SECOND QUARTER 2014

Report to Shareholders for the period ended June 30, 2014

MEG Energy Corp. reported second quarter 2014 operational and financial results on July 30, 2014. Highlights include:

- Record cash flow from operations of $261.7 million;
- Record quarterly production of 68,984 barrels per day (bpd), nearly 18 per cent higher than the first quarter and 115 per cent higher than the second quarter of 2013, all while factoring in the impact of planned maintenance on Phases 1 and 2;
- Christina Lake Phase 2B reaching design capacity seven months after first oil production;
- 2014 production guidance increased eight per cent to 65,000 to 70,000 bpd, reflecting strong operational performance;
- Completion of the Phase 1 and 2 plant turnaround, with inspections and maintenance confirming assets are in good operating condition.

"Exceptional operating performance and higher realized pricing drove record cash flow in the quarter," said Bill McCaffrey, MEG President and Chief Executive Officer. "This step change in our cash flow represents the beginning of a new chapter for MEG. Internal cash flow is now poised to be the major contributor to our future capital funding plans, with this past quarter being an important milestone."

Cash flow from operations in the second quarter of 2014 reached a record $261.7 million ($1.16 per share, diluted), compared to $79.2 million ($0.35 per share, diluted) for the same period of 2013. The increase in cash flow from operations was primarily due to higher production volumes and increased netbacks per barrel.

MEG's production during the second quarter of 2014 increased nearly 115 per cent to 68,984 bpd compared to second quarter 2013 production of 32,144 bpd. For the first six months of 2014, production approximately doubled to 63,842 bpd compared to 32,337 bpd in the first half of 2013. Quarterly and year-to-date production volumes in both comparative periods were impacted by planned maintenance.

"Phase 2B reached planned production volumes seven months after first oil, just prior to the Phase 1 and 2 plant turnaround," said McCaffrey. "We are looking to a strong second half and have raised our production guidance to 65,000 to 70,000 barrels per day for the year."

Second quarter 2014 non-energy operating costs were $9.64 per barrel, down from $10.00 per barrel in the second quarter of 2013, including costs for planned maintenance. Net operating costs were $14.49 per barrel for the second quarter of 2014 compared to $8.85 per barrel in the second quarter of 2013. This reflects lower non-energy operating costs offset by increased natural gas costs and lower electricity sales revenues from the company's cogeneration facilities. MEG's steam-oil ratio declined to 2.4 in the second quarter of 2014 from 2.5 in the first quarter, reflecting the performance of RISER in Phases 1 and 2 as well as the ramp-up of Phase 2B.

Average bitumen price realizations increased approximately 17% in the second quarter of 2014 compared to the previous quarter and were approximately 35% higher than price realizations in the second quarter of 2013. Continued logistics enhancements, including increased crude-by-rail transportation, pipelines connecting the U.S. mid-continent to the U.S. Gulf Coast and refinery modifications in the U.S. Midwest contributed to improved pricing. The anticipated completion of the Flanagan-Seaway pipeline system in the second half of 2014 is expected to further enhance transportation logistics and pricing.

Operating earnings, which are adjusted for items that are not indicative of operating performance, were $111.1 million ($0.49 per share, diluted) in the second quarter of 2014 compared to $13.6 million ($0.06 per share, diluted) in the same period of 2013, reflecting the same factors that impacted cash flow from operations.

Net income was $249.0 million ($1.11 per share, diluted) in the second quarter of 2014, compared to a net loss of $62.3 million ($0.28 per share, diluted) in the second quarter of 2013.

Forward-Looking Information and Non-IFRS Financial Measures

This quarterly report contains forward-looking information and financial measures that are not defined by IFRS and should be read in conjunction with the "Forward-Looking Information" and Non-IFRS Financial Measures" sections 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, 2014 is dated July 29, 2014. This MD&A should be read in conjunction with the Corporation's MD&A for the year ended December 31, 2013, the Corporation's audited consolidated financial statements and notes thereto for the year ended December 31, 2013 and the unaudited condensed consolidated interim financial statements and notes thereto for the period ended June 30, 2014. 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, 2013, with a preparation date of January 16, 2014, GLJ Petroleum Consultants Ltd. estimated that the oil sands leases it had evaluated contained 2.9 billion barrels of proved plus probable bitumen reserves and 3.7 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 each phase, the performance of each phase and the development schedule. 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.

MEG is currently focused on the phased development of the Christina Lake Project. MEG's first two production phases at the Christina Lake Project, Phases 1 and 2, commenced production in 2008 and 2009, respectively, with a combined design capacity of 25,000 bbls/d. Phase 2B, an expansion with a design capacity of 35,000 bbls/d, commenced production in the fourth quarter of 2013 and attained its full design capacity during the second quarter of 2014. In 2012, the Corporation announced the RISER initiative for Phases 1 and 2, which was designed to achieve increased production from existing Phase 1 and 2 assets, with relatively low capital and operating costs. The RISER initiative uses a combination of proprietary reservoir technologies, redeployment of steam, and facilities modifications including plant debottlenecking and expansions. As a result of the operational success achieved from the application of the RISER initiative on Phases 1 and 2, and the successful ramp-up of Phase 2B, MEG anticipates reaching a near-term production target from Christina Lake Phases 1, 2 and 2B of 80,000 bbls/d by 2015.

MEG's next phase of production growth will be primarily driven by the application of RISER on Phase 2B. RISER 2B includes the application of a combination of proprietary reservoir technologies, redeployment of steam and a major brownfield expansion of the existing Phase 2B facilities. Utilizing the results of recent production testing of the Phase 2B facility, MEG is in the early stages of designing a series of brownfield expansions of Phase 2B. Given the attractiveness of this strategy, MEG has prioritized RISER 2B ahead of its next greenfield expansion.

MEG has also filed regulatory applications for the Surmont Project. The Surmont Project, which is situated along the same geological trend as Christina Lake, has an anticipated design 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 benefit from the use of a standardized plant design which will include the use of 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 operations. 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. The Access Pipeline currently has a gross capacity of approximately 260,000 bbls/d of blended bitumen, and approximately 140,000 bbls/d of condensate. MEG is currently undertaking the expansion of the Access Pipeline, which includes the construction of a 42-inch blend line from Christina Lake to Sturgeon to accommodate anticipated increases in production, as well as provide expansion capacity for future production volumes that are expected to be produced from the Christina Lake Project, from the Surmont Project and from MEG's Growth Properties. The initial capacity of the expanded 42-inch blend line will be approximately 400,000 bbls/d of blended bitumen. Additional capacity can be added in future years to accommodate further growth. The current expansion is expected to be completed in the third quarter of 2014.

In addition to the Access Pipeline, MEG owns 100% of 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 connected to the Access Pipeline and is also connected by pipeline to a third party rail-loading terminal. 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:

	Three months ended June 30		**Six months ended June 30**	
	2014	**2013**	**2014**	**2013**
Bitumen production - bbls/d	68,984	32,144	63,842	32,337
Bitumen sales - bbls/d	70,849	32,175	64,504	32,284
Steam to oil ratio (SOR)	2.4	2.3	2.4	2.4
West Texas Intermediate (WTI) US$/bbl	102.99	94.22	100.84	94.30
West Texas Intermediate (WTI) C$/bbl	112.31	96.42	110.62	95.82
Differential - WTI vs AWB - %	24.1%	27.1%	26.3%	34.7%
Bitumen realization - $/bbl	72.75	53.98	68.06	42.04
Net operating costs(1) - $/bbl	14.49	8.85	14.11	9.65
Non-energy operating costs - $/bbl	9.64	10.00	9.38	9.41
Cash operating netback(2) - $/bbl	51.45	41.93	47.89	29.94
Total cash capital investment(3) - $000	320,826	653,827	663,829	1,322,759
Net income (loss)(4) - $000	248,954	(62,312)	145,513	(133,606)
Per share, diluted	1.11	(0.28)	0.65	(0.60)
Operating earnings (loss)(5) - $000	111,139	13,612	151,798	(23,100)
Per share, diluted(5)	0.49	0.06	0.68	(0.10)
Cash flow from operations(5) - $000	261,713	79,184	418,700	86,255
Per share, diluted(5)	1.16	0.35	1.86	0.39
Cash, cash equivalents and short-term investments - $000	839,870	1,203,457	839,870	1,203,457
Long-term debt - $000	4,016,257	2,923,382	4,016,257	2,923,382

(1) *Net operating costs include energy and non-energy operating costs, reduced by power sales. Please refer to Cash Operating Netbacks discussed further under the heading "RESULTS OF OPERATIONS".*

(2) *Cash operating netbacks are calculated by deducting the related diluent, transportation, field operating costs and royalties from proprietary sales volumes and power revenues, on a per barrel basis. Please refer to note 3 of the Cash Operating Netbacks table within "RESULTS OF OPERATIONS".*

(3) *Includes capitalized interest of $22.1 million and $41.6 million for the three and six months ended June 30, 2014, respectively ($18.2 million and $31.8 million respectively, for the three and six months ended June 30, 2013).*

(4) *Includes a foreign exchange gain of $144.1 million on conversion of the U.S. dollar denominated debt for the three months ended June 30, 2014. Includes a foreign exchange loss of $15.4 million on conversion of the U.S. dollar denominated debt for the six months ended June 30, 2014. Includes foreign exchange losses on conversion of U.S. dollar denominated debt of $100.9 million and $150.1 million, respectively, for the three and six months ended June 30, 2013.*

(5) *Operating earnings, cash flow from operations and the related per share amounts do not have standardized meanings prescribed by IFRS and therefore may not be comparable to similar measures used by other companies. The Corporation uses these non-IFRS measurements for its own performance measures and to provide its shareholders with a measurement*

of the Corporation's ability to internally fund future capital investments. These non-IFRS measurements are reconciled to net income (loss) and net cash provided by (used in) operating activities in accordance with IFRS under the heading "NON-IFRS MEASUREMENTS" and discussed further in the "ADVISORY" section.

Bitumen production for the three months ended June 30, 2014 averaged 68,984 bbls/d compared to 58,643 bbls/d for the three months ended March 31, 2014 and 32,144 bbls/d for the three months ended June 30, 2013. Bitumen production for the six months ended June 30, 2014 averaged 63,842 bbls/d compared to 32,337 bbls/d for the six months ended June 30, 2013. The increase in production volumes in the second quarter of 2014 compared to the first quarter of 2014 is due to the ramp-up of Phase 2B. During the second quarter of 2014, the Phase 1 and 2 facilities were down for approximately three weeks for scheduled plant maintenance. The increase in production volumes in the second quarter of 2014 compared to the same period in 2013 is due to the start-up of Phase 2B and the implementation of RISER on Christina Lake Phases 1 and 2. The implementation of the RISER initiative within Phases 1 and 2 has expanded the steam generation capacity and improved reservoir efficiency, thereby enabling the Corporation to place additional wells into production. The Corporation achieved first production from Phase 2B in the fourth quarter of 2013. As a result of the successful ramp-up of Phase 2B, in combination with the success achieved from applying RISER to Phases 1 and 2, MEG anticipates reaching a near-term production target from Christina Lake Phases 1, 2 and 2B of 80,000 bbls/d by 2015.

Bitumen sales for the three months ended June 30, 2014 were 70,849 bbls/d compared to production of 68,984 bbls/d for the same period. The Corporation sold additional volumes that it had placed into inventory at the Stonefell Terminal during the fourth quarter of 2013 and the first quarter of 2014. The Stonefell Terminal provides MEG with the ability to store blend during periods of market disruption or constraint and then deliver these volumes when market conditions improve.

The Corporation’s average steam to oil ratio (“SOR”) was 2.4 for the three months ended June 30, 2014 compared to an SOR of 2.3 for the three months ended June 30, 2013. The SOR averaged 2.4 during the six months ended June 30, 2014 and June 30, 2013. The average SOR in the first half of 2014 has decreased from an SOR of 2.9 for the fourth quarter of 2013, as more Phase 2B well pairs have been converted from steam circulation to production. The Corporation continues to focus on increasing production and improving 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.

For the three months ended June 30, 2014, average bitumen realizations increased compared to the three months ended June 30, 2013 primarily due to higher crude oil benchmark prices arising from improved market access and increased market demand. In addition, MEG continued to implement its marketing strategy to broaden its access to downstream markets. As a result of these factors, the differential between the Corporation’s blend sales price and the relevant crude oil benchmark sales price decreased. The differential between the Corporation’s blend sales price and the C$/bbl West Texas Intermediate (“WTI”) price improved to an average of 24.1% during the three months ended June 30, 2014 compared to a differential of 27.1% during the three months ended June 30, 2013. The C$/bbl WTI price averaged $112.31 per barrel during the second quarter of 2014 compared to an average price of $96.42 per barrel during the second quarter of 2013.

The C$/bbl WTI price averaged $110.62 per barrel during the first six months of 2014 compared to $95.82 per barrel during the first six months of 2013. The differential between the Corporation’s blend sales price and WTI improved to an average of 26.3% during the first half of 2014 compared to an average differential of 34.7% during the first half of 2013.

Net operating costs averaged $14.49 per barrel for the three months ended June 30, 2014 compared to $8.85 per barrel for the three months ended June 30, 2013. The increase in net operating costs on a per barrel basis is primarily attributable to the increase in energy operating costs and the decrease in the average power sales price.

- Energy operating costs increased to $6.45 per barrel for the three months ended June 30, 2014 compared to $4.85 per barrel for the three months ended June 30, 2013. Energy costs increased as a result of the increase in natural gas prices, which increased to an average of $5.25 per thousand cubic feet ("mcf") in the second quarter of 2014, compared to $3.82 per mcf in the second quarter of 2013.
- Non-energy operating costs decreased to $9.64 per barrel for the three months ended June 30, 2014 compared to $10.00 per barrel for the three months ended June 30, 2013. Non-energy operating costs include $12.5 million, or $1.94 per barrel, for the approximately three-week turnaround in the second quarter of 2014 compared to $1.8 million, or $0.61 per barrel, for the minor turnaround carried out in the second quarter of 2013.
- Power sales decreased to $1.60 per barrel for the three months ended June 30, 2014 compared to $6.00 per barrel for the three months ended June 30, 2013. The Corporation's realized power price during the three months ended June 30, 2014 averaged $40.98 per megawatt hour compared to $138.96 per megawatt hour for the same period in 2013. The decrease in the power price is mainly a result of increased power generation capacity in the province. Power sales had the effect of offsetting 25% of energy operating costs during the three months ended June 30, 2014 compared to 124% of energy operating costs during the three months ended June 30, 2013.

