase in the provision represents changes in estimates relating to office building lease contracts as well as contracts for camp construction and drilling. 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 0.8% (December 31, 2015 – 1.0%). This estimate may vary as a result of changes in estimated recoveries.

(c) Derivative financial liabilities:

| As at | | June 30, 2016 | | December 31, 2015 |
|---|---|---|---|---|
| 1% interest rate floor | **$** | **20,727** | $ | 11,740 |
| Interest rate swaps (Note 21) | | **1,500** | | 4,483 |
| Derivative financial liabilities | | **22,227** | | 16,223 |
| Less current portion | | **(7,779)** | | (8,316) |
| Non-current portion | **$** | **14,448** | $ | 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:

| | Six months ended June 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 | **1,359,955** | **39,038** | 1,150,098 | 38,947 |
| Balance, end of period | **226,356,944** | **$ 4,875,838** | 224,996,989 | $ 4,836,800 |

(b) Contributed surplus:

| **Six months ended June 30, 2016** | |
|---|---|
| Balance, beginning of year | **$ 171,835** |
| Stock-based compensation - expensed | **21,961** |
| Stock-based compensation - capitalized | **3,594** |
| RSUs vested and released | **(39,038)** |
| Balance, end of period | **$ 158,352** |

## 11. STOCK-BASED COMPENSATION PLANS

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.

| **Six months ended June 30, 2016** | **Stock options** | **Weighted average exercise price** |
|---|---|---|
| Outstanding, beginning of year | **9,925,313** | **$ 29.94** |
| Granted | **1,214,300** | **6.52** |
| Forfeited | **(232,202)** | **26.69** |
| Expired | **(356,525)** | **24.00** |
| Outstanding, end of period | **10,550,886** | **$ 27.52** |

(b) Restricted share units and performance share units:

The Restricted Share Unit Plan allows for the granting of RSUs, including PSUs, to directors, officers, employees and consultants of the Corporation. 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, and that the holder remains actively employed, a director or a consultant with the Corporation on the vesting date.

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 June 30, 2016, the Corporation recognized a liability of $1.8 million relating to the fair value of RSUs and PSUs, of which $0.8 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:

| Six months ended June 30, 2016 | Cash-settled | Equity-settled |
|---|---|---|
| Outstanding, beginning of year | **-** | **3,280,112** |
| Granted | **6,028,553** | **-** |
| Vested and released | **-** | **(1,359,955)** |
| Forfeited | **(22,766)** | **(122,549)** |
| Outstanding, end of period | **6,005,787** | **1,797,608** |

(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 June 30, 2016, there were 141,500 DSUs outstanding (December 31, 2015 – 47,696 DSUs outstanding).

(d) Stock-based compensation expense:

| | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| | **2016** | **2015** | **2016** | **2015** |
| Cash-settled | **$ 1,450** | $ - | **$ 1,450** | $ - |
| Equity-settled | **9,069** | 12,286 | **21,961** | 24,816 |
| | **$ 10,519** | $ 12,286 | **$ 23,411** | $ 24,816 |

## 12. PETROLEUM REVENUE, NET OF ROYALTIES

| | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| | **2016** | **2015** | **2016** | **2015** |
| Petroleum revenue: | | | | |
| Proprietary | **$ 430,119** | $ 509,968 | **$ 680,516** | $ 965,721 |
| Third-party[(a)] | **77,509** | 38,769 | **106,239** | 44,848 |
| Petroleum revenue | **$ 507,628** | $ 548,737 | **$ 786,755** | $ 1,010,569 |
| Royalties | **(1,965)** | (5,853) | **(1,468)** | (12,003) |
| Petroleum revenue, net of royalties | **$ 505,663** | $ 542,884 | **$ 785,287** | $ 998,566 |

