



**ANNUAL INFORMATION FORM
FOR THE YEAR ENDED DECEMBER 31, 2015**

March 3, 2016

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NOTICE REGARDING FORWARD LOOKING INFORMATION

Forward looking information is based on, among other things, the Corporation's expectations regarding its future growth, results of operations, production, future capital and other expenditures (including the amount, nature and sources of funding thereof), competitive advantages, plans for and results of drilling activity, environmental matters, business prospects and opportunities. Such forward looking information reflects the Corporation's current beliefs and assumptions and is based on information currently available to it. Forward looking information involves significant known and unknown risks and uncertainties. A number of factors could cause actual results to differ materially from the results discussed in the forward looking information including risks associated with the impact of general economic conditions, industry conditions, governmental regulation, volatility of commodity prices, currency fluctuations, and uncertainties related to commodity price, interest rate and foreign exchange rate swap contracts and/or derivative financial instruments that MEG may enter into from time to time to manage its risk related such prices and rates imprecision of reserves and resources estimates, environmental risks, competition from other industry participants, the lack of availability of qualified personnel or management, stock market volatility and the Corporation's ability to access sufficient capital from internal and external sources, the risks discussed under "Risk Factors" and elsewhere in this Annual Information Form and in the Corporation's public disclosure documents, and other factors, many of which are beyond the Corporation's control. Although the forward looking information contained in this Annual Information Form is based on assumptions which the Corporation believes to be reasonable, the Corporation cannot make assurances that actual results will be consistent with such forward looking information. Such forward looking information is made as of the date of this Annual Information Form unless otherwise stated, and the Corporation assumes no obligation to update or revise such information to reflect new events or circumstances, except as required by applicable Canadian securities law. Due to the risks, uncertainties and assumptions inherent in forward looking information, prospective investors in the Corporation's securities should not place undue reliance on this forward looking information. Unless otherwise indicated, all capitalized terms shall have the meaning set forth in the Glossary and Definitions section of this Annual Information Form.

Specific forward looking information contained in this Annual Information Form includes, among others, statements pertaining to the following:

- the reserve and resource potential of the Corporation's assets;
- the bitumen production and designed capacity of the Corporation's assets;
- the Corporation's growth strategy and opportunities, including additional development opportunities associated with the Corporation's existing properties;
- the Corporation's capital expenditure programs and future capital requirements;
- the estimated quantity of the Corporation's proved reserves, probable reserves and contingent resources;
- the effect of the Corporation's continued application of the RISER initiative;
- the Corporation's projections of commodity prices, costs and netbacks;
- the Corporation's estimates of future interest and foreign exchange rates;
- the Corporation's environmental considerations, including water usage and GHG emissions;
- the Corporation's blending capability for its bitumen diluent blend;
- the timing and size of certain of the Corporation's operations, optimizations, and 'brownfield' and 'greenfield' phases, including its planned bitumen development projects, and the anticipated production levels from the Corporation's existing producing properties and its planned developments;
- the intention and timing of potentially refinancing the Corporation's term loans, the 2011 Notes, the 2012 Notes and the 2013 Notes and potentially expanding the Corporation's Credit Facilities;

- supply and demand fundamentals for crude oil, bitumen blend, natural gas, electricity, condensate and other diluents;
- the Corporation's access to adequate pipeline capacity;
- the Corporation's access to third party infrastructure;
- industry conditions including with respect to project development;
- potential future markets for the Corporation's products;
- the planned construction of the Corporation's facilities;
- the Corporation's drilling plans;
- the Corporation's plans for, and results of, exploration and development activities;
- the expected application timeframe for the Surmont Project, May River Regional Project and for the Growth Properties;
- the timing for receipt of various regulatory approvals, including receipt of various regulatory approvals for the Surmont Project, the May River Regional Project, the RISER initiatives and Growth Properties projects;
- the Corporation's treatment under governmental regulatory and royalty regimes and tax laws;
- the Corporation's relationship with local and regional stakeholders;
- the Corporation's future general and administrative expenses; and
- the Corporation's dividend policy.

With respect to forward looking information contained in this Annual Information Form, assumptions have been made regarding, among other things:

- future crude oil, bitumen blend, natural gas, electricity, condensate and other diluent prices, foreign exchange rates and interest rates;
- the Corporation's ability to obtain qualified staff and equipment in a timely and cost-efficient manner;
- the regulatory framework governing royalties, land use, taxes and environmental matters in the jurisdictions in which the Corporation conducts and will conduct its business;
- the Corporation's ability to market production of bitumen blend successfully to customers;
- the Corporation's future production levels and SORs;
- the applicability of technologies for the recovery and production of the Corporation's reserves and contingent resources;
- the recoverability of the Corporation's reserves and contingent resources;
- operating costs;
- future capital expenditures to be made by the Corporation;
- future sources of funding for the Corporation's capital programs;
- the Corporation's future debt levels;
- geological and engineering estimates in respect of the Corporation's reserves and contingent resources;
- the geography of the areas in which the Corporation is conducting exploration and development activities;
- the impact of increasing competition on the Corporation; and
- the Corporation's ability to obtain financing on acceptable terms.

Many of the foregoing assumptions are subject to change and are beyond the Corporation's control.

Some of the risks that could affect the Corporation's future results and could cause results to differ materially from those expressed in the forward looking information include:

- operating costs;
- the Corporation's status and stage of development;
- the concentration of the Corporation's production in a single project;
- the majority of the Corporation's total reserves and contingent resources are non-producing and/or undeveloped;
- uncertainties associated with estimating reserves and resources volumes;
- long-term reliance on third parties;
- the effect or outcome of litigation;
- the effect of any diluent supply constraints and increases in the cost thereof;
- operational hazards;
- natural hazards such as lightning and fires;
- competition for, among other things, capital, the acquisition of reserves and resources, pipeline capacity and skilled personnel;
- risks inherent in the SAGD bitumen recovery process;
- changes to royalty regimes;
- the failure of the Corporation to meet specific requirements in respect of its oil sands leases;
- aboriginal claims;
- unforeseen title defects and changes to the mineral tenure framework;
- risks arising from future acquisition activities;
- fluctuations in market prices for crude oil, natural gas, electricity and bitumen blend;
- general economic, market and business conditions;
- volatility of commodity inputs;
- variations in foreign exchange rates and interest rates;
- hedging strategies;
- national or global financial crisis;
- environmental risks and hazards and the cost of compliance with environmental legislation and regulations, including GHG regulations and potential climate change legislation;
- proposed export and import restrictions;
- failure to accurately estimate abandonment and reclamation costs;
- the need to obtain regulatory approvals and maintain compliance with regulatory requirements;
- extent of, and cost of compliance with, laws and regulations and the effect of changes in such laws and regulations from time to time including changes which could restrict the Corporation's ability to access foreign capital;

- failure to obtain or retain key personnel;
- potential conflicts of interest;
- changes to tax laws and government incentive programs;
- the potential for management estimates and assumptions to be inaccurate;
- risks associated with establishing and maintaining systems of internal controls;
- political risks and terrorist attacks;
- sufficiency of funds;
- restrictions contained in the Credit Facilities and the indentures governing the 2011 Notes, the 2012 Notes and the 2013 Notes and any future indebtedness;
- any requirement to incur additional indebtedness; and
- the other factors discussed under the heading "Risk Factors" in this Annual Information Form.

In addition, designed capacity is not necessarily indicative of the stabilized production levels that may be achieved at the Corporation's SAGD facilities as such production levels could be less or more than the designed capacities. Moreover, reported average or instantaneous production levels may not be reflective of sustainable production rates and future production rates may differ materially from the production rates reflected in this Annual Information Form due to, among other factors, difficulties or interruptions encountered during the production of bitumen. Actual capital costs may differ from estimates of capital costs prepared by management in connection with the construction of the Corporation's projects and such differences may be material. Estimated capital costs are based on historical experience in constructing Phases 1, 2 and 2B of the Christina Lake Project, the application of the RISER initiative, and have been adjusted for inflation, actual expenditures incurred to date and existing contractual commitments. However, costs for and access to required labour, services and equipment, operational efficiencies or difficulties in construction and drilling, changes in scope of design and weather conditions may individually or collectively materially impact the actual capital costs incurred in the construction of the Corporation's projects.

The information contained in this Annual Information Form, including the information provided under the heading "Risk Factors", identifies additional factors that could affect the Corporation's operating results and performance. Statements relating to "reserves" and "resources" are deemed to be forward looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and contingent resources described exist in the quantities predicted or estimated and can be profitably produced in the future. The assumptions relating to the reserves and contingent resources of the Corporation are discussed under the heading "Independent Reserves Evaluation" and Appendix D.

Forward looking information in this Annual Information Form is expressly qualified in its entirety by this cautionary statement.

THE CORPORATION

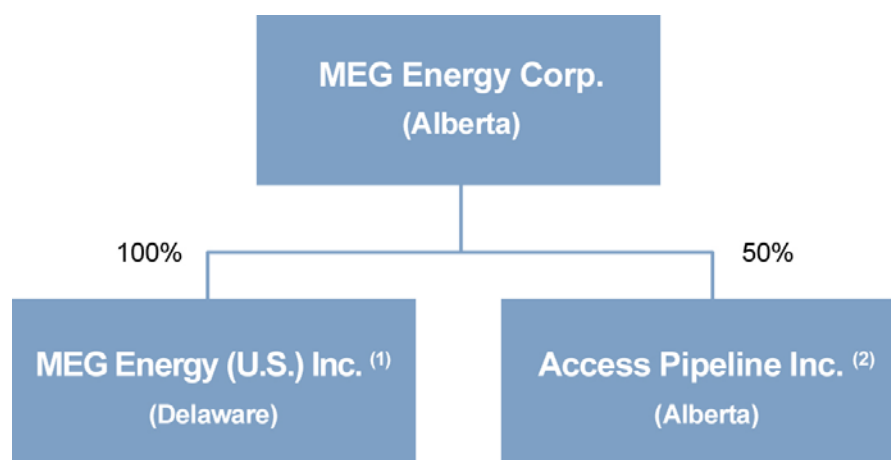
Incorporation and Organization

The Corporation was incorporated on March 9, 1999 under the *Business Corporations Act* (Alberta) ("ABCA") as McCaffrey Energy Group Inc. On June 11, 2002, the Corporation filed articles of amendment to amend its share capital and to change its name to MEG Energy Corp.

The Corporation's head office is located at 800, 520 – 3rd Avenue S.W., Calgary, Alberta, Canada T2P 0R3 and its registered office is located at 4500, 855 – 2nd Street S.W., Calgary, Alberta, Canada T2P 4K7.

MEG Energy (U.S.) Inc. ("MEG US"), a wholly-owned subsidiary of the Corporation, was incorporated on June 26, 2012 under the *Delaware General Corporation Law*.

The following organizational chart illustrates the intercorporate relationship of the Corporation, MEG US and Access Pipeline Inc., including the percentage of votes attaching to all voting securities of such entities that are beneficially owned, or controlled or directed, directly or indirectly, by the Corporation.



Notes:

- (1) MEG US is the corporate vehicle used for the Corporation's marketing-related activities in the United States. MEG US is a guarantor under the 2011 Notes, the 2012 Notes, the 2013 Notes and the Credit Facilities.
- (2) Access Pipeline Inc. is incorporated under the ABCA and is a management company that operates the Access Pipeline. MEG owns a 50% interest in Access Pipeline Inc. and the remaining 50% interest is held by Devon. See "Marketing Assets Overview".

Three Year Development

On February 25, 2013, the Corporation completed a refinancing of its Credit Facilities, through which the maturity of the term loan was extended by two years, the interest rate was reduced by 25 basis points and the principal amount was increased by US\$300 million.

On May 24, 2013, the Corporation expanded its senior secured revolving credit facility from US\$1.0 billion to US\$2.0 billion and extended the maturity of the revolving facility by one year to 2018.

On October 1, 2013, the Corporation issued US\$800 million in aggregate principal amount of 7.0% senior unsecured notes due in 2024. On November 6, 2013, the Corporation issued an additional US\$200 million in aggregate principal amount of 7.0% senior unsecured notes due in 2024, which are traded as a single series as, and trade fungibly with, the US\$800 million senior unsecured notes (together, the "2013 Notes").

In the fourth quarter of 2013, the Corporation commissioned its proprietary 900,000 barrel Stonefell Terminal, a strategic terminalling and storage facility located near Edmonton, Alberta, and completed a proprietary pipeline connection to a third party rail-loading facility near Bruderheim, Alberta. The first unit train of the Corporation's product was loaded and shipped in December 2013.

In the fourth quarter of 2013, Christina Lake Phase 2B commenced production. Phase 2B is an expansion with a designed capacity of 35,000 bbls/d. See "Projects Overview – Business Overview" and "Projects Overview – Christina Lake Project" for further information.

Production during the fourth quarter of 2013 averaged 42,251 bbls/d. Annual production for 2013 averaged 35,317 bbls/d.

Throughout 2014, the Corporation strategically shifted focus to a lower-cost brownfield expansion strategy at the Christina Lake Project. This strategic shift has allowed the Corporation to increase production more quickly and efficiently with lower capital costs than are typically associated with a greenfield expansion.

As a result of the successful ramp-up of Phase 2B, along with the success achieved from applying RISER to Phases 1 and 2, MEG achieved average production in excess of 80,000 bbls/d from the Christina Lake Project in the fourth quarter of 2014.

On November 5, 2014, the Corporation expanded its senior secured revolving credit facility from US\$2.0 billion to US\$2.5 billion and extended the maturity of the revolving facility by one year to November 2019. During the fourth quarter of 2014, the Corporation obtained a five year US\$500 million guaranteed letter of credit facility guaranteed by Export Development Canada ("EDC"). The facility matures November 2019. Letters of credit issued under the facility with EDC do not consume capacity of the Corporation's revolving credit facility.

Production during the fourth quarter of 2014 averaged 80,349 bbls/d. Annual production for 2014 averaged 71,186 bbls/d.

During 2015, the Corporation focused on reducing capital spending and lowering operating and non-operating costs as a result of the sustained weakness in the global commodity price environment. The Corporation continued to focus on the continuing application of RISER at the Christina Lake Project. This strategy has allowed the Corporation to increase and maintain production more efficiently and at lower capital intensity. In 2015, MEG significantly reduced capital expenditures and achieved the lowest net and non-energy per barrel operating costs in its operating history while increasing annual production to 80,025 bbls/d.

In the first and second quarter of 2015, the Corporation completed processing facility capacity testing at the Christina Lake Project. The results from this testing will be utilized in the development of future brownfield expansions plans at the Christina Lake Project.

In the third quarter of 2015, and following commissioning of the 42-inch expanded blend line, Access Pipeline converted the former 24-inch blend pipeline from Sturgeon Terminal to the Christina Lake Project into diluent service. MEG currently holds a 50% interest in the Access Pipeline.

On August 31, 2015, the Corporation announced the formation of a committee of the Board of Directors and that it had retained financial advisors to assist management in the review of options available to the Corporation to potentially utilize its interest in the Access Pipeline to reduce the financial leverage of the Corporation. The Corporation is working to complete this process, while ensuring any transaction is in the long-term interest of MEG's shareholders.

In the fourth quarter of 2015, the Corporation completed a disposition of non-core oil sands leases for proceeds of approximately \$110 million.

Production during the fourth quarter of 2015 averaged 83,514 bbls/d. Annual production for 2015 averaged 80,025 bbls/d.

The Corporation expects that the commodity price environment will continue to influence the development of MEG's business in 2016.

See "Projects Overview" and "Marketing Assets Overview" for further information.

PROJECTS OVERVIEW

Business 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 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 the GLJ Report, dated effective December 31, 2015 with a preparation date of January 29, 2016, GLJ Petroleum Consultants Ltd. ("GLJ") estimated that the oil sands leases it had evaluated contained 3.0 billion barrels of proved plus probable bitumen reserves. Appendix D to this Annual Information Form contains information relating GLJ estimates of MEG's economic bitumen contingent resources. See Appendix D for further information.

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 bbls/d of production and MEG has applied for regulatory approval for 120,000 bbls/d of production at the Surmont Project. The ultimate production rate and life of each project will be dependent on a number of factors, including the size, performance and development schedule for each expansion or phase in those projects. In addition, the Corporation holds other leases known as the "May River Regional Project" and the "Growth Properties". The Corporation is pursuing these opportunities for development and anticipates filing regulatory applications in 2016 for the May River Regional Project. The Growth Properties are in the resource definition and data gathering stage of development.

The Corporation's first two production phases at the Christina Lake Project, Phases 1 and 2, commenced production in 2008 and 2009, respectively, with a combined designed capacity of 25,000 bbls/d. On July 16, 2012, the Corporation announced the RISER initiative, which is designed to increase production from existing assets at lower capital and operating costs using a combination of proprietary reservoir technologies, redeployment of steam and facilities modifications, including debottlenecking and expansions (collectively, "RISER"). Phase 2B, an expansion with an initial designed capacity of 35,000 bbls/d, commenced production in the fourth quarter of 2013 and was successfully ramped up throughout 2014. Due to the successful ramp-up of Phase 2B, in combination with the success achieved from applying RISER, the Corporation achieved average production in excess of 80,000 bbls/d from the Christina Lake Project in the fourth quarter of 2014. Bitumen production for the year ended December 31, 2014 averaged 71,186 bbls/d and for the year ended December 31, 2015 averaged 80,025 bbls/d. In 2015, MEG significantly reduced capital expenditures and achieved the lowest net and non-energy per barrel operating costs in its operating history while increasing annual production to 80,025 bbls/d.

The Corporation is currently focused on the continuing application of RISER. "RISER" is an initiative that uses a combination of proprietary reservoir technologies, redeployment of steam and facilities modifications, including a series of brownfield expansions of existing facilities. The Corporation anticipates that this strategy will continue to allow the Corporation to increase production more quickly and efficiently and at lower capital intensity. The Corporation anticipates maintaining average annual bitumen production of 80,000 - 83,000 bbls/d in 2016, while providing for scheduled plant maintenance.

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 bbls/d over multiple phases. MEG filed a regulatory application for the project in September 2012. As a normal part of the regulatory review process, the Company received supplemental information requests ("SIRs") from the AER and ESRD in July 2013, March 2014 and October 2014. MEG responded to the SIRs in October 2013, June 2014 and October 2014. In November 2014, the Environmental Impact Assessment ("EIA") report for the Surmont Project was deemed technically complete by ESRD and the EIA report was referred to the AER. In accordance with AER

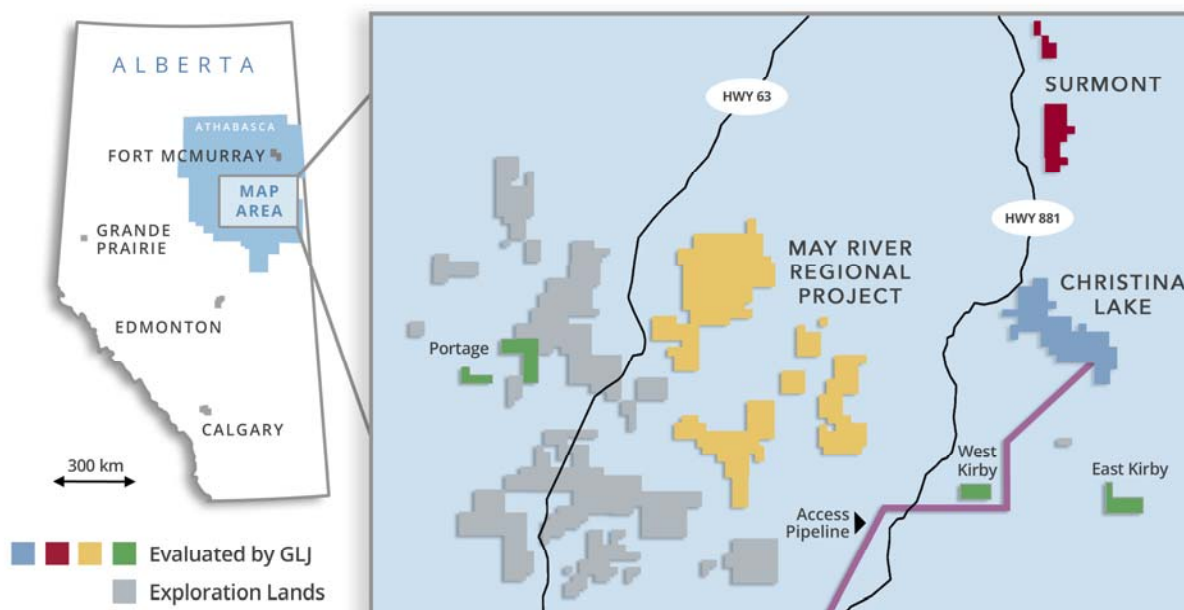
requirements, MEG is actively working with stakeholders to address concerns raised on the Surmont Project. The proposed project is expected to use SAGD technology and include multi-well production pads, electricity and steam cogeneration and other facilities similar to MEG's current Christina Lake Project. 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 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. MEG's 50% interest of the capacity in the 42-inch blend line is approximately 200,000 bbls/d of blended bitumen. See "Marketing Assets Overview".

In addition to the Access Pipeline, MEG holds a 100% interest in the Stonefell Terminal located near Edmonton, Alberta. The Stonefell Terminal was commissioned in the fourth quarter of 2013 and has 900,000 barrels of terminalling and storage capacity. The Stonefell Terminal is connected to local and export markets by pipeline, in addition to being pipeline connected to a third party rail-loading terminal near Bruderheim, Alberta. This combination of facilities allows for the loading of bitumen blend for transport by rail.

The following map highlights the locations of MEG's oil sands leases at Christina Lake, Surmont, May River Regional Project and the Growth Properties and the location of the Access Pipeline.

MEG Lease Overview Map



The following table sets forth certain summary information from the GLJ Report with respect to MEG's oil sands assets as of December 31, 2015:

Asset	Proved Reserves (MMbbls)	Probable Reserves (MMbbls)	Proved plus Probable Before Tax PV-10% (MM\$)
Christina Lake Project.....	1,474	804	17,505
Surmont Project	–	709	3,095
May River Regional Project.....	–	–	–
Total⁽²⁾	1,474	1,514	20,600

Notes:

(1) Totals may not add due to rounding.

As of December 31, 2015, the Corporation employed 617 full time permanent employees and 10 part-time permanent employees. The Corporation has also engaged a number of contractors and service providers.

Christina Lake Project

The Christina Lake Project is situated on 80 square miles of oil sands leases in the southern Athabasca oil sands region of Alberta. Phases 1 and 2 are approximately six miles northeast of Cenovus Energy Inc.'s Christina Lake SAGD project and 11 miles northeast of Devon's Jackfish SAGD project. MEG owns a 100% working interest in the oil sands leases associated with the Christina Lake Project, which were largely acquired between 1999 and 2006 through Alberta Crown auctions and through purchases of existing leases from third parties.

Reserves and Resources

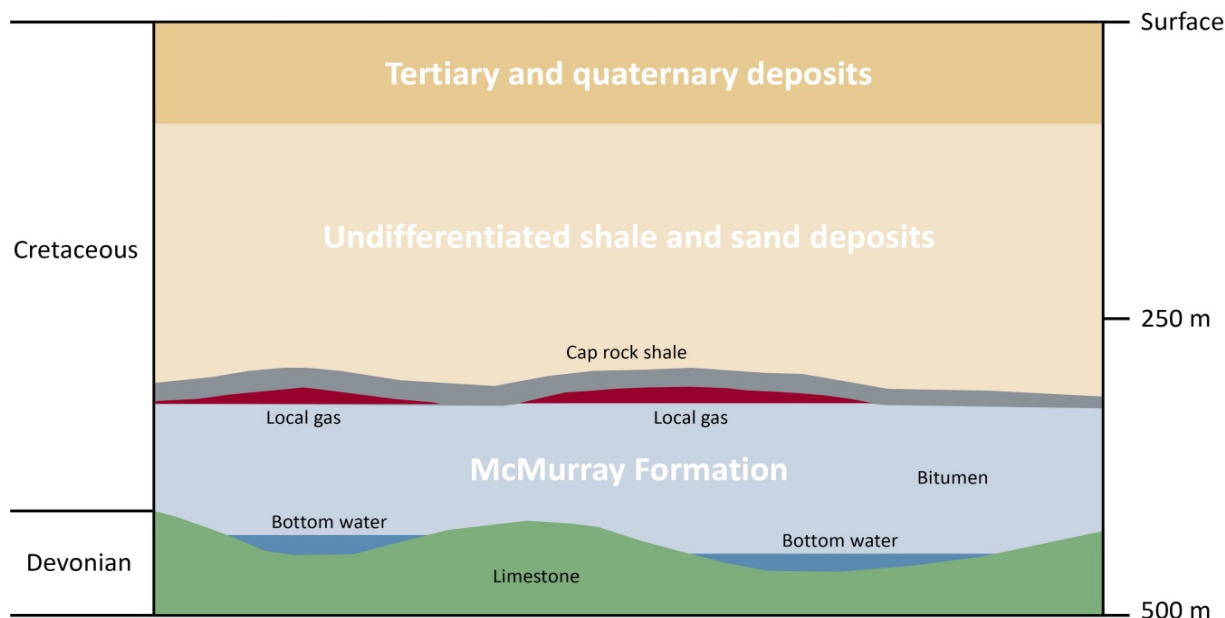
GLJ Report

In the GLJ Report, GLJ assigned proved developed reserves and proved undeveloped reserves to the Phase 1, Phase 2 and portions of Phase 2B of the Christina Lake Project, along with proved undeveloped reserves for sub-phases associated with the RISER initiative at the Christina Lake Project. Probable reserves were assigned to Phases 1, 2, and 2B. Contingent resources were also assigned to the Christina Lake Project. See "Independent Reserves Evaluation" and Appendix D to this Annual Information Form.

