SECOND QUARTER 2015

Report to Shareholders for the period ended June 30, 2015

MEG Energy Corp. reported second quarter 2015 operational and financial results on July 28, 2015. Highlights include:

- Production volumes for the second quarter ahead of plan at 71,376 barrels per day (bpd), which include the impact of major planned plant turnarounds involving Phases 1, 2 and 2B in the quarter;

- Cash flow from operations of $99 million, or $0.44 per share;

- Net operating costs of $9.43 per barrel, supported by low non-energy operating costs of $7.01 per barrel, MEG's second best result on record;

- Continuing strong financial liquidity, exiting the quarter with $438 million of cash and an undrawn US$2.5 billion credit facility;

- With the overall objective of positioning the company to grow in a low price environment, MEG initiated a review of its financial leverage.

"The major turnaround work for 2015 is now complete, leaving MEG well-positioned for strong operations through the balance of the year," said Bill McCaffrey, President and CEO. "Equally important, plant testing of oil and water processing facilities carried out during the turnaround set the stage to enhance our expansion plans. MEG is utilizing these results to develop its future brownfield expansions that are anticipated to occur over the next several years."

MEG's production during the second quarter was impacted by planned major turnaround work at the company's Phase 1, 2 and 2B facilities, as well as unplanned delays to work schedules due to wildfires in northern Alberta. Staff and contractors working on the turnarounds were temporarily evacuated as a precautionary measure, resulting in a delay of approximately one week to turnaround activities. Despite these impacts, second quarter production averaged 71,376 bpd, above the 68,984 bpd recorded for the second quarter of 2014, during which turnaround activities were relatively minor. Strong projected production volumes over the balance of the year, with operations resuming following the turnaround and the continuing application of the company's RISER initiative, are expected to support targeted record annual production of 78,000 to 82,000 bpd.

Net operating costs for the second quarter averaged $9.43 per barrel compared to $14.49 per barrel for the same period in 2014. 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 the average power sales price from electricity sold to the market from MEG's cogeneration facilities. Non-energy operating costs decreased to $7.01 per barrel for the three months ended June 30, 2015 compared to $9.64 per barrel for the same period in 2014, which included $1.94 per barrel for annual inspection and maintenance activities at Christina Lake. Non-energy operating costs for 2015 take into account the capitalization of $20.8 million associated with the major turnarounds.

MEG reported cash flow from operations of $99.2 million for the second quarter of 2015 compared to $261.7 million for the second quarter of 2014. The decrease is primarily due to lower U.S. crude oil benchmark pricing and higher transportation and interest costs, partially offset by lower net operating costs and reduced royalties (reflecting lower commodity prices).

MEG recognized an operating loss (adjusted for items that are not indicative of operating performance) of $23.0 million for the second quarter of 2015, compared to operating earnings of $111.1 million for the same period in 2014. Operating earnings were impacted by a lower bitumen realization, primarily as a result of the significant decline of U.S. crude oil benchmark pricing, higher transportation costs and an increase in interest expense, partially offset by lower net operating costs and lower royalties.

Financial Liquidity

As at June 30, 2015, MEG's available capital resources included $438.2 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$157.3 million of letters of credit have been issued.

The previous guidance for non-energy operating costs of $8 to $10 per barrel contained an estimate for turnaround costs. These costs of $20.8 million are now being capitalized. As a result, the guidance for full-year 2015 non-energy operating costs is now $7.30 to $9.30 per barrel. There is no change to the annual 2015 capital budget of $305 million.

During the second quarter, MEG initiated a review of its financial leverage, with the overall objective of better positioning the Corporation to grow in a low price environment. All of MEG's outstanding long-term debt is covenant lite, with the first maturity not due until 2020. Notwithstanding the above, MEG and its advisors are reviewing deleveraging options available to the Corporation, including how its interest in the Access Pipeline could contribute to this initiative. Any alternative pursued must align with the Corporation's overall long-term strategy.

"We continue to have a very solid financial foundation," said McCaffrey. "Our efforts since late last year have been focused on how we can build on that foundation to continue to deliver growth in a lower oil price environment."

Forward-Looking Information and Non-GAAP Financial Measures

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

Management's Discussion and Analysis

This Management's Discussion and Analysis ("MD&A") of the financial condition and performance of MEG Energy Corp. ("MEG" or the "Corporation") for the period ended June 30, 2015 is dated July 27, 2015. This MD&A should be read in conjunction with the Corporation's audited consolidated financial statements and notes thereto for the year ended December 31, 2014 and the unaudited condensed consolidated interim financial statements and notes thereto for the period ended June 30, 2015. All tabular amounts are stated in thousands of Canadian dollars ($ or C$) unless indicated otherwise.

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1. OVERVIEW

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

MEG owns a 100% working interest in over 900 square miles of oil sands leases. In a report dated effective December 31, 2014, with a preparation date of January 30, 2015, GLJ Petroleum Consultants Ltd. estimated that the oil sands leases it had evaluated contained 3.0 billion barrels of proved plus probable bitumen reserves and 3.8 billion barrels of contingent bitumen resources (best estimate).

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 of, the performance of, and the development schedule for, each expansion or phase in those projects. In addition, the Corporation holds other leases (the "Growth Properties") that are still in the resource definition stage and that are anticipated to provide significant additional development opportunities.

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"). 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 to Phases 1 and 2, the Corporation achieved average production in excess of 80,000 bbls/d from Christina Lake Phases 1, 2 and 2B in the fourth quarter of 2014.

The Corporation is currently focused on the expansion of the Christina Lake Project through the continuing application of RISER 2B. RISER 2B is an initiative that uses a combination of proprietary reservoir technologies, redeployment of steam and facilities modifications, including a series of brownfield expansions of existing Phase 2B facilities. The Corporation anticipates this strategy will allow the Corporation to increase production more quickly and efficiently and at lower capital intensity.

In addition, MEG has filed for 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. 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 also holds a 50% interest in the Access Pipeline, a strategic 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 the third quarter of 2014, MEG completed an expansion of the Access Pipeline, which included the construction of a 42-inch blend line from the Christina Lake Project to the Edmonton, Alberta area. The expansion of the Access Pipeline will accommodate anticipated increases in production from the Christina Lake Project as well as provide expansion capacity for future production volumes from the Surmont Project and from the Growth Properties. MEG's 50% interest of the capacity in the expanded 42-inch line is approximately 200,000 bbls/d of blended bitumen. The system's former 24-inch blend line is anticipated to be converted to diluent service during the second half of 2015.

In addition to the Access Pipeline, MEG owns the Stonefell Terminal, located near Edmonton, Alberta. The Stonefell Terminal was commissioned in the fourth quarter of 2013 and has 900,000 barrels of strategic terminalling and storage capacity. The Stonefell Terminal is strategically located near the southern end of the Access Pipeline and 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 both the loading of bitumen blend for transport by rail and the receipt of railed diluent, giving direct access to multiple blend markets and diluent sources throughout North America.

2. OPERATIONAL AND FINANCIAL HIGHLIGHTS

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		2015		2014				2013	
($ millions, except as indicated)	**2015**	**2014**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**
Bitumen production - bbls/d	**76,856**	63,842	**71,376**	82,398	80,349	76,471	68,984	58,643	42,251	34,246
Bitumen realization - $/bbl	**34.39**	68.06	**44.54**	25.82	50.48	65.12	72.75	62.28	38.22	74.33
Net operating costs - $/bbl(1)	**10.01**	14.11	**9.43**	10.49	10.13	10.31	14.49	13.63	11.22	9.40
Non-energy operating costs - $/bbl	**7.31**	9.38	**7.01**	7.57	6.42	7.16	9.64	9.05	8.09	9.20
Cash operating netback(2) - $/bbl	**18.89**	47.89	**29.64**	9.83	35.56	48.70	51.45	43.51	23.78	59.59
Cash flow from (used in) operations(3)	**70**	419	**99**	(30)	134	238	262	157	23	144
Per share, diluted(3)	**0.31**	1.86	**0.44**	(0.13)	0.60	1.06	1.16	0.70	0.10	0.64
Operating earnings (loss)(3)	**(147)**	152	**(23)**	(124)	8	87	111	41	(33)	56
Per share, diluted(3)	**(0.66)**	0.68	**(0.10)**	(0.56)	0.04	0.39	0.49	0.18	(0.15)	0.25
Revenue(4)	**1,022**	1,509	**555**	467	615	706	829	680	350	402
Net earnings (loss)(5)	**(445)**	146	**63**	(508)	(150)	(101)	249	(103)	(148)	115
Per share, basic	**(1.99)**	0.65	**0.28**	(2.27)	(0.67)	(0.45)	1.12	(0.46)	(0.67)	0.52
Per share, diluted	**(1.99)**	0.65	**0.28**	(2.27)	(0.67)	(0.45)	1.11	(0.46)	(0.67)	0.51
Total cash capital investment(6)	**171**	622	**90**	80	324	291	299	324	366	455
Cash, cash equivalents and short-term investments	**438**	840	**438**	471	656	777	840	890	1,179	647
Long-term debt(7)	**4,694**	4,016	**4,694**	4,776	4,366	4,218	4,016	4,162	4,005	2,858

(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, transportation, operating expenses and royalties from proprietary sales volumes and power revenues, on a per barrel basis.

(3) Cash flow from (used in) operations, Operating earnings (loss), and the related per share amounts do not have standardized meanings prescribed by International Financial Reporting Standards ("IFRS") and therefore may not be comparable to similar measures used by other companies. For the three and six months ended June 30, 2015 and June 30, 2014, the non-GAAP measure of cash flow from operations is reconciled to net cash provided by operating activities and the non-GAAP measure of operating earnings (loss) is reconciled to net earnings (loss) in accordance with IFRS under the heading "NON-GAAP MEASURES" and discussed further in the "ADVISORY" section.

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

(5) Includes a net unrealized foreign exchange gain of $75.0 million and a net unrealized foreign exchange loss of $295.8 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, 2015, respectively. The net earnings for the three and six months ended June 30, 2014 include a net unrealized foreign exchange gain of $135.1 million and a net unrealized foreign exchange loss of $5.5 million, respectively.

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

(7) Includes current and long-term portions, as presented on the Consolidated Balance Sheet.

(8) Totals may not add due to rounding.

Bitumen Production

Bitumen production for the three months ended June 30, 2015 averaged 71,376 bbls/d compared to 68,984 bbls/d for the three months ended June 30, 2014. Bitumen production for the six months ended June 30, 2015 averaged 76,856 bbls/d compared to 63,842 bbls/d for the six months ended June 30, 2014. The increase in production volumes is primarily due to the successful ramp-up of Phase 2B and the continued implementation of 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. These increases in production were partially offset by a reduction in production volumes as a result of a major planned turnaround in the second quarter of 2015, which was longer in duration and had a greater impact on production volumes than the turnaround for the same period in 2014. In addition, forest fires near the Christina Lake Project extended the duration of time required to complete the 2015 turnaround.

Bitumen Realization

Bitumen realization, as discussed in this MD&A, represents the Corporation's realized proprietary petroleum revenue ("blend sales revenue"), net of the cost of diluent, 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 cost of diluent is effectively recovered in the sales price of the blended product. The cost of diluent is also impacted by U.S. benchmark pricing and the timing of diluent inventory purchases.

For the three months ended June 30, 2015, average bitumen realization decreased to $44.54 per barrel compared to $72.75 per barrel for the three months ended June 30, 2014. For the six months ended June 30, 2015, average bitumen realization decreased to $34.39 per barrel compared to $68.06 per barrel for the six months ended June 30, 2014. The decrease in bitumen realization is a result of the significant decline of U.S. crude oil benchmark pricing which resulted in lower blend sales revenue.

The C$/bbl West Texas Intermediate ("WTI") price averaged $71.24 per barrel during the three months ended June 30, 2015 compared to $112.31 per barrel during the three months ended June 30, 2014. The WTI:WCS ("Western Canadian Select") differential increased slightly to an average of 20.0% for the three months ended June 30, 2015 compared to 19.5% for the three months ended June 30, 2014. The C$/bbl WTI price averaged $65.83 per barrel during the six months ended June 30, 2015 compared to $110.62 per barrel during the six months ended June 30, 2014. The WTI:WCS differential increased to an average of 24.7% for the six months ended June 30, 2015 compared to 21.4% for the six months ended June 30, 2014.

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, 2015 averaged $9.43 per barrel compared to $14.49 per barrel for the three months ended June 30, 2014. 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 decreased to $7.01 per barrel for the three months ended June 30, 2015 compared to $9.64 per barrel for the same period in 2014. Non-energy costs for the three months ended June 30, 2014 included $1.94 per barrel for annual inspection and maintenance activities at the Christina Lake facilities. Historically, the Corporation has only performed annual inspection and maintenance activities on the Christina Lake facilities, with the associated costs expensed as non-energy operating costs. Consistent with the Corporation's capitalization policy, in the second quarter of 2015, the major turnaround costs of $20.8 million have been capitalized, as the work performed will benefit future years of operations. As a result, the cost of the 2015 turnaround is treated as a component of capital investment and will be depreciated on a straight line basis over the period to the next major turnaround, which is currently anticipated to occur in 2017.
- Energy operating costs decreased to $3.71 per barrel for the three months ended June 30, 2015 compared to $6.45 per barrel for the same period in 2014. Energy costs decreased as a result of the decline in natural gas prices, which decreased to an average of $3.15 per thousand cubic feet ("mcf") for the three months ended June 30, 2015 compared to $5.25 per mcf for the same period in 2014.
- Power revenue decreased to $1.29 per barrel for the three months ended June 30, 2015 compared to $1.60 per barrel for the same period in 2014. The decrease is primarily due to a decrease in power sales volumes as a result of the major turnaround in the second quarter of 2015. Power sales volumes decreased to 97 megawatts per hour ("MW/h") in the three months ended June 30, 2015 compared to 115 MW/h for the same period in 2014. The Corporation's realized power price during the three months ended June 30, 2015 decreased to $39.55 per megawatt hour compared to $40.98 per megawatt hour for the same period in 2014. Power revenue had the effect of offsetting 35% of energy operating costs during the three months ended June 30, 2015 compared to offsetting 25% of energy operating costs during the same period in 2014.