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

## 13. OTHER REVENUE

| | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| | **2016** | 2015 | **2016** | 2015 |
| Power revenue | **$ 2,529** | $ 8,371 | **$ 8,083** | $ 17,190 |
| Transportation revenue | **5,163** | 3,392 | **10,323** | 5,886 |
| Other revenue | **$ 7,692** | $ 11,763 | **$ 18,406** | $ 23,076 |

## 14. DILUENT AND TRANSPORTATION

| | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| | **2016** | 2015 | **2016** | 2015 |
| Diluent expense | **$ 203,428** | $ 220,585 | **$ 376,293** | $ 477,633 |
| Transportation expense | **54,012** | 33,107 | **104,510** | 71,769 |
| Diluent and transportation | **$ 257,440** | $ 253,692 | **$ 480,803** | $ 549,402 |

## 15. FOREIGN EXCHANGE LOSS (GAIN), NET

| | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| | **2016** | 2015 | **2016** | 2015 |
| Unrealized foreign exchange loss (gain) on: | | | | |
| Long-term debt | **$ 14,416** | $ (79,622) | **$ (315,677)** | $ 332,784 |
| US$ denominated cash, cash equivalents and other | **(627)** | 4,596 | **9,185** | (36,961) |
| Unrealized net loss (gain) on foreign exchange | **13,789** | (75,026) | **(306,492)** | 295,823 |
| Realized loss (gain) on foreign exchange | **808** | 938 | **(4,858)** | 8,168 |
| Foreign exchange loss (gain), net | **$ 14,597** | $ (74,088) | **$ (311,350)** | $ 303,991 |

## 16. NET FINANCE EXPENSE

| | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| | **2016** | **2015** | **2016** | **2015** |
| Total interest expense | **$ 80,758** | $ 75,550 | **$ 164,673** | $ 151,276 |
| Less capitalized interest | **-** | (16,485) | **-** | (32,488) |
| Net interest expense | **80,758** | 59,065 | **164,673** | 118,788 |
| Accretion on provisions | **1,820** | 1,244 | **3,514** | 2,556 |
| Unrealized loss (gain) on derivative financial liabilities | **516** | (7,738) | **6,005** | (4,207) |
| Realized loss on interest rate swaps | **1,471** | 1,404 | **3,040** | 2,805 |
| Net finance expense | **$ 84,565** | $ 53,975 | **$ 177,232** | $ 119,942 |

## 17. OTHER EXPENSES (RECOVERIES)

| | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| | **2016** | **2015** | **2016** | **2015** |
| Onerous contracts | **$ 9,055** | $ - | **$ 13,426** | $ - |
| Contract cancellation recovery | **-** | (5,880) | **-** | (5,880) |
| Severance and other | **6,179** | - | **6,179** | - |
| Other expenses (recoveries) | **$ 15,234** | $ (5,880) | **$ 19,605** | $ (5,880) |

## 18. INCOME TAX EXPENSE (RECOVERY)

| | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| | **2016** | **2015** | **2016** | **2015** |
| Current income tax expense (recovery) | **$ 97** | $ (800) | **$ 614** | $ (800) |
| Deferred income tax expense (recovery) | **(48,804)** | 5,256 | **(117,960)** | (22,518) |
| Income tax expense (recovery) | **$ (48,707)** | $ 4,456 | **$ (117,346)** | $ (23,318) |