Geology

The reserves and contingent resources assigned by GLJ to the Christina Lake Project are contained within the Cretaceous-aged McMurray formation (the "McMurray"). The McMurray is a succession of sands and shale deposited in a fluvial estuarine environment that developed in a major valley that was cut into Devonian-aged limestone. Sands were deposited in tide-influenced channels. McMurray sands are variably saturated with water, bitumen and natural gas. Bitumen from the McMurray has an average API gravity of approximately 8 degrees.

McMurray Geology



The unconsolidated sands of the McMurray at the Christina Lake Project are suitable for *in situ* recovery. The reservoir is situated at an average depth of 360 metres. The reservoir sand ranges in thickness from 9 - 56 metres with an average approximate thickness of 19 metres. Bitumen saturation is between 75% and 85%. Reservoir sands have average porosity of 33%. Absolute permeability of the sand is 3,000 - 5,000 millidarcies. Initial reservoir pressure is 2,100 kPa and *in situ* reservoir temperature is 12°C. Bitumen viscosity at reservoir temperature is typically greater than 1,000,000 centipoise. Bitumen pay can be underlain by water saturated sand in the Christina Lake area. The Corporation considers bottom water in direct contact with the bitumen pay to be manageable when utilizing proper SAGD operating strategies. Overlying gas pools are on occasion in contact with the McMurray reservoir sands for the Christina Lake Project. Some of these gas pools have had historical gas production but were shut-in by the ERCB in 2004 in order to conserve the bitumen resource. Some depleted gas pools that are in direct pressure communication with the bitumen reservoirs will require repressurization. Other SAGD operators have successfully repressurized depleted gas pools.

SAGD projects require adequate supplies of water for steam generation. In steady state operations, approximately 90% of the water used to generate steam for MEG's SAGD process is expected to be recycled from produced water. The remaining water is sourced from one of several very large underground non-potable water formations in the Christina Lake region that provide water that could not otherwise be used for domestic or agricultural purposes. This water is cleaned for use in steam generators. Processed water containing impurities extracted from the produced water is returned to underground formations.

Development Plan

The Christina Lake Project is being developed in phases to help control costs and implement improving technologies. The Corporation expects that each future phase of the Christina Lake Project will be completed in a series of stages. The first stage consists of the activities required to be completed before steam is first injected into a well pair, which is referred to as "first steam". These activities include the engineering, resource definition, public consultation and environmental work required to support the regulatory applications, the filing of regulatory applications, the receipt of the necessary regulatory approvals and the construction of well pairs, the construction or expansion, as the case may be, of steam generation, oil treatment facilities and related infrastructure. The second stage consists of activities required to bring the facilities and well pairs up to their designed level of capacity. The final stage consists of the activities needed to continuously operate the facilities and well pairs at their designed level of capacity and the implementation of RISER. In general, the Corporation expects that the facilities and well pairs at future phases of the Christina Lake Project will ramp-up to their designed capacity within 9 to 12 months following the initial well steaming phase and RISER will be deployed once the Corporation determines it is appropriate to do so.

Stage of Development

Phase 1, Phase 2 and Phase 2B

Phase 1, Phase 2 and Phase 2B of the Christina Lake Project are complete and on production. The 3,000 bbls/d Phase 1 bitumen pilot plant commenced production in 2008 and has now been integrated with Phase 2. Phase 2B commenced production in the fourth quarter of 2013.

The Corporation completed initial capacity testing on Phase 2B during the facility turnaround conducted in the second and third quarters of 2015. As part of a broader focus, the learnings from these tests will continue to be used to further reduce the capital required to increase plant throughput capabilities with the goal of improving the economics of the Christina Lake Project. The Corporation intends to build smaller expansions onto existing facilities to lower costs.

The Corporation is currently focused on the continuing application of RISER. The Corporation anticipates that this strategy will continue to allow the Corporation to increase production more quickly and efficiently and at lower capital intensity. The Corporation anticipates maintaining average annual bitumen production of 80,000 - 83,000 bbls/d in 2016, while providing for scheduled plant maintenance.

Christina Lake Project – Phases 1, 2 and 2B

Production

The Corporation's first two production phases at the Christina Lake Project, Phases 1 and 2, commenced production in 2008 and 2009, respectively, with a combined designed capacity of 25,000 bbls/d. In 2012, the Corporation announced the RISER initiative, which is designed to increase production from existing assets at lower capital and operating costs using a combination of proprietary reservoir technologies, redeployment of steam and facilities modifications, including debottlenecking and expansions. Phase 2B, an expansion with an initial designed capacity of 35,000 bbls/d, commenced production in the fourth quarter of 2013 and was successfully ramped up throughout 2014. Due to the successful ramp-up of Phase 2B, in combination with the success achieved from applying RISER, the Corporation achieved average production in excess of 80,000 bbls/d from the Christina Lake Project during the fourth quarter of 2014. Annual production for 2015 averaged 80,025 bbls/d compared to 71,186 bbls/d in 2014. In 2015, MEG significantly reduced capital expenditures and achieved the lowest net and non-energy per barrel operating costs in its operating history while increasing annual production to 80,025 bbls/d.

The Corporation's average SOR was 2.5 for the three months ended December 31, 2015 and for the three months ended December 31, 2014.

The table below summarizes MEG's unaudited operating costs for each quarter of 2015.

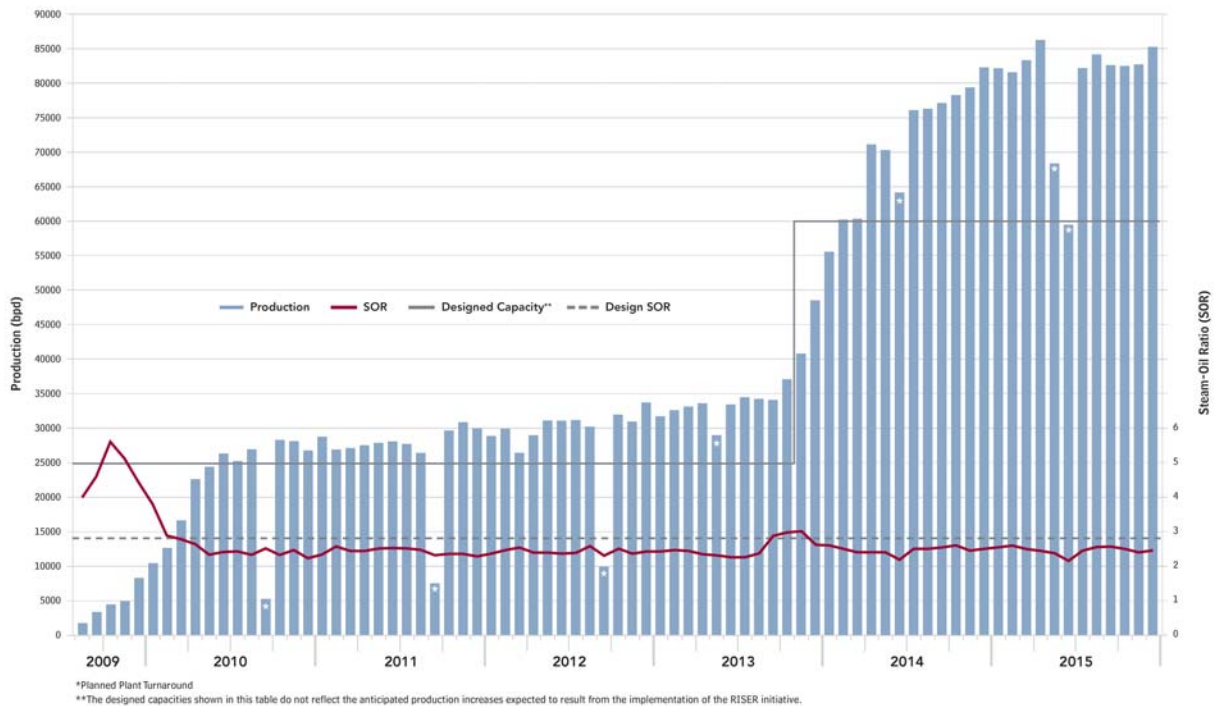
	MEG – Operating Costs 2015			
	First Quarter	Second Quarter⁽¹⁾	Third Quarter	Fourth Quarter
Operating Costs (\$/bbl):				
Energy costs ⁽²⁾	\$2.92	\$2.42	\$3.12	\$2.86
Non-energy costs	\$7.57	\$7.01	\$5.98	\$5.66
Total Net Operating Costs.....	\$10.49	\$9.43	\$9.10	\$8.52
Production (bbls/d)	82,398	71,376	82,768	83,514
SOR	2.6	2.3	2.5	2.5

Notes:

- (1) MEG conducted a scheduled plant turnaround in the end of the second quarter and the beginning of the third quarter of 2015 which reduced production.
- (2) Energy costs are calculated net of power revenue.

Phase 2 and Phase 2B of the Christina Lake Project each include an 85 MW cogeneration facility (together 170 MW) which are both operating near capacity. The capacity of the cogeneration units and HRSG was chosen based on steam generation requirements, not based on MEG's power needs. Power is considered to be the by-product of the steam generation facilities and the sale of this power helps to offset natural gas input costs. Approximately 50% of the Phase 1, 2 and 2B steam generation capacity is provided by the cogeneration units and the HRSG.

Steam injection into Phase 2B well pairs commenced in the third quarter of 2013. Due to the successful ramp-up of Phase 2B, in combination with the success achieved from applying RISER, the Corporation achieved average production in excess of 80,000 bbls/d from the Christina Lake Project in the fourth quarter of 2014. Bitumen production for the year ended December 31, 2014 averaged 71,186 bbls/d and for the year ended December 31, 2015 averaged 80,025 bbls/d. MEG increased production throughout 2015 and production averaged 83,514 bbls/d in the fourth quarter with an SOR of 2.5. In 2015, MEG significantly reduced capital expenditures and achieved the lowest net and non-energy per barrel operating costs in its operating history while increasing annual production to 80,025 bbls/d. The Corporation anticipates maintaining average annual bitumen production of 80,000 - 83,000 bbls/d in 2016, while providing for scheduled plant maintenance.



Future Development at Christina Lake

In 2008, a regulatory application for Phase 3 was filed with regulatory authorities for the Christina Lake Project. The application was made for phased development totalling an additional 150,000 bbls/d of designed capacity. Regulatory approvals for Phase 3 were received from the ERCB on January 31, 2012 and from ESRD on February 10, 2012. MEG's regulatory approval for the Christina Lake Project allows for production of up to 210,000 bbls/d. On May 8, 2014, MEG applied to the AER for an amendment to its Christina Lake regulatory approval to allow for brownfield expansions at the Phase 2B facility at the Christina Lake Project. Approval for the amendment was received from the AER on June 26, 2014. MEG's next phase of production growth will be primarily driven by the application of RISER and further brownfield expansions at Christina Lake. Given the economic attractiveness of this strategy, MEG has prioritized the continuing application of RISER ahead of its next greenfield expansion at Christina Lake. The Corporation will maintain the flexibility to temporarily defer growth projects if warranted by market conditions.

Upon reaching full development, based on GLJ estimates, the Corporation expects that the Christina Lake Project can support an average of over 200,000 bbls/d of bitumen production for approximately 30 years.

Surmont Project

The Surmont Project comprises 32 square miles of lands in the southern Athabasca oil sands region of Alberta. The Surmont Project is located approximately 50 miles south of Fort McMurray. 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. The Surmont Project is adjacent to an *in situ* oil sands project operated by ConocoPhillips Canada and is approximately 30 miles north of the Christina Lake Project. MEG owns a 100% working interest in the oil sands leases associated with the Surmont Project. MEG has conducted extensive seismic programs and delineation drilling programs in the Surmont Project area and on September 13, 2012 MEG filed regulatory applications with the ERCB and ESRD for a multi-phase development at Surmont with a designed capacity of approximately 120,000 bbls/d. As a normal part of the regulatory review process, the Company received SIRs from the AER and ESRD in July 2013, March 2014 and October 2014. MEG responded to the SIRs in October 2013, June 2014 and October 2014. In November 2014, the EIA report for the Surmont Project was deemed technically complete by ESRD and the EIA report was referred to the AER. In accordance with AER requirements, MEG is actively working with stakeholders to address concerns raised on the Surmont Project.

MEG's Surmont Project is situated along the same geological trend as the Christina Lake Project. The proposed project is expected to use SAGD technology and RISER development techniques and include multi-well production pads, steam generators, cogeneration and other facilities similar to the Christina Lake Project.

Reserves and Resources

GLJ Report

In the GLJ Report, GLJ assigned 709 million barrels of probable reserves to the lands evaluated within the Surmont Project area as of December 31, 2015. Contingent resources were also assigned to the Surmont Project. See "Independent Reserves Evaluation" and Appendix D to this Annual Information Form.

Geology

The probable reserves and contingent resources assigned by GLJ to the Surmont Project are contained within the McMurray. The McMurray at the Surmont Project has similar reservoir properties to those at the Christina Lake Project. The reservoir is at an average depth of 250 metres. The reservoir sand ranges in thickness from 10 - 50 metres with an average thickness of 24 metres. Bitumen saturation is between 75% and 85%. Initial reservoir pressure is 1,500 kPa. At the Surmont Project, bitumen pay can be underlain by water saturated sand. The Corporation considers bottom water in direct contact with the bitumen pay to be manageable when utilizing proper SAGD operating strategies. Overlying gas pools are on occasion in contact with the McMurray reservoir sands for the Surmont Project. Some of these gas pools have had historical gas production but were shut-in by the ERCB in 1999 in order to conserve the bitumen resource. Some depleted gas pools and lean zones that are in direct pressure communication with the bitumen reservoirs will require repressurization.

The Surmont Project is expected to have access to adequate supplies of water from non-potable subsurface formations for steam generation as well as geological formations that can be used for water disposal.

Development Plan

On September 13, 2012 MEG filed regulatory applications with the ERCB and ESRD for the Surmont Project. A total of 50 core holes have been drilled by MEG on the Surmont Project leases. These core holes, in combination with the acquisition of 34 square miles of 3D seismic, were used to define the resources of the Surmont Project. Management anticipates, consistent with GLJ estimates, that the Surmont Project can support an average of 120,000 bbls/d of bitumen production for approximately 20 years. The proposed project is expected to use SAGD and RISER development techniques, including multi-well production pads, steam generators, cogeneration and other facilities similar to the Christina Lake Project. MEG plans to connect the Surmont Project to the Access Pipeline and Stonefell Terminal, which management anticipates will offer diluent supply and marketing advantages similar to those realized at the Christina Lake Project.

May River Regional Project

The May River Regional Project properties are situated on 285 square miles of lands in the southern Athabasca oil sands region of Alberta and include the May River and Thornbury oil sands leases. MEG owns a 100% working interest in the oil sands leases of the May River Regional Project, which it acquired between 2005 and 2013 through Alberta Crown auctions as well as through purchases of existing leases from third parties.

As of December 31, 2015, MEG had drilled and cored 122 stratigraphic test wells (core holes) and recorded 77 square miles of 3D seismic data over the May River Regional Project area.

Resources

GLJ Report

In the GLJ Report, contingent resources were assigned to the May River Regional Project. See Appendix D to this Annual Information Form. GLJ evaluated all 285 square miles of the May River Regional Project area.

Geology

The contingent resources assigned by GLJ to the May River Regional Project lands are mainly contained within the McMurray formation. The McMurray formation at the May River Regional Project has very similar reservoir properties to those at the Christina Lake Project. The reservoir is at an average depth of 470 - 480 metres. The reservoir sand ranges in thickness from 10 - 40 metres with an average thickness of 20 metres. Bitumen saturation is between 75% and 85%. Initial reservoir pressure is between 1,900 kPa - 2,450 kPa., Bitumen pay at the May River Regional Project can be underlain by water saturated sand. MEG considers bottom water in direct contact with the bitumen pay to be manageable when utilizing proper SAGD operating strategies. Overlying gas pools are on occasion in contact with the McMurray reservoir sands. Some of these gas pools have had historical gas production but were shut-in by the ERCB in 2003 in order to conserve the bitumen resource. Some depleted gas pools that are in direct pressure communication with the bitumen reservoirs will require repressurization. MEG has water source opportunities from non-potable subsurface formations at the May River Regional Project and is evaluating several disposal options at this site.

Development Plan

MEG has been conducting core-hole programs at the May River Regional Project with the objectives of identifying additional contingent resources, defining areas for commercial development and determining the size of potential commercial developments. MEG anticipates filing a regulatory application for the May River Regional Project area in 2016. MEG also plans to connect the May River Regional Project to the Access Pipeline and the Stonefell Terminal, which management anticipates will offer diluent supply and transportation advantages similar to those realized at the Christina Lake Project.

Growth Properties

The Growth Properties are situated on approximately 550 square miles of lands in the southern Athabasca oil sands region of Alberta and includes the Portage, East Kirby and West Kirby oil sands leases. MEG owns a 100% working interest in the oil sands leases of the Growth Properties, which it acquired between 2005 and 2013 through Alberta Crown auctions as well as through purchases of existing leases from third parties. As of December 31, 2015, MEG had drilled and cored 21 stratigraphic test wells (core holes) in the Growth Properties.

Development Plan

MEG has been conducting core-hole programs on the Growth Properties with the objectives of identifying additional contingent resources, defining areas for commercial development and determining the size of potential commercial developments. MEG anticipates filing future regulatory applications for future projects within the Growth Properties once commercial development plans have been better defined. MEG also plans to connect the Growth Properties to

the Access Pipeline and the Stonefell Terminal, which management anticipates will offer diluent supply and transportation advantages similar to those realized at the Christina Lake Project.

Capital Investment

Due to the lower crude oil price environment, MEG reduced capital spending in 2015. MEG's capital investment in 2015 totalled \$257 million. The revised 2015 program was largely directed toward a combination of sustaining and maintenance capital.

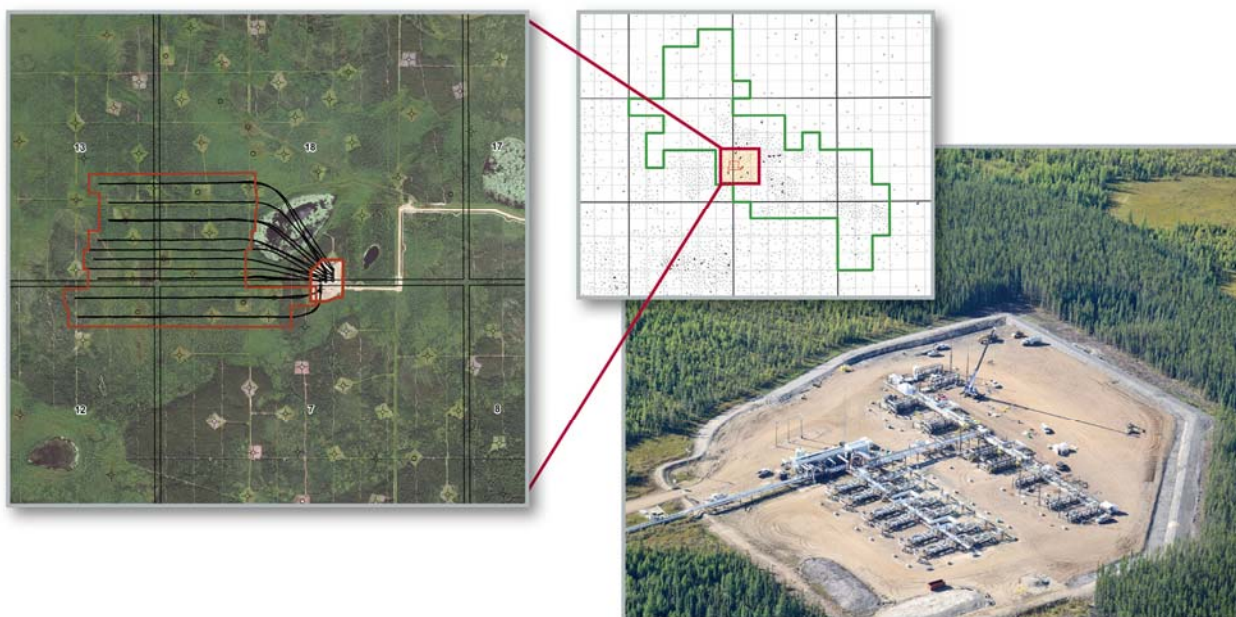
In December 2015, MEG announced a 2016 annual capital program of \$328 million. Since the announcement, the 2016 annual capital program has been revised downward by approximately 50% to \$170 million.

The reduction in 2016 capital spending is not expected to impact MEG's 2016 production guidance of 80,000 – 83,000 bbls/d and non-energy operating costs of \$6.75 to \$7.75 per barrel, although the Corporation will maintain the flexibility to temporarily defer production if warranted by market conditions.

See "Risk Factors – Risks Related to Financing and the Corporation's Indebtedness – Sufficiency of Funds".

Environmental Strategy

Aerial View of Pad A Footprint at the Christina Lake Project



Canada's oil sands are being developed using mining and *in situ* technologies. MEG is not engaged in oil sands mining. SAGD, which is the extraction method that MEG is currently employing at its oil sands developments, is a commercially proven technology that has numerous environmental advantages over mining operations:

- Reduced land use – in SAGD, production wells with a horizontal length of between 800 - 1000 metres are drilled from multi-well pads. The surface area of a standard six-well production pad is approximately 9% of the area drained by the six horizontal well pairs on the pad.

- Water use – MEG anticipates that over 90% of the water used to generate steam during MEG's steady state operations will be comprised of recycled produced water; the remaining water is sourced from large underground non-potable water formations that provide water that could not otherwise be used for domestic or agricultural purposes. This water is treated for use in steam generators. Processed water containing impurities extracted from the produced water is returned to underground formations.
- Reduced air emissions – SAGD projects use clean burning natural gas to generate steam. This results in fewer emissions (including carbon dioxide and nitrous oxide).

In addition to the environmental advantages associated with SAGD projects relative to mining operations, MEG's operations have several important environmental advantages over certain other SAGD projects:

- Low SOR – the quality of MEG's oil sands reservoir results in lower SORs and therefore MEG is able to use less natural gas and produce less air emissions per barrel of bitumen produced;
- Clean burning technologies – MEG has incorporated clean burn technologies, which reduce nitrous oxide emissions per unit of natural gas burned. MEG also conserves produced and production lift gases for use in steam generation;
- Use of existing land disturbances – MEG uses, where possible, existing disturbances for development in order to minimize further land disturbances and to reduce the footprint of the project;
- Cogeneration – MEG's natural gas turbine generates electricity that is used in its operations, with surplus power sold into the Alberta Power Pool electricity grid. The heat from the turbine is recovered by a heat recovery steam generator for use in the SAGD process, resulting in more efficient use of natural gas and the sale of surplus power to the Alberta Power Pool electricity grid. Revenues from the sale of surplus power help offset the Corporation's energy costs; and
- GHG management – the corporation's low SOR resulting from RISER and the use of cogeneration results in effective GHG management and emission intensity reductions and offers the potential to further decrease the emissions intensity of MEG's production.

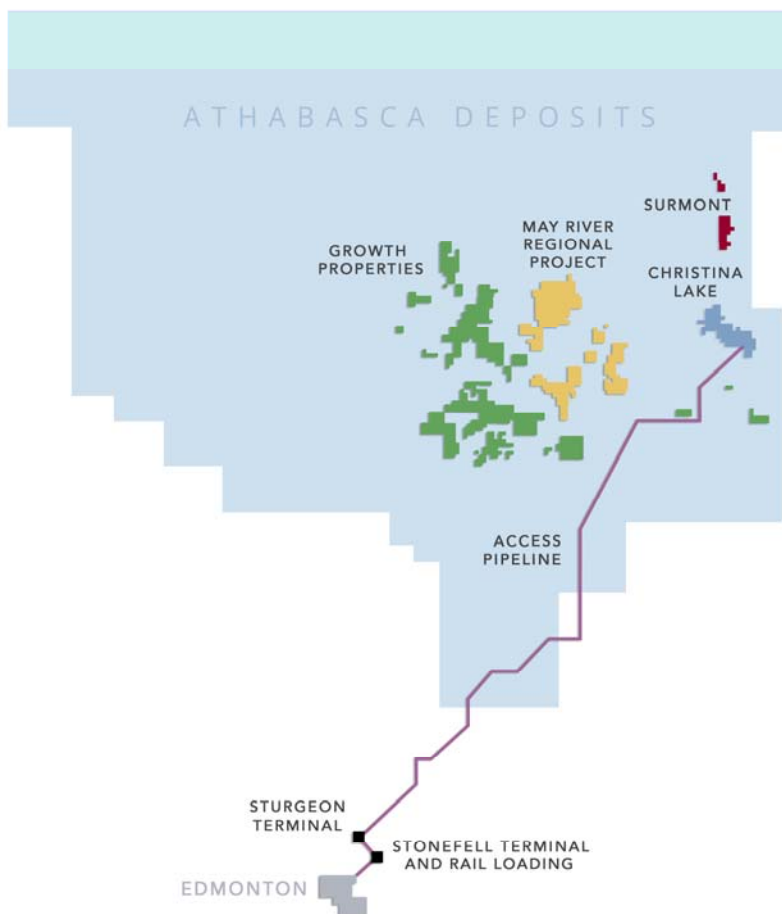
MARKETING ASSETS OVERVIEW

MEG employs a "hub & spoke" strategy to deliver and sell its production to crude oil markets and manage diluent supply. MEG employs a combination of owned and leased facilities to transport and sell its dilbit blend, Access Western Blend ("AWB"), to refiners in western and eastern Canada, the US Midwest, the US Gulf Coast, the US East Coast and the US West Coast.

MEG owns a 50% interest in the Access Pipeline. It is a dual pipeline system that MEG uses to deliver AWB from the Christina Lake Project to MEG's Stonefell Terminal near Bruderheim, Alberta, and to refiners and other blend export pipelines near Edmonton, Alberta.

The blend pipeline system consists of a 42" blend line from the Christina Lake Project to Sturgeon Terminal and a 30" pipeline from Sturgeon Terminal to MEG's Stonefell Terminal and to refiners and other blend export pipelines near Edmonton, Alberta. Access Pipeline also has a 16" diluent pipeline from the Edmonton area to Sturgeon Terminal and a 24" diluent pipeline from Sturgeon Terminal to the Christina Lake Project that is used to transport diluent for blending and use in processing at the Christina Lake Project.