Net operating costs for the six months ended June 30, 2015 averaged $10.01 per barrel compared to $14.11 per barrel for the six months ended June 30, 2014. 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 decreased to $7.31 per barrel for the six months ended June 30, 2015 compared to $9.38 per barrel for the same period in 2014. Non-energy costs for 2014 include $1.07 per barrel for annual inspection and maintenance activities at the Christina Lake facilities. On a per barrel basis, non-energy operating costs decreased as a result of the inclusion of annual inspection and maintenance activities within operating costs for 2014 and an increase in sales volumes, as relatively fixed components of operating costs are spread over a greater number of barrels. Consistent with the Corporation's capitalization policy, in the second quarter of 2015, the major turnaround costs of $20.8 million have been capitalized, as the work performed will benefit future years of operations. As a result, the cost of the 2015 turnaround is treated as a component of capital investment and will be depreciated on a straight line basis over the period to the next major turnaround, which is currently anticipated to occur in 2017.
- Energy operating costs decreased to $3.91 per barrel for the six months ended June 30, 2015 compared to $7.34 per barrel for the same period in 2014. Energy costs decreased as a result

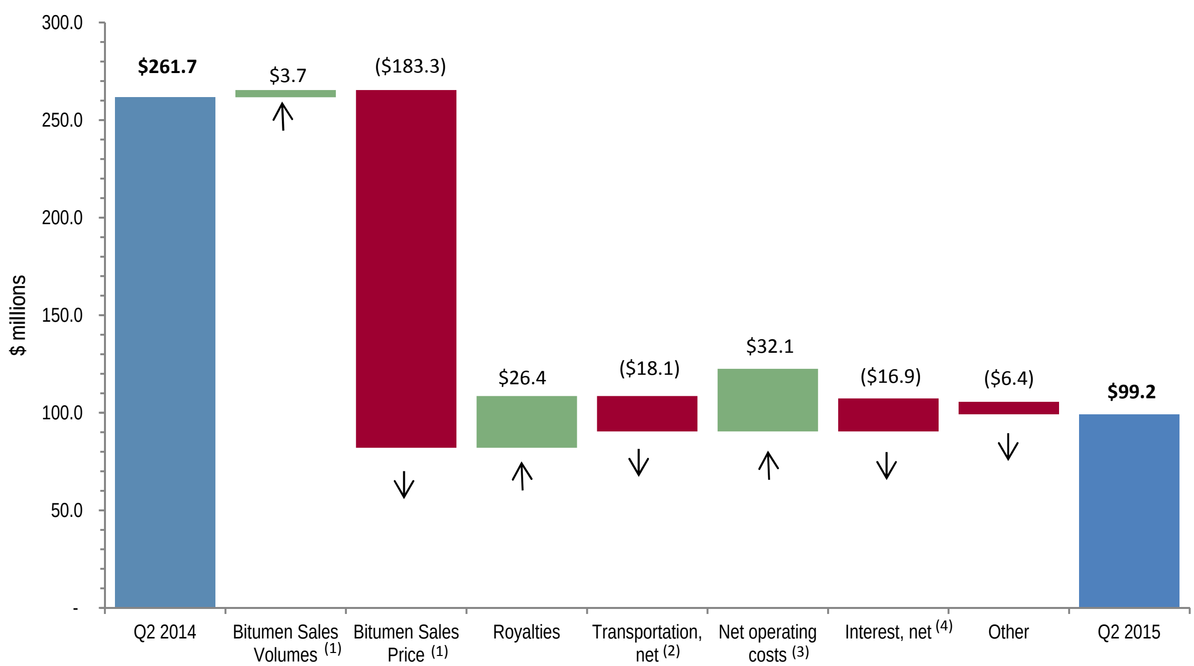
of the decline in natural gas prices, which decreased to an average of $3.17 per mcf for the six months ended June 30, 2015 compared to $5.65 per mcf for the same period in 2014.

- Power revenue decreased to $1.21 per barrel for the six months ended June 30, 2015 compared to $2.61 per barrel for the same period in 2014. The decrease is primarily due to a decrease in the Corporation's realized power price. The Corporation's realized power price during the six months ended June 30, 2015 decreased to $32.79 per megawatt hour compared to $52.95 per megawatt hour for the same period in 2014. The decrease in the power price is mainly a result of increased power generation capacity in the province of Alberta. Power revenue had the effect of offsetting 31% of energy operating costs during the six months ended June 30, 2015 compared to offsetting 36% of energy operating costs during the same period in 2014.

Cash Operating Netback

Cash operating netback for the three months ended June 30, 2015 was $29.64 per barrel compared to $51.45 per barrel for the three months ended June 30, 2014. Cash operating netback for the six months ended June 30, 2015 was $18.89 per barrel compared to $47.89 per barrel for the six months ended June 30, 2014. The decrease in the cash operating netback is primarily due to a decrease in bitumen realization as a result of the significant decline of U.S. crude oil benchmark pricing.

Cash Flow from Operations – Three Months Ended June 30, 2015



(1) Net of diluent.

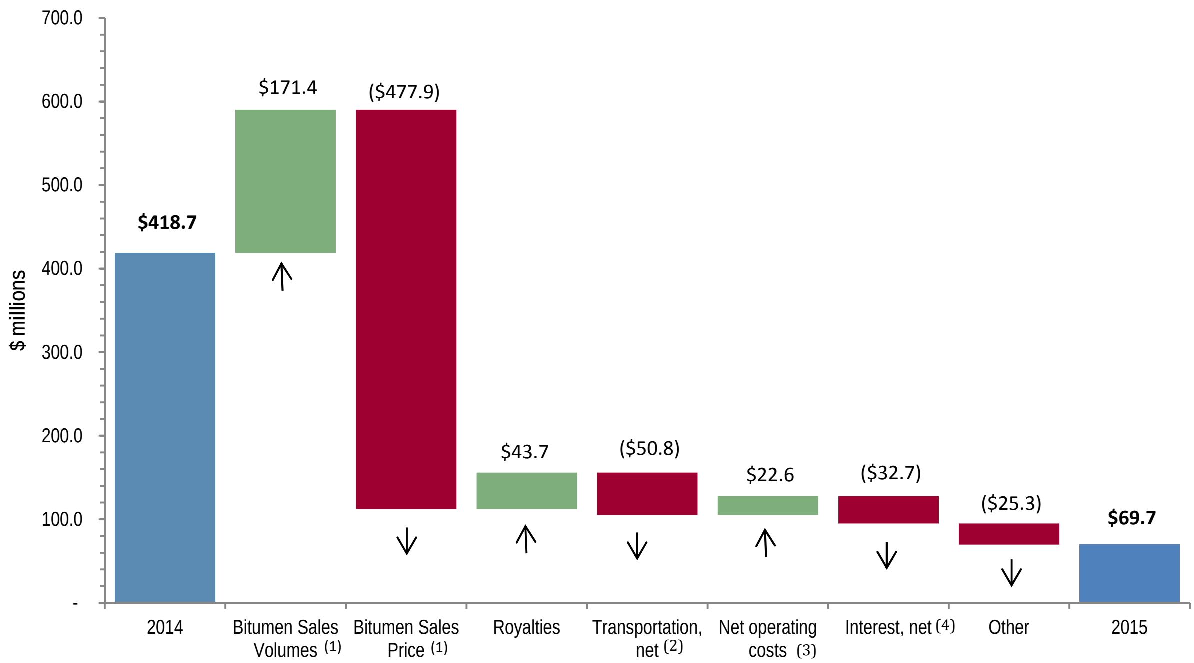
(2) Defined as transportation expense less transportation revenue.

(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 $99.2 million for the three months ended June 30, 2015 compared to $261.7 million for the three months ended June 30, 2014. Cash flow from operations decreased primarily due to lower bitumen realization and higher transportation and interest costs, partially offset by lower net operating costs and lower royalties. The decrease in bitumen realization and decrease in royalties is directly correlated to the significant decline of U.S. crude oil benchmark pricing. Transportation expense increased primarily due to the cost of transporting blend volumes from Edmonton to the U.S. Gulf Coast via the Flanagan-Seaway Pipeline, which commenced operations in the fourth quarter of 2014. During the past several quarters, the Corporation's transportation costs have increased to accommodate a greater proportion of blend sales now being directly sold to refineries at the refinery gate. Interest costs increased as a result of the weakening of the Canadian dollar relative to the U.S. dollar, as the Corporation's debt is denominated in U.S. dollars.

Cash Flow from Operations – Six Months Ended June 30, 2015



(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 $69.7 million for the six months ended June 30, 2015 compared to cash flow from operations of $418.7 million for the six months ended June 30, 2014. Cash flow from operations decreased primarily due to lower bitumen realization and higher transportation and interest costs, partially offset by an increase in bitumen sales volumes, lower royalties and lower net operating costs.

Operating Earnings (Loss)

The Corporation recognized an operating loss of $23.0 million for the three months ended June 30, 2015 compared to operating earnings of $111.1 million for the three months ended June 30, 2014. Operating earnings have decreased due to lower bitumen realization, primarily as a result of the significant decline of U.S. crude oil benchmark pricing, higher transportation costs and an increase in interest expense, partially offset by lower net operating costs and lower royalties.

The operating loss for the six months ended June 30, 2015 was $147.4 million compared to operating earnings of $151.8 million for the six months ended June 30, 2014. Operating earnings have decreased due to lower bitumen realization, primarily as a result of the significant decline of U.S. crude oil benchmark pricing, higher transportation costs, an increase in depletion and depreciation expense and an increase in interest expense, partially offset by higher sales volumes, lower royalties and lower net operating costs.

Revenue

Revenue for the three months ended June 30, 2015 totalled $554.6 million compared to $829.2 million for the three months ended June 30, 2014. Revenue for the six months ended June 30, 2015 totalled $1.0 billion compared to $1.5 billion for the six months ended June 30, 2014. Revenue represents the total of Petroleum revenue, net of royalties and Other revenue.

Net Earnings (Loss)

The Corporation recognized net earnings of $63.4 million for the three months ended June 30, 2015 compared to $249.0 million for the three months ended June 30, 2014. Net earnings for the three months ended June 30, 2015 included a net unrealized foreign exchange gain of $75.0 million on the Corporation's U.S. dollar denominated debt and U.S. dollar denominated cash and cash equivalents. Net earnings for the three months ended June 30, 2014 included a net unrealized foreign exchange gain of $135.1 million on U.S. dollar denominated debt and U.S. dollar denominated cash and cash equivalents.

The Corporation recognized a net loss of $444.9 million for the six months ended June 30, 2015 compared to net earnings of $145.5 million for the six months ended June 30, 2014. The net loss for the six months ended June 30, 2015 included a net unrealized foreign exchange loss of $295.8 million on the Corporation's U.S. dollar denominated debt and U.S. dollar denominated cash and cash equivalents. Net earnings for the six months ended June 30, 2014 included a net unrealized foreign exchange loss of $5.5 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, 2015 totalled $90.5 million compared to a total of $298.7 million for the three months ended June 30, 2014. Total cash capital investment during the six months ended June 30, 2015 totalled $170.6 million compared to a total of $622.3 million for the six months ended June 30, 2014. Capital investment in 2015 has been primarily directed towards sustaining and maintenance 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 $438.2 million as at June 30, 2015 compared to a cash and cash equivalents balance of $656.1 million as at December 31, 2014. The Corporation's cash and cash equivalents balance decreased primarily due to the use of cash to settle accounts payable related to 2014 capital investment activity.

All of the Corporation's long-term debt is denominated in U.S. dollars. Long-term debt increased to C$4.7 billion as at June 30, 2015 from C$4.4 billion as at December 31, 2014 due to the decrease in the value of the Canadian dollar relative to the U.S. dollar. 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, 2015, the Corporation's capital resources included $438.2 million of cash and cash equivalents, an additional undrawn US$2.5 billion syndicated revolving credit facility and a US$500 million guaranteed letter of credit facility.

3. OUTLOOK

The Corporation had previously disclosed annual non-energy operating costs for 2015 to be targeted in the range of $8 to $10 per barrel and annual bitumen production volumes to be in the 78,000 to 82,000 bbls/d range, while providing for two scheduled plant turnarounds. The Corporation had also disclosed a 2015 planned capital program of $305 million.