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 June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| | **2016** | **2015** | **2016** | **2015** |
| Cash provided by (used in): | | | | |
| Trade receivables and other | **$ (61,796)** | $ (25,254) | **$ (59,290)** | $ (31,323) |
| Inventories | **11,174** | (8,875) | **(20,217)** | 27,324 |
| Accounts payable and accrued liabilities | **94,352** | 12,098 | **24,049** | (116,191) |
| | **$ 43,730** | $ (22,031) | **$ (55,458)** | $ (120,190) |
| Changes in non-cash working capital relating to: | | | | |
| Operating | **$ 56,923** | $ 16,993 | **$ (30,917)** | $ 30,481 |
| Investing | **(13,193)** | (39,024) | **(24,541)** | (150,671) |
| | **$ 43,730** | $ (22,031) | **$ (55,458)** | $ (120,190) |
| Cash and cash equivalents:[(a)] | | | | |
| Cash | **$ 152,711** | $ 283,497 | **$ 152,711** | $ 283,497 |
| Cash equivalents | **-** | 154,741 | **-** | 154,741 |
| | **$ 152,711** | $ 438,238 | **$ 152,711** | $ 438,238 |
| Cash interest paid | **$ 15,335** | $ 14,768 | **$ 144,347** | $ 137,822 |

(a) As at June 30, 2016, C$91.6 million of the Corporation's total cash and cash equivalents balance was held in U.S. dollars (June 30, 2015 - C$257.9 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$1.3009 (June 30, 2015 - US$1 = C$1.2474).

## 20. NET EARNINGS (LOSS) PER COMMON SHARE

| | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| | **2016** | **2015** | **2016** | **2015** |
| Net earnings (loss) | **$ (146,165)** | $ 63,414 | **$ (15,336)** | $ (444,893) |
| Weighted average common shares outstanding[(a)] | **225,601,265** | 224,263,336 | **225,370,092** | 224,077,668 |
| Dilutive effect of stock options, RSUs and PSUs[(b)] | **-** | 902,133 | **-** | - |
| Weighted average common shares outstanding – diluted | **225,601,265** | 225,165,469 | **225,370,092** | 224,077,668 |
| Net earnings (loss) per share, basic | **$ (0.65)** | $ 0.28 | **$ (0.07)** | $ (1.99) |
| Net earnings (loss) per share, diluted | **$ (0.65)** | $ 0.28 | **$ (0.07)** | $ (1.99) |

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

(b) For the three and six months ended June 30, 2016, there was no dilutive effect of stock options, RSUs and PSUs due to the Corporation incurring a net loss. If the Corporation had recognized net earnings during the three and six months ended June 30, 2016, the dilutive effect of stock options, RSUs and PSUs would have been 443,816 (three months ended June 30, 2015 – 902,133) and 407,726 (six months ended June 30, 2015 – 872,775) 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 June 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 June 30, 2016** | **Carrying amount** | **Level 1** | **Level 2** | **Level 3** |
| Recurring measurements: | | | | |
| Financial assets | | | | |
| ARS (Note 7) | **$ 3,264** | **$ -** | **$ 3,264** | **$ -** |
| Financial liabilities | | | | |
| Long-term debt[1] (Note 8) | **4,933,013** | **-** | **3,960,161** | **-** |
| Derivative financial liabilities (Note 9) | **22,227** | **-** | **22,227** | **-** |
| Commodity risk management contracts | **20,471** | **-** | **20,471** | **-** |

| | | 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 June 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 June 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 derivative financial instruments 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.

Crude oil sales contracts:

| As at June 30, 2016 | Volumes (bbls/d) | Term | Average Price (US$/bbl) |
|---|---|---|---|
| Fixed Price: | | | |
| WTI Fixed Price | 18,663 | Jul 1, 2016 – Sep 30, 2016 | $45.22 |
| WTI Fixed Price | 12,000 | Oct 1, 2016 – Dec 31, 2016 | $48.06 |
| WCS Differential | 48,660 | Jul 1, 2016 – Sep 30, 2016 | $(13.74) |
| WCS Differential | 1,000 | Oct 1, 2016 – Dec 31, 2016 | $(14.90) |
| Collars: | | | |
| WTI Collars | 30,000 | Jul 1, 2016 – Sep 30, 2016 | $44.61 – $51.25 |
| WTI Collars | 19,000 | Oct 1, 2016 – Dec 31, 2016 | $44.99 – $53.68 |