Access Pipeline and Sturgeon Terminal



MEG's owned capacity in the Access Pipeline is currently approximately 200,000 bbls/d of blended bitumen and 87,000 bbls/d of condensate. MEG uses condensate as diluent. The blend line can be expanded through the addition of pump capacity as throughput requirements expand. The owners of Access Pipeline converted the system's former 24" blend line to diluent service in the third quarter of 2015.

Access Pipeline delivers diluent to the Christina Lake Project from a variety of sources in the Edmonton area. The 24" diluent line is able to receive volumes from four fractionation facilities and is able to access two major underground diluent storage sites and two major diluent tank car offloading sites in the Edmonton/Fort Saskatchewan corridor. The diluent line is also connected to the main hub for Alberta mixed stream condensate and the Enbridge Southern Lights pipeline. This system provides a range of diluent supply alternatives and helps to mitigate diluent supply risk and diluent costs.

On August 31, 2015, MEG announced the formation of a committee of the Board of Directors and that it had retained financial advisors to assist management in the review of options available to MEG to potentially utilize its interest in the Access Pipeline to reduce the financial leverage of the Corporation. MEG is working diligently to complete this process, while ensuring any transaction is in the long-term interest of MEG's shareholders.

MEG's wholly-owned 900,000 barrel Stonefell Terminal is located near Edmonton, Alberta. Stonefell Terminal and its connections form the "hub" of MEG's "hub and spoke" marketing strategy. The Stonefell Terminal provides MEG with the ability to: (i) sell and deliver AWB to a variety of markets; (ii) access multiple sources of diluent; and (iii) store both AWB and diluent in periods of market and transportation disruptions or constraints. MEG's Stonefell Terminal is directly connected by pipeline to a third party rail-loading facility near Bruderheim, Alberta.

Additionally, MEG has currently contracted for 50,000 bbls/d (rising to 100,000 bbls/d over time) of transportation capacity on the Flanagan South and Seaway pipeline systems providing pipeline transportation directly to U.S. Gulf Coast refineries. This pipeline system went into operation in late 2014. This combination of pipeline access, along with continuing options for rail and other transportation, is expected to provide MEG with reliable access to higher valued markets as MEG's production increases.

INDEPENDENT RESERVES EVALUATION

MEG is required to report its reserves and to provide other oil and gas information in accordance with National Instrument 51-101—*Standards of Disclosure for Oil and Gas Activities* ("NI 51-101"). The Corporation engaged GLJ to prepare the GLJ Report. Specifically, GLJ evaluated certain of the Corporation's 100% working interest assets at the Christina Lake Project, the Surmont Project, the May River Regional Project and the Growth Properties. All of the Corporation's properties are located in the Province of Alberta and are described elsewhere in this Annual Information Form. See "Projects Overview".

GLJ is a private Canadian company established in 1972 which provides independent engineering and geological consulting services to the petroleum industry. GLJ's services include economic evaluations, technical studies, advice and opinions. GLJ carried out its evaluations in accordance with standards established by the Canadian Securities Administrators in NI 51-101. Those standards require that the reserves and contingent resources data be prepared in accordance with the COGE Handbook. GLJ's responsibility is to express opinions on the reserves and contingent resources data including the associated net present values based on its evaluations. The preparation and disclosure of the reported reserves and contingent resources estimates are the responsibility of the Corporation's management.

GLJ's "Report on Reserves Data, Contingent Resource Data and Prospective Resources Data by Independent Qualified Reserves Evaluator or Auditor" in the form of Form 51-101F2 is set forth in Appendix A to this Annual Information Form. The Corporation's "Report of Management and Directors on Oil and Gas Disclosure" in the form of Form 51-101F3 is set forth in Appendix B to this Annual Information Form. Supplemental disclosure concerning the Corporation's contingent resources is set out in Appendix D to this Annual Information Form.

The GLJ Report does take into account taxes or other amounts payable by MEG at Christina Lake pursuant to existing provincial and federal laws and regulations that restrict or otherwise regulate GHG emissions (including without limitations the Climate Change and Emissions Management Act (Alberta) and the Specified Emitters Regulation). The GLJ report does not take into account taxes or other amounts that may be payable by MEG as a result of any future development which has yet to establish GHG emissions baselines, nor does it take into account taxes or other amounts that may be payable by MEG as a result of new or proposed laws or regulations which may be enacted at a later date. See "Regulatory Matters – Environmental Regulation", "Regulatory Matters – The Future of GHG Emission Regulations" and "Risk Factors – Environmental and Regulatory Risks".

The information set forth below relating to the Corporation's reserves and in Appendix D relating to the Corporation's contingent resources constitutes forward looking information which is subject to certain risks and uncertainties. See "Notice Regarding Forward Looking Information" and "Risk Factors".

Reserves Classification

The estimated recoverable volumes from an *in situ* bitumen project are classified according to their stage of development. Before a regulatory application seeking approval to proceed with a project has been initiated, the associated estimated recoverable volumes may be classified as contingent resources. Upon the initiation of the regulatory approval process, determining the project has positive economics, and defining the timing of development, and assuming no other significant contingencies exist, a portion of the estimated recoverable volumes associated with the project may then be classified as reserves. These reserves may be categorized as proved reserves, probable reserves or possible reserves, depending on the degree of certainty associated with the estimates. Proved reserves would only be assessed following regulatory approval and corporate sanctioning of the project. Each of these categories may be further divided into developed and undeveloped categories. Developed reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (e.g. when compared to the cost of drilling a well) to put the reserves on production. Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (e.g. when compared to the cost of drilling a well) is required to render them capable of production.

Through the GLJ Report, GLJ assigned: (i) proved developed producing reserves in respect of Phase 1, Phase 2 and portions of Phase 2B of the Christina Lake Project; (ii) proved developed non-producing reserves in respect of Phase 1, Phase 2 and portions of Phase 2B at the Christina Lake Project; (iii) proved undeveloped reserves in respect of Phase 1, Phase 2 and portions of Phase 2B sustaining wells and sub-phases associated with the RISER initiative of the Christina Lake Project; and (iv) probable undeveloped reserves in respect of Phases 1, 2, 2B and sub-phases associated with the RISER initiative of the Christina Lake Project and in respect of the Surmont Project. Additional recoverable volumes of bitumen were classified as contingent resources. See Appendix D to this Annual Information Form.

Reserves Estimates

Below is a summary of MEG's bitumen reserves and the value of future net revenues from such bitumen reserves as of December 31, 2015 as evaluated by GLJ in the GLJ Report, reflecting the Corporation's 100% working interest in the Christina Lake and Surmont leases. The aggregate reserves estimates and valuations presented in this section are arithmetic sums of the estimates and valuations contained in the GLJ Report. The pricing used in the forecast price evaluations is set forth below under "GLJ Price Forecast".

The reserves estimates described herein are estimates only and the actual quantities of recoverable bitumen may be greater or less than those estimated. The estimated future net revenues contained in the following tables do not necessarily represent the fair market value of the Corporation's reserves. All evaluations of future revenue are after the deduction of royalties, development costs, production costs and well abandonment costs but before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses. There is no assurance that the forecast price and cost assumptions contained in the GLJ Report will be realized and variances could be material. Other assumptions and qualifications relating to project schedules, costs and other matters are inherent in these estimates. See "Notice Regarding Forward Looking Information" and "Risk Factors".

**Summary of Bitumen Reserves as of December 31, 2015
(Forecast Prices and Costs)**

<u>Reserves Category</u>	<u>Bitumen</u>	
	<u>Gross⁽¹⁾</u> <u>(MMbbls)</u>	<u>Net⁽²⁾</u> <u>(MMbbls)</u>
Proved Reserves⁽³⁾		
Proved Developed Producing	231.8	210.8
Proved Developed Non-Producing	0.9	0.7
Proved Undeveloped	1,233.4	927.7
Total Proved Reserves	1,473.9	1,146.0
Total Probable Reserves⁽⁴⁾	1,513.6	1,099.5
Total Proved Plus Probable Reserves⁽⁵⁾	2,987.5	2,245.5

Notes:

- (1) "Gross" is the Corporation's working interest share before deducting royalties.
- (2) "Net" is the Corporation's working interest share after deducting royalties.
- (3) "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.
- (4) "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.
- (5) Totals may not add due to rounding.

**Net Present Value of Future Net Revenue
as of December 31, 2015
Before Income Taxes
(Forecast Prices and Costs)**

<u>Reserves Category</u>	<u>Before Income Taxes</u> <u>Discounted at %/Year</u>					<u>Unit Value Before</u> <u>Income Taxes</u> <u>Discounted</u> <u>at 10%/Year⁽¹⁾</u> <u>\$/bbl</u>
	<u>0%</u>	<u>5%</u>	<u>10%</u>	<u>15%</u>	<u>20%</u>	
	<u>(MM\$)</u>	<u>(MM\$)</u>	<u>(MM\$)</u>	<u>(MM\$)</u>	<u>(MM\$)</u>	
Proved Reserves						
Proved Developed Producing	6,995	5,557	4,529	3,777	3,211	21.49
Proved Developed Non-Producing	110	98	79	64	51	10.68
Proved Undeveloped	47,923	16,630	7,203	3,618	1,968	7.76
Total Proved Reserves⁽²⁾	55,028	22,285	11,811	7,458	5,231	10.31
Total Probable Reserves	61,881	21,489	8,788	3,934	1,791	7.99
Total Proved Plus Probable Reserves⁽²⁾	116,909	43,774	20,600	11,392	7,022	9.17

Notes:

- (1) Unit values have been calculated using MEG's net reserves after deducting royalties.
- (2) Totals may not add due to rounding.

**Net Present Value of Future Net Revenue
as of December 31, 2015
After Income Taxes (Forecast Prices and Costs)
(Discounted at %/Year)**

<u>Reserves Category</u>	<u>0%</u>	<u>5%</u>	<u>10%</u>	<u>15%</u>	<u>20%</u>
	<u>(MM\$)</u>	<u>(MM\$)</u>	<u>(MM\$)</u>	<u>(MM\$)</u>	<u>(MM\$)</u>
Proved Reserves					
Proved Developed Producing	6,995	5,557	4,529	3,777	3,211
Proved Developed Non-Producing	110	98	79	64	51
Proved Undeveloped	34,899	11,994	5,125	2,522	1,324
Total Proved Reserves⁽¹⁾	42,003	17,649	9,734	6,362	4,587
Total Probable Reserves	45,319	15,385	6,055	2,524	987
Total Proved Plus Probable Reserves⁽¹⁾	87,323	33,034	15,789	8,886	5,574

Notes:

- (1) Totals may not add due to rounding.

**Future Net Revenue (undiscounted)
as of December 31, 2015
(Forecast Prices and Costs)**

<u>Reserves Category</u>	<u>Revenue (MM\$)</u>	<u>Royalties (MM\$)</u>	<u>Operating Costs (MM\$)</u>	<u>Capital Development Costs (MM\$)</u>	<u>Aband. And Reclam. Costs⁽¹⁾ (MM\$)</u>	<u>Future Net Revenue Before Income Taxes (MM\$)</u>	<u>Income Taxes (MM\$)</u>	<u>Future Net Revenue After Income Taxes (MM\$)</u>
Proved Reserves								
Proved Developed Producing	13,521	1,368	4,101	702	354	6,995	0	6,995
Proved Developed Non- Producing	1,088	82	748	122	26	110	0	110
Proved Undeveloped	123,081	30,570	24,086	18,336	2,165	47,923	13,025	34,899
Total Proved Reserves⁽¹⁾	137,689	32,020	28,935	19,160	2,546	55,028	13,025	42,003
Total Probable Reserves	146,326	41,060	24,193	17,503	1,688	61,881	16,562	45,319
Total Proved Plus Probable Reserves⁽²⁾	284,015	73,080	53,129	36,663	4,234	116,909	29,587	87,323

Note:

- (1) Total abandonment and reclamation costs included for all reserves wells and major dedicated facilities, known and existing, and to be incurred as a result of future development activity.
- (2) Totals may not add due to rounding.

**Future Net Revenue By Production Group
as of December 31, 2015
(Forecast Prices and Costs)**

<u>Reserves Category</u>	<u>Production Group</u>	<u>Future Net Revenue Before Income Taxes (discounted at 10%/yr) MM\$</u>	<u>Unit Value⁽¹⁾ (\$/bbl)</u>
Total Proved Producing Reserves.....	Bitumen	4,529	21.49
Total Proved Reserves	Bitumen	11,811	10.31
Total Proved Plus Probable Reserves	Bitumen	20,600	9.17

Note:

- (1) Other revenue and costs not related to a specific production group have been allocated proportionately to the production groups. Unit values have been calculated using MEG's net reserves after deducting royalties.

Reconciliation of Reserves by Principal Product Type (Forecast Prices and Costs)

The following table sets forth a reconciliation of the changes to MEG's working interest, before royalties, of bitumen reserves as of December 31, 2015 against such reserves as of December 31, 2014 based on the forecast price and cost assumptions set forth in Note 1 of the table.

	Total Bitumen Reserves ⁽¹⁾⁽²⁾		
	Gross Proved (Mbbbls)	Gross Probable (Mbbbls)	Gross Proved Plus Probable (Mbbbls)
December 31, 2014	1,500,567	1,504,950	3,005,517
Discoveries.....	0	0	0
Extensions and Improved Recovery	0	0	0
Technical Revisions	2,846	8,654	11,500
Acquisitions	0	0	0
Dispositions.....	0	0	0
Economic Factors	0	0	0
Production	-29,513	0	-29,513
December 31, 2015	1,473,900	1,513,604	2,987,504

Notes:

- (1) The pricing assumptions used in the GLJ Report with respect to values of future net revenue as well as the inflation rates used for operating and capital costs are set forth below under "GLJ Price Forecast".
- (2) Totals may not add due to rounding.

GLJ Price Forecast

The price forecasts that formed the basis for the revenue projections and net present value estimates in the GLJ Report were based on GLJ's January 1, 2016 pricing models. A summary of selected price forecasts is set forth below.

Forecast Prices used in Preparing Reserves Data GLJ – January 1, 2016

Forecast	Oil Sands Inflation (%)	Exchange Rate (US\$/Cdn\$)	West Texas Intermediate Crude Oil at Cushing Oklahoma Current (US\$/bbl)	AECO/ NIT Spot Current (Cdn\$/MM Btu)	WCS Crude Oil Stream Quality at Hardisty Current (Cdn\$/bbl)	Diluent Edmonton Pentanes Plus (Cdn\$/bbl)	Heavy Crude Oil (12 API) at Hardisty (Cdn\$/bbl)	Light Crude Oil (35 API, 1.2% S) at Cromer (Cdn\$/bbl)	Medium Crude Oil (29 API, 2.0% S) at Cromer (Cdn\$/bbl)
2016	2.0	0.725	44.00	2.76	42.26	60.79	35.70	53.59	50.80
2017	2.0	0.75	52.00	3.27	51.20	68.48	45.02	62.72	59.52
2018	2.0	0.775	58.00	3.45	55.39	73.17	49.06	67.02	63.60
2019	2.0	0.80	64.00	3.68	60.84	78.91	54.42	72.28	68.59
2020	2.0	0.825	70.00	3.81	66.18	84.30	59.75	77.21	72.27
2021	2.0	0.85	75.00	3.90	70.00	88.12	63.56	80.71	76.59
2022	2.0	0.85	80.00	4.10	75.88	94.41	69.32	86.47	82.06
2023	2.0	0.85	85.00	4.30	81.41	100.71	74.62	92.24	87.53
2024	2.0	0.85	87.88	4.50	84.90	103.24	78.40	94.55	89.73
2025	2.0	0.85	89.63	4.60	86.60	105.30	79.99	96.44	91.52
2026+/yr ..	2.0	0.85	+2%	+2%	+2%	+2%	+2%	+2%	+2%

The Corporation realized an average price of \$30.63/bbl of bitumen for the year ended December 31, 2015.

Undeveloped Reserves

Through the GLJ Report, GLJ has assigned the Christina Lake property proved undeveloped reserves of 1,233 MMbbls and the Christina Lake and Surmont properties probable undeveloped reserves of 1,471 MMbbls. The Corporation's proved undeveloped reserves and probable undeveloped reserves are expected to be developed as wells and plant capacity become available. See "Projects Overview".

The following tables set out the volumes of gross proved undeveloped reserves of bitumen and gross probable undeveloped reserves of bitumen first attributed for each of the Corporation's most recent three financial years and in the aggregate before that time using forecast prices and costs.

Proved Undeveloped Bitumen Reserves

<u>Period</u>	<u>First Attributed (MMbbls)</u>	<u>Total at Year-end (MMbbls)</u>
December 31, 2013.....	173	1,194
December 31, 2014.....	11	1,293
December 31, 2015.....	0	1,233

Probable Undeveloped Bitumen Reserves

<u>Period</u>	<u>First Attributed (MMbbls)</u>	<u>Total at Year-end (MMbbls)</u>
December 31, 2013.....	148	1,411
December 31, 2014.....	0	1,469
December 31, 2015.....	0	1,471

Significant Factors or Uncertainties

The Corporation does not anticipate that any important economic factors or significant uncertainties would affect particular components of its reported reserves. However a number of factors which are beyond the Corporation's control can significantly affect the reserves, including global product pricing, royalty and tax regimes, changes in operating and capital costs, surface access issues, weather, receipt of regulatory approvals, availability of services and processing facilities and technical issues affecting well performance. See "Risk Factors".

Future Development Costs

The following table sets forth the development costs associated with the proved reserves and proved plus probable reserves which were deducted in the estimation of future net revenue attributable to each of the reserves categories contained in the GLJ Report. Future development costs are anticipated to be funded as described under "Projects Overview – Christina Lake Project", "Projects Overview – Surmont Project" and "Projects Overview – Capital Investment".

	Total Proved Future Development Costs Using Forecast Escalated Costs (MM\$)	Total Proved Plus Probable Future Development Costs Using Escalated Dollars Costs (MM\$)
2016	568	568
2017	616	535
2018	460	1,170
2019	174	1,999
2020	459	2,227
2021	242	761
2022	330	358
2023	295	826
2024	446	1,073
2025	388	816
2026	581	596
2027	412	1,211
Remainder.....	14,189	24,520
Total, undiscounted.....	<u>19,160</u>	<u>36,663</u>

OTHER OIL AND GAS INFORMATION

Oil and Gas Properties and Wells

The following table sets out the Corporation's producing and non-producing bitumen production wells as of December 31, 2015, all of which are in Alberta, Canada:

	Bitumen Production Wells as of December 31, 2015	
	Gross	Net
Christina Lake		
Producing SAGD Well Pairs	136	136
Non-producing SAGD Well Pairs.....	7	7
Producing Infill Wells	45	45
Non-producing Infill Wells.....	1	1
Total	<u>189</u>	<u>189</u>

Note:

- (1) All producing and non-producing SAGD wells and Infill Wells shown in this table are located at Phases 1, 2 and 2B of the Christina Lake Project.

MEG has also drilled a total of 802 stratigraphic test wells, 287 observation wells, 18 water source wells, and 5 water disposal wells on or adjacent to its oil sands leases. These wells did not produce any bitumen volumes in 2015.

The following table sets out the Corporation's producing and non-producing gas wells, all of which are in Alberta, as of December 31, 2015:

Gas Production Wells as of December 31, 2015

	Gas Production Wells as of December 31, 2015	
	Gross	Net
Producing.....	0	0
Non-producing.....	180	160
Total.....	180	160

Properties With No Attributed Reserves

The following table sets out the Corporation's properties to which no reserves had been assigned as of December 31, 2015. All properties are located in Alberta and no material underlying leases are expected to expire within the next year:

Oil Sands Leases without Attributed Reserves

Undeveloped Acreage (acres)	
Gross	Net
576,600	576,600

Additional Information Concerning Abandonment and Reclamation Costs

The Corporation follows the IFRS standards on decommissioning provision to account for and report the estimated cost of future site abandonment and restoration. This standard requires liability recognition for retirement obligations associated with long-lived assets, which would include abandonment of oil sands wells and related facilities, natural gas wells and related facilities, the Access Pipeline, Stonefell Terminal, removal of equipment from leased acreage and returning such land to its original condition. Under the standard, the estimated fair value of each decommissioning obligation is recorded in the period a well or related asset is drilled, constructed or acquired. Fair value is estimated using the present value of the estimated future cash outflows to abandon the asset at the Corporation's credit-adjusted risk-free rate. The obligation is reviewed regularly by management based upon current regulations, costs, technologies and industry standards. The discounted obligation is recognized as a liability and is accreted against income until it is settled or the property is sold and is included as a component of net finance expense. Actual restoration expenditures are charged to the accumulated obligation as incurred.

As of December 31, 2015, the estimated total undiscounted amount required to settle the decommissioning obligations in respect of the Corporation's facilities, the Access Pipeline, Stonefell Terminal and certain wells (including producing, non-producing, observation, water source and water disposal wells), net of estimated salvage recoveries, was approximately \$816.4 million. This obligation is estimated to be settled in periods up to 2064. The 8.3% discounted present value of this amount is approximately \$130.4 million (\$114.9 million discounted at 10%). Over the next three years, the Corporation expects to incur approximately \$11.0 million in decommissioning expenditures.

In the GLJ Report, abandonment and reclamation costs for total proved plus probable reserves were estimated to be \$4.234 billion, undiscounted, and \$290.0 million, discounted at 10%. These estimates include well abandonment and reclamation costs only for wells that have been assigned reserves and the associated steam injector wells plus the abandonment and reclamation costs associated with major dedicated facilities. These estimates do not include abandonment and reclamation costs for non-reserves wells or other liabilities which the Corporation has included in determining its asset retirement obligation. These costs include the abandonment of the 189 net wells and 3,403 producers including infills and 1,704 injectors anticipated to be required to develop the assigned reserves over the life of the projects.

Tax Horizon

As of December 31, 2015, the Corporation had approximately \$7.3 billion of available tax pools and had recognized a deferred income tax liability of \$87.5 million. In addition, as of December 31, 2015, the Corporation had \$0.6 billion of capital investment in respect of incomplete projects which will increase available tax pools upon completion of the projects. Based on anticipated capital spending, which augments the tax pools, the Corporation does not expect to pay Canadian income taxes during the next five years. This estimate will be impacted by, among other factors, construction costs, commodity prices, foreign exchange rates, operating costs, interest rates and the Corporation's other business activities. Changes in these factors from estimates used by the Corporation could result in the Corporation paying income taxes earlier than expected.

Costs Incurred

The Corporation did not acquire any property with reserves or resources in the year ended December 31, 2015. During 2015, the Corporation divested of a non-core undeveloped oil sands asset for proceeds of approximately \$110 million. The following table summarizes the net capital investment made by MEG on its properties for the year ended December 31, 2015:

Summary of Net Capital Investment

	Year ended December 31
(\$000)	2015
Total cash capital investment	257,178
Capitalized interest	56,449
	313,627
Dispositions	(41,827)
Net capital investment	\$ 271,800

Exploration and Development Activities

MEG conducted a series of drilling programs on its oil sands leases in 2015. The following table sets forth the number of exploratory and development wells which MEG completed during the year ended December 31, 2015:

Exploration and Development Activities

	2015 Wells (Gross & Net)
Exploration Wells	0
Stratigraphic Test Wells	0
SAGD Wells	13
Observation Wells	0
Infill Wells	0
Water Source Wells	0
Water Disposal Wells	0
Total Completed Wells⁽¹⁾	13

Note:

(1) The Corporation has a 100% working interest in all wells drilled.

See "Projects Overview" for a description of the Corporation's current and anticipated exploration and development activities.

Production Estimates

The following table sets forth the estimated volume of net working interest production of proved reserves and probable reserves in 2016, before royalties, as set out in the GLJ Report:

Production Estimates

<u>Period</u>	<u>Bitumen (bbls/d)⁽¹⁾⁽²⁾</u>
Total Proved Reserves.....	83,665
Total Probable Reserves.....	1,798
Total Proved Plus Probable Reserves	<u>85,462</u>

Notes:

- (1) The Corporation has a 100% working interest.
- (2) All estimated production is associated with Phases 1, 2 and 2B of the Christina Lake Project. The values above are based on estimated annual production over 365 days.

Production History

The following table sets forth certain information in respect of production at Phases 1, 2 and 2B of the Christina Lake Project, product prices, royalties, operating and transportation costs and netbacks on a per barrel basis received for each quarter of MEG's most recently completed financial year:

	Production History			
	Three months ended March 31, 2015	Three months ended June 30, 2015	Three months ended September 30, 2015	Three months ended December 31, 2015
Average Daily Production.....	82,398	71,376	82,768	83,514
Bitumen (bbls/d)				
Average Net Prices Received.....	25.82	44.54	31.03	23.17
Bitumen (\$/bbl)				
Royalties	0.80	0.90	0.88	0.25
Bitumen (\$/bbl)				
Net Operating Costs ⁽¹⁾	10.49	9.43	9.10	8.52
Bitumen (\$/bbl)				
Transportation ⁽²⁾	4.70	4.57	4.64	5.35
Bitumen (\$/bbl)				
Netback ⁽³⁾	9.83	29.64	16.41	9.05
Bitumen (\$/bbl)				

Notes:

- (1) Net Operating Costs include energy and non-energy operating costs, reduced by power revenue.
- (2) Transportation is comprised of transportation and selling costs, net of transportation revenue.
- (3) Netbacks on a per-unit basis are calculated by dividing related production revenue, less costs and royalties, by sales volumes.

The Corporation's average daily production for the year ended December 31, 2015 from Phases 1, 2 and 2B of the Christina Lake Project was 80,025 bbls/d.