When setting the previously disclosed 2015 guidance for non-energy operating costs of $8 to $10 per barrel, estimated expenses related to annual turnarounds were incorporated. Due to the scope of the work related to the major turnaround completed in the second quarter of 2015, the expenditures incurred have been appropriately treated as a capital expenditure. This has resulted in lower than anticipated non-energy operating costs for the six months ended June 30, 2015. Non-energy operating costs are now targeted to be in the range of $7.30 to $9.30 per barrel for 2015. The next major turnaround is currently anticipated to occur in 2017. The Corporation's 2015 annual bitumen production volumes continue to be targeted in the 78,000 to 82,000 bbls/d range and the 2015 planned capital program remains unchanged at $305 million.

During the second quarter, MEG initiated a review of its financial leverage, with the overall objective of better positioning the Corporation to grow in a low price environment. All of MEG's outstanding long-term debt is covenant lite, with the first maturity not due until 2020. Notwithstanding the above, MEG and its advisors are reviewing deleveraging options available to the Corporation, including how its interest in the Access Pipeline could contribute to this initiative. Any alternative pursued must align with the Corporation's overall long-term strategy.

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		2015		2014				2013	
	2015	**2014**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**
Average Commodity Prices										
Crude oil prices										
Brent (US$/bbl)	**59.33**	108.84	**63.50**	55.16	76.98	103.39	109.77	107.90	109.35	109.71
WTI (US$/bbl)	**53.29**	100.84	**57.94**	48.63	73.15	97.16	102.99	98.68	97.43	105.83
WTI (C$/bbl)	**65.83**	110.62	**71.24**	60.35	83.08	105.84	112.31	108.89	102.08	109.90
Differential – Brent:WTI (US$/bbl)	**6.04**	8.00	**5.56**	6.53	3.83	6.23	6.78	9.22	11.92	3.88
Differential – Brent:WTI (%)	**10.2%**	7.4%	**8.8%**	11.8%	5.0%	6.0%	6.2%	8.5%	10.9%	3.5%
WCS (C$/bbl)	**49.56**	86.93	**56.98**	42.13	66.74	83.82	90.44	83.41	68.31	91.75
Differential – WTI:WCS (C$/bbl)	**16.28**	23.69	**14.25**	18.22	16.34	22.02	21.87	25.48	33.77	18.15
Differential – WTI:WCS (%)	**24.7%**	21.4%	**20.0%**	30.2%	19.7%	20.8%	19.5%	23.4%	33.1%	16.5%
Condensate prices										
C5+ at Edmonton (C$/bbl)	**63.88**	113.99	**71.17**	56.59	81.98	101.72	114.72	113.26	99.19	107.81
Natural gas prices										
AECO (C$/mcf)	**2.69**	5.19	**2.64**	2.74	3.58	4.00	4.70	5.69	3.52	2.42
Electric power prices										
Alberta power pool (C$/MWh)	**43.20**	51.51	**57.25**	29.14	30.55	63.91	42.43	60.58	48.60	83.61
Foreign exchange rates										
C$ equivalent of 1 US$ - average	**1.2353**	1.0970	**1.2294**	1.2411	1.1357	1.0893	1.0905	1.1035	1.0477	1.0385
C$ equivalent of 1 US$ - period end	**1.2474**	1.0676	**1.2474**	1.2683	1.1601	1.1208	1.0676	1.1053	1.0636	1.0285

Crude Oil Pricing

Brent crude is a major representative of global light sweet crude oil prices and serves as a benchmark price. The Brent benchmark price averaged US$63.50 per barrel in the second quarter of 2015 compared to US$55.16 per barrel for the first quarter of 2015 and US$109.77 per barrel for the second quarter of 2014. The Brent benchmark price averaged US$59.33 per barrel for the six months ended June 30, 2015 compared to US$108.84 per barrel for the six months ended June 30, 2014. The decrease is primarily due to the global imbalance between supply and demand for crude oil.

The price of WTI is the current benchmark for mid-continent North American crude oil prices, at Cushing Oklahoma, and its Canadian dollar equivalent is the basis for determining royalties on the Corporation's bitumen sales. The WTI price averaged US$57.94 per barrel in the second quarter of 2015 compared to US$48.63 per barrel for the first quarter of 2015 and US$102.99 per barrel for the second quarter of 2014. The WTI price averaged US$53.29 per barrel for the six months ended June 30, 2015 compared to US$100.84 per barrel for the six months ended June 30, 2014. The decrease is primarily due to the global imbalance between supply and demand for crude oil.

The Western Canadian Select ("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 $14.25 per barrel or 20.0% for the second quarter of 2015, compared to $21.87 per barrel or 19.5% for the second quarter of 2014. The WTI:WCS differential averaged $16.28 per barrel or 24.7% for the first half of 2015, compared to $23.69 per barrel or 21.4% for the first half of 2014.

Apportionment of pipeline capacity between western Canada and the U.S. coastal markets reduces the ability for MEG to access higher heavy oil pricing at the U.S. Gulf Coast for its blend sales. Recent additions of crude-by-rail, new and expanded pipeline connections from the U.S. mid-continent to the U.S. Gulf Coast, and refinery modifications in the U.S. Midwest, are collectively working towards improved product value for bitumen by gaining access to the higher prices at the U.S. Gulf Coast.

Natural Gas Prices

Natural gas is a primary energy input cost for the Corporation, as it is used to generate steam for the SAGD process and to create electricity from the Corporation's cogeneration facilities. The AECO natural gas price averaged $2.64 per mcf for the second quarter of 2015 compared to $4.70 per mcf for the second quarter of 2014. The AECO natural gas price averaged $2.69 per mcf for the six months ended June 30, 2015 compared to $5.19 per mcf for the six months ended June 30, 2014. Natural gas prices have weakened due to record production levels in the U.S. and an increase of natural gas inventory in storage.

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 $57.25 per megawatt hour for the second quarter of 2015 compared to $42.43 per megawatt hour for second quarter of 2014. Average power prices for the second quarter of 2015 were affected by several plant outages late in the second quarter of 2015.

The Alberta power pool price averaged $43.20 per megawatt hour for the six months ended June 30, 2015 compared to $51.51 per megawatt hour for the same period in 2014. The decrease in the Alberta power pool price is mainly a result of increased power generation capacity in the province, partially offset by several plant outages late in the second quarter of 2015. This increased power generation in the province is anticipated to continue to moderate power prices.

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, as blend sales prices 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 principal and interest payments, while an increase in the value of the Canadian dollar has a negative impact on blend sales revenue and a positive impact on 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, 2015, the Canadian dollar, at a rate of 1.2474, had increased in value by approximately 2% against the U.S. dollar compared to its value as at March 31, 2015, when the rate was 1.2683. During the six month period from December 31, 2014 to June 30, 2015, the Canadian dollar weakened in value by approximately 8%.

5. RESULTS OF OPERATIONS

COMPARISON OF THE THREE MONTHS ENDED JUNE 30, 2015 TO JUNE 30, 2014

	Three months ended June 30	
	2015	**2014**
Bitumen production – bbls/d	**71,376**	68,984
Steam to oil ratio (SOR)	**2.3**	2.4

Bitumen Production

Production for the three months ended June 30, 2015 averaged 71,376 bbls/d compared to 68,984 bbls/d for the three months ended June 30, 2014. The increase in production volumes is primarily due to the successful ramp-up of Phase 2B and the continued implementation of 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. These increases in production were partially offset by a reduction in production volumes as a result of a major planned turnaround in the second quarter of 2015, which was longer in duration and had a greater impact on production volumes than the turnaround for the same period in 2014. In addition, forest fires in the Christina Lake extended the duration of time required to complete the 2015 turnaround.

Steam to Oil Ratio

The Corporation continues to focus on increasing production and maintaining efficiency of current production through a lower steam to oil ratio (“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, 2015 compared to a SOR of 2.4 for the three months ended June 30, 2014.

Operating Cash Flow

	Three months ended June 30	
($000)	**2015**	**2014**
Petroleum revenue – proprietary(1)	**$ 509,968**	$ 795,072
Diluent	**(220,585)**	(326,065)
	289,383	469,007
Royalties	**(5,853)**	(32,323)
Transportation expense	**(33,107)**	(19,329)
Operating expenses	**(69,678)**	(103,712)
Power revenue	**8,371**	10,312
Transportation revenue	**3,392**	7,726
Operating cash flow(2)	**$ 192,508**	$ 331,681

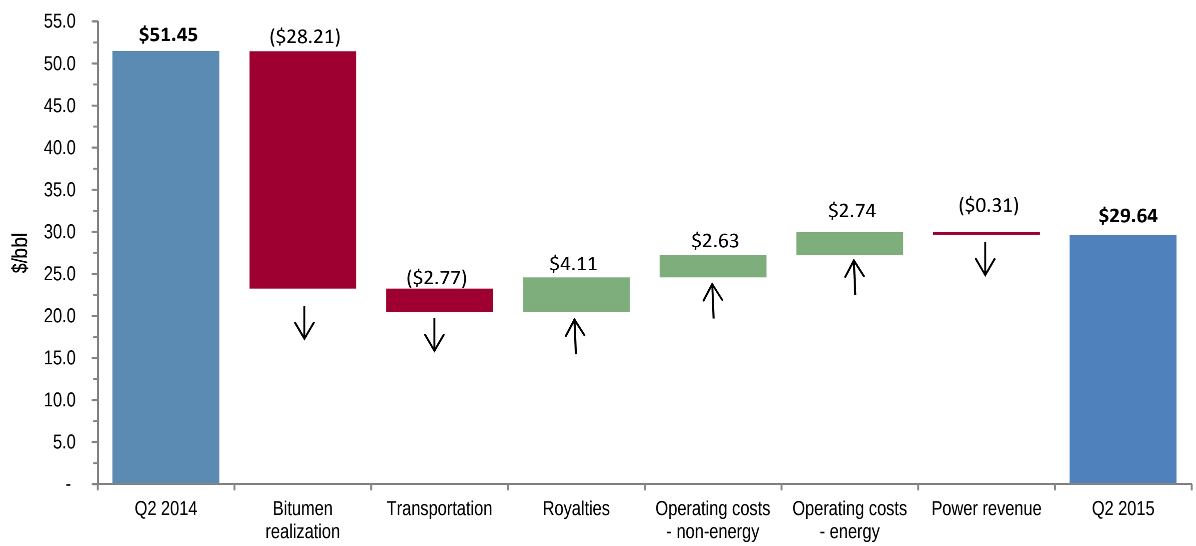
(1) Proprietary petroleum revenue represents MEG's revenue (“blend sales revenue”) from its heavy crude oil blend known as Access Western Blend ("AWB” or “blend”). Blend is comprised of bitumen produced at the Christina Lake Project blended with purchased diluent.

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

Operating cash flow decreased primarily due to lower blend sales revenue, primarily as a result of the significant decline of U.S. crude oil benchmark pricing, partially offset by a decrease in the cost of diluent, lower operating expenses and lower royalties.

Blend sales revenue for the three months ended June 30, 2015 were $510.0 million compared to $795.1 million for the three months ended June 30, 2014. The decrease in blend sales revenue is due to a 37% decrease in the average realized blend price partially offset by a 2% increase in sales volumes. The cost of diluent for the three months ended June 30, 2015 was $220.6 million compared to $326.1 million for the three months ended June 30, 2014. The total cost of diluent decreased primarily due to the decrease in condensate prices partially offset by higher volumes of diluent required for the increased blend sales volumes.

Cash Operating Netback



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

	Three months ended June 30	
($/bbl)	**2015**	**2014**
Bitumen realization[1]	**$ 44.54**	$ 72.75
Transportation[2]	**(4.57)**	(1.80)
Royalties	**(0.90)**	(5.01)
	39.07	65.94
Operating costs – non-energy	**(7.01)**	(9.64)
Operating costs – energy	**(3.71)**	(6.45)
Power revenue	**1.29**	1.60
Net operating costs	**(9.43)**	(14.49)
Cash operating netback	**$ 29.64**	$ 51.45

(1) Blend sales revenue net of diluent costs.

(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.

Bitumen Realization

Bitumen realization represents the Corporation's blend sales revenue, net of the cost of diluent. Bitumen realization averaged $44.54 per barrel for the three months ended June 30, 2015 compared to $72.75 per barrel for the three months ended June 30, 2014. The decrease in bitumen realization is primarily as a result of the significant decline of U.S. crude oil benchmark pricing which resulted in lower blend sales revenue.

For the three months ended June 30, 2015, the Corporation’s cost of diluent was $73.86 per barrel compared to $113.33 per barrel for the three months ended June 30, 2014. The decrease in the cost of diluent is primarily as a result of the significant decline of U.S. crude oil benchmark pricing.

Transportation

Transportation costs include rail, Stonefell Terminal costs and third-party pipelines as well as MEG’s share of the operating costs for the Access Pipeline, net of third-party recoveries on diluent transportation arrangements. Transportation costs averaged $4.57 per barrel for the three months ended June 30, 2015 compared to $1.80 per barrel for the three months ended June 30, 2014. Transportation expense increased primarily due to the cost of transporting blend volumes from Edmonton to the U.S. Gulf Coast via the Flanagan-Seaway Pipeline, which commenced operations in the fourth quarter of 2014. During the past several quarters, the Corporation’s transportation costs have increased to accommodate a greater proportion of blend sales now being directly sold to refineries at the refinery gate. These increasing direct sales to refineries at the refinery gate are a result of MEG’s strategy of broadening market access to world prices to improve netbacks.

