CREATING SUSTAINABLE

# VALUE

*Building on our **Strong Foundation***

**2019**
**March 7**

***Annual Information Form***

**MEG ENERGY**

*For the period ended December 31, 2018*

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# NOTICE REGARDING FORWARD LOOKING INFORMATION

Certain statements contained in this Annual Information Form may contain forward-looking statements and forward looking information (collectively, "forward-looking information") within the meaning of applicable securities laws. Forward-looking information is frequently characterized by words such as "plan", "expect", "project", "intend", "believe", "anticipate", "estimate", "target", "scheduled", "potential", or other similar words, or statements that certain events or conditions "may", "should", "might" or "could" occur. 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. Statements relating to “reserves” and “resources” are deemed to be forward looking information, 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 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, uncertainties related to commodity price, interest rate and foreign exchange rate swap contracts and/or derivative financial instruments that the Corporation may enter into from time to time to manage its risk related to 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 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 laws. 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 meanings 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 design 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 and value of the Corporation's proved reserves, probable reserves and contingent resources;
- the Corporation's projections of commodity prices, price differentials, 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 phases, including anticipated production levels from the Corporation’s existing producing properties and its planned developments;
- 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 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, price differentials, 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, production curtailments 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 results;
- 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;
- sufficiency of funds;
- fluctuations in market prices for crude oil, bitumen blend, price differentials, natural gas and electricity;
- general economic, market and business conditions;
- volatility of commodity inputs;
- variations in foreign exchange rates and interest rates;
- hedging strategies;
- national or global financial crises;
- environmental risks and hazards and the cost of compliance with environmental legislation and regulations, including GHG regulations, potential climate change legislation and potential land use regulations,
- IMO 2020 and the associated potential impact to pricing differentials;
- 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;
- the 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;
- risks associated with downgrades in the credit ratings for the Corporation's securities;
- cybersecurity errors, omissions or failures;
- restrictions contained in the Credit Facilities, the EDC Guaranteed L/C Facility and the indentures governing the Notes and any future indebtedness;

- any requirement to incur additional indebtedness;
- the Corporation defaulting on its obligations under its indebtedness;
- the inability of the Corporation to generate cash to service its indebtedness; and
- the other factors discussed under the heading "Risk Factors" in this Annual Information Form.

In addition, design 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 design 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, Phase 2 and Phase 2B of the Christina Lake Project, and the application of the Corporation's production enhancement program which uses a combination of proprietary reservoir technologies (including eMSAGP, as defined herein) and processing plant enhancements, debottlenecking and brownfield expansions, 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.

The foregoing list of risks, uncertainties and factors is not exhaustive. The effect of any one risk, uncertainty or factor on particular forward-looking information is uncertain because these factors are independent, and management's future course of action would depend on an assessment of all available information at that time. Based on information available to the Corporation on the date of this Annual Information Form, management believes that the expectations in the forward-looking information are reasonable. However, the Corporation gives no assurances as to future results, levels of activity or achievements.

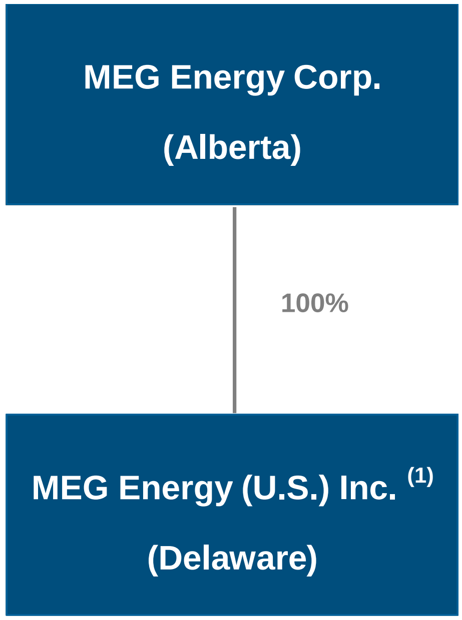
This cautionary statement qualifies all forward-looking information contained in this Annual Information Form.

# THE CORPORATION

## Incorporation and Organization

The Corporation was incorporated on March 9, 1999 under the ABCA. The Corporation's head office is located at 25th Floor, 600 – 3rd Avenue S.W., Calgary, Alberta, Canada T2P 0G5 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.* MEG US is the corporate vehicle used for the Corporation's marketing-related activities in the United States. The following organizational chart illustrates the current intercorporate relationship of the Corporation and MEG US.




**Notes:**

(1) MEG US is a guarantor under the Notes and the Credit Facilities.

## Three Year Development

**2016**

As a result of the sustained weakness in the global commodity price environment, the Corporation continued to focus on reducing capital spending and further lowering operating and non-operating costs. This strategy allowed the Corporation to increase and maintain production more efficiently and at lower capital intensity.

During the second half of 2016, the Corporation commenced testing of its proprietary recovery process known as enhanced modified vapour extraction ("eMVAPEX") at the Christina Lake Project. eMVAPEX involves the targeted injection of light hydrocarbons in replacement of steam.

During 2016, the Corporation implemented a strategic commodity risk management program to partially manage its exposure on blend sales prices and condensate purchases with the intent to increase the predictability of the Corporation's future cash flow.

**2017**

On January 24, 2017, the Corporation closed a public offering on a bought deal basis (the "Subscription Receipt Offering") of 66,815,000 subscription receipts (the "Subscription Receipts") at a price of $7.75 per Subscription Receipt for aggregate gross proceeds from the Subscription Receipt Offering of approximately $517.8 million.

On January 27, 2017, the Corporation closed a comprehensive refinancing plan, comprised of the following four transactions:

- The maturity date on substantially all of the commitments under the Corporation's covenant-lite revolving credit facility was extended to November 2021. The commitment amount of the five year facility is US$1.4 billion, and such facility has no financial covenants and is not subject to any borrowing base redetermination.
- MEG's US$1.2 billion term loan was successfully refinanced to extend its maturity from March 2020 to December 2023. The refinanced term loan bears interest at an annual rate of LIBOR + 3.50% with a LIBOR floor of 1%. The term loan was issued at a price equal to 99.75% of its face value.