REGULATORY MATTERS

The oil and gas industry is subject to extensive controls and regulations. In Alberta, provincial legislation and regulations govern land tenure, royalties, production practices and rates, environmental protection, the prevention of waste and other matters. Federal legislation and regulations may also apply. Although it is not expected that any of these controls and regulations will affect the operations of the Corporation in a manner materially different than they would affect other oil and natural gas producers of similar size, the controls and regulations should be considered carefully by investors in the oil and natural gas industry. The regulatory scheme as it relates to oil sands is somewhat different from that related to oil and gas generally. Outlined below are some of the more significant aspects of the legislation and regulations governing the recovery and marketing of bitumen from oil sands. All current legislation is a matter of public record and the Corporation is unable to predict with certainty what additional legislation or amendments may be enacted.

Regulatory Framework

The Alberta Department of Energy is responsible for administering the legislation that governs the ownership, royalty and administration of Alberta's oil, gas, oil sands, coal, metallic and other mineral resources. Prior to June 17, 2013, energy resource activities in Alberta were primarily regulated by the ERCB and ESRD. On October 24, 2012, the Government of Alberta introduced Bill 2, the *Responsible Energy Development Act* ("REDA").

REDA was passed on December 10, 2012, and was designed to come into effect in three phases. On June 17, 2013 the first phase of REDA commenced with the establishment of the Alberta Energy Regulator ("AER") and the repealing of the *Energy Resources Conservation Act*. As a result, the ERCB was dissolved and the AER assumed all of the ERCB's responsibilities under energy resource legislation, including the *Oil Sands Conservation Act*. The second phase was completed on November 30, 2013, when the AER assumed the ESRD's responsibilities in relation to energy resource activities under the *Public Lands Act* and Part 8 of the *Mines and Minerals Act*. The third phase was completed on March 29, 2014 when the AER announced that it had assumed jurisdiction over energy resource activities formerly under the jurisdiction of the ESRD. Included in the third phase was the transfer of the ESRD's responsibilities in relation to energy resources activities under the *Environmental Protection and Enhancement Act* and the *Water Act*.

The AER is now Alberta's single energy regulator, responsible for full life-cycle regulation of oil, gas, oil sands and coal projects in Alberta. The AER is responsible for applications, exploration, construction, development, abandonment, reclamation and remediation. The recent changes in Alberta's regulatory framework are the result of a four-year Regulatory Enhancement Project undertaken by the Government of Alberta with the stated goal of creating a regulatory system that delivers clarity, predictability, certainty and efficiency. Despite the recent changes, the regulatory regime for oil sands is essentially unchanged following REDA. The most significant difference is that oversight and administration are now carried out by a single regulatory body. However, the AER has not assumed control over the activities of the Alberta Utilities Commission ("AUC"). As a result, electrical facilities of oil sands projects, including cogeneration facilities, will continue to be regulated by the AUC. The Alberta Electric System Operator will remain responsible for regulating access to the Alberta electricity grid and electricity market.

Regulation of Operations

In Alberta, regulation of the construction, operation, decommissioning, and reclamation of oil sands recovery, pipeline, and upgrader projects is undertaken by the AER under various statutes, including the REDA, *Oil Sands Conservation Act*, *Water Act*, *Environmental Protection and Enhancement Act*, *Public Lands Act* and others. For example, AER approvals are required prior to the construction and operation of oil sands recovery, pipeline and

upgrader projects, and the legislation allows the AER to inspect and investigate operations. Inspection and investigations by provincial regulators may result, among other things, in remedial orders.

Additionally, the construction, operation, decommissioning and reclamation of oil sands recovery, pipeline and upgrader projects, and associated electrical facilities, may be subject to regulation by the Government of Canada under various federal statutes and regulations, which may include the *Canadian Environmental Assessment Act, 2012*, the *Canadian Environmental Protection Act, 1999*, the *Fisheries Act*, the *Navigation Protection Act* and where applicable, the *National Energy Board Act* ("NEB Act"). Certain federal approvals or authorizations may be needed prior to construction, operation or modification of facilities. Inspections and investigations by federal regulators may result, among other things, in remedial orders.

Pricing and Marketing – Crude Oil, Bitumen and Bitumen Blend

In Canada, producers of crude oil, bitumen and bitumen blend negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of such commodities. The price received by the Corporation depends in part on product quality, prices of competing fuels, distance to market, the value of refined products, the supply/demand balance and other contractual terms.

Subject to certain exemptions, exports from Canada must be made pursuant to short-term export orders or long-term licences obtained from the National Energy Board ("NEB"). An export order for light crude oil, defined to include blended oils with a density less than 875.7 kg/m³, may be granted for up to one year. An export order for heavy crude oil, defined to include blended oils with a density greater than 875.7 kg/m³, may be granted for a period not exceeding two years. If a longer term for export approval is required, an export licence must be obtained from the NEB, which must hold a public hearing prior to granting an export licence. Licences for the export of light or heavy crude oil may be granted for a period not exceeding 25 years and require the approval of the Governor in Council.

The NEB has proposed a series of amendments to Part VI of the NEB Act, which would, among other things, eliminate the distinction between heavy and light crude oil, creating a single definition for "crude oil". Currently, the NEB and the federal Government are in the process of drafting regulations for the proposed changes.

Pricing and Marketing – Natural Gas Liquids

In Canada, the price of condensate and other natural gas liquids ("NGLs") sold in intraprovincial, interprovincial and international trade is determined by negotiation between buyers and sellers. Such price depends, in part, on the origin and quality of the NGLs, prices of competing product, distance to market, access to downstream transportation, length of contract term, the supply/demand balance and other contractual terms.

Subject to certain exemptions, exports of NGLs from Canada must be made pursuant to short-term export orders or long-term licences obtained from the NEB. For example, an export order in respect of propane or butanes may be granted for up to one year and up to two years for ethane. Licences for the export of NGLs may be granted for a period not exceeding 25 years and require the approval of the Governor in Council.

The proposed changes to Part VI of the NEB Act outlined above would also impact NGLs.

Land Tenure

The oil sands mineral rights in approximately 97% of Alberta's estimated 142,200 square kilometers (54,904 square miles) of oil sands areas are owned by the provincial Crown and managed by the Alberta Department of Energy. The remaining approximately 3% of oil sands mineral rights are held "freehold" by individuals and companies, or by the federal Crown, for example in Indian reserves and National Parks.

Oil produced from oil sands owned by the Province of Alberta is produced under provincial Crown oil sands leases. Two types of oil sands agreements are issued under the *Oil Sands Tenure Regulation, 2010* made under the *Mines and Minerals Act*: (i) permits, issued for a five-year term, which can be converted to leases; and (ii) leases, issued for an initial 15-year term, which can be continued as to all or any portion the Minister of Energy may determine. The regulation requires that exploration or development activity be undertaken according to prescribed levels of evaluation or production. Permits may generally be converted to leases provided certain minimum levels of exploration have been achieved and all rentals have been timely paid. A lease may generally be continued after the initial term as to all or any portion the Minister of Energy may determine, provided certain minimum levels of exploration or production have been achieved and all rentals have been timely paid. The surface rights required for pipelines, upgraders and cogeneration and other facilities are generally governed by leases, easements, rights-of-way, permits or licenses granted by landowners or governmental authorities.

Royalties

For crude oil, natural gas and related production, the royalty regime is a significant factor in the profitability of production operations. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production. The rate of royalties payable generally depends in part on well productivity, geographical location and field discovery date and commodity prices. The Corporation's bitumen leases are all situated on Crown lands.

From time to time, the provincial governments have established incentive programs for exploration and development. Such programs often provide for royalty reductions, credits and holidays, and are generally introduced when commodity prices are low. The programs are designed to encourage exploration and development activity by improving earnings and cash flow within the industry.

On January 29, 2016 the Government of Alberta released the results of its Royalty Review Advisory Panel ("Panel") and announced that it will accept the recommendations in the Panel's report and implement a Modernized Royalty Framework. The Panel recommends new royalty rules for oil, natural gas and NGLs coming into effect in 2017, but also recommends grandfathering, under the current royalty rules, all wells drilled before 2017 for a ten year period. The Panel also recommends that the current royalty rates for oil sands remain unchanged, with some minor adjustments to allowable costs and transparency.

The current oil and gas royalty framework, effective January 1, 2009, establishes royalties for conventional oil, natural gas, and bitumen that are linked to price and production levels and apply to both new and existing conventional oil and natural gas activities and oil sands projects. Under the Alberta royalty regime, the calculation of conventional oil and natural gas royalties is made in accordance with sliding rate formulas, known as royalty curves, that adjust for market price and production volumes. Under the current framework, royalty rates for conventional oil range from 0 - 40% and natural gas royalty rates range from 5 - 36%.

The Alberta oil sands royalty payable is based on price-sensitive royalty rates. The royalty range applicable to price sensitivities changes depending on whether the project's status is pre-payout or post-payout. "Payout" is generally defined as the point in time when a project has generated enough net revenue to recover its costs and provide a designated return allowance. When a project reaches payout, its cumulative revenue equals or exceeds its cumulative costs. Costs include specified allowed capital and operating costs pursuant to the *Oil Sands Allowed Costs (Ministerial) Regulation*. The royalty payable for pre-payout projects is the gross revenue royalty based on the gross revenue royalty rate. The gross revenue royalty rate starts at 1% and increases for every dollar that the world oil price, as reflected by 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. The royalty payable for post-payout projects is the greater of the gross revenue royalty based on the gross revenue royalty rate or the net revenue royalty based on the

net revenue royalty rate. The net revenue royalty rate starts at 25% and increases for every dollar the WTI crude oil price is above \$55 per barrel to a maximum of 40% when the WTI crude oil price is \$120 per barrel or higher.

As the resource owner, the Government of Alberta is entitled to take its royalty share of bitumen production in kind, as it does currently for conventional oil production. The Government of Alberta has committed to have a portion of its bitumen royalty in-kind volumes commercially upgraded to higher value products in the province.

Environmental Regulation

Oil sands recovery, pipelines and upgrader projects, and associated electrical facilities, are subject to provincial and federal environmental laws and regulations. Environmental laws and regulations require various approvals and provide for restrictions and prohibitions on releases or emissions of various substances produced or used in association with such projects. In addition, environmental laws and regulations require that facilities and operating sites be abandoned and reclaimed to the satisfaction of provincial or federal authorities. Compliance with such legislation can require significant expenditures. A breach of such legislation may, among other things, result in the imposition of material fines and penalties, the revocation of necessary licences and authorizations, and civil liability for pollution damage.

Water usage by *in situ* oil sands projects, including restrictions on amounts and type of water used, is regulated by the AER. In general, regulatory requirements maximize recycling of water and minimize use of fresh (non-brackish) water.

The Corporation may be affected by the Lower Athabasca Regional Plan ("LARP") under the *Alberta Land Stewardship Act* ("ALSA"), which came into effect on September 1, 2012 and is currently being implemented. The LARP is a legislative instrument equivalent to regulations and is binding on the government of Alberta and provincial regulators, including those governing the oil and gas industry. The LARP is the first of an anticipated seven regional land-use plans in the province and applies to over two million hectares of land and, among other things, implements environmental management frameworks for air emissions, water use, and land disturbance to control cumulative environmental effects of industrial development.

Environmental management frameworks for air quality, surface water quality and groundwater and surface water quantity are currently being implemented under LARP, subjecting future and existing operations in the region to more onerous environmental constraints and stringent operating parameters. While the LARP has not had a significant effect on the Corporation, there can be no assurance that changes to the LARP or that future laws or regulations will not adversely impact the Corporation's ability to develop or operate its projects.

The Alberta Environmental Monitoring, Evaluation and Reporting Agency ("AEMERA") was established in April 2014 with the proclamation of Bill 31, *Protecting Alberta's Environment Act* and is designed to be the comprehensive source for information on the province's environment. AEMERA is responsible for monitoring air, water and biodiversity indicators in Alberta. In addition to environmental monitoring and reporting, AEMERA will lead Alberta's involvement in the Joint Canada-Alberta Implementation Plan for Oil Sands Monitoring ("Monitoring Plan"). The Monitoring Plan is designed to provide an improved understanding of the potential cumulative environmental effects of oil sands development and the plan will increase air, water, land and biodiversity monitoring in the oil sands region. The Monitoring Plan is currently being phased in with assistance provided by industry. To support the Monitoring Plan, industry has agreed to provide aggregate funding of up to \$50 million a year.

The operations of the Corporation are, and will continue to be, affected in varying degrees by laws and regulations regarding environmental protection. It is impossible to predict the full impact of these laws and regulations on the Corporation's operations. However, it is not anticipated that the Corporation's competitive position will be adversely affected by current or future environmental laws and regulations governing its current oil sands operations. The Corporation is committed to meeting its responsibilities to protect the environment wherever it operates and

anticipates making increased expenditures of both a capital and expense nature as a result of increasingly stringent laws relating to environmental protection. The Corporation also believes that it is likely that the trend in environmental legislation and regulation will continue toward stricter standards.

Greenhouse Gases and Industrial Air Pollutants

Climate Change Regulation

Internationally, Canada is a signatory to the United Nations Framework Convention on Climate Change ("UNFCCC") and previously ratified the Kyoto Protocol established thereunder, which set legally binding targets to reduce nation-wide emissions of carbon dioxide, methane, nitrous oxide and other GHGs. The first commitment period under the Kyoto Protocol was the five year period from 2008-2012. In December 2011, the Canadian federal government withdrew from the Kyoto Protocol. In December, 2009, UNFCCC representatives met in Copenhagen, Denmark, where they reached a deal termed the Copenhagen Accord, a successor to the Kyoto Protocol. The Copenhagen Accord represents a broad political consensus and reinforces commitments to reducing GHG emissions but is not a binding international treaty.

In December 2011, the UNFCCC established the Ad Hoc Working Group on the Durban Platform for Enhanced Action ("Durban Platform"). The goal of the Durban Platform is to "develop a protocol, another legal instrument or an agreed outcome with legal force" through negotiations among UNFCCC countries to accelerate the reduction of GHG.

In December, 2015, UNFCCC members met in Paris, France. Canada, along with 195 other countries, signed the new climate agreement called the "Paris Agreement". Under the Paris Agreement, Canada is required to report and monitor its GHG emissions, though details of how this will take place have yet to be determined. Signatory countries agreed to meet every five years to review their individual progress on GHG emissions reductions and consider amendments to their targets. Generally, the Paris Agreement includes the goal of "holding the increase in the global average temperature to well below 2°C above pre-industrial levels and pursuing efforts to limit the temperature increase to 1.5°C." However, individual country targets designed to reach these levels are not legally binding.

Additionally, the Paris Agreement contemplates that, by 2020, the parties will develop a new market-based mechanism related to carbon trading. It is expected that this mechanism will largely be based on the best practices and lessons learned from the Kyoto Protocol.

On December 12, 2015, the federal government stated that it will develop and announce its Canada-wide approach to implementing the Paris Agreement within 90 days.

On February 12, 2016 at the North American Energy Ministers' meeting, energy leaders from Canada, Mexico and the United States signed a memorandum of understanding on climate change and energy collaboration. The parties also launched a website where information related to the North American energy industry will be aggregated and shared with the public.

Government of Canada Regulations

On May 15, 2015, the federal government announced its plan to reduce GHG emissions by 30% below Canada's 2005 levels by 2030 (referred to as the Nationally Determined Contribution). Canada's previous GHG emission reduction target under the Copenhagen Accord was to reduce GHG emissions to 17% below 2005 levels by 2020. Canada formally submitted the Nationally Determined Contribution to the UNFCCC.

In December 2014, the federal government published *Canada's Action on Climate Change* declaring its intention to take action on climate change by reducing GHG emissions through a sector-by-sector regulatory approach to protect the environment and support economic prosperity. To date, Canada has implemented GHG reducing regulations for

renewable fuels, transportation, and coal-fired electricity; however, given the recent change in federal government, the status of any unimplemented initiatives proposed by the former government is unclear. No oil and gas sector regulations have been developed with respect to meeting Canada's GHG targets.

In 2009, the Canadian federal government announced its commitment to work with provincial governments to implement a North America-wide cap-and-trade system for GHG emissions in cooperation with the United States, under which Canada would have its own cap-and-trade market for Canadian-specific industrial sectors that could be integrated into a North American market for carbon permits. The Government of Canada currently proposes to enter into equivalency agreements with the provinces to establish a consistent regulatory regime for GHGs, but the success of any such plan is uncertain and may lead to overlapping levels of regulation. It is uncertain whether or when either Canadian federal GHG regulations for the oil and gas industry or an integrated North American cap-and-trade system will be implemented, or what obligations might be imposed under any such systems. As the details of the implementation of any federal legislation for GHGs that is applicable to the oil and gas industry have not yet been announced, the effect on the Corporation's operations cannot be determined at this time.

Government of Alberta Regulations

Alberta introduced the *Climate Change and Emissions Management Act*, which provides a framework for managing GHG emissions by reducing specified gas emissions, relative to gross domestic product, to an amount that is equal to or less than 50% of 1990 levels by December 31, 2020. The accompanying regulations include the *Specified Gas Emitters Regulation* ("SGER"), which imposes GHG emissions limits, and the *Specified Gas Reporting Regulation* ("SGRR"), which imposes GHG emissions reporting requirements.

The SGER, which was recently amended and expires on December 31, 2017, applies to facilities in Alberta that have produced 100,000 or more tonnes of GHG emissions in 2003 or any subsequent year, and requires reductions in GHG emissions intensity (i.e., the quantity of GHG emissions per unit of production) from emissions intensity baselines that are established in accordance with the SGER. The SGER distinguishes between "established" facilities that completed their first year of commercial operation before January 1, 2000 or have completed eight years of commercial operation, and "new" facilities that have completed their first year of commercial operation on December 31, 2000 or a subsequent year and have completed less than eight years of commercial operation. Generally, the baseline for an established facility reflects the average of emissions intensity in 2003, 2004, and 2005. For a new facility, the baseline emissions intensity is generally calculated based on a "rolling three-year baseline", which starts in the facility's third year of commercial operation. Prior to the recent amendments to the SGER, for an established facility, the required reduction in GHG emissions was 12% from its baseline with such reduction required to be maintained over time. Recent amendments to the SGER on June 25, 2015 have increased the maximum emission intensity reduction requirement for facilities from 12% to 15% as of January 1, 2016 and to 20% as of January 1, 2017. For a new facility, the required reduction from its baseline is phased in by annual increments beginning in the fourth year of commercial operation until the maximum emission intensity reduction requirement is reached, and once reached, such reduction must be maintained over time. There are three methods for operators of facilities that are subject to the SGER to comply with the annual emission intensity reduction requirements: (i) improve emissions intensity at the facility; (ii) purchase emission performance or emission offset credits in the open market, which are generated from Alberta based projects; and/or (iii) purchase "fund credits" by contributing to the Alberta Climate Change and Emissions Management Fund ("Fund") run by the Alberta government. Historically the contribution costs to the Fund have been set at \$15 per tonne although this is subject to change by Ministerial order. On June 30, 2015, the Government of Alberta increased the contribution costs to the Fund from \$15 per tonne to \$20 per tonne in 2016 and to \$30 per tonne in 2017. Compliance reports for facilities subject to the SGER are due to ESRD on March 31 annually.

The SGRR imposes GHG emissions reporting requirements on facilities that have GHG emissions of 50,000 tonnes or more in a year. In addition, Alberta facilities must currently report emissions of industrial air pollutants and comply with obligations imposed in permits and under other environmental regulations.

On November 22, 2015, the Government of Alberta announced its Climate Leadership Plan ("Plan") and released to the public the Climate Leadership Report to the Minister of Environment and Parks ("Report") that it commissioned from the Climate Change Advisory Panel and on which the Plan is largely based. The Plan highlights four key strategies that the Government of Alberta will implement to address climate change: (1) the complete phase-out of coal-fired sources of electricity by 2030; (2) an Alberta economy-wide carbon price on GHG emissions of \$30 per tonne (\$20 per tonne in 2017 and \$30 per tonne in 2018); (3) a cap on oil sands emissions to a province-wide total of 100 megatonnes per year (compared to current emissions of approximately 70 megatonnes per year), with certain exceptions for cogeneration and new upgrading capacity; and (4) reduce methane emissions from oil and gas activities by 45% by 2025. Details regarding how the Plan will be implemented have not been released, but the Report notes that carbon pricing will be central to the new strategy. The Report proposes a *Carbon Competitiveness Regulation* ("CCR") to replace the SGER. The CCR would include elements of a carbon tax regime with distinctions between industrial emissions and end-use emissions (those from transportation and heating fuels).

No assurance can be given that environmental laws and regulations, including the implementation of the Plan, will not result in a curtailment of the Corporation's production or a material increase in the Corporation's costs of production, development or exploration activities or otherwise have a material adverse effect on the Corporation's results of operations, financial condition and prospects. The Corporation believes that it is reasonably likely that the trend towards stricter standards in environmental legislation will continue and anticipates that capital and operating costs may increase as a result of more stringent environmental laws. A legislated cap on oil sands greenhouse gas emissions could significantly reduce the value of the Corporation's assets.

United States Regulations

Several federal programs regulate the transportation sector on the basis of greenhouse gas emissions and fuel consumption, and could accordingly impact demand for crude or synthetic crude oil. The EPA and the National Highway Traffic Safety Administration, administer regulations restricting GHG emissions from automobiles and trucks. The EPA also administers the Renewable Fuel Standard, which requires specified "renewable fuels" to be blended into U.S. transportation fuel, with increasing volumes coming from lower GHG emitting fuels over time. The EPA also regulates certain stationary sources of greenhouse gas emissions pursuant to the Clean Air Act.

At the state level, California's Air Resources Board ("ARB") administers two regulatory programs that impact the crude or synthetic crude oil industry: a Low Carbon Fuel Standard ("LCFS") and a cap-and-trade program. California's LCFS regulates fuel suppliers based on the "carbon intensity" of their fuel supplied to market, i.e., the GHG emissions associated with the entire lifecycle of the fuel, from extraction to refining to end use. ARB's determination that Canadian synthetic crude has a high carbon intensity imposes certain costs on its use under the LCFS, potentially decreasing demand for such fuel vis-à-vis other less carbon intensive fuel types. Despite a legal challenge claiming that the LCFS improperly discriminated against out-of-state sources of ethanol and crude oil in violation of the Commerce Clause of the United States Constitution, the LCFS was upheld and the United States Supreme Court denied a petition to review the case. California's cap-and-trade program began regulating the GHG emissions of fuel supplied to the California market on January 1, 2015, imposing costs in proportion to the GHG emissions potential of fuel supplied to the California market. Unlike the LCFS, the cap-and-trade program does not involve a lifecycle analysis and accordingly will not have any disproportionate impact on high-carbon-intensity crude or synthetic crude. Nonetheless, the regulation will impose additional costs on suppliers of petroleum fuel products and, accordingly, may decrease demand for crude and synthetic crude oil. In addition, a number of other states have adopted or are considering similar measures that could impact the demand for crude and/or synthetic crude oil.

The Future of GHG Emission Regulations

There will likely be some financial impact of GHG emission regulation on most oil sands industry participants and their projects, possibly including MEG and its projects, however the extent of that impact is not yet known. In particular, there is uncertainty regarding the ultimate GHG emission regulatory regime that will be applicable to MEG due to, among other things, the anticipated changes to Alberta's GHG regime and the potential for changes to the United States' regulation of GHG emissions and the potential for the harmonization of GHG emission regulatory regimes in Canada and the United States.

At present, there is no assurance that any new regulations implemented by the Government of Canada relating to the reduction of GHG emissions will be harmonized with the Government of Alberta's GHG emissions reduction regulations. In such case, the costs of meeting new federal government requirements could be considerably higher than the costs of meeting Alberta's requirements.

DIRECTORS AND EXECUTIVE OFFICERS

Directors and Executive Officers

As of the date of this Annual Information Form, the name, municipality of residence, positions held with the Corporation and principal occupation during the preceding five years of each of the directors and executive officers of the Corporation are as set forth below.

Name, Province and Country of Residence	Position(s) Held	Director Since	Principal Occupation During the Preceding Five Years
William J. McCaffrey..... Alberta, Canada	Chairman, President, Chief Executive Officer and a Director	March 9, 1999	President, Chief Executive Officer and a director of the Corporation since March 1999.
Eric L. Toews Alberta, Canada	Chief Financial Officer	N/A	Chief Financial Officer of the Corporation since September 2013. Formerly a Managing Director of BMO Capital Markets from February 2006 until August 2013.
Chi-Tak Yee Alberta, Canada	Senior Vice President, Reservoir and Geosciences	N/A	Senior Vice President, Reservoir and Geosciences of the Corporation since November 2011, prior to which he served as Vice President, Reservoir & Production of the Corporation from September 2004 until November 2011.

Grant W. Boyd.....	Senior Vice President, Resource Management – Growth Properties	N/A	Senior Vice President, Resource Management – Growth Properties of the Corporation since November 2011, prior to which he served as Vice President, Growth & Emissions Management of the Corporation from June 2010 to November 2011 and Vice President, Resource Management of the Corporation from December 2007 until June 2010.
Jamey Fitzgibbon	Senior Vice President, Resource Management – Christina Lake and Special Projects	N/A	Senior Vice President, Resource Management – Christina Lake and Special Projects of the Corporation since November 2011, prior to which he served as Vice President, Special Projects of the Corporation from September 2010 until November 2011. Formerly a consultant to OPTI Canada Inc. from September 2009 until September 2010.
Donald G. Moe	Senior Vice President, Supply and Marketing	N/A	Senior Vice President, Supply and Marketing of the Corporation since January 2014, prior to which he served as Vice President, Supply and Marketing of the Corporation from January 2012 until January 2014. Formerly an energy consultant from January 2010 until December 2011, Chief Executive Officer, ALTEX Energy Ltd. from June 2011 until December 2011.
Richard F. Sendall.....	Senior Vice President, Strategy and Government Relations	N/A	Senior Vice President, Strategy and Government Relations of the Corporation since November 2011, prior to which he served as Vice President, Business & Strategic Planning of the Corporation from April 2010 until November 2011 and Vice President, Regulatory & Public Affairs of the Corporation from June 2007 until April 2010.
Grant Borbridge.....	Vice President, Legal and General Counsel and Corporate Secretary	N/A	Vice President Legal & General Counsel of the Corporation since September 2013 and Corporate Secretary of the Corporation since May 2015. Formerly Executive Vice President, Investments and General Counsel of Emergo Canada Ltd. from October 2004 until August 2013.

