MEG Energy

WE'RE ADDING MORE

2013 ANNUAL REPORT

EXPERIENCE

VALUE

INNOVATION

A PURE PLAY OIL SANDS INVESTMENT

MEG Energy Corp. is a Canadian energy company focused on sustainable in situ development and production in the southern Athabasca oil sands region of Alberta.

The oil sands industry is about more than producing oil to meet the world's energy needs. It's about driving innovation, maximizing the value of our resources and developing these resources in a responsible manner that supports our communities, our economy and our shared environment. In all of these elements, MEG is committed to maintaining our strong track record. And adding more.

TO OUR SHAREHOLDERS

In 2013, MEG Energy continued to deliver on its long-term strategic mission of enhancing shareholder value through the efficient development of our high-quality resource base.

In our producing assets, we exited 2013 at production volumes of more than 48,500 barrels per day, about 70 per cent above 2012 average levels, supported by the successful commissioning and start-up of our Christina Lake Phase 2B expansion. We also advanced our marketing strategy with the commissioning of MEG's proprietary Stonefell storage hub and the completion of Canada's first well-head to unit train rail-loading connection. We're proud of the significant milestones we achieved in 2013 and very excited about our future. We believe we have the building blocks in place to achieve continued production growth, with stronger and more stable price realizations that, together, should result in a further strengthening of cash flows in 2014 and beyond.

A large, high-quality resource base

Our current focus is the Christina Lake region, which has been established as one of the premium plays in the oil sands and which will remain central to our plans over the next decade. With our Phase 1 and 2 assets, launched in 2008 and 2009 respectively, we have established a strong operating performance and a solid production base. In 2013, we added to that production base with the successful start-up of Christina Lake Phase 2B. This has laid the foundation for our next stage of growth, which will include a major brownfield expansion of our Phase 2B facilities.

As we continue the development of Christina Lake, we are also preparing for longer-term growth at our nearby Surmont leases to the north and Growth Properties to the west of Christina Lake.

Our multi-year corehole development programs have defined a high-quality resource development opportunity in both the Surmont and Growth Property areas. With their proximity to Christina Lake, MEG will be able to leverage off its existing infrastructure and proven technologies to advance meaningful value for shareholders.

Optimized growth

The size and certainty of our resource base is the foundation for our growth plans, but how we develop those resources is also critical to our strategy. Historically, the oil sands industry has focused on one mode of growth: greenfield expansions in new development areas. MEG is taking a different approach.

Our approach, called the RISER initiative, builds on our greenfield development projects through the use of our proprietary eMSAGP reservoir technology and then accommodates the incremental production resulting from the implementation of this technology with complementary plant expansions.

RISER has been underway on MEG's Phase 1 assets for over two years and was implemented in Phase 2 in 2013. On the well patterns where we have applied eMSAGP, we have recorded steam-oil ratios, a key efficiency measure, below 2.0 and, at our Phase 1 and 2 central processing facilities, we have debottlenecked the plant to increase production 60 per cent above the original design capacity.

Going forward, we are applying the lessons learned from RISER to Phase 2B. RISER 2B, which will incorporate a major brownfield expansion rather than plant debottlenecking, is expected to yield even greater production increases than those realized on Phases 1 and 2.

MEG's Christina Lake Project

PROVED RESERVES

1.45 billion barrels

PROBABLE RESERVES

1.45 billion barrels

CONTINGENT RESOURCES

3.65 billion barrels

*Estimates of MEG's reserves and contingent resources are based upon a report prepared by GLJ Petroleum Consultants Ltd., effective as of December 31, 2013. Contingent resources are best-estimate. There is no certainty that it will be commercially viable to produce any of the contingent resources. Statements relating to reserves and contingent resources estimates and certain other statements in this annual report including those relating to MEG's development plans, 2014 goals and expectations constitute forward-looking information. For further information and important advisories regarding forward-looking information and MEG's reserves and resources, please refer to MEG's annual information form dated March 5, 2014.

2013 Highlights

- Record exit rate production of 48,557 barrels per day, approximately 70% above 2012 average annual rates
- Successful commissioning and start-up of Christina Lake Phase 2B expansion
- Commissioning and start-up of Stonefell Terminal
- Completion of Canada's first well-head to unit train rail-loading facility

Controlling the value chain

We're proud of our accomplishments and strong performance on the production side of our business. However, we recognize that we must also focus on realizing the maximum value for every barrel we produce. This is the goal of our "Hub and Spoke" marketing strategy, which increases our control over the value chain from well-head to customer to reach the highest value markets for our products.

Central to this effort is our Stonefell Terminal, which became fully operational in late 2013. Stonefell is directly tied into our Christina Lake site by MEG's Access Pipeline, completing a proprietary, low-cost transportation system that allows us to stage our product sales.

From Stonefell's location in the Edmonton area, all current and developing markets for Alberta heavy oils are accessible. At the same time that Stonefell positions MEG to reach sales markets, it also serves as a gathering point for diluent supplies required to process and transport our crude blends. And very importantly, for both outgoing blends and incoming diluents, having storage capacity provides options to buy or sell either product at optimized pricing.

With Stonefell as the "hub" of our strategy, we have also been actively developing market "spokes" to help bypass the pipeline constraints that have impacted heavy oil pricing.

These connections include our contracted capacity on the Flanagan-Seaway pipeline which, following its planned start-up in mid-2014, will provide a conduit to high-value markets on the U.S. Gulf Coast. While we recognize that pipelines are the most cost-efficient means of transportation, we are also developing alternate spokes in the form of barging capacity on the U.S. Inland Waterway and through rail transportation, both of which offer attractive options to move our blends around market congestion, and both of which can be ramped up or down relatively quickly.

MEG's strategic mission focuses on maximizing the value chain by increasing production, minimizing costs and achieving the highest realized price.

In terms of the broader issue of market access, we recognize that there continues to be intense interest in the various options, including a number of pipeline proposals and movement by rail. For MEG, the focus is not on any specific option. Rather, the focus is on having all the options available to control MEG's value chain within North America.

In addition to developing market spokes, our strategy within each of these spokes also includes efforts to reduce the transportation costs that impact our netbacks—the price we receive against the costs we incur to produce and transport those barrels. One of these costs is diluents, which represent a significant component of the cost structure for heavy oil producers.

To help address this challenge in the near-term, we recently announced plans to construct a diluent removal facility to be located near MEG's Stonefell Terminal. This facility will allow us to transport bitumen by rail with minimal or no diluent, reducing our cost per barrel to reach rail-connected markets. In 2014, MEG is also investing in a field demonstration pilot project to continue to develop a proprietary technology called HI-Q™ that aims to produce a high-quality heavy oil that can be transported through pipelines without diluents. While we are still in the early phases of developing this technology, the potential to produce diluent-free, pipeline-ready heavy oil is exciting.

Innovative approaches like our enhanced wildlife crossing designs minimize our environmental impact.

Responsible development

Much of our past successes and future plans have been based on "adding more"—increasing our reserves, wringing cost-efficient production out of existing assets, or seizing greater value from our product sales—but "more" can also mean "less." Careful development planning and the deployment of highly efficient technologies for power generation, water and surface land management have contributed to an environmental footprint for MEG that is among the best in the industry. This focus will continue to be central to our day-to-day operations and our future plans.

The strategic mission that I've described for MEG comes together in a fairly simple equation: increasing our barrels of production at the lowest cost per barrel, while achieving the highest realized price, all with the goal of driving increased shareholder value. And, importantly, it is also about doing it all in a way that acknowledges the importance of being responsible to MEG's people, our business partners, our neighbours and our shared environment.

While the equation is simple, the work that goes into it can be tremendously complex and reflects what I see as one of the critical elements in MEG's current and future success—the MEG team. I would like to thank the talented people behind our strategy and MEG's Board of Directors for their wise stewardship.

On behalf of the entire MEG team, I also thank you for your support as we continue our efforts to build on our past performance and strive to reach even greater heights in 2014 and beyond.

Sincerely,

W. J. McCaffrey

Bill McCaffrey
President and CEO

OPERATIONAL + FINANCIAL HIGHLIGHTS

	2013 Quarterly Performance				Full Year	
($ per barrel unless specified)	**Q1**	**Q2**	**Q3**	**Q4**	**2013**	**2012**
Bitumen production *(barrels per day)*	32,531	32,144	34,246	42,251	**35,317**	28,773
Bitumen sales *(barrels per day)*	32,393	32,175	34,256	35,990	**33,715**	28,845
Steam-oil ratio (SOR)	2.5	2.3	2.5	2.9	**2.6**	2.4
West Texas Intermediate (WTI) *(US$/barrel)*	94.37	94.22	105.83	97.43	**97.96**	94.21
Differential – WTI/blend *(%)*	41.9%	27.1%	21.4%	40.6%	**32.7%**	31.2%
Bitumen realization	30.04	53.98	74.33	38.22	**49.28**	46.93
Transportation	(0.12)	(0.17)	(0.20)	(0.51)	**(0.26)**	(0.31)
Royalties	(1.58)	(3.03)	(5.14)	(2.71)	**(3.14)**	(2.46)
Net bitumen revenue	28.34	50.78	68.99	35.00	**45.88**	44.16
Energy costs	(4.93)	(4.85)	(3.32)	(5.38)	**(4.62)**	(3.46)
Non-energy costs	(8.81)	(10.00)	(9.20)	(8.09)	**(9.00)**	(9.71)
Power sales	3.30	6.00	3.12	2.25	**3.61**	3.19
Net operating costs	(10.44)	(8.85)	(9.40)	(11.22)	**(10.01)**	(9.98)
Cash operating netback (1)	17.90	41.93	59.59	23.78	**35.87**	34.18
Net income (loss) *($millions)*	(71.3)	(62.3)	115.4	(148.2)	**(166.4)**	52.6
Per share, diluted *($)*	(0.32)	(0.28)	0.51	(0.67)	**(0.75)**	0.26
Operating earnings (loss) *($millions)* (2)	(36.7)	13.6	56.2	(32.7)	**0.4**	21.2
Per share, diluted *($)* (2)	(0.16)	0.06	0.25	(0.15)	**0.00**	0.11
Cash flow from operations *($millions)* (2)	7.1	79.2	144.5	22.6	**253.4**	212.5
Per share, diluted *($)* (2)	0.03	0.35	0.64	0.10	**1.13**	1.06
Cash, cash equivalents and short-term investments *($millions)*	1,803.3	1,203.5	647.1	1,179.1	**1,179.1**	2,007.8
Long-term debt *($millions)*	2,823.2	2,923.4	2,857.7	4,004.6	**4,004.6**	2,488.6
Total cash capital investment *($millions)*	668.9	653.8	476.4	389.2	**2,188.4**	1,598.5

(1) 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 Netback table within the "Results of Operations" section in the attached Management's Discussed and Analysis ("MD&A").

(2) Operating earnings (loss), 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 and investors 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 operating activities in accordance with IFRS under the heading "Non-IFRS Measurements" in the attached MD&A.

TRACKING PROGRESS

2013 GOALS + RESULTS

23%
increase in average annual production

Achieve average annual production of 32,000 to 35,000 barrels per day at a non-energy operating cost of $9 to $11 per barrel.

Production in 2013 averaged 35,317 bpd, a 23% increase over 2012 average production. Non-energy operating costs averaged $9.00 per barrel, at the lowest end of MEG's targeted range maintaining our position as a low-cost producer.

Maximize productivity and reliability of existing plants.

The implementation of the RISER initiative across Phase 2 assets in 2013 supported exit rate production of 48,557 bpd, with the combined Phase 1 and 2 plants successfully demonstrating combined processing capacity of 35,000 to 40,000 bpd.

Complete construction, commissioning and start-up of Christina Lake Phase 2B.

Phase 2B produced first-oil in the fourth quarter of 2013 and was fully commissioned ahead of schedule in December.

Advance development, strategy and engineering for Christina Lake Phase 3 and Surmont projects.

MEG has established a standardized platform for future greenfield expansion phases that is expected to reduce front-end engineering and optimize supply-chain efficiencies.

Advance MEG's Hub and Spoke marketing strategy.

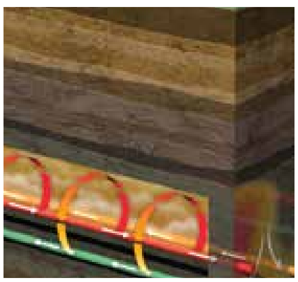
The Stonefell Terminal, the hub of MEG's strategy, was completed in 2013 with lateral connections to a nearby rail-loading facility marking the first well-head to rail pipeline connection in the Canadian industry with the first shipment in December. MEG's fleet of barges also began operations on the U.S. Inland Waterway in 2013, connecting the Midwest to the U.S. Gulf Coast.

2014 GOALS + ACTION PLANS

60,000 *to* **65,000**
bpd average annual production

Achieve average annual production of 60,000 to 65,000 barrels per day at a non-energy operating cost of $8 to $10 per barrel.

The ramp-up of Christina Lake Phase 2B is expected to drive significant production increases, while supporting lower non-energy operating costs through plant efficiencies.



Focus on implementation of RISER 2B expansion to drive near-term production increases.

Planned investments in reservoir technology and ‘brownfield’ plant expansion targets a significant, rapid and relatively low-capital cost increase in production from Phase 2B assets, supporting MEG’s strategy of optimizing currently operating phases before launching the next ‘greenfield’ phases.

Advance plans for longer-term projects that will be the foundation for our future growth.

Engineering and procurement of long lead-time materials for future phases at Christina Lake will be advanced, while regulatory and resource delineation efforts will continue at MEG’s Surmont and May River leases to set the stage for production growth beyond 2020.

Continue the development of MEG’s Hub and Spoke marketing strategy.

Contracted shipments on the Flanagan-Seaway pipeline system are expected to begin in mid-2014, providing a direct link to high-value markets on the U.S. Gulf Coast, while rail and barge transportation arrangements will remain in place as an option to move significant volumes around any potential market congestion or to new high-value markets.

Invest in facilities and technologies that reduce the need for diluents and reduce transportation costs.

Capital investment in a diluent removal facility is expected to lower costs and increase netbacks for products shipped by rail beginning in 2015, while ongoing development of MEG’s proprietary HI-Q™ technology is aimed at having the ability to ship a high-quality, diluent-free product over pipelines in the longer-term.

HOW MEG IS ADDING MORE

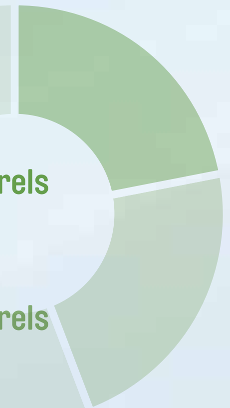
MAXIMIZING MEG'S VALUE CHAIN

From our established, high-quality resource base to our innovative Hub and Spoke marketing strategy, MEG strives to find ways to maximize the value in every barrel that we produce across the full value chain. The equation is simple:

increase production + minimize costs + capture the highest available price = increased shareholder value

resource base

Adding more starts with our world-class resource base. MEG has secured more than 900 square miles of high-quality oil sands assets in the southern Athabasca region of Alberta—an area that we know well. In 2013, we increased our proved reserves by 13% and proved plus probable reserves by 10%, placing MEG among the largest reserve holders in the industry. While our current focus is in the Christina Lake region, our exploration programs have defined high-quality resource development opportunities at both the Surmont and Growth Property areas. With their similar geology and proximity to Christina Lake and our existing infrastructure, these areas will be central to MEG's long-term development plans.



PROVED RESERVES

1.45 billion barrels

PROBABLE RESERVES

1.45 billion barrels

CONTINGENT RESOURCES

3.65 billion barrels

**Estimates of MEG's reserves and contingent resources are based upon a report prepared by GLJ Petroleum Consultants Ltd., effective as of December 31, 2013. Contingent resources are best-estimate. There is no certainty that it will be commercially viable to produce any of the contingent resources. Statements relating to reserves and contingent resources estimates and certain other statements in this annual report including those relating to MEG's development plans, 2014 goals and expectations constitute forward-looking information. For further information and important advisories regarding forward-looking information and MEG's reserves and resources, please refer to MEG's annual information form dated March 5, 2014.

Christina Lake Phase 2B

In the fourth quarter of 2013, MEG doubled production capacity with the successful start-up of Christina Lake Phase 2B. Together with the ongoing implementation of MEG's RISER initiative, incremental production from Phase 2B pushed exit production rates to a record high 48,557 bpd, supporting record fourth quarter production of 42,251 bpd. This represents a 31% increase from 2012 fourth quarter averages.

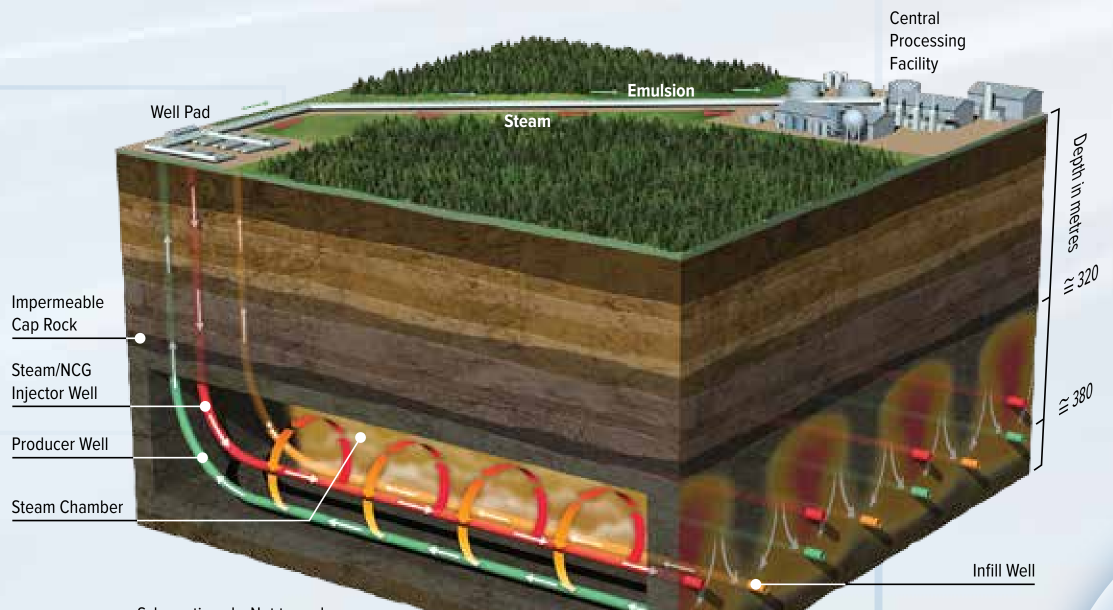
Phase 2B has set a strong foundation for MEG's near-term target of 80,000 bpd by 2015 and medum-term target of 115,000 to 125,000 bpd by 2017.

RISER—
the right way to grow

The RISER initiative has redefined how MEG approaches growth. Through RISER, existing assets are optimized by deploying proven technologies, debottlenecking existing plants and initiating brownfield expansions before launching new "greenfield" phases. This approach to growth adds significant value by accelerating production and cash flows, increasing recovery rates and reducing both capital and operating costs per barrel as well as greenhouse gas intensity.

Proven Technologies

In the reservoir, RISER employs proven technologies: non-condensable gas (NCG) injection and infill wells, in combination with proprietary reservoir development techniques in a process called enhanced modified steam and gas push (eMSAGP). With eMSAGP, steam is displaced with non-condensable gas to maintain reservoir pressure. The resulting freed-up steam can then be redeployed to other areas of the operation. Infill wells are strategically placed between SAGD well pairs to capture incremental production from existing heat and developing gas pressure, while low-capital cost plant debottlenecks and brownfield expansions are put in place to process the increased production.