Net operating costs for the six months ended June 30, 2014 averaged $14.11 per barrel compared to $9.65 per barrel for the six months ended June 30, 2013. The increase in net operating costs on a per barrel basis is attributable to an increase in energy operating costs and a decrease in the average power sales price.

- Energy operating costs increased to $7.34 per barrel for the six months ended June 30, 2014 compared to $4.89 per barrel for the six months ended June 30, 2013. Energy costs increased as a result of the increase in natural gas prices, which increased to an average of $5.65 per mcf for the six months ended June 30, 2014 compared to $3.63 per mcf for the six months ended June 30, 2013.
- Non-energy operating costs decreased to $9.38 per barrel for the six months ended June 30, 2014 compared to $9.41 per barrel for the six months ended June 30, 2013. Non-energy operating costs include $1.07 per barrel, for the turnaround in the second quarter of 2014 compared to $0.31 per barrel, for the minor turnaround carried out in the second quarter of 2013.
- Power sales decreased to $2.61 per barrel for the six months ended June 30, 2014 compared to $4.65 per barrel for the six months ended June 30, 2013. The Corporation's realized power price during the six months ended June 30, 2014 decreased to $52.95 per megawatt hour compared to $94.74 per megawatt hour for the same period in 2013. The decrease in the power price is mainly a result of increased power generation capacity in the province. The first half of 2013 was affected by significant supply disruptions. Power sales had the effect of offsetting 36% of energy operating costs during the six months ended June 30, 2014 compared to 95% of energy operating costs during the six months ended June 30, 2013.

Cash operating netback for the three months ended June 30, 2014 was $51.45 per barrel compared to $41.93 per barrel for the three months ended June 30, 2013. Cash operating netback for the first half of

2014 was $47.89 per barrel compared to $29.94 per barrel for the first half of 2013. The increase in cash operating netback is due primarily to the increase in bitumen realizations, partially offset by the increase in net operating costs, for the periods ended June 30, 2014 as compared to the same periods in 2013.

Capital investment for the second quarter of 2014 totalled $320.8 million (including $22.1 million of capitalized interest) compared to a total of $653.8 million (including $18.2 million of capitalized interest) for the second quarter of 2013. Capital investment for the six months ended June 30, 2014 totalled $663.8 million (including $41.6 million of capitalized interest) compared to a total of $1.3 billion (including $31.8 million of capitalized interest) for the six months ended June 30, 2013. Capital investment during the first half of 2014 has been focused on the initial investment in RISER 2B, engineering and procurement of long-lead items for future expansions at Christina Lake, the expansion of the Access Pipeline, and delineation drilling at Christina Lake, Surmont and the Growth Properties.

The Corporation recognized net income of $249.0 million for the three months ended June 30, 2014 compared to a net loss of $62.3 million for the three months ended June 30, 2013. Net income for the second quarter was positively impacted by the increase in blend sales volumes and an increase in bitumen realizations as compared to the second quarter of 2013. Net income for the three months ended June 30, 2014 also included a $144.1 million gain on conversion of the Corporation’s U.S. dollar denominated debt, while the net loss for the three months ended June 30, 2013 included a $100.9 million loss on conversion of the U.S. dollar denominated debt.

The Corporation recognized net income of $145.5 million for the six months ended June 30, 2014 compared to a net loss of $133.6 million for the six months ended June 30, 2013. The significant increase in net income for the first half of 2014 was positively impacted by the increase in bitumen realizations and higher production and blend sales volumes compared to the first half of 2013. Net income for the six months ended June 30, 2014 included a loss of $15.4 million on conversion of the Corporation’s U.S. dollar denominated debt. The net loss for the six months ended June 30, 2013 included a foreign exchange loss of $150.1 million on conversion of U.S. dollar denominated debt.

Operating earnings for the three months ended June 30, 2014 were $111.1 million compared to $13.6 million for the three months ended June 30, 2013. The significant increase in operating earnings is primarily due to the 121% increase in blend sales volumes and a 35% increase in bitumen realization per barrel.

The Corporation recognized operating earnings of $151.8 million for the six months ended June 30, 2014 compared to an operating loss of $23.1 million for the six months ended June 30, 2013. Operating earnings have increased for the first half of 2014 as blend sales volumes have nearly doubled, and bitumen realizations per barrel have increased by 62%, compared to the first half of 2013.

Cash flow from operations increased to $261.7 million for the three months ended June 30, 2014 from $79.2 million for the three months ended June 30, 2013. Cash flow from operations increased to $418.7 million for the six months ended June 30, 2014 from $86.3 million for the six months ended June 30, 2013. Cash flow from operations increased primarily due to higher blend sales volumes and increased cash operating netbacks.

The Corporation's cash and cash equivalents balance totalled $0.8 billion as at June 30, 2014 compared to a cash, cash equivalents and short-term investments balance of $1.2 billion as at June 30, 2013. The Corporation's cash, cash equivalents and short-term investments balances have been impacted by the increases in long-term debt during 2013 and capital investments over the past year. Long-term debt increased to $4.0 billion as at June 30, 2014 from $2.9 billion as at June 30, 2013. The increase in long-term debt is due to the issuance of US$1.0 billion of senior unsecured notes in the fourth quarter of 2013.

As at June 30, 2014, the Corporation's capital resources included $0.8 billion of cash and cash equivalents and an undrawn US$2.0 billion revolving credit facility. As at June 30, 2014, US$109.6 million of the revolving credit facility was utilized to support letters of credit.

3. OUTLOOK

Primarily as a result of the operational success achieved to date on Phase 2B and the ongoing success of RISER, MEG's targeted 2014 annual bitumen production volume has been increased to 65,000 – 70,000 bbls/d from MEG's previous guidance of 60,000 to 65,000 bbls/d. Annual non-energy operating costs are still anticipated to be in the range of $8 to $10 per barrel.

The Corporation's remaining 2014 capital budget totals approximately $1.2 billion, including $200 million in discretionary capital that is subject to the timing of current and future projects.

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		2014		2013			
	2014	2013	Q2	Q1	Q4	Q3	Q2	Q1
Average Commodity Prices								
Crude oil prices								
West Texas Intermediate (WTI) US$/bbl	100.84	94.30	102.99	98.68	97.43	105.83	94.22	94.37
West Texas Intermediate (WTI) C$/bbl	110.62	95.82	112.31	108.89	102.08	109.90	96.42	95.21
Western Canadian Select (WCS) C$/bbl	86.93	69.91	90.44	83.41	68.31	91.75	76.82	63.01
Differential – WTI vs WCS (C$/bbl)	23.69	25.90	21.87	25.48	33.77	18.15	19.60	32.20
Differential – WTI vs WCS (%)	21.4%	27.0%	19.5%	23.4%	33.1%	16.5%	20.3%	33.8%
Natural gas prices								
AECO (C$/mcf)	5.19	3.35	4.70	5.69	3.52	2.42	3.51	3.18
Electric power prices								
Alberta power pool (C$/MWh)	51.51	94.34	42.43	60.58	48.60	83.61	123.41	65.26
Foreign exchange rates								
C$ equivalent of 1 US$ - average	1.0970	1.0161	1.0905	1.1035	1.0477	1.0385	1.0233	1.0089
C$ equivalent of 1 US$ - period end	1.0676	1.0512	1.0676	1.1053	1.0636	1.0285	1.0512	1.0156

The price of WTI is the current benchmark for Canadian crude oil, as it reflects mid-continent North American prices and its Canadian dollar equivalent is the basis for determining royalties on the Corporation's bitumen sales. The WTI price averaged US$102.99 per barrel for the three months ended June 30, 2014 compared to US$94.22 per barrel for the three months ended June 30, 2013. The WTI price averaged US$100.84 per barrel for the six months ended June 30, 2014 compared to US$94.30 per barrel for the six months ended June 30, 2013.

Western Canadian Select ("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 to WCS differential averaged 19.5% for the second quarter of 2014 compared to 20.3% for the second quarter of 2013. The WTI to WCS differential averaged 21.4% for the first half of 2014 compared to 27.0% for the first half of 2013.

Pipeline congestion between western Canada and the U.S. coastal markets can negatively impact the price received for WCS, and hence the value that MEG receives for its blend sales. Recent additions of crude-by-rail, new pipeline connections from the U.S. mid-continent to the U.S. Gulf Coast and refinery modifications in the U.S. Midwest are collectively relieving some of this price pressure and, once complete, should help realign Canadian crude oil prices with international benchmarks.

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 $4.70 per mcf for three months ended June 30, 2014 compared to $3.51 per mcf for the three months ended June 30, 2013. The AECO natural gas price averaged $5.19 per mcf for the first half of 2014 compared to $3.35 per mcf for the first half of 2013. Natural gas prices have retreated from the five year high they reached in February 2014, but are still significantly higher than the same period in 2013 as a result of depleted storage levels across North America.

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 $42.43 per megawatt hour during the three months ended June 30, 2014 compared to an average price of $123.41 per megawatt hour for the three months ended June 30, 2013. The Alberta power pool price averaged $51.51 per megawatt hour during the first half of 2014 compared to $94.34 per megawatt hour during the first half of 2013. The decrease in the Alberta Pool price is mainly a result of increased power generation capacity in the province. The first half of 2013 was affected by significant supply disruptions. Incremental power generation in the province is anticipated to continue to moderate power prices.

Changes in the value of the Canadian dollar relative to the U.S. dollar have an impact on the Corporation's bitumen revenues, as 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 bitumen revenues and a negative impact on principal and interest payments, while an increase in the value of the Canadian dollar has a negative impact on bitumen revenues and a positive impact on principal and interest payments. As at June 30, 2014, the Canadian dollar, at a rate of 1.0676, had increased in value by approximately 3% against the U.S. dollar compared to its value as at March 31, 2014, when the rate was 1.1053. The value of the Canadian dollar as at June 30, 2014 had decreased slightly from its value as at December 31, 2013, when the rate was 1.0636.

5. RESULTS OF OPERATIONS

	Three months ended June 30		Six months ended June 30	
	2014	2013	2014	2013
Bitumen production – bbls/d	68,984	32,144	63,842	32,337
Bitumen sales – bbls/d	70,849	32,175	64,504	32,284
Steam to oil ratio (SOR)	2.4	2.3	2.4	2.4

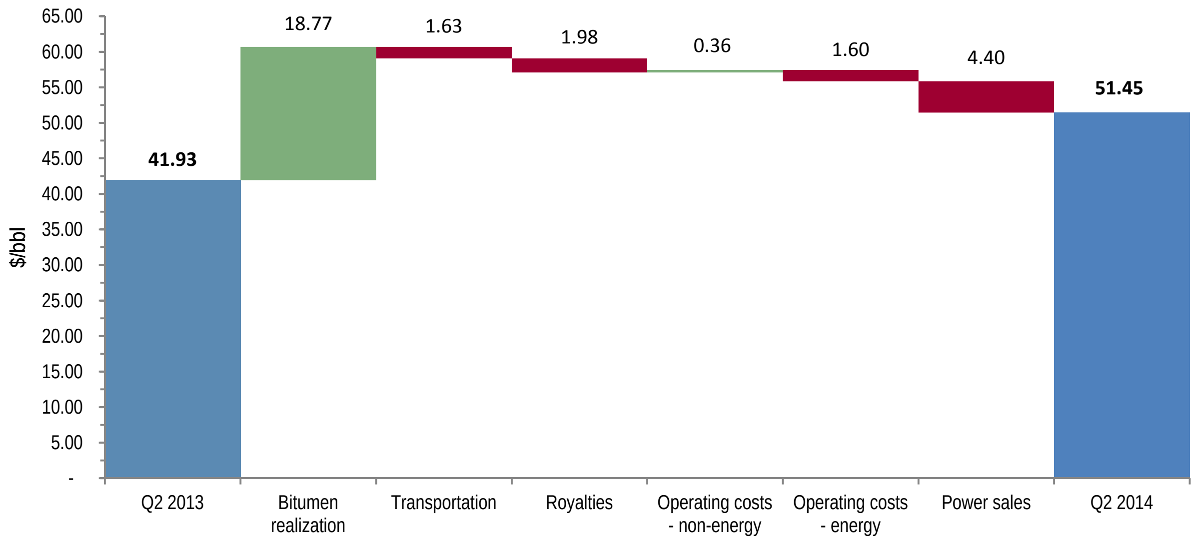
Production

Production for the three months ended June 30, 2014 averaged 68,984 bbls/d compared to 32,144 bbls/d for the three months ended June 30, 2013. Production for the first six months of 2014 averaged 63,842 bbls/d compared to 32,337 bbls/d for the first six months of 2013. The increase in production volumes in 2014 compared to 2013 is due to the start-up of Phase 2B and the implementation of RISER on Christina Lake Phases 1 and 2. The implementation of the RISER initiative within Phases 1 and 2 has expanded the steam generation capacity and improved reservoir efficiency, thereby enabling the Corporation to place additional wells into production. The Corporation achieved first production from Phase 2B in the fourth quarter of 2013 and as a result of the successful ramp-up of Phase 2B, along with the success achieved from applying RISER to Phases 1 and 2, MEG anticipates reaching a near-term production target from Christina Lake Phases 1, 2 and 2B of 80,000 bbls/d by 2015.

Bitumen sales for the three months ended June 30, 2014 were 70,849 bbls/d compared to production of 68,984 bbls/d for the same period. During the second quarter of 2014, the Corporation sold additional volumes that it had placed into inventory at the Stonefell Terminal during the fourth quarter of 2013 and the first quarter of 2014. The Stonefell Terminal provides MEG with the ability to store blend during periods of market disruption or constraint and then deliver these volumes when market conditions improve.

The Corporation’s average SOR was 2.4 for the three months ended June 30, 2014 compared to an SOR of 2.3 for the three months ended June 30, 2013. The SOR averaged 2.4 during the six months ended June 30, 2014 and June 30, 2013. As expected, the average SOR in 2014 has decreased from an SOR of 2.9 for the fourth quarter of 2013, as more Phase 2B well pairs have now been converted to production mode. The Corporation continues to focus on increasing production and improving 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.