John M. Rogers..... Alberta, Canada	Vice President, Investor Relations and External Communications	N/A	Vice President, Investor Relations and External Communications of the Corporation since March 2012. Formerly Vice President, Investor Relations since 2010. Formerly Vice President, Investor Relations at Suncor Energy Inc. until 2010.
Chris Sloof..... Alberta, Canada	Vice President, Projects	N/A	Vice President, Projects of the Corporation since February 2011, prior to which he served as Project Director of the Corporation from February 2009 until January 2011.
John Nearing..... Alberta, Canada	Vice President, Finance and Controller	N/A	Vice President, Finance & Controller of the Corporation since December 2013, prior to which he served as Controller of the Corporation since December 2010.
John McCoshen Alberta, Canada	Vice President, Finance and Treasurer	N/A	Vice President, Finance & Treasurer of the Corporation since May 2015. Formerly Director, Treasury, Canadian Natural Resources Limited from July 2012 to May 2015, prior to which he served as Manager, Treasury, Canadian Natural Resources Limited from May 2008 to July 2012.
Don Sutherland Alberta, Canada	Vice President, Regulatory and Community Relations	N/A	Vice President, Regulatory and Community Relations of the Corporation since January 2011.
Stephen Diotte Alberta, Canada	Vice President, HR, IT and Corporate Services	N/A	Vice President, HR, IT and Corporate Services of the Corporation since April 2012, prior to which he served as North American Energy and Resources Leader for Mercer Human Capital from 2009 to April 2012.
Boyd Anderson ⁽¹⁾⁽³⁾⁽⁴⁾⁽⁵⁾ Alberta, Canada	Director	June 14, 2007	Director of the Corporation since June 2007 and Lead Director of the Corporation since June 2010. Formerly Vice President Natural Gas Liquids, BP North America Inc. and former director of Amoco Canada Petroleum Company.
Harvey Doerr ⁽¹⁾⁽³⁾⁽⁴⁾ British Columbia, Canada	Director	June 9, 2010	Director of the Corporation since June 2010. Director of Newalta Corporation since 2014 and Chairman of Velvet Energy Ltd. since 2011.

Robert B. Hodgins ⁽¹⁾⁽²⁾⁽⁴⁾ Director Alberta, Canada	September 23, 2010	Director of the Corporation since September 2010. Independent businessman and director of AltaGas Ltd., Enerplus Corporation and GranTierra Energy Inc.
Peter R. Kagan ⁽³⁾⁽⁴⁾ Director New York, U.S.A.	February 27, 2004	Director of the Corporation since February 2004. Managing Director, Warburg Pincus LLC since 2002 and director of Laredo Petroleum Holdings, Inc. since 2007.
David B. Krieger ⁽²⁾⁽⁴⁾ Director New York, U.S.A.	February 27, 2004	Director of the Corporation since February 2004. Managing Director, Warburg Pincus LLC since 2006.
James D. McFarland ⁽²⁾⁽³⁾⁽⁴⁾ Director Alberta, Canada	June 9, 2010	Director of the Corporation since June 2010. President and Chief Executive Officer and Director of Valeura Energy Inc. since April 2010. Director of Pengrowth Energy Corporation since 2010.
Jeffrey J. McCaig ⁽²⁾⁽³⁾⁽⁴⁾ Director Alberta, Canada	March 1, 2014	Director of the Corporation since March 2014. Director of Potash Corporation of Saskatchewan since January 2001. Director of Bantrel Company since 2000, becoming its Chairman in December 2007. Currently Chairman of the Board of the Trimac Group of Companies. Formerly served in various senior leadership roles, including CEO until December 31, 2015, in the Trimac Group of Companies for approximately 30 years.
Diana J. McQueen ⁽⁴⁾ Director Alberta, Canada	October 6, 2015	Director of the Corporation since October 2015. Self-employed consultant since September 2015. Formerly MLA and Cabinet Minister of the Government of Alberta from 2008 to 2015.

Notes:

- (1) Member of the Audit Committee. Mr. Hodgins is the Chairman of the Audit Committee.
- (2) Member of the Compensation Committee. Mr. McFarland is the Chairman of the Compensation Committee.
- (3) Member of the Governance and Nominating Committee. Mr. Doerr is the Chairman of the Governance and Nominating Committee.
- (4) Independent director.
- (5) Lead Director.

As of December 31, 2015, the directors and executive officers of the Corporation, as a group, beneficially owned or held control or direction over, directly or indirectly, 39,393,839 Common Shares, representing approximately 17.5% of the issued and outstanding Common Shares. These Common Shares include a total of 37,769,285 Common Shares which are owned of record and beneficially by WP Lexington Private Equity, B.V. ("WP Lex") and WP X LuxCo S.a.r.l. ("WPX Luxco"). WP Lex is a company incorporated under the laws of the Netherlands and WPX Luxco is a company incorporated under the laws of Luxembourg. WP Lex is an affiliate of Warburg Pincus Private Equity VIII, L.P., a Delaware limited partnership, and two affiliated partnerships (collectively "WP VIII"), and Warburg Pincus

International Partners, L.P., a Delaware limited partnership, and two affiliated partnerships (collectively "WPIP"). WP Luxco is an affiliate of Warburg Pincus Private Equity X, L.P., a Delaware limited partnership, and Warburg Pincus X Partners, L.P., a Delaware limited partnership (collectively "WP X"). Warburg Pincus X, L.P., a Delaware limited partnership ("WP X LP"), is the general partner of WP X. Warburg Pincus X GP L.P., a Delaware limited partnership ("WP X GP"), is the general partner of WP X LP. WPP GP LLC, a Delaware limited liability company ("WPP GP") is the general partner of WP X GP. Warburg Pincus Partners, L.P., a Delaware limited partnership ("WP Partners"), is the general partner of WPIP and WP VIII, and the managing member of WPP GP. Warburg Pincus Partners GP LLC, a Delaware limited liability company ("WPP GP LLC"), is the general partner of WP Partners. Warburg Pincus & Co., a New York general partnership ("WP"), is the managing member of WPP GP LLC. Warburg Pincus LLC, a New York limited liability company ("WP LLC"), manages WP VIII, WPIP and WP X. Charles R. Kaye and Joseph P. Landy are Managing General Partners of WP and Managing Members and Co-Chief Executive Officers of WP LLC and may be deemed to control WP Lex, WPX Luxco, WP VIII, WPIP, WP X, WP X LP, WP X GP, WPP GP, WP Partners, WPP GP LLC, WP X International Holdings (as defined below), WP X International Investments (as defined below), WP International Holdings I (as defined below), WP Luxco II (as defined below), WP Luxco III (as defined below), WP and WP LLC (the "Warburg Pincus entities"). The address of the Warburg Pincus entities is 450 Lexington Avenue, New York, New York, 10017.

WP X holds an indirect interest in the Corporation through its beneficial interests in (i) WP X International Holdings LLC, a Delaware limited liability company ("WP X International Holdings"), which is wholly owned by WP X, (ii) WP X International Investments LLC a Delaware limited liability company ("WP X International Investments"), which is wholly owned by WP X International Holdings, and (iii) WPX Luxco, which is wholly owned by WP X International Investments.

WPIP and WP VIII hold an indirect interest in the Corporation through its beneficial interest in (i) WP International Holdings I LLC, a Delaware limited liability company ("WP International Holdings I"), which is wholly owned by WPIP and WP VIII, (ii) WP LuxCo II S.a.r.l., a company organized under the laws of Luxembourg ("WP Luxco II"), which is wholly owned by WP International Holdings I, (iii) WP LuxCo III S.a.r.l., a company organized under the laws of Luxembourg ("WP Luxco III"), which is wholly owned by WP Luxco II, and (iv) WP Lex, which is wholly owned by WP Luxco III.

Corporate Cease Trade Orders or Bankruptcies

Other than as described below, to our knowledge, none of our current directors or executive officers is, as of the date of this Annual Information Form, or has been, within ten years before the date of this Annual Information Form, a director, chief executive officer or chief financial officer of any company that:

- (a) was subject to a cease trade order, an order similar to a cease trade order or an order that denied the relevant company access to any exemption under securities legislation, that was in effect for a period of more than 30 consecutive days (collectively, an "Order") and that was issued while that person was acting in the capacity as director, chief executive officer or chief financial officer; or
- (b) was subject to an Order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer of the company being the subject of such an Order and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer.

To our knowledge, other than as described below, none of our directors, executive officers or shareholders holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation:

- (a) is, as of the date of this Annual Information Form, or has been, within ten years before the date of this Annual Information Form, a director or executive officer of any company that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to its own bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or
- (b) has, within ten years before this Annual Information Form, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, executive officer or shareholder.

Robert Hodgins was a director of Skope Energy Inc. ("Skope"), a TSX listed company, which in November 2012, commenced proceedings in the Court of Queen's Bench of Alberta under the *Companies' Creditors Arrangement Act*, to implement a restructuring which was completed on February 19, 2013. Mr. Hodgins ceased to be a director of Skope on February 19, 2013.

Jeffrey McCaig was a director of Orbus Pharam Inc. ("Orbus"), an NEX listed company, which in May 2010 commenced proposal proceedings pursuant to the *Bankruptcy and Insolvency Act (Canada)* by filing a notice of intention to make a proposal. A proposal was submitted to and approved by the creditors of Orbus in September 2010 and was approved on October 10, 2010.

Penalties or Sanctions

To the knowledge of the Corporation, no director or executive officer of the Corporation (nor any personal holding company of any of such persons), or shareholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation, has been subject to: (a) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or (b) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

Conflicts of Interest

Certain of the directors and officers of the Corporation are engaged in, and may continue to be engaged in, other activities in the oil and natural gas industry from time to time. As a result of these and other activities, certain directors and officers of the Corporation may become subject to conflicts of interest from time to time. The ABCA provides that in the event that an officer or director is a party to, or is a director or an officer of, or has a material interest in any person who is a party to, a material contract or material transaction or proposed material contract or proposed material transaction, such officer or director shall disclose the nature and extent of his or her interest and shall refrain from voting to approve such contract or transaction, unless otherwise provided under the ABCA. To the extent that conflicts of interest arise, such conflicts will be resolved in accordance with the provisions of the ABCA.

As of the date of this Annual Information Form, the Corporation is not aware of any existing or potential material conflicts of interest between the Corporation and any director or officer of the Corporation.

AUDIT COMMITTEE

The full text of the Audit Committee Charter is included in Appendix C of this Annual Information Form.

Composition of the Audit Committee

The Audit Committee has been structured to comply with the requirements of NI 52-110. The Board has determined that the Audit Committee members have the appropriate level of financial understanding and industry-specific knowledge to be able to perform their duties.

The Audit Committee's charter requires that the Audit Committee periodically assess the adequacy of procedures for the public disclosure of financial information and review on behalf of the Board, and report to the Board, the results of its review and its recommendation regarding all material matters of a financial reporting and audit nature, including the following main subject areas:

- financial statements and management's discussion and analysis;
- financial information in any annual information form, management proxy circular, prospectus or other offering document, material change report or business acquisition report;
- reports to shareholders and others;
- press releases regarding annual and interim financial results;
- internal controls;
- audits and reviews of financial statements of the Corporation and its subsidiaries; and
- filings with securities regulators containing financial information.

The Audit Committee is responsible for implementing satisfactory procedures for the receipt, retention and treatment of complaints and for the confidential, anonymous submission by employees regarding any accounting, internal accounting controls or auditing matters. The Board is kept informed of the Audit Committee's activities by means of a report delivered at each regularly scheduled meeting of the Board.

The Audit Committee recommends the appointment of the external auditor to the Board and annually reviews and evaluates the external auditor. The Audit Committee determines the compensation of the external auditor. Once appointed by the shareholders, the external auditor reports directly to the Audit Committee. The Audit Committee has direct responsibility for overseeing the work of the external auditor engaged for the purpose of preparing or issuing an auditor's report or performing other audit, review or attest services, including the resolution of disagreements between the external auditor and management. The Audit Committee reviews and approves the Corporation's hiring policies regarding current and former partners and employees of the external auditor. In addition, the Audit Committee pre-approves non-audit services undertaken by the external auditor.

The Audit Committee meets at least once per financial quarter to fulfill its mandate. The members of the Audit Committee are Messrs. Anderson, Hodgins and Doerr. The Board has determined that each member of the Audit Committee is independent and financially literate within the meaning of NI 52-110. Mr. Hodgins is the chair of the Audit Committee. The charter of the Audit Committee and additional disclosure required under NI 52-110 is provided in Appendix C of this Annual Information Form.

DESCRIPTION OF CAPITAL STRUCTURE

The Corporation's authorized share capital currently consists of an unlimited number of Common Shares without nominal or par value and an unlimited number of Preferred Shares, issuable in series. 224,996,989 Common Shares, and no Preferred Shares, were issued and outstanding as of December 31, 2015. The following is a summary of the rights, privileges, restrictions and conditions attached to the Common Shares and Preferred Shares.

Common Shares

Each Common Share entitles the holder thereof to: (i) one vote at all meetings of shareholders of the Corporation except meetings at which only holders of a specified class of share are entitled to vote; (ii) subject to the prior rights and privileges attaching to any other class of shares, the right to receive any dividend on the Common Shares declared by the Corporation; and (iii) subject to the prior rights and privileges attaching to any other class of shares, the right to receive the remaining property of the Corporation upon dissolution. For a description of the Corporation's dividend policy, see "Dividends Policy".

In connection with the initial public offering of its Common Shares on August 6, 2010, the Corporation adopted a shareholder rights plan (the "Rights Plan"). At the annual and special meeting of shareholders of the Corporation held on May 1, 2014, shareholders passed a resolution extending the term of the Rights Plan until the annual meeting of shareholders of the Corporation to be held in 2017. The objective of the Rights Plan is to ensure, to the extent possible, that all shareholders of the Corporation are treated equally and fairly in connection with any take-over bid or similar proposal to acquire the Common Shares and to provide the Board of Directors with sufficient time to evaluate any unsolicited take-over bid and develop alternatives to maximize shareholder value.

The Rights Plan discourages the making of any unsolicited take-over bid by creating the potential of significant dilution to any offeror who does so. This is done through the issuance to all shareholders of contingent rights to acquire additional Common Shares at a significant discount to the then prevailing market prices, which could, in certain circumstances, become exercisable by all shareholders other than an offeror and its associates, affiliates and joint actors.

In connection with the adoption of the Rights Plan, the Corporation issued one right in respect of each Common Share outstanding at the close of business on August 6, 2010 (the "Effective Date") and authorized the issuance of one right in respect of each additional Common Share issued after the Effective Date and prior to the earlier of the Separation Time (as defined in the Shareholder Rights Plan Agreement that governs the Rights Plan) and the time at which the rights expire and terminate. The rights trade with and are represented by Common Share certificates, including certificates issued prior to the Effective Date.

Preferred Shares

The Preferred Shares may at any time and from time to time be issued in one or more series, each series to consist of such number of shares as may, before the issue thereof, be determined by resolution of the Board; and subject to the provisions of the ABCA, the Board may by resolution fix from time to time before the issue thereof the designation, rights, privileges, restrictions and conditions attaching to each series of the Preferred Shares.

DIVIDENDS POLICY

The Corporation has never declared or paid any cash dividends on the Common Shares. The Corporation does not currently anticipate paying any cash dividends on the Common Shares in the foreseeable future but will review that policy from time to time as circumstances warrant. The Corporation currently intends to retain future earnings, if any,

for future operations, expansion and debt repayment. Any decision to declare and pay dividends in the future will be made at the discretion of the Board of Directors and will depend on, among other things, the Corporation's results of operations, current and anticipated cash requirements and surplus, financial condition, contractual restrictions and financing agreement covenants, solvency tests imposed by corporate law and other factors that the Board may deem relevant.

In addition to the foregoing, the Corporation's ability to pay dividends now or in the future may be limited by covenants contained in the agreements governing any indebtedness that the Corporation has incurred or may incur in the future.

MARKET FOR SECURITIES

The Common Shares are listed and posted for trading on the TSX under the trading symbol "MEG". The following table sets out the high and low price for, and the volume of trading in, the Common Shares on the TSX, as reported by the TSX, on a monthly basis for the year ended December 31, 2015.

	Volume (Shares)	Monthly Price Range	
		High (\$)	Low (\$)
January	24,203,162	20.91	14.84
February	19,652,236	24.31	19.33
March	13,847,806	21.99	17.75
April	10,056,198	25.20	20.65
May	16,845,389	23.73	18.28
June	14,151,232	20.94	17.56
July	14,557,679	20.36	13.30
August	27,417,195	15.06	9.54
September	31,229,680	11.45	7.87
October	34,826,275	13.15	7.86
November	17,916,684	12.38	10.51
December	24,040,725	11.32	7.33

CREDIT RATINGS

The following information relating to the Corporation's credit ratings is provided as it relates to the Corporation's financing costs, liquidity and operations. Specifically, credit ratings affect the Corporation's ability to obtain short-term and long-term financing and the cost of such financing. Additionally, the ability of the Corporation to engage in certain collateralized business activities on a cost effective basis depends on the Corporation's credit ratings. A reduction in the current rating on the Corporation's debt by its rating agencies, particularly a downgrade below current ratings, or a negative change in the Corporation's ratings outlook could adversely affect the Corporation's cost of financing and its access to sources of liquidity and capital. In addition, changes in credit ratings may affect the Corporation's ability to, and the associated costs of, (i) entering into ordinary course derivative or hedging transactions and may require the Corporation to post additional collateral under certain of its contracts, and (ii) entering into and maintaining ordinary course contracts with customers and suppliers on acceptable terms.

The following table outlines the credit ratings received by the Corporation as at the date of this Annual Information Form:

	Moody's Investors Service ("Moody's")	Standard & Poor's Ratings Services ("S&P")
Issuer Credit Rating	Caa2 (Negative)	BB- (Stable)
Senior Secured Debt (Term Loan & Revolving)	B3	BB+
Senior Unsecured Debt (High Yield Notes)	Caa3	BB-

Moody's issuer credit rating is a long term rating that reflects the likelihood of a default on a corporate family's contractable promised payments and the expected financial loss suffered in the event of a default. S&P's issuer credit rating is a forward-looking opinion about an obligor's overall financial capacity (its creditworthiness) to pay its financial obligations. Long-term credit ratings are intended to provide an independent measure of the credit quality of long-term debt.

Moody's credit ratings are on a rating scale that ranges from Aaa to C, which represents the range from highest to lowest quality of such securities rated. A rating of "Caa" by Moody's is within the seventh highest of nine categories and is assigned to debt securities which are judged to be speculative and of poor standing and are subject to very high credit risk. A rating of "B" by Moody's is within the sixth highest of nine categories and is assigned to debt securities which are considered speculative and are subject to high credit risk. The addition of a 1, 2 or 3 modifier after a rating indicates the relative standing within a particular rating category. The modifier 1 indicates that the obligation ranks in the higher end of its generic rating category, the modifier 2 indicates a mid-range ranking and the modifier 3 indicates a ranking in the lower end of that generic rating category. The "stable" rating outlook indicates a low likelihood of a rating change over the medium term. A "negative" rating outlook indicates a higher likelihood of a rating change over the medium term.

S&P's issuer credit ratings are on a rating scale that ranges from AAA to CC, which represents the range from highest to lowest quality. The ratings from AA to CCC may be modified by the addition of a plus (+) or minus (-) sign to show the relative standing within the major rating categories. An issuer credit rating of BB by S&P is within the fifth highest of ten categories and indicates that the obligor is less vulnerable in the near-term than other lower-rated obligors; however, it faces major ongoing uncertainties and exposure to adverse business, financial or economic conditions which could lead to the obligor's inadequate capacity to meet its financial commitments. S&P assigns "stable" outlooks to issuer ratings when S&P believes that a rating is not likely to change over the intermediate term for investment-grade credits (generally up to two years) and over the shorter term for speculative-grade credits (generally up to one year).

S&P's long-term credit ratings are on a rating scale that ranges from AAA to D, which represents the highest to lowest quality of such securities rated. The ratings from AA to CCC may be modified by the addition of a plus (+) or minus (-) sign to show the relative standing within the major rating categories. A long-term credit rating of BB is within the fifth highest of ten categories and is considered less vulnerable to non-payment in the near-term than other speculative grade investments but faces major ongoing uncertainties and exposure to adverse business, financial and economic conditions which could lead to the obligor's inadequate capacity to meet its financial commitment on the obligation.

The credit ratings assigned by the rating agencies are not recommendations to purchase, hold or sell the debt nor do the ratings comment on market price or suitability for a particular investor. A rating may not remain in effect for any

given period of time and may be revised or withdrawn entirely by a rating agency in the future if, in its judgment, circumstances so warrant.

RISK FACTORS

If any event arises from the risk factors set forth below, our business, prospects, financial condition, results of operation or cash flows and, in some cases, the Corporation's reputation could be materially adversely affected.

Risks Relating to the Corporation's Business

Operating Results

MEG's operating results and the value of its reserves and contingent resources depend, in part, on the price received for bitumen and on the operating costs of the Christina Lake Project and MEG's other projects, all of which may significantly vary from that currently anticipated. If such operating costs increase or MEG does not achieve its expected revenues, MEG's earnings and cash flow will be reduced and its business and financial condition may be materially adversely affected. Principal factors, amongst others, which could affect MEG's operating results include (without limitation):

- a decline in oil prices;
- lower than expected reservoir performance, including, but not limited to, lower oil production rates and/or higher SORs or the inability to recognize continued or increased efficiencies from the RISER initiative;
- reduced access to or an increase in the cost of diluent;
- an increase in the cost of natural gas;
- the reliability and maintenance of MEG's facilities;
- the safety and reliability of the Access Pipeline, other pipelines and railways to transport MEG's products;
- the need to replace significant portions of existing wells, referred to as "workovers", or the need to drill additional wells;
- the cost to transport bitumen, diluent and bitumen diluent blends, and the cost to dispose of certain by-products;
- the cost of insurance and the inability to insure against certain types of losses;
- severe weather or catastrophic events such as fires, lightning, earthquakes, extreme cold weather, storms or explosions;
- seasonal weather patterns and the corresponding effects of the spring thaw on accessibility to MEG's properties;
- the availability of water supplies and the ability to transmit power on the electrical transmission grid;
- changes in the political landscape and/or legal and regulatory regimes in Canada, the United States and elsewhere;
- the ability to obtain further approvals and permits for MEG's future projects;
- the availability of pipeline capacity and other transportation facilities for MEG's bitumen diluent blends;
- refining markets for MEG's bitumen diluent blends;

- increased royalty payments resulting from changes in regulatory regimes;
- the cost of chemicals used in MEG's operations, including, but not limited to, in connection with water and/or oil treatment facilities;
- the availability of and access to drilling equipment; and
- the cost of compliance with applicable regulatory regimes, including, but not limited to, environmental regulation.

Status and Stage of Developments

MEG has a relatively short history of bitumen production and sales. Prior to the first quarter of 2008, MEG was engaged exclusively in planning, construction, development and investment activities with respect to the Christina Lake Project and MEG's other projects. The well pairs associated with Phase 1, Phase 2 and Phase 2B of the Christina Lake Project have only been producing bitumen since May 2008, August 2009 and the fourth quarter of 2013 respectively. Because of MEG's limited operating history, it may be difficult to evaluate MEG's prospects. In particular, the ability to evaluate the prospects of MEG's business will be limited due to MEG's:

- limited historical financial data relating to the sale of bitumen;
- lack of historical financial data relating to the purchase of natural gas;
- short duration of operating its facilities;
- limited track record in producing and marketing its bitumen; and
- limited history of generating profits from its commercial operations.

While the first three phases of the Christina Lake Project are operational and the first RISER initiative has been implemented successfully, additional phases, subsequent RISER implementation and other projects may not be completed on budget, on time or at all, and the costs associated with additional phases and other projects may be greater than the Corporation expects. Additional phases of development of the Christina Lake Project or MEG's other projects may also suffer from delays, cancellations, interruptions or increased costs due to many factors, some of which may be beyond the Corporation's control, including (without limitation):

- future capital expenditures to be made by the Corporation;
- engineering and/or procurement performance falling below expected levels of output or efficiency;
- construction 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 materials;
- changes in project scope or errors in design;
- additional requirements imposed by changes in laws, including environmental laws;
- the availability of and access to drilling equipment; and
- severe weather or catastrophic events such as fire, earthquakes, extreme cold weather, storms or explosions.

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 or other future projects, which would materially adversely affect its business, financial condition, results of operations and prospects. In addition, if any of the Corporation's future phases do not become operational after it has made significant investments therein, the Corporation's operations may not generate sufficient revenue to support its capital structure.

Concentration of Production in Single Project

All of MEG's current production and a significant amount of future production, is or will be generated by the Christina Lake Project and transported to markets on the Access Pipeline. Any event that interrupts operations at the Christina Lake Project or the operations of the Access Pipeline may result in a significant loss or delay in production.

Non-Producing or Undeveloped Reserves and Contingent Resources

The substantial majority of MEG's total reserves and contingent resources are non-producing and/or undeveloped. These reserves and contingent resources may not ultimately be developed or produced, either because it may not be commercially viable to do so or for other reasons. Furthermore, not all of MEG's undeveloped or developed non-producing reserves or contingent resources may be ultimately produced at the time periods MEG has planned, at the costs MEG has budgeted or at all.