- The 2011 Notes were successfully refinanced and extended with US$750 million in aggregate principal amount of 6.50% senior secured second lien notes due January 2025 (“Second Lien Notes”). Interest on the Second Lien Notes is payable on January 15 and July 15 of each year. The Second Lien Notes will mature on January 15, 2025. The 2011 Notes were redeemed with the proceeds from the Second Lien Notes on March 15, 2017.
- The Subscription Receipts converted into 66,815,000 Common Shares.

In addition to the transactions noted above, on February 15, 2017, the Corporation extended the maturity date on the Corporation’s guaranteed letter of credit facility, guaranteed by Export Development Canada, to November 2021 from November 2019. The guaranteed letter of credit facility was reduced from US$500 million to US$440 million.

Commencing in the first quarter of 2017, and continuing throughout the year, MEG initiated the expansion of its enhanced Modified Steam and Gas Push ("eMSAGP”) technology to Phase 2B of the Christina Lake Project. Bitumen production at the Christina Lake Project averaged 90,228 bbls/d for the three months ended December 31, 2017 compared to 81,780 bbls/d for the three months ended December 31, 2016. The increase in production volumes for the three months ended December 31, 2017 is primarily due to the efficiency gains achieved through the continued implementation of eMSAGP. The implementation of eMSAGP improved reservoir efficiency and allowed for the redeployment of steam, thereby enabling MEG to place additional wells into production. Annual production for 2017 averaged 80,774 bbls/d.

During 2017, MEG continued testing eMVAPEX at the Christina Lake Project. Results demonstrated the effectiveness of propane injection, with a small amount of steam to vapourize the propane. Sufficient data was collected to justify expanding the experimental scheme during the second half of 2017.

**2018**

On March 22, 2018 the Corporation announced that it had successfully closed its sale of the Corporation’s 50% interest in the Access Pipeline and its 100% interest in the Stonefell Terminal for cash proceeds of C$1.52 billion and other consideration of C$90 million. As part of the transaction, MEG entered into a Transportation Services Agreement (“TSA”) dedicating MEG’s Christina Lake production and condensate transport to Access Pipeline for an initial term of 30 years. The transaction also includes a Stonefell Lease Agreement which is a 30-year arrangement that secures MEG operational control and exclusive use of 100% of Stonefell Terminal’s 900,000 barrel blend and condensate storage facility.

On April 23, 2018 the Corporation announced the retirement of Bill McCaffrey from his role as President & Chief Executive Officer as well as from the Board of Directors following the Corporation’s Annual General Meeting. Harvey Doerr, a member of the Corporation’s Board of Directors acted as interim CEO until Derek Evans was appointed to the position of President and Chief Executive Officer on August 10, 2018.

The implementation of eMSAGP continued on Phase 2B during 2018 with capital investment substantially completed during the year. During 2018, the Corporation continued further eMVAPEX pilot testing at the Christina Lake Project.

On October 2, 2018, Husky Energy Inc. made an unsolicited offer to acquire all of the issued and outstanding common shares of the Corporation at the election of each of the Corporation’s shareholders, for (i) $11.00 in cash or (ii) 0.485 of a common share of Husky for each of the Corporation’s common share, subject to a maximum aggregate cash consideration of $1 billion and a maximum aggregate number of Husky Shares of approximately 107 million. The Husky offer remained open until January 16, 2019.

In the fourth quarter of 2018, MEG executed a binding agreement to access 30,000 bbls/d of rail loading capacity at a pipeline connected crude-by-rail transloading terminal, operated by Bruderheim Energy Terminal Ltd., a wholly-owned subsidiary of Cenovus (the “Bruderheim Terminal”). This three-year agreement, with a one-year extension at MEG’s option, balances both free-on-board rail sales and delivered rail sales dependent on customer needs, asset availability and market conditions.

In 2018, the Corporation produced an average of 87,731 bbls/d of bitumen from Christina Lake compared to 80,774 bbls/d in 2017. See "Projects Overview" and "Marketing 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 uses multiple facilities to transport and sell AWB to refiners throughout North America and beyond.

MEG owns a 100% working interest in over 900 square miles of oil sands leases. In the GLJ Report, dated effective December 31, 2018 with a preparation date of January 11, 2019, GLJ Petroleum Consultants Ltd. ("GLJ") estimated that the oil sands leases it had evaluated contained 2.8 billion barrels of proved plus probable bitumen reserves. Appendix D to this Annual Information Form contains information relating to GLJ's estimates of MEG's economic bitumen contingent resources. See Appendix D for further information.

The Corporation has identified three commercial SAGD projects; the Christina Lake Project, the Surmont Project and the May River Regional Project. The Christina Lake Project has received regulatory approval for 210,000 bbls/d of production. MEG has applied for regulatory approval for approximately 120,000 bbls/d of production at the Surmont Project and anticipates receiving regulatory approval in 2019. On February 21, 2017, MEG filed regulatory applications with the AER for the May River Regional Project. Management anticipates, consistent with the estimates contained in the GLJ Report, that the May River Regional Project can support an average of 164,000 bbls/d of bitumen production.

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 "Growth Properties". The Growth Properties are in the resource definition and data gathering stage of development.

MEG has invested in three major projects at its Christina Lake Project, known as Phase 1, Phase 2 and Phase 2B. Phase 1 commenced production in 2008 with an initial bitumen production design capacity of approximately 3,000 bbls/d ("Phase 1"). Phase 2 commenced production in 2009 with an initial bitumen production design capacity of approximately 22,000 bbls/d and which utilized existing central processing facilities associated with Phase 1, and primarily expanded well pad drilling and tie-ins to increase production ("Phase 2"). Together, Phase 1 and Phase 2 had an initial bitumen production design capacity of approximately 25,000 bbls/d. Phase 2B commenced production in 2013 with an initial bitumen production design capacity of approximately 35,000 bbls/d ("Phase 2B"). The combined Phase 1, Phase 2 and Phase 2B initial bitumen production design capacity was approximately 60,000 bbls/d. Supported by proprietary reservoir technologies, MEG has been able to subsequently increase overall bitumen production in excess of 100,000 bbls/d through a series of low-cost debottlenecking and expansion projects and the redeployment of steam into new well pairs. 2018 bitumen production averaged 87,731 bbls/d. 2019 annual average production is expected to be in the range of 90,000 to 92,000 bbls/d, assuming the Alberta Government mandated production curtailment remains in place for 2019 with easing over the course of the year. If curtailments were not in place, MEG would have the ability to average approximately 100,000 bbls/d in 2019. See "Production Overview" on page 11 of this AIF for further information.