Condensate purchase contracts:

| As at June 30, 2016 | Volumes (bbls/d) | Term | Average % of WTI |
|---|---|---|---|
| Mont Belvieu fixed % of WTI | 9,250 | Jul 1, 2016 – Sep 30, 2016 | 84.2% |
| Mont Belvieu fixed % of WTI | 12,750 | Oct 1, 2016 – Dec 31, 2016 | 83.7% |
| 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 | June 30, 2016 | December 31, 2015 |
|---|---|---|
| Commodity risk management: | | |
| Liabilities | **$ 107,347** | $ - |
| Assets | **(86,876)** | - |
| Net liabilities | **$ 20,471** | $ - |

Summary of unrealized commodity risk management positions:

| As at | June 30, 2016 | | | December 31, 2015 | | |
|---|---|---|---|---|---|---|
| | **Asset** | **Liability** | **Net** | **Asset** | **Liability** | **Net** |
| Crude oil contracts | **$ -** | **$ 18,289** | **$ 18,289** | $ - | $ - | $ - |
| Condensate contracts[1] | **-** | **2,182** | **2,182** | - | - | - |
| Total fair value | **$ -** | **$ 20,471** | **$ 20,471** | $ - | $ - | $ - |

[1] Relates to condensate purchase contracts that effectively fix the average percentage differentials of condensate prices at Mont Belvieu, Texas to a percentage of WTI (US$/bbl)

Commodity risk management loss:

| | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| | **2016** | **2015** | **2016** | **2015** |
| Realized loss on commodity risk management | **$ 3,487** | $ - | **$ 3,487** | $ - |
| Unrealized loss on commodity risk management | **37,434** | - | **20,471** | - |
| Commodity risk management loss | **$ 40,921** | $ - | **$ 23,958** | $ - |

Price sensitivities on commodity risk management positions as at June 30, 2016:

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 June 30:

| Commodity | Sensitivity Range | Increase | Decrease |
|---|---|---|---|
| Crude oil commodity price | ± US$1.00 per bbl applied to WTI contracts | $ (3,670) | $ 3,670 |
| Crude oil differential price | ± US$1.00 per bbl applied to WCS differential contracts | $ 5,944 | $ (5,944) |
| Condensate differential % | ± 1% in differential condensate price to the US$ WTI price per bbl applied to condensate differential contracts | $ 4,168 | $ (4,168) |

(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. In order to mitigate a portion of this risk, the Corporation has entered into interest rate swap contracts to effectively fix the interest rate at approximately 4.4% on US$748.0 million of the US$1.242 billion senior secured term loan until September 30, 2016. 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.

## 22. GEOGRAPHICAL DISCLOSURE

As at June 30, 2016, the Corporation had non-current assets related to operations in the United States of $105.1 million (December 31, 2015 - $111.1 million). For the three and six months ended June 30, 2016, petroleum revenue related to operations in the United States were $181.7 million and $278.0 million respectively (three and six months ended June 30, 2015 - $169.5 million and $278.4 million, respectively).

## 23. COMMITMENTS AND CONTINGENCIES

(a) Commitments

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

| | 2016 | 2017 | 2018 | 2019 | 2020 | Thereafter |
|---|---|---|---|---|---|---|
| Transportation and storage | $ 85,598 | $ 180,353 | $ 196,440 | $ 187,018 | $ 225,644 | $ 3,202,273 |
| Office lease rentals | 7,797 | 34,137 | 32,700 | 32,729 | 33,619 | 268,259 |
| Diluent purchases | 101,196 | 46,250 | 19,943 | 19,943 | 19,997 | 56,498 |
| Other operating commitments | 9,011 | 16,085 | 8,779 | 10,796 | 11,432 | 80,340 |
| Capital commitments | 13,937 | 5,750 | - | - | - | - |
| **Commitments** | **$ 217,539** | **$ 282,575** | **$ 257,862** | **$ 250,486** | **$ 290,692** | **$ 3,607,370** |

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.