Uncertainties Associated with Estimating Reserves and Resources Volumes

There are numerous uncertainties inherent in estimating quantities of proved and probable reserves, quantities of contingent resources and future net revenues to be derived therefrom, including many factors beyond the Corporation's control. The reserves, contingent resources and estimated financial information with respect to certain of the Corporation's oil sands leases have been independently evaluated by GLJ. These evaluations include a number of factors and assumptions made as of the date on which the evaluation is made such as geological and engineering estimates which have inherent uncertainties, the effects of regulation by governmental agencies such as initial production rates, production decline rates, ultimate recovery of reserves and contingent resources, timing and amount of capital expenditures, marketability of production, current and forecast prices of blended bitumen, crude oil and natural gas, MEG's ability to transport its product to various markets, operating costs, abandonment and salvage values and royalties and other government levies that may be imposed over the producing life of the reserves and contingent resources. Many of these assumptions are subject to change and may not, over time, prove to be accurate. Actual production and cash flow derived from MEG's oil sands leases may vary from these evaluations, and such variations may be material.

MEG has a limited history of producing bitumen. Estimates with respect to reserves and contingent resources that may be developed and produced in the future are often based upon volumetric calculations, probabilistic and deterministic methods and analogy to similar types of reserves and contingent resources, rather than upon actual production history. Estimates based on these methods generally are less reliable than those based on actual production history. Subsequent evaluation of the same reserves or contingent resources based upon production history will result in variations, which may be material, from current estimated reserves and contingent resources.

Reserves and contingent resources estimates may require revision based on actual production experience. Such figures have been determined based upon assumed commodity prices and operating costs. Market price fluctuations of bitumen, diluent and natural gas prices may render the recovery of certain grades of bitumen uneconomic. The present value of MEG's estimated future net revenue disclosed herein and in the GLJ Report should not be construed as the fair market value of MEG's reserves or contingent resources, as applicable.

Long-Term Reliance on Third Parties

The Christina Lake Project and MEG's other projects will depend on the availability and successful operation of certain infrastructure owned and operated by third parties or joint ventures with third parties, including (without limitation):

- 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, airstrips, terminals and vessels.

For example, the Christina Lake Project and future projects will depend on the successful operation of the Access Pipeline. Any interruption in the operation of the Access Pipeline or other pipeline infrastructure could have a material adverse impact on the Corporation by limiting its ability to transport bitumen to end markets and increasing MEG's cost for both sourcing diluent and transporting its bitumen. Such interruptions could result in all or a portion of MEG's production being shut-in. In addition, if certain pipelines currently forecast to be built or currently under construction are not completed on time, to the specifications MEG expects or at all, MEG's anticipated costs could increase and MEG's operating results would be adversely affected.

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

Third Party Claims

From time to time the Corporation may be the subject of litigation arising out of its operations. Claims under such litigation may be material or may be indeterminate. The outcome of such litigation may materially affect the Corporation's financial condition or results from operations. The Corporation may be required to incur significant expenses or devote significant resources in defense of any litigation.

Diluent Supply

Bitumen has a high specific gravity or weight and high viscosity or resistance to flow. Diluent is required to facilitate the processing and transportation of bitumen. In addition, the use of condensate diluent is important in MEG's strategy of developing bitumen blends for marketing purposes. A shortage of condensate may cause its cost to increase or alternative diluent supplies to be purchased, thereby increasing the cost to transport bitumen to market and increasing MEG's operating cost, as well as affecting MEG's bitumen blend marketing strategy.

Operational Hazards

The operation of the Corporation's oil sands properties and projects are and will continue to be subject to the customary hazards of recovering, transporting and processing hydrocarbons, such as fires, explosions, gaseous leaks, migration of harmful substances, blowouts and spills. For example, the completion of Phase 1 was delayed due to steam line failure in May 2007. 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. MEG does not and will not carry insurance with respect to all potential casualties, damages, losses and disruptions. MEG's insurance may not be sufficient to cover any such 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 results of operations, financial condition and prospects.

Competition

The Canadian and international petroleum industry is highly competitive in all aspects, including the exploration for, and the development of, new sources of supply, the acquisition of oil sands leases and the distribution and marketing of petroleum products. MEG competes with producers of bitumen, synthetic crude oil blends and conventional crude oil. Some of the conventional producers have lower operating costs than MEG and many of them have greater resources to source, attract and retain the personnel, materials and services that MEG requires to conduct its operations. The petroleum industry also competes with other industries in supplying energy, fuel and related products to consumers. Some of these industries benefit from lighter regulation, lower taxes and subsidies. In addition, certain of these industries are less capital intensive.

A number of other companies have announced plans to enter the oil sands business or expand existing operations. Expansion of existing operations and development of new projects could significantly increase the supply of bitumen and other competing crude oil products in the marketplace. Depending on the levels of future demand, increased supplies could have a negative impact on prices of bitumen and, accordingly, the Corporation's results of operations, financial condition and prospects. In addition, expansion of existing operations and development of new projects could materially increase the costs of inputs such as natural gas, diluent, labour, equipment, materials or services which, in turn, may have a material adverse effect on the Corporation's results of operations and financial condition.

SAGD Bitumen Recovery Process

The recovery of bitumen using SAGD processes is subject to uncertainty. Current SAGD technologies for *in situ* extraction of bitumen are energy intensive, requiring significant consumption of natural gas or other fuels to produce steam for use in the recovery process. There can be no assurance that the Corporation's operations will produce bitumen at the expected levels or on schedule. The amount of steam required in the production process can vary and impact costs significantly. The quality and performance of the bitumen reservoir can also impact the Corporation's SOR and the timing and levels of production using this technology. Should the Corporation encounter adverse reservoir conditions, bitumen recovery levels achieved by the Corporation using SAGD processes may be negatively impacted.

Royalty Regimes

The Corporation's operating cash flow will be directly affected by the applicable royalty regime. The Province of Alberta receives royalties on the production of natural resources from lands in which it owns the mineral rights that are linked to price and production levels and that apply to both new and existing oil sands projects. See "Regulatory Matters".

The Government of Alberta announced that, following the completion of its royalty review in February, 2016, it will begin drafting a modernized royalty framework to incorporate a single royalty structure to all oil and gas products, to improve the process of calculating costs and collecting oil sands royalties, and to improve disclosure of cost, revenue and collection information. The specific changes that will be implemented have not been announced, and accordingly it is uncertain what the effects of the new policies will be on the Corporation's operations. Additionally, 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 results of operations, financial condition or prospects.

An increase in royalties would reduce the Corporation's earnings and could make future capital investments or the Corporation's operations uneconomic and could make it more difficult to service and repay the Corporation's debt. Any material increase in royalties would also significantly reduce the value of the Corporation's assets.

Lease Expiries

Certain of MEG's oil sands leases may expire and MEG may be required to surrender lands to the Province of Alberta. The initial term for MEG's oil sands leases, some of which began in or subsequent to 1996, is 15 years. At the conclusion of this initial term, each oil sands lease may be continued if it meets certain criteria related to the extent to which MEG has evaluated the oil sands resource covered by the lease. Continued leases have indefinite terms. An application for continuation may be made during the last year of the term of the lease or at any time during the lease with the consent of the Minister. The Province of Alberta, pursuant to the most recent *Oil Sands Tenure Regulation* (which came into effect in 2010) under the *Mines and Minerals Act*, has designated the minimum level of evaluation (the "MLE") to qualify for continuation. Currently, the Province of Alberta, through the Department of Energy, is conducting a comprehensive review of the *Oil Sands Tenure Regulation* in an effort to address concerns raised by industry with respect to interpretation and application of the MLE. The Department of Energy has issued an "interim approach" and "interim approach update" during this review period, both modifying the MLE requirements and providing optional extensions to leases expiring between December 1, 2010 and the end of the review period. Leases that have not been continued by the date of the "interim approach update" (February 22, 2012) will be eligible for a three year term extension and any leases that would have been eligible to receive a two year term extension under the "interim approach" will also be eligible for an additional three year term extension resulting in a total extension of five years. MEG has been granted all optional extensions on all of its oil sands leases. With such extensions in place, and the next lease expiries set to occur in 2016, MEG is currently evaluating all leases to determine the best continuation approach.

Claims Made by Aboriginal Peoples

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. Such claims and other similar claims that may be initiated, if successful, could have a significant adverse effect on the Corporation, the Christina Lake Project, the Surmont Project and the Corporation's future projects.

Unforeseen Title Defects

The Corporation has not obtained title opinions in respect of the oil sands leases that it intends to develop and, accordingly, the Corporation's ownership of the leases could be subject to prior unregistered agreements or interests, or claims or interests of which the Corporation is currently unaware. If such an event were to occur, the Corporation's rights to the production and reserves associated with such leases could be jeopardized, which could have a material adverse effect on the Corporation's results of operations, financial condition and prospects.

Future Acquisitions

As part of its growth strategy, MEG expects to continue to evaluate and, where appropriate, pursue acquisitions of additional oil sands leases. Acquisitions of oil sands leases, as well as the exploration and development of land subject to such leases, may require substantial capital or the incurrence of substantial additional indebtedness. Furthermore, the acquisition of any additional oil sands leases may not ultimately increase MEG's reserves and contingent resources or result in any additional production of bitumen. If MEG consummates any future acquisitions of oil sands leases, it may need to change its anticipated capital expenditure programs and the use of the Corporation's capital resources. Additionally, such acquisitions may result in MEG's capitalization and results of operations changing significantly. Investors will not have the opportunity to evaluate the economic, financial and other

relevant information that MEG will consider in determining the application of its funds and other resources with respect to such acquisitions.

Risks Relating to Economic Conditions, Commodity Pricing and Exchange Rate Fluctuations

Fluctuations in Market Prices of Crude Oil and Bitumen Blend

MEG's results of operations and financial condition will be dependent upon, among other things, the prices that it receives for the bitumen, bitumen blend or other bitumen products that it sells, and the prices that it receives for such products will be closely correlated to the price of crude oil. Historically, crude oil markets have been volatile and are likely to continue to be volatile in the future. Crude oil prices have fluctuated widely during recent years and, in particular, in recent months, and are subject to fluctuations in response to changes in supply, demand, market uncertainty and other factors that are beyond MEG's control. These factors include, but are not limited to:

- global energy policy, including (without limitation) the ability of the Organization of the Petroleum Exporting Countries to set and maintain production levels and influence prices for crude oil;
- political instability and hostilities;
- domestic and foreign supplies of crude oil;
- the overall level of energy demand;
- weather conditions;
- government regulations;
- taxes;
- currency exchange rates;
- the availability of refining capacity and transportation infrastructure;
- the effect of worldwide environmental and/or energy conservation measures;
- the price and availability of alternative energy supplies; and
- the overall economic environment.

Any prolonged period of low crude oil prices could result in a decision by MEG to suspend or slow development activities, to suspend or slow the construction or expansion of bitumen recovery projects or to suspend or reduce production levels. Any of such actions could have a material adverse effect on MEG's results of operations, financial condition and prospects.

The market prices for heavy oil (which includes bitumen blends) are lower than the established market prices for light and medium grades of oil, due principally to diluent prices and the higher transportation and refining costs associated with heavy oil. Also, the market for heavy oil is more limited than for light and medium grades of oil, making it more susceptible to supply and demand fluctuations. Future price differentials are uncertain and any increase in the heavy oil differentials could have an adverse effect on MEG's results of operations, financial condition and prospects.

MEG conducts an assessment of the carrying value of its assets to the extent required by IFRS. If crude oil prices decline, the carrying value of MEG's assets could be subject to downward revision, and MEG's earnings could be adversely affected by any reduction in such carrying value.

General Economic Conditions, Business Environment and Other Risks

The business of the Corporation is subject to general economic conditions. Adverse changes in general economic and market conditions could negatively impact demand for crude oil, bitumen and bitumen blends, revenue, operating costs, results of financing efforts, timing and extent of capital expenditures, credit risk and counterparty risk.

Volatility in crude oil, bitumen blend, natural gas and diluent prices, fluctuations in interest rates, product supply and demand fundamentals, market competition, labour market supplies, risks associated with technology, risks of a widespread pandemic, the Corporation's ability to generate sufficient cash flow from operations to meet its current and future obligations, the Corporation's ability to access external sources of debt and equity capital, general economic and business conditions, the Corporation's ability to make capital investments and the amounts of capital investments, risks associated with potential future lawsuits and regulations, assessments and audits (including income tax) against the Corporation (and its subsidiaries), political and economic conditions in the geographic regions in which the Corporation and its subsidiaries operate, difficulty or delays in obtaining necessary regulatory approvals, a significant decline in the Corporation's reputation, and such other risks and uncertainties, could individually or in the aggregate have a material adverse impact on the Corporation's business, prospects, financial condition, results of operation or cash flows. Challenging market conditions and the health of the economy as a whole may have a material adverse effect on the Corporation's results of operations, financial condition and prospects. There can be no assurance that any risk management steps taken by the Corporation with the objective of mitigating the foregoing risks will avoid future loss due to the occurrence of such risks.

Volatility of Commodity Inputs

The nature of the Corporation's operations results in exposure to fluctuations in bitumen, diluent and gas prices. Natural gas is a significant component of the Corporation's cost structure, as it is used to generate steam for the SAGD process and to create electricity at the Corporation's cogeneration facility. Diluent, such as condensate, is also one of the Corporation's significant commodity inputs and is used as part of MEG's product marketing strategy and to decrease the viscosity of the bitumen in order to allow it to be transported.

Historically, crude oil and electricity prices have been positively correlated with the prices of natural gas and condensate. As a result, the Corporation expects to be able to offset a portion or all of the increase in its costs associated with an increase in the price of natural gas or condensate with an increase in revenue that results from higher oil prices and electricity sold by the Corporation's planned cogeneration units. MEG believes that this correlation has been caused by factors that are not within its control, and investors are cautioned not to rely on this correlation continuing. If the prices of these commodities cease to be positively correlated, and the price of crude oil or electricity falls while the prices of natural gas or diluent rise or remain steady, the Corporation's results of operations, financial condition and prospects could be adversely affected.

Variations in Foreign Exchange Rates and Interest Rates

Most of MEG's revenues are based on the U.S. dollar, since revenue received from the sale of bitumen and bitumen blends is generally referenced to a price denominated in U.S. dollars, and MEG incurs most of its operating and other costs in Canadian dollars. As a result, MEG is impacted by exchange rate fluctuations between the U.S. dollar and the Canadian dollar, and any strengthening of the Canadian dollar relative to the U.S. dollar could negatively impact MEG's operating margins and cash flows. In addition, as MEG reports its operating results in Canadian dollars, fluctuations in product pricing and in the rate of exchange between the U.S. dollar and Canadian dollar affect MEG's reported results.

Further, substantially all of the Corporation's debt, including the Credit Facilities, the 2011 Notes, the 2012 Notes and the 2013 Notes is or will be denominated in U.S. dollars and is at variable rates of interest. Fluctuations in exchange rates and interest rates may significantly increase or decrease the amount of debt and interest expense recorded on

the Corporation's financial statements, which could have a significant effect on the Corporation's results of operations, financial condition and prospects.

Hedging Strategies

The Corporation may use physical and financial instruments to hedge its exposure to fluctuations in commodity prices, exchange rates and interest rates. If the Corporation engages in any such hedging activities, it will be exposed to credit related losses in the event of non-performance by counterparties to the physical or financial instruments. Additionally, if bitumen, diluent or gas prices, interest rates or exchange rates increase above or decrease below those levels specified in any future hedging agreements, such hedging arrangements may prevent the Corporation from realizing the full benefit of such increases or decreases. In addition, any future commodity hedging arrangements could cause the Corporation to suffer financial loss, if it is unable to produce sufficient quantities of the commodity to fulfill its obligations, if it is required to pay a margin call on a hedge contract or if it is required to pay royalties based on a market or reference price that is higher than the Corporation's fixed ceiling price.

To the extent that risk management activities and hedging strategies are employed to address commodity prices, exchange rates, interest rates or other risks, risks associated with such activities and strategies, including (without limitation) counterparty risk, settlement risk, basis risk, liquidity risk and market risk, could impact or negate such activities and strategies, which would have a negative impact on MEG's results of operations, financial position and prospects.

Global Financial Markets

The market events and conditions that transpired in recent years, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, have, among other things, caused significant volatility in commodity prices. These events and conditions caused a loss of confidence in the broader U.S., European Union and global credit and financial markets and resulted in the collapse of, and government intervention in, numerous major banks, financial institutions and insurers, and created a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. These factors negatively impacted enterprise valuations and impacted the performance of the global economy.

Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties regarding the supply and demand fundamentals for petroleum products due to the current state of the world's economies, actions taken by the Organization of the Petroleum Exporting Countries, the ongoing risks facing the North American and global economies and new supplies of crude oil which may be created by the application of new drilling technology to unconventional resource plays. It is possible that petroleum prices could move lower, or could remain near current price levels for a considerable period of time.

Environmental and Regulatory Risks

Environmental Considerations

The operations of the Corporation are, and will continue to be, affected in varying degrees by federal and provincial laws and regulations regarding the protection of the environment. Should there be changes to existing laws or regulations, the Corporation's competitive position within the oil sands industry may be adversely affected, and many industry players have greater resources than the Corporation to adapt to legislative changes.

No assurance can be given that future environmental approvals, laws or regulations will not adversely impact the Corporation's ability to develop and operate its oil sands projects or increase or maintain production or control its costs of production. Equipment which can meet future environmental standards may not be available on an economic or timely basis and instituting measures to ensure environmental compliance in the future may significantly increase operating costs or reduce output. There is a risk that the federal and/or provincial governments could pass legislation that would tax air emissions or require, directly or indirectly, reductions in air emissions produced by energy industry participants, which the Corporation may be unable to mitigate.

All phases of the oil sands business present environmental risks and hazards and are subject to environmental legislation and regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, permit requirements, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil sands operations and restrictions on water usage and land disruption. The legislation also requires that wells and facility sites be constructed, operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs, and both the federal government and the government of Alberta have indicated an intent to impose more stringent environmental legislation that will affect the oil sands industry. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Corporation to incur costs to remedy such discharge. No assurance can be given that environmental laws and regulations will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on the Corporation's results of operations, financial condition and prospects.

The Corporation believes that it is reasonably likely that the trend towards stricter standards in environmental legislation will continue and anticipates that capital and operating costs may increase as a result of more stringent environmental laws.

Greenhouse Gas Regulations

The direct and indirect costs of the various GHG regulations, existing and proposed in both Canada and the United States, including the implementation of the government of Alberta's Climate Leadership Plan and the federal government's implementation of the Paris Agreement, may adversely affect MEG's business, operations and financial results. Equipment that meets future GHG emission standards may not be available on an economic basis and other compliance methods to reduce emissions or emissions intensity to future required levels may significantly increase operating costs or reduce the output of the projects. Offset, performance or fund credits may not be available for acquisition or may not be available on an economical basis. Any failure to meet GHG emission reduction compliance obligations may have a material adverse effect on the Corporation's business and result in fines, penalties and the suspension of operations.

Future federal legislation, including the implementation of potential international requirements enacted under Canadian law, as well as provincial legislation and emissions reduction requirements, may require the reduction of GHG or other industrial air emissions, or emissions intensity, from the Corporation's operations and facilities. Mandatory emissions reduction requirements may result in increased operating costs and capital expenditures for oil and natural gas producers. The Corporation is unable to predict the impact of emissions reduction legislation on the Corporation and it is possible that such legislation may have a material adverse effect on MEG's financial condition, results of operations and prospects.

See "Regulatory Matters – Environmental Regulation – Greenhouse Gases and Industrial Air Pollutants".

United States Climate Change Legislation

Environmental regulation of greenhouse gas emissions in the United States could result in increased costs and/or reduced revenue for oil sands companies such as MEG. At the federal level, the U.S. Environmental Protection Agency (the "EPA") is currently responsible for regulating GHG emissions, pursuant to the Clean Air Act. The EPA has issued regulations restricting GHG emissions from automobiles and trucks, and also administers the Renewable Fuel Standard, which requires specified "renewable fuels" to be blended into U.S. transportation fuel, with increasing volumes coming from lower GHG emitting fuels over time. While the future regulatory environment in the United States is uncertain, it is possible that fuel suppliers' GHG emissions will eventually be regulated in the United States, although there are no currently active proposals to that effect. The Corporation's operations may be impacted by such regulation, which could impose increased costs on direct or indirect users of the Corporation's products, and thereby result in reduced demand for and increased costs of use of the Corporation's products.

The Corporation may also be impacted by various state policies which regulate GHG emissions. For example, the ARB administers two regulatory programs that impact the crude or synthetic crude oil industry: a LCFS and a cap-and-trade program. California's LCFS regulates fuel suppliers based on the "carbon intensity" of their fuel supplied to market, i.e., the GHG emissions associated with the entire lifecycle of the fuel, from extraction to refining to end use. ARB's determination that Canadian synthetic crude has a high carbon intensity imposes certain costs on its use under the LCFS, potentially decreasing demand for such fuel vis-à-vis other less carbon intensive fuel types. Despite a legal challenge claiming that the LCFS improperly discriminated against out-of-state sources of ethanol and crude oil in violation of the Commerce Clause of the United States Constitution, the LCFS was upheld and the United States Supreme Court denied a petition to review the case. California's cap-and-trade program began regulating fuel suppliers in 2015, imposing costs in proportion to the GHG emissions potential of fuel supplied to the California market. Unlike the LCFS, the cap-and-trade program does not involve a lifecycle analysis and accordingly will not have any disproportionate impact on high-carbon-intensity crude or synthetic crude. The further introduction of carbon fuel standards or GHG emission regulations may negatively affect the marketing of bitumen, bitumen blend or SCO, or require the purchase of emissions credits in connection with sales in such jurisdictions.

The Future of GHG Emission Regulations

GHG emission regulation is expected to have a financial impact on oil sands industry participants and their projects, including MEG and its projects. However the extent of that impact is not yet known. In particular, there is uncertainty regarding the ultimate GHG emission regulatory regime that will be applicable to MEG due to, among other things, the potential for changes to the regulation of GHG emissions in Alberta, Canada and the United States and the potential for the harmonization of GHG emission regulatory regimes in Canada and the United States.

At present, there is no assurance that any new regulations implemented by the Government of Canada relating to the reduction of GHG emissions will be harmonized with the Government of Alberta's GHG emissions reduction regulations. In such case, the costs of meeting new government requirements could be considerably higher than the costs of meeting Alberta's requirements.

Proposed Export Restrictions

The Government of Canada previously announced that it will review and may restrict exports from Canada of bitumen and bitumen blend products to countries with less stringent GHG emissions limits than those which apply in Canada. Any export restrictions imposed with respect to bitumen or bitumen blend products may restrict the markets in which the Corporation may sell its bitumen and bitumen blend products, which may result in the Corporation receiving a lower price for its production.

Proposed Import Restrictions

Some foreign jurisdictions, including the State of California have attempted to introduce carbon fuel standards that require a reduction in life cycle GHG emissions from vehicle fuels. Some standards propose a system to calculate the life cycle of GHG emissions of fuels to permit the identification and use of lower-emitting fuels. See “Regulatory Matters — Environmental Regulation — Greenhouse Gases and Industrial Air Pollutants — United States Regulations”.

Any foreign import restrictions or financial penalties imposed on the use of bitumen or bitumen blend products may restrict the markets in which the Corporation may sell its bitumen and bitumen blend products and/or result in the Corporation receiving a lower price for such products.

Abandonment and Reclamation Costs

The Corporation will need to comply with the terms and conditions of environmental and regulatory approvals and all laws and regulations regarding the abandonment of its projects and reclamation of the project lands at the end of their economic life, which will result in substantial abandonment and reclamation costs. Any failure to comply with the terms and conditions of the Corporation's approvals and such legislation and/or regulations may result in the imposition of fines and penalties.

It is not possible at this time to estimate abandonment and reclamation costs reliably since they will, in part, depend on future regulatory requirements. In addition, in the future, the Corporation may determine it prudent or be required by applicable laws, regulations or regulatory approvals to establish and fund one or more reclamation funds to provide for payment of future abandonment and reclamation costs. If the Corporation establishes a reclamation fund, its liquidity and cash flow may be adversely affected.

Regulatory Approvals and Compliance

The construction, operation and decommissioning of the Christina Lake Project and MEG's other projects are and will be conditional upon various environmental and regulatory approvals, permits, leases and licenses issued by governmental authorities, including but not limited to the approval of the AER. There can be no assurance such approvals, permits, leases and licenses will be granted, or, once granted or renewed, that they will subsequently be renewed or will not be cancelled or contain terms and conditions which make the Christina Lake Project, or MEG's other projects uneconomic, or cause the Corporation to significantly alter the Christina Lake Project or MEG's other projects. Further, the construction, operation and decommissioning of the Christina Lake Project and MEG's other projects will be subject to regulatory approvals and statutes and regulations relating to environmental protection and operational safety. There can be no assurance that third parties will not object to the development of such projects during applicable regulatory processes.

Although the Corporation believes that the Christina Lake Project and its other projects are or will be in general compliance with applicable environmental and safety regulatory approvals, statutes and regulations, risks of substantial costs and liabilities are inherent in oil sands operations and there can be no assurance that substantial costs and liabilities will not be incurred or that the Christina Lake Project or the Corporation's other projects will be permitted to carry on operations. Moreover, it is possible that other developments, such as increasingly strict environmental and safety statutes, regulations and enforcement policies thereunder, and claims for damages to property or persons resulting from the operations of the projects, could result in substantial costs and liabilities to the Corporation or delays to or abandonment of the Christina Lake Project or MEG's other projects.

Additional Regulation and Regulatory Compliance

The oil and gas industry in Canada, including the oil sands industry, operates under Canadian federal, provincial and municipal legislation and regulations governing such matters as land tenure, lease extensions, aboriginal consultation, prices, royalties, taxes, production rates, environmental protection controls, operating practices, income, the production, transportation, sale and export of crude oil, natural gas and other products, the use of subsurface water, land use, expropriation and other matters. In addition, there are many international rules, regulations and requirements relating to the shipping of oil and gas products, via land or sea.

The introduction of new regulations, including regulations modifying safety standards for rail tank cars used to transport crude oil, could adversely affect the timing of planned crude oil shipments by rail, our ability to ship crude oil by rail and the economics of shipping crude oil by rail.