Royalties

The Corporation's royalty expense is based on price-sensitive royalty rates set by the Government of Alberta. The applicable royalty rates change depending on whether a project is pre-payout or post-payout, with payout being defined as the point in time when a project has generated enough 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 $0.90 per barrel during the three months ended June 30, 2015 compared to $5.01 per barrel for the three months ended June 30, 2014. The decrease in royalties is attributable to the decrease in the Canadian dollar price of WTI and the decrease in bitumen realization.

Net Operating Costs

Non-energy operating costs

Non-energy operating costs decreased to $7.01 per barrel for the three months ended June 30, 2015 compared to $9.64 per barrel for the three months ended June 30, 2014. Non-energy costs for the three months ended June 30, 2014 included $1.94 per barrel for annual inspection and maintenance activities at the Christina Lake facilities.

Historically, the Corporation has only performed annual inspection and maintenance activities on the Christina Lake facilities, with the associated costs expensed as non-energy operating costs. Consistent with the Corporation’s capitalization policy, in the second quarter of 2015, the major turnaround costs of $20.8 million have been capitalized, as the work performed will benefit future years of operations. As a result, the cost of the 2015 turnaround is treated as a component of capital investment and will be depreciated on a straight line basis over the period to the next major turnaround, which is currently anticipated to occur in 2017.

Energy related operating costs

Energy related operating costs averaged $3.71 per barrel for the three months ended June 30, 2015 compared to $6.45 per barrel for the three months ended June 30, 2014. The decrease in energy operating costs on a per barrel basis is attributable to the decrease in natural gas prices. The Corporation's natural gas purchase price averaged $3.15 per mcf during the second quarter of 2015 compared to $5.25 per mcf for the second quarter of 2014.

Power revenue

Power revenue averaged $1.29 per barrel for the three months ended June 30, 2015 compared to $1.60 per barrel for the three months ended June 30, 2014. The decrease is primarily due to a decrease in power sales volumes as a result of the major turnaround in the second quarter of 2015. Power sales volumes decreased to 97 MW/h in the three months ended June 30, 2015 compared to 115 MW/h for the same period in 2014. The Corporation's realized power price during the three months ended June 30, 2015 decreased to $39.55 per megawatt hour compared to $40.98 per megawatt hour for the same period in 2014.

COMPARISON OF THE SIX MONTHS ENDED JUNE 30, 2015 TO JUNE 30, 2014

	Six months ended June 30	
	2015	**2014**
Bitumen production – bbls/d	**76,856**	63,842
Steam to oil ratio (SOR)	**2.5**	2.4

Bitumen Production

Production for the six months ended June 30, 2015 averaged 76,856 bbls/d compared to 63,842 bbls/d for the six months ended June 30, 2014. The increase in production volumes is primarily due to the successful ramp-up of Phase 2B and the continued implementation of 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. These increases in production were partially offset by a reduction in production volumes as a result of a planned major turnaround in the second quarter of 2015, which was longer in duration and had a greater impact on production volumes than the turnaround for the same period in 2014. In addition, forest fires near the Christina Lake Project extended the duration of time required to complete the 2015 turnaround.

Steam to Oil Ratio

The Corporation continues to focus on increasing 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 2.5 for the six months ended June 30, 2015 compared to a SOR of 2.4 for the six months ended June 30, 2014.

Operating Cash Flow

	Six months ended June 30	
($000)	**2015**	**2014**
Petroleum revenue – proprietary[(1)]	**$ 965,721**	$ 1,396,900
Diluent	**(477,633)**	(602,273)
	488,088	794,627
Royalties	**(12,003)**	(55,706)
Transportation expense	**(71,769)**	(32,219)
Operating expenses	**(159,276)**	(195,102)
Power revenue	**17,190**	30,443
Transportation revenue	**5,886**	17,105
Operating cash flow[(2)]	**$ 268,116**	$ 559,148

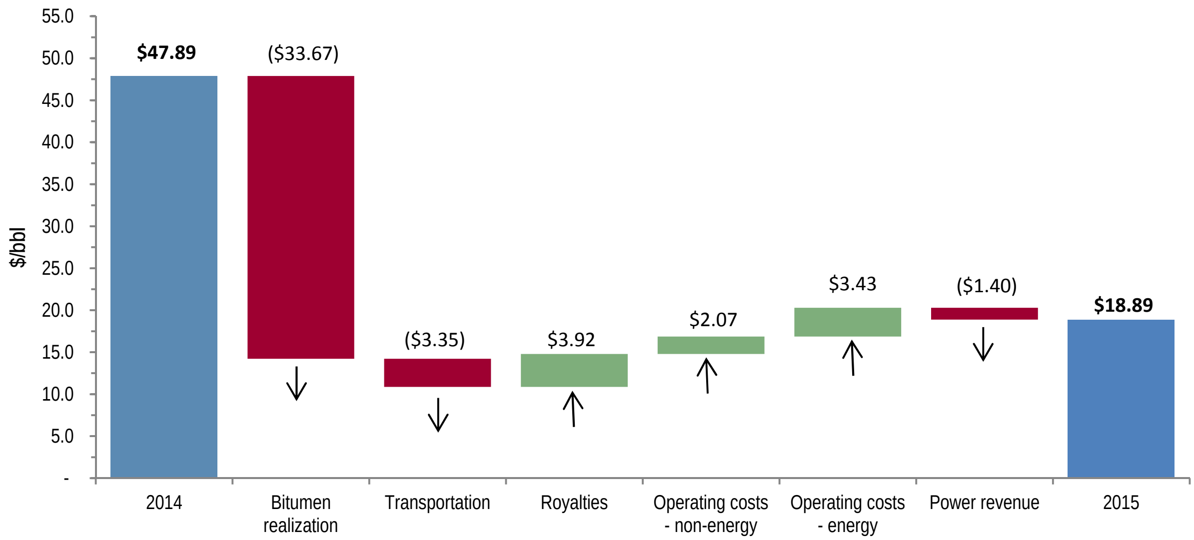
(1) Proprietary petroleum revenue represents MEG's revenue ("blend sales revenue") from its heavy crude oil blend known as Access Western Blend ("AWB" or "blend"). Blend is comprised of bitumen produced at the Christina Lake Project blended with purchased diluent.

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

Operating cash flow decreased primarily due to lower blend sales revenue as a result of the significant decline of U.S. crude oil benchmark pricing and higher transportation costs. These factors were partially offset by a decrease in the cost of diluent, lower royalties and lower operating expenses.

Blend sales revenue for the six months ended June 30, 2015 were $965.7 million compared to $1.4 billion for the six months ended June 30, 2014. The decrease in blend sales revenue is due to a 43% decrease in the average realized blend price partially offset by a 22% increase in sales volumes. The cost of diluent for the six months ended June 30, 2015 was $477.6 million compared to $602.3 million for the six months ended June 30, 2014. The total cost of diluent decreased primarily due to the decrease in condensate prices partially offset by higher volumes of diluent required for the increased blend sales volumes.

Cash Operating Netback



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

	Six months ended June 30	
($/bbl)	**2015**	**2014**
Bitumen realization[(1)]	**$ 34.39**	$ 68.06
Transportation[(2)]	**(4.64)**	(1.29)
Royalties	**(0.85)**	(4.77)
	28.90	62.00
Operating costs – non-energy	**(7.31)**	(9.38)
Operating costs – energy	**(3.91)**	(7.34)
Power revenue	**1.21**	2.61
Net operating costs	**(10.01)**	(14.11)
Cash operating netback	**$ 18.89**	$ 47.89

(1) Blend sales net of diluent costs.

(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.

Bitumen Realization

Bitumen realization averaged $34.39 per barrel for the six months ended June 30, 2015 compared to $68.06 per barrel for the six months ended June 30, 2014. The decrease in bitumen realization is primarily as a result of the significant decline of U.S. crude oil benchmark pricing which resulted in lower blend sales revenue. For the six months ended June 30, 2015, the Corporation's cost of diluent was $71.28 per barrel compared to $110.13 per barrel for the six months ended June 30, 2014. The decrease in the cost of diluent is primarily as a result of the significant decline of U.S. crude oil benchmark pricing.

Transportation

Transportation costs averaged $4.64 per barrel for the six months ended June 30, 2015 compared to $1.29 per barrel for the six months ended June 30, 2014. Transportation expense increased primarily due to the cost of transporting blend volumes from Edmonton to the U.S. Gulf Coast via the Flanagan-Seaway Pipeline, which commenced operations in the fourth quarter of 2014. During the past several quarters, the Corporation's transportation costs have increased to accommodate a greater proportion of blend sales now being directly sold to refineries at the refinery gate. These increasing direct sales to refineries at the refinery gate are a result of MEG's strategy of broadening market access to world prices to improve netbacks. In addition, there were lower transportation revenues from third parties.

Royalties

Royalties averaged $0.85 per barrel during the six months ended June 30, 2015 compared to $4.77 per barrel for the six months ended June 30, 2014. The decrease in royalties is attributable to the decrease in the Canadian dollar price of WTI and the decrease in bitumen realization.

Net Operating Costs

Non-energy operating costs

Non-energy operating costs decreased to $7.31 per barrel for the six months ended June 30, 2015 compared to $9.38 per barrel for the six months ended June 30, 2014. Non-energy costs were higher in the first half of 2014 as a result of the ongoing ramp up of Phase 2B production. Non-energy costs per barrel are lower in the first six months of 2015, as relatively fixed components of operating costs are spread over a greater number of barrels. Non-energy costs for the six months ended June 30, 2014 also include $1.07 per barrel for annual inspection and maintenance activities at the Christina Lake facilities.

Historically, the Corporation has only performed annual inspection and maintenance activities on the Christina Lake facilities, with the associated costs expensed as non-energy operating costs. Consistent with the Corporation's capitalization policy, in the second quarter of 2015, the major turnaround costs of $20.8 million have been capitalized, as the work performed will benefit future years of operations. As a result, the cost of the 2015 turnaround is treated as a component of capital investment and will be depreciated on a straight line basis over the period to the next major turnaround, which is currently anticipated to occur in 2017.

Energy related operating costs

Energy related operating costs averaged $3.91 per barrel for the six months ended June 30, 2015 compared to $7.34 per barrel for the six months ended June 30, 2014. The decrease in energy operating costs on a per barrel basis is attributable to the decrease in natural gas prices. The Corporation's natural gas purchase price averaged $3.17 per mcf during the six months ended June 30, 2015 compared to $5.65 per mcf for the six months ended June 30, 2014.

Power revenue

Power revenue averaged $1.21 per barrel for the six months ended June 30, 2015 compared to $2.61 per barrel for the six months ended June 30, 2014. The Corporation's average realized power sales price during the six months ended June 30, 2015 was $32.79 per megawatt hour compared to $52.95 per megawatt hour for the same period in 2014. The decrease in the realized power sales price is primarily due to increased power generation capacity in the province.

6. OTHER OPERATING RESULTS

Net Marketing Activity

	Three months ended June 30		Six months ended June 30	
($000)	**2015**	**2014**	**2015**	**2014**
Petroleum sales – third party	**$ 38,769**	$ 48,405	**$ 44,848**	$ 120,012
Purchased product and storage:				
Purchased product	**(37,145)**	(48,142)	**(43,187)**	(117,849)
Marketing and storage arrangements	**(4,592)**	(2,308)	**(10,657)**	(4,263)
	(41,737)	(50,450)	**(53,844)**	(122,112)
Net marketing activity[1]	**$ (2,968)**	$ (2,045)	**$ (8,996)**	$ (2,100)

(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 and in the United States. Accordingly, the Corporation has entered into product storage arrangements and marketing arrangements for rail, barge and U.S.-based pipelines. These arrangements are kept in place to optimize the value of all barrels sold to the marketplace. To the extent 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.

Depletion and Depreciation

	Three months ended June 30		Six months ended June 30	
($000)	**2015**	**2014**	**2015**	**2014**
Depletion and depreciation	**$ 102,912**	$ 98,618	**$ 218,483**	$ 179,862
Depletion and depreciation per barrel of production	**$ 15.84**	$ 15.71	**$ 15.71**	$ 15.57

Depletion and depreciation expense for the three months ended June 30, 2015 totalled $102.9 million compared to $98.6 million for the three months ended June 30, 2014. Depletion and depreciation expense was $15.84 per barrel for the three months ended June 30, 2015 compared to $15.71 per barrel for the three months ended June 30, 2014.

Depletion and depreciation expense for the six months ended June 30, 2015 totalled $218.5 million compared to $179.9 million for the six months ended June 30, 2014. The increase is primarily due to a 20% increase in bitumen production volumes for the six months ended June 30, 2015, compared to the six months ended June 30, 2014. Depletion and depreciation expense was $15.71 per barrel for the six months ended June 30, 2015 compared to $15.57 per barrel for the six months ended June 30, 2014.

The Corporation's producing oil sands properties are depleted on a unit-of-production basis based on estimated proved reserves. Major facilities and equipment are depreciated on a unit-of-production basis over the estimated total productive capacity of the facilities and equipment. Pipeline and storage assets are depreciated on a straight-line basis over their estimated useful lives.