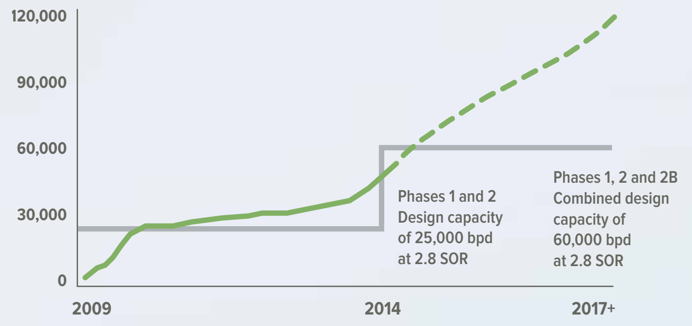


Schematic only. Not to scale.

Results

RISER was launched at Christina Lake Phase 1 in early 2012 and in Phase 2 in 2013. Since deploying RISER, production has increased by 60% over the initial Phase 1 and 2 design capacity. RISER 2B represents the next stage of significant growth for MEG. The impact of RISER and brownfield expansions on Phase 2B is anticipated to yield production increases nearly 130% over the original design capacity of Phase 2B.

RISER "Brownfield" Expansion – Impact on Phase 1, 2 & 2B

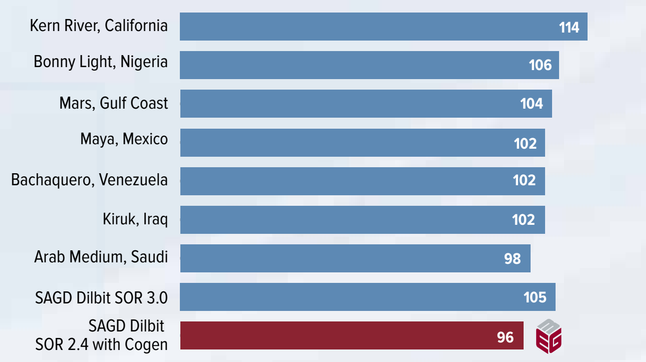


cogeneration

This technology adds more to the reliability and efficiency of MEG's operations, while reducing net operating costs and significantly reducing total greenhouse gas emissions. In the cogeneration process, natural gas is used to simultaneously create steam and electricity at the project site. MEG uses both the steam and electricity generated for our operations and sells surplus power to the Alberta electrical grid. These power sales have offset approximately 80% of MEG's energy costs throughout 2013, supporting our position as a low-operating cost producer.

Cogeneration is another example of how MEG is adding more in a larger sense. Power generated through this process has a lower carbon intensity than the provincial average. This places MEG among the lowest greenhouse gas intensity producers in the industry and helps to reduce Alberta's total greenhouse gas emissions.

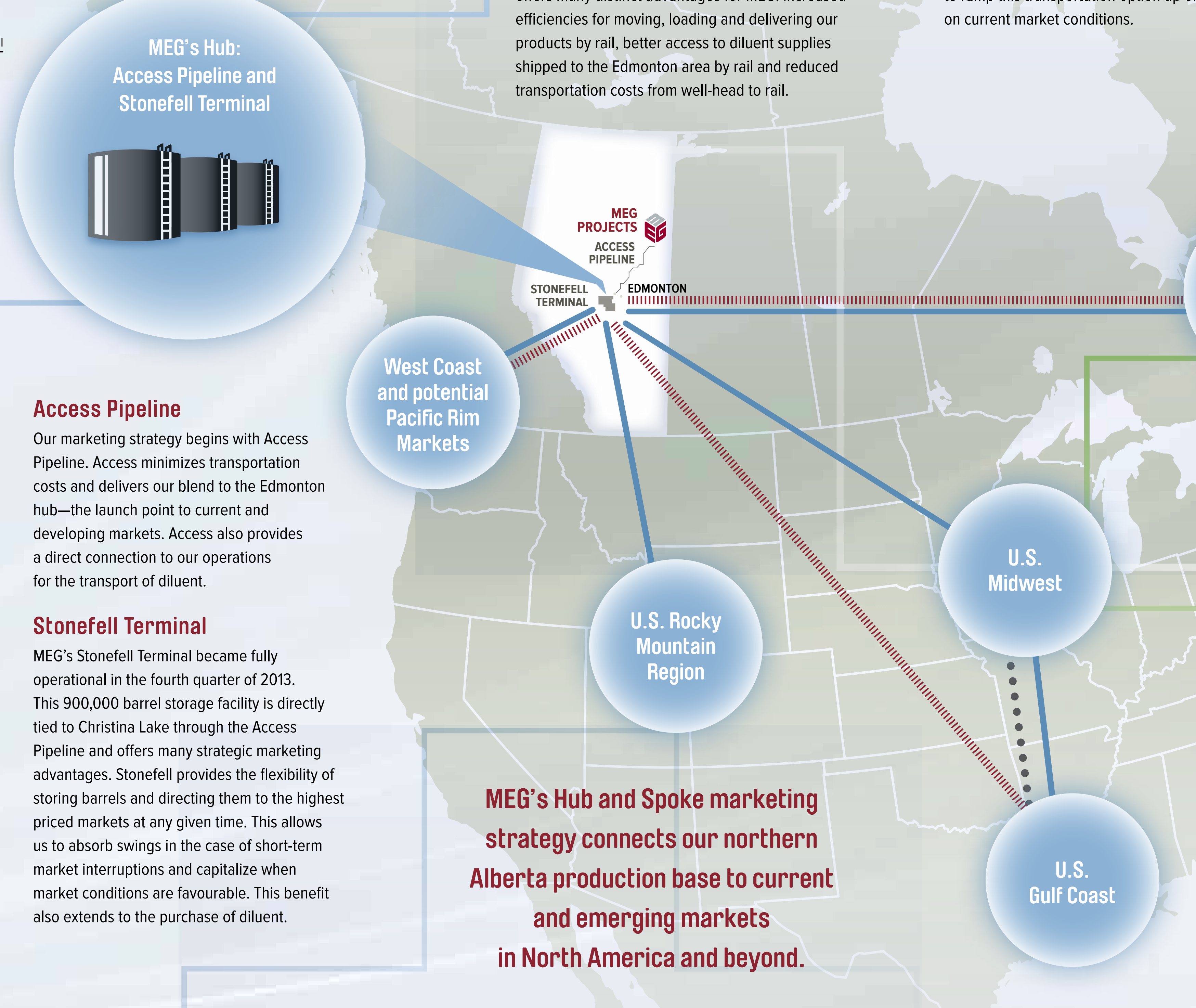
GHG Intensity
(g/MJ)



Source: Jacobs Consultancy, "Life Cycle Assessment of North America and Imported Crudes" July 2009.

the hub

MEG's Access Pipeline connects our producing assets to the company's Stonefell Terminal, the launch point for our product sales.



Access Pipeline

Our marketing strategy begins with Access Pipeline. Access minimizes transportation costs and delivers our blend to the Edmonton hub—the launch point to current and developing markets. Access also provides a direct connection to our operations for the transport of diluent.

Stonefell Terminal

MEG's Stonefell Terminal became fully operational in the fourth quarter of 2013. This 900,000 barrel storage facility is directly tied to Christina Lake through the Access Pipeline and offers many strategic marketing advantages. Stonefell provides the flexibility of storing barrels and directing them to the highest priced markets at any given time. This allows us to absorb swings in the case of short-term market interruptions and capitalize when market conditions are favourable. This benefit also extends to the purchase of diluent.

MEG's Hub and Spoke marketing strategy connects our northern Alberta production base to current and emerging markets in North America and beyond.

the spokes

Long-term capacity on pipelines and flexible options for rail and barging on the U.S. Inland Waterway provide the spokes to reach high-value markets.

Rail

Rail transport, with infrastructure connections across the continent, is a key spoke in MEG's Hub and Spoke strategy. In 2013, MEG successfully completed Canada's first well-head to unit-train loading connection via pipeline. This proprietary connection offers many distinct advantages for MEG: increased efficiencies for moving, loading and unloading our products by rail, better access to diluent supplies shipped to the Edmonton area by rail and reduced transportation costs from well-head to rail.

Barge

Barge transportation provides another "spoke" to move our product to the U.S. Gulf Coast. MEG has leased 18 barges which are available for use as needed. During 2013, MEG successfully tested new refining markets with barge shipments and is well-positioned to ramp this transportation option up or down based on current market conditions.

Pipe

MEG has secured capacity on a number of existing and planned pipelines that can deliver our crude to various markets across North America and position us to reach further to global markets. Through our long-term commitment on the Flanagan-Seaway line, expected to be in-service in the second half of 2014, we will also be able to access higher prices on the U.S. Gulf Coast. Moving our product by pipe continues to be the most efficient and reliable method of transportation, adding significant value to our overall marketing strategy.

emerging technologies

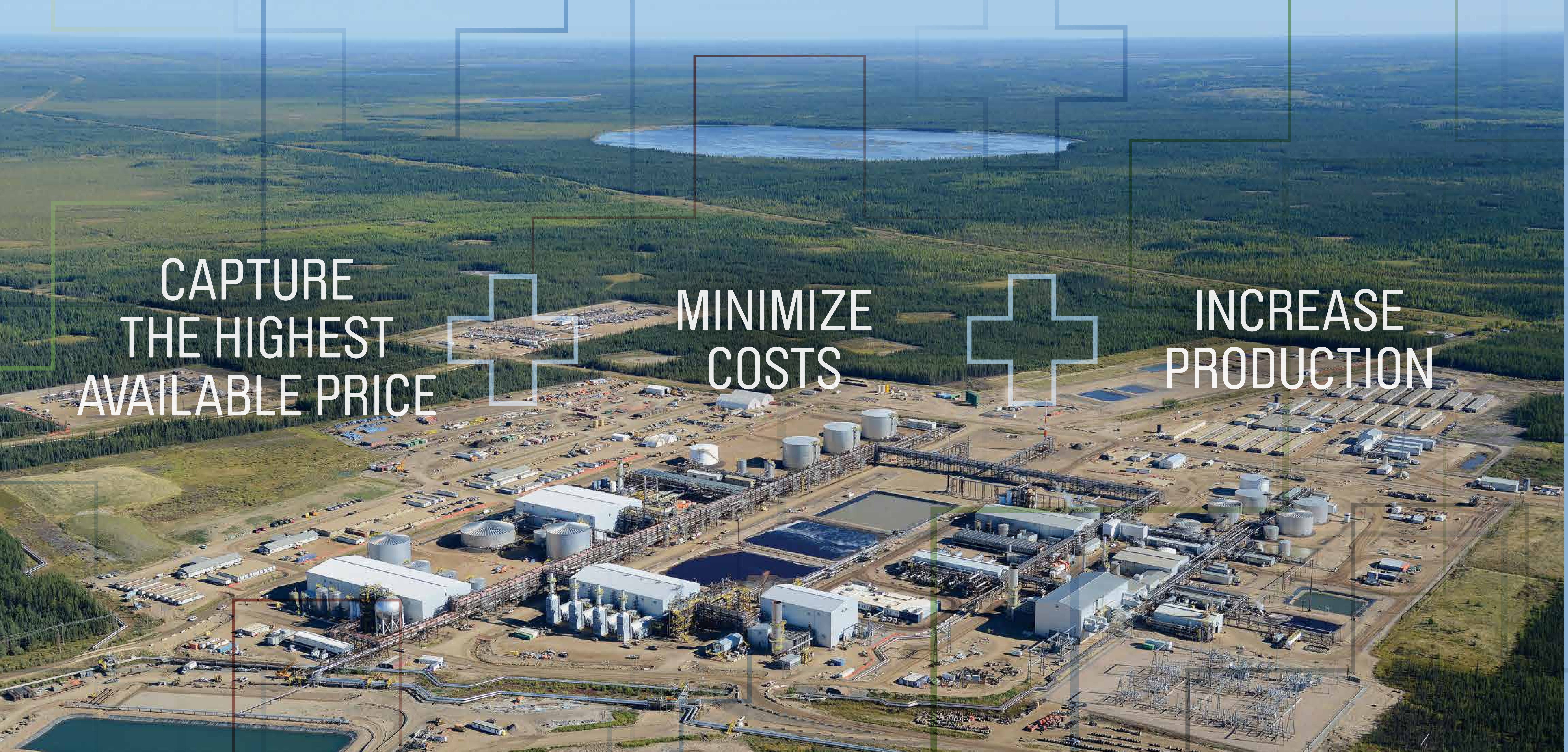
MEG is a technology driven company. We continually seek opportunities to incorporate technologies that can increase performance and efficiency in everything we do, including how we get our product to market.

Diluent Removal Facility

In 2013, MEG announced plans to construct a diluent removal facility that will be connected to our Stonefell Terminal. This technology will recycle expensive diluents needed to move our heavy crude by pipeline and return them to our Christina Lake project via the Access Pipeline. The resulting product, "railbit", can be transported by rail to refining markets across the continent. This technology is anticipated to add value by both increasing our rail shipping capacity and reducing operating costs.

HI-Q™

MEG's proprietary HI-Q™ process is an innovative technology with the potential to add further value to our products. HI-Q™ has been successfully demonstrated on a smaller scale to modify bitumen blends to a product suitable for shipping by pipeline without diluent, at significantly reduced environmental impacts relative to conventional oil sands upgrading processes. The benefits include substantially reduced diluent supply requirements which increase pipeline capacity and ultimately expand market access. In 2014, MEG plans to begin construction of a field demonstration pilot to prove this technology at a commercial scale.



CAPTURE THE HIGHEST AVAILABLE PRICE

MINIMIZE COSTS

INCREASE PRODUCTION

IT ALL ADDS UP TO INCREASED SHAREHOLDER VALUE

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 year ended December 31, 2013 is dated March 4, 2014. This MD&A should be read in conjunction with the Corporation's audited consolidated financial statements and notes thereto for the year ended December 31, 2013. All tabular amounts are stated in thousands of Canadian dollars ($ or C$) unless indicated otherwise.

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 (the "GLJ Report"), with a preparation date of January 16, 2014, GLJ Petroleum Consultants Ltd. ("GLJ") 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 ("bpd") of production and MEG has applied for regulatory approval for 120,000 bpd 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 could 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 designed capacity of 25,000 bpd. Phase 2B, an expansion with a designed capacity of 35,000 bpd, commenced production in the fourth quarter of 2013. MEG anticipates that Phase 2B will ramp up to full designed capacity over the 9 to 12 months following the initial well steaming phase. On July 16, 2012, the Corporation announced the RISER initiative, which is designed to increase production from existing assets at relatively low capital and operating costs using a combination of proprietary reservoir technologies, redeployment of steam and facilities modifications, including debottlenecking and expansions (collectively, "RISER"). As a result of the operational success achieved at Phases 1 and 2, including the success achieved from applying RISER to each of these phases, and the ongoing ramp-up of Phase 2B, MEG anticipates reaching a near-term production target from Christina Lake Phases 1, 2 and 2B of 80,000 bpd by 2015 and a medium-term production target of 115,000 to 125,000 bpd by 2017.

The medium-term production target will be primarily driven by the application of the RISER initiative to Phase 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 (collectively, "RISER 2B"). RISER 2B is anticipated to add incremental production on the scale of a typical greenfield project at approximately two-thirds the cost. Given the attractiveness of this brownfield strategy, MEG expects to prioritize RISER 2B ahead of the full development of Phase 3A, which represents MEG's next greenfield expansion. Phase 3 has received regulatory authorization to proceed and MEG continues to advance engineering and the procurement of long lead-time items to be in a position to develop Phase 3A once RISER 2B has been optimized.

In addition, MEG has filed regulatory applications for the Surmont Project. The Surmont Project, which is situated along the same geological trend as Christina Lake, has an anticipated designed capacity of approximately 120,000 bpd over multiple phases. MEG filed a regulatory application for the project in September 2012. The proposed project is expected to use SAGD technology and include multi-well production pads, electricity and steam cogeneration and other facilities similar to MEG's current Christina Lake Project. The Surmont Project is located approximately 30 miles north of the Corporation's Christina Lake 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.

In addition to the Access Pipeline, MEG owns the Stonefell Terminal located near Edmonton, Alberta. The Stonefell Terminal was commissioned in the fourth quarter of 2013 and has 900,000 barrels of strategic terminalling and storage capacity. The Stonefell Terminal is 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.

SUMMARY ANNUAL INFORMATION

$000s, except per share amounts	**2013**	**2012**	**2011**
Total revenue, net of royalties	**1,334,497**	1,050,504	1,036,613
Net income (loss)	**(166,405)**	52,569	63,837
Per share – basic	**(0.75)**	0.27	0.33
Per share – diluted	**(0.75)**	0.26	0.32
Total assets	**9,447,741**	8,018,679	6,201,049
Total non-current liabilities	**4,209,719**	2,667,860	1,900,369

Total revenues have increased primarily as a result of the increase in production from the Christina Lake Project. The increase in production is due to the implementation of RISER on Christina Lake Phases 1 and 2 and the start-up of Christina Lake Phase 2B. The expanded steam generation capacity and improved reservoir efficiency from the RISER implementation has enabled the Corporation to place additional wells into production in 2013. Steam injection into the Phase 2B well pairs commenced in the third quarter of 2013 and the Corporation achieved first production from Phase 2B in the fourth quarter of 2013.

Net income has been impacted by foreign exchange gains and losses (2013 – $180.3 million loss; 2012 – $36.6 million gain; 2011 – $35.7 million loss) 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 and U.S. dollar cash and cash equivalents. Net income has also been impacted by the increase in depletion and depreciation expense (2013 – $189.1 million; 2012 – $145.0 million; 2011 – $124.3 million), the increase in general and administrative expense (2013 – $92.8 million; 2012 – $70.6 million; 2011 – $55.7 million gain), and the increase in interest expense (2013 – $110.3 million; 2012 – $91.8 million; 2011 – $73.6 million).

Total assets have increased due to capital investment in the Christina Lake Project, the RISER initiative, the Access Pipeline and the Stonefell Terminal, as well as resource definition at the Surmont Project and the Growth Properties.

Investment activity was partially funded by:

- the issuance of US$750.0 million in aggregate principal amount of 6.5% senior unsecured notes in March 2011;
- the issuance of US$800 million in aggregate principal amount of 6.375% senior unsecured notes in July 2012;
- the issuance of 24.2 million common shares at a price of $33.00 per share for proceeds of $774.8 million, net of issue costs, in December 2012;
- the increased borrowing under the senior secured term loan of US$300.0 million in February 2013; and
- the issuance of US$1.0 billion in aggregate principal amount of 7.0% senior unsecured notes in the fourth quarter of 2013.

For a detailed discussion of the Corporation's investing activities, see "LIQUIDITY AND CAPITAL RESOURCES – Cash Flows – Investing Activities".

OPERATIONAL AND FINANCIAL HIGHLIGHTS

The following table summarizes selected operational and financial information of the Corporation for the years ended:

	2013	2012
Bitumen production *(bpd)*	**35,317**	28,773
Bitumen sales *(bpd)*	**33,715**	28,845
Steam to oil ratio (SOR)	**2.6**	2.4
West Texas Intermediate (WTI) *(US$/bbl)*	**97.96**	94.21
Differential – Blend vs WTI *(%)*	**32.7%**	31.2%
Bitumen realization *($/bbl)*	**49.28**	46.93
Net operating costs (1) *($/bbl)*	**10.01**	9.98
Non-energy operating costs *($/bbl)*	**9.00**	9.71
Cash operating netback (2) *($/bbl)*	**35.87**	34.18
Total cash capital investment (3) *($000)*	**2,188,353**	1,598,514
Net income (loss) *($000)*	**(166,405)**	52,569
Per share, diluted	**(0.75)**	0.26
Operating earnings *($000)* (4)	**386**	21,242
Per share, diluted (4)	**0.00**	0.11
Cash flow from operations *($000)* (4)	**253,424**	212,514
Per share, diluted (4)	**1.13**	1.06
Cash, cash equivalents and short-term investments *($000)*	**1,179,072**	2,007,841
Long-term debt *($000)*	**4,004,575**	2,488,609
Bitumen Reserves and Contingent Resources *(millions of barrels, before royalties)*		
Bitumen Reserves *(millions of barrels, before royalties)*		
Proved (1P) Reserves (5)	**1,446**	1,284
Probable Reserves (6)	**1,451**	1,360
Proved Plus Probable (2P) Reserves (5)(6)	**2,897**	2,644
Bitumen Contingent Resources *(millions of barrels, before royalties)*		
Best Estimate Contingent Resources (2C) (7)(8)(9)	**3,653**	3,420

(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 $76.5 million for the year ended December 31, 2013 ($30.6 million for the year ended December 31, 2012).