Government regulations may be changed from time to time in response to economic or political conditions. The exercise of discretion by governmental authorities under existing regulations, the implementation of new regulations or the modification of existing regulations affecting the oil sands industry may adversely affect MEG's business, operations and financial results.

Other Risks Affecting the Corporation's Business

Reliance on, Competition for, Loss of, and Failure to Attract Key Personnel and Labour Force

The Corporation's success depends in large measure on certain key personnel. The loss of the services of such key personnel may have a material adverse effect on its business, financial condition, results of operations and prospects. The Corporation does not have any key person insurance in effect. The contributions of the existing management team to the Corporation's immediate and near term operations are likely to be of central importance and the competition for qualified personnel in the oil and natural gas industry is intense. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of management of the Corporation.

The design, development and construction of, and commencement of operations at, the Christina Lake Project, and MEG's other projects will require experienced executive, management and technical personnel and operational employees and contractors with expertise in a wide range of areas. The labour force in Alberta, and in the surrounding area, is limited and there can be no assurance that all of the required employees with the necessary expertise will be available. Other oil sands projects or expansions will proceed in the same time frame as MEG's projects. MEG's projects will compete with these other projects for experienced employees and such competition may result in increases to compensation paid to such personnel or a lack of qualified personnel. Increased labour costs would adversely affect MEG's results of operations, financial condition and prospects.

Conflicts of Interest

Some of the Corporation's directors and officers are engaged and will continue to be engaged in the oil and gas business on their own behalf and on behalf of others, and situations may arise where the directors and officers will be in direct or indirect competition with MEG. For example, these directors or officers could pursue acquisition opportunities that may be complementary to MEG's business and, as a result, those acquisition opportunities may not be available to MEG. Conflicts of interest, if any, which arise will be subject to and be governed by procedures prescribed by the ABCA which require a director or officer of a corporation who is party to a material contract or proposed material contract with the Corporation to disclose such director's or officer's interest and, with respect to a director, to refrain from voting on any matter in respect of such contract unless otherwise permitted under the ABCA.

Changes to Tax Laws and Government Incentive Programs

Income tax laws or government incentive programs relating to the oil and gas industry and in particular the oil sands sector may in the future be changed or interpreted in a manner that adversely affects MEG's result of operations, financial condition or prospects.

Management Estimates and Assumptions

In preparing consolidated financial statements in conformity with IFRS, estimates and assumptions are used by management in determining the reported amounts of assets and liabilities, revenues and expenses recognized during the periods presented and disclosures of contingent assets and liabilities known to exist as of the date of the financial statements. These estimates and assumptions must be made because certain information that is used in the preparation of such financial statements is dependent on future events, cannot be calculated with a high degree of precision from data available, or is not capable of being readily calculated based on generally accepted methodologies. In some cases, these estimates are particularly difficult to determine and the Corporation must exercise significant judgment. Estimates may be used in management's assessment of items such as depreciation and accretion, fair values, useful lives of assets, deferred income taxes, stock based compensation, estimates of reserves, derivative financial instruments and decommissioning obligations. Actual results for all estimates could differ materially from the estimates and assumptions used by the Corporation, which could have a material adverse effect on MEG's financial condition, results of operations and prospects.

Internal Controls

Effective internal controls are necessary for the Corporation to provide reliable financial reports and to help prevent fraud. Although the Corporation undertakes a number of procedures in order to help ensure the reliability of its financial reports, including those imposed on it under Canadian securities laws, the Corporation cannot be certain that such measures will ensure that the Corporation will maintain adequate control over financial processes and reporting. Failure to implement required new or improved controls, or difficulties encountered in their implementation, could impact the Corporation's results of operations or cause it to fail to meet its reporting obligations. If the Corporation or its independent auditors discover a material weakness, the disclosure of that fact, even if quickly remedied, could reduce the market's confidence in the Corporation's financial statements and reduce the trading price of the Common Shares.

Political Risks and Terrorist Attacks

The marketability and price of bitumen is and will continue to be affected by political events throughout the world that cause disruptions in the supply of oil. Conflicts, or conversely peaceful developments, arising in the Middle East, and other areas of the world, have a significant impact on the price of oil. Any particular event could result in a material decline in prices and therefore could have a material adverse effect on the Corporation's results of operations, financial condition and prospects.

In addition, the long-term impact of previous terrorist attacks and the threat of future terrorist attacks on the oil and gas industry in general, and on facilities for the transportation and refinement of oil and gas in particular, is not known at this time. The possibility that infrastructure and other facilities, such as pipelines, terminals and refineries, may be direct targets of, or indirect casualties of, an act of terror and the implementation of security measures which may be taken as a precaution against possible terrorist attacks have resulted in, and are expected to continue to result in, increased costs to the Corporation's business. Furthermore, any interruption in the services provided by infrastructure on which the Corporation relies (such as the Access Pipeline) as a result of a terrorist attack would have a material adverse effect on the Corporation's results of operations, financial condition and prospects.

Risks Relating to Financing and the Corporation's Indebtedness

Sufficiency of Funds

Significant amounts of capital will be required to develop future phases of the Christina Lake Project, the Surmont Project, the May River Regional 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 main 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. If sufficient capital is not available, it could adversely affect the expected growth and development of MEG's business.

MEG's actual costs and revenues may vary from expected amounts, possibly to a material degree, and such variations are likely to affect MEG's future capital requirements. Accordingly, MEG may be required to raise substantial additional capital in the future and MEG's current projections may not prove to be accurate. In addition, MEG may accelerate the expansion and development of its projects. If MEG decides to do so, its funding needs will increase, possibly to a significant degree.

The Corporation's ability to make payments on, and to refinance, its indebtedness, and to fund planned capital expenditures will depend upon, amongst other matters, the Corporation's ability to generate cash in the future which, in turn, is subject to general economic, financial, competitive, legislative, regulatory and other factors, many of which are beyond the Corporation's control.

Restrictions Contained in Credit Facilities and Senior Notes

The Credit Facilities, the indenture governing the 2011 Notes, the indenture governing the 2012 Notes and the indenture governing the 2013 Notes impose operating and financial restrictions on the Corporation. These restrictions limit the Corporation's ability and that of its restricted subsidiaries to, among other things:

- pay dividends on, repurchase or make distributions in respect of the Corporation's capital stock or make other restricted payments;
- incur additional indebtedness and issue preferred or disqualified stock;
- create liens;
- create or permit to exist restrictions on the ability of the Corporation's restricted subsidiaries to make certain payments and distributions;
- engage in amalgamations, mergers or consolidations or sell or otherwise dispose of all or substantially all of the Corporation's assets;
- make certain dispositions and transfers of assets; and
- engage in transactions with affiliates.

The restrictions in the Credit Facilities, the indenture governing the 2011 Notes, the indenture governing the 2012 Notes or the indenture governing the 2013 Notes may adversely affect the Corporation's ability to finance its future operations and capital needs and to pursue available business opportunities. Moreover, any new indebtedness the Corporation incurs may impose financial restrictions and other covenants on the Corporation that may be more restrictive than the Credit Facilities, the indenture governing the 2011 Notes, the indenture governing the 2012 Notes and the indenture governing the 2013 Notes.

Upon the occurrence of any event of default under the Credit Facilities, the lenders under the Credit Facilities could elect to declare all amounts outstanding thereunder, together with accrued interest, to be immediately due and payable and to terminate any commitments to extend further credit. If the lenders under the Credit Facilities accelerate the payment of the indebtedness outstanding thereunder, the Corporation cannot be certain that its assets would be sufficient to repay in full that indebtedness and its other indebtedness.

Debt Service Obligations

The Corporation's ability to make payments on, and to refinance, its indebtedness and to fund planned capital expenditures will depend on its ability to generate cash in the future which, in turn, is subject to general economic, financial, competitive, legislative, regulatory and other factors, many of which are beyond the Corporation's control.

The Corporation may not generate sufficient cash flow from operations and may not have available to it future borrowings in an amount sufficient to enable the Corporation 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, including the Credit Facilities, on commercially reasonable terms or at all. Without such financing, the Corporation could be forced to sell assets or secure additional financing to make up for any shortfall in its payment obligations under unfavorable circumstances. However, the Corporation may not be able to raise additional capital or secure additional financing on terms favorable to the Corporation or at all, and the terms of the Credit Facilities, the indenture governing the 2011 Notes, the indenture governing the 2012 Notes and the indenture governing the 2013 Notes limit its ability to sell assets and also restrict the use of proceeds from such a sale. Moreover, substantially all of the Corporation's assets have been pledged to secure repayment of its indebtedness under the Credit Facilities. The Corporation may not be able to sell assets quickly enough or for sufficient amounts to enable it to meet its obligations.

Additional Indebtedness

Despite MEG's current level of indebtedness, MEG may be able to incur substantial additional indebtedness in the future, including additional secured indebtedness. The terms of the Credit Facilities restrict, but do not prevent, MEG from doing so. Also, these restrictions do not prevent MEG from incurring obligations that do not constitute "indebtedness" as defined in agreements forming the Credit Facilities. If new debt is added to MEG's current level of indebtedness, the risks associated with MEG's indebtedness will be increased.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

During the year ended December 31, 2015, there have been no legal proceedings to which the Corporation is or was a party, or that any of the Corporation's property is or was the subject of, which is or was, or can be reasonably considered to be, material to the Corporation or any of its properties and the Corporation is not aware of any such legal proceedings that are contemplated. For the purposes of the foregoing, a legal proceeding is not considered to be "material" by the Corporation if it involves a claim for damages and the amount involved, exclusive of interest and costs, does not exceed 10% of the Corporation's current assets, provided that if any proceeding presents in large degree the same legal and factual issues as other proceedings pending or known to be contemplated, the Corporation has included the amount involved in the other proceedings in computing the percentage. See "Risk Factors".

During the year ended December 31, 2015, there were no penalties or sanctions imposed against the Corporation by a court relating to provincial and territorial securities legislation or by a securities regulatory authority, nor have there been any other penalties or sanctions imposed by a court or regulatory body against the Corporation that would likely be considered important to a reasonable investor in making an investment decision, and it has not entered into any

settlement agreements before a court relating to provincial and territorial securities legislation or with a securities regulatory authority.

INTERESTS OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Except as disclosed under the heading "Transactions with Related Parties" in the Corporation's Management's Discussion and Analysis for the year ended December 31, 2015 which can be found on SEDAR at www.sedar.com, no director, executive officer or principal shareholder of the Corporation, or associate or affiliate of those persons, has any material interest, direct or indirect, in any transaction within the last three years that has materially affected or is reasonably expected to materially affect the Corporation.

INTERESTS OF EXPERTS

The Corporation's auditors are PricewaterhouseCoopers LLP, Chartered Professional Accountants, who have prepared an independent auditors' report dated March 3, 2016 in respect of the Corporation's consolidated financial statements as of December 31, 2015 and December 31, 2014 and for each of the years then ended. PricewaterhouseCoopers LLP has advised that they are independent with respect to the Corporation within the meaning of the rules of professional conduct of the Canadian Institute of Chartered Professional Accountants. GLJ prepared the GLJ Report, referenced herein. As of the date of the GLJ Report, the principals of GLJ, as a group, owned beneficially, directly or indirectly, less than one percent of the outstanding Common Shares. GLJ did not receive nor will they receive any interest, direct or indirect, in any securities or other property of the Corporation or its affiliates in connection with the preparation of its report.

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for the Common Shares is Computershare Investor Services Inc. at its principal offices in Calgary, Alberta and Toronto, Ontario.

MATERIAL CONTRACTS

The only contract material to the Corporation, other than contracts entered into in the ordinary course of business, entered into during the most recently completed financial year or before the most recently completed financial year that is still in effect is the Shareholder Rights Plan Agreement described under the heading "Description of Capital Structure – Common Shares".

ADDITIONAL INFORMATION

Additional information relating to the Corporation is available via SEDAR at www.sedar.com.

Additional information including directors' and officers' remuneration and indebtedness, principal holders of the Corporation's securities and securities authorized for issuance under equity compensation plans will be contained in the Corporation's information circular for its next annual general meeting of shareholders that involves the election of directors. Additional financial information is contained in the Corporation's audited consolidated financial statements and Management's Discussion and Analysis for the year ended December 31, 2015.

GLOSSARY AND DEFINITIONS

In this Annual Information Form, unless otherwise indicated or the context otherwise requires, the following terms shall have the meaning set forth below:

"2011 Notes" means the US\$750 million in aggregate principal amount of 6.5% senior unsecured notes, issued by the Corporation effective March 18, 2011.

"2012 Notes" means the US\$800 million in aggregate principal amount of 6.375% senior unsecured notes issued by the Corporation effective July 19, 2012.

"2013 Notes" means, collectively, the US\$800 million in aggregate principal amount of 7.0% senior unsecured notes due in 2024 and the additional US\$200 million in aggregate principal amount of 7.0% senior unsecured notes due in 2024, which are traded as a single series as, and trade fungibly with, the US\$800 million senior unsecured notes.

"3D seismic data" means three-dimensional seismic data, being geophysical data that depicts the subsurface strata in three dimensions. 3D seismic data typically provides a more detailed and accurate interpretation of the subsurface strata than 2D seismic data.

"ABCA" means the *Business Corporations Act (Alberta)*.

"Access Pipeline" means the dual pipeline system, in which MEG holds a 50% interest, which connects the Christina Lake Project to both the Stonefell Terminal and to a large regional upgrading, refining, diluent supply and transportation hub in the Edmonton, Alberta area and includes the Sturgeon Terminal.

"AER" means the Alberta Energy Regulator, which replaced the ERCB on June 17, 2013 and the ESRD on March 29, 2014 to become the single energy regulator for energy resource activities in Alberta in 2014.

"API" means the American Petroleum Institute.

"API gravity" means the American Petroleum Institute gravity, which is a measure of how heavy or light a petroleum liquid is compared to water. If a petroleum liquid's API gravity is greater than 10, it is lighter and floats on water; if less than 10, it is heavier than water and sinks. API gravity is thus a measure of the relative density of a petroleum liquid and the density of water, but it is used to compare the relative densities of petroleum liquids.

"Audit Committee" means the audit committee of the Board.

"AWB" means Access Western Blend.

"best estimate" has the meaning given to that term under the subheading "Aggregated Contingent Resources Estimates" within Appendix D.

"bitumen" means a naturally occurring viscous mixture consisting mainly of pentanes and heavier hydrocarbons. Its viscosity is greater than 10,000 milliPascal seconds (centipoise) measured at original temperature in the reservoir and atmospheric pressure, on a gas-free basis. Crude bitumen may contain sulphur and other non-hydrocarbon compounds.

"**Board**" or "**Board of Directors**" means the board of directors of the Corporation.

"**Christina Lake Project**" means the *in situ* oil sands project described under the heading "Projects Overview – Christina Lake Project".

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook prepared jointly by The Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society), as amended from time to time.

"**Common Shares**" means the common shares in the capital of the Corporation.

"**Compensation Committee**" means the compensation committee of the Board.

"**Contingent Resources**" has the meaning given to that term under the subheading "Aggregated Contingent Resources Estimates" within Appendix D.

"**Credit Facilities**" means the Corporation's senior secured credit facilities comprised of a US\$1.0 billion principal amount term loan and a US\$2.5 billion principal amount revolving credit facility, all as may be further amended or replaced from time to time.

"**delineation well**" means a well that is so located in relation to another well penetrating an accumulation of petroleum that there is a reasonable expectation that another portion of the accumulation will be penetrated by the first mentioned well and that the drilling of the first-mentioned well is necessary in order to determine the commercial value of the accumulation.

"**Devon**" means Devon NEC Corporation, a subsidiary of Devon Energy Corporation.

"**dilbit**" means a blend of condensate and bitumen.

"**diluent**" means lighter viscosity petroleum products that are used to dilute bitumen for transportation in pipelines.

"**EPA**" means the United States Environmental Protection Agency.

"**ERCB**" means the Energy Resources Conservation Board of Alberta, a predecessor to the AER.

"**ESRD**" means Alberta Environment and Sustainable Resource Department, a predecessor to the AER.

"**GAAP**" means generally accepted accounting principles.

"**GHG**" means greenhouse gas.

"**GLJ**" means GLJ Petroleum Consultants Ltd., an independent qualified reserves and resources evaluator.

"**GLJ Report**" means the report of GLJ dated effective as of December 31, 2015, with a preparation date of January 29, 2016, assessing and evaluating the proved and probable reserves and contingent resources of the Corporation located in the Christina Lake, Surmont, Thornbury, Greater May River, West Kirby, East Kirby and Portage areas of Alberta.

"**Growth Properties**" means the oil sands leases held by the Corporation in the West Kirby, East Kirby and Portage areas of Alberta, as further described under the heading "Projects Overview – Growth Properties".

"**HRSG**" means heat recovery steam generator.

"**IFRS**" means International Financial Reporting Standards.

"**in situ**" means "in place" and, when referring to oil sands, means a process for recovering bitumen from oil sands by means other than surface mining, such as SAGD.

"**kPa**" means KiloPascal, the metric unit for pressure.

"**LCFS**" means the "Low Carbon Fuel Standard" established by California's Assembly Bill 32 – the *Global Warming Solutions Act of 2006* (AB32).

"**management**" means the executive officers of the Corporation.

"**May River Regional Project**" means the oil sands leases held by the Corporation in the Thornbury and Greater May River areas of Alberta, as further described under the heading "Projects Overview – May River Regional Project".

"**McMurray**" means a succession of sands and shale deposited in a fluvial estuarine environment that developed into a major valley that was cut into Devonian-aged limestone within the Cretaceous-aged McMurray formation.

"**MEG**" or the "**Corporation**" means MEG Energy Corp., a corporation amalgamated under the ABCA.

"**MEG US**" means MEG Energy (U.S.) Inc., the Corporation's wholly-owned subsidiary incorporated on June 26, 2012 under the Delaware *General Corporation Law*.

"**MW**" means a unit of electrical power to measure the generating capability of a generating station, 1 million Watts equal 1 MW.

"**NI 51-101**" means National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities*.

"**NI 52-110**" means National Instrument 52-110 – *Audit Committees*.

"**oil sands**" means deposits of sand, sandstone, carbonate or other mineral material containing bitumen.

"**permeability**" is a measure of the ability of a rock to conduct a fluid through its interconnected pores when that fluid is at 100% saturation. A rock may be highly porous and yet impermeable if it has no interconnecting pore network (communication). Permeability is measured in darcies or millidarcies.

"**porosity**" means the volume of a rock available to contain fluids; the ratio of void space to the bulk volume of rock containing that void space. Porosity can be expressed as a fraction or percentage of pore volume in a volume of rock.

"**possible reserves**" are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.

"**Preferred Shares**" means the preferred shares, issuable in series, of the Corporation.

"**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 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.

"**reserves**" are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on: (i) analysis of drilling, geological, geophysical and engineering data; (ii) the use of established technology; and (iii) specified economic conditions, which are generally accepted as being reasonable. Reserves are classified according to the degree of certainty associated with the estimates.

"**reservoir**" means a subsurface body of rock having sufficient porosity and permeability to store and transmit fluids.

"**Rights Plan**" means the shareholder rights plan established through the Shareholder Rights Plan Agreement.

"**RISER**" means the Corporation's production enhancement program announced in July 2012 which is designed to increase production from existing assets at lower capital and operating costs using a combination of proprietary reservoir technologies, redeployment of steam and facilities modifications, including debottlenecking and brownfield expansions.

"**SAGD**" means steam assisted gravity drainage, an *in situ* process used to recover bitumen from oil sands.

"**saturation**" is the fraction or percentage of the pore volume occupied by a specific fluid (e.g., oil, gas, water, etc.).

"**SCO**" or "**synthetic crude oil**" means crude oil produced by upgrading bitumen to a mixture of hydrocarbons similar to light crude oil produced either by the removal of carbon (coking) or the addition of hydrogen through hydrotreating. It is considered synthetic because its original composition mark has been altered in the upgrading process.

"**Second Amended and Restated Credit Agreement**" means the second amended and restated credit agreement dated as of March 18, 2011 among the Corporation, as Borrower, the several lenders from time to time parties thereto, Barclays Capital PLC, Credit Suisse Securities (USA) LLC and BMO Capital Markets as Joint Lead Arrangers, Barclays Capital PLC, Credit Suisse Securities (USA) LLC, BMO Capital Markets and Morgan Stanley Senior Funding, Inc. as Joint Bookrunners, Bank of Montreal, as Revolving Administrative Agent under the Revolving Credit Facility, and Barclays Bank PLC, as Administrative Agent and Collateral Agent, as amended by the First Amendment, dated as of March 21, 2012, the Second Amendment dated as of November 13, 2012, the Third Amendment dated as of February 25, 2013, the Fourth Amendment dated as of May 24, 2013, the Fifth Amendment

dated as of November 5, 2014 and as the same may be further amended, amended and restated, supplemented or otherwise modified from time to time.

"Shareholder Rights Plan Agreement" means the shareholder rights plan agreement dated August 6, 2010, as amended and restated May 1, 2014, between the Corporation and Olympia Trust Company, as rights agent, and as described under the heading "Description of Capital Structure – Common Shares".

"shareholders" means the holders, from time to time, of the Common Shares, collectively or individually, as the context requires.

"SOR" means steam to oil ratio.

"Stonefell Terminal" means the terminalling and storage facility owned 100% by MEG which is located approximately three miles east of the Sturgeon Terminal and with a capacity of approximately 900,000 bbls.

"Surmont Project" means the potential *in situ* oil sands project described under the heading "Projects Overview – Surmont Project".

"TSX" means the Toronto Stock Exchange.

ABBREVIATIONS

bbl	Barrel
bbls	Barrels
bbls/d	barrels per day
boe	barrels of oil equivalent (on the basis of one being equal to one barrel of oil or six Mcf of natural gas)
Mbbls	thousand barrels
Mbbls/d	thousand barrels per day
MMbbls	million barrels
MMbbls/d	million barrels per day
MMBtu	million British thermal units
Mcf	thousand cubic feet
Tcf	trillion cubic feet
Mtoe	million tonnes oil equivalent
M\$	thousand dollars (Canadian)
MM\$	million dollars (Canadian)
\$	dollars (Canadian)

In this Annual Information Form, certain natural gas volumes have been converted to BOE or MBOE on the basis of six Mcf to one bbl. BOE and MBOE may be misleading, particularly if used in isolation. A BOE conversion ratio of one bbl to six Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent value equivalency at the well head. Given that the value ratio based on the current price of oil as compared to natural gas is significantly different from the energy equivalency conversion ratio of six to one, utilizing a BOE conversion ratio of six Mcf to one bbl would be misleading as an indication of value.

APPENDIX A – FORM 51-101F2

REPORT ON RESERVES DATA AND CONTINGENT RESOURCES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

To the board of directors of MEG Energy Corp. (the "Company"):

1. We have evaluated the Company's reserves data and contingent resources data as at December 31, 2015. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2015, estimated using forecast prices and costs. The contingent resources data are risked estimates of volume of contingent resources related risked net present value of future net revenue as at December 31, 2015, estimated using forecast prices and costs.
2. The reserves data and contingent resources data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data and contingent resources data based on our evaluation.
3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "COGE Handbook") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).
4. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data and contingent resources data are free of material misstatement. An evaluation also includes assessing whether the reserves data and contingent resources data are in accordance with principles and definitions presented in the COGE Handbook.
5. The following table shows the net present value of future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated for the year ended December 31, 2015, and identifies the respective portions thereof that we have evaluated and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator or Auditor	Effective Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate – MM\$)			
			Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants	Dec. 31, 2015	Canada	-	20,600	-	20,600

6. The following tables set forth the risked volume and risked net present value of future net revenue of contingent resources (before deduction of income taxes) attributed to contingent resources, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the Company's statement prepared in accordance with Form 51-101F1 and identifies the respective portions of the contingent resources data that we have evaluated and reported on to the Company's board of directors:

<u>Classification</u>	<u>Independent Qualified Reserves Evaluator or Auditor</u>	<u>Effective Date of Evaluation Report</u>	<u>Location of Resources Other than Reserves (Country or Foreign Geographic Area)</u>	<u>Riskd Volume (Mboe)</u>	<u>Riskd Net Present Value of Future Net Revenue (before income taxes, 10% discount rate – MM\$)</u>		
					<u>Audited</u>	<u>Evaluated</u>	<u>Total</u>
Development Pending Contingent Resources (2C)	GLJ Petroleum Consultants	Dec. 31, 2015	Canada	1,781,566	-	7,604	7,604

<u>Classification</u>	<u>Independent Qualified Reserves Evaluator or Auditor</u>	<u>Effective Date of Evaluation Report</u>	<u>Location of Resources Other than Reserves (Country or Foreign Geographic Area)</u>	<u>Riskd Volume (Mboe)</u>
Development Unclarified Contingent Resources (2C)	GLJ Petroleum Consultants	Dec. 31, 2015	Canada	750,934

7. In our opinion, the reserves data and contingent resources data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data and contingent resources data that we reviewed but did not audit or evaluate.
8. We have no responsibility to update our reports referred to in paragraphs 5 and 6 for events and circumstances occurring after the effective date of our reports.
9. Because the reserves data and contingent resources data are based on judgements regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, January 29, 2016

“Originally Signed by”
 Caralyn P. Bennett, P. Eng.
 Vice President, Corporate Strategy

APPENDIX B – FORM 51-101F3

REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

Management of MEG Energy Corp. (the "Corporation") are responsible for the preparation and disclosure of information with respect to the Corporation's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data and includes, if disclosed in the statement required by item 1 of section 2.1 of NI 51-101, other information such as contingent resources data.

An independent qualified reserves evaluator has evaluated the Corporation's reserves data and contingent resources data. The report of the independent qualified reserves evaluator is presented in Appendix A to this Annual Information Form.

The board of directors of the Corporation has:

- (a) reviewed the Corporation's procedures for providing information to the independent qualified reserves evaluator;
- (b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and
- (c) reviewed the reserves data and contingent resources data with management and the independent qualified reserves evaluator.