General and Administrative

	Three months ended June 30		Six months ended June 30	
($000)	**2015**	**2014**	**2015**	**2014**
General and administrative expense	**$ 31,596**	$ 25,720	**$ 64,902**	$ 52,095
General and administrative expense per barrel of production	**$ 4.86**	$ 4.10	**$ 4.67**	$ 4.51

General and administrative expense for the three months ended June 30, 2015 was $31.6 million compared to $25.7 million for the three months ended June 30, 2014. General and administrative expense for the six months ended June 30, 2015 was $64.9 million compared to $52.1 million for the six months ended June 30, 2014.

The increase in general and administrative expense for the three and six months ended June 30, 2015 compared to the same periods in 2014 was partially offset on a per barrel basis by higher production volumes, as expenses are spread over a greater number of barrels.

Stock-based Compensation

	Three months ended June 30		Six months ended June 30	
($000)	**2015**	**2014**	**2015**	**2014**
Stock-based compensation costs	**$ 14,390**	$ 13,913	**$ 28,497**	$ 29,551
Capitalized stock-based compensation costs	**(2,104)**	(3,232)	**(3,681)**	(6,248)
Stock-based compensation expense	**$ 12,286**	$ 10,681	**$ 24,816**	$ 23,303

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 value is determined using the Black-Scholes option pricing model. Stock-based compensation costs, before capitalization, for the three months ended June 30, 2015 were $14.4 million compared to $13.9 million for three months ended June 30, 2014. Stock-based compensation costs, before capitalization, for the six months ended June 30, 2015 were $28.5 million compared to $29.6 million for six months ended June 30, 2014.

The Corporation capitalizes a portion of stock-based compensation associated with capitalized salaries and benefits. The Corporation capitalized $2.1 million of stock-based compensation for the three months ended June 30, 2015 compared to $3.2 million for three months ended June 30, 2014. The Corporation capitalized $3.7 million of stock-based compensation for the six months ended June 30, 2015 compared to $6.2 million for six months ended June 30, 2014. The decrease in capitalized stock-based compensation is primarily due to a decrease in the capitalization rate as a result of a reduction of capital investing activity.

Research and Development

	Three months ended June 30		Six months ended June 30	
($000)	**2015**	**2014**	**2015**	**2014**
Research and development	**$ 1,619**	$ 880	**$ 2,791**	$ 1,871

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 $1.6 million for the three months ended June 30, 2015 compared to $0.9 million for the three months ended June 30, 2014. Research and development expenditures were $2.8 million for the six months ended June 30, 2015 compared to $1.9 million for the six months ended June 30, 2014.

Net Foreign Exchange Gain (Loss)

	Three months ended June 30		Six months ended June 30	
($000)	**2015**	**2014**	**2015**	**2014**
Unrealized foreign exchange gain (loss) on:				
Long-term debt	**$ 79,622**	$ 144,051	**$ (332,784)**	$ (15,434)
Other	**(4,596)**	(8,903)	**36,961**	9,981
Unrealized net gain (loss) on foreign exchange	**75,026**	135,148	**(295,823)**	(5,453)
Realized gain (loss) on foreign exchange	**(938)**	1,530	**(8,168)**	(1,113)
Foreign exchange gain (loss), net	**$ 74,088**	$ 136,678	**$ (303,991)**	$ (6,566)

C$ equivalent of 1 US$				
Beginning of period	**1.2683**	1.1053	**1.1601**	1.0636
End of period	**1.2474**	1.0676	**1.2474**	1.0676

The Corporation recognized a net foreign exchange gain of $74.1 million for the three months ended June 30, 2015 compared to a net foreign exchange gain of $136.7 million for the three months ended June 30, 2014. The decrease in the net foreign exchange gain is primarily due to an unrealized foreign exchange gain on the translation of U.S. dollar denominated debt as a result of strengthening of the Canadian dollar compared to the U.S. dollar by approximately 2% during the three months ended June 30, 2015. During the three months ended June 30, 2014, the Canadian dollar strengthened in value by approximately 4%.

The Corporation recognized a net foreign exchange loss of $304.0 million for the six months ended June 30, 2015 compared to a net foreign exchange loss of $6.6 million for the six months ended June 30, 2014. The increase in the net foreign exchange loss is primarily due to an unrealized foreign exchange loss on the translation of U.S. dollar denominated debt as a result of weakening of the Canadian dollar compared to the U.S. dollar by approximately 8% during the six months ended June 30, 2015. During the six months ended June 30, 2014, the Canadian dollar weakened in value by less than 1%.

Net Finance Expense

($000)	Three months ended June 30 2015	Three months ended June 30 2014	Six months ended June 30 2015	Six months ended June 30 2014
Total interest expense	**$ 75,550**	$ 65,074	**$ 151,276**	$130,774
Less capitalized interest	**(16,485)**	(22,099)	**(32,488)**	(41,569)
Net interest expense	**59,065**	42,975	**118,788**	89,205
Accretion on decommissioning provision	**1,244**	1,105	**2,556**	2,141
Unrealized fair value gain on embedded derivative financial liabilities	**(6,859)**	(1,136)	**(1,772)**	(2,246)
Unrealized fair value loss (gain) on interest rate swaps	**(879)**	546	**(2,435)**	29
Realized loss on interest rate swaps	**1,404**	1,367	**2,805**	2,489
Net finance expense	**$ 53,975**	$ 44,857	**$ 119,942**	$ 91,618
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, 2015 was $75.6 million compared to $65.1 million for the three months ended June 30, 2014. Total interest expense, before capitalization, for the six months ended June 30, 2015 was $151.3 million compared to $130.8 million for the six months ended June 30, 2014. Total interest expense for the three and six months ended June 30, 2015 increased primarily due to the weakening Canadian dollar and its impact on U.S. dollar denominated interest expense.

The Corporation recognized an unrealized gain on embedded derivative financial liabilities of $6.9 million for the three months ended June 30, 2015 compared to $1.1 million for the three months ended June 30, 2014. The Corporation recognized an unrealized gain on embedded derivative financial liabilities of $1.8 million for the six months ended June 30, 2015 compared to $2.2 million for the six months ended June 30, 2014. These gains relate to the change in fair value of the interest rate floor associated with the Corporation's senior secured credit facilities. The interest rate floor is considered an embedded derivative as the floor rate was higher than the London Interbank Offered Rate ("LIBOR") at the time that the debt agreements were entered into. Accordingly, the fair value of the embedded derivatives at the time the debt agreements were entered into was netted against the carrying value of the long-term debt and is amortized over the life of the debt agreements. The fair value of the embedded derivative is included in derivative financial liabilities on the balance sheet, with gains and losses associated with changes in the fair value of the embedded derivative included in net finance expense.

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$1.255 billion senior secured term loan until September 30, 2016. The Corporation recognized an unrealized gain of $0.9 million and $2.4 million on the interest rate swap contracts for the three and six months ended June 30, 2015, respectively, compared to an unrealized loss of $0.5 million and less than $0.1 million for the three and six months ended June 30, 2014, respectively. In addition, the Corporation recognized a realized loss on the interest swap contracts of $1.4 million and $2.8 million for the three and six months ended June 30, 2015, respectively, compared to a realized loss of $1.4 million and $2.5 million for the three and six months ended June 30, 2014, respectively.

Other Income

	Three months ended June 30		Six months ended June 30	
($000)	**2015**	**2014**	**2015**	**2014**
Interest income	**$ 750**	$ 2,058	**$ 1,714**	$ 5,318
Contract cancellation recovery	**5,880**	-	**5,880**	-
Other income	**$ 6,630**	$ 2,058	**$ 7,594**	$ 5,318

The Corporation recognized a $5.9 million recovery relating to $16.5 million of project cancellation costs recognized in the fourth quarter of 2014.

Income Tax Expense (Recovery)

	Three months ended June 30		Six months ended June 30	
($000)	**2015**	**2014**	**2015**	**2014**
Current income tax recovery	**$ (800)**	$ -	**$ (800)**	$ -
Deferred income tax expense (recovery)	**5,256**	38,662	**(22,518)**	61,538
Income tax expense (recovery)	**$ 4,456**	$ 38,662	**$ (23,318)**	$ 61,538

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 deferred income tax expense of $5.3 million for the three months ended June 30, 2015 compared to deferred income tax expense of $38.7 million for the three months ended June 30, 2014. The Corporation recognized a deferred income tax recovery of $22.5 million for the six months ended June 30, 2015 compared to deferred income tax expense of $61.5 million for the six months ended June 30, 2014.

During the second quarter of 2015, the Government of Alberta enacted an increase in the Alberta corporate income tax rate from 10% to 12%. As a result, the Corporation increased its deferred income tax liability by $11.4 million, with a corresponding increase to deferred income tax expense.

The Corporation's effective tax rate on earnings is impacted by permanent differences and variances in taxable capital losses not recognized. The significant 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, 2015, the non-taxable gain was $39.8 million compared to a non-taxable gain of $72.0 million for the three months ended June 30, 2014. For the six months ended June 30, 2015, the non-taxable loss was $166.4 million compared to a non-taxable loss of $7.7 million for the six months ended June 30, 2014.

- Stock-based compensation expense is a permanent difference. Stock-based compensation expense was $12.3 million for the three months ended June 30, 2015 compared to $10.7 million for the three months ended June 30, 2014. Stock-based compensation expense for the six months ended June 30, 2015 was $24.8 million compared to $23.3 million for the three months ended June 30, 2014.

- During the three and 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. There was no tax benefit recognized for the three months and six months ended June 30, 2014 on vested RSUs.

The Corporation is not currently taxable. As of June 30, 2015, the Corporation had approximately $7.3 billion of available tax pools and had recognized a deferred income tax liability of $155.7 million. In addition, at June 30, 2015, the Corporation had $624.8 million of capital investment in respect of incomplete projects which will increase available tax pools upon completion of the projects. As at June 30, 2015, the Corporation had not recognized the tax benefit related to $439.3 million of unrealized taxable capital foreign exchange losses.

7. TOTAL CASH AND NON-CASH CAPITAL INVESTING

	Three months ended June 30		Six months ended June 30	
($000)	**2015**	**2014**	**2015**	**2014**
Total cash capital investment	**$ 90,465**	$ 298,727	**$ 170,566**	$ 622,261
Capitalized interest	**16,485**	22,099	**32,488**	41,568
	106,950	320,826	**203,054**	663,829
Non-cash capital investment	**10,069**	11,406	**28,896**	21,968
Total cash and non-cash capital investment	**$ 117,019**	$ 332,232	**$ 231,950**	$ 685,797

MEG's total cash and non-cash capital investment for the three months ended June 30, 2015 was $117.0 million (including capitalized interest of $16.5 million and non-cash capital investment of $10.1 million), in comparison to $332.2 million (including capitalized interest of $22.1 million and non-cash capital investment of $11.4 million) for the three months ended June 30, 2014. Total cash and non-cash capital investment for the six months ended June 30, 2015 was $232.0 million (including capitalized interest of $32.5 million and non-cash capital investment of $28.9 million) in comparison to $685.8 million (including capitalized interest of $41.6 million and non-cash capital investment of $22.0 million) for the six months ended June 30, 2014.

Total cash capital investment for the six months ended June 30, 2015 was $170.6 million in comparison to $622.3 million for the six months ended June 30, 2014. Total cash capital investing for the six months ended June 30, 2015 was primarily directed to sustaining and maintenance capital activities as the Corporation has been focused on reducing capital spending until there is a sustained improvement in crude oil pricing.

In the second quarter of 2015, major turnaround costs of $20.8 million have been capitalized as there is future economic benefit associated with the work performed. As a result, the cost of the 2015 turnaround is treated as a component of capital investment and will be depreciated on a straight line basis over the period to the next turnaround, which is currently anticipated to occur in 2017.

The Corporation capitalizes interest associated with qualifying assets. A total of $32.5 million of interest was capitalized during the six months ended June 30, 2015.

Non-cash capital investment for the six months ended June 30, 2015 included a $25.0 million provision for future reclamation and decommissioning and $3.7 million in capitalized stock-based compensation.

8. LIQUIDITY AND CAPITAL RESOURCES

($000)	**June 30, 2015**	**December 31, 2014**
Cash and cash equivalents	**$ 438,238**	$ 656,097
Senior secured term loan (June 30, 2015 – US$1.255 billion; December 31, 2014 – US$1.262 billion; due 2020)	**1,565,487**	1,463,466
US$2.5 billion revolver (due 2019)	**-**	-
6.5% senior unsecured notes (US$750.0 million; due 2021)	**935,550**	870,075
6.375% senior unsecured notes (US$800.0 million; due 2023)	**997,920**	928,080
7.0% senior unsecured notes (US$1.0 billion; due 2024)	**1,247,400**	1,160,100
Total debt[(1)]	**$ 4,746,357**	$ 4,421,721

(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, 2015 and the Corporation's consolidated financial statements as at December 31, 2014.

Capital Resources

As at June 30, 2015, the Corporation's available capital resources included $438.2 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$157.3 million of letters of credit have been issued.

During the fourth quarter of 2014, the Corporation increased the syndicated revolving credit facility from US$2.0 billion to US$2.5 billion and extended the maturity of the revolving credit facility to November 2019. The revolving credit facility remains undrawn as at June 30, 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.

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 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$1.255 billion senior secured term loan until September 30, 2016.