(4) 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 operating activities in accordance with IFRS under the heading "NON-IFRS MEASUREMENTS" and discussed further in the "ADVISORY" section.

(5) "Proved Reserves" are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves. Proved Reserves are also referred to as "1P Reserves".

(6) "Probable Reserves" are those additional reserves that are less certain to be recovered than Proved Reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves. Proved plus probable reserves are also referred to as "2P Reserves".

(7) "Contingent Resources" are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Such contingencies include further reservoir delineation, additional facility and reservoir design work, submission of regulatory applications and the receipt of corporate approvals. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage. Contingent resources are further classified in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status. There is no certainty that it will be commercially viable to produce any portion of the contingent resources.

(8) There are three categories in evaluating Contingent Resources: Low Estimate, Best Estimate and High Estimate. The resource numbers presented all refer to the Best Estimate category. Best Estimate is a classification of resources described in the Canadian Oil and Gas Evaluation (COGE) Handbook as being considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the Best Estimate. If probabilistic methods are used, there should be a 50% probability (P50) that the quantities actually recovered will equal or exceed the Best Estimate. Best Estimate Contingent Resources are also referred to as "2C Resources".

(9) These volumes are the arithmetic sums of the Best Estimate Contingent Resources for Christina Lake, Surmont and the Growth Properties.

Bitumen production for the year ended December 31, 2013 averaged 35,317 bpd compared to 28,773 bpd for the year ended December 31, 2012. The increase in production volumes in 2013 compared to 2012 is due to the implementation of RISER on Christina Lake Phases 1 and 2 and the start-up of Christina Lake Phase 2B. The expanded steam generation capacity and improved reservoir efficiency from the RISER implementation has enabled the Corporation to place additional wells into production in 2013. Steam injection into the Phase 2B well pairs commenced in the third quarter of 2013 and the Corporation achieved first production from Phase 2B in the fourth quarter of 2013.

For the year ended December 31, 2013, the average SOR was 2.6, compared to an average SOR of 2.4 for the year ended December 31, 2012. The increase in the average SOR is the result of Phase 2B start-up. It is anticipated that the SOR for the next several months will be higher than historical values due to the start-up of new well pairs in Phase 2B. Each of these new well pairs will require steam preheating prior to conversion to production mode. Once well pairs commence production, the SOR will begin to decrease. 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.

Bitumen realizations increased for the year ended December 31, 2013 as compared to the year ended December 31, 2012 primarily as a result of the increase in the price of WTI. The price of WTI averaged US$97.96 per barrel during 2013 compared to US$94.21 per barrel during 2012. For the year ended December 31, 2013, the differential between WTI and the Corporation's blend sales price was 32.7% compared to a differential of 31.2% for the year ended December 31, 2012.

Net operating costs on a per barrel basis for the year ended December 31, 2013 were $10.01 per barrel compared to $9.98 per barrel for the year ended December 31, 2012. The increase in net operating costs on a per barrel basis is attributable to the increase in energy operating costs, as natural gas prices increased to $3.21 per mcf in 2013, from an average of $2.49 per mcf in 2012. This was partially offset by:

- an increase in power realizations to $76.23 per megawatt hour in 2013 from $59.22 per megawatt hour in 2012, and;
- a decrease in non-energy costs, as expressed on a per barrel basis, to $9.00 per barrel in 2013, from $9.71 per barrel in 2012. This decrease is largely the result of higher production volumes from the implementation of RISER.

Power sales had the effect of offsetting 78% of energy operating costs during the year ended December 31, 2013 compared to 92% of energy operating costs during the year ended December 31, 2012. Power generation volatility in Alberta was higher during the first half of 2013, which resulted in full year 2013 power prices above 2012 levels.

Cash operating netback for the year ended December 31, 2013 was $35.87 per barrel compared to $34.18 per barrel for the year ended December 31, 2012. The increase in cash operating netbacks is due largely to the increase in bitumen realizations for the year ended December 31, 2013 as compared to the year ended December 31, 2012.

Capital investment for the year ended December 31, 2013 was $2.2 billion (including $76.5 million of capitalized interest) compared to $1.6 billion for the year ended December 31, 2012. Capital investment during 2013 has focused on the completion of Phase 2B, the RISER initiative, completion of the Stonefell Terminal, the expansion of the Access Pipeline, engineering, procurement of long-lead equipment and site preparation for Phase 3A and delineation drilling at Christina Lake and Surmont.

The net loss for the year ended December 31, 2013 was $166.4 million, which was primarily due to the $213.7 million foreign exchange loss on conversion of the Corporation's U.S. dollar denominated debt. As at December 31, 2013, the Canadian dollar, at a rate of 1.0636, had decreased in value by approximately 7% against the U.S. dollar compared to its value as at December 31, 2012, when the rate was 0.9949. Net income for the year ended December 31, 2012 was $52.6 million and included a foreign exchange gain of $48.8 million on conversion of the Corporation's U.S. dollar denominated debt.

The Corporation recognized operating earnings for the year ended December 31, 2013 of $0.4 million compared to operating earnings of $21.2 million for the year ended December 31, 2012. In 2013, the increase in cash operating netback resulting from higher bitumen sales volumes and bitumen realizations was offset by higher depletion and depreciation, general and administrative and interest expense compared to 2012.

Cash flow from operations was $253.4 million for the year ended December 31, 2013, compared to $212.5 million for the year ended December 31, 2012. Cash flow from operations increased due to higher bitumen sales volumes and bitumen realizations. These increases were partially offset by higher general and administrative and interest expense as compared to 2012. Cash flow from operations was further impacted by approximately 576,000 barrels of production being placed in storage, used as line-fill or capitalized in association with the commissioning of Phase 2B during the fourth quarter of 2013.

The Corporation's cash, cash equivalents and short-term investments balance was $1.2 billion as at December 31, 2013 compared to $2.0 billion as at December 31, 2012. The Corporation's cash, cash equivalents and short-term investments balances have been impacted by the increases in long-term debt and capital investments over the past year. Long-term debt increased to $4.0 billion as at December 31, 2013, from $2.5 billion as at December 31, 2012. The increase in long-term debt is due to the increase in the senior secured term loan, the issuance of senior unsecured notes and the impact of foreign exchange on the U.S. dollar denominated debt. Effective 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 0.25 percent. During the fourth quarter of 2013 the Corporation issued US$1.0 billion in aggregate principal amount of 7.0% senior unsecured notes which will mature on March 31, 2024.

As at December 31, 2013, the Corporation's capital resources included $1.2 billion of cash and cash equivalents and an undrawn US$2.0 billion revolving credit facility. As at December 31, 2013, $133.9 million of the revolving credit facility was utilized to support letters of credit.

OUTLOOK

Annual bitumen production volumes for 2014 are targeted to be in the 60,000 to 65,000 bpd range and annual non-energy operating costs are targeted to be in the range of $8 to $10 per barrel.

The Corporation's 2014 planned capital program totals $1.8 billion, including $200 million which is available on a discretionary basis subject to the timing of current and future projects. MEG's 2014 base capital program includes $920 million in growth capital, $445 million focused on marketing initiatives and $235 million in sustaining and other capital. Capital investment for the Corporation's RISER initiative at Christina Lake Phases 1 and 2 is now complete and with the demonstrated success of the initiative, MEG is now advancing its RISER 2B program. The RISER 2B program will include MEG's proprietary eMSAGP technology and a major brownfield expansion of the Phase 2B facilities. This project is anticipated to result in ultimate production levels from Phase 2B of 75,000 to 85,000 bpd, an increase of approximately 130% over its initial designed capacity.

In addition to the medium-term growth capital directed to RISER 2B, MEG will allocate $580 million to position itself for longer-term growth. This investment includes $275 million towards engineering and long lead-time items for Phase 3, in order to prepare for the next growth platform in the Corporation's portfolio once Phase 2B is fully optimized. MEG is also planning a facility which will remove diluent from a significant portion of the Corporation's bitumen blend that is to be shipped by rail. The diluent would then be recycled back to the Christina Lake Project site. The resulting product would be shipped by rail to refining markets at substantially reduced transportation costs. Capital investment of $75 million in 2014 is planned for the project, with completion targeted for late 2015.

On a longer-term strategic basis, MEG has also committed $125 million in 2014 for the construction of a Field Demonstration Pilot project of the Corporation's proprietary HI-Q™ technology. This technology, which has been successfully demonstrated over a number of years on a smaller scale, is designed to modify MEG's bitumen production to a HI-Q™ product suitable for shipping by pipeline without diluent.

The Corporation will also invest approximately $210 million in 2014 for the continuing expansion of the jointly-owned Access Pipeline.

BUSINESS ENVIRONMENT

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

	Year ended December 31		2013				2012			
	2013	**2012**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**
Commodity Prices (Averages)										
Crude oil prices										
West Texas Intermediate (WTI) *(US$/bbl)*	**97.96**	94.21	**97.43**	**105.83**	**94.22**	**94.37**	88.18	92.22	93.49	102.92
West Texas Intermediate (WTI) *(C$/bbl)*	**100.86**	94.14	**102.08**	**109.90**	**96.42**	**95.21**	87.41	91.73	94.44	103.06
Western Canadian Select (WCS) *(C$/bbl)*	**74.97**	73.13	**68.31**	**91.75**	**76.82**	**63.01**	69.47	70.06	71.34	81.66
Differential—WTI vs WCS *(C$/bbl)*	**25.89**	21.01	**33.77**	**18.15**	**19.60**	**32.20**	17.94	21.67	23.10	21.39
Differential—WTI vs WCS *(%)*	**25.7%**	22.3%	**33.1%**	**16.5%**	**20.3%**	**33.8%**	20.5%	23.6%	24.5%	20.8%
Natural gas prices										
AECO *(C$/mcf)*	**3.16**	2.38	**3.52**	**2.42**	**3.51**	**3.18**	3.20	2.27	1.89	2.14
Electric power prices										
Alberta power pool *(C$/MWh)*	**80.22**	64.24	**48.60**	**83.61**	**123.41**	**65.26**	78.73	78.09	40.03	60.10
Foreign exchange rates										
C$ equivalent of 1 US$—average	**1.0296**	0.9994	**1.0477**	**1.0385**	**1.0233**	**1.0089**	0.9913	0.9948	1.0102	1.0012
C$ equivalent of 1 US$—period end	**1.0636**	0.9949	**1.0636**	**1.0285**	**1.0512**	**1.0156**	0.9949	0.9837	1.0191	0.9991

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$97.96 per barrel for the year ended December 31, 2013 compared to US$94.21 per barrel for the year ended December 31, 2012.

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 25.7% for the year ended December 31, 2013 compared to 22.3% for the year ended December 31, 2012.

Ongoing pipeline congestion between the Western Canada and U.S. coastal markets negatively impacts the price received for WCS. Recent additions of crude-by-rail to access new markets as well as pipeline additions connecting the U.S. mid-continent to the U.S. Gulf Coast and refinery modifications in the U.S. Midwest are anticipated to relieve some of this price pressure in the first half of 2014. Incrementally, initiatives to access additional markets, including the recently completed TransCanada Gulf Coast Pipeline and the ongoing construction of the Flanagan South pipeline and Seaway expansion, 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. During the year ended December 31, 2013, the AECO natural gas price averaged $3.16 per mcf compared to $2.38 per mcf for the year ended December 31, 2012.

During the year ended December 31, 2013, the Alberta power pool price averaged $80.22 per megawatt hour compared to an average price of $64.24 per megawatt hour for 2012. Power generation volatility over the first half of 2013 resulted in full year 2013 prices above 2012 levels.

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 December 31, 2013, the Canadian dollar, at a rate of 1.0636, had decreased in value by approximately 7% against the U.S. dollar compared to its value as at December 31, 2012, when the rate was 0.9949.

RESULTS OF OPERATIONS

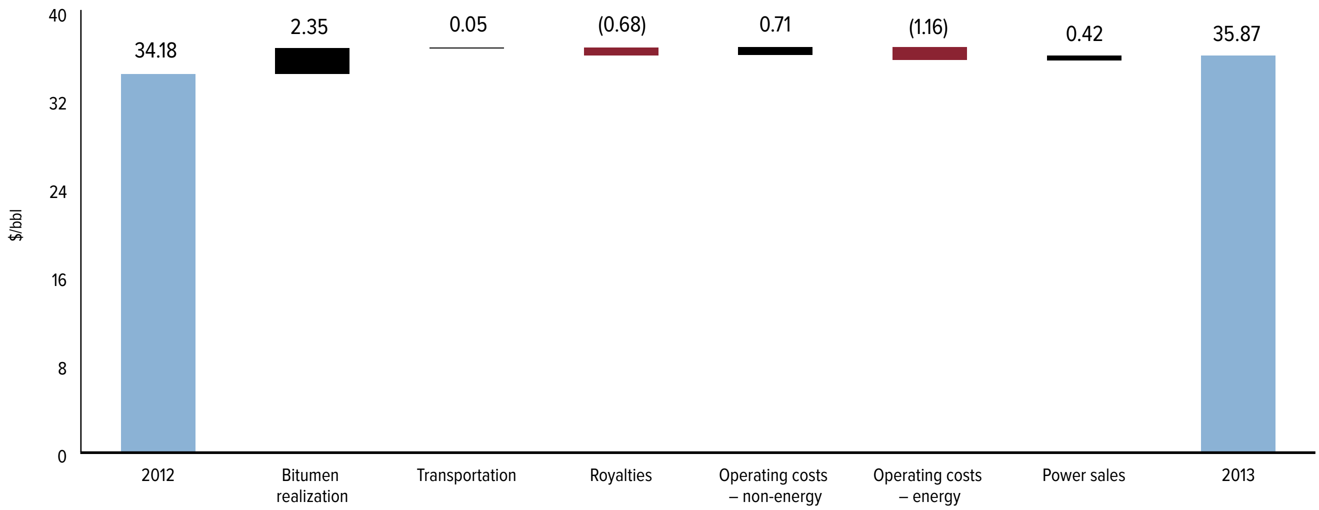
	2013	2012
Bitumen production *(bpd)*	**35,317**	28,773
Steam to oil ratio (SOR)	**2.6**	2.4

Production

Production for the year ended December 31, 2013 averaged 35,317 bpd compared to 28,773 bpd for the year ended December 31, 2012. The increase in production volumes in 2013 compared to 2012 is due to the implementation of RISER on Phases 1 and 2 and the start-up of Christina Lake Phase 2B, which achieved first production in the fourth quarter of 2013. 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 in 2013.

For the year ended December 31, 2013, the average SOR was 2.6, compared to an average SOR of 2.4 for the year ended December 31, 2012. The increase in the average SOR for these periods is the result of Phase 2B start-up. It is anticipated that the SOR for the next several months will be higher than historical values due to the start-up of new well pairs in Phase 2B. Each of these new well pairs will require steam preheating prior to conversion to production mode. Once well pairs commence production, the SOR will begin to decrease. 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—Year Ended December 31, 2013 versus December 31, 2012



The following table summarizes the Corporation's cash operating netback for the years ended December 31:

	2013		2012	
	$000	*$ per bbl*	*$000*	*$ per bbl*
Bitumen realization [1]	**606,458**	**49.28**	495,425	46.93
Transportation [2]	**(3,172)**	**(0.26)**	(3,231)	(0.31)
Royalties	**(38,642)**	**(3.14)**	(25,959)	(2.46)
Net bitumen revenue	**564,644**	**45.88**	466,235	44.16
Operating costs – non-energy	**(110,742)**	**(9.00)**	(102,481)	(9.71)
Operating costs – energy	**(56,844)**	**(4.62)**	(36,538)	(3.46)
Power sales	**44,455**	**3.61**	33,634	3.19
Net operating costs	**(123,131)**	**(10.01)**	(105,385)	(9.98)
Cash operating netback [3]	**441,513**	**35.87**	360,850	34.18

(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.

($000)	2013	2012
Blend sales – proprietary	**1,207,649**	991,975
Cost of diluent	**(601,191)**	(496,550)
Bitumen realization	**606,458**	495,425

Blend sales for the year ended December 31, 2013 were $1.2 billion compared to $1.0 billion for the year ended December 31, 2012. The increase in blend sales for 2013 compared to 2012 is due to a 17% increase in sales volumes combined with an increase in the average realized price. Sales volumes increased as a result of the increased production volumes in 2013. Blend sales averaged $67.88 per barrel during the year ended December 31, 2013 compared to $64.78 per barrel for the year ended December 31, 2012.

The cost of diluent for the year ended December 31, 2013 was $601.2 million compared to $496.6 million for the year ended December 31, 2012. The total cost of diluent increased due to the increase in the per barrel cost of diluent and the higher volumes of diluent purchased as a result of increased bitumen sales. On a per barrel basis, the Corporation's average cost of diluent was $109.60 per barrel during the year ended December 31, 2013 compared to an average cost of $104.41 per barrel during the year ended December 31, 2012.

Transportation

Transportation costs, which include MEG's share of the operating costs for the Access Pipeline, net of third party recoveries, were $3.2 million for both the year ended December 31, 2013 and December 31, 2012, net of $19.3 million and $13.0 million in recoveries, respectively. Transportation costs averaged $0.26 per barrel for the year ended December 31, 2013 compared to $0.31 per barrel for the year ended December 31, 2012.

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 were $38.6 million for the year ended December 31, 2013 compared to $26.0 million for the year ended December 31, 2012. The increase in royalties for the year ended December 31, 2013 compared to the same period in 2012 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 $3.14 per barrel during the year ended December 31, 2013 compared to $2.46 per barrel for the year ended December 31, 2012. The Corporation's royalty rate averaged 6.4% for the year ended December 31, 2013 compared to 5.2% for the year ended December 31, 2012.

Operating Costs

Non-energy operating costs were $110.7 million for the year ended December 31, 2013, compared to $102.5 million for the year ended December 31, 2012. Non-energy operating costs averaged $9.00 per barrel for the year ended December 31, 2013 compared to $9.71 per barrel for the same period in 2012. The increase in non-energy related operating costs is primarily attributable to higher materials, camp and labor costs. These increases were more than offset on a per barrel basis by the increase in sales volumes.

Energy related operating costs were $56.8 million for the year ended December 31, 2013 compared to $36.5 million for the year ended December 31, 2012. On a per barrel basis, energy related operating costs were $4.62 per barrel for the year ended December 31, 2013 compared to $3.46 per barrel for the year ended December 31, 2012. The increase in energy related operating costs per barrel is primarily the result of higher natural gas prices. The benchmark AECO natural gas price averaged $3.16 per mcf during the year ended December 31, 2013 compared to $2.38 per mcf for the year ended December 31, 2012.

Power Sales

With the completion of the Christina Lake Phase 2B cogeneration facility, the Corporation now has two 85 megawatt cogeneration facilities which produce steam for current SAGD operations. MEG's Christina Lake facilities utilize the heat produced by the cogeneration facility and a portion of the power generated. Surplus power is sold into the Alberta power pool.

Power sales were $44.5 million for the year ended December 31, 2013, compared to $33.6 million for the year ended December 31, 2012. The average realized power price in 2013 was $76.23 per megawatt hour compared to $59.22 per megawatt hour in 2012. 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. Power generation volatility over the first half of 2013 resulted in full year 2013 prices above 2012 levels.

NON-IFRS MEASUREMENTS

The following tables reconcile the non-IFRS measurements "Operating earnings" 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 operating activities", the nearest IFRS measure. Operating earnings 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 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.