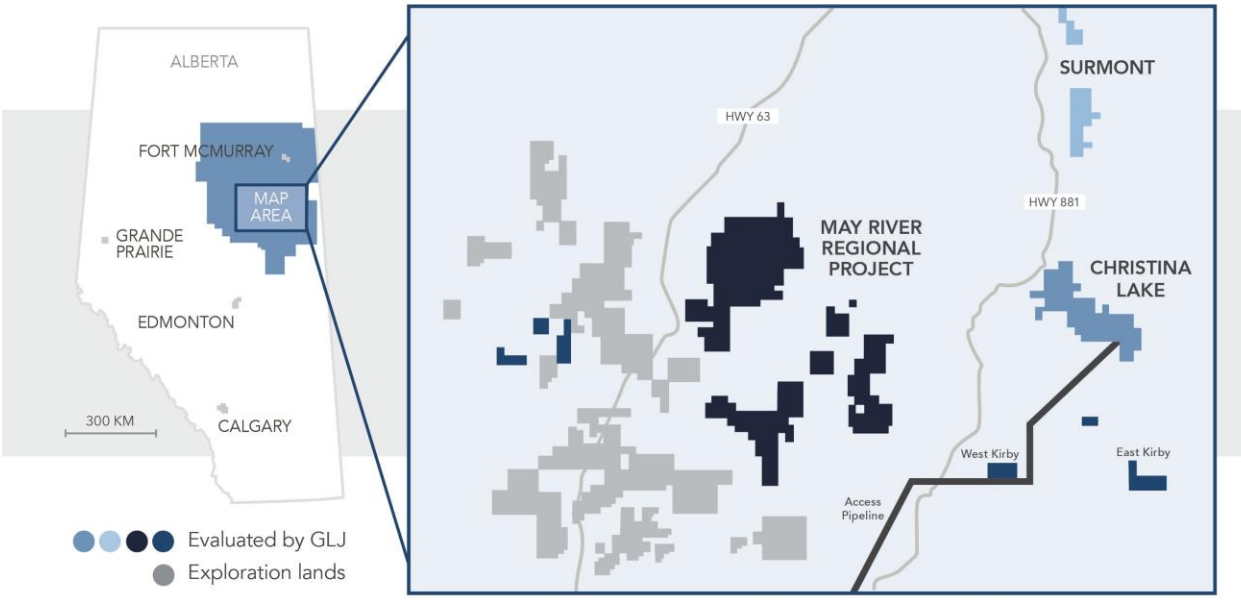
On March 22, 2018 the Corporation announced that it had successfully closed the sale of the Corporation's 50% interest in the Access Pipeline and its 100% interest in the Stonefell Terminal for cash proceeds of C$1.52 billion and other consideration of C$90 million. As part of the transaction, MEG entered into a Transportation Services Agreement ("TSA") dedicating MEG's Christina Lake production and condensate transport to Access Pipeline for an initial term of 30 years. The Access Pipeline is a dual pipeline system that connects the Christina Lake Project to a large regional upgrading, refining, diluent supply and transportation hub in Edmonton, Alberta area.

The transaction also includes a Stonefell Lease Agreement which is a 30-year arrangement that secures MEG operational control and exclusive use of 100% of Stonefell Terminal's 900,000 barrel blend and condensate storage facility. The Stonefell Terminal is connected to local and export markets by pipeline, in addition to being pipeline connected to the Bruderheim Terminal. This combination of facilities allows for the loading of bitumen blend for transport by rail. MEG has secured a 30,000 bbls/d loading commitment at the Bruderheim Terminal for 3 years, with a 1 year extension option.

MEG uses multiple facilities to transport and sell AWB to refiners throughout North America and beyond. MEG has contracted for 50,000 bbls/d (expanding to 100,000 bbls/d in 2020) of transportation capacity on the Flanagan South and Seaway pipeline systems providing pipeline transportation directly to U.S. Gulf Coast refineries. In addition, MEG is a shipper on the Trans Mountain Expansion Project which, when in service, will provide MEG with 20,000 bbls/d of committed tidewater access on Canada's West Coast. This combination of pipeline access, along with continuing options for rail and other transportation, advances MEG's strategy of having, long term, broadening and reliable market access to world oil prices for its production.

The following map highlights the locations of MEG's oil sands leases at the Christina Lake Project, the Surmont Project, the May River Regional Project, 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, 2018:

| **Asset** | **Proved Reserves (MMbbls)** | **Probable Reserves (MMbbls)** | **Proved plus Probable Before Tax PV-10% (MM$)** |
|---|---|---|---|
| Christina Lake Project | 1,368 | 731 | 17,259 |
| Surmont Project | - | 709 | 2,787 |
| May River Regional Project | - | - | - |
| **Total**(1) | 1,368 | 1,441 | 20,045 |

**Note:**
(1) Totals may not add due to rounding.

As of December 31, 2018, the Corporation employed 510 full time permanent employees, 4 part-time permanent employees and 23 independent contractors.

On March 22, 2018 the Corporation announced that it had successfully closed the sale of the Corporation's 50% interest in the Access Pipeline and its 100% interest in the Stonefell Terminal for cash proceeds of C$1.52 billion and other consideration of C$90 million. A portion of the net cash proceeds was used to repay approximately C$1.225 billion of MEG's senior secured term loan.