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 investment 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**	
($000)	**2015**	**2014**	**2015**	**2014**
Net cash provided by (used in):				
Operating activities	**$ 121,761**	$ 296,607	**$ 104,819**	$ 335,656
Investing activities	**(148,492)**	(341,251)	**(354,302)**	(685,962)
Financing activities	**(4,024)**	3,082	**(8,148)**	1,123
Foreign exchange gains (losses) on cash and cash equivalents held in foreign currency	**(1,785)**	(8,903)	**39,772**	9,981
Change in cash and cash equivalents	**$ (32,540)**	$ (50,465)	**$ (217,859)**	$ (339,202)

Cash Flow – Operating Activities

Net cash provided by operating activities totalled $121.8 million for the three months ended June 30, 2015 compared to net cash provided by operating activities of $296.6 million for the three months ended June 30, 2014. The decrease in cash flow from operating activities is primarily due to lower blend sales revenue, primarily as a result of the significant decline of U.S. crude oil benchmark pricing, partially offset by a decrease in the cost of diluent, lower operating expenses and lower royalties.

Net cash provided by operating activities totalled $104.8 million for the six months ended June 30, 2015 compared to net cash provided by operating activities of $335.7 million for the six months ended June 30, 2014. The decrease in cash flow from operating activities is primarily due to lower blend sales revenue as a result of the significant decline of U.S. crude oil benchmark pricing and higher transportation costs. These factors were partially offset by a decrease in the cost of diluent, lower royalties and lower operating expenses. Net cash used in operating activities for the six months ended June 30, 2015 included an increase in the net change in non-cash working capital of $30.5 million, primarily as a result of the sales of blend inventory on hand at December 31, 2014.

Transportation expense increased primarily due to the cost of transporting blend volumes from Edmonton to the U.S. Gulf Coast via the Flanagan-Seaway Pipeline, which commenced operations in the fourth quarter of 2014, in addition to lower transportation revenues from third parties. Interest costs increased as a result of the weakening of the Canadian dollar relative to the U.S. dollar, as the Corporation's debt is denominated in U.S. dollars.

Cash Flow – Investing Activities

Net cash used in investing activities for the three months ended June 30, 2015 primarily consisted of $107.0 million in capital investment, including $16.5 million of capitalized interest, (refer to the "CAPITAL INVESTING" section of this MD&A for further details) and a $39.0 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, 2014 primarily consisted of $320.8 in capital investment, including $22.1 million of capitalized interest.

Net cash used in investing activities for the six months ended June 30, 2015 primarily consisted of $203.1 million in capital investment, including $32.5 million of capitalized interest, (refer to the "CAPITAL INVESTING" section of this MD&A for further details) and a $150.7 million decrease in the net change in non-cash investing working capital, primarily relating to the settlement of accounts payable related to 2014 capital investment activity.

Net cash used in investing activities for the six months ended June 30, 2014 primarily consisted of $663.8 in capital investment, including $41.6 million of capitalized interest.

Cash Flow – Financing Activities

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 provided by financing activities for the three months ended June 30, 2014 consisted of $6.6 million of proceeds received from the exercise of stock options, partially offset by $3.5 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.

Net cash provided by financing activities for the six months ended June 30, 2014 consisted of $8.2 million of proceeds received from the exercise of stock options, partially offset by $7.1 million of debt principal repayment.

9. SHARES OUTSTANDING

As at June 30, 2015, the Corporation had the following share capital instruments outstanding:

Common shares	224,880,655
Convertible securities	
Stock options outstanding - exercisable and unexercisable	10,290,378
RSUs and PSUs outstanding	3,501,464

As at July 22, 2015, the Corporation had 224,880,655 common shares, 10,242,405 stock options and 3,473,571 restricted share units and performance share units outstanding.

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)	Total	Less than 1 year	1 - 3 years	4 - 5 years	More than 5 years
Long-term debt[1]	$ 4,746,357	$ 16,216	$ 32,432	$ 32,432	$ 4,665,277
Interest on long-term debt[1]	1,863,655	270,072	538,472	515,203	539,908
Decommissioning obligation[2]	843,550	3,000	10,305	11,400	818,845
Transportation and storage[3]	3,915,578	166,571	340,653	315,887	3,092,467
Contracts and purchase orders[4]	483,424	202,693	86,519	54,564	139,648
Operating leases[5]	419,086	16,132	58,247	64,314	280,393
	$12,271,650	**$ 674,684**	**$ 1,066,628**	**$ 993,800**	**$ 9,536,538**

(1) This represents the scheduled principal repayment 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, 2015.

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

(3) This represents transportation and storage commitments from 2015 to 2040.

(4) This represents the future commitment associated with the Corporation's capital program, diluent purchases and other operating and maintenance commitments.

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

11. NON-GAAP MEASURES

Certain financial measures in this MD&A including: net marketing activity, cash flow from operations, operating earnings (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 sales – third party is disclosed in Note 11 in the notes to the interim consolidated financial statements and purchased product and storage is presented as a line item on the interim Consolidated Statement of Earnings (Loss) and Comprehensive Income (Loss).

Cash Flow from Operations

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

	Three months ended June 30		Six months ended June 30	
($000)	**2015**	**2014**	**2015**	**2014**
Net cash provided by operating activities	**$ 121,761**	$ 296,607	**$ 104,819**	$ 335,656
Add (deduct):				
Net change in non-cash operating working capital items	**(16,993)**	(35,491)	**(30,481)**	82,272
Contract cancellation recovery	**(5,880)**	-	**(5,880)**	-
Decommissioning expenditures	**355**	597	**1,251**	772
Cash flow from operations	**$ 99,243**	$ 261,713	**$ 69,709**	$ 418,700

Operating Earnings (Loss)

Operating earnings (loss) is a non-GAAP measure which the Corporation uses as a performance measure to provide comparability of financial performance between periods by excluding non-operating items. Operating earnings (loss) is defined as net earnings (loss) as reported, excluding unrealized foreign exchange gains and losses, unrealized gains and losses on derivative financial liabilities, unrealized fair value gains and losses on other assets, contract cancellation recovery and the respective deferred tax impact of these adjustments. Operating earnings (loss) is reconciled to "Net earnings (loss)", the nearest IFRS measure, in the table below.

	Three months ended June 30		Six months ended June 30	
($000)	**2015**	**2014**	**2015**	**2014**
Net earnings (loss)	**$ 63,414**	$ 248,954	**$ (444,893)**	$ 145,513
Add (deduct):				
Unrealized net loss (gain) on foreign exchange(1)	**(75,026)**	(135,148)	**295,823**	5,453
Unrealized gain on derivative financial liabilities(2)	**(7,738)**	(590)	**(4,207)**	(2,217)
Contract cancellation recovery (3)	**(5,880)**	-	**(5,880)**	-
Deferred tax expense (recovery) relating to these adjustments	**2,280**	(2,077)	**11,786**	3,049
Operating earnings (loss)	**$ (22,950)**	$ 111,139	**$ (147,371)**	$ 151,798

(1) Unrealized net foreign exchange gains and losses result from the translation of U.S. dollar denominated long-term debt and cash and cash equivalents using period-end exchange rates.

(2) Unrealized gains and losses on derivative financial liabilities result from the interest rate floor on the Corporation's long-term debt and interest rate swaps entered into to effectively fix a portion of its variable rate long-term debt.

(3) A recovery related to project cancellation costs initially recorded in the fourth quarter of 2014.

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, transportation, field operating costs and royalties 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, transportation, operating expenses and royalties from proprietary sales volumes and power revenues, on a per barrel 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 2014 annual MD&A.

13. TRANSACTIONS WITH RELATED PARTIES

The Corporation did not enter into any related party transactions during the three and six month periods ended June 30, 2015 and June 30, 2014, 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

At June 30, 2015 and December 31, 2014 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, 2015 and December 31, 2014.

15. NEW ACCOUNTING POLICIES

There were no new accounting standards adopted during the six months ended June 30, 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, 2014. Further information regarding the risk factors which may affect the Corporation is contained in 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.

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 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. 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 and foreign exchange 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 the Corporation 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 and Resources

This document contains references to estimates of the Corporation's reserves and contingent resources. For supplemental information regarding the classification and uncertainties related to MEG's estimated reserves and resources please see "Independent Reserve and Resource Evaluation" in the 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 operations, operating earnings (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 the Corporation'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.

20. 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.

21. QUARTERLY SUMMARIES

	2015		2014				2013	
Unaudited	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**
FINANCIAL ($000 unless specified)								
Net earnings (loss)(1)	**63,414**	(508,307)	(150,076)	(100,975)	248,954	(103,441)	(148,182)	115,383
Per share, diluted	**0.28**	(2.27)	(0.67)	(0.45)	1.11	(0.46)	(0.67)	0.51
Operating earnings (loss)	**(22,950)**	(124,421)	8,084	87,471	111,139	40,659	(32,685)	56,171
Per share, diluted	**(0.10)**	(0.56)	0.04	0.39	0.49	0.18	(0.15)	0.25
Cash flow from (used in) operations	**99,243**	(29,534)	134,099	238,659	261,713	156,987	22,648	144,521
Per share, diluted	**0.44**	(0.13)	0.60	1.06	1.16	0.70	0.10	0.64
Cash capital investment	**90,465**	80,101	323,970	291,309	298,727	323,533	366,321	454,589
Cash, cash equivalents and short-term investments	**438,238**	470,778	656,097	776,522	839,870	890,335	1,179,072	647,096
Working capital	**374,766**	386,130	525,534	747,928	805,742	877,069	1,045,607	365,676
Long-term debt(2)	**4,693,793**	4,775,590	4,365,502	4,217,536	4,016,257	4,162,209	4,004,575	2,857,740
Shareholders' equity	**4,358,078**	4,279,873	4,768,235	4,894,444	4,970,144	4,705,966	4,788,430	4,919,407
BUSINESS ENVIRONMENT								
WTI (US$/bbl)	**57.94**	48.63	73.15	97.16	102.99	98.68	97.43	105.83
C$ equivalent of 1US$ - average	**1.2294**	1.2411	1.1357	1.0893	1.0905	1.1035	1.0477	1.0385
Differential – WTI:WCS ($/bbl)	**14.25**	18.22	16.34	22.02	21.87	25.48	33.77	18.15
Differential – WTI:WCS (%)	**20.0%**	30.2%	19.7%	20.8%	19.5%	23.4%	33.1%	16.5%
Natural gas – AECO ($/mcf)	**2.64**	2.74	3.58	4.00	4.70	5.69	3.52	2.42
OPERATIONAL ($/bbl unless specified)								
Bitumen production – bbls/d	**71,376**	82,398	80,349	76,471	68,984	58,643	42,251	34,246
Bitumen sales – bbls/d	**71,401**	85,519	70,116	69,757	70,849	58,089	35,990	32,175
Steam to oil ratio (SOR)	**2.3**	2.6	2.5	2.5	2.4	2.5	2.9	2.5
Bitumen realization	**44.54**	25.82	50.48	65.12	72.75	62.28	38.22	74.33
Transportation – net	**(4.57)**	(4.70)	(1.82)	(1.09)	(1.80)	(0.67)	(0.51)	(0.20)
Royalties	**(0.90)**	(0.80)	(2.97)	(5.02)	(5.01)	(4.47)	(2.71)	(5.14)
Operating costs – non-energy	**(7.01)**	(7.57)	(6.42)	(7.16)	(9.64)	(9.05)	(8.09)	(9.20)
Operating costs – energy	**(3.71)**	(4.07)	(5.16)	(5.58)	(6.45)	(8.43)	(5.38)	(3.32)
Power revenue	**1.29**	1.15	1.45	2.43	1.60	3.85	2.25	3.12
Cash operating netback	29.64	9.83	35.56	48.70	51.45	43.51	23.78	59.59
Power sales price (C$/MWh)	**39.55**	28.21	31.67	59.07	40.98	62.26	44.63	75.96
Power sales (MW/h)	**97**	145	134	119	115	150	76	59
Depletion and depreciation rate per bbl of production	**15.84**	15.58	13.63	13.92	15.71	15.39	13.25	15.54
COMMON SHARES								
Shares outstanding, end of period (000)	**224,881**	223,847	223,847	223,794	223,673	222,575	222,507	222,489
Volume traded (000)	**40,929**	57,657	94,588	30,649	70,199	32,102	33,400	28,403
Common share price ($)								
High	**25.20**	24.31	34.69	40.75	41.29	37.84	36.00	36.69
Low	**17.56**	14.84	13.30	34.00	35.52	29.41	28.60	28.81
Close (end of period)	**20.40**	20.46	19.55	34.38	38.89	37.36	30.61	35.54

(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) Includes current and long-term portions, as presented on the Consolidated Balance Sheet.