($000)	**2013**	**2012**
Net income (loss)	**(166,405)**	52,569
Add (deduct):		
Unrealized foreign exchange (gain) loss, net of tax (1)	**181,234**	(39,090)
Unrealized (gain) loss on derivative financial liabilities, net of tax (2)	**(14,443)**	9,651
Unrealized fair value (gain) loss on other assets, net of tax (3)	**–**	(1,888)
Operating earnings	**386**	21,242
Add (deduct):		
Interest income	**(22,550)**	(19,896)
Depletion and depreciation	**189,147**	144,950
General and administrative	**92,828**	70,597
Stock-based compensation	**38,792**	25,246
Research and development	**5,588**	5,157
Interest expense	**110,306**	91,816
Accretion	**4,763**	3,670
Gain on disposition of assets	**(1,410)**	(3,075)
Realized (gain) loss on foreign exchange	**2,916**	(796)
Realized loss on derivative financial liabilities	**4,720**	4,518
Net marketing activity	**2,365**	1,762
Deferred income tax expense (recovery), operating	**13,662**	15,659
Cash operating netback	**441,513**	360,850

(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 expense of $3,872 for the year ended December 31, 2013 (deferred tax recovery of $3,269 for the year ended December 31, 2012).

(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 fix a portion of its variable rate long-term debt, net of a deferred tax expense of $4,813 for the year ended December 31, 2013 (deferred tax recovery of $3,217 for the year ended December 31, 2012).

(3) Unrealized fair value gain on other assets results from the fair market valuation of other assets held during the year, net of a deferred tax expense of $630 for the year ended December 31, 2012.

Non-IFRS Measurements – Reconciliation of net cash provided by operating activities to cash flow from operations *($000)*	**2013**	**2012**
Net cash provided by operating activities	**129,963**	240,824
Add:		
Net change in non-cash operating working capital items	**123,461**	(28,310)
Cash flow from operations	**253,424**	212,514

Depletion and Depreciation

Depletion and depreciation expense was $189.1 million for the year ended December 31, 2013, compared to $145.0 million for the year ended December 31, 2012. The increase is primarily due to higher sales volumes and an increase in the rate per barrel as a result of an increase in GLJ's estimate of future development costs of the producing oil sands properties. The future development costs are a key element of the rate determination. Sales volumes increased by approximately 17% in 2013, as compared to the same periods in 2012. The depletion and depreciation rate for the year ended December 31, 2013 was $15.37 per barrel compared to $13.76 per barrel for the year ended December 31, 2012.

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 Costs

($000)	2013	2012
General and administrative costs	**123,194**	91,510
Capitalized general and administrative costs	**(30,366)**	(20,913)
General and administrative expense	**92,828**	70,597

General and administrative expense for the year ended December 31, 2013 was $92.8 million compared to $70.6 million for the year ended December 31, 2012. 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

($000)	2013	2012
Stock-based compensation costs	**50,060**	32,042
Capitalized stock-based compensation costs	**(11,268)**	(6,796)
Stock-based compensation expense	**38,792**	25,246

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 $38.8 million for the year ended December 31, 2013, compared to $25.2 million for the year ended December 31, 2012. The increase in stock-based compensation for the year ended December 31, 2013 compared to 2012 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 $11.3 million of stock-based compensation for the year ended December 31, 2013 compared to $6.8 million during the year ended December 31, 2012.

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 $5.6 million for the year ended December 31, 2013, compared to $5.2 million for the year ended December 31, 2012.

Net Finance Expense

($000)	2013	2012
Total interest expense	**186,835**	122,424
Less capitalized interest	**(76,529)**	(30,608)
Net interest expense	**110,306**	91,816
Accretion on decommissioning provision	**4,763**	3,670
Unrealized fair value (gain) loss on embedded derivative financial liabilities	**(14,352)**	2,953
Unrealized fair value (gain) loss on interest rate swaps	**(4,904)**	9,915
Realized loss on interest rate swaps	**4,720**	4,518
Fair value (gain) loss on other assets	**–**	(2,518)
Net finance expense	**100,533**	110,354
Average effective interest rate	**6.0%**	5.8%

For the year ended December 31, 2013, total interest expense increased to $186.8 million compared to $122.4 million for the year ended December 31, 2012. Total interest expense increased primarily as a result of the increased debt outstanding. 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 $14.4 million for the year ended December 31, 2013 compared to an unrealized loss of $3.0 million for the same period in 2012. These gains and losses 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 $4.7 million for the year ended December 31, 2013 compared to a realized loss of $4.5 million for the year ended December 31, 2012. In addition, the Corporation recognized an unrealized gain of $4.9 million for the year ended December 31, 2013 compared to an unrealized loss of $9.9 million in 2012.

Net Foreign Exchange Gain (Loss)

($000)	**2013**	**2012**
Foreign exchange gain (loss) on:		
Long-term debt	**(213,715)**	48,822
US$ denominated cash and cash equivalents	**36,353**	(13,000)
Other	**(2,916)**	796
Net foreign exchange gain (loss)	**(180,278)**	36,618

C$-US$ exchange rate as at December 31,	**2013**	**2012**	**2011**
C$ equivalent of 1 US$	**1.0636**	0.9949	1.0170

The Corporation recognized a net foreign exchange loss for the year ended December 31, 2013 of $180.3 million compared to a net foreign exchange gain of $36.6 million for the year ended December 31, 2012. During the year ended December 31, 2013, the Canadian dollar weakened in value compared to the U.S. dollar by approximately 7%. In comparison, the Canadian dollar strengthened by approximately 2% during the year ended December 31, 2012.

Net Marketing Activity

($000)	**2013**	**2012**
Sales of purchased product	**101,750**	37,822
Purchased product and storage	**(104,115)**	(39,584)
Net marketing activity	**(2,365)**	(1,762)

Net marketing activity includes the Corporation's 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 deferred income tax expense of $22.3 million for the year ended December 31, 2013 compared to $9.8 million for the year ended December 31, 2012.

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 non-taxable portion of foreign exchange gains and losses arising on the translation of the U.S. dollar denominated debt is a permanent difference. For the year ended December 31, 2013, the non-taxable loss was $106.9 million compared to a non-taxable gain of $24.4 million for the year ended December 31, 2012;
- As at December 31, 2013, the Corporation had not recognized the tax benefit related to $86.0 million in unrealized taxable capital foreign exchange losses; and
- For the year ended December 31, 2013, non-taxable stock-based compensation expense was $38.8 million compared to $25.2 million for the year ended December 31, 2012.

The Corporation is not currently taxable. As of December 31, 2013, the Corporation had approximately $6.8 billion of available tax pools and had recognized a deferred income tax liability of $93.8 million. In addition, at December 31, 2013, the Corporation had $508.1 million of capital investment in respect of incomplete projects which will increase available tax pools upon completion of the projects.

SUMMARY OF QUARTERLY RESULTS

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

	2013				**2012**			
($ millions, except per share amounts)	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**
Revenue	**350.3**	**401.8**	**324.4**	**258.0**	297.6	213.7	259.7	279.6
Net income (loss)	**(148.2)**	**115.4**	**(62.3)**	**(71.3)**	(18.7)	47.5	(29.5)	53.4
Per share—basic	**(0.67)**	**0.52**	**(0.28)**	**(0.32)**	(0.09)	0.24	(0.15)	0.28
Per share—diluted	**(0.67)**	**0.51**	**(0.28)**	**(0.32)**	(0.09)	0.24	(0.15)	0.27

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

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

- increased production due to the implementation of RISER on Phases 1 and 2, which has allowed additional wells to be placed into production;
- 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);
- changes in the fair value of the LIBOR floor on the senior secured term loans (embedded derivative financial liability);
- risk management activities for interest rate swaps;
- an increase in depletion and depreciation expense as a result of the increase in production 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;
- scheduled annual plant maintenance activities performed in May 2013 and September 2012; and
- the start-up of Christina Lake Phase 2B.

CAPITAL INVESTING

($000)	2013	2012
Christina Lake Phase 2B	**200,789**	631,495
Christina Lake Phase 3A	**196,359**	61,982
RISER	**502,711**	166,782
Inventory wells	**132,260**	92,277
Delineation drilling and seismic	**93,025**	127,959
Regulatory	**5,109**	5,577
Other	**198,027**	47,797
Growth	**1,328,280**	1,133,869
Access Pipeline	**257,629**	115,807
Stonefell Terminal	**124,155**	136,399
Field infrastructure	**179,072**	118,372
Infrastructure related to growth	**560,856**	370,578
Sustaining	**100,305**	42,277
Land and other	**122,383**	21,182
Cash capital investment	**2,111,824**	1,567,906
Capitalized interest	**76,529**	30,608
Total cash capital investment	**2,188,353**	1,598,514
Non-cash	**39,799**	21,169
Total capital investment	**2,228,152**	1,619,683

MEG's capital investment for the year ended December 31, 2013 was $2.2 billion (including capitalized interest of $76.5 million and non-cash items of $39.8 million) in comparison to $1.6 billion (including capitalized interest of $30.6 million and non-cash items of $21.2 million) for the year ended December 31, 2012. Capital investment included $1.3 billion in growth focused investment for the year ended December 31, 2013, compared to $1.1 billion for the year ended December 31, 2012.

MEG invested $200.8 million in Phase 2B of the Christina Lake Project during the year ended December 31, 2013. The Phase 2B facility is now complete and attained first oil in the fourth quarter of 2013.

The Corporation invested $196.4 million for the year ended December 31, 2013 on engineering, purchasing of long-lead equipment and materials, and site preparation activity for Phase 3A.

MEG invested $502.7 million during the year ended December 31, 2013 on RISER. The investment was made to accommodate the implementation of RISER on Phases 1 and 2 and to prepare Phase 2B for the first stage of adoption.

The Corporation invested $132.3 million for the drilling of inventory wells at the Christina Lake Project during the year ended December 31, 2013. These inventory wells will be placed on production as freed-up steam becomes available from the implementation of the enhanced Modified Steam and Gas Push (eMSAGP) process.

The Corporation invested $93.0 million during the year ended December 31, 2013 on delineation drilling and seismic. The Corporation drilled 132 stratigraphic wells, one water observation well and four water source wells to support horizontal well placement, further delineate the resource base at Christina Lake and to increase deliverability to the source water system. A total of 24 stratigraphic wells, one water source well and three water test wells were completed at Surmont.

Other capital investment during 2013 includes $128.1 million of commissioning costs for Phase 2B of the Christina Lake Project. These commissioning costs include labour and services, spare parts and inventory, initial chemicals and lubricants, and demobilization costs required for the Phase 2B facility.

A total of $560.9 million was invested during the year ended December 31, 2013 in the Corporation's growth-related infrastructure. During 2013 the Corporation invested $257.6 million on material purchases and construction related to the expansion of the 50%-owned Access Pipeline. Regulatory approval of the pipeline expansion was received in 2012 and over half of the expansion for the 300 kilometer pipeline has been installed. The expansion is expected to be complete and in service by the fourth quarter of 2014. Investment in the Stonefell storage terminal totaled $124.2 million for the year ended December 31, 2013. The Stonefell storage terminal is a 900,000 barrel marketing terminal that is connected to the Access Pipeline. The Corporation completed the commissioning of the terminal in the fourth quarter of 2013 and it is now operational. The Corporation also completed the connection from the Stonefell storage terminal to the Canexus operated rail terminal in the fourth quarter and has commenced shipping blend by unit-train rail facilities. The Corporation invested an additional $179.1 million in field infrastructure for current and future operations at Christina Lake.

The Corporation capitalizes interest associated with qualifying assets. A total of $76.5 million in interest was capitalized during the year ended December 31, 2013 compared to $30.6 million during the year ended December 31, 2012.

Land and other investments includes $39.0 million for land acquired northeast of Edmonton, Alberta in the second quarter of 2013 and $23.5 million to purchase undeveloped oil sands leases near Leismer, Alberta in the third quarter of 2013. Other investments include investments in administrative assets and amounts paid to maintain the right to participate in a potential pipeline project.

Non-cash capital investment for the year ended December 31, 2013 included a $26.0 million provision for future reclamation and decommissioning of the Corporation's property, plant and equipment, $11.3 million in capitalized stock-based compensation and $2.5 million in capitalized depletion and depreciation expense related to the commissioning of Phase 2B.

LIQUIDITY AND CAPITAL RESOURCES

($000, except as noted)	**2013**	**2012**
Cash, cash equivalents and short-term investments	**1,179,072**	2,007,841
Senior secured term loan (December 31, 2013 – US$1.275 billion; December 31, 2012 – US$987.5 million; due 2020)	**1,355,558**	982,464
US$2.0 billion revolver due 2018	**–**	–
6.5% senior unsecured notes (US$750.0 million; due 2021)	**797,700**	746,175
6.375% senior unsecured notes (US$800.0 million; due 2023)	**850,880**	795,920
7.0% senior unsecured notes (US$1.0 billion; due 2024)	**1,063,600**	–
Total debt (1)	**4,067,738**	2,524,559
Shareholders' equity	**4,788,430**	4,870,534
Total book capitalization (2)	**8,856,168**	7,395,093
Total debt/book capitalization (2)	**45.9%**	34.1%

(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 December 31, 2013 and 2012.

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

As at December 31, 2013, the Corporation's available capital resources included $1.2 billion of cash and cash equivalents and an additional undrawn US$2.0 billion syndicated revolving credit facility. As at December 31, 2013, $133.9 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 twelve 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, which commenced March 28, 2013, 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.

On December 28, 2012, the Corporation issued 24.2 million common shares at a price of $33.00 per share for net proceeds of $774.8 million.

On July 19, 2012, the Corporation issued US$800.0 million in aggregate principal amount of 6.375% senior unsecured notes, with interest paid semi-annually. The notes are due on January 30, 2023. The $13.6 million cost of the transaction has been deferred and is being amortized over the life of the notes.

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

($000)	**2013**	**2012**
Net cash provided by (used in):		
Operating activities	**129,963**	240,824
Investing activities	**(1,794,175)**	(1,820,520)
Financing activities	**1,332,088**	1,572,408
Foreign exchange gains (losses) on cash and cash equivalents held in foreign currency	**36,353**	(13,000)
Change in cash and cash equivalents	**(295,771)**	(20,288)

Cash Flows—Operating Activities

Net cash provided by operating activities for the year ended December 31, 2013 was $130.0 million compared to $240.8 million for the year ended December 31, 2012. The decrease in cash flows from operating activities in 2013 compared to 2012 is primarily due to the $151.8 million decrease in non-cash operating working capital. The decrease in non-cash operating working capital was due primarily to the $70.9 million increase in accounts receivable and the $112.4 million increase in inventories. Accounts receivable increased due to an increase in sales volumes, combined with an increase in the realized blend sales price, for December 2013 compared to December 2012. Inventories increased due to production being placed into storage at the Stonefell Terminal in the fourth quarter of 2013.

Cash Flows—Investing Activities

Net cash used for investing activities during the year ended December 31, 2013 primarily consists of $2.2 billion in cash capital investment (refer to the "CAPITAL INVESTING" section of this MD&A for further details), and a $41.5 million purchase of diluent linefill. The Corporation entered into an agreement to transport diluent on a third-party pipeline and is required to supply diluent linefill for the pipeline. These amounts were partially offset by a $430.3 million increase in non-cash investing working capital which is due mainly to the $533.0 million decrease in short-term investments from December 31, 2012 to December 31, 2013.

Net cash used for investing activities for the year ended December 31, 2012 primarily consisted of $1.6 billion in cash capital investment, $7.5 million in proceeds from the disposition of assets and a $230.6 million increase in non-cash investing working capital.

Cash Flows—Financing Activities

Net cash provided by financing activities for the year ended December 31, 2013 primarily consists of $1.3 billion of proceeds from the US$300 million increase in the senior secured term loan and the US$1.0 billion issuance of senior unsecured notes and $31.4 million of proceeds received from the exercise of stock options. These amounts were partially offset by $13.5 million of debt principal repayments and $28.8 million in financing costs.

Net cash provided by financing activities for the year ended December 31, 2012 included: $774.8 million of net proceeds from the issuance of 24.3 million common shares at a price of $33.00 per share; the $792.6 million in net proceeds from the US$750.0 million senior unsecured notes issuance; and $20.7 million in proceeds received from the exercise of stock options. These amounts were partially offset by $10.0 million of debt principal repayment on the senior secured term loan and $5.6 million of fees associated with the revolving credit facility amendment.

SHARES OUTSTANDING

As at December 31, 2013, the Corporation had the following share capital instruments outstanding:

Common shares	222,506,896
Convertible securities	
Stock options outstanding – exercisable and unexercisable	8,859,028
RSUs and PSUs outstanding	2,589,700

As at February 15, 2014, the Corporation had 222,539,891 common shares, 8,707,847 stock options and 2,576,073 restricted share units and performance share units outstanding.

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**	**< 1 year**	**1 – 3 years**	**4 – 5 years**	**More than 5 years**
Long-term debt (1)	4,067,738	13,827	27,654	27,654	3,998,603
Interest on long-term debt (1)	1,938,494	231,313	461,208	458,997	786,976
Decommissioning obligation (2)	293,837	4,848	5,401	–	283,588
Transportation and storage (3)	3,659,047	135,897	275,213	445,258	2,802,679
Contracts and purchase orders (4)	512,196	277,003	58,489	41,629	135,075
Operating leases (5)	414,517	12,288	25,392	61,507	315,330
	10,885,829	675,176	853,357	1,035,045	8,322,251

(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 rates in effect on December 31, 2013.

(2) This represents the undiscounted future obligation associated with the decommissioning of the Corporation's oil and gas properties and facilities.

(3) This represents transportation and storage commitments from 2013 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.

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 and foreign exchange 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.

TRANSACTIONS WITH RELATED PARTIES

The Corporation paid $0.3 million in costs on behalf of WP Lexington Private Equity B.V. ("WP Lex"), in relation to a secondary offering of the Corporation's shares during the year ended December 31, 2013. WP Lex is considered to be a related party of the Corporation as two managing directors of WP Lex also hold positions as members of the Board of Directors of the Corporation. The only other related party transactions during the year ended December 31, 2013 or December 31, 2012, was the compensation of key management personnel. The Corporation considers directors and executive officers of the Corporation as key management personnel.

($000)	**2013**	**2012**
Salaries and short-term employee benefits	**9,230**	8,489
Share-based compensation expense	**12,477**	9,885
	21,707	18,374

OFF-BALANCE SHEET ARRANGEMENTS

At December 31, 2013 and December 31, 2012, the Corporation did not have any off-balance sheet arrangements.

NEW ACCOUNTING POLICIES

The Corporation has adopted the following new and revised standards, along with all consequential amendments, effective January 1, 2013. These changes are made in accordance with the applicable transitional provisions.

IFRS 10, Consolidated Financial Statements, replaces the guidance on control and consolidation in International Accounting Standard ("IAS") 27, Consolidated and Separate Financial Statements, and SIC-12, Consolidation—Special Purpose Entities. IFRS 10 requires consolidation of an investee only if the investor possesses power over the investee, has exposure to variable returns from its involvement with the investee and has the ability to use its power over the investee to affect its returns. Detailed guidance is provided on applying the definition of control. The accounting requirements for consolidation have remained largely consistent with IAS 27. The Corporation assessed its consolidation conclusions on January 1, 2013 and determined that the adoption of IFRS 10 did not result in any change in the consolidation status of its wholly-owned subsidiary, MEG Energy (U.S.) Inc.

IFRS 11, Joint Arrangements, supersedes IAS 31, Interests in Joint Ventures, and requires joint arrangements to be classified either as joint operations or joint ventures depending on the contractual rights and obligations of each investor that jointly controls the arrangement. For joint operations, a company recognizes its share of assets, liabilities, revenues and expenses of the joint operation. An investment in a joint venture is accounted for using the equity method as set out in IAS 28, Investments in Associates and Joint Ventures. The other amendments to IAS 28 did not affect the Corporation. The Corporation classified its joint arrangements in accordance with IFRS 11 on January 1, 2013 and concluded that the adoption of the standard did not result in any changes in the accounting for its joint arrangements.