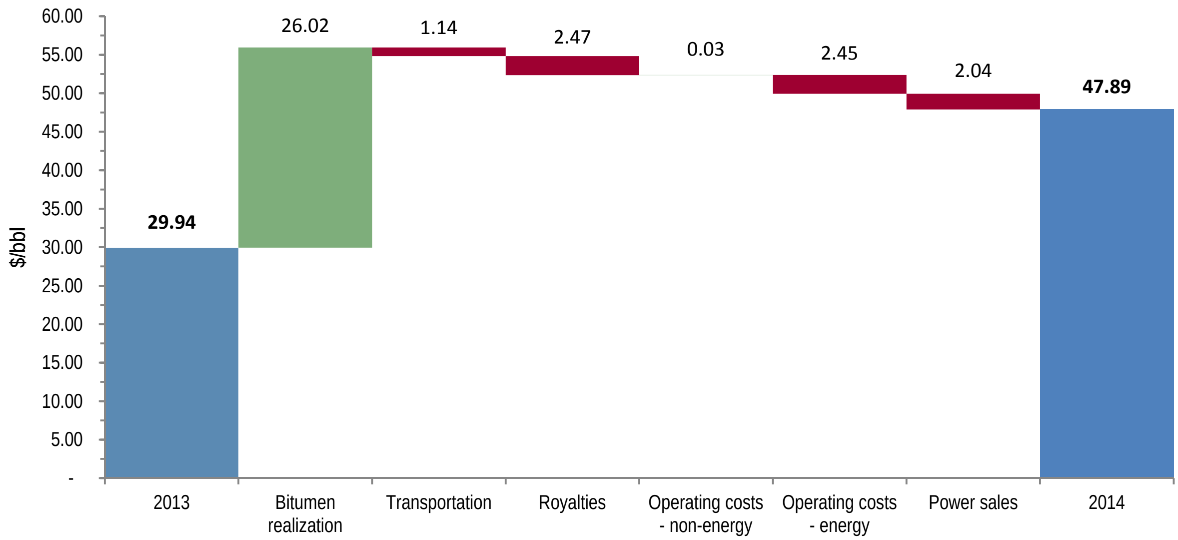
Cash Operating Netback – Three months ended June 30, 2014 versus June 30, 2013:



The following table summarizes the Corporation's cash operating netback for the three months ended June 30:

	2014		2013	
	$000	**$ per bbl**	**$000**	**$ per bbl**
Bitumen realization[(1)]	469,007	72.75	158,039	53.98
Transportation[(2)]	(11,602)	(1.80)	(499)	(0.17)
Royalties	(32,323)	(5.01)	(8,867)	(3.03)
Net bitumen revenue	**425,082**	**65.94**	**148,673**	**50.78**
Operating costs – non-energy	(62,151)	(9.64)	(29,287)	(10.00)
Operating costs – energy	(41,561)	(6.45)	(14,207)	(4.85)
Power sales	10,312	1.60	17,555	6.00
Net operating costs	**(93,400)**	**(14.49)**	**(25,939)**	**(8.85)**
Cash operating netback[(3)]	**331,682**	**51.45**	**122,734**	**41.93**

Cash Operating Netback – Six months ended June 30, 2014 versus June 30, 2013:



The following table summarizes the Corporation's cash operating netback for the six months ended June 30:

	2014		2013	
	$000	**$ per bbl**	**$000**	**$ per bbl**
Bitumen realization(1)	794,627	68.06	245,628	42.04
Transportation(2)	(15,114)	(1.29)	(859)	(0.15)
Royalties	(55,706)	(4.77)	(13,469)	(2.30)
Net bitumen revenue	**723,807**	**62.00**	**231,300**	**39.59**
Operating costs – non-energy	(109,463)	(9.38)	(54,969)	(9.41)
Operating costs – energy	(85,639)	(7.34)	(28,566)	(4.89)
Power sales	30,443	2.61	27,171	4.65
Net operating costs	**(164,659)**	**(14.11)**	**(56,364)**	**(9.65)**
Cash operating netback(3)	**559,148**	**47.89**	**174,936**	**29.94**

(1) *Net of diluent costs. For further details, refer to the "Bitumen Realization" section.*

(2) *Net of third party recoveries on diluent transportation arrangements. For further details, refer to the "Transportation" section.*

(3) *Cash operating netbacks are calculated by deducting the related diluent, transportation, field operating costs and royalties from proprietary sales volumes and power revenues. Netbacks on a per-unit basis are calculated by dividing related production revenue, costs and royalties by bitumen sales volumes. Netbacks do not have a standardized meaning prescribed by IFRS and therefore may not be comparable to similar measures used by other companies. This non-IFRS measurement is widely used in the oil and gas industry as a supplemental measure of the Corporation's efficiency and its ability to fund future growth through capital expenditures. "Cash operating netback is reconciled to "Net income (loss)", the nearest IFRS measure, under the heading "NON-IFRS MEASUREMENTS".*

Bitumen Realization

Bitumen produced at the Christina Lake Project is mixed with purchased diluent and marketed as a heavy crude oil blend known as Access Western Blend ("AWB" or "blend"). Bitumen realization as discussed in this document represents the Corporation's realized proprietary blend sales revenues, net of the cost of diluent.

	Three months ended June 30		Six months ended June 30	
($000)	**2014**	**2013**	**2014**	**2013**
Blend sales – proprietary	795,072	296,300	1,396,900	538,100
Cost of diluent	(326,065)	(138,261)	(602,273)	(292,472)
Bitumen realization	469,007	158,039	794,627	245,628

Blend sales for the three months ended June 30, 2014 were $795.1 million compared to $296.3 million for the three months ended June 30, 2013. The increase in blend sales in the second quarter of 2014 compared to the second quarter of 2013 is due to a 121% increase in sales volumes combined with a 21% increase in the average realized blend price. Sales volumes have increased as a result of the increase in production volumes due to the start-up of Phase 2B and the implementation of RISER on Christina Lake Phases 1 and 2. Blend sales averaged $85.27 per barrel during the three months ended June 30, 2014 compared to $70.25 per barrel for the three months ended June 30, 2013.

Blend sales for the six months ended June 30, 2014 were $1.4 billion compared to $0.5 billion for the six months ended June 30, 2013. The increase in blend sales in the first half of 2014 compared to the first half of 2013 is due to a 99% increase in sales volumes combined with a 30% increase in the average realized blend price. Blend sales averaged $81.48 per barrel for the six months ended June 30, 2014 compared to $62.61 per barrel for the six months ended June 30, 2013.

The cost of diluent for the three months ended June 30, 2014 was $326.1 million compared to $138.3 million for the three months ended June 30, 2013. The total cost of diluent increased primarily due to the higher volumes of diluent purchased as a result of increased blend sales volumes. The Corporation’s average cost of diluent was $113.33 per barrel during the three months ended June 30, 2014 compared to $107.17 per barrel during the three months ended June 30, 2013.

The cost of diluent for the six months ended June 30, 2014 was $602.3 million compared to $292.5 million for the six months ended June 30, 2013. The total cost of diluent increased primarily due to the higher volumes of diluent purchased as a result of increased blend sales volumes. The Corporation’s average cost of diluent was $110.13 per barrel during the six months ended June 30, 2014 compared to $106.29 per barrel during the six months ended June 30, 2013.

Transportation

Transportation costs include rail, barging and the Stonefell Terminal costs, as well as MEG’s share of the operating costs for the Access Pipeline, net of third party recoveries. Transportation costs resulted in an expense of $11.6 million for the three months ended June 30, 2014 compared to $0.5 million for the three months ended June 30, 2013. The Corporation recognized third party recoveries of $7.7 million during the three months ended June 30, 2014 compared to $5.8 million during the same period in 2013. On a per barrel basis, transportation costs averaged $1.80 per barrel for the three months ended June 30, 2014 compared to $0.17 per barrel for the three months ended June 30, 2013. The increase in transportation costs is primarily due to the costs associated with the Corporation’s use of unit-train rail shipments in 2014.

Transportation costs totalled $15.1 million, net of $17.1 million in third party recoveries, for the six months ended June 30, 2014 compared to $0.9 million, net of $11.1 million in third party recoveries, for the six months ended June 30, 2013. Transportation costs averaged $1.29 per barrel for the first half of

2014 compared to $0.15 per barrel for the first half of 2013. The increase in transportation costs is primarily due to the costs associated with the Corporation's use of unit-train rail shipments in 2014.

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 totalled $32.3 million for the three months ended June 30, 2014 compared to $8.9 million for the three months ended June 30, 2013. The increase in royalties for the three months ended June 30, 2014 compared to the same period in 2013 is attributable to the increase in bitumen realizations, the increase in sales volumes and the increase in the Canadian dollar price of WTI. Royalties averaged $5.01 per barrel during the second quarter of 2014 compared to $3.03 per barrel for the second quarter of 2013. The Corporation's royalty rate, expressed as a percentage of bitumen realizations, averaged 6.9% for the three months ended June 30, 2014 compared to 5.6% for the three months ended June 30, 2013.

Royalties totalled $55.7 million for the six months ended June 30, 2014 compared to $13.5 million for the six months ended June 30, 2013. The increase in royalties for the three months ended June 30, 2014 compared to the same period in 2013 is attributable to the increase in bitumen realizations, the increase in sales volumes and the increase in the Canadian dollar price of WTI. Royalties averaged $4.77 per barrel during the first half of 2014 compared to $2.30 per barrel for the first half of 2013. The Corporation's royalty rate averaged 7.0% for the six months ended June 30, 2014 compared to 5.5% for the same period in 2013.

Operating Costs

Non-energy operating costs were $62.2 million for the three months ended June 30, 2014 compared to $29.3 million for the three months ended June 30, 2013. The increase in non-energy operating costs is primarily attributable to the increased costs associated with Phase 2B production volumes and higher plant turnaround costs on Phases 1 and 2 compared to 2013. Non-energy operating costs include $12.5 million for the approximately three-week turnaround in 2014 compared to $1.8 million for the minor turnaround carried out in 2013. The increase in non-energy operating costs was more than offset on a per barrel basis by higher sales volumes. Non-energy operating costs averaged $9.64 per barrel for the three months ended June 30, 2014 compared to $10.00 per barrel for the three months ended June 30, 2013.

Non-energy operating costs totalled $109.5 million for the first half of 2014 compared to $55.0 million for the first half of 2013. The increase in non-energy operating costs is primarily attributable to the increased costs associated with Phase 2B production volumes and higher turnaround costs in 2014. Non-energy operating costs include $12.5 million, or $1.07 per barrel, for the approximately three-week turnaround in the second quarter of 2014 compared to $1.8 million, or $0.31 per barrel, for the minor turnaround carried out in the second quarter of 2013. The increase in non-energy operating costs was offset on a per barrel basis by higher sales volumes. Non-energy operating costs averaged $9.38 per barrel for the six months ended June 30, 2014 compared to $9.41 per barrel for the six months ended June 30, 2013.

Energy related operating costs were $41.6 million for the three months ended June 30, 2014 compared to $14.2 million for the three months ended June 30, 2013. The increase in energy operating costs for the second quarter of 2014 compared to the second quarter of 2013 is attributable to the start-up of Phase 2B and the increase in natural gas prices. On a per barrel basis, energy related operating costs averaged $6.45 per barrel for the three months ended June 30, 2014 compared to $4.85 per barrel for the same period in 2013. The Corporation’s natural gas purchase price averaged $5.25 per mcf during the second quarter of 2014 compared to $3.82 per mcf for the second quarter of 2013.

Energy related operating costs were $85.6 million for the six months ended June 30, 2014 compared to $28.6 million for the six months ended June 30, 2013. The increase in energy operating costs for the first half of 2014 compared to the first half of 2013 is attributable to the start-up of Phase 2B and the increase in natural gas prices. On a per barrel basis, energy related operating costs averaged $7.34 per barrel for the six months ended June 30, 2014 compared to $4.89 per barrel for the six months ended June 30, 2013. The Corporation’s natural gas purchase price averaged $5.65 per mcf during the first half of 2014 compared to $3.63 per mcf for the first half of 2013.

Power Sales

The Corporation currently operates two 85 megawatt cogeneration facilities which produce steam for its SAGD operations. MEG's Christina Lake facilities utilize the heat produced by the cogeneration facilities and a portion of the power generated. Surplus power is sold into the Alberta power pool.

Power sales were $10.3 million for the three months ended June 30, 2014 compared to $17.6 million for the three months ended June 30, 2013. The additional power generation capacity as a result of the second cogeneration facility becoming operational with the start-up of Phase 2B was more than offset by a decrease in the Corporation’s average realized power price in the second quarter of 2014 compared to the second quarter of 2013. The Corporation’s average realized power price during the three months ended June 30, 2014 was $40.98 per megawatt hour compared to $138.96 per megawatt hour for the same period in 2013.

Power sales were $30.4 million for the six months ended June 30, 2014 compared to $27.2 million for the six months ended June 30, 2013. The increase in power sales is due to the increase in the Corporation’s electrical power generation capacity as a result of the second cogeneration facility becoming operational with the start-up of Christina Lake Phase 2B. The additional power generation capacity was largely offset by a decrease in the Corporation’s average realized power price. The Corporation’s average realized power price during the six months ended June 30, 2014 was $52.95 per megawatt hour compared to $94.74 per megawatt hour for the same period in 2013. Variations in the Corporation's realized power prices during the periods are largely consistent with variations in the Alberta power pool prices during the periods noted.

6. NON-IFRS MEASUREMENTS

The following tables reconcile the non-IFRS measurements "Operating earnings (loss)" and "Cash operating netback" to "Net income (loss)", the nearest IFRS measure, and also reconcile the non-IFRS measurement "Cash flow from operations" to "Net cash provided by (used in) operating activities", the nearest IFRS measure. Operating earnings (loss) is defined as net income (loss) as reported, excluding the after-tax unrealized foreign exchange gains and losses, unrealized gains and losses on derivative financial liabilities, and unrealized fair value gains and losses on other assets. Cash flow from operations excludes the net change in non-cash operating working capital, while the IFRS measurement "Net cash provided by (used in) operating activities" includes these items. Cash operating netback is comprised of proprietary petroleum and power sales less royalties, operating costs, cost of diluent and transportation costs.