Interim Consolidated Financial Statements

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

As at	Note	June 30, 2015	December 31, 2014
Assets			
Current assets			
Cash and cash equivalents	18	**$ 438,238**	$ 656,097
Trade receivables and other		**208,591**	177,219
Inventories		**73,151**	153,320
		719,980	986,636
Non-current assets			
Property, plant and equipment	4	**8,198,750**	8,195,490
Exploration and evaluation assets	5	**589,601**	588,526
Other intangible assets	6	**85,274**	83,090
Other assets	7	**137,715**	76,366
Total assets		**$ 9,731,320**	$ 9,930,108
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities		**$ 311,719**	$ 427,910
Current portion of long-term debt	8	**16,216**	15,081
Current portion of provisions and other liabilities	9	**17,279**	18,111
		345,214	461,102
Non-current liabilities			
Long-term debt	8	**4,677,577**	4,350,421
Provisions and other liabilities	9	**194,771**	172,154
Deferred income tax liability	17	**155,680**	178,196
Total liabilities		**5,373,242**	5,161,873
Shareholders' equity			
Share capital	10	**4,833,254**	4,797,853
Contributed surplus	10	**146,933**	153,837
Deficit		**(641,563)**	(196,670)
Accumulated other comprehensive income		**19,454**	13,215
Total shareholders' equity		**4,358,078**	4,768,235
Total liabilities and shareholders' equity		**$ 9,731,320**	$ 9,930,108

Commitments and contingencies (note 22)

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	**2015**	**2014**	**2015**	**2014**
Petroleum revenue, net of royalties	11	**$ 542,884**	$ 811,154	**$ 998,566**	$1,461,206
Other revenue	12	**11,763**	18,038	**23,076**	47,548
		554,647	829,192	**1,021,642**	1,508,754
Diluent and transportation	13	**253,692**	345,394	**549,402**	634,492
Purchased product and storage		**41,737**	50,450	**53,844**	122,112
Operating expenses		**69,678**	103,712	**159,276**	195,102
Depletion and depreciation	4,6	**102,912**	98,618	**218,483**	179,862
General and administrative		**31,596**	25,720	**64,902**	52,095
Stock-based compensation	10	**12,286**	10,681	**24,816**	23,303
Research and development		**1,619**	880	**2,791**	1,871
		513,520	635,455	**1,073,514**	1,208,837
Revenues less expenses		**41,127**	193,737	**(51,872)**	299,917
Other income (expense)					
Other income	14	**6,630**	2,058	**7,594**	5,318
Foreign exchange gain (loss), net	15	**74,088**	136,678	**(303,991)**	(6,566)
Net finance expense	16	**(53,975)**	(44,857)	**(119,942)**	(91,618)
		26,743	93,879	**(416,339)**	(92,866)
Earnings (loss) before income taxes		**67,870**	287,616	**(468,211)**	207,051
Income tax expense (recovery)	17	**4,456**	38,662	**(23,318)**	61,538
Net earnings (loss)		**63,414**	248,954	**(444,893)**	145,513
Other comprehensive income (loss), net of tax					
Items that may be reclassified to profit or loss:					
Foreign currency translation adjustment		**401**	(5,251)	**6,239**	(1,549)
Comprehensive income (loss) for the period		**$ 63,815**	$ 243,703	**$ (438,654)**	$ 143,964

Net earnings (loss) per common share					
Basic	19	**$ 0.28**	$ 1.12	**$ (1.99)**	$ 0.65
Diluted	19	**$ 0.28**	$ 1.11	**$ (1.99)**	$ 0.65

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	Retained Earnings (Deficit)	Accumulated Other Comprehensive Income	Total Shareholders' Equity
Balance as at December 31, 2014		**$ 4,797,853**	**$ 153,837**	**$ (196,670)**	**$ 13,215**	**$ 4,768,235**
Stock-based compensation	10	**-**	**28,497**	**-**	**-**	**28,497**
RSUs vested and released	10	**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**
Balance as at December 31, 2013		$ 4,751,374	$ 126,666	$ (92,493)	$ 2,883	$ 4,788,430
Stock options exercised		10,693	(2,494)	-	-	8,199
Stock-based compensation		-	29,551	-	-	29,551
RSUs vested and released		29,284	(29,284)	-	-	-
Comprehensive income (loss)		-	-	145,513	(1,549)	143,964
Balance as at June 30, 2014		$ 4,791,351	$ 124,439	$ 53,020	$ 1,334	$ 4,970,144

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	**2015**	**2014**	**2015**	**2014**
Cash provided by (used in):					
Operating activities					
Net earnings (loss)		**$ 63,414**	$ 248,954	**$ (444,893)**	$ 145,513
Adjustments for:					
Depletion and depreciation	4,6	**102,912**	98,618	**218,483**	179,862
Stock-based compensation	10	**12,286**	10,681	**24,816**	23,303
Unrealized (gain) loss on foreign exchange	15	**(75,026)**	(135,148)	**295,823**	5,453
Unrealized gain on derivative financial liabilities	16	**(7,738)**	(590)	**(4,207)**	(2,217)
Deferred income tax expense (recovery)	17	**5,256**	38,662	**(22,518)**	61,538
Amortization of debt issue costs	7,9	**2,933**	2,413	**5,818**	4,993
Decommissioning expenditures	9	**(355)**	(597)	**(1,251)**	(772)
Other		**1,086**	(1,877)	**2,267**	255
Net change in non-cash operating working capital items	18	**16,993**	35,491	**30,481**	(82,272)
Net cash provided by (used in) operating activities		**121,761**	296,607	**104,819**	335,656
Investing activities					
Capital investments					
Property, plant and equipment	4	**(105,600)**	(318,407)	**(197,190)**	(655,447)
Exploration and evaluation	5	**(611)**	(1,829)	**(858)**	(4,417)
Other intangible assets	6	**(739)**	(590)	**(5,006)**	(3,965)
Other		**(2,518)**	(1,189)	**(577)**	113
Net change in non-cash investing working capital items	18	**(39,024)**	(19,236)	**(150,671)**	(22,246)
Net cash provided by (used in) investing activities		**(148,492)**	(341,251)	**(354,302)**	(685,962)
Financing activities					
Issue of shares	10	**-**	6,562	**-**	8,199
Repayment of long-term debt	8	**(4,024)**	(3,480)	**(8,148)**	(7,076)
Net cash provided by (used in) financing activities		**(4,024)**	3,082	**(8,148)**	1,123
Effect of exchange rate changes on cash and cash equivalents held in foreign currency		**(1,785)**	(8,903)	**39,772**	9,981
Change in cash and cash equivalents		**(32,540)**	(50,465)	**(217,859)**	(339,202)
Cash and cash equivalents, beginning of period		**470,778**	890,335	**656,097**	1,179,072
Cash and cash equivalents, end of period		**$ 438,238**	$ 839,870	**$ 438,238**	$ 839,870

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 Regional Project ("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, 2014. 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 3 of the Corporation’s audited consolidated financial statements for the year ended December 31, 2014. These interim consolidated financial statements should be read in conjunction with the Corporation’s audited consolidated financial statements for the year ended December 31, 2014, which are included in the Corporation’s 2014 annual report.

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 effective July 27, 2015.

3. CHANGE IN ACCOUNTING POLICIES

New accounting standards

There were no new accounting standards adopted during the six months ended June 30, 2015.

Accounting standards issued but not yet applied

There were no new accounting standards issued during the six months ended June 30, 2015 that are anticipated to be applicable to the Corporation in future periods. A description of 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, 2014.

4. PROPERTY, PLANT AND EQUIPMENT

	Crude oil	Transportation and storage	Corporate assets	Total
Cost				
Balance as at December 31, 2013	$ 6,493,665	$ 1,276,447	$ 41,035	$ 7,811,147
Additions	1,002,619	295,568	6,082	1,304,269
Change in decommissioning liabilities	43,085	680	-	43,765
Transfer to other assets	-	(12,381)	-	(12,381)
Balance as at December 31, 2014	7,539,369	1,560,314	47,117	9,146,800
Additions	164,362	34,593	2,154	201,109
Change in decommissioning liabilities	23,956	804	-	24,760
Transfer to other assets (Note 7)	-	(6,938)	-	(6,938)
Balance as at June 30, 2015	**$ 7,727,687**	**$ 1,588,773**	**$ 49,271**	**$ 9,365,731**
Accumulated depletion and depreciation				
Balance as at December 31, 2013	$ 513,422	$ 31,452	$ 11,322	$ 556,196
Depletion and depreciation for the year	370,301	19,661	5,152	395,114
Balance as at December 31, 2014	883,723	51,113	16,474	951,310
Depletion and depreciation for the period	198,272	14,537	2,862	215,671
Balance as at June 30, 2015	**$ 1,081,995**	**$ 65,650**	**$ 19,336**	**$ 1,166,981**
Carrying amounts				
Balance as at December 31, 2014	$ 6,655,646	$ 1,509,201	$ 30,643	$ 8,195,490
Balance as at June 30, 2015	**$ 6,645,692**	**$ 1,523,123**	**$ 29,935**	**$ 8,198,750**

During the six months ended June 30, 2015, the Corporation capitalized $32.5 million of interest and finance charges related to the development of capital projects (six months ended June 30, 2014 - $41.0 million). As at June 30, 2015, $887.0 million of assets under construction were included within property, plant and equipment (December 31, 2014 - $864.7 million). Assets under construction are not subject to depletion and depreciation. As of June 30, 2015, no impairment has been recognized on these assets.

5. EXPLORATION AND EVALUATION ASSETS

Cost		
Balance as at December 31, 2013	$	579,497
Additions		7,749
Change in decommissioning liabilities		1,280
Balance as at December 31, 2014		588,526
Additions		858
Change in decommissioning liabilities		217
Balance as at June 30, 2015	**$**	**589,601**

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 of June 30, 2015, no impairment has been recognized on these assets. During the six months ended June 30, 2015, the Corporation did not capitalize any interest and finance charges related to exploration and evaluation assets (six months ended June 30, 2014 - $0.6 million).

6. OTHER INTANGIBLE ASSETS

Cost		
Balance as at December 31, 2013	$	66,209
Additions		23,571
Balance as at December 31, 2014		89,780
Additions		5,006
Balance as at June 30, 2015	**$**	**94,786**

Accumulated depreciation		
Balance as at December 31, 2013	$	3,004
Depreciation for the year		3,686
Balance as at December 31, 2014		6,690
Depreciation for the period		2,822
Balance as at June 30, 2015	**$**	**9,512**

Carrying amounts		
Balance as at December 31, 2014	$	83,090
Balance as at June 30, 2015	**$**	**85,274**

As at June 30, 2015, other intangible assets include $63.4 million invested to maintain the right to participate in a potential pipeline project and $21.9 million invested in software that is not an integral component of the related computer hardware (December 31, 2014 - $60.2 million and $22.9 million, respectively). As of June 30, 2015, no impairment has been recognized on these assets.

7. OTHER ASSETS

		June 30, 2015		December 31, 2014
Long-term pipeline linefill[(a)]	**$**	**120,406**	$	56,900
U.S. auction rate securities		**3,127**		2,908
Deferred financing costs		**18,546**		20,874
		142,079		80,682
Less current portion of deferred financing costs		**(4,364)**		(4,316)
	$	**137,715**	$	76,366

(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. During the six months ended June 30, 2015, the Corporation transferred $6.9 million of bitumen blend from property, plant and equipment to long-term pipeline linefill. In addition, $40.7 million of diluent and $11.5 million of bitumen blend was transferred from inventories to long-term pipeline linefill to meet these linefill obligations. The linefill is classified as a long-term asset as these transportation contracts extend beyond the year 2025. As of June 30, 2015, no impairment has been recognized on these assets.

8. LONG-TERM DEBT

		June 30, 2015		December 31, 2014
Senior secured term loan (June 30, 2015 – US$1.255 billion; December 31, 2014 – US$1.262 billion)	**$**	**1,565,487**	$	1,463,466
6.5% senior unsecured notes (US$750 million)		**935,550**		870,075
6.375% senior unsecured notes (US$800 million)		**997,920**		928,080
7.0% senior unsecured notes (US$1.0 billion)		**1,247,400**		1,160,100
		4,746,357		4,421,721
Less current portion of senior secured term loan		**(16,216)**		(15,081)
Less unamortized financial derivative liability discount		**(15,969)**		(17,514)
Less unamortized deferred debt issue costs		**(36,595)**		(38,705)
	$	**4,677,577**	$	4,350,421

The U.S. dollar denominated debt was translated into Canadian dollars at the period end exchange rate of US$1 = C$1.2474 (December 31, 2014 - US$1 = C$1.1601).

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

		June 30, 2015		December 31, 2014
Derivative financial liabilities[(a)]	**$**	**25,304**	$	29,511
Decommissioning provision[(b)]		**182,663**		156,382
Deferred lease inducements		**4,083**		4,372
Provisions and other liabilities		**212,050**		190,265
Less current portion		**(17,279)**		(18,111)
Non-current portion	**$**	**194,771**	$	172,154

(a) Derivative financial liabilities:

		June 30, 2015		December 31, 2014
1% interest rate floor	**$**	**19,073**	$	20,844
Interest rate swaps		**6,231**		8,667
Derivative financial liabilities		**25,304**		29,511
Less current portion		**(13,541)**		(15,538)
Non-current portion	**$**	**11,763**	$	13,973

(b) 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:

Decommissioning provision		June 30, 2015		December 31, 2014
Balance, beginning of year	**$**	**156,382**	$	108,695
Changes in estimated future cash flows		**16,930**		20,406
Changes in discount rates		**2,980**		13,798
Liabilities incurred		**5,066**		10,841
Liabilities settled		**(1,251)**		(1,893)
Accretion		**2,556**		4,535
Balance, end of period		**182,663**		156,382
Less current portion		**(3,000)**		(1,835)
Non-current portion	**$**	**179,663**	$	154,547

The decommissioning provision represents the present value of the estimated future costs to reclaim and abandon 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 5.9% (December 31, 2014 – 6.0%).