IFRS 13, Fair Value Measurement, provides a single framework for measuring fair value. The measurement of the fair value of an asset or liability is based on assumptions that market participants would use when pricing the asset or liability under current market conditions, including assumptions about risk. Under IFRS 13, the fair value of a liability must reflect the effect of non-performance risk, which includes an entity's own credit risk. Upon adoption of IFRS 13, the Corporation began including an estimate of its own credit risk in determining the fair value of its derivative financial liabilities. The Corporation adopted IFRS 13 and the required change in valuation techniques on January 1, 2013 on a prospective basis. Upon adoption of IFRS 13, derivative financial liabilities decreased by $1.8 million.

The Corporation has adopted the amendments to IAS 1, Presentation of Financial Statements, effective January 1, 2013. These amendments required the Corporation to group other comprehensive income items by those that will be reclassified subsequently to profit or loss and those that will not be reclassified. These changes did not result in any adjustments to other comprehensive income or comprehensive income.

The Corporation has adopted the amendments to IAS 19, Employee Benefits, effective January 1, 2013. These amendments make significant changes to the recognition and measurement of defined benefit pension expense and termination benefits and to enhance the disclosure of all employee benefits. The adoption of these amendments did not have an impact on the Corporation's consolidated financial statements.

Accounting standards issued but not yet applied

The IASB has issued the following standards which have not yet been adopted by the Corporation: IFRS 9, Financial Instruments; IAS 32, Financial Instruments: Presentation; and IAS 36, Impairment of Assets. 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 and classification and measurement requirements. IFRS 9 will still be available for early adoption. The amendments to IAS 32 and IAS 36 are effective for periods beginning on or after January 1, 2014. The Corporation has performed an initial assessment of the impact of the new and amended standards and does not currently expect that the adoption of these standards will have a significant impact on the Corporation's financial statements.

The following is a brief summary of the new and amended standards:

IFRS 9 is the first step to replace IAS 39, Financial Instruments: Recognition and Measurement. IFRS 9 uses a single approach to determine whether a financial asset is measured at amortized cost or fair value, replacing the multiple rules in IAS 39. The 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, the approach to the fair value option for financial liabilities may require different accounting for changes to the fair value of a financial liability as a result of changes to an entity's own credit risk.

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.

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 below as construction risks, operations risks and project development risks. Further information regarding the risk factors affecting the Corporation is contained in the Annual Information Form.

Risks Arising From Construction Activities

Cost and Schedule Risk

Additional phases of development of the Christina Lake Project and the development of the Corporation's other projects may suffer from delays, cancellation, interruptions or increased costs due to many factors, some of which may be beyond the Corporation's control, including:

- engineering, construction and/or procurement performance falling below expected levels of output or efficiency;
- denial or delays in receipt of regulatory approvals, additional requirements imposed by changes in laws or non-compliance with conditions imposed by regulatory approvals;
- labour disputes or disruptions, declines in labour productivity or the unavailability of skilled labour;
- increases in the cost of labour and materials; and
- changes in project scope or errors in design.

If any of the above events occur, they could have a material adverse effect on the Corporation's ability to continue to develop the Christina Lake Project, the Corporation's facilities or the Corporation's other future projects and facilities, which would materially adversely affect its business, financial condition and results of operations.

Risks Arising From Operations

Operating Risk

The operation of the Corporation's oil sands properties and projects are and will continue to be subject to the customary hazards associated with recovering, transporting and processing hydrocarbons, such as fires, severe weather, natural disasters (including wildfires), explosions, gaseous leaks, migration of harmful substances, blowouts and spills. A casualty occurrence might result in the loss of equipment or life, as well as injury, property damage or the interruption of the Corporation's operations. The Corporation's insurance may not be sufficient to cover all potential casualties, damages, losses or disruptions. Losses and liabilities arising from uninsured or under-insured events could have a material adverse effect on the Corporation's business, financial condition and results of operations.

Operating Results

The Corporation's operating results are affected by many factors. The principal factors, amongst others, which could affect MEG's operating results include:

- a substantial decline in oil, bitumen or electricity prices, due to a lack of infrastructure or otherwise;
- lower than expected reservoir performance, including, but not limited to, lower oil production rates and/or higher steam-to-oil ratios;
- a lack of access to or an increase in the cost of diluent;
- an increase in the cost of natural gas;

- the reliability and maintenance of the Access Pipeline and MEG's other facilities;
- the need to repair existing horizontal wells, or the need to drill additional horizontal wells;
- the ability and cost to transport bitumen, diluent and bitumen diluent blends, and the cost to dispose of certain by-products;
- increased royalty payments resulting from changes in the regulatory regime;
- a lack of sufficient pipeline or electrical transmission capacity, and the effect that an apportionment may have on MEG's access to such capacity;
- the cost of labour, materials, services and chemicals used in MEG's operations; and
- the cost of compliance with existing and new regulations.

Labour Risk

The Corporation depends on its management team and other key personnel to run its business and manage the operation of its projects. The loss of any of these individuals could adversely affect the Corporation's operations. Due to the specialized nature of the Corporation's business, the Corporation believes that its future success will also depend upon its ability to continue to attract, retain and motivate highly skilled management, technical, operations and marketing personnel.

Project Development Risks

Reliance on Third Parties

The Christina Lake Project and the Corporation's future projects will depend on the successful operation and the adequate capacities of certain infrastructure owned and operated by third parties or joint ventures with third parties, including:

- pipelines for the transport of natural gas, diluent and blended bitumen;
- power transmission grids supplying and exporting electricity; and
- other third party transportation infrastructure such as roads, rail, terminals, barges and airstrips.

The failure or lack of any or all of the infrastructure described above will negatively impact the operation of the Christina Lake Project and MEG's future projects, which, in turn, may have a material adverse effect on MEG's business, results of operations and financial condition.

Reserves and Resources

There are numerous uncertainties inherent in estimating quantities of in-place bitumen reserves and resources, including many factors beyond the Corporation's control. In general, estimates of economically recoverable bitumen reserves and resources and the future net cash flow therefrom are based upon a number of factors and assumptions made as of the date on which the reserve and resource estimates were determined, such as geological and engineering estimates which have inherent uncertainties, the effects of regulation by governmental agencies, and estimates of future commodity prices and operating costs, all of which may vary considerably from actual results. All such estimates are, to some degree, uncertain and classifications of reserves and resources are only attempts to define the degree of uncertainty involved. For these reasons, estimates of the economically recoverable bitumen, the classification of such reserves and resources based on risk of recovery and estimates of future net revenues expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially.

Although third parties have prepared the GLJ Report and other reviews, reports and projections relating to the viability and expected performance of the Christina Lake Project, the Surmont Project and the Growth Properties, the GLJ Report, the reviews, reports and projections and the assumptions on which they are based may not, over time, prove to be accurate. Actual production and cash flow derived from the Corporation's oil sands leases may vary from the GLJ Report and other reviews, reports and projections.

Financing Risk

Significant amounts of capital will be required to develop future phases of the Christina Lake Project, the Surmont Project and the Growth Properties. At present, cash flow from the Corporation's operations is largely dependent on the performance of a single project and the major source of funds available to the Corporation is the issuance of additional equity or debt. Capital requirements are subject to capital market risks, including the availability and cost of capital. There can be no assurance that sufficient capital will be available or be available on acceptable terms or on a timely basis, to fund the Corporation's capital obligations in respect of the development of its projects or any other capital obligations it may have. The Corporation may not generate sufficient cash flow from operations and may not have additional equity or debt available to it in amounts sufficient to enable it to make payments with respect to its indebtedness or to fund its other liquidity needs. In these circumstances, the Corporation may need to refinance all or a portion of its indebtedness on or before maturity. The Corporation may not be able to refinance any of its indebtedness on commercially reasonable terms or at all.

Commodity Price Risk

The Corporation's business, financial condition, results of operations and cash flow are dependent upon the prevailing prices of its bitumen blend, condensate, power and natural gas. Prices of these commodities have historically been extremely volatile and fluctuate significantly in response to regional, national and global supply and demand, and other factors beyond the Corporation's control.

Declines in prices received for the Corporation's bitumen blend could materially adversely affect the Corporation's business, financial position, results of operations and cash flow. In addition, any prolonged period of low bitumen blend prices or high natural gas or condensate prices could result in a decision by the Corporation to suspend or reduce production. Any suspension or reduction of production would result in a corresponding decrease in the Corporation's revenues and could materially impact the Corporation's ability to meet its debt service obligations.

Interest Rate Risk

The Corporation has obtained certain credit facilities to finance a portion of the capital costs of the Christina Lake Project and to fund the Corporation's other development and acquisition activities. Variations in interest rates could result in significant changes to debt service requirements and would affect the financial results of the Corporation. If over-the-counter derivative structures are employed to mitigate interest rate risk, risks associated with such products, including counterparty risk, settlement risk, basis risk, liquidity risk and market risk, could impact or negate the hedging strategy, which would have a negative impact on the Corporation's financial position, earnings and cash flow.

Foreign Currency Risk

The Corporation's credit facilities and high yield notes are denominated in U.S. dollars and prices of the Corporation's bitumen blend are generally based on U.S. dollar market prices. Fluctuations in U.S. and Canadian dollar exchange rates may cause a negative impact on revenue, costs and debt service obligations and may have a material adverse impact on the Corporation. If over-the-counter derivative structures are employed to mitigate foreign currency risk, risks associated with such products, including counterparty risk, settlement risk, basis risk, liquidity risk and market risk, could impact or negate the hedging strategy, which would have a negative impact on the Corporation's financial position, earnings and cash flow.

Regulatory and Environmental Risk

The oil and gas industry in Canada, including the oil sands industry, operates under Canadian federal, provincial and municipal legislation and regulations. Future development of the Christina Lake Project, the Surmont Project and the Growth Properties is dependent on the Corporation maintaining its current oil sands leases and licences and receiving required regulatory approvals and permits on a timely basis. The Government of Alberta has initiated a process to control cumulative environment effects of industrial development through the Lower Athabasca Regional Plan ("LARP").While the LARP has not had a significant effect on the Corporation, there can be no assurance that changes to the LARP or future laws or regulations will not adversely impact the Corporation's ability to develop or operate its projects.

The Corporation is committed to meeting its responsibilities to protect the environment and fully comply with all environmental laws and regulations. Alberta regulates emissions of carbon dioxide, methane, nitrous oxide and other greenhouse gases ("GHG"), and Canada's federal government has proposed significant extensions to its GHG regulatory requirements, which currently deal only with reporting. The direct and indirect costs of the various regulations, existing, proposed and future, may adversely affect MEG's business, operations and financial results. The emission reduction compliance obligations required under existing and future federal and provincial industrial air pollutant and GHG emission reduction targets and requirements, together with emission reduction requirements in future regulatory approvals, may not be technically or economically feasible to implement for MEG's bitumen recovery and cogeneration activities. Any failure to meet MEG's emission reduction compliance obligations may materially adversely affect MEG's business and result in fines, penalties and the suspension of operations.

Royalty Risk

The Corporation's revenue and expenses will be directly affected by the royalty regime applicable to its oil sands development. The Government of Alberta implemented a new oil and gas royalty regime effective January 1, 2009 through which the royalties for conventional oil, natural gas and bitumen are linked to price and production levels. The royalty regime applies to both new and existing oil sands projects.

Under the royalty regime, the Government of Alberta increased its royalty share from oil sands development by introducing price-sensitive formulas applied both before and after specified allowed costs have been recovered. Prior to payout of the specified costs, the royalty starts at one percent of gross bitumen revenue and increases for every dollar that the world oil price, as reflected by the WTI crude oil price (converted to Canadian dollars), is above $55 per barrel, to a maximum of nine percent of gross bitumen revenue when the WTI crude oil price is $120 per barrel or higher. After payout, the net royalty on oil sands starts at 25 percent of net bitumen revenue and increases for every dollar the WTI crude oil price (converted to Canadian dollars) is above $55 per barrel to 40 percent of net bitumen revenue when the WTI crude oil price is $120 per barrel or higher.

The Government of Alberta has publicly indicated that it intends for the revised royalty regime to be further reviewed and revised from time to time. There can be no assurances that the Government of Alberta or the Government of Canada will not adopt new royalty regimes which may render the Corporation's projects uneconomic or otherwise adversely affect its business, financial condition or results of operations.

Third Party Risks

Aboriginal peoples have claimed aboriginal title and rights to a substantial portion of western Canada. Certain aboriginal peoples have filed a claim against the Government of Canada, the Province of Alberta, certain governmental entities and the Regional Municipality of Wood Buffalo (which includes the City of Fort McMurray, Alberta) claiming, among other things, aboriginal title to large areas of lands surrounding Fort McMurray, including the lands on which the Christina Lake Project, MEG's other projects and most of the other oil sands operations in Alberta are located. Such claims, if successful, could have an adverse effect on MEG and the Christina Lake Project and MEG's other projects.

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. Such officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Corporation's disclosure controls and procedures at the financial year end of the Corporation and have concluded that the Corporation's disclosure controls and procedures are effective at the financial year end of the Corporation for the foregoing purposes.

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. Such officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Corporation's internal controls over financial reporting at the financial year end of the Corporation and concluded that the Corporation's internal controls over financial reporting are effective at the financial year end of the Corporation for the foregoing purpose.

No material changes in the Corporation's internal controls over financial reporting were identified during the year ended December 31, 2013 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.

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", "Risk Factors" and "Regulatory Matters" 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 MD&A 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 MD&A 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 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 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 operating activities.

ADDITIONAL INFORMATION

Additional information relating to the Corporation, including its AIF, is available on MEG's website at **www.megenergy.com** and is also available on SEDAR at **www.sedar.com**.

QUARTERLY SUMMARIES

	2013				2012			
Unaudited	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**
FINANCIAL *($000 unless specified)*								
Net income (loss)	**(148,182)**	**115,383**	**(62,312)**	**(71,294)**	(18,740)	47,474	(29,534)	53,369
Per share, diluted	**(0.67)**	**0.51**	**(0.28)**	**(0.32)**	(0.09)	0.24	(0.15)	0.27
Operating earnings (loss)	**(32,685)**	**56,171**	**13,612**	**(36,712)**	(538)	(12,883)	11,134	23,529
Per share, diluted	**(0.15)**	**0.25**	**0.06**	**(0.16)**	0.00	(0.07)	0.06	0.12
Cash flow from operations	**22,648**	**144,521**	**79,184**	**7,071**	56,106	24,442	59,975	71,991
Per share, diluted	**0.10**	**0.64**	**0.35**	**0.03**	0.27	0.12	0.30	0.36
Capital investment	**394,370**	**477,335**	**674,576**	**681,871**	500,223	406,526	341,840	371,094
Cash, cash equivalents and short-term investments	**1,179,072**	**647,096**	**1,203,457**	**1,803,338**	2,007,841	1,607,036	1,111,150	1,402,390
Working capital	**1,045,607**	**365,676**	**731,290**	**1,298,955**	1,655,915	1,307,325	902,424	1,183,628
Long-term debt	**4,004,575**	**2,857,740**	**2,923,382**	**2,823,207**	2,488,609	2,461,676	1,751,552	1,718,474
Shareholders' equity	**4,788,430**	**4,919,407**	**4,771,616**	**4,817,253**	4,870,534	4,092,556	4,027,652	4,049,633
BUSINESS ENVIRONMENT								
West Texas Intermediate (WTI) *(US$/bbl)*	**97.43**	**105.83**	**94.22**	**94.37**	88.18	92.22	93.49	102.92
C$ equivalent of 1US$ *(average)*	**1.0477**	**1.0385**	**1.0233**	**1.0089**	0.9913	0.9948	1.0102	1.0012
Differential – WTI vs blend *($/bbl)*	**41.48**	**23.50**	**26.17**	**39.96**	26.13	29.54	29.83	32.10
Differential – WTI vs blend *(%)*	**40.6%**	**21.4%**	**27.1%**	**41.9%**	29.9%	32.2%	31.6%	31.2%
OPERATIONAL *($/bbl unless specified)*								
Bitumen production *(bpd)*	**42,251**	**34,246**	**32,144**	**32,531**	32,292	23,941	30,429	28,446
Bitumen sales *(bpd)*	**35,990**	**34,256**	**32,175**	**32,393**	32,722	23,876	30,229	28,567
Diluent usage *(bpd)*	**16,680**	**13,032**	**14,176**	**16,239**	14,810	9,466	13,800	13,919
Blend sales *(bpd)*	**52,670**	**47,288**	**46,351**	**48,632**	47,532	33,342	44,029	42,486
Steam to oil ratio (SOR)	**2.9**	**2.5**	**2.3**	**2.5**	2.4	2.5	2.4	2.5
Blend sales	**60.60**	**86.40**	**70.25**	**55.24**	61.29	62.19	64.62	70.95
Cost of diluent	**(22.38)**	**(12.07)**	**(16.27)**	**(25.20)**	(15.62)	(15.70)	(19.03)	(20.80)
Bitumen realization	**38.22**	**74.33**	**53.98**	**30.04**	45.67	46.49	45.59	50.15
Transportation – net	**(0.51)**	**(0.20)**	**(0.17)**	**(0.12)**	(0.05)	(0.93)	(0.03)	(0.37)
Royalties	**(2.71)**	**(5.14)**	**(3.03)**	**(1.58)**	(2.23)	(2.10)	(2.84)	(2.63)
Operating costs – non-energy	**(8.09)**	**(9.20)**	**(10.00)**	**(8.81)**	(8.70)	(15.23)	(7.79)	(8.24)
Operating costs – energy	**(5.38)**	**(3.32)**	**(4.85)**	**(4.93)**	(4.65)	(3.22)	(2.62)	(3.18)
Power sales	**2.25**	**3.12**	**6.00**	**3.30**	4.40	2.84	1.86	3.47
Cash operating netback	**23.78**	**59.59**	**41.93**	**17.90**	**34.44**	**27.85**	**34.17**	**39.20**
Power sales price *(C$/MWh)*	**44.63**	**75.96**	**138.96**	**59.92**	79.62	57.99	36.85	58.25
Power sales *(MW/h)*	**76**	**59**	**58**	**74**	75	49	64	71
Depletion and depreciation rate per bbl	**15.56**	**15.54**	**15.13**	**15.16**	14.98	13.39	13.01	13.44
COMMON SHARES								
Shares outstanding, end of period *(000)*	**222,507**	**222,489**	**221,829**	**221,256**	220,190	195,248	194,326	193,986
Volume traded *(000)*	**33,400**	**28,403**	**43,789**	**28,495**	20,370	13,578	21,560	18,230
Common share price *($)*								
High	**36.00**	**36.69**	**32.98**	**35.67**	38.74	41.90	43.96	47.11
Low	**28.60**	**28.81**	**25.50**	**30.89**	30.25	35.20	32.92	36.73
Close (end of period)	**30.61**	**35.54**	**28.83**	**32.61**	30.44	37.39	36.49	38.46

REPORT OF MANAGEMENT

MANAGEMENT'S RESPONSIBILITY FOR THE CONSOLIDATED FINANCIAL STATEMENTS

The accompanying consolidated financial statements of MEG Energy Corp. (the "Corporation") are the responsibility of Management. The consolidated financial statements have been prepared by Management in Canadian dollars in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") and include certain estimates that reflect Management's best judgments. Financial information contained throughout the annual report is consistent with these consolidated financial statements.

The Corporation maintains systems of internal accounting and administrative controls. These systems are designed to provide reasonable assurance that the financial information is relevant, reliable and accurate and that the Corporation's assets are properly accounted for and adequately safeguarded. Management's evaluation concluded that our internal controls over financial reporting were effective as of December 31, 2013.

The Corporation's Board of Directors has approved the consolidated financial statements. The Board of Directors fulfills its responsibility regarding the consolidated financial statements mainly through its Audit Committee, which is made up of three independent directors. The Audit Committee has a written mandate that complies with the current requirements of Canadian securities legislation. The Audit Committee meets with Management and the independent auditors at least on a quarterly basis to review and approve interim consolidated financial statements and management's discussion and analysis prior to their release as well as annually to review the annual consolidated financial statements and management's discussion and analysis and recommend their approval to the Board of Directors.