	Three months ended June 30		Six months ended June 30	
($000)	**2014**	**2013**	**2014**	**2013**
Net income (loss)	248,954	(62,312)	145,513	(133,606)
Add (deduct):				
Unrealized foreign exchange loss (gain), net of tax[(1)]	(137,372)	87,024	7,948	124,834
Unrealized loss (gain) on derivative financial liabilities, net of tax[(2)]	(443)	(11,100)	(1,663)	(14,328)
Operating earnings (loss)	111,139	13,612	151,798	(23,100)
Add (deduct):				
Interest and other income	(2,058)	(6,225)	(5,318)	(11,496)
Depletion and depreciation	98,618	44,252	179,862	88,667
General and administrative	25,720	24,298	52,095	47,065
Stock-based compensation	10,681	9,563	23,303	16,518
Research and development	880	787	1,871	2,070
Interest expense	42,975	24,783	89,205	49,872
Accretion	1,105	1,186	2,141	2,262
Realized loss (gain) on foreign exchange	(1,531)	1,617	1,112	2,845
Realized loss on derivative financial liabilities	1,367	1,182	2,489	2,283
Net marketing activity	2,045	74	2,100	307
Deferred income tax expense (recovery), operating	40,741	7,605	58,490	(2,357)
Cash operating netback	331,682	122,734	559,148	174,936

(1) Unrealized foreign exchange gains and losses result from the translation of U.S. dollar denominated long-term debt and cash and cash equivalents to period-end exchange rates. Unrealized foreign exchange gains and losses are presented net of a deferred tax recovery of $2,224 and a deferred tax expense of $2,495 for the three and six months ended June 30, 2014 (deferred tax expense of $4,610 and $1,503 for the three and six months ended June 30, 2013).

(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. Unrealized gains and losses on derivative liabilities are presented net of a deferred tax expense of $147 and $554 for the three and six months ended June 30, 2014 (deferred tax expense of $3,700 and $4,776 for the three and six months ended June 30, 2013).

	Three months ended June 30		Six months ended June 30	
($000)	**2014**	**2013**	**2014**	**2013**
Net cash provided by (used in) operating activities	297,204	46,704	336,428	21,712
Add:				
Net change in non-cash operating working capital items	(35,491)	32,480	82,272	64,543
Cash flow from operations	261,713	79,184	418,700	86,255

Depletion and Depreciation

Depletion and depreciation expense was $98.6 million for the three months ended June 30, 2014 compared to $44.3 million for the three months ended June 30, 2013. Depletion and depreciation expense for the six months ended June 30, 2014 totalled $179.9 million compared to $88.7 million for same period in 2013. The increase is primarily due to the 120% increase in bitumen sales volumes for the second quarter of 2014, and a 100% increase for the six months ended June 30, 2014, compared to the same periods in 2013. The depletion and depreciation rate for the three months ended June 30, 2014 was $15.30 per barrel compared to $15.11 per barrel for the three months ended June 30, 2013. Depletion and depreciation expense was $15.41 per barrel for the first six months of 2014 compared to $15.17 per barrel for the first six months of 2013.

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)	**2014**	**2013**	**2014**	**2013**
General and administrative costs	34,429	30,599	69,619	59,246
Capitalized general and administrative costs	(8,709)	(6,301)	(17,524)	(12,181)
General and administrative expense	25,720	24,298	52,095	47,065

General and administrative expense for the three months ended June 30, 2014 was $25.7 million compared to $24.3 million for the three months ended June 30, 2013. General and administrative expense for the six months ended June 30, 2014 was $52.1 million compared to $47.1 million for the six months ended June 30, 2013. The increase in expense is primarily the result of the planned growth in the Corporation's professional staff and office costs to support the operation and development of its oil sands assets.

Stock-based Compensation

	Three months ended June 30		Six months ended June 30	
($000)	**2014**	**2013**	**2014**	**2013**
Stock-based compensation costs	13,913	11,760	29,551	20,374
Capitalized stock-based compensation costs	(3,232)	(2,197)	(6,248)	(3,856)
Stock-based compensation expense	10,681	9,563	23,303	16,518

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 in its consolidated financial statements. Fair value is determined using the Black-Scholes option pricing model. Stock-based compensation expense was $10.7 million for the three months ended June 30, 2014 compared to $9.6 million for the three months ended June 30, 2013. Stock based compensation expense for the first six months of 2014 totalled $23.3 million compared to $16.5 million for the first six months of 2013. The increase in stock-based compensation is due to the increased number of share-based awards granted and as a result of the growth in the Corporation's professional staff.

The Corporation capitalizes a portion of stock-based compensation expense associated with capitalized salaries and benefits. The Corporation capitalized $3.2 million of stock-based compensation for the three months ended June 30, 2014 compared to $2.2 million during the three months ended June 30, 2013. The Corporation capitalized $6.2 million of stock-based compensation for the six months ended June 30, 2014 compared to $3.9 million for the six months ended June 30, 2013.

Research and Development

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 $0.9 million for the three months ended June 30, 2014 compared to $0.8 million for the three months ended June 30, 2013. Research and development expenditures were $1.9 million for the six months ended June 30, 2014 compared to $2.1 million for the six months ended June 30, 2013.

Net Finance Expense

	Three months ended June 30		**Six months ended June 30**	
($000)	**2014**	**2013**	**2014**	**2013**
Total interest expense	65,074	42,994	130,774	81,717
Less capitalized interest	(22,099)	(18,211)	(41,569)	(31,845)
Net interest expense	42,975	24,783	89,205	49,872
Accretion on decommissioning provision	1,105	1,186	2,141	2,262
Unrealized fair value loss (gain) on embedded derivative financial liabilities	(1,136)	(9,828)	(2,246)	(12,903)
Unrealized fair value loss (gain) on interest rate swaps	546	(4,973)	29	(6,202)
Realized loss on interest rate swaps	1,367	1,182	2,489	2,283
Net finance expense	44,857	12,350	91,618	35,312
Average effective interest rate	6.2%	5.9%	6.2%	5.9%

Total interest expense, before capitalization, was $65.1 million for the three months ended June 30, 2014 compared to $43.0 million for the three months ended June 30, 2013. Total interest expense for the six months ended June 30, 2014 was $130.8 million compared to $81.7 million for the six months ended June 30, 2013. Total interest expense increased primarily as a result of the increased debt outstanding in 2014. In the first quarter of 2013, the senior secured term loan was increased by US$300.0 million to approximately US$1.3 billion and in the fourth quarter of 2013 the Corporation issued US$1.0 billion in aggregate principal amount of 7.0% senior unsecured notes.

The Corporation recognized an unrealized gain on embedded derivative financial liabilities of $1.1 million for the three months ended June 30, 2014 compared to an unrealized gain of $9.8 million for the three months ended June 30, 2013. The Corporation recognized an unrealized gain on embedded derivative financial liabilities of $2.2 million for the six months ended June 30, 2014 compared to an unrealized gain of $12.9 million for the six months ended June 30, 2013. 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 and gains and losses associated with changes in the fair value of the embedded derivative are 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$1.3 billion senior secured term loan until September 30, 2016. The Corporation realized a loss of $1.4 million for the three months ended June 30, 2014, and a loss of $2.5 million for the six months ended June 30, 2014, on the interest rate swap contracts. This compared to a loss of $1.2 million for the three months ended June 30, 2013 and a loss of $2.3 million for the six months ended June 30, 2013. In addition, the Corporation recognized an unrealized loss of $0.5 million for the second quarter of 2014 and an unrealized loss of less than $0.1 million for the first half of 2014. This compared to an unrealized gain of $5.0 million for the second quarter of 2013 and an unrealized gain of $6.2 million for the first half of 2013.

Net Foreign Exchange Gain (Loss)

	Three months ended June 30		Six months ended June 30	
($000)	**2014**	**2013**	**2014**	**2013**
Foreign exchange gain (loss) on:				
Long-term debt	144,051	(100,889)	(15,434)	(150,145)
US$ denominated cash and cash equivalents	(8,903)	18,476	9,981	26,815
Other	1,530	(1,618)	(1,113)	(2,846)
Net foreign exchange gain (loss)	136,678	(84,031)	(6,566)	(126,176)

	June 30, 2014	March 31, 2014	December 31, 2013	June 30, 2013	March 31, 2013	December 31, 2012
C$ equivalent of 1 US$	1.0676	1.1053	1.0636	1.0512	1.0156	0.9949

The Corporation recognized a net foreign exchange gain of $136.7 million for the three months ended June 30, 2014 compared to a loss of $84.0 million for the three months ended June 30, 2013. The foreign exchange gain for the second quarter of 2014 is due primarily to the strengthening of the Canadian dollar compared to the U.S. dollar by approximately 3%. In comparison, the Canadian dollar weakened in value by approximately 4% during the second quarter of 2013.

The Corporation recognized a net foreign exchange loss of $6.7 million for the six months ended June 30, 2014 compared to a net loss of $126.2 million for the six months ended June 30, 2013. The decrease in the net foreign exchange loss is due primarily to the change in the value of the Canadian dollar compared to the U.S. dollar. The Canadian dollar weakened in value compared to the U.S. dollar by less than 1% during the first half of 2014 and weakened in value by approximately 6% during the first half of 2013.

Net Marketing Activity

	Three months ended June 30		Six months ended June 30	
($000)	**2014**	**2013**	**2014**	**2013**
Sales of purchased product	48,405	13,621	120,012	19,399
Purchased product and storage	(50,450)	(13,695)	(122,112)	(19,706)
Net marketing activity	(2,045)	(74)	(2,100)	(307)

Net marketing activity includes the Corporation's increased activities to secure pipeline capacity and to pursue opportunities to move product to a wider range of markets through the development of proprietary transportation and storage facilities.

Income Taxes

The Corporation recognized a deferred income tax expense of $38.7 million for the three months ended June 30, 2014 compared to a deferred income tax expense of $15.9 million for the three months ended June 30, 2013. The Corporation recognized a deferred income tax expense of $61.5 million for the six months ended June 30, 2014 compared to a deferred income tax expense of $3.9 million for the six months ended June 30, 2013.

The Corporation's effective income tax rate 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 foreign exchange gains and losses arising on the translation of the U.S. dollar denominated debt. For the three months ended June 30, 2014, the non-taxable gain was $72.0 million compared to a non-taxable loss of $50.4 million for the three months ended June 30, 2013. For the six months ended June 30, 2014, the non-taxable loss was $7.7 million compared to a non-taxable loss of $75.1 million for the six months ended June 30, 2013.

- As at June 30, 2014, the Corporation had not recognized the tax benefit related to $97.5 million in unrealized taxable capital foreign exchange losses.

- Non-taxable stock-based compensation expense for the three months ended June 30, 2014 was $10.7 million compared to $9.6 million for the three months ended June 30, 2013. Non-taxable stock-based compensation expense for the six months ended June 30, 2014 was $23.3 million compared to $16.5 million for the six months ended June 30, 2013.

The Corporation is not currently taxable. As of June 30, 2014, the Corporation had approximately $6.8 billion of available tax pools and had recognized a deferred income tax liability of $155.3 million. In addition, at June 30, 2014, the Corporation had $793.9 million of capital investment in respect of incomplete projects which will increase available tax pools upon completion of the projects.

7. SUMMARY OF QUARTERLY RESULTS

The following table summarizes selected financial information for the Corporation for the preceding eight quarters:

	2014		2013				2012	
($ millions, except per share amounts)	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**
Revenue	829.2	679.6	350.3	401.8	324.4	258.0	297.6	213.7
Net income (loss)	249.0	(103.4)	(148.2)	115.4	(62.3)	(71.3)	(18.7)	47.5
Per share - basic	1.12	(0.46)	(0.67)	0.52	(0.28)	(0.32)	(0.09)	0.24
Per share - diluted	1.11	(0.46)	(0.67)	0.51	(0.28)	(0.32)	(0.09)	0.24

Revenue for the eight most recent quarters has been impacted by the increases in production and fluctuations in blend sales pricing. Revenue for the second quarter of 2014 and 2013 and the third quarter of 2012 had reduced production volumes as a result of scheduled annual maintenance activities at the Christina Lake facilities.

Net income (loss) during the periods noted was impacted by:

- increased blend sales volumes due to the start-up of Christina Lake Phase 2B and implementation of RISER on Phases 1 and 2, which has allowed additional wells to be placed into production;
- fluctuations in natural gas pricing;
- fluctuations in blend sales pricing due to changes in the price of WTI and the differential between WTI and the Corporation's AWB;
- foreign exchange gains and losses attributable to fluctuations in the rate of exchange between the Canadian and U.S. dollar in translating the Corporation's U.S. dollar denominated debt (net of U.S. dollar denominated cash, cash equivalents and short-term investments);
- an increase in depletion and depreciation expense as a result of the increase in bitumen sales volumes and higher estimated future development costs;
- higher general and administrative expense as a result of the planned increase in office staff to support growth;
- an increase in interest expense as a result of the increase in long-term debt; and
- scheduled annual plant maintenance activities performed in June 2014, May 2013 and September 2012.

8. CAPITAL INVESTING

	Three months ended June 30		Six months ended June 30	
($000)	2014	2013	2014	2013
Intraphase growth	77,324	233,204	150,115	336,680
Portfolio growth				
Christina Lake	55,965	62,554	105,460	128,549
Resource development	7,750	32,946	66,928	170,481
Growth infrastructure	21,448	111,399	50,438	236,114
Enhancements and other	20,955	11,391	30,988	39,349
Total portfolio growth	106,118	218,290	253,814	574,493
Marketing initiatives				
Access pipeline	40,892	47,845	114,119	138,656
Other	22,491	44,100	24,609	113,475
Total marketing initiatives	63,383	91,945	138,728	252,131
Sustaining and maintenance	40,877	27,799	57,162	38,311
Other	11,025	64,378	22,442	89,299
Total base capital investment	**298,727**	**635,616**	**622,261**	**1,290,914**
Capitalized interest	22,099	18,211	41,568	31,845
Total cash capital investment	**320,826**	**653,827**	**663,829**	**1,322,759**
Non-cash	11,406	20,749	21,968	33,682
Total capital investment	**332,232**	**674,576**	**685,797**	**1,356,441**

MEG's total capital investment for the three months ended June 30, 2014 was $332.2 million (including capitalized interest of $22.1 million and non-cash items of $11.4 million) in comparison to $674.6 million (including capitalized interest of $18.2 million and non-cash items of $20.7 million) for the three months ended June 30, 2013. Total capital investment for the six months ended June 30, 2014 was $685.8 million (including capitalized interest of $41.6 million and non-cash items of $22.0 million) in comparison to $1.4 billion (including capitalized interest of $31.8 million and non-cash items of $33.7 million) for the six months ended June 30, 2013.