10. SHARE CAPITAL

(a) Authorized:

Unlimited number of common shares
Unlimited number of preferred shares

(b) Changes in issued common shares are as follows:

	Six months ended June 30, 2015		Year ended December 31, 2014	
	Number of shares	**Amount**	**Number of shares**	**Amount**
Balance, beginning of year	**223,846,891**	**$ 4,797,853**	222,506,896	$ 4,751,374
Issued upon exercise of stock options	**-**	**-**	412,644	14,665
Issued upon vesting and release of RSUs	**1,033,764**	**35,401**	927,351	31,814
Balance, end of period	**224,880,655**	**$ 4,833,254**	223,846,891	$ 4,797,853

(c) 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, 2015	**Stock options**	**Weighted average exercise price**
Outstanding, beginning of year	**7,865,788**	**$ 34.87**
Granted	**2,917,169**	**18.68**
Forfeited	**(275,329)**	**35.35**
Expired	**(217,250)**	**41.00**
Outstanding, end of period	**10,290,378**	**$ 30.14**

(d) Restricted share units outstanding and performance share units outstanding:

The Restricted Share Unit Plan allows for the granting of Restricted Share Units ("RSUs"), including Performance Share Units ("PSUs"), to directors, officers, employees and consultants of the Corporation.

Six months ended June 30, 2015	
Outstanding, beginning of year	2,745,439
Granted	1,916,768
Vested and released	(1,033,764)
Forfeited	(126,979)
Outstanding, end of period	3,501,464

(e) Deferred share units outstanding:

The Deferred Share Unit Plan allows for the granting of Deferred Share Units (“DSUs”) to directors of the Corporation. At June 30, 2015, there were 41,683 DSUs outstanding (December 31, 2014 – 17,281 DSUs outstanding).

(f) Contributed surplus:

Six months ended June 30, 2015	
Balance, beginning of year	$ 153,837
Stock-based compensation - expensed	24,816
Stock-based compensation - capitalized	3,681
RSUs vested and released	(35,401)
Balance, end of period	$ 146,933

11. PETROLEUM REVENUE, NET OF ROYALTIES

	Three months ended June 30		Six months ended June 30	
	2015	2014	2015	2014
Petroleum revenue:				
Proprietary	$ 509,968	$ 795,072	$ 965,721	$ 1,396,900
Third party [(a)]	38,769	48,405	44,848	120,012
	548,737	843,477	1,010,569	1,516,912
Royalties	(5,853)	(32,323)	(12,003)	(55,706)
Petroleum revenue, net of royalties	$ 542,884	$ 811,154	$ 998,566	$ 1,461,206

(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”

12. OTHER REVENUE

	Three months ended June 30		Six months ended June 30	
	2015	**2014**	**2015**	**2014**
Power revenue	**$ 8,371**	$ 10,312	**$ 17,190**	$ 30,443
Transportation revenue	**3,392**	7,726	**5,886**	17,105
Other revenue	**$ 11,763**	$ 18,038	**$ 23,076**	$ 47,548

13. DILUENT AND TRANSPORTATION

	Three months ended June 30		Six months ended June 30	
	2015	**2014**	**2015**	**2014**
Diluent	**$ 220,585**	$ 326,065	**$ 477,633**	$ 602,273
Transportation	**33,107**	19,329	**71,769**	32,219
Diluent and transportation	**$ 253,692**	$ 345,394	**$ 549,402**	$ 634,492

14. OTHER INCOME

	Three months ended June 30		Six months ended June 30	
	2015	**2014**	**2015**	**2014**
Interest income	**$ 750**	$ 2,058	**$ 1,714**	$ 5,318
Contract cancellation recovery	**5,880**	-	**5,880**	-
Other income	**$ 6,630**	$ 2,058	**$ 7,594**	$ 5,318

The Corporation recognized a $5.9 million recovery relating to $16.5 million of project cancellation costs recorded in the fourth quarter of 2014.

15. FOREIGN EXCHANGE GAIN (LOSS), NET

	Three months ended June 30		Six months ended June 30	
	2015	**2014**	**2015**	**2014**
Unrealized foreign exchange gain (loss) on:				
Long-term debt	**$ 79,622**	$ 144,051	**$ (332,784)**	$ (15,434)
Other	**(4,596)**	(8,903)	**36,961**	9,981
Unrealized net gain (loss) on foreign exchange	**75,026**	135,148	**(295,823)**	(5,453)
Realized gain (loss) on foreign exchange	**(938)**	1,530	**(8,168)**	(1,113)
Foreign exchange gain (loss), net	**$ 74,088**	$ 136,678	**$ (303,991)**	$ (6,566)

16. NET FINANCE EXPENSE

	Three months ended June 30		Six months ended June 30	
	2015	2014	**2015**	2014
Total interest expense	**$ 75,550**	$ 65,074	**$ 151,276**	$ 130,774
Less capitalized interest	**(16,485)**	(22,099)	**(32,488)**	(41,569)
Net interest expense	**59,065**	42,975	**118,788**	89,205
Accretion on decommissioning provision	**1,244**	1,105	**2,556**	2,141
Unrealized fair value gain on embedded derivative liabilities	**(6,859)**	(1,136)	**(1,772)**	(2,246)
Unrealized fair value loss (gain) on interest rate swaps	**(879)**	546	**(2,435)**	29
Realized loss on interest rate swaps	**1,404**	1,367	**2,805**	2,489
Net finance expense	**$ 53,975**	$ 44,857	**$ 119,942**	$ 91,618

17. INCOME TAX EXPENSE (RECOVERY)

	Three months ended June 30		Six months ended June 30	
	2015	2014	**2015**	2014
Current income tax recovery	**$ (800)**	$ -	**$ (800)**	$ -
Deferred income tax expense (recovery)	**5,256**	38,662	**(22,518)**	61,538
Income tax expense (recovery)	**$ 4,456**	$ 38,662	**$ (23,318)**	$ 61,538

During the second quarter of 2015, the Corporation recognized a current income tax recovery of $0.8 relating to the refundable Alberta tax credit on Scientific Research and Experimental Development expenditures.

During the second quarter of 2015, the Government of Alberta enacted an increase in the Alberta corporate income tax rate from 10% to 12%. As a result, the Corporation increased its deferred income tax liability by $11.4 million, with a corresponding increase to deferred income tax expense.

18. SUPPLEMENTAL CASH FLOW DISCLOSURES

	Three months ended June 30		Six months ended June 30	
	2015	2014	**2015**	2014
Cash provided by (used in):[(a)]				
Trade receivables and other	**$ (25,254)**	$ (16,812)	**$ (31,323)**	$ (106,990)
Inventories	**(8,875)**	45,084	**27,324**	28,005
Accounts payable and accrued liabilities	**12,098**	(12,017)	**(116,191)**	(25,533)
	$ (22,031)	$ 16,255	**$ (120,190)**	$ (104,518)
Changes in non-cash working capital relating to:				
Operating	**$ 16,993**	$ 35,491	**$ 30,481**	$ (82,272)
Investing	**(39,024)**	(19,236)	**(150,671)**	(22,246)
	$ (22,031)	$ 16,255	**$ (120,190)**	$ (104,518)
Cash and cash equivalents:[(b)]				
Cash	**$ 283,497**	$ 359,800	**$ 283,497**	$ 359,800
Cash equivalents	**154,741**	480,070	**154,741**	480,070
	$ 438,238	$ 839,870	**$ 438,238**	$ 839,870

(a) The amounts for the three and six months ended June 30, 2015, exclude non-cash working capital increases of $0.8 million and $52.9 million, respectively (three and six months ended June 30, 2014 - $2.5 million and $2.7 million, respectively) primarily related to transfers from inventory to other assets (Note 7).

(b) As at June 30, 2015, C$257.9 million of the Corporation's total cash and cash equivalents balance was held in U.S. dollars. (June 30, 2014 - C$292.0 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$1.2474 (June 30, 2014 - US$1 = C$1.0676).

19. EARNINGS (LOSS) PER COMMON SHARE

	Three months ended June 30		Six months ended June 30	
	2015	2014	**2015**	2014
Net earnings (loss)	**$ 63,414**	$ 248,954	**$ (444,893)**	$ 145,513
Weighted average common shares outstanding	**224,263,336**	223,049,767	**224,077,668**	222,798,406
Dilutive effect of stock options, RSUs and PSUs[(a)]	**902,133**	2,099,685	**-**	1,786,588
Weighted average common shares outstanding – diluted	**225,165,469**	225,149,452	**224,077,668**	224,584,994
Net earnings (loss) per share, basic	**$ 0.28**	$ 1.12	**$ (1.99)**	$ 0.65
Net earnings (loss) per share, diluted	**$ 0.28**	$ 1.11	**$ (1.99)**	$ 0.65

(a) For the six month period ended June 30, 2015, there was no dilutive effect of stock options, RSUs and PSUs due to the Corporation incurring a net loss during the period. If the Corporation had recognized net earnings during the six months ended June 30, 2015, the dilutive effect of stock options, RSUs and PSUs would have been 872,775 weighted average common shares.

20. 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, accounts payable and accrued liabilities, derivative financial liabilities and long-term debt. As at June 30, 2015, the ARS and derivative financial liabilities were classified as held-for-trading financial instruments; cash and cash equivalents and trade receivables and other were classified as loans and receivables; and accounts payable and accrued liabilities were classified as other financial liabilities. Long-term debt was carried at amortized cost.

The carrying value of cash and cash equivalents, trade receivables and other, and accounts payable and accrued liabilities included on the Consolidated Balance Sheet approximate the fair value of the respective assets and liabilities due to the short-term nature of those instruments.

(a) Fair value measurement of ARS, long-term debt and derivative financial liabilities:

			Fair value measurements using		
As at June 30, 2015	**Carrying amount**	**Fair value**	**Quoted prices in active markets (Level 1)**	**Significant other observable inputs (Level 2)**	**Significant unobservable inputs (Level 3)**
Recurring measurements:					
Financial assets					
ARS (Note 7)	**$ 3,127**	**$ 3,127**	**$ -**	**$ 3,127**	**$ -**
Financial liabilities					
Long-term debt[(1)] (Note 8)	**4,746,357**	**4,562,622**	**-**	**4,562,622**	**-**
Derivative financial liabilities (Note 9)	**25,304**	**25,304**	**-**	**25,304**	**-**

			Fair value measurements using		
As at December 31, 2014	**Carrying amount**	**Fair value**	**Quoted prices in active markets (Level 1)**	**Significant other observable inputs (Level 2)**	**Significant unobservable inputs (Level 3)**
Recurring measurements:					
Financial assets					
ARS (Note 7)	$ 2,908	$ 2,908	$ -	$ 2,908	$ -
Financial liabilities					
Long-term debt[(1)] (Note 8)	4,421,721	4,075,233	4,075,233	-	-
Derivative financial liabilities (Note 9)	29,511	29,511	-	29,511	-

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

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

As at June 30, 2015, 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 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 for the Corporation's interest rate swaps and floors. Management's assumptions rely on external observable market data including 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, 2015, 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. The Corporation's long-term debt was transferred from Level 1 to Level 2 fair value hierarchy level as at June 30, 2015 as its fair value was derived from observable inputs from a third-party independent broker.

(b) 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. As noted below, in order to mitigate a portion of this risk, the Corporation has entered into interest rate swap contracts to effectively fix the interest rate on US$748.0 million of the US$1.255 billion senior secured term loan. Interest rate swaps are classified as derivative financial liabilities and measured at fair value, with gains and losses on re-measurement included in net finance expense in the period in which they arise.

Amount	Effective date	Remaining term	Fixed rate	Floating rate
US$300 million	September 30, 2011	Jul 2015-Sept 2016	4.436%	3 month LIBOR[(1)]
US$150 million	December 31, 2011	Jul 2015-Sept 2016	4.376%	3 month LIBOR[(1)]
US$150 million	January 12, 2012	Jul 2015-Sept 2016	4.302%	3 month LIBOR[(1)]
US$148 million	January 27, 2012	Jul 2015-Sept 2016	4.218%	3 month LIBOR[(1)]

[(1)] *London Interbank Offered Rate*

21. GEOGRAPHICAL DISCLOSURE

As at June 30, 2015, the Corporation had non-current assets related to operations in the United States of $97.8 million (December 31, 2014 - $44.1 million). For the three and six months ended June 30, 2015, petroleum revenue related to operations in the United States were $169.5 million and $278.4 million, respectively (three and six months ended June 30, 2014 - $33.6 million and $86.1 million, respectively).

22. COMMITMENTS AND CONTINGENCIES

(a) Commitments

The Corporation had the following commitments as at June 30, 2015:

Operating:

	2015	2016	2017	2018	2019	Thereafter
Office lease rentals	$ 7,997	$ 16,269	$ 34,044	$ 32,135	$ 32,164	$ 296,477
Diluent purchases	114,047	57,908	19,123	19,123	19,123	73,346
Pipeline transportation and storage	75,726	181,690	167,252	165,111	156,178	3,169,621
Other commitments	8,371	14,930	9,157	5,873	8,921	80,324
Commitments	**$ 206,141**	**$ 270,797**	**$ 229,576**	**$ 222,242**	**$ 216,386**	**$ 3,619,768**

Capital:

As part of normal operations, the Corporation has entered into a total of $53.2 million in capital commitments to be made in periods through 2017.

(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.