PricewaterhouseCoopers LLP, an independent firm of Chartered Accountants, has been engaged, as approved by a vote of the shareholders at the Corporation's most recent Annual General Meeting, to audit and provide their independent audit opinion on the Corporation's consolidated financial statements as at and for the year ended December 31, 2013. Their report, contained herein, outlines the nature of their audit and expresses their opinion on the consolidated financial statements.

W.J. McCaffrey

William (Bill) McCaffrey, P.Eng.
Chairman, President and Chief Executive Officer

Eric L. Toews, CA
Chief Financial Officer

March 4, 2014

INDEPENDENT AUDITOR'S REPORT

March 4, 2014

INDEPENDENT AUDITOR'S REPORT

To the Shareholders of MEG Energy Corp.

We have audited the accompanying consolidated financial statements of MEG Energy Corp., which comprise the consolidated balance sheet as at December 31, 2013 and December 31, 2012 and the consolidated statements of comprehensive income, changes in shareholders' equity and cash flow for the years ended December 31, 2013 and December 31, 2012, and the related notes, which comprise a summary of significant accounting policies and other explanatory information.

MANAGEMENT'S RESPONSIBILITY FOR THE CONSOLIDATED FINANCIAL STATEMENTS

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

AUDITOR'S RESPONSIBILITY

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

OPINION

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of MEG Energy Corp. as at December 31, 2013 and December 31, 2012 and its financial performance and its cash flows for the years then ended in accordance with International Financial Reporting Standards.

PricewaterhouseCoopers LLP

Chartered Accountants

Calgary, Alberta

CONSOLIDATED BALANCE SHEET

(Expressed in thousands of Canadian dollars)

As at December 31,	Note	2013	2012
Assets			
Current assets			
Cash and cash equivalents	*23*	**$ 1,179,072**	$ 1,474,843
Short-term investments		**-**	532,998
Trade receivables and other	*6*	**186,183**	110,823
Inventories	*7*	**129,943**	17,536
		1,495,198	2,136,200
Non-current assets			
Property, plant and equipment	*8*	**7,254,951**	5,267,885
Exploration and evaluation assets	*9*	**579,497**	554,349
Other intangible assets	*10*	**63,205**	46,033
Other assets	*11*	**54,890**	14,212
Total assets		**$ 9,447,741**	$ 8,018,679
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities	*12*	**$ 416,288**	$ 463,077
Current portion of long-term debt	*13*	**13,827**	9,949
Current portion of provisions and other liabilities	*14*	**19,477**	7,259
		449,592	480,285
Non-current liabilities			
Long-term debt	*13*	**3,990,748**	2,478,660
Provisions and other liabilities	*14*	**125,177**	117,756
Deferred income tax liability	*15*	**93,794**	71,444
Total liabilities		**4,659,311**	3,148,145
Commitments and contingencies	*25*		
Shareholders' equity			
Share capital	*16*	**4,751,374**	4,694,378
Contributed surplus	*16*	**126,666**	102,219
Retained earnings (deficit)		**(92,493)**	73,912
Accumulated other comprehensive income		**2,883**	25
Total shareholders' equity		**4,788,430**	4,870,534
Total liabilities and shareholders' equity		**$ 9,447,741**	$ 8,018,679

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

These consolidated financial statements were approved by the Corporation's Board of Directors on March 4, 2014.

W. J. McCaffrey

William (Bill) McCaffrey, Director

Robert B. Hodgins

Robert B. Hodgins, Director

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

(Expressed in thousands of Canadian dollars, except per share amounts)

For the year ended December 31,	**Note**	**2013**	**2012**
Petroleum revenue, net of royalties	*17*	**$ 1,270,757**	$ 1,003,838
Other revenue	*18*	**63,740**	46,666
		1,334,497	1,050,504
Diluent and transportation	*19*	**623,648**	512,814
Purchased product and storage		**104,115**	39,584
Operating expenses	*21*	**167,586**	139,019
Depletion and depreciation	*8, 10*	**189,147**	144,950
General and administrative	*21*	**92,828**	70,597
Stock-based compensation	*16*	**38,792**	25,246
Research and development		**5,588**	5,157
		1,221,704	937,367
Revenues less expenses		**112,793**	113,137
Other income (expense)			
Interest and other income		**22,550**	19,896
Gain on disposition of assets		**1,410**	3,075
Foreign exchange gain (loss), net		**(180,278)**	36,618
Net finance expense	*20*	**(100,533)**	(110,354)
		(256,851)	(50,765)
Income (loss) before income taxes		**(144,058)**	62,372
Deferred income tax expense	*15*	**22,347**	9,803
Net income (loss)		**(166,405)**	52,569
Other comprehensive income			
Foreign currency translation adjustment		**2,858**	25
Comprehensive income (loss)		**$ (163,547)**	$ 52,594
Net earnings (loss) per common share			
Basic	*24*	**$ (0.75)**	$ 0.27
Diluted	*24*	**$ (0.75)**	$ 0.26

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

CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS' EQUITY

(Expressed in thousands of Canadian dollars)

	Note	Share Capital	Contributed Surplus	Retained Earnings (Deficit)	Accumulated Other Comprehensive Income (AOCI)	Total Shareholders' Equity
Balance as at January 1, 2013		**$ 4,694,378**	**$ 102,219**	**$ 73,912**	**$ 25**	**$ 4,870,534**
Share issue costs, net of tax	*16*	**79**				**79**
Stock options exercised	*16*	**40,522**	**(9,217)**			**31,305**
RSUs vested and released	*16*	**16,395**	**(16,395)**			**–**
Stock-based compensation	*16*		**50,059**			**50,059**
Net loss				**(166,405)**		**(166,405)**
Other comprehensive income					**2,858**	**2,858**
Balance as at December 31, 2013		**$ 4,751,374**	**$ 126,666**	**$ (92,493)**	**$ 2,883**	**$ 4,788,430**
Balance as at January 1, 2012		$ 3,877,193	$ 85,568	$ 21,343	$ –	$ 3,984,104
Shares issued		800,125				800,125
Share issue costs, net of tax		(18,988)				(18,988)
Stock options exercised		26,520	(5,863)			20,657
RSUs vested and released		9,528	(9,528)			–
Stock-based compensation			32,042			32,042
Net income				52,569		52,569
Other comprehensive income					25	25
Balance as at December 31, 2012		$ 4,694,378	$ 102,219	$ 73,912	$ 25	$ 4,870,534

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

CONSOLIDATED STATEMENT OF CASH FLOW

(Expressed in thousands of Canadian dollars)

Year ended December 31,	Note	2013	2012
Cash provided by (used in):			
Operating activities			
Net income (loss)		**$ (166,405)**	$ 52,569
Adjustments for:			
Depletion and depreciation	*8, 10*	**189,147**	144,950
Stock-based compensation	*16*	**38,792**	25,246
Unrealized (gain) loss on foreign exchange		**177,362**	(35,822)
Unrealized (gain) loss on derivative financial liabilities	*20*	**(19,256)**	12,868
Deferred income tax expense	*15*	**22,347**	9,803
Other		**11,437**	2,900
Net change in non-cash operating working capital items	*23*	**(123,461)**	28,310
Net cash provided by operating activities		**129,963**	240,824
Investing activities			
Capital investments		**(2,188,353)**	(1,598,514)
Purchase of other assets	*11*	**(41,517)**	–
Proceeds on disposition of assets		**6,801**	7,456
Other		**(1,422)**	1,176
Net change in non-cash investing working capital items	*23*	**430,316**	(230,638)
Net cash used in investing activities		**(1,794,175)**	(1,820,520)
Financing activities			
Issue of shares, net of issue costs		**31,747**	795,466
Issue of long-term debt, net of issue costs	*13*	**1,322,540**	792,552
Repayment of long-term debt	*13*	**(13,506)**	(9,988)
Financing costs		**(8,693)**	(5,622)
Net cash provided by financing activities		**1,332,088**	1,572,408
Effect of exchange rate changes on cash and cash equivalents held in foreign currency		**36,353**	(13,000)
Change in cash and cash equivalents		**(295,771)**	(20,288)
Cash and cash equivalents, beginning of year	*23*	**1,474,843**	1,495,131
Cash and cash equivalents, end of year	*23*	**$ 1,179,072**	$ 1,474,843

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Year ended December 31, 2013
(All amounts are in thousands of Canadian dollars, unless otherwise noted.)

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 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

These consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS").

3. SIGNIFICANT ACCOUNTING POLICIES

(a) Basis of measurement

The consolidated financial statements have been prepared on the historical cost basis, except for the revaluation of certain financial assets and financial liabilities to fair value, including derivative instruments, which are measured at fair value.

(b) Basis of consolidation

The consolidated financial statements of the Corporation comprise the Corporation and its wholly-owned subsidiary, MEG Energy (U.S.) Inc., that was incorporated on June 26, 2012. Income and expenses of its subsidiary are included in the consolidated statement of comprehensive income from the date of incorporation.

All intercompany transactions, balances, income and expenses are eliminated on consolidation.

(c) Foreign currency translation

i. Functional and presentation currency

Items included in the consolidated financial statements are measured using the currency of the primary economic environment in which the Corporation operates (the "functional currency"). The consolidated financial statements are presented in Canadian dollars, which is the Corporation's functional currency.

ii. Transactions and balances

Foreign currency transactions are translated into Canadian dollars at exchange rates prevailing at the dates of the transactions. Monetary assets and liabilities denominated in a foreign currency are translated into Canadian dollars at rates of exchange in effect at the end of the period. Foreign currency differences arising on translation are recognized in income or loss.

For the purposes of presenting consolidated financial statements, the assets and liabilities of the foreign subsidiary are translated into Canadian dollars at rates of exchange in effect at the end of the period. Income and expense items are translated at the average exchange rates prevailing at the dates of the transactions. Exchange differences arising, if any, are recognized in other comprehensive income.

(d) Joint venture operations

The Corporation conducts a portion of its exploration, production and pipeline activities with other entities and, accordingly, the accounts reflect only the Corporation's proportionate interest in such activities.

(e) Financial instruments

Financial assets and liabilities are recognized when the Corporation becomes a party to the contractual provisions of the instrument. Financial assets are derecognized when the rights to receive cash flows from the assets have expired or have been transferred and the Corporation has transferred substantially all risks and rewards of ownership.

Financial assets and liabilities are offset and the net amount is reported on the balance sheet when there is a legally enforceable right to offset the recognized amounts and there is an intention to settle on a net basis, or realize the asset and settle the liability simultaneously.

At initial recognition, the Corporation classifies its financial instruments in the following categories depending on the purpose for which the instruments were acquired:

i. Financial assets and liabilities at fair value through income or loss

A financial asset or liability is classified in this category if acquired principally for the purpose of selling or repurchasing in the short term. Derivative financial instruments are also included in this category unless they are designated as hedges. The Corporation's other assets are classified as fair value through income or loss.

Financial instruments in this category are recognized initially and subsequently at fair value. Transaction costs are expensed in the consolidated statement of comprehensive income. Gains and losses arising from changes in fair value are presented in income or loss within net finance expense in the period in which they arise. Financial assets and liabilities at fair value through income or loss are classified as current except for any portion expected to be realized or paid beyond twelve months from the balance sheet date.

ii. Loans and receivables

Loans and receivables are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market. The Corporation's loans and receivables are comprised of cash and cash equivalents, short-term investments and trade receivables and other, and are included in current assets due to their short-term nature.

Loans and receivables are initially recognized at the amount expected to be received less any required discount to reduce the loans and receivables to fair value. Subsequently, loans and receivables are measured at amortized cost using the effective interest method less any provision for impairment.

iii. Financial liabilities at amortized cost

Financial liabilities at amortized cost include accounts payable and accrued liabilities and long-term debt. Accounts payable and accrued liabilities are initially recognized at the amount required to be paid less any required discount to reduce the payables to fair value. Long-term debt is recognized initially at fair value, net of any transaction costs incurred, and subsequently at amortized cost using the effective interest method.

Financial liabilities are classified as current liabilities if payment is due within twelve months. Otherwise, they are presented as non-current liabilities.

iv. Derivative financial instruments

The Corporation may use derivatives in the form of interest rate swaps and floors to manage risks related to its variable rate debt. All derivatives have been classified at fair value through income or loss. Derivative financial instruments are included on the balance sheet within provisions and other liabilities and are classified as current or non-current based on the contractual terms specific to the instrument.

Gains and losses on re-measurement of derivatives related to finance activities are included in net finance expense in the period in which they arise.

(f) Cash and cash equivalents

Cash and cash equivalents include cash on hand, deposits held with banks, and other short-term highly liquid investments such as commercial paper, money market deposits or similar instruments, with a maturity of 90 days or less.

(g) Short-term investments

Short-term investments consist of commercial paper, money market deposits or similar instruments with a maturity of between 91 and 365 days.

(h) Trade receivables and other

Trade receivables are recorded based on the Corporation's revenue recognition policy as described in note 3(r). If applicable, an allowance for doubtful accounts is recorded to provide for specific doubtful receivables. Other amounts include deposits and advances which include funds placed in escrow in accordance with the terms of certain agreements, funds held in trust in accordance with governmental regulatory requirements and funds advanced to joint venture partners.

(i) Inventories

Product inventories consist of crude oil products and are valued at the lower of cost and net realizable value on a weighted average cost basis. Costs include direct and indirect expenditures incurred in bringing an item or product to its existing condition and location. Net realizable value is the estimated selling price less applicable selling expenses.

(j) Property, plant and equipment and exploration and evaluation assets

i. Recognition and measurement

Exploration and evaluation ("E&E") expenditures, including the costs of acquiring licenses and directly attributable general and administrative costs, initially are capitalized as either tangible or intangible exploration and evaluation assets according to the nature of the assets acquired. The costs are accumulated in cost centres pending determination of technical feasibility and commercial viability. Costs incurred prior to obtaining a legal right or license to explore are expensed in the period in which they are incurred.

Exploration and evaluation assets are assessed for impairment if (i) sufficient data exists to determine technical feasibility and commercial viability, and (ii) facts and circumstances suggest that the carrying amount exceeds the recoverable amount. For purposes of impairment testing, exploration and evaluation assets are allocated to cash-generating units ("CGU's").

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. A review of each project area is carried out, at least annually, to ascertain whether proved or probable reserves have been discovered. Upon determination of proved or probable reserves, intangible exploration and evaluation assets attributable to those reserves are first tested for impairment and then reclassified from exploration and evaluation assets to a separate category within property, plant and equipment.

Development and production items of property, plant and equipment, which include oil sands development, production, pipeline and storage assets are measured at cost less accumulated depletion and depreciation and accumulated impairment losses. Development, production, pipeline and storage assets are grouped into CGU's for impairment testing. A CGU is the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets. When significant parts of an item of property, plant and equipment have different useful lives, they are accounted for as separate items (major components).

Borrowing costs incurred for the construction of a qualifying asset are capitalized when a substantial period of time is required to complete and prepare the asset for its intended use. All other borrowing costs are recognized over the term of the related debt facility as an expense using the effective interest method. The Corporation capitalizes overhead and administrative expenses that are directly attributable to bringing qualifying assets into operation.

ii. Subsequent costs

Costs incurred subsequent to the determination of technical feasibility and commercial viability and the costs of replacing parts of property, plant and equipment are recognized as oil sands, pipeline and storage assets only when it is probable that future economic benefits associated with the item will flow to the Corporation and the cost of the item can be measured reliably. Such capitalized oil sands, pipeline and storage assets generally represent costs incurred in developing proved and/or probable reserves and enhancing production from such reserves. All other expenditures are recognized in income or loss as incurred. The carrying amount of any replaced or sold component is derecognized and any gain or loss is recognized in income or loss.

iii. Depletion and depreciation

The net carrying value of field production assets are depleted using the unit of production method by reference to the ratio of production in the year to the related proved reserves, taking into account estimated future development costs necessary to bring those reserves into production. Future development costs are estimated taking into account the level of development required to produce the reserves. These estimates are reviewed by independent reserve engineers at least annually.

The net carrying value of major facilities and equipment are depreciated on a unit of production basis over the total productive capacity of the facilities. Where significant components of development or production assets have different useful lives, they are accounted for and depreciated as separate items of property, plant and equipment.

The net carrying values of pipeline transportation and storage equipment are depreciated on a straight-line basis over their estimated fifty year useful lives.

Corporate assets consist primarily of office equipment and leasehold improvements and are stated at cost less accumulated depreciation. Depreciation of office equipment is provided over the useful life of the assets on the declining balance basis at 25% per year. Leasehold improvements are depreciated on a straight-line basis over the term of the lease.

(k) Other intangible assets

Other intangible assets acquired by the Corporation which have a finite useful life are carried at cost less accumulated depreciation. Subsequent expenditures are capitalized only to the extent that they increase the future economic benefits embodied in the asset to which they relate.
The Corporation incurs costs associated with research and development. Expenditures during the research phase are expensed. Expenditures during the development phase are capitalized only if certain criteria, including technical feasibility and the intent to develop and use the technology, are met. If these criteria are not met, the costs are expensed as incurred. The cost associated with purchasing or creating software which is not an integral part of the related computer hardware is included within other intangible assets. The net carrying value of software is amortized over the useful life of the asset on the declining balance basis at 25% per year.

(l) Leased assets

Leases where the Corporation assumes substantially all the risks and rewards of ownership are classified as finance leases. Upon initial recognition, the leased asset is measured at an amount equal to the lower of its fair value and the present value of the minimum lease payments. Subsequent to initial recognition, the asset is accounted for in accordance with the accounting policy applicable to that asset.

Minimum lease payments made under finance leases are apportioned between the finance expenses and the reduction of the outstanding liability. The finance expenses are allocated to each year during the lease term to produce a constant periodic rate of interest on the remaining balance of the liability.

All other leases are operating leases, which are not recognized on the Corporation's balance sheet. Payments made under operating leases are recognized as an expense on a straight-line basis over the term of the lease.

When lease inducements are received to enter into operating leases, such inducements are recognized as a deferred liability. The aggregate benefit of inducements is recognized as a reduction of the related lease expense on a straight-line basis, except where another systematic basis is more representative of the time pattern in which economic benefits from the leased asset are consumed.

(m) Impairments

i. Financial assets

A financial asset is assessed at each reporting date to determine whether there is any objective evidence that it is impaired. A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the fair value or estimated future cash flows of an asset.

An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount and the present value of the estimated future cash flows discounted at the original effective interest rate.

Individually significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics.

All impairment losses are recognized in income or loss. An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized. For financial assets measured at amortized cost, the reversal is recognized in income or loss.

ii. Non-financial assets

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. E&E assets are assessed for impairment when they are reclassified to property, plant and equipment, as oil sands assets, or if facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

For the purpose of impairment testing, assets are grouped into CGU's. 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. E&E assets are assessed for impairment within the aggregation of all CGU's 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 in income or loss. Impairment losses recognized in respect of CGU's 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.

(n) Provisions

A provision is recognized if, as a result of a past event, the Corporation has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a rate that reflects current market assessments of the time value of money and the risks specific to the liability. Provisions are not recognized for future operating losses.

The Corporation's activities give rise to dismantling, decommissioning and site disturbance remediation activities. Provision is made for the estimated cost of site restoration and capitalized in the relevant asset category.

The decommissioning provision is measured at the present value of management's best estimate of the expenditure required to settle the present obligation at the balance sheet date. Subsequent to the initial measurement, the decommissioning provision is adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation as well as any changes in the discount rate. Increases in the decommissioning provision due to the passage of time are recognized as a finance expense whereas increases/decreases due to changes in the estimated future cash flows are capitalized. Actual costs incurred upon settlement of the obligations are charged against the decommissioning provision.

(o) Deferred income taxes

Deferred income tax is recognized 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 tax is not recognized on the initial recognition of assets or liabilities in a transaction that is not a business combination. Deferred tax is 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 as at the reporting date. Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset, and they relate to income taxes levied by the same tax authority on the same taxable entity, or on different tax entities, but they intend to settle current tax liabilities and assets on a net basis or their tax assets and liabilities will be realized simultaneously.