The implementation of the Corporation’s production enhancement technologies and specifically the deployment of eMSAGP has resulted in further reducing the Corporation’s per barrel total net operating costs and has strengthened the Corporation’s ability to deal with the ongoing volatility in crude oil prices. On-going investment in brownfield expansions, if sanctioned, would be expected to generate similar benefits.

The Corporation announced a 2019 base capital budget of $200 million, which sustains production capacity of 100,000 bbls/d. MEG’s capital budget includes an additional $75 million of discretionary capital, which can be sanctioned mid-2019 subject to market conditions to advance the Phase 2B brownfield expansion that would bring production capacity to 113,000 bbls/d.

## 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. Phase 1, Phase 2 and Phase 2B are all 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 its 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

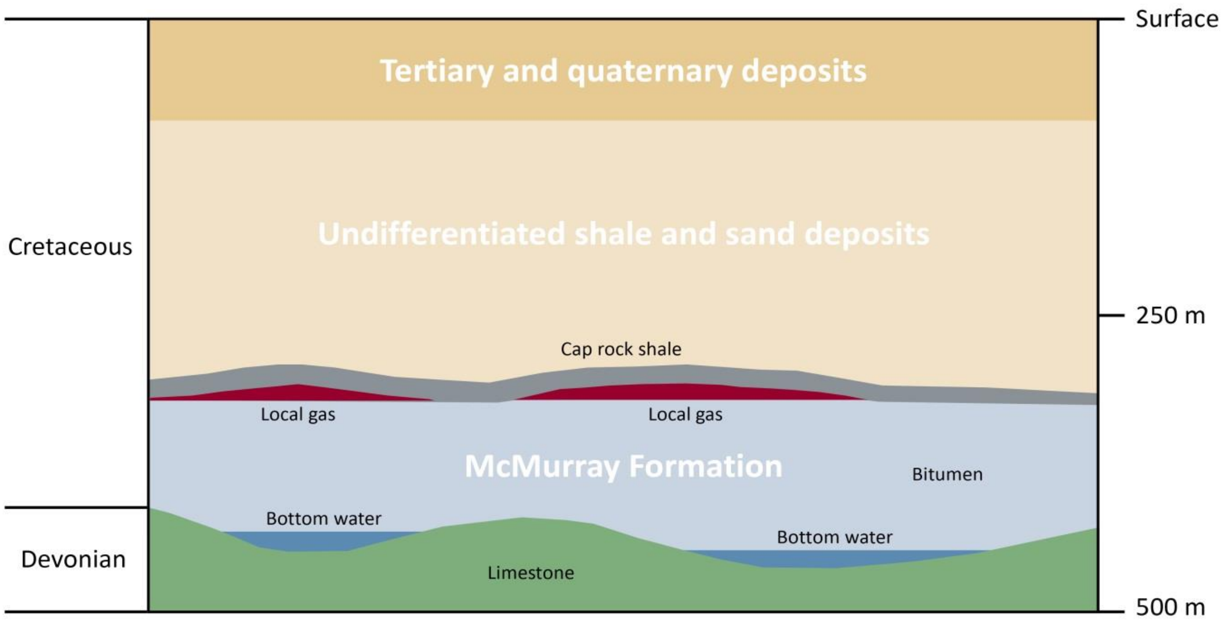
***GLJ Report***

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 Corporation’s production enhancement program which uses a combination of proprietary reservoir technologies (including eMSAGP) and processing plant enhancements, debottlenecking and brownfield expansions 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 Formation"). The McMurray Formation 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 Formation sands are variably saturated with water, bitumen and natural gas. Bitumen from the McMurray Formation has an average API gravity of approximately 8 degrees.

**McMurray Formation Geology**




The unconsolidated sands of the McMurray Formation 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 12ºC. 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 Formation 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 re-pressurized depleted gas pools.

SAGD projects require adequate supplies of non-potable water for steam generation. In steady state operations, approximately 90% of the water produced from the reservoir is recycled in MEG's SAGD process for the purpose of generating steam. This water is cleaned for use in steam generators. Produced water volumes remaining after water treatment, not suitable as boiler feedwater, are re-injected into sub-surface disposal zones that are hydraulically isolated from surrounding aquifers. Any additional make-up water demands for operations are met through deep non-potable groundwater sources in the Christina Lake region that could not otherwise be used for domestic or agricultural purposes. No potable fresh water is used by MEG as make-up water in operations. The ratio of makeup water MEG used compared to the bitumen produced was approximately 53% lower than the in situ industry average according to the 2017 AER Water Use Performance Report.

**Production Overview**

Phase 1 commenced production in 2008 with an initial bitumen production design capacity of approximately 3,000 bbls/d. Phase 2 commenced production in 2009 with an initial bitumen production design capacity of approximately 22,000 bbls/d, which utilized existing central processing facilities associated with Phase 1, and primarily expanded well pad drilling and tie-ins to increase production. Together, Phase 1 and Phase 2 had an initial bitumen production design capacity of approximately 25,000 bbls/d. In 2012, MEG commenced the deployment of eMSAGP and facilities modifications, including central processing facilities debottlenecking, which resulted in increased bitumen production from Phase 1 and Phase 2. Phase 2B commenced production in 2013 with an initial bitumen production design capacity of approximately 35,000 bbls/d. The combined Phase 1, Phase 2 and Phase 2B initial bitumen production design capacity was approximately 60,000 bbls/d. Supported by proprietary reservoir technologies, MEG has been able to subsequently increase overall bitumen production in excess of 100,000 bbls/d through a series of low-cost debottlenecking and expansion projects and the redeployment of steam into new well pairs. In 2018, MEG invested approximately $619 million, with substantially all capital directed towards development at the Christina Lake Project. In the third quarter of 2018, MEG successfully completed the application of its proprietary eMSAGP technology on existing wells at Christina Lake Phase 2B, resulting in additional bitumen production capacity of approximately 20,000 bbls/d for total Christina Lake Project bitumen production capacity of approximately 100,000 bbls/d. During the year, MEG also proceeded with work on the Phase 2B brownfield expansion, which includes incremental steam capacity at Phase 2B and two additional well pads. MEG's 2018 capital investment summary is as follows:

| **2018 Capital Investment Summary** | **$ millions** |
|---|---|
| eMSAGP growth capital | 90 |
| eMVAPEX and future growth capital | 65 |
| Sustaining and maintenance | 251 |
| Field infrastructure, corporate and other | 47 |
| Phase 2B brownfield expansion | 166 |
| **Total** | **619** |

In 2018, the Corporation produced an average of 87,731 bbls/d of bitumen from Christina Lake compared to 80,774 bbls/d in 2017. The Corporation's average annual SOR was 2.2 for the year ended December 31, 2018 as compared to 2.3 for the year ended December 31, 2017.