MEG invested $150.1 million during the six months ended June 30, 2014 on intraphase growth, which includes RISER 2B. RISER 2B includes the application of a combination of proprietary reservoir technologies, redeployment of steam and facilities modifications, including a major brownfield expansion of the existing Phase 2B facilities. The RISER 2B investment was directed towards engineering and the procurement of long lead-time items.

During the first half of 2014, the Corporation invested a total of $105.5 million in engineering and the procurement of long lead-time items for future Christina Lake expansions.

Resource development investment of $66.9 million during the first six months of 2014 included the drilling of 80 stratigraphic wells to support horizontal well placement and to further delineate the resource base at Christina Lake. The investment also included the drilling of eight stratigraphic wells and two water source wells at Surmont and four stratigraphic wells on the Growth Properties.

A total of $50.4 million was invested in the Corporation's growth infrastructure during the six months ended June 30, 2014. Growth infrastructure investment was directed towards the construction of a sulphur recovery plant at Christina Lake and the installation of electrical submersible pumps.

A total of $138.7 million was invested during the six months ended June 30, 2014 in the Corporation's marketing initiatives. The majority of the investment in marketing initiatives related to the expansion of the 50%-owned Access Pipeline. The 300-kilometer pipeline is anticipated to be in service in the third quarter of 2014.

The Corporation capitalizes interest associated with qualifying assets. A total of $22.1 million in interest was capitalized during the three months ended June 30, 2014 compared to $18.2 million during the three months ended June 30, 2013. A total of $41.6 million in interest was capitalized during the six months ended June 30, 2014 compared to $31.8 million for the six months ended June 30, 2013.

Non-cash capital investment for the three months ended June 30, 2014 included an $8.2 million increase in the provision for future reclamation and decommissioning of the Corporation's property, plant and equipment and $3.2 million in capitalized stock-based compensation. Non-cash capital investment for the six months ended June 30, 2014 included a $15.7 million provision for future reclamation and decommissioning and $6.2 million in capitalized stock-based compensation.

9. LIQUIDITY AND CAPITAL RESOURCES

($000)	As at June 30, 2014	As at December 31, 2013
Cash and cash equivalents	839,870	1,179,072
Senior secured term loan (June 30, 2014 – US$1.268 billion; December 31, 2013 – US$1.275 billion; due 2020)	1,353,717	1,355,558
US$2.0 billion revolver; due 2018	-	-
6.5% senior unsecured notes (US$750.0 million; due 2021)	800,700	797,700
6.375% senior unsecured notes (US$800.0 million; due 2023)	854,080	850,880
7.0% senior unsecured notes (US$1.0 billion; due 2024)	1,067,600	1,063,600
Total debt(1)	4,076,097	4,067,738
Shareholders’ equity	4,970,144	4,788,430
Total book capitalization(2)	9,046,241	8,856,168
Total debt/book capitalization(2)	45.1%	45.9%

(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-IFRS measurement 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 consolidated financial statements as at June 30, 2014 and December 31, 2013.*

(2) *Non-IFRS measurements and related metrics that use total debt plus shareholders' equity.*

Capital Resources

As at June 30, 2014, the Corporation's available capital resources included $0.8 billion of cash and cash equivalents and an additional undrawn US$2.0 billion syndicated revolving credit facility. As at June 30, 2014, US$109.6 million of the revolving credit facility was utilized to support letters of credit, leaving unutilized borrowing capacity of US$1.9 billion. The revolving credit facility is syndicated with 12 banks and has a renewal date of May 2018.

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 below.

Effective October 1, 2013, the Corporation issued US$800.0 million in aggregate principal amount of 7.0% senior unsecured notes, with a maturity date of March 31, 2024. On November 6, 2013 an additional US$200 million of 7.0% senior unsecured notes were issued under the same indenture. Interest is paid semi-annually, beginning on March 31, 2014. The $13.0 million cost of the transaction has been deferred and is being amortized over the term of the revolving credit facility.

On May 24, 2013, MEG expanded its senior secured revolving credit facility from US$1.0 billion to US$2.0 billion. In addition, the Corporation extended the maturity of the revolving credit facility by one year to May 24, 2018. The transaction was completed through an amendment of MEG's existing credit facility. The $8.7 million cost of the transaction has been deferred and is being amortized over the term of the revolving credit facility.

On February 25, 2013, the Corporation re-priced, increased and extended its US$987.5 million senior secured term loan. The Corporation extended the maturity date to March 31, 2020 and increased its borrowing under the senior secured term loan by US$300.0 million. In addition, the Corporation reduced the interest rate on the term loan by 25 basis points. The amended term loan bears a floating interest rate based on either U.S. Prime or LIBOR, at the Corporation's option, plus a credit spread of 175 or 275 basis points, respectively. The term loan also has an interest rate floor of 200 basis points based on U.S. Prime or 100 basis points based on LIBOR. The term loan is being repaid in quarterly installments of US$3.25 million, with the balance due March 31, 2020. The $6.8 million cost of the transaction has been deferred and is being amortized over the term of the revolving credit facility.

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$1.3 billion senior secured term loan until September 30, 2016.

The Corporation's cash is held in high interest savings accounts with a diversified group of highly-rated financial institutions. The Corporation has also invested in high grade, liquid, short-term instruments such as government, commercial and bank paper as well as term deposits. To date, 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 policy 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 Flows Summary

	Three months ended June 30		Six months ended June 30	
($000)	**2014**	**2013**	**2014**	**2013**
Net cash provided by (used in):				
Operating activities	297,204	46,704	336,428	21,712
Investing activities	(341,848)	(676,835)	(686,734)	(757,161)
Financing activities	3,082	(6,897)	1,123	300,049
Foreign exchange gains (losses) on cash and cash equivalents held in foreign currency	(8,903)	18,476	9,981	26,815
Change in cash and cash equivalents	(50,465)	(618,552)	(339,202)	(408,585)

Cash Flows – Operating Activities

Net cash provided by operating activities totalled $297.2 million for the three months ended June 30, 2014 compared to $46.7 million for the three months ended June 30, 2013. The increase in cash flows from operating activities is primarily due to increased blend sales revenues as a result of the increase in production and increased bitumen realizations.

Net cash provided by operating activities totalled $336.4 million for the six months ended June 30, 2014 compared to $21.7 million for the six months ended June 30, 2013. The increase in cash flows from operating activities is primarily due to increased blend sales revenues as a result of the increase in production and increased bitumen realizations. Net cash provided by operating activities in the first half of 2014 has been reduced to include an $82.3 million increase in non-cash working capital items. Net cash provided by operating activities in the first half of 2013 has been reduced to include a $64.5 million increase in non-cash working capital items.

Cash Flows – Investing Activities

Net cash used in investing activities during the three months ended June 30, 2014 primarily consisted of $320.8 million in cash capital investment (refer to the “CAPITAL INVESTING” section of this MD&A for further details) and a $19.2 million increase in non-cash investing working capital. Net cash used in investing activities during the six months ended June 30, 2014 included $663.8 million in cash capital investment and a $22.2 million increase in non-cash investing working capital.

Net cash used in investing activities during the three months ended June 30, 2013 consisted of $653.8 million in cash capital investment and a $21.2 million increase in non-cash investing working capital. Net cash used in investing activities during the six months ended June 30, 2013 consisted of $1.3 billion in cash capital investment offset by a $0.6 billion decrease in non-cash investing working capital primarily related to the decrease in short-term investments.

Cash Flows – Financing Activities

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 on the senior secured term loan. 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.

Net cash used in financing activities for the three months ended June 30, 2013 consisted of $4.9 million in proceeds from the exercise of stock options offset by $3.4 million in debt principal repayment and $8.4 million in financing costs. Net cash provided by financing activities for the six months ended June 30, 2013 consisted of $301.1 million of net proceeds from the increase in the senior secured term loan and $14.3 million received from the exercise of stock options. These amounts were partially offset by $8.7 million in financing costs and $6.7 million of debt principal repayment.

10. SHARES OUTSTANDING

Common shares	223,672,579
Convertible securities	
Stock options outstanding - exercisable and unexercisable	9,688,402
RSUs and PSUs outstanding	2,655,519

As at July 21, 2014, the Corporation had 223,684,886 common shares, 9,676,437 stock options and 2,650,261 restricted share units and performance share units outstanding.

11. 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)	4,076,097	13,879	27,758	27,758	4,006,702
Interest on long-term debt(1)	1,826,761	231,665	461,899	459,817	673,380
Decommissioning obligation(2)	591,646	4,075	5,401	5,671	576,499
Transportation and storage(3)	3,391,791	110,565	296,501	404,488	2,580,237
Contracts and purchase orders(4)	671,954	409,506	93,595	41,950	126,903
Operating leases(5)	417,119	14,008	35,462	53,606	314,043
	10,975,368	783,698	920,616	993,290	8,277,764

(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, 2014.

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

(3) This represents transportation and storage commitments from 2014 to 2028.

(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.

12. NEW ACCOUNTING POLICIES

The Corporation has adopted the following revised standards effective January 1, 2014. These changes, along with all the corresponding amendments, are made in accordance with the applicable transitional provisions. The adoption of these revisions did not have an impact on the Corporation’s consolidated financial statements.

IAS 32, Financial Instruments: Presentation, has been amended to clarify the requirements for offsetting financial assets and liabilities. The amendments clarify that the right to offset must be available on the current date and cannot be contingent on a future event.

IAS 36, Impairment of Assets, has been amended to require additional disclosures in the event of recognizing an impairment of assets.

Accounting standards issued but not yet applied

IFRS 9, Financial Instruments, is intended to replace IAS 39, Financial Instruments: Recognition and Measurement. IFRS 9 will be published in three phases. The first two phases, which have been published, address classification and measurement requirements for financial assets and liabilities and hedge accounting. The third phase of the project will address impairment of financial instruments.

IFRS 9 uses a single approach to determine whether a financial asset is measured at amortized cost or fair value, replacing the multiple rules in IAS 39. The approach in IFRS 9 is based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. The new standard also requires a single impairment method to be used, replacing the multiple impairment methods in IAS 39. For financial liabilities, although the classification criteria for financial liabilities will not change under IFRS 9, when the fair value option is applied to financial liabilities, the change in fair value resulting from an entity’s own credit risk is recorded in OCI rather than net earnings, unless this creates an accounting mismatch.

IFRS 9 introduces a simplified hedge accounting model, aligning hedge accounting more closely with risk management. In addition, improvements have been made to hedge accounting and risk management disclosure requirements. The Corporation does not currently apply hedge accounting to any of its risk management contracts.

The IASB has decided to defer the mandatory effective date of IFRS 9 and the mandatory effective date will be left open pending the finalization of the impairment requirements. IFRS 9 will still be available for early adoption. The impact of the new standard on the Corporation’s consolidated financial statements will not be known until the project is complete.

13. 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. The following are the critical accounting estimates used in the preparation of the Corporation's consolidated financial statements.

Property, Plant and Equipment

Items of property, plant and equipment, including oil sands property and equipment, are measured at cost less accumulated depletion and depreciation and accumulated impairment losses. Capitalized costs associated with the Corporation's producing oil sands properties, including estimated future development costs, are depleted using the unit of production method based on estimated proved reserves. The Corporation's oil sands facilities are depreciated on a unit of production method based on the facilities' productive capacity over their estimated remaining useful lives. The costs associated with the Corporation's interest in pipeline and storage assets are depreciated on a straight-line basis over the estimated remaining useful life of the assets. The determination of future development costs, proved reserves, productive capacity and remaining useful lives are subject to significant judgments and estimates.

Exploration and Evaluation Assets

Pre-exploration costs incurred before the Corporation obtains the legal right to explore an area are expensed. Exploration and evaluation costs associated with the Corporation's oil sands activities are capitalized. These costs are accumulated in cost centres pending determination of technical feasibility and commercial viability at which point the costs are transferred to property, plant and equipment. The technical feasibility and commercial viability of extracting a mineral resource is considered to be determinable when proved or probable reserves are determined to exist. The determination of proved or probable reserves is dependent on reserve evaluations which are subject to significant judgments and estimates.

Impairments

The carrying amounts of the Corporation's non-financial assets are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, the asset's recoverable amount is estimated. An impairment test is completed each year for intangible assets that are not yet available for use. Exploration and evaluation assets are assessed for impairment when they are reclassified to property, plant and equipment or if facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

For the purpose of impairment testing, assets are grouped into cash-generating units ("CGUs"). The recoverable amount of an asset or a CGU is the greater of its value in use and its fair value less costs to sell. Exploration and evaluation assets are assessed for impairment within the aggregation of all CGUs in that segment.

In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. Value in use is generally computed by reference to the present value of the future cash flows expected to be derived from production of proved and probable reserves. Fair value less costs to sell is defined as the amount obtainable from the sale of an asset or CGU in an arm's length transaction between knowledgeable, willing parties, less the costs of disposal.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized within net income during the period in which they arise. Impairment losses recognized in respect of CGUs are allocated to reduce the carrying amounts of the assets in the CGU on a pro rata basis.

Impairment losses recognized in prior years are assessed at each reporting date for any indication that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimate used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depletion and depreciation, if no impairment loss had been recognized.