A deferred tax asset is recognized to the extent that it is probable that future taxable income will be available against which the temporary difference can be utilized. Deferred tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

(p) Share capital

Common shares are classified as equity. Incremental costs directly attributable to the issuance of shares are recognized as a reduction of shareholders' equity, net of any income tax.

(q) Share based payments

The grant date fair value of stock options, restricted share units ("RSUs") and performance share units ("PSUs") granted to employees, directors and consultants is recognized as stock-based compensation expense, with a corresponding increase in contributed surplus, over the vesting period of the options, RSUs and PSUs, respectively. Each tranche in an award is considered a separate grant with its own vesting period and grant date fair value. Fair value is determined using the Black-Scholes option pricing model. A forfeiture rate is estimated on the grant date and is adjusted to reflect the actual number of options, RSUs and PSUs that vest. The Corporation's RSU Plan, including PSUs, allows the holder of a RSU or PSU unit to receive a cash payment or its equivalent in fully-paid common shares, at the Corporation's discretion, equal to the fair market value of the Corporation's common shares calculated at the date of such payment. The Corporation does not intend to make cash payments under the RSU Plan and, as such, the RSU and PSU units are accounted for within shareholders' equity.

(r) Revenues

Petroleum revenue and royalty recognition: Revenue associated with the sale of proprietary and purchased crude oil and natural gas owned by the Corporation is recognized when title passes from the Corporation to its customers. Royalties are recognized at the time of production.

Other revenue recognition: Revenue from power generated in excess of the Corporation's internal requirements is recognized when the power leaves the plant gate at the point at which the risks and rewards are transferred to the customer. Revenue generated from the transportation of crude oil products is recognized in the period the product is delivered and the service is provided.

(s) Diluent and transportation

Diluent and transportation include diluent costs and the cost of operating the Access Pipeline and Stonefell Terminal and are recognized as the related product is utilized.

(t) Purchased product and storage

Purchased product and storage costs include the cost of crude oil products purchased from third parties and associated storage costs.

(u) Net finance expense

Finance expense is comprised of interest expense on borrowings, accretion of the discount on provisions, and gains and losses on derivative financial instruments and other assets.

Borrowing costs incurred for the construction of qualifying assets are capitalized during the period of time required to complete and prepare the assets for their intended use. All other borrowing costs are recognized in finance expense using the effective interest method.

(v) Net earnings per share

Basic earnings per share is calculated by dividing the net income (loss) for the period attributable to common shareholders of the Corporation by the weighted average number of common shares outstanding during the period.

Diluted earnings per share is calculated by adjusting the weighted average number of common shares outstanding for dilutive instruments. The number of shares included with respect to options, RSUs and other similar instruments is computed using the treasury stock method. The Corporation's potentially dilutive instruments comprise stock options and RSUs granted to employees and directors.

(w) New accounting standards adopted during the year

The Corporation has adopted the following new and revised standards, along with all consequential amendments, effective January 1, 2013. These changes are made in accordance with the applicable transitional provisions.

i. IFRS 10, Consolidated Financial Statements, replaces the guidance on control and consolidation in International Accounting Standard ("IAS") 27, Consolidated and Separate Financial Statements, and SIC-12, Consolidation – Special Purpose Entities. IFRS 10 requires consolidation of an investee only if the investor possesses power over the investee, has exposure to variable returns from its involvement with the investee and has the ability to use its power over the investee to affect its returns. Detailed guidance is provided on applying the definition of control. The accounting requirements for consolidation have remained largely consistent with IAS 27. The Corporation assessed its consolidation conclusions on January 1, 2013 and determined that the adoption of IFRS 10 did not result in any change in the consolidation status of its wholly-owned subsidiary, MEG Energy (U.S.) Inc.

ii. IFRS 11, Joint Arrangements, supersedes IAS 31, Interests in Joint Ventures, and requires joint arrangements to be classified either as joint operations or joint ventures depending on the contractual rights and obligations of each investor that jointly controls the arrangement. For joint operations, a company recognizes its share of assets, liabilities, revenues and expenses of the joint operation. An investment in a joint venture is accounted for using the equity method as set out in IAS 28, Investments in Associates and Joint Ventures. The other amendments to IAS 28 did not affect the Corporation. The Corporation classified its joint arrangements in accordance with IFRS 11 on January 1, 2013 and concluded that the adoption of the standard did not result in any changes in the accounting for its joint arrangements.

iii. IFRS 13, Fair Value Measurement, provides a single framework for measuring fair value. The measurement of the fair value of an asset or liability is based on assumptions that market participants would use when pricing the asset or liability under current market conditions, including assumptions about risk. Under IFRS 13 the fair value of a liability must reflect the effect of non-performance risk, which includes an entity's own credit risk. Upon adoption of IFRS 13, the Corporation began including an estimate of its own credit risk in determining the fair value of its derivative financial liabilities. The Corporation adopted IFRS 13 and the required change in valuation techniques on January 1, 2013 on a prospective basis. Upon adoption of IFRS 13, derivative financial liabilities decreased by $1.8 million.

iv. The Corporation has adopted the amendments to IAS 1, Presentation of Financial Statements, effective January 1, 2013. These amendments required the Corporation to group other comprehensive income items by those that will be reclassified subsequently to profit or loss and those that will not be reclassified. These changes did not result in any adjustments to other comprehensive income or comprehensive income.

v. The Corporation has adopted the amendments to IAS 19, Employee Benefits, effective January 1, 2013. These amendments make significant changes to the recognition and measurement of defined benefit pension expense and termination benefits and to enhance the disclosure of all employee benefits. The adoption of these amendments did not have an impact on the Corporation's consolidated financial statements.

(x) Accounting standards issued but not yet applied

The IASB has issued the following standards which have not yet been adopted by the Corporation: IFRS 9, Financial Instruments; IAS 32, Financial Instruments: Presentation; and IAS 36, Impairment of Assets. 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 and classification and measurement requirements. IFRS 9 will still be available for early adoption. The amendments to IAS 32 and IAS 36 are effective for periods beginning on or after January 1, 2014. The Corporation has performed an initial assessment of the impact of the new and amended standards and does not currently expect that the adoption of these standards will have a significant impact on the Corporation's financial statements.

The following is a brief summary of the new and amended standards:

IFRS 9 is the first step to replace IAS 39, Financial Instruments: Recognition and Measurement. IFRS 9 uses a single approach to determine whether a financial asset is measured at amortized cost or fair value, replacing the multiple rules in IAS 39. The 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, the approach to the fair value option for financial liabilities may require different accounting for changes to the fair value of a financial liability as a result of changes to an entity's own credit risk.

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.

4. SIGNIFICANT ACCOUNTING ESTIMATES, ASSUMPTIONS AND JUDGEMENTS

The timely preparation of the consolidated financial statements requires that management make estimates and assumptions and use judgment regarding the reported amounts of assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the period. Such estimates primarily relate to unsettled transactions and events as of the date of the consolidated financial statements. The estimated fair value of financial assets and liabilities, by their very nature, are subject to measurement uncertainty. Accordingly, actual results may differ materially from estimated amounts as future confirming events occur. Significant judgments, estimates and assumptions made by management in the preparation of these consolidated financial statements are outlined below.

(a) Property, plant and equipment

Field production assets within property, plant and equipment are depleted using the unit of production method based on estimates of proved bitumen reserves and future costs required to develop those reserves. There are a number of inherent uncertainties associated with estimating reserves. By their nature, these estimates of reserves, including the estimates of future prices and costs, and related future cash flows are subject to measurement uncertainty, and the impact on the consolidated financial statements of future periods could be material.

In addition, management is required to make estimates and assumptions and use judgment regarding the timing of when major development projects are ready for their planned use, which also determines when these assets are subject to depreciation and depletion.

Amounts recorded for depreciation of major facilities pipelines, and storage equipment are based on management's best estimate of their useful lives. Accordingly, those amounts are subject to measurement uncertainty.

(b) Exploration and evaluation assets

The application of the Corporation's accounting policy for exploration and evaluation expenditures requires judgment in determining whether it is likely that future economic benefit exists when activities have not reached a stage where technical feasibility and commercial viability can be reasonably determined and when technical feasibility and commercial viability have been reached. Estimates and assumptions may change as new information becomes available.

(c) 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 property, plant and equipment carrying amounts.

(d) Decommissioning provision

Decommissioning costs are incurred when certain of the Corporation's tangible long-lived assets are retired. Assumptions, based on current economic factors which management believes are reasonable, have been made to estimate the future liability. However, the actual cost of decommissioning is uncertain and cost estimates may change in response to numerous factors including changes in legal requirements, technological advances, inflation and the timing of expected decommissioning and restoration. The impact to net income over the remaining economic life of the assets could be significant due to the changes in cost estimates as new information becomes available. In addition, management exercises judgment to determine the appropriate discount rate at the end of each reporting period. This discount rate, which is credit adjusted, is used to determine the present value of the estimated future cash outflows required to settle the obligation and may change in response to numerous market factors.

(e) Impairments

CGU's are defined as the lowest grouping of integrated assets that generate identifiable cash inflows that are largely independent of the cash inflows of other assets or groups of assets. The classification of assets into CGU's requires significant judgment and interpretations with respect to the integration between assets, the existence of active markets, external users, shared infrastructures, and the way in which management monitors the Corporation's operations.

The recoverable amounts of CGU's and individual assets have been determined as the higher of the CGU's or the asset's fair value less costs to sell and its value in use. These calculations require the use of estimates and assumptions and are subject to changes as new information becomes available including information on future commodity prices, expected production volumes, quantity of reserves and discount rates as well as future development and operating costs. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets and CGU's.

(f) Stock-based compensation

Amounts recorded for stock-based compensation expense are based on several assumptions including the risk-free interest rate, the forfeiture rate, the expected volatility of the Corporation's share price and those of similar publicly listed enterprises, which may not be indicative of future volatility. Accordingly, those amounts are subject to measurement uncertainty.

(g) Deferred income taxes

Tax regulations and legislation and the interpretations thereof in which the Corporation operates are subject to change. As such, income taxes are subject to measurement uncertainty.

Deferred income tax liabilities are recognized when there are taxable temporary differences that will reverse and result in a future outflow of funds to a taxation authority. The Corporation records a provision for the amount that is expected to be settled, which requires the application of judgment as to the ultimate outcome. Deferred income tax liabilities could be impacted by changes in the Corporation's estimate of the likelihood of a future outflow and the expected settlement amount. As such, there may be a significant impact on the consolidated financial statements of future periods.

Deferred income tax assets are recognized to the extent that it is probable that the deductible temporary differences will be recoverable in future periods. The recoverability assessment involves a significant amount of estimation including an evaluation of when the temporary differences will reverse, an analysis of the amount of future taxable earnings, the availability of cash flow to offset the tax assets when the reversal occurs and the application of tax laws. To the extent that assumptions used in the recoverability assessment change, there may be a significant impact on the consolidated financial statements of future periods.

(h) Derivative financial instruments

The estimated fair values of financial assets and liabilities, by their very nature, are subject to measurement uncertainty due to their exposure to credit, liquidity and market risks. Furthermore, the Corporation may use derivative instruments to manage commodity price, foreign currency and interest rate exposures. The fair values of these derivatives are determined using valuation models which require assumptions concerning the amount and timing of future cash flows and discount rates. Management's assumptions rely on external observable market data including quoted commodity prices and volatility, interest rate yield curves and foreign exchange rates. The resulting fair value estimates may not be indicative of the amounts realized or settled in current market transactions and as such are subject to measurement uncertainty.

5. FINANCIAL INSTRUMENTS AND DERIVATIVE FINANCIAL LIABILITIES

The financial instruments recognized on the balance sheet are comprised of cash and cash equivalents, short-term investments, trade receivables and other, components of other assets, accounts payable and accrued liabilities, derivative financial liabilities and long-term debt. As at December 31, 2013, short-term investments, components of 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, short-term investments, 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 components of other assets, derivative financial liabilities and long-term debt

			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**	**–**	**–**

			Fair value measurements using		
As at December 31, 2012	**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	$ 7,581	$ 7,581	$ –	$ –	$ 7,581
Financial liabilities					
Derivative financial liabilities	37,195	37,195	–	37,195	–
Long-term debt	2,488,609	2,612,763	2,612,763	–	–

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 asset-backed commercial paper that were restructured into MAV notes and US auction rate securities. The Corporation estimated the fair value of the MAV notes and the auction rate securities 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.

Movement in level 3 instruments during the year:

	MAV Notes	ARS	Total
Balance as at December 31, 2012	$ 5,475	$ 2,106	$ 7,581
Decrease in fair value	(84)	–	(84)
Proceeds received	(6,801)	–	(6,801)
Gain on sale	1,410		1,410
Foreign exchange	–	146	146
Balance as at December 31, 2013	**$ –**	**$ 2,252**	**$ 2,252**

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 year ended December 31, 2013.

(b) Interest rate risk

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$1.275 billion senior secured term loan. At December 31, 2013, there was an unrealized loss on the interest rate swaps of $7.5 million (December 31, 2012 – $12.4 million).

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

(1) London Interbank Offered Rate

As at December 31, 2013, a 100 basis points increase in LIBOR on floating rate debt, excluding the impact of interest capitalized, would have resulted in a $3.6 million decrease in net income before income taxes (December 31, 2012 – $5.6 million). As at December 31, 2013, a 100 basis points decrease in LIBOR, excluding the impact of interest capitalized, would have had no impact on net income before income taxes (December 31, 2012 – $nil).

(c) Foreign currency risk

Foreign currency risk is the risk that a variation in exchange rates between the Canadian dollar and foreign currencies will affect the fair value or future cash flows of the Corporation's financial assets or liabilities. The Corporation has US dollar denominated long-term debt as described in note 13. As at December 31, 2013, a US$0.01 change in the US dollar relative to the Canadian dollar exchange rate would have resulted in a corresponding change in the carrying value of long-term debt of US$38.3 million (December 31, 2012 – US$25.4 million).

(d) Commodity price risk

Commodity price risk arises from the effect that fluctuations of future commodity prices may have on the fair value or future cash flows of financial assets and liabilities. The Corporation's financial results may be significantly impacted by factors outside of the Corporation's control, including commodity prices and heavy oil differentials. Future fluctuations in commodity prices will affect the amount of revenue earned by the Corporation on the sale of its bitumen production and will impact the amount the Corporation pays for natural gas, electricity and diluent, which are all inputs into the steam-assisted gravity drainage ("SAGD") production and transportation process.

Surplus power from the Corporation's cogeneration unit is sold into the Alberta power grid to partially offset natural gas and power costs associated with operations, acting as a partial hedge against fuel price changes.

(e) Credit risk

Credit risk arises from the potential that the Corporation may incur a loss if a counterparty to a financial instrument fails to meet its obligations in accordance with agreed terms. This credit risk exposure is mitigated through the use of credit policies governing the Corporation's credit portfolio and with credit practices that limit transactions according to counterparties' credit quality. A substantial portion of accounts receivable are with customers in the petroleum and natural gas industry and are subject to normal industry credit risk. All transactions with financial institutions are made only with those that have investment grade credit ratings. At December 31, 2013, the Corporation's estimated maximum exposure to credit risk related to customers was $182.8 million. There were no significant amounts which were greater than 90 days as at December 31, 2013.

The Corporation's cash balances are used to fund the development of its oil sands properties. As a result, the primary objectives of the investment portfolio are low risk capital preservation and high liquidity. The cash balances are invested in high grade liquid short term debt such as commercial, government and bank paper. The cash and cash equivalents balance at December 31, 2013 was $1.2 billion. None of the investments are past their maturity or considered impaired. The Corporation's estimated maximum exposure to credit risk related to its cash and cash equivalents is $1.2 billion.

The Corporation's investments in ARS are subject to the credit risk associated with the counterparties to the investments. The Corporation's estimated maximum exposure to credit risk related to its investments in ARS is $2.5 million. The Corporation sold its investment in MAV Notes in 2013.

(f) Liquidity risk

Liquidity risk is the risk that the Corporation will not be able to meet all of its financial obligations as they become due. Liquidity risk also includes the risk that the Corporation cannot earn enough income from the Christina Lake Project or is unable to raise further capital in order to meet its debt service obligations. The lenders are entitled to exercise any and all remedies available under the security documents. The Corporation manages its liquidity risk through the active management of cash and debt and by maintaining appropriate access to credit.

The future undiscounted financial obligations of the Corporation are noted below:

As at December 31, 2013	**Total**	**<1 year**	**1 – 3 years**	**4 – 5 years**	**More than 5 years**
Long-term debt	**$ 4,067,738**	**$ 13,827**	**$ 27,654**	**$ 27,654**	**$ 3,998,603**
Interest on long-term debt	**1,938,494**	**231,313**	**461,208**	**458,997**	**786,976**
Derivative financial liabilities	**30,981**	**14,168**	**12,772**	**3,161**	**880**
Accounts payable and accrued liabilities	**359,724**	**359,724**	**–**	**–**	**–**
	$ 6,396,937	**$ 619,032**	**$ 501,634**	**$ 489,812**	**$ 4,786,459**

As at December 31, 2012	**Total**	**<1 year**	**1 – 3 years**	**4 – 5 years**	**More than 5 years**
Long-term debt	$ 2,524,559	$ 9,949	$ 19,898	$ 19,898	$ 2,474,814
Interest on long-term debt	1,109,044	138,391	275,587	273,995	421,071
Derivative financial liabilities	37,195	11,044	18,492	7,659	–
Accounts payables and accrued liabilities	463,077	463,077	–	–	–
	$ 4,133,875	$ 622,461	$ 313,977	$ 301,552	$ 2,895,885

6. TRADE RECEIVABLES AND OTHER

As at December 31,	**2013**	**2012**
Trade receivables	**$ 174,935**	$ 104,008
Deposits and advances	**7,908**	4,757
Current portion of deferred financing costs	**3,340**	2,058
	$ 186,183	$ 110,823

7. INVENTORIES

As at December 31,	2013	2012
Diluent	**$ 84,628**	$ 14,778
Bitumen blend	**43,358**	1,948
Materials and supplies	**1,957**	810
	$ 129,943	$ 17,536

During the year ended December 31, 2013, a total of $601.2 million (2012 – $496.6 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, 2011	$ 3,027,073	$ 530,684	$ 27,610	$ 3,585,367
Additions	1,300,515	262,987	5,987	1,569,489
Disposals	(6,340)	–	–	(6,340)
Transfer from exploration and evaluation assets *(note 9)*	478,347	–	–	478,347
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**
Accumulated depletion and depreciation				
Balance as at December 31, 2011	$ 197,469	$ 15,758	$ 3,321	$ 216,548
Depletion and depreciation for the period	134,045	7,073	3,270	144,388
Disposals	(1,958)	–	–	(1,958)
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**
Carrying Amounts				
As at December 31, 2012	$ 4,470,039	$ 770,840	$ 27,006	$ 5,267,885
As at December 31, 2013	**$ 5,980,243**	**$ 1,244,995**	**$ 29,713**	**$ 7,254,951**

During the year ended December 31, 2013 the Corporation capitalized $30.4 million (year ended December 31, 2012 – $20.9 million) of general and administrative costs and $11.3 million (year ended December 31, 2012 – $6.8 million) of stock-based compensation costs relating to oil sands exploration and development activities. In addition, $76.5 million of interest and finance charges related to the development of capital projects were capitalized during the year ended December 31, 2013 utilizing a weighted average capitalization rate of 6.0% (year ended December 31, 2012 – $30.6 million; weighted average capitalization rate – 6.1%).

The Corporation transports its bitumen blend volumes and diluents purchases on pipelines that are operated by Access Pipeline. The Corporation has an undivided 50% interest in this jointly controlled entity and accounts for its investment using the proportionate consolidation method. As at December 31, 2013, the Corporation's proportionate interest in the joint venture's related pipeline assets was $812.1 million, which have been included in property, plant and equipment (December 31, 2012 – $543.2 million).

Operating commitments of $4.7 million related to the joint venture are included in "Other commitments" presented within Note 25.