The table below summarizes MEG's unaudited operating costs, production levels and SORs for each quarter of 2018.

| | **MEG – Operating Costs 2018** | | | |
|---|---|---|---|---|
| | **First Quarter** | **Second Quarter** | **Third Quarter** | **Fourth Quarter** |
| Operating Costs ($/bbl): | | | | |
| Energy costs[1] | **$1.43** | **$0.17** | **$(0.04)** | **$0.30** |
| Non-energy costs | **$4.55** | **$5.47** | **$4.38** | **$4.25** |
| Total Net Operating Costs | **$5.98** | **$5.64** | **$4.34** | **$4.55** |
| Production (bbls/d) | **93,207** | **71,325** | **98,751** | **87,582** |
| SOR | **2.2** | **2.2** | **2.2** | **2.2** |

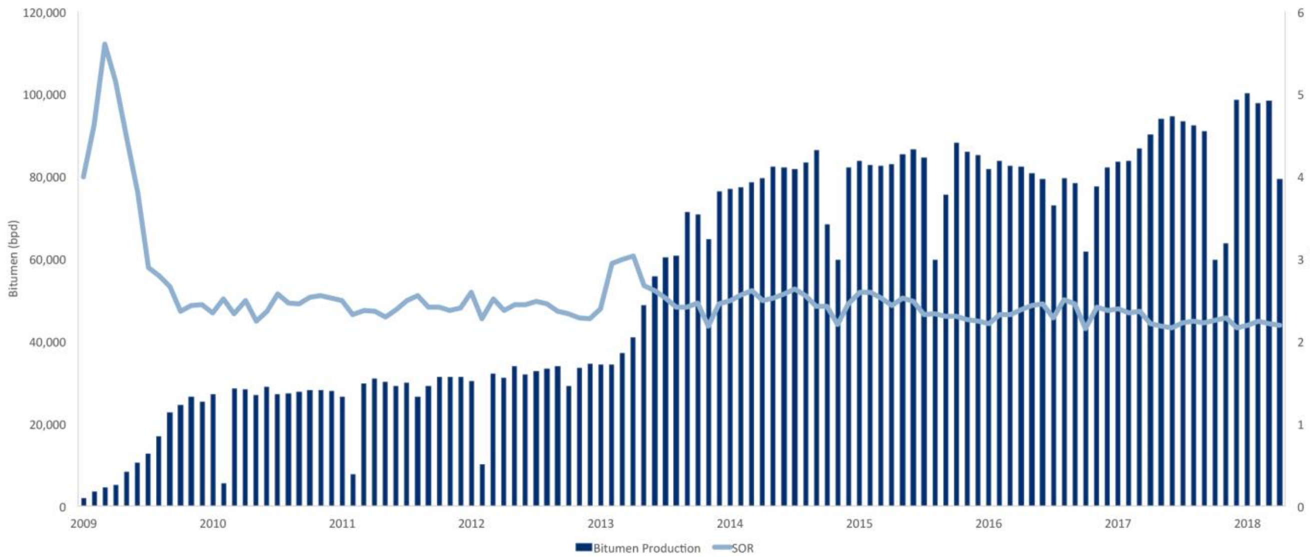
**Note:**

(1) Energy costs are presented 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, Phase 2 and Phase 2B steam generation capacity is provided by the cogeneration units and the HRSG.

Bitumen production for the year ended December 31, 2018 averaged 87,731 bbls/d. 2019 annual average production is expected to be in the range of 90,000 to 92,000 bbls/d, assuming the Alberta Government mandated production curtailment remains in place for 2019 with easing over the course of the year. If curtailments were not in place, MEG would have the ability to average 100,000 bbls/d in 2019. MEG's capital budget includes an additional $75 million of discretionary capital, which can be sanctioned mid-2019 subject to market conditions to advance the 2B brownfield expansion that would bring production capacity to 113,000 bbls/d.

### Historical Production and SOR Graphic




### Future Development at Christina Lake

MEG has regulatory approvals in place to support up to 210,000 bbls/d at the Christina Lake Project. MEG anticipates that the build out of Christina Lake will be through low cost brownfield expansions and the application of reservoir technologies including eMSAGP and/or eMVAPEX.

The Corporation announced a 2019 base capital budget of $200 million, to sustain production at 100,000 bbls/d in 2019 and 2020. There is opportunity for an additional $75 million of discretionary capital, which would be sanctioned mid-2019 subject to market conditions. If sanctioned, the discretionary capital would be directed towards the completion of the Phase 2B brownfield expansion and allow MEG to reach its previously announced target of 113,000 bbls/d in 2020. The 2019 annual average production is expected to be in the range of 90,000 to 92,000 bbls/d, assuming the Alberta Government mandated production curtailment remains in place for 2019, with easing over the course of the year. If curtailments were not in place, MEG would have the ability to average 100,000 bbls/d in 2019.

Beyond 2020, MEG has an inventory of low-cost execution-ready growth opportunities at Christina Lake, which would support production to 210,000 bbls/d, achieved through the application of brownfield expansions and reservoir technologies including eMSAGP and/or eMVAPEX. The pace and timing of these projects will be dependent on market conditions.