Bitumen Reserves

The estimation of reserves involves the exercise of judgment. Forecasts are based on engineering data, estimated future prices, expected future rates of production and the cost and timing of future capital expenditures, all of which are subject to many uncertainties and interpretations. The Corporation expects that over time its reserves estimates will be revised either upward or downward based on updated information such as the results of future drilling, testing and production. Reserves estimates can have a significant impact on net earnings, as they are a key component in the calculation of depletion and depreciation and for determining potential asset impairment. For example, a revision to the proved reserves estimates would result in a higher or lower depletion and depreciation charge to net earnings. Downward revisions to reserves estimates may also result in an impairment of oil sands property, plant and equipment carrying amounts.

Decommissioning Provision

The Corporation recognizes an asset and a liability for any existing decommissioning obligations associated with the retirement of property, plant and equipment and exploration and evaluation assets. The provision is determined by estimating the fair value of the decommissioning obligation at the end of the period. This fair value is determined by estimating expected timing and cash flows that will be required for future dismantlement and site restoration, and then calculating the present value of these future payments using a credit-adjusted rate specific to the liability. Any change in timing or amount of the cash flows subsequent to initial recognition results in a change in the asset and liability, which then impacts the depletion and depreciation on the asset and accretion charged on the liability. Estimating the timing and amount of third party cash flows to settle these obligations is inherently difficult and is based on third party estimates and management's experience.

Deferred Income Taxes

The Corporation recognizes deferred income taxes in respect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred income taxes are measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted at the reporting date. The periods in which timing differences reverse are impacted by future earnings and capital expenditures. Rates are also affected by changes to tax legislation.

Stock-based Compensation

Amounts recorded for stock-based compensation expense are based on the historical volatility of the Corporation's share price and those of similar publicly listed enterprises, which may not be indicative of future volatility. Accordingly, these amounts are subject to measurement uncertainty.

Derivative Financial Instruments

The Corporation may utilize derivative financial instruments to manage its currency and interest rate exposures. These financial instruments are not used for trading or speculative purposes. The fair values of derivative financial instruments are estimated at the end of each reporting period based on expectations of future cash flows associated with the derivative instrument. Estimates of future cash flows are based on forecast interest rates expected to be in effect over the remaining life of the contract. Any subsequent changes in these rates will impact the amounts ultimately recognized in relation to the derivative instruments.

14. TRANSACTIONS WITH RELATED PARTIES

The Corporation did not enter into any related party transactions during the three and six month periods ended June 30, 2014 or June 30, 2013, other than compensation of key management personnel.

15. OFF-BALANCE SHEET ARRANGEMENTS

At June 30, 2014 and December 31, 2013 the Corporation did not have any off balance sheet arrangements.

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, 2013. In addition, MEG is also subject to other risks and uncertainties which are described in the Corporation's Annual Information Form dated March 5, 2014 under the heading "Regulatory Matters" and "Risk Factors".

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, SORs, 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; the anticipated capital requirements, timing for receipt of regulatory approvals, development plans, timing for completion, commissioning and start-up, capacities and performance of the Access Pipeline expansion, the RISER initiative, the Stonefell Terminal, third party barging and rail facilities, the future phases and expansions of the Christina Lake Project, the Surmont Project and potential projects on the Growth Properties; 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 (including the amount, nature and sources of funding thereof), 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 (e.g. operational risks and delays in the development, exploration or production associated with MEG's projects; the securing of adequate supplies and access to markets and transportation infrastructure; the availability of capacity on the electrical 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; and risks and uncertainties associated with securing and maintaining the necessary regulatory approvals and financing to proceed with the continued expansion of the Christina Lake Project and the development of the Corporation's other projects and facilities. 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.

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. For more information regarding forward-looking information see "Notice Regarding Forward Looking Information", "Regulatory Matters" and “Risk Factors” within MEG's Annual Information Form dated March 5, 2014 (the "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 (www.sedar.com) or by contacting MEG's investor relations department.

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-IFRS Financial Measures

This document includes references to financial measures commonly used in the crude oil and natural gas industry, such as net bitumen revenue, operating earnings, cash flow from operations and cash operating netback. These financial measures are not defined by IFRS as issued by the International Accounting Standards Board and therefore are referred to as non-IFRS measures. The non-IFRS measures used by the Corporation may not be comparable to similar measures presented by other companies. The Corporation uses these non-IFRS measures to help evaluate its performance. Management considers net bitumen revenue, operating earnings and cash operating netback to be important measures as they indicate profitability relative to current commodity prices. Management uses cash flow from operations to measure the Corporation's ability to generate funds to finance capital expenditures and repay debt. These non-IFRS measures should not be considered as an alternative to or more meaningful than net income (loss) or net cash provided by (used in) operating activities, as determined in accordance with IFRS, as an indication of the Corporation's performance. The non-IFRS operating earnings and cash operating netback measures are reconciled to net income (loss), while cash flow from operations is reconciled to net cash provided by (used in) operating activities.

In addition, the Corporation uses the non-IFRS measures of total book capitalization and total debt/book capitalization to analyze the Corporation's leverage and liquidity. Total book capitalization is defined as total debt plus shareholders' equity, while total debt is defined as total long-term debt, including the current portion.

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

	2014		2013				2012	
Unaudited	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**
FINANCIAL ($000 unless specified)								
Net income (loss)[1]	248,954	(103,441)	(148,182)	115,383	(62,312)	(71,294)	(18,740)	47,474
Per share, diluted	1.11	(0.46)	(0.67)	0.51	(0.28)	(0.32)	(0.09)	0.24
Operating earnings (loss)	111,139	40,659	(32,685)	56,171	13,612	(36,712)	(538)	(12,883)
Per share, diluted	0.49	0.18	(0.15)	0.25	0.06	(0.16)	0.00	(0.07)
Cash flow from operations	261,713	156,987	22,648	144,521	79,184	7,071	56,106	24,442
Per share, diluted	1.16	0.70	0.10	0.64	0.35	0.03	0.27	0.12
Capital investment	332,232	353,565	394,370	477,335	674,576	681,871	500,223	406,526
Cash, cash equivalents and short-term investments	839,870	890,335	1,179,072	647,096	1,203,457	1,803,338	2,007,841	1,607,036
Working capital	805,742	877,069	1,045,607	365,676	731,290	1,298,955	1,655,915	1,307,325
Long-term debt	4,016,257	4,162,209	4,004,575	2,857,740	2,923,382	2,823,207	2,488,609	2,461,676
Shareholders' equity	4,970,144	4,705,966	4,788,430	4,919,407	4,771,616	4,817,253	4,870,534	4,092,556
BUSINESS ENVIRONMENT								
West Texas Intermediate (WTI) US$/bbl	102.99	98.68	97.43	105.83	94.22	94.37	88.18	92.22
C$ equivalent of 1US$ - average	1.0905	1.1035	1.0477	1.0385	1.0233	1.0089	0.9913	0.9948
Differential – WTI vs blend ($/bbl)	27.04	31.93	41.48	23.50	26.17	39.96	26.13	29.54
Differential – WTI vs blend (%)	24.1%	29.3%	40.6%	21.4%	27.1%	41.9%	29.9%	32.2%
Natural gas – AECO ($/mcf)	4.70	5.69	3.52	2.42	3.51	3.18	3.20	2.27
OPERATIONAL ($/bbl unless specified)								
Bitumen production – bbls/d	68,984	58,643	42,251	34,246	32,144	32,531	32,292	23,941
Bitumen sales – bbls/d	70,849	58,089	35,990	34,256	32,175	32,393	32,722	23,876
Diluent usage – bbls/d	31,617	28,797	16,680	13,032	14,176	16,239	14,810	9,466
Blend sales – bbls/d	102,446	86,886	52,670	47,288	46,351	48,632	47,532	33,342
Steam to oil ratio (SOR)	2.4	2.5	2.9	2.5	2.3	2.5	2.4	2.5
Blend sales	85.27	76.96	60.60	86.40	70.25	55.24	61.29	62.19
Cost of diluent	(12.52)	(14.68)	(22.38)	(12.07)	(16.27)	(25.20)	(15.62)	(15.70)
Bitumen realization	72.75	62.28	38.22	74.33	53.98	30.04	45.67	46.49
Transportation – net	(1.80)	(0.67)	(0.51)	(0.20)	(0.17)	(0.12)	(0.05)	(0.93)
Royalties	(5.01)	(4.47)	(2.71)	(5.14)	(3.03)	(1.58)	(2.23)	(2.10)
Operating costs – non-energy	(9.64)	(9.05)	(8.09)	(9.20)	(10.00)	(8.81)	(8.70)	(15.23)
Operating costs – energy	(6.45)	(8.43)	(5.38)	(3.32)	(4.85)	(4.93)	(4.65)	(3.22)
Power sales	1.60	3.85	2.25	3.12	6.00	3.30	4.40	2.84
Cash operating netback	**51.45**	**43.51**	**23.78**	**59.59**	**41.93**	**17.90**	**34.44**	**27.85**
Power sales price (C$/MWh)	40.98	62.26	44.63	75.96	138.96	59.92	79.62	57.99
Power sales (MW/h)	115	150	76	59	58	74	75	49
Depletion and depreciation rate per bbl	15.30	15.54	15.56	15.54	15.11	15.24	14.79	13.45
COMMON SHARES								
Shares outstanding, end of period (000)	223,673	222,575	222,507	222,489	221,829	221,256	220,190	195,248
Volume traded (000)	70,199	32,102	33,400	28,403	43,789	28,495	20,370	13,578
Common share price ($)								
High	41.29	37.84	36.00	36.69	32.98	35.67	38.74	41.90
Low	35.52	29.41	28.60	28.81	25.50	30.89	30.25	35.20
Close (end of period)	38.89	37.36	30.61	35.54	28.83	32.61	30.44	37.39

(1) Includes foreign exchange gains and losses on conversion of U.S. dollar denominated debt.

Interim Financial Statements

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

As at	Note		June 30, 2014		December 31, 2013
Assets					
Current assets					
Cash and cash equivalents	20	$	**839,870**	$	1,179,072
Trade receivables and other	6		**293,173**		186,183
Inventories	7		**99,227**		129,943
			1,232,270		1,495,198
Non-current assets					
Property, plant and equipment	8		**7,756,438**		7,254,951
Exploration and evaluation assets	9		**584,255**		579,497
Other intangible assets	10		**65,630**		63,205
Other assets	11		**53,144**		54,890
Total assets		$	**9,691,737**	$	9,447,741
Liabilities					
Current liabilities					
Accounts payable and accrued liabilities	12	$	**390,755**	$	416,288
Current portion of long-term debt	13		**13,879**		13,827
Current portion of provisions and other liabilities	14		**21,894**		19,477
			426,528		449,592
Non-current liabilities					
Long-term debt	13		**4,002,378**		3,990,748
Provisions and other liabilities	14		**137,355**		125,177
Deferred income tax liability			**155,332**		93,794
Total liabilities			**4,721,593**		4,659,311
Commitments and contingencies	22				
Shareholders' equity					
Share capital	15		**4,791,351**		4,751,374
Contributed surplus	15		**124,439**		126,666
Retained earnings (deficit)			**53,020**		(92,493)
Accumulated other comprehensive income			**1,334**		2,883
Total shareholders' equity			**4,970,144**		4,788,430
Total liabilities and shareholders' equity		$	**9,691,737**	$	9,447,741

The accompanying notes are an integral part of these condensed interim consolidated financial statements.

Consolidated Statement of Income and Comprehensive Income
(Unaudited, expressed in thousands of Canadian dollars, except per share amounts)

		Three months ended June 30		Six months ended June 30	
	Note	**2014**	2013	**2014**	2013
Petroleum revenue, net of royalties	16	**$ 811,154**	$ 301,054	**$1,461,206**	$ 544,030
Other revenue	17	**18,038**	23,306	**47,548**	38,299
		829,192	324,360	**1,508,754**	582,329
Diluent and transportation	18	**345,394**	144,512	**634,492**	304,460
Purchased product and storage	16	**50,450**	13,695	**122,112**	19,706
Operating expenses		**103,712**	43,494	**195,102**	83,535
Depletion and depreciation	8, 10	**98,618**	44,252	**179,862**	88,667
General and administrative		**25,720**	24,298	**52,095**	47,065
Stock-based compensation	15	**10,681**	9,563	**23,303**	16,518
Research and development		**880**	787	**1,871**	2,070
		635,455	280,601	**1,208,837**	562,021
Revenues less expenses		**193,737**	43,759	**299,917**	20,308
Other income (expense)					
Interest and other income		**2,058**	6,225	**5,318**	11,496
Foreign exchange gain (loss), net		**136,678**	(84,031)	**(6,566)**	(126,176)
Net finance expense	19	**(44,857)**	(12,350)	**(91,618)**	(35,312)
		93,879	(90,156)	**(92,866)**	(149,992)
Income (loss) before income taxes		**287,616**	(46,397)	**207,051**	(129,684)
Deferred income tax expense		**38,662**	15,915	**61,538**	3,922
Net income (loss)		**248,954**	(62,312)	**145,513**	(133,606)
Other comprehensive income (loss)					
Foreign currency translation adjustment		**(5,251)**	45	**(1,549)**	97
Comprehensive income (loss) for the period		**$ 243,703**	$ (62,267)	**143,964**	$ (133,509)

Net earnings (loss) per share					
Basic	21	**$ 1.12**	$ (0.28)	**$ 0.65**	$ (0.60)
Diluted	21	**$ 1.11**	$ (0.28)	**$ 0.65**	$ (0.60)

The accompanying notes are an integral part of these condensed 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 at January 1, 2014		**$ 4,751,374**	**$ 126,666**	**$ (92,493)**	**$ 2,883**	**$ 4,788,430**
Stock options exercised	15	**10,693**	**(2,494)**	**-**	**-**	**8,199**
RSUs vested and released	15	**29,284**	**(29,284)**	**-**	**-**	**-**
Stock-based compensation	15	**-**	**29,551**	**-**	**-**	**29,551**
Net income		**-**	**-**	**145,513**	**-**	**145,513**
Other comprehensive loss		**-**	**-**	**-**	**(1,549)**	**(1,549)**
Balance at June 30, 2014		**$ 4,791,351**	**$ 124,439**	**$ 53,020**	**$ 1,334**	**$ 4,970,144**
Balance at January 1, 2013		$ 4,694,378	$ 102,219	$ 73,912	$ 25	$ 4,870,534
Share issue costs, net of tax		332	-	-	-	332
Stock options exercised		18,038	(4,154)	-	-	13,884
RSUs vested and released		15,201	(15,201)	-	-	-
Stock-based compensation		-	20,375	-	-	20,375
Net loss		-	-	(133,606)	-	(133,606)
Other comprehensive income		-	-	-	97	97
Balance at June 30, 2013		$ 4,727,949	$ 103,239	$ (59,694)	$ 122	$ 4,771,616