The board of directors has reviewed the Corporation's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has approved:

- (a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and contingent resources data and other oil and gas information;
- (b) the filing of Form 51-101F2 which are the reports of the independent qualified reserves evaluator on the reserves data and contingent resources data; and
- (c) the content and filing of this report.

Because the reserves and resources data are based on judgments regarding future events, actual results will vary and the variations may be material.

(signed) "*William McCaffrey*"
William McCaffrey
President and Chief Executive Officer

(signed) "*Jeffrey J. McCaig*"
Jeffrey J. McCaig
Director

(signed) "*Eric L. Toews*"
Eric L. Toews
Chief Financial Officer

(signed) "*James D. McFarland*"
James D. McFarland
Director

March 3, 2016

APPENDIX C

AUDIT COMMITTEE CHARTER

1. Mandate

The mandate of the audit committee (the "Committee") of MEG Energy Corp. (the "Corporation") is to assist the board of directors (the "Board") in fulfilling its stewardship with respect to

- (a) the Corporation's financial statements, management's discussion and analysis, and accounting and financial reporting practices,
- (b) the relationship with and assessment of the performance of the Corporation's external auditor, and
- (c) the adequacy and effectiveness of the Corporation's disclosure controls and procedures and internal control over financial reporting.

2. Membership

The Committee shall consist of at least three directors as determined by the Board. Each member shall be an independent director, as defined in the Corporation's Board of Directors Mandate, and at least 25 percent of the members shall be Canadian residents. Members shall be appointed from time to time at the pleasure of the Board. A member of the Committee shall cease to be a member of the Committee upon ceasing to be a director of the Corporation. The Board shall appoint the chair (the "Chair") of the Committee annually from among the members of the Committee. If in any year the Board does not appoint a Chair, the incumbent Chair shall continue in office until the Board appoints another person as Chair.

All members of the Committee shall be financially literate. At the date of adoption of this charter, a member is financially literate if he or she has the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of the issues that can reasonably be expected to be raised by the Corporation's financial statements.

3. Duties and Responsibilities

3.1 External Auditor

The duties and responsibilities of the Committee as they relate to the external auditor shall be as follows.

- (a) Recommend to the Board the external auditor to be nominated for appointment by the shareholders for the purpose of preparing or issuing an auditor's report or performing other audit, review or attest services for the Corporation.
- (b) Determine the compensation of the external auditor.
- (c) Review the independence and performance of the external auditor, and recommend the discharge of the external auditor when circumstances warrant.
- (d) Oversee the work of the external auditor, including the resolution of disagreements between management and the external auditor regarding financial reporting.

- (e) Review and approve the audit plan of the external auditor.
- (f) Review and discuss with the external auditor all significant relationships that the external auditor and its affiliates have with the Corporation and its affiliates in order to assess the external auditor's independence, including requesting, receiving and reviewing, on at least an annual basis, a formal written statement from the external auditor delineating all relationships that may reasonably be thought to affect the independence of the external auditor.
- (g) Pre-approve all non-audit services to be provided to the Corporation or its subsidiary entities by the external auditor, provided that the Committee may satisfy the pre-approval requirement either by delegating to one or more members of the Committee the authority to pre-approve non-audit services or by adopting specific policies and procedures for the engagement of non-audit services.
- (h) Review and approve hiring policies of the Corporation regarding present and former partners and employees of the present or former external auditor.

The external auditor shall report directly to the Committee but is ultimately accountable to the Board, which has the ultimate authority and responsibility to select, evaluate and, where appropriate, replace the external auditor (or to nominate the external auditor to be appointed by the shareholders of the Corporation).

3.2 Financial Statements

The duties and responsibilities of the Committee as they relate to the financial statements shall be as follows.

- (a) Review with management and the external auditor, and recommend to the Board for approval, the annual financial statements of the Corporation and related management's discussion and analysis and annual earnings press releases.
- (b) Review with the external auditor the results of the audit, including giving consideration to
 - (i) the contents of the audit report, including
 - (A) critical accounting policies and practices used,
 - (B) alternative treatments of financial information within generally accepted accounting principles that have been discussed with management, ramifications of the use of such treatments, and the treatment preferred by the external auditor, and
 - (C) other material written communications between the external auditor and management;
 - (ii) the scope and quality of the audit work performed;
 - (iii) the adequacy of the Corporation's accounting personnel;
 - (iv) the internal resources used;
 - (v) significant transactions outside of the normal business of the Corporation;
 - (vi) significant proposed adjustments and recommendations for improving internal accounting controls, accounting principles or management systems;
 - (vii) non-audit services provided by the external auditor;
 - (viii) the external auditor's judgments about the quality and appropriateness of the Corporation's accounting principles and critical accounting estimates as applied in its financial reporting; and

- (ix) disagreements, if any, with management;
- (c) Review information for which the Committee is responsible which may be contained within the Corporation's annual management information circular, annual information form or any prospectus.
- (d) Review with management and the external auditor and approve the interim financial statements of the Corporation and related management's discussion and analysis and interim earnings press releases.
- (e) Regularly review with management, the financial commitments of the Corporation.
- (f) Review with management, the external auditor and, if necessary, legal counsel any litigation, claim or other contingency, including tax assessments that could have a material effect upon the financial position or operating results of the Corporation, and the manner in which such matters have been disclosed in the financial statements.
- (g) Confirm that adequate procedures are in place for the review of the Corporation's disclosure of financial information extracted or derived from the Corporation's financial statements and periodically assess the adequacy of those procedures.
- (h) Confirm that adequate procedures are in place for
 - (i) the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal accounting controls, auditing and other matters, and
 - (ii) the confidential, anonymous submission of concerns regarding questionable accounting, auditing or other matters.

3.3 Internal Control

The duties and responsibilities of the Committee as they relate to the internal control procedures of the Corporation shall be as follows.

- (a) Review with management and the external auditor the adequacy and effectiveness of the internal control and management information systems and procedures of the Corporation, with particular attention given to accounting, financial statement and financial reporting matters.
- (b) Review the external auditor's recommendations regarding any matters, including internal control and management information systems and procedures.

4. Administrative Matters

The following general provisions shall have application to the Committee.

- (a) The Committee shall meet at least four times annually or more frequently as circumstances may require.
- (b) A majority of members of the Committee shall constitute a quorum, and no business may be transacted by the Committee except
 - (i) at a meeting of its members at which a quorum of the Committee is present in person or by telephone or other communication device that permits all persons participating in the meeting to speak and hear each other, or

- (ii) by a resolution in writing signed by all the members of the Committee.
- (c) Any member of the Committee may be removed or replaced at any time by the Board and the Board may fill vacancies on the Committee.
- (d) The Committee may invite such advisers and directors, officers and employees of the Corporation as it may see fit from time to time to attend at meetings of the Committee and assist thereat in the discussion and consideration of the matters being considered by the Committee.
- (e) The time and place at which the meetings of the Committee shall be held and the calling of meetings and the procedure in all respects at such meetings shall be determined by the Committee, unless otherwise determined by the by-laws of the Corporation or by resolution of the Board.
- (f) The Chair shall preside at all meetings of the Committee and in the absence of the Chair the members of the Committee present at a meeting shall appoint one of those present members to act as chair of the meeting.
- (g) The Committee shall have the authority to
 - (i) conduct investigations and engage independent counsel and other advisers or consultants as it determines necessary to carry out its duties,
 - (ii) set and require the Corporation to pay the compensation for any advisers engaged by the Committee, and
 - (iii) communicate directly with the external auditor and the Corporation's other financial advisers to the extent necessary to carry out the Committee's duties.
- (h) The Committee shall report to the Board on such matters and questions relating to the financial statements and financial reporting of the Corporation as the Board may from time to time refer to the Committee.
- (i) The members of the Committee shall, for the purpose of performing their duties, have the right to inspect all the books and records of the Corporation and its subsidiaries and to discuss such books and records as are in any way related to the financial statements and financial reporting of the Corporation with the officers and employees of the Corporation and its subsidiaries.
- (j) The Committee shall review and reassess the adequacy of this charter on an annual basis and recommend any proposed changes to the Board for approval.
- (k) The Chair of the Committee shall report on the Committee's activities at each regularly scheduled meeting of the Board.
- (l) At each meeting of the Committee, the independent directors shall have a meeting in the absence of non-independent directors and members of management.
- (m) At each meeting of the Committee, the independent directors shall have a meeting with the external auditors, in the absence of non-independent directors and members of management
- (n) Minutes of the Committee will be recorded and maintained and, upon request, will be promptly circulated to the directors who are not members of the Committee or, if that is not practicable, shall be made available at the next meeting of the Board.

COMPOSITION OF THE AUDIT COMMITTEE

As of the date of this Annual Information Form, the members of the Audit Committee are Messrs. Hodgins (Chair), Anderson and Doerr. The Board has determined that each member of the Audit Committee is independent and financially literate within the meaning of NI 52-110.

Relevant Education and Experience

The education and experience of each Audit Committee member that is relevant to the performance of his or her responsibilities as an Audit Committee member is as follows:

- Mr. Hodgins has been an independent businessman since November 2004 and is currently a director of several public companies. From 2002 to 2004 Mr. Hodgins served as the Chief Financial Officer of Pengrowth Energy Trust (now Pengrowth Energy Corporation), a TSX and NYSE-listed energy trust. Prior to that, Mr. Hodgins held the position of Vice President and Treasurer of Canadian Pacific Limited (a diversified energy, transportation and hotels company) from 1998 to 2002 and was Chief Financial Officer of TransCanada Pipeline Limited (a TSX and NYSE-listed energy transportation company) from 1993 to 1998. Mr. Hodgins received a Bachelor of Arts in Business from the Richard Ivey School of Business at the University of Western Ontario in 1975 and received a Chartered Accountant designation and was admitted as a member of the Institute of Chartered Accountants of Ontario in 1977 and Alberta in 1991.
- Mr. Anderson is the former Vice President Natural Gas Liquids for BP North America Inc. He is also a former director of Amoco Canada Petroleum Company. Mr. Anderson received a Bachelor of Engineering - Chemical from McGill University in 1968, a Certificate of Post-Graduate Study in Chemical Engineering from the University of Cambridge in 1969, a Master of Business Administration from McMaster University in 1974 and received the designation of Professional Engineer in 1974.
- Mr. Doerr is the former Executive Vice President, Downstream and Planning, Murphy Oil Corporation. Mr. Doerr has been involved in the oil and gas industry since 1981. He held various roles with Murphy Oil Corporation between 1989 and 2009, including that of Executive Vice President, Downstream and Planning from January of 2007 until August of 2009 and President, Murphy Oil Company Ltd. (Canada) from August 1997 until December of 2006. Mr. Doerr currently serves as Chairman of Velvet Energy Ltd., a private Canadian oil and gas company and serves as director of Newalta Corporation. Mr. Doerr received a Bachelor of Science (Mechanical Engineering) from the University of Alberta in 1981, completed the Advanced Management Program at Harvard Business School in 2004 and received the designation of Professional Engineer in 1985. In 2011, Mr. Doerr obtained a certified designation (ICD.D) from the Institute of Corporate Directors.

Pre-Approval Policies and Procedures

The Audit Committee and the Board have adopted a policy for approval of external auditor services. The policy prohibits the external auditor from providing specified services to the Corporation and its subsidiaries.

The engagement of the external auditor for a range of services defined in the policy has been pre-approved by the Audit Committee. If an engagement of the external auditor is contemplated for a particular service that is neither prohibited nor covered under the range of pre-approved services, such engagement must be pre-approved. The Audit Committee has delegated the authority to grant such pre-approval to the Chairman of the Audit Committee.

Services provided by the external auditor are subject to an engagement letter. The policy requires that the Audit Committee receive regular reports of all new pre-approved engagements of the external auditor.

External Auditor Service Fees

The aggregate fees billed by the Corporation's external auditor in each of the last two fiscal years were as follows:

	<u>2014</u>	<u>2015</u>
Audit Fees	\$ 395,823	\$ 321,563
Audit Related Fees ⁽¹⁾	\$ 209,440	\$ 164,581
Tax Fees ⁽²⁾	\$ 142,439	\$ 69,907
All Other Fees ⁽³⁾	\$ 10,510	\$ 2,950
Total	\$ 758,212	\$ 559,001

Notes:

- (1) Fees for assurance and related services by PricewaterhouseCoopers LLP in connection with their review of the Corporation's financial statements and not otherwise reported under "Audit Fees".
- (2) Fees for tax compliance and tax advice.
- (3) EHS document review and software license fee.

APPENDIX D

CONTINGENT RESOURCES

Contingent Resources Estimates

The Corporation engaged GLJ to prepare the GLJ Report, which includes an evaluation of the Corporation's contingent resources. Specifically, GLJ evaluated certain of the Corporation's 100% working interest assets at the Christina Lake Project, the Surmont Project, the May River Regional Project and the Growth Properties. All of the Corporation's properties are located in the Province of Alberta and are described elsewhere in this Annual Information Form. See "Projects Overview". The disclosure of GLJ's evaluation of the Corporation's contingent resources has been placed in this Appendix D and modified from prior disclosure in order to comply with recent amendments to NI 51-101.

GLJ is a private Canadian company established in 1972 which provides independent engineering and geological consulting services to the petroleum industry. GLJ's services include economic evaluations, technical studies, advice and opinions. GLJ carried out its evaluations in accordance with standards established by the Canadian Securities Administrators in NI 51-101. Those standards require that the reserves and contingent resources data be prepared in accordance with the COGE Handbook. GLJ's responsibility is to express opinions on the reserves and contingent resources data including the associated net present values based on its evaluations. The preparation and disclosure of the reported reserves and contingent resources estimates are the responsibility of the Corporation's management.

GLJ's "Report on Reserves Data and Contingent Resource Data by Independent Qualified Reserves Evaluator or Auditor" in the form of Form 51-101F2 is set forth in Appendix A to this Annual Information Form. The Corporation's "Report of Management and Directors on Oil and Gas Disclosure" in the form of Form 51-101F3 is set forth in Appendix B to this Annual Information Form. The contingencies preventing classification of contingent resources as reserves may generally be described as technical, economic and/or other non-technical. A technical contingency would exist if the development plan involves the use of "technology under development" as opposed to "established technology". Technology under development is defined as technology developed and verified by testing as feasible for future commercial applications to the subject reservoir whereas established technology is defined as technology that has been proven to be successful in commercial applications in the reservoir of interest or in a reservoir that is a good analogy. All of MEG's properties evaluated by GLJ are to be developed using established technology, namely, the application of SAGD technology in sandstone reservoirs analogous to multiple successful commercial developments within the Athabasca oil sands region. There are therefore no technical contingencies preventing the future classification of these volumes as reserves. See "Projects Overview" for a description of the Christina Lake, Surmont and May River Regional Projects.

The contingent resources were evaluated by GLJ using the same fiscal conditions applicable in the evaluation of reserves and all of the evaluated properties exhibited positive net present values at a discount rate of ten percent. As such, the contingent resources for such properties are considered to be economically recoverable. As a result, all remaining contingencies preventing such contingent resources from being classified as reserves are "non-technical contingencies" which under the COGE handbook include contingencies such as legal, environmental, political and regulatory matters and are directly related to the stage of development or project evaluation scenario status. Such contingent resources may be re-classified as reserves pending further delineation, facility and project design, the initiation of regulatory applications and receipt of regulatory approvals (in the case of lands associated with the May River Regional Project and the Growth Properties), the preparation of timely development plans and MEG's corporate commitment to proceed.

Quantities of contingent resources may be estimated using low estimate (high certainty), best estimate (most likely) and high estimate (low certainty) cases. MEG reports its contingent resources using the best estimate case. The best

estimate case is considered to be the best estimate of the quantity of contingent resources that would actually be recovered. It is equally likely that the actual remaining quantities recovered would be greater than or less than the best estimate. There is a 50% probability that the actual quantities recovered would equal or exceed the best estimate.

The contingent resources estimates described herein are estimates only and the actual quantities of recoverable bitumen may be greater or less than those estimated. The estimated future net revenues contained in the following tables do not necessarily represent the fair market value of the Corporation's contingent resources. Estimates of contingent resources involve additional risks over estimates of reserves. There is uncertainty that it will be commercially viable to produce any portion of the contingent resources. All evaluations of future revenue are after the deduction of royalties, development costs, production costs and well abandonment costs but before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses. There is no assurance that the forecast price and cost assumptions contained in the GLJ Report will be realized and variances could be material. Other assumptions and qualifications relating to project schedules, costs and other matters are inherent in these estimates. See "Notice Regarding Forward Looking Information" and "Risk Factors".

Aggregated Contingent Resources Estimates

The following tables set forth arithmetic sums of the risked contingent resources (best estimate) contained in the GLJ Report with respect to the Christina Lake Project, the Surmont Project and the May River Regional Project. The evaluation procedures employed by GLJ are based on GLJ's January 1, 2016 pricing models. See "GLJ Price Forecast" under the heading "Independent Reserves Evaluation". The following tables do not include the proved and probable reserves volumes and values that have been assigned by GLJ to the Christina Lake Project and the Surmont Project. See "Reserves Estimates".

**SUMMARY OF RISKED OIL AND GAS CONTINGENT RESOURCES
as of December 31, 2015
FORECAST PRICES AND COSTS**

Resources Project Maturity Sub-Class	Contingent Resources – Best Estimate ⁽¹⁾⁽²⁾⁽³⁾	
	Bitumen	
	Gross (Mbbbl)	Net (Mbbbl)
CONTINGENT (2C) Development Pending.....	1,782	1,326
CONTINGENT (2C) Development Unclarified ⁽⁴⁾	751	587

Notes:

- (1) "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. Contingencies may include factors such as economic, legal, environmental political, and regulatory matters, or a lack of markets. 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. For a description of the contingencies that must be met in order for MEG's contingent resources to be classified as reserves, see "Reserves and Resources Classification".
- (2) "Best Estimate" is a classification of estimated resources described in the 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.
- (3) There is no certainty that it will be commercially viable to produce any portion of the contingent resources.
- (4) Volumes of Contingent Resource, Development Unclarified are in respect of the May River Regional Project only. Contingent Resource, Development Unclarified associated with the Growth Properties has not been included. Resource definition and data

gathering is ongoing for the Growth Properties. The Corporation expects to provide additional information relating to the Growth Properties once the projects advance to a higher stage of development. On an unrisks basis, there has been no material change between the contingent resources assigned to the Corporation's properties in 2014 GLJ Report and the 2015 GLJ Report.

**SUMMARY OF RISKED NET PRESENT VALUE OF FUTURE NET REVENUE⁽¹⁾
(CONTINGENT RESOURCES – Best Estimate) as of December 31, 2015
FORECAST PRICES AND COSTS**

An estimate of risked net present value of future net revenue of contingent resources is preliminary in nature and is provided to assist the reader in reaching an opinion on the merit and likelihood of the Corporation proceeding with the required investment. It includes contingent resources that are considered too uncertain with respect to the chance of development to be classified as reserves. There is uncertainty that the risked net present value of future net revenue will be realized.

Resources Project Maturity Sub-Class	Risked Net Present Value of Future Net Revenue (Bitumen)									
	Before Income Taxes Discounted at (%/Year)					After Income Taxes Discounted at (%/Year)				
	0 (MM\$)	5 (MM\$)	10 (MM\$)	15 (MM\$)	20 (MM\$)	0 (MM\$)	5 (MM\$)	10 (MM\$)	15 (MM\$)	20 (MM\$)
CONTINGENT (2C) Development Pending.....	68,135	21,356	7,604	2,816	927	39,563	9,347	1,576	-700	-1,370
CONTINGENT (2C) Development Unclassified.....	23,646	6,926	2,145	646	149	20,124	5,689	1,677	458	70

Project maturity subclasses are sub-classifications of contingent resources which help identify a project's chance of commerciality. Project maturity subclasses (in order of increasing chance of commerciality) are 'development not viable', 'development unclassified', 'development on hold' and 'development pending'. Characteristics of the 'development pending' and 'development unclassified' subclasses are as follows:

- Development Pending: resolution of the final conditions for development is being actively pursued, indicating there is a high chance of development.
- Development Unclassified: the evaluation is incomplete and there is ongoing activity to resolve any risks or uncertainties.

The contingent resources have been risked for the chance of commerciality (CoC) which is equal to the 'chance of development' multiplied by the 'chance of discovery'. The 'chance of discovery' in respect of contingent resources is equal to 1, and therefore the CoC for contingent resources is equal to the 'chance of development'. The method of quantifying the chance of development is set out in the COGEH Hand Book Volume 2, Section 2.

MEG's contingent resources classified as 'development pending' are located at the Christina Lake Project, the Surmont Project and the May River Regional Project area. MEG's contingent resources classified as 'development unclassified' are located primarily in the May River Regional Project area. The following table summarizes the risked best estimate contingent resources for the Christina Lake, Surmont and May River projects:

Project	Project Maturity Subclass	Project Evaluation Scenario Status	Riskd Best Estimate Contingent Resource Gross (MMbbl)	Project C.O.C. (Chance of Commerciality)	Estimated Capital to Reach First Commercial Production (MM\$)⁽¹⁾	Timing of First Commercial Production⁽¹⁾
Christina Lake	Development Pending	Development Study	1,014	95%	\$2,206	2022
Surmont	Development Pending	Development Study	334	93%	\$403	2022
May River Regional Project	Development Pending	Pre-Development Study	434	93%	\$2,174	2023
	Development Unclassified	Pre-Development Study	751	78%	\$2,242	2026

Note:

(1) The estimates of capital and timing to reach first commercial production are prepared by GLJ and are based on variable factors and assumptions and are subject to numerous risks and uncertainties associated with the recovery of such resources, including many factors beyond the Corporation's control. Actual results may vary significantly from these estimates and such variances could be material. The Corporation expects that the commodity price environment will continue to influence the development of MEG's business in 2016. See "Risk Factors".

The contingent resources are evaluated based on the same fiscal conditions used in the assessment of reserves, and as such, are forecasted to be economic. Contingent resource values are estimated on the basis of established technology, namely the application of SAGD technology in sandstone reservoirs with numerous commercially successful analogues. On an unrisked basis, there has been no material change between the contingent resources assigned to the Corporation's properties in 2014 GLJ Report and the 2015 GLJ Report.

MEG's decision to proceed with each project development is dependent upon numerous factors (see "Risk Factors – Risk Relating to the Corporation's Business" and "Projects Overview"). Project timing and execution is dependent on, among other things, the availability of capital and of MEG's future strategic decisions to optimize capital utilization. The Corporation believes the high rates of return exhibited by these projects based on forecast pricing, even in the current commodity price environment, makes these projects attractive from an investment perspective. The Corporation believes its low operating and capital cost make it more likely that these projects will be developed when compared to relatively higher cost third party project alternatives.

Specific risks and contingencies by project are listed below for the Christina Lake Project, the Surmont Project and the May River Regional Project.

Christina Lake Project

Contingent resources have been assessed to lands within the Christina Lake project area which have not otherwise been assigned reserves. These lands are in close proximity to existing production facilities at Christina Lake.

The project maturity subclass is 'development pending' based on the established technology status, economic status,

project evaluation scenario status and the reasonable timeframe for development. Chance of commerciality is estimated by GLJ to be 95%. The Corporation expects that development of contingent resources within Christina Lake will advance sequentially following development of the reserves projects.

Contingencies preventing the contingent resources from being classified as reserves include: (i) additional delineation; (ii) routine application and approval for facility expansion to capture these additional recoverable volumes within the existing project approval area; (iii) firm development plans and company commitment including confirmation of corporate intent to proceed with the defined expansion plans; and (iv) final project design and sanctioning.

Surmont Project

Contingent resources have been assessed to lands within the Surmont project area which have not otherwise been assigned proved or probable reserves. On September 13, 2012 MEG filed regulatory applications with the ERCB and ESRD for the Surmont Project. As a normal part of the regulatory review process, the Company received SIRs from the AER and ESRD in July 2013, March 2014 and October 2014. MEG responded to the SIRs in October 2013, June 2014 and October 2014. In November 2014, the EIA report for the Surmont Project was deemed technically complete by ESRD and the EIA report was referred to the AER. In accordance with AER requirements, MEG is actively working with stakeholders to address concerns raised on the Surmont Project. MEG has addressed all material technical concerns and does not anticipate further material impediments to the receipt of regulatory approval for the Surmont project.

The project maturity subclass is development pending based on the established technology status, economic status, project evaluation scenario status and the reasonable timeframe for development. Chance of commerciality is estimated by GLJ to be 93%. The development of contingent resources within Surmont will advance as a follow up to the development of the reserves projects, in natural progression.

Contingencies preventing the contingent resources from being classified as reserves include: (i) additional delineation; (ii) routine application and approval for facility expansion to capture these additional recoverable volumes within the applied for project approval area; (iii) firm development plans and company commitment including confirmation of corporate intent to proceed with the defined expansion plans; and (iv) final project design and sanctioning.

May River Regional Project

Contingent resources have been assessed for lands that have been delineated sufficiently to allow for development planning. MEG anticipates filing a regulatory application for the May River Regional Project in 2016.

Based on established technology status, economic status, project evaluation scenario status and the timeframe for development in MEG's long-range plans, the initial development is categorized in the 'development pending' project maturity sub-class of contingent resources and the subsequent development is categorized in the 'development unclarified' project maturity sub-class of contingent resources. Chance of commerciality is estimated by GLJ to be 93% for the 'development pending' and to be 78% for the 'development unclarified' portions of the contingent resources. The principal reason for distinguishing the 'development unclarified' contingent resources from the 'development pending' contingent resources is the longer timeframe for development. Data gathering has been completed to the degree necessary for development planning for both the initial development and subsequent developments.

Contingencies preventing the contingent resources from being classified as reserves include: (i) project area regulatory application submission and approval; (ii) additional delineation; (iii) firm development plans and company commitment including the confirmation of corporate intent to proceed with the defined development plans; and (iv) final project design and sanctioning.