## 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 and is approximately 30 miles north of the Christina Lake Project. MEG's Surmont Project is situated along the same geological trend as the Christina Lake Project. This area has been extensively explored and developed for natural gas projects, and more recently for oil sands resources. Other thermal recovery projects are already operating in this area. The Surmont Project is adjacent to an in situ oil sands project operated by ConocoPhillips Canada. MEG owns a 100% working interest in its oil sands leases associated with the Surmont Project. MEG has conducted extensive seismic programs and delineation drilling programs in the Surmont Project area. On September 13, 2012 the Corporation filed regulatory applications with the ERCB (now AER) and ESRD (now AEP) for the Surmont Project. As a normal part of the regulatory review process, the Corporation received supplemental information requests ("SIRs") from the AER and AEP 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 report for the Surmont Project was deemed technically complete by AEP and the environmental impact assessment report was referred to the AER. Throughout the regulatory process, MEG actively worked with stakeholders to address concerns raised on the Surmont Project. In 2018, MEG worked specifically with Chipewyan Prairie Dene First Nation and ConocoPhillips Canada Resources Corp. to resolve the remaining statements of concern. As such, the technical aspects of the regulatory approval have been completed and there are no remaining stakeholder statements of concern. The Corporation anticipates receiving approval for the Surmont Project from the AER in 2019. A total of 50 core holes have been drilled by the Corporation 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 the reserve and resource estimates contained in the GLJ Report, that the Surmont Project can support an average of over 120,000 bbls/d of bitumen production for approximately 20 years.

## 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, 2018. 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 Formation. The McMurray Formation 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 Formation 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 re-pressurization.

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 (now AER) and the ESRD (now AEP) for the Surmont Project. The Corporation is actively pursuing regulatory approval in respect of 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 reserve and resource estimates, that the Surmont Project can support an average of over 120,000 bbls/d of bitumen production for approximately 20 years.

The Surmont Project is expected to use SAGD and eMSAGP recovery technologies similar to the Christina Lake Project. The Corporation’s development plan for the Surmont Project is expected to follow a similar development plan to that of the Christina Lake Project, along with further refinements, including technological, design and operational improvements applied to the Surmont Project. Once regulatory approval for the Surmont Project is received, the Corporation plans to advance toward project sanctioning with construction and on-stream timing dependent upon development logistics, market conditions and capital planning.

As a normal part of the regulatory review process, the Corporation received SIRs from the AER and AEP 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 report for the Surmont Project was deemed technically complete by AEP and the environmental impact assessment report was referred to the AER. Throughout the regulatory process, MEG actively worked with stakeholders to address concerns raised on the Surmont Project. In 2018, MEG worked specifically with Chipewyan Prairie Dene First Nation and ConocoPhillips Canada Resources Corp. to resolve the remaining statements of concern. As such, the technical aspects of the regulatory approval have been completed and there are no remaining stakeholder statements of concern. The Corporation is awaiting an Order In Council from the Government of Alberta for the Surmont Project and anticipates regulatory approval from the AER in 2019. As of the date of this AIF, the Corporation anticipates incurring significant expenditures with development of the first phase of the Surmont Project to occur over the course of the next five years. Development is expected to involve the following sequential steps: refining detailed engineering and design plans, initiating long lead equipment procurement, development of infrastructure and construction of associated steam generation and oil processing facilities, construction of well pads and associated infrastructure, and drilling and completion of SAGD well pairs.

## May River Regional Project

The May River Regional Project properties are situated on 292 square miles of lands in the southern Athabasca oil sands region of Alberta. MEG owns a 100% working interest in the oil sands leases of its May River Regional Project, which it acquired between 2005 and 2017 through Alberta Crown auctions as well as through commercial agreements with third parties.

As of December 31, 2018, 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. On February 21, 2017 the Corporation filed regulatory applications with the AER for the May River Regional Project. As a normal part of the regulatory review process, the Company received SIRs from the AER and AEP in May 2017 and November 2017. MEG responded to the SIRs in September 2017 and January 2018. The May River Project environmental impact assessment was deemed technically complete by the AER in February 2018. In accordance with AER requirements, MEG is actively discussing the May River Regional Project with stakeholders.

Management anticipates, consistent with the resource estimates contained in the GLJ Report, that the May River Regional Project can support an average of 164,000 bbls/d of bitumen production for over 20 years. The May River Regional Project is expected to use SAGD and eMSAGP development techniques similar to the Christina Lake Project.

### 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 292 square miles of the May River Regional Project area.

### Geology

The contingent resources assigned by GLJ to the May River Regional Project lands are 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 444 - 518 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 1,825 kPa – 2,465 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 Formation reservoir sands. Some of these gas pools have had historical gas production but were shut-in by the ERCB (now AER) 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. The Corporation's development plan for the May River Regional Project tracks the development plan for the Christina Lake Project, along with further refinements, including technological, design and operational improvements applied to the May River Regional Project. Management anticipates, consistent with the estimates contained in the GLJ Report, that the May River Regional Project can support an average of 164,000 bbls/d of bitumen production for over 20 years.

## 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, 2018, 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.

### Capital Investment

The Corporation announced a 2019 base capital budget of $200 million, to be fully funded with expected 2019 adjusted funds flow. The budget is designed to sustain production capability at 100,000 bbls/d in 2019 and support future growth projects beyond 2019.

| **2019 Capital Investment Summary** | **$ millions** |
|---|---|
| Sustaining and maintenance | 115 |
| Future growth projects (eMVAPEX, 2B brownfield expansion & other) | 40 |
| Field infrastructure, corporate & other | 45 |
| **Total** | **200** |

The Corporation has the flexibility to adapt the pace of spending in 2019 in response to market conditions. MEG has announced a discretionary capital budget of $75 million, which would not be sanctioned until mid-2019, subject to market conditions at that time. If sanctioned, capital would be directed to advancing MEG’s Phase 2B brownfield expansion, which would allow MEG to reach production capacity of 113,000 bbls/d once complete. See "Risk Factors – Risks Related to Financing and the Corporation's Indebtedness – Sufficiency of Funds".