The accompanying notes are an integral part of these condensed 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	**2014**	2013	**2014**	2013
Cash provided by (used in):					
Operating activities					
Net income (loss)		**$ 248,954**	$ (62,312)	**$ 145,513**	$ (133,606)
Adjustments for:					
Depletion and depreciation		**98,618**	44,252	**179,862**	88,667
Stock-based compensation		**10,681**	9,563	**23,303**	16,518
Unrealized loss (gain) on foreign exchange		**(135,148)**	82,413	**5,453**	123,330
Unrealized loss (gain) on derivative financial liabilities	19	**(590)**	(14,801)	**(2,217)**	(19,105)
Deferred income tax expense		**38,662**	15,915	**61,538**	3,922
Other		**536**	4,154	**5,248**	6,529
Net change in non-cash operating working capital items	20	**35,491**	(32,480)	**(82,272)**	(64,543)
Net cash provided by (used in) operating activities		**297,204**	46,704	**336,428**	21,712
Investing activities					
Capital investments		**(320,826)**	(653,827)	**(663,829)**	(1,322,759)
Other		**(1,786)**	(1,767)	**(659)**	(3,655)
Net change in non-cash investing working capital items	20	**(19,236)**	(21,241)	**(22,246)**	569,253
Net cash provided by (used in) investing activities		**(341,848)**	(676,835)	**(686,734)**	(757,161)
Financing activities					
Issue of shares		**6,562**	4,870	**8,199**	14,327
Issue of long-term debt, net of debt issue costs		**-**	-	**-**	301,122
Repayment of long-term debt		**(3,480)**	(3,406)	**(7,076)**	(6,707)
Financing costs		**-**	(8,361)	**-**	(8,693)
Net cash provided by (used in) financing activities		**3,082**	(6,897)	**1,123**	300,049
Effect of exchange rate changes on cash and cash equivalents held in foreign currency		**(8,903)**	18,476	**9,981**	26,815
Change in cash and cash equivalents		**(50,465)**	(618,552)	**(339,202)**	(408,585)
Cash and cash equivalents, beginning of period		**890,335**	1,684,810	**1,179,072**	1,474,843
Cash and cash equivalents, end of period		**$ 839,870**	$1,066,258	**$ 839,870**	$1,066,258

The accompanying notes are an integral part of these condensed 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 sections of oil sands leases in the 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 financial statements for the year ended December 31, 2013, except as described in Note 3 below. 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 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 financial statements for the year ended December 31, 2013. These interim consolidated financial statements should be read in conjunction with the Corporation’s audited financial statements for the year ended December 31, 2013, which are included in the Corporation’s 2013 annual report.

These interim consolidated financial statements were approved by the Corporation’s Audit Committee on July 29, 2014.

3. CHANGE IN ACCOUNTING POLICIES

The Corporation has adopted the following revised standards effective January 1, 2014. These changes, along with all the consequential amendments, are made in accordance with the applicable transitional provisions. The adoption of these revisions did not have an impact on the Corporation’s consolidated financial statements.

IAS 32, Financial Instruments: Presentation, has been amended to clarify the requirements for offsetting financial assets and liabilities. The amendments clarify that the right to offset must be available on the current date and cannot be contingent on a future event.

IAS 36, Impairment of Assets, has been amended to require additional disclosures in the event of recognizing an impairment of assets.

Accounting standards issued but not yet applied

IFRS 9, Financial Instruments, is intended to replace IAS 39, Financial Instruments: Recognition and Measurement. IFRS 9 will be published in three phases. The first two phases, which have been published, address classification and measurement requirements for financial assets and liabilities and hedge accounting. The third phase of the project will address impairment of financial instruments.

IFRS 9 uses a single approach to determine whether a financial asset is measured at amortized cost or fair value, replacing the multiple rules in IAS 39. The approach in IFRS 9 is based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. The new standard also requires a single impairment method to be used, replacing the multiple impairment methods in IAS 39. For financial liabilities, although the classification criteria for financial liabilities will not change under IFRS 9, when the fair value option is applied to financial liabilities, the change in fair value resulting from an entity's own credit risk is recorded in other comprehensive income rather than net earnings, unless this creates an accounting mismatch.

IFRS 9 introduces a simplified hedge accounting model, aligning hedge accounting more closely with risk management. In addition, improvements have been made to hedge accounting and risk management disclosure requirements. The Corporation does not currently apply hedge accounting to any of its risk management contracts.

The IASB has decided to defer the mandatory effective date of IFRS 9 and the mandatory effective date will be left open pending the finalization of the impairment requirements. IFRS 9 will still be available for early adoption. The impact of the new standard on the Corporation's consolidated financial statements will not be known until the IASB project is complete.

4. PRINCIPLES OF CONSOLIDATION

The interim consolidated financial statements of the Corporation comprise the Corporation and its wholly-owned subsidiary, MEG Energy (U.S.) Inc. All intercompany transactions and balances are eliminated on consolidation.

5. FINANCIAL INSTRUMENTS AND DERIVATIVE FINANCIAL LIABILITIES

The financial instruments recognized on the balance sheet are comprised of cash and cash equivalents, trade receivables and other, other assets, accounts payable and accrued liabilities, derivative financial liabilities and long-term debt. As at June 30, 2014, other assets 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 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 other assets, derivative financial liabilities and long-term debt

			Fair value measurements using		
As at June 30, 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					
Other assets	**$ 2,260**	**$ 2,260**	**$ -**	**$ -**	**$ 2,260**
Financial liabilities					
Derivative financial liabilities	**28,762**	**28,762**	**-**	**28,762**	**-**
Long-term debt	**4,076,097**	**4,292,467**	**4,292,467**	**-**	**-**

			Fair value measurements using		
As at December 31, 2013	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					
Other assets	$ 2,252	$ 2,252	$ -	$ -	$ 2,252
Financial liabilities					
Derivative financial liabilities	30,981	30,981	-	30,981	-
Long-term debt	4,067,738	4,135,639	4,135,639	-	-

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

The fair value of long-term debt is derived using quoted prices in an active market.

Level 2 fair value measurements are based on valuation models and techniques where the significant inputs are derived from quoted prices or indices.

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.

Level 3 fair value measurements are based on unobservable information.

Other assets are comprised of investments in U.S. auction rate securities (“ARS”). The Corporation estimated the fair value of the ARS based on the following: (i) the underlying structure of the notes and the securities; (ii) the present value of future principal and interest payments discounted at rates considered to reflect current market conditions for similar securities; and (iii) consideration of the probabilities of default, based on the quoted credit rating for the respective notes and securities. These estimated fair values could change significantly based on future market conditions.

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. There were no transfers between levels of the fair value hierarchy during the period ended June 30, 2014.

(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$1.3 billion senior secured term loan. At June 30, 2014, there was an unrealized loss on the interest rate swaps of $7.5 million (December 31, 2013 - $7.5 million).

Amount	Effective date	Remaining term	Fixed rate	Floating rate
US$300 million	September 30, 2011	Jul 2014-Sept 2016	4.436%	3 month LIBOR[(1)]
US$150 million	December 31, 2011	Jul 2014-Sept 2016	4.376%	3 month LIBOR[(1)]
US$150 million	January 12, 2012	Jul 2014-Sept 2016	4.302%	3 month LIBOR[(1)]
US$148 million	January 27, 2012	Jul 2014-Sept 2016	4.218%	3 month LIBOR[(1)]

[(1)] *London Interbank Offered Rate*

6. TRADE RECEIVABLES AND OTHER

		June 30, 2014		December 31, 2013
Trade receivables	$	284,490	$	174,935
Deposits and advances		5,343		7,908
Current portion of deferred financing costs		3,340		3,340
	$	293,173	$	186,183

7. INVENTORIES

		June 30, 2014		December 31, 2013
Diluent	$	79,470	$	84,628
Bitumen blend		17,636		43,358
Materials and supplies		2,121		1,957
	$	99,227	$	129,943

During the period ended June 30, 2014, a total of $602.3 million (2013 - $292.5 million) in inventory product costs were charged to earnings through diluent and transportation.

8. PROPERTY, PLANT AND EQUIPMENT

	Crude oil	Transportation and storage	Corporate assets	Total
Cost				
Balance as at December 31, 2012	$ 4,799,595	$ 793,671	$ 33,597	$ 5,626,863
Additions	1,694,070	480,263	7,438	2,181,771
Transfer from exploration and evaluation assets (note 9)	-	2,513	-	2,513
Balance as at December 31, 2013	$ 6,493,665	$ 1,276,447	$ 41,035	$ 7,811,147
Additions	517,811	152,680	6,583	677,074
Balance as at June 30, 2014	**$ 7,011,476**	**$ 1,429,127**	**$ 47,618**	**$ 8,488,221**

	Crude oil	Transportation and storage	Corporate assets	Total
Accumulated depletion and depreciation				
Balance as at December 31, 2012	$ 329,556	$ 22,831	$ 6,591	$ 358,978
Depletion and depreciation for the period	183,866	8,621	4,731	197,218
Balance as at December 31, 2013	$ 513,422	$ 31,452	$ 11,322	$ 556,196
Depletion and depreciation for the period	165,438	7,591	2,558	175,587
Balance as at June 30, 2014	**$ 678,860**	**$ 39,043**	**$ 13,880**	**$ 731,783**

	Crude oil	Transportation and storage	Corporate assets	Total
Carrying Amounts				
As at December 31, 2013	$ 5,980,243	$ 1,244,995	$ 29,713	$ 7,254,951
As at June 30, 2014	**$ 6,332,616**	**$ 1,390,084**	**$ 33,738**	**$ 7,756,438**

During the six months ended June 30, 2014, the Corporation capitalized $17.5 million (six months ended June 30, 2013 - $12.2 million) of general and administrative costs and $6.2 million (six months ended June 30, 2013 - $3.9 million) of stock-based compensation costs relating to oil sands exploration and development activities. In addition, $41.6 million of interest and finance charges related to the development of capital projects were capitalized during the six months ended June 30, 2014 (six months ended June 30, 2013 - $31.8 million).

9. EXPLORATION AND EVALUATION ASSETS

Cost		
Balance as at December 31, 2012	$	554,349
Additions		27,661
Transfer to property, plant and equipment (note 8)		(2,513)
Balance as at December 31, 2013	$	579,497
Additions		4,758
Balance as at June 30, 2014	**$**	**584,255**

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, 2014, no impairment has been recognized on these assets.

10. OTHER INTANGIBLE ASSETS

Cost		
Balance as at December 31, 2012	$	47,489
Additions		18,720
Balance as at December 31, 2013	$	66,209
Additions		3,965
Balance as at June 30, 2014	**$**	**70,174**

Accumulated depreciation		
Balance as at December 31, 2012	$	1,456
Depreciation		1,548
Balance as at December 31, 2013	$	3,004
Depreciation		1,540
Balance as at June 30, 2014	**$**	**4,544**

Carrying Amounts		
As at December 31, 2013	$	63,205
As at June 30, 2014	**$**	**65,630**

Other intangible assets include the cost to maintain the right to participate in a potential pipeline project and the cost of software that is not an integral part of the related computer hardware.

11. OTHER ASSETS

	June 30, 2014	December 31, 2013
Long-term pipeline linefill[a]	**$ 41,432**	$ 41,517
ARS[b]	**2,260**	2,252
Deferred financing costs[c]	**12,792**	14,461
	56,484	58,230
Less current portion of deferred financing costs	**(3,340)**	(3,340)
	$ 53,144	$ 54,890

(a) In 2013, the Corporation entered into an agreement to transport diluent on a third party pipeline and was required to supply diluent linefill for the pipeline. As the pipeline is owned by a third party, the linefill is not considered to be a part of the Corporation's property, plant and equipment.

(b) The investment in ARS is considered an illiquid asset and is recorded at its fair value based on a discounted cash flow valuation using observable information with changes in fair value included in net finance expense in the period in which they arise.

(c) Costs associated with establishing the Corporation's revolving credit facility are deferred and amortized over the term of the credit facility.

12. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

	June 30, 2014	December 31, 2013
Trade payables	**$ 27,919**	$ 114,752
Accrued and other liabilities	**306,260**	244,972
Interest payable	**56,576**	56,564
	$ 390,755	$ 416,288

13. LONG-TERM DEBT

	June 30, 2014	December 31, 2013
Senior secured term loan (June 30, 2014 – US$1.268 billion; December 31, 2013 – US$1.275 billion)[a]	**$ 1,353,717**	$ 1,355,558
6.5% senior unsecured notes (US$750 million)[b]	**800,700**	797,700
6.375% senior unsecured notes (US$800 million)[c]	**854,080**	850,880
7.0% senior unsecured notes (US$1.0 billion)[d]	**1,067,600**	1,063,600
	4,076,097	4,067,738
Less current portion of senior secured term loan	**(13,879)**	(13,827)
Less unamortized financial derivative liability discount	**(19,063)**	(20,565)
Less unamortized deferred debt issue costs	**(40,777)**	(42,598)
	$ 4,002,378	$ 3,990,748

The U.S. dollar denominated debt was translated into Canadian dollars at the period end exchange rate of US$1 = C$1.0676 (December 31, 2013 - US$1 = C$1.0636).

There are no maintenance financial covenants associated with the Corporation's debt as at June 30, 2014 and December 31, 2013.

(a) On February 25, 2013, the Corporation re-priced, increased and extended its existing US$987.5 million senior secured term loan. The Corporation extended the maturity date to March 31, 2020 and increased its borrowing under the senior secured term loan by US$300.0 million. In addition, the Corporation reduced the interest rate on the term loan by 25 basis points.

    Effective May 24, 2013, the Corporation agreed to amend, extend and increase its revolving credit facility from US$1.0 billion to US$2.0 billion with a maturity date of May 24, 2018. As at June 30, 2014, US$109.6 million (December 31, 2013 - US$125.8 million) of the revolving credit facility was utilized to support letters of credit. As at June 30, 2014, no amount had been drawn under the revolving credit facility.