9. EXPLORATION AND EVALUATION ASSETS

Cost	
Balance as at December 31, 2011	$ 991,805
Additions	40,891
Transfer to property, plant and equipment *(note 8)* [(a)]	(478,347)
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**

(a) Exploration and evaluation assets were transferred to property, plant and equipment following the determination of technical feasibility and commercial viability of the Surmont Project.

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 December 31, 2013, no impairment has been recognized on these assets.

10. OTHER INTANGIBLE ASSETS

Cost	
Balance as at December 31, 2011	$ 38,186
Additions	9,303
Balance as at December 31, 2012	$ 47,489
Additions	18,720
Balance as at December 31, 2013	**$ 66,209**

Accumulated depreciation	
Balance as at December 31, 2011	$ 894
Depreciation	562
Balance as at December 31, 2012	$ 1,456
Depreciation	1,548
Balance as at December 31, 2013	**$ 3,004**

Carrying Amounts	
As at December 31, 2012	$ 46,033
As at December 31, 2013	**$ 63,205**

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

As at December 31,	2013	2012
Long-term pipeline linefill [(a)]	$ 41,517	$ –
MAV notes [(b)]	–	5,475
Auction rate securities ("ARS") [(c)]	2,252	2,106
Deferred financing costs [(d)]	14,461	8,689
	58,230	16,270
Less current portion of deferred financing costs	(3,340)	(2,058)
	$ 54,890	$ 14,212

(a) The Corporation has entered into an agreement to transport diluent on a third-party pipeline and is 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) In December 2013, the Corporation sold its remaining investment in the MAV notes for proceeds of $6.8 million and recognized a gain of $1.4 million.

(c) 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.

(d) 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

As at December 31,	2013	2012
Trade payables	$ 114,752	$ 51,651
Accrued liabilities	230,984	370,431
Interest payable	56,564	36,848
Other payables	13,988	4,147
	$ 416,288	$ 463,077

13. LONG-TERM DEBT

As at December 31,	2013	2012
Senior secured term loan (December 31, 2013 – US$1.275 billion; December 31, 2012 – US$987.5 million) [(a)]	$ 1,355,558	$ 982,464
6.5% senior unsecured notes (US$750 million) [(b)]	797,700	746,175
6.375% senior unsecured notes (US$800 million) [(c)]	850,880	795,920
7.0% senior unsecured notes (US$1.0 billion) [(d)]	1,063,600	–
	4,067,738	2,524,559
Less current portion of senior secured term loan	(13,827)	(9,949)
Less unamortized financial derivative liability discount	(20,565)	(10,324)
Less unamortized deferred debt issue costs	(42,598)	(25,626)
	$ 3,990,748	$ 2,478,660

The U.S. dollar denominated debt was translated into Canadian dollars at the year-end exchange rate of US$1 = C$1.0636 (December 31, 2012 – US$1 = C$0.9949).

There are no maintenance financial covenants associated with the Corporation's debt as at December 31, 2013 and 2012.

(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 December 31, 2013, $133.9 million (December 31, 2012 – $2.6 million) of the revolving credit facility was utilized to support letters of credit. As at December 31, 2013, no amount had been drawn under the revolving credit facility.

The senior secured credit facilities are comprised of a US$1.275 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 $6.1 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 $11.2 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 $12.2 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, beginning on March 31, 2014. No principal payments are required until March 31, 2024. The Corporation has deferred the associated remaining debt issue costs of $13.1 million and is amortizing these costs over the life of the notes utilizing the effective interest method.

	2014	**2015**	**2016**	**2017**	**2018**	**Thereafter**
Required debt principal repayments	$ 13,827	$ 13,827	$ 13,827	$ 13,827	$ 13,827	$ 3,998,603

14. PROVISIONS AND OTHER LIABILITIES

As at December 31,	2013	2012
Derivative financial liabilities [(a)]	$ 30,981	$ 37,195
Decommissioning provision [(b)]	108,695	82,087
Deferred lease inducements [(c)]	4,978	5,733
Provisions and other liabilities	144,654	125,015
Less current portion	(19,477)	(7,259)
Non-current portion	$ 125,177	$ 117,756

(a) Derivative financial liabilities

As at December 31,	2013	2012
1% interest rate floor	$ 23,497	$ 24,807
Interest rate swaps	7,484	12,388
Derivative financial liabilities	30,981	37,195
Less current portion	(13,886)	(6,509)
Non-current portion	$ 17,095	$ 30,686

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 and 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 December 31, 2013, the Corporation had entered into interest rate swaps on US$748.0 million (note 6(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:

As at December 31,	2013	2012
Decommissioning provision, beginning of year	$ 82,087	$ 65,360
Changes in estimated future cash flows	15,082	–
Changes in discount rates	(19,110)	(3,846)
Liabilities incurred	30,068	18,218
Liabilities settled	(4,195)	(1,315)
Accretion	4,763	3,670
Decommissioning provision, end of year	108,695	82,087
Less current portion	(4,848)	–
Non-current portion	$ 103,847	$ 82,087

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 $108.7 million as at December 31, 2013 (December 31, 2012 – $82.1 million) based on an undiscounted total future liability of $293.8 million (December 31, 2012 – $228.1 million) and a credit-adjusted rate of 6.4% (December 31, 2012 – 5.7%). This obligation is estimated to be settled in periods up to 2064.

As at December 31, 2013, a 1% increase in the credit-adjusted discount rate would result in a $14.2 million decrease in the present value of the decommissioning provision.

(c) 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. DEFERRED INCOME TAXES

The deferred tax provisions differ from results which would be obtained had the Corporation applied the combined federal and provincial statutory rates of 25% (2012 – 25%) to earnings. The reasons for these differences are as follows:

For the years ended December 31,	2013	2012
Expected income tax expense (recovery)	$ (35,993)	$ 15,593
Add (deduct) the effect of:		
Stock-based compensation	9,698	6,312
Non-taxable (gain) loss on foreign exchange	26,715	(6,103)
Taxable capital losses (gain) not recognized	21,498	(6,121)
Other	429	122
	$ 22,347	$ 9,803

The analysis of deferred tax assets and deferred tax liabilities is as follows:

As at December 31,	2013	2012
Deferred tax liabilities:		
Deferred tax liabilities to be recovered after more than 12 months	$ 723,016	$ 542,075
Deferred tax liabilities to be recovered within 12 months	1,783	–
	724,799	542,075
Deferred tax assets:		
Deferred tax assets to be recovered after more than 12 months	(627,328)	(461,958)
Deferred tax assets to be recovered within 12 months	(3,677)	(8,673)
	(631,005)	(470,631)
Deferred tax liabilities (net)	$ 93,794	$ 71,444

The net movement on the deferred income tax account is as follows:

	2013	2012
Balance as at January 1,	$ 71,444	$ 67,969
Income statement charge	22,347	9,803
Other	(23)	–
Tax credited directly to equity [1]	26	(6,328)
Balance as at December 31,	$ 93,794	$ 71,444

(1) Deferred tax asset resulting from share issue costs incurred for the December 2012 equity issuance (note 16(b)).

The movement in deferred income tax assets and liabilities during the year is as follows:

Deferred tax liabilities	Property, plant and equipment	Provisions	Other	Total
Balance as at January 1, 2012	$ 477,300	$ 240	$ 656	$ 478,196
Charged (credited) to the income statement	64,775	(240)	(656)	63,879
Balance as at December 31, 2012	542,075	–	–	542,075
Charged to the income statement	178,383		4,315	182,698
Charged to equity			26	26
Balance as at December 31, 2013	**$ 720,458**	**$ –**	**$ 4,341**	**$ 724,799**

Deferred tax assets	Tax losses	Derivative financial liabilities	Provisions	Other	Total
Balance as at January 1, 2012	$ (395,055)	$ (6,081)	$ –	$ (9,091)	$ (410,227)
Charged to the income statement	(56,148)	(3,217)	(349)	5,638	(54,076)
Credited to equity	–	–	–	(6,328)	(6,328)
Balance as at December 31, 2012	(451,203)	(9,298)	(349)	(9,781)	(470,631)
Charged (credited) to the income statement	(169,781)	1,553	(142)	8,019	(160,351)
Other	–	–	–	(23)	(23)
Balance as at December 31, 2013	**$ (620,984)**	**$ (7,745)**	**$ (491)**	**$ (1,785)**	**$ (631,005)**

As at December 31, 2013, the Corporation had approximately $6.8 billion in available tax pools (December 31, 2012 – $3.6 billion). Included in the tax pools are $2.5 billion of non-capital loss carry forward balances ($0.2 billion expiring in 2026; $0.2 billion expiring in 2027; $0.4 billion expiring in 2028; $0.5 billion expiring in 2029; and $1.2 billion expiring after 2029). In addition, as at December 31, 2013, the Corporation had an additional $0.5 billion (December 31, 2012 – $1.8 billion) of capital investment in incomplete projects which will serve to increase available tax pools upon completion of the projects.

16. SHARE CAPITAL

(a) Authorized:
Unlimited number of common shares
Unlimited number of preferred shares

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

	2013		2012	
	Number of shares	**Amount**	**Number of shares**	**Amount**
Balance, beginning of year	**220,190,084**	**$ 4,694,378**	193,471,705	$ 3,877,193
Shares issued	**–**	**–**	24,246,212	800,125
Share issue costs, net of tax	**–**	**79**	–	(18,988)
Issued upon exercise of stock options	**1,893,732**	**40,522**	2,243,319	26,520
Issued upon vesting and release of RSUs	**423,080**	**16,395**	228,848	9,528
Balance, end of year	**222,506,896**	**$ 4,751,374**	220,190,084	$ 4,694,378

On December 28, 2012, the Corporation issued 24,246,212 common shares at a price of $33.00 per share for gross proceeds of $800.1 million.

(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 by the third anniversary of the grant date and expire seven years after the grant date.

	2013		2012	
	Stock options	**Weighted average exercise price per share**	**Stock options**	**Weighted average exercise price per share**
Outstanding, beginning of year	**9,147,404**	**$ 32.50**	10,190,103	$ 27.12
Granted	**1,774,854**	**30.95**	1,456,537	35.67
Exercised	**(1,893,732)**	**16.53**	(2,243,319)	9.21
Forfeited	**(169,498)**	**38.19**	(255,917)	40.29
Outstanding, end of year	**8,859,028**	**$ 35.49**	9,147,404	$ 32.50

	Outstanding			Vested		
Range of exercise prices	**Options**	**Weighted average exercise price**	**Weighted average remaining life (in years)**	**Options**	**Weighted average exercise price**	**Weighted average remaining life (in years)**
$24.00 – $29.99	1,469,524	$ 24.07	2.61	1,448,045	$ 24.00	2.56
$30.00 – $39.99	3,970,413	33.23	5.47	1,353,561	34.61	4.23
$40.00 – $49.99	2,797,560	41.17	1.01	2,742,696	41.10	1.03
$50.00 – $51.43	621,531	51.42	4.43	418,946	51.42	4.43
	8,859,028	$ 35.49	3.54	5,963,248	$ 36.20	2.37

The fair value of each option granted during the year ended December 31, 2013 and 2012 is estimated on the date of the grant using the Black-Scholes option pricing model with weighted average assumptions for grants as follows:

	2013	2012
Risk free rate	**1.57%**	1.30%
Expected lives	**5 years**	5 years
Volatility	**36%**	40%
Annual dividend per share	**$ nil**	$ nil
Fair value of options granted	**$ 10.54**	$ 14.65

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

The Restricted Share Unit Plan allows for the granting of Restricted Share Units ("RSUs"), (including Performance Share Units ("PSUs"), effective June 13, 2013) 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	2013	2012
Outstanding, beginning of year	**953,804**	554,362
Granted	**2,157,534**	664,796
Vested and released	**(423,080)**	(228,848)
Forfeited	**(98,558)**	(36,506)
Outstanding, end of year	**2,589,700**	953,804

(e) Deferred share units outstanding:

Effective June 13, 2013, the Corporation's Board of Directors approved the Deferred Share Unit Plan. 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 December 31, 2013, there were 8,874 DSUs outstanding.

(f) Contributed surplus:

	2013	2012
Balance, beginning of year	**$ 102,219**	$ 85,568
Stock-based compensation—expensed	**38,792**	25,246
Stock-based compensation—capitalized	**11,267**	6,796
Stock options exercised	**(9,217)**	(5,863)
RSUs vested and released	**(16,395)**	(9,528)
Balance, end of year	**$ 126,666**	$ 102,219

17. PETROLEUM REVENUE, NET OF ROYALTIES

For the years ended December 31,	2013	2012
Petroleum sales:		
Proprietary	**$ 1,207,650**	$ 991,975
Third party	**101,750**	37,822
	1,309,400	1,029,797
Royalties	**(38,643)**	(25,959)
Petroleum revenue, net of royalties	**$ 1,270,757**	$ 1,003,838

18. OTHER REVENUE

For the years ended December 31,	2013	2012
Power revenue	**$ 44,456**	$ 33,634
Transportation revenue	**19,284**	13,032
Other revenue	**$ 63,740**	$ 46,666

19. DILUENT AND TRANSPORTATION

For the years ended December 31,	2013	2012
Diluent	**$ 601,191**	$ 496,548
Transportation	**22,457**	16,266
Diluent and transportation	**$ 623,648**	$ 512,814

20. NET FINANCE EXPENSE

For the years ended December 31,	2013	2012
Total interest expense	**$ 186,835**	$ 122,424
Less capitalized interest	**(76,529)**	(30,608)
Net interest expense	**110,306**	91,816
Accretion on decommissioning provision	**4,763**	3,670
Unrealized fair value (gain) loss on embedded derivative liabilities	**(14,352)**	2,953
Unrealized fair value (gain) loss on interest rate swaps	**(4,904)**	9,915
Realized loss on interest rate swaps	**4,720**	4,518
Unrealized fair value (gain) on other assets	**–**	(2,518)
Net finance expense	**$ 100,533**	$ 110,354

21. WAGES AND EMPLOYEE BENEFITS EXPENSE

For the years ended December 31,	2013	2012
Operating expense:		
Salaries and wages	**$ 37,994**	$ 32,618
Short-term employee benefits	**3,753**	2,778
General and administrative expense:		
Salaries and wages	**67,621**	52,307
Short-term employee benefits	**10,616**	6,086
	$ 119,984	$ 93,789

22. COMPENSATION OF KEY MANAGEMENT PERSONNEL

Key management personnel are comprised of the Corporation’s directors and executive officers and their compensation is as follows:

For the years ended December 31,	2013	2012
Salaries and short-term employee benefits	**$ 9,230**	$ 8,489
Share-based compensation expense	**12,477**	9,885
	$ 21,707	$ 18,374

23. SUPPLEMENTAL CASH FLOW DISCLOSURES

As at December 31,	2013	2012
Changes in non-cash working capital		
Operating activities:		
Trade receivables and other	**$ (75,107)**	$ 26,640
Inventories [a]	**(105,276)**	(8,329)
Accounts payables and accrued liabilities	**56,922**	9,999
Change in operating non-cash working capital	**(123,461)**	28,310
Investing activities:		
Short-term investments	**532,998**	(381,060)
Accounts payable and accrued liabilities	**(103,711)**	151,451
Trade receivables and other	**1,029**	(1,029)
Change in investing non-cash working capital	**430,316**	(230,638)
Change in total non-cash working capital	**$ 306,855**	$ (202,328)
Cash and cash equivalents:		
Cash	**$ 1,065,179**	$ 224,241
Cash equivalents	**113,893**	1,250,602
	$ 1,179,072	$ 1,474,843

(a) The December 31, 2013 amount excludes a non-cash increase in inventory of $7,131 (2012 – nil).

24. NET EARNINGS (LOSS) PER COMMON SHARE

For the years ended December 31,	2013	2012
Net income (loss)	**$ (166,405)**	$ 52,569
Weighted average common shares outstanding	**221,800,594**	196,667,540
Dilutive effect of stock options and restricted share units	**2,508,677**	3,294,847
Weighted average common shares outstanding – diluted	**224,309,271**	199,962,387
Net earnings (loss) per common share, basic	**$ (0.75)**	$ 0.27
Net earnings (loss) per common share, diluted	**$ (0.75)**	$ 0.26

25. COMMITMENTS AND CONTINGENCIES

(a) Commitments

The Corporation had the following commitments as at December 31, 2013.

Operating:

	2014	2015	2016	2017	2018	Thereafter
Office lease rentals	$ 12,288	$ 12,491	$ 12,901	$ 30,710	$ 30,797	$ 315,330
Diluent purchases	120,546	16,305	16,305	16,305	16,305	85,590
Transportation and storage	135,897	127,614	147,599	238,061	207,197	2,802,679
Other commitments	13,686	10,597	5,039	4,517	4,502	49,485
Commitments	$ 282,417	$ 167,007	$ 181,844	$ 289,593	$ 258,801	$ 3,253,084

Capital:

As part of normal operations, the Corporation has entered into a total of $153.0 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.

26. CAPITAL DISCLOSURES

As at December 31, 2013, the Corporation's capital resources included $1.0 billion of working capital and an additional undrawn US$2.0 billion revolving credit facility. Working capital is comprised of $1.2 billion of cash, cash equivalents, offset by a non-cash working capital deficiency of $0.2 billion.

The Corporation's cash and short-term investments are held in accounts with a diversified group of highly-rated third party financial institutions and consist of invested cash and cash equivalents in the Corporation's operating accounts. The cash is invested in high grade liquid short-term instruments such as government, commercial and bank paper, term deposits, and high interest savings accounts. 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.

DIRECTORS AND OFFICERS

BOARD OF DIRECTORS

Boyd Anderson [1][3]
Lead Director, Independent

Harvey Doerr [1][3]
Governance and Nominating Committee Chair, Independent

Robert B. Hodgins [1][2]
Audit Committee Chair, Independent

Peter R. Kagan [3]
Independent

David B. Krieger [2]
Independent

William (Bill) McCaffrey
Chairman, President and Chief Executive Officer, Non-Independent

Jeffrey J. McCaig [2][3][4]
Independent

James D. McFarland [2][3]
Compensation Committee Chair, Independent

David J. Wizinsky
Corporate Secretary, Non-Independent

(1) Audit Committee
(2) Compensation Committee
(3) Governance and Nominating Committee
(4) Mr. McCaig joined the Board on March 1, 2014.

Detailed biographies of MEG's Board of Directors and Corporate Officers are available on the corporation's website at **www.megenergy.com**

CORPORATE OFFICERS

William (Bill) McCaffrey
Chairman, President and Chief Executive Officer

Eric L. Toews
Chief Financial Officer

Grant Boyd
Senior Vice President, Resource Management – Growth Properties

Jamey Fitzgibbon
Senior Vice President, Resource Management – Christina Lake and Special Projects

Don Moe
Senior Vice President, Supply and Marketing

Richard Sendall
Senior Vice President, Strategy and Government Relations

Chi-Tak Yee
Senior Vice President, Reservoir and Geosciences

Grant Borbridge
Vice President, Legal and General Counsel

Scott Carrothers
Vice President, Finance and Treasurer

Stephen Diotte
Vice President, Human Resources, Information Technology and Corporate Services

John Nearing
Vice President, Finance and Controller

John Rogers
Vice President, Investor Relations and External Communications

Chris Sloof
Vice President, Projects

Don Sutherland
Vice President, Regulatory and Community Relations

David J. Wizinsky
Corporate Secretary

INFORMATION FOR SHAREHOLDERS

MEG Energy Corp. shares are traded on the Toronto Stock Exchange under the symbol "MEG".

TRANSFER AGENT

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cssinquiries@olympiatrust.com
www.olympiatrust.com

AUDITOR

PricewaterhouseCoopers LLP

INDEPENDENT RESERVE EVALUATOR

GLJ Petroleum Consultants

ANNUAL GENERAL MEETING

May 1, 2014
Bow Glacier Room
Centennial Place, West Tower
3rd Floor, 250 – 5th Street SW
Calgary, Alberta

HEAD OFFICE

8th Floor, 520 – 3rd Avenue SW
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FURTHER INFORMATION

MEG's financial reports, annual regulatory filings and news releases are available at **www.sedar.com** and on our website at **www.megenergy.com**.

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