## Environmental Strategy

### Aerial View of Pad L & Gen-C Well Pad Design

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, including:

- 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 and this percentage is expected to be significantly reduced by the continued deployment of Gen-C pads (discussed below).
- Water use – MEG does not use potable water in its operation processes. MEG recycles over 90% of the produced water returned from the reservoir to generate steam; the remaining water demand 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. There is no surface discharge of process water used in the operation.
- 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, including:

- Low SOR – the quality of MEG's oil sands reservoir and the use of proprietary technology to extract bitumen results in lower SORs and therefore MEG is able to use less natural gas, less make up water 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 and has extensive fugitive emissions detection and management programs in place to monitor and reduce emissions;

- Use of existing land disturbances – MEG uses, where possible, existing disturbances for development in order to minimize further land disturbances and is actively reducing the footprint of its projects through innovative engineering designs;
- 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. Revenues from the sale of surplus power help offset the Corporation's energy costs. The increased efficiency of the cogeneration system helps reduce the overall provincial GHG footprint from the generation of power; and
- GHG management – MEG's low SOR resulting from the Corporation's production enhancement program which uses a combination of proprietary reservoir technologies (including eMSAGP) and processing plant enhancements, debottlenecking and brownfield expansions 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.

## Sustainability

To manage the risk of increasingly stringent carbon regulations, MEG has several strategies in place that align with the overall business objectives which are built on energy efficiency and technology advancements. Cogeneration has been utilized in facility design to optimize the production of both heat and electricity used in the recovery process and provides a benefit back to the provincial power grid of stable base load power. Reducing power production below the electricity performance benchmark has enabled MEG to earn emissions performance credits that can further offset compliance burden.

MEG continued to advance reservoir recovery technologies in 2018 to support its growth. A significant portion of MEG's 2018 capital program was allocated to the eMSAGP growth project at Christina Lake Phase 2B, the first in a series of high-return projects that will boost production while lowering the Corporation's cash costs and environmental footprint. eMSAGP technology involves co-injecting a non-condensable gas into the reservoir with steam. Once there is sufficient heat in the reservoir, the non-condensable gas helps maintain pressure and reduces the steam-oil ratio and frees up steam to be redeployed into new SAGD well pairs, thereby improving capital efficiency and reducing emissions.

In 2018, MEG continued testing of its eMVAPEX technology. This proprietary technology, if proven successful through expanded pilot operations, will further enhance MEG's growth potential by reducing capital requirements and operating costs, while minimizing environmental impacts to land, air and water. In 2018, the expanded eMVAPEX pilot commenced and propane recycling facilities became fully operational. The eMVAPEX pilot is funded in part through government grants received from Alberta Innovates, Natural Resources Canada, and Emissions Reduction Alberta.

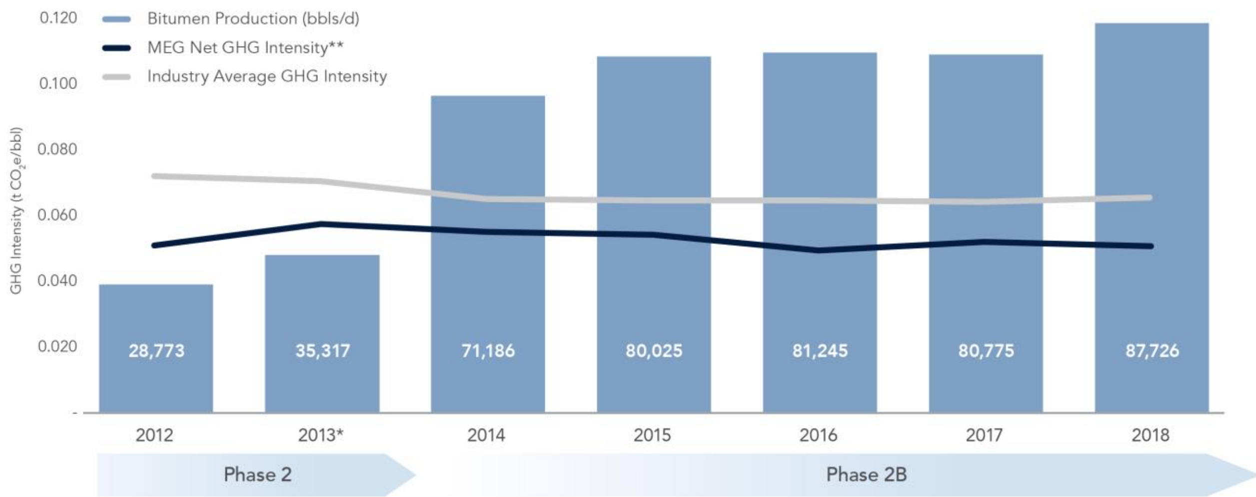
In 2018, MEG's business sustainability was further enhanced through measurable improvements in its environmental performance. MEG continued to achieve record low per barrel net operating costs and optimize water requirements with a substantial reduction in non-saline water demand by executing a reconfiguration of the clean backwash tank to utilize produced water instead of non-saline water. A reduction in GHG intensity on a year-over-year basis was further realized through SOR efficiencies achieved with the continued application of eMSAGP and expansion of the eMVAPEX pilot.

To further support the corporate commitment to environmental performance, environmental indicators were added to the Corporate Performance Scorecard. The chosen indicators were based on reportable spill intensity and net GHG intensity to reflect the accountabilities across the organization to deliver responsible operations and manage climate-related issues. In 2018, the performance associated with both metrics improved from previous years and met or surpassed corporate performance targets.

Oversight of the metrics is provided by MEG's Board, which also ensures MEG sets high environmental standards, is in compliance with environmental laws and regulations, and has appropriate programs and policies in place for the health and safety of its employees in the workplace. On a quarterly basis, MEG's Environmental performance is formally reported to the Board.