    The senior secured credit facilities are comprised of a US$1.268 billion term loan and a US$2.0 billion revolving credit facility. The term loan bears a floating interest rate based on either U.S. Prime or LIBOR, at the Corporation's option, plus a credit spread of 175 or 275 basis points, respectively. The term loan also has an interest rate floor of 200 basis points based on U.S. Prime or 100 basis points based on LIBOR. The term loan is to be repaid in quarterly installment payments equal to US$3.25 million, with the balance due on March 31, 2020. Interest is paid quarterly. The Corporation has deferred the associated remaining debt issue costs of $5.6 million and is amortizing these costs over the life of the loan utilizing the effective interest method.

(b) Effective March 18, 2011, the Corporation issued US$750.0 million in aggregate principal amount of 6.5% Senior Unsecured Notes, with a maturity date of March 15, 2021. Interest is paid semi-annually on March 15 and September 15. No principal payments are required until March 15, 2021. The Corporation has deferred the associated remaining debt issue costs of $10.8 million and is amortizing these costs over the life of the notes utilizing the effective interest method.

(c) Effective July 19, 2012, the Corporation issued US$800.0 million in aggregate principal amount of 6.375% Senior Unsecured Notes, with a maturity date of January 30, 2023. Interest is paid semi-annually on January 30 and July 30. No principal payments are required until January 30, 2023. The Corporation has deferred the associated remaining debt issue costs of $11.8 million and is amortizing these costs over the life of the notes utilizing the effective interest method.

(d) Effective October 1, 2013, the Corporation issued US$800.0 million in aggregate principal amount of 7.0% Senior Unsecured Notes, with a maturity date of March 31, 2024. On November 6, 2013 an additional US$200 million of 7.0% Senior Unsecured Notes were issued under the same indenture. Interest is paid semi-annually on March 31 and September 30. No principal payments are required until March 31, 2024. The Corporation has deferred the associated remaining debt issue costs of $12.6 million and is amortizing these costs over the life of the notes utilizing the effective interest method.

14. PROVISIONS AND OTHER LIABILITIES

		June 30, 2014		December 31, 2013
Derivative financial liabilities[a]	**$**	**28,762**	$	30,981
Decommissioning provision[b]		**125,811**		108,695
Deferred lease inducements[c]		**4,676**		4,978
Provisions and other liabilities		**159,249**		144,654
Less current portion		**(21,894)**		(19,477)
Non-current portion	**$**	**137,355**	$	125,177

(a) Derivative financial liabilities

		June 30, 2014		December 31, 2013
1% interest rate floor	**$**	**21,250**	$	23,497
Interest rate swaps		**7,512**		7,484
Derivative financial liabilities		**28,762**		30,981
Less current portion of derivative financial liabilities		**(14,380)**		(13,886)
Non-current portion of derivative financial liabilities	**$**	**14,382**	$	17,095

The interest rate floor on the senior secured term loan has been recognized as an embedded derivative, as the floor rate exceeded the market rate of interest at the time that the debt was incurred. As a result, the interest rate floor derivative is required to be separated from the carrying value of long-term debt and accounted for as a separate derivative financial liability measured at fair value, with gains and losses on re-measurement included in net finance expense in the period in which they arise.

The Corporation is exposed to interest rate risk in relation to interest income earned on cash, cash equivalents and short-term investments and in relation to interest expense on floating rate long-term debt. To mitigate a portion of the risk of interest rate increases on long-term debt, the Corporation periodically enters into interest rate swap contracts to manage its floating to fixed interest rate mix on long-term debt. As of June 30, 2014, the Corporation had entered into interest rate swaps on US$748.0 million (note 5(b)) and these interest rate swap contracts expire on September 30, 2016. Interest rate swaps are classified as derivative financial liabilities and measured at fair value, with gains and losses on re-measurement included in net finance expense in the period in which they arise.

(b) The following table presents the decommissioning provision associated with the reclamation and abandonment of crude oil and transportation and storage assets:

		June 30, 2014		December 31, 2013
Decommissioning provision, beginning of period	**$**	**108,695**	$	82,087
Changes in estimated future cash flows		**2,997**		15,082
Changes in discount rates		**7,596**		(19,110)
Liabilities incurred		**5,154**		30,068
Liabilities settled		**(772)**		(4,195)
Accretion		**2,141**		4,763
Decommissioning provision, end of period		**125,811**		108,695
Less current portion of decommissioning provision		**(6,775)**		(4,848)
Non-current portion of decommissioning provision	**$**	**119,036**	$	103,847

The total decommissioning provision is based on the estimated costs to reclaim and abandon the Corporation's crude oil properties and transportation and storage assets and the estimated timing of the costs to be incurred in future years. The Corporation has estimated the net present value of the decommissioning obligations to be $125.8 million as at June 30, 2014 (December 31, 2013 - $108.7 million) based on an undiscounted total future liability of $591.6 million (December 31, 2013 - $569.5 million) and a credit-adjusted rate of 6.2% (December 31, 2013 – 6.4%). This obligation is estimated to be settled in periods up to the year 2058.

(c) Deferred lease inducements

		June 30, 2014		December 31, 2013
Deferred lease inducements	**$**	**4,676**	$	4,978
Less current portion of deferred lease inducements		**(739)**		(743)
Non-current portion of deferred lease inducements	**$**	**3,937**	$	4,235

Leasehold inducements were received when the Corporation entered into the corporate office lease. These inducements are recognized as a deferred liability and amortized through general and administrative expense over the life of the lease.

15. 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, 2014		Year ended December 31, 2013	
	Number of shares	**Amount**	Number of shares	Amount
Balance, beginning of period	**222,506,896**	**$ 4,751,374**	220,190,084	$ 4,694,378
Share issue costs, net of tax	**-**	**-**	-	79
Issued upon exercise of stock options	**312,918**	**10,693**	1,893,732	40,522
Issued upon vesting and release of RSUs	**852,765**	**29,284**	423,080	16,395
Balance, end of period	**223,672,579**	**$ 4,791,351**	222,506,896	$ 4,751,374

(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, 2014		Year ended December 31, 2013	
	Stock options	**Weighted average exercise price per share**	Stock options	Weighted average exercise price per share
Outstanding, beginning of period	**8,859,028**	**$ 35.49**	9,147,404	$ 32.50
Granted	**1,733,310**	**37.86**	1,774,854	30.95
Exercised	**(312,918)**	**26.20**	(1,893,732)	16.53
Forfeited	**(290,269)**	**38.83**	(169,498)	38.19
Expired	**(300,749)**	**40.18**	-	-
Outstanding, end of period	**9,688,402**	**$ 35.97**	8,859,028	$ 35.49

(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. An RSU, including a PSU, represents the right for the holder to receive a cash payment equal to the fair market value of the Corporation's common shares calculated at the date of such payment or, at the election of the Corporation, its equivalent in fully-paid common shares. A PSU is an RSU, the vesting of which has been made conditional on the satisfaction of certain performance criteria. PSUs become eligible to vest if the Corporation satisfies the performance criteria identified by the Corporation's Board of Directors within a target range. A pre-determined multiplier is then applied to PSUs that have become eligible to vest, dependent on the point in the target range to which such performance criteria are satisfied. RSUs granted under the Restricted Share Unit Plan generally vest annually over a three year period. PSUs granted under the Restricted Share Unit Plan generally vest on the third anniversary of the grant date, provided that the performance criteria have been satisfied, and that the holder remains actively employed, a director or a consultant with the Corporation on the vesting date.

RSUs and PSUs outstanding	**Six months ended June 30, 2014**	Year ended December 31, 2013
Outstanding, beginning of period	**2,589,700**	953,804
Granted	**988,077**	2,157,534
Vested and released	**(852,765)**	(423,080)
Forfeited	**(69,493)**	(98,558)
Outstanding, end of period	**2,655,519**	2,589,700

(e) Deferred share units outstanding:

The Deferred Share Unit Plan allows for the granting of Deferred Share Units ("DSUs") to directors of the Corporation. A DSU represents the right for the holder to receive a cash payment equal to the fair market value of the Corporation's common shares calculated at the date of such payment or, at the election of the Corporation, its equivalent in fully-paid common shares purchased through a broker. DSUs are vested when they are granted and are redeemed on the third business day following the date on which the holder ceases to be a director. At June 30, 2014, there were 17,281 DSUs outstanding.

(f) Contributed Surplus:

		Six months ended June 30, 2014		Year ended December 31, 2013
Balance, beginning of period	**$**	**126,666**	$	102,219
Stock-based compensation - expensed		**23,303**		38,792
Stock-based compensation - capitalized		**6,248**		11,267
Stock options exercised		**(2,494)**		(9,217)
RSUs vested and released		**(29,284)**		(16,395)
Balance, end of period	**$**	**124,439**	$	126,666

16. PETROLEUM REVENUE, NET OF ROYALTIES

	Three months ended June 30		Six months ended June 30	
	2014	2013	**2014**	2013
Petroleum sales:				
Proprietary	**$ 795,072**	$ 296,300	**$ 1,396,900**	$ 538,100
Third party [(a)]	**48,405**	13,621	**120,012**	19,399
	843,477	309,921	**1,516,912**	557,499
Royalties	**(32,323)**	(8,867)	**(55,706)**	(13,469)
Petroleum revenue, net of royalties	**$ 811,154**	$ 301,054	**$ 1,461,206**	$ 544,030

(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 Income and Comprehensive Income under the caption “Purchased product and storage”.

17. OTHER REVENUE

	Three months ended June 30		Six months ended June 30	
	2014	2013	**2014**	2013
Power revenue	**$ 10,312**	$ 17,555	**$ 30,443**	$ 27,171
Transportation revenue	**7,726**	5,751	**17,105**	11,128
Other revenue	**$ 18,038**	$ 23,306	**$ 47,548**	$ 38,299

18. DILUENT AND TRANSPORTATION

	Three months ended June 30		Six months ended June 30	
	2014	2013	**2014**	2013
Diluent	**$ 326,065**	$ 138,261	**$ 602,273**	$ 292,472
Transportation	**19,329**	6,251	**32,219**	11,988
Diluent and transportation	**$ 345,394**	$ 144,512	**$ 634,492**	$ 304,460

19. NET FINANCE EXPENSE

	Three months ended June 30		Six months ended June 30	
	2014	2013	**2014**	2013
Total interest expense	**$ 65,074**	$ 42,994	**$ 130,774**	$ 81,717
Less capitalized interest	**(22,099)**	(18,211)	**(41,569)**	(31,845)
Net interest expense	**42,975**	24,783	**89,205**	49,872
Accretion on decommissioning provision	**1,105**	1,186	**2,141**	2,262
Unrealized fair value loss (gain) on embedded derivative liabilities	**(1,136)**	(9,828)	**(2,246)**	(12,903)
Unrealized fair value loss (gain) on interest rate swaps	**546**	(4,973)	**29**	(6,202)
Realized loss on interest rate swaps	**1,367**	1,182	**2,489**	2,283
Net finance expense	**$ 44,857**	$ 12,350	**$ 91,618**	$ 35,312

20. SUPPLEMENTAL CASH FLOW DISCLOSURES

	Three months ended June 30		Six months ended June 30	
	2014	2013	**2014**	2013
Changes in non-cash working capital				
Operating activities:				
Trade receivables and other	**$ (16,812)**	$ (14,455)	**$ (106,990)**	$ (36,460)
Inventories[(a)]	**45,084**	555	**28,005**	(2,741)
Accounts payable and accrued liabilities	**7,219**	(18,580)	**(3,287)**	(25,342)
Change in operating non-cash working capital	**$ 35,491**	$ (32,480)	**$ (82,272)**	$ (64,543)
Investing activities:				
Short-term investments	**$ -**	$ (18,671)	**$ -**	$ 395,798
Accounts payable and accrued liabilities	**(19,236)**	(2,570)	**(22,246)**	173,455
Change in investing non-cash working capital	**$ (19,236)**	$ (21,241)	**$ (22,246)**	$ 569,253
Change in total non-cash working capital	**$ 16,255**	$ (53,721)	**$ (104,518)**	$ 504,710
Cash and cash equivalents:				
Cash	**$ 359,800**	$ 421,382	**$ 359,800**	$ 421,382
Cash equivalents	**480,070**	644,876	**480,070**	644,876
	$ 839,870	$ 1,066,258	**$ 839,870**	$ 1,066,258

a) The three and six months ended June 30, 2014 amounts exclude a non-cash decrease in inventory of $158 and $2,711, respectively (three and six months ended June 30, 2013 – nil).

21. EARNINGS PER COMMON SHARE

	Three months ended June 30		Six months ended June 30	
	2014	2013	**2014**	2013
Net income (loss)	**$ 248,954**	$ (62,312)	**$ 145,513**	$ (133,606)
Weighted average common shares outstanding	**223,049,767**	221,484,529	**222,798,406**	221,266,813
Dilutive effect of stock options, RSUs and PSUs	**2,099,685**	2,833,271	**1,786,588**	2,267,009
Weighted average common shares outstanding – diluted	**225,149,452**	224,317,800	**224,584,994**	223,533,822
Net earnings (loss) per share, basic	**$ 1.12**	$ (0.28)	**$ 0.65**	$ (0.60)
Net earnings (loss) per share, diluted	**$ 1.11**	$ (0.28)	**$ 0.65**	$ (0.60)

22. COMMITMENTS AND CONTINGENCIES

(a) Commitments

The Corporation had the following commitments as at June 30, 2014:

Operating:

	2014	2015	2016	2017	2018	Thereafter
Office lease rentals	$ 7,768	$ 15,103	$ 15,513	$ 32,666	$ 30,785	$ 315,284
Diluent purchases	219,295	93,670	16,366	16,366	16,366	85,910
Transportation and storage	54,594	111,943	130,677	219,704	188,835	2,686,038
Other commitments	8,158	13,215	5,920	4,678	4,555	51,500
Commitments	$ 289,815	$ 233,931	$ 168,476	$ 273,414	$ 240,541	$ 3,138,732

Capital:

As part of normal operations, the Corporation has entered into a total of $136.0 million in capital commitments to be made in periods through 2018.

(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.