### Net GHG Intensity Performance

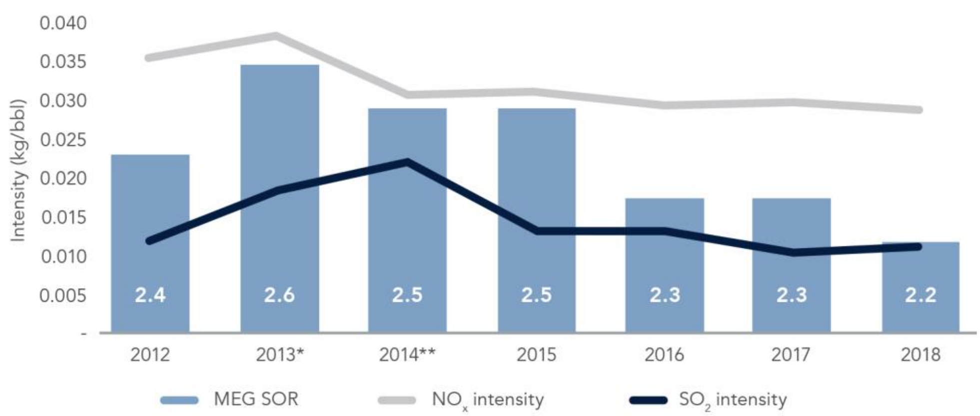
MEG believes it is a top quartile performer with one of the lowest GHG emissions intensity operations in the in situ oil sands industry. For full-year 2018, MEG's overall net GHG emissions intensity was approximately 20% below the in situ industry average, determined using third party verified methodology.




*Note: 2018 data is preliminary and has yet to be verified through MEG's assurance process*
** Phase 2B start-up: higher steam requirements with low initial production*
*** Net GHG Intensity includes the associated benefits of cogeneration*

#### $NO_X$ /$SO_2$ Intensity

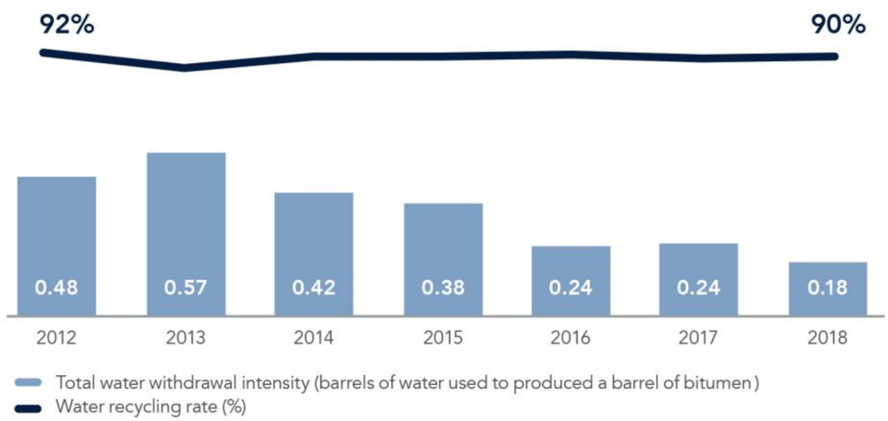
In 2018 MEG was able to further reduce the NOx emissions intensity through investment in operational efficiencies that measurably enhance emissions performance. Between 2011 and 2018, MEG reduced the nitrogen oxide per barrel intensity by 22% and the sulphur dioxide per barrel intensity by 41%.




*Note: 2018 data is preliminary and has yet to be validated through MEG's assurance process*
** Phase 2B start-up: higher steam requirements with low initial production*
*** Sulphur removal facility installed at central plant.*

#### Makeup-Water Use

Between 2012 and 2018, MEG's eMSAGP process and optimization of recycling technology enabled MEG to reduce its total water withdrawal intensity by 63%. In 2018, MEG recycled 90% of the water recovered from the reservoir to produce steam while volumes remaining after water treatment, not suitable as boiler feedwater, are re-injected into sub-surface disposal zones that are hydraulically isolated from surrounding aquifers. Any additional make-up water demands for operations are met through deep non-potable groundwater sources. No potable fresh water is used by MEG as make-up water in operations. The ratio of makeup water MEG used compared to the bitumen produced was approximately 53% lower than the in situ industry average according to the 2017 AER Water Use Performance Report.




*Note: 2018 data is preliminary and has yet to be validated through MEG's assurance process*

**Land Disturbance**

MEG has implemented a new well pad design that reduces pad size by as much as 40%. The "Gen-C" design involves running injection and producer wells across from each other as opposed to side-by-side. This well design has been implemented on three well pads in 2018 and is anticipated to be implemented on all future well pads at the Christina Lake Project. MEG has also reduced GHG emissions at the Gen-C pads by replacing natural gas heaters with heaters powered by electricity. In addition, MEG is optimizing the design of access roadways and gathering lines to reduce right of way widths and the overall footprint.

MEG is committed to minimizing total land disturbance through its operations and in 2017/18 continued restoration and reclamation activities within the Dillon River Wildland Park. This area is adjacent to MEG's existing operations and overlaps Boreal Woodland Caribou habitat. Restoration efforts in this protected Wildland Park will assist in the species recovery efforts being undertaken by the Province of Alberta. To date, MEG has completed a total of approximately 5,000 hectares of restoration in high quality caribou habitat.

## MARKETING OVERVIEW

MEG employs a marketing strategy that delivers and sells its production to current and emerging crude oil markets throughout North America and internationally. MEG owns, leases and contracts for services on facilities to transport, store, and sell AWB to refiners.

MEG has entered into a long-term commitment to deliver AWB on the Access Pipeline from its Christina Lake Project to the Edmonton market connecting to local refineries and blend export pipelines. The pipeline is comprised of a blend and diluent system. The blend pipeline system runs from the Christina Lake Project to Edmonton. The diluent pipeline runs from the Edmonton area to MEG's Christina Lake Project. The diluent system allows MEG to manage its diluent supply for purposes of blending and processing at its Christina Lake Project. MEG uses condensate as diluent. Access Pipeline delivers diluent to the Christina Lake Project from a variety of sources in the Edmonton area. The diluent system can receive volumes from fractionation facilities, underground diluent storage sites, a diluent tank car offloading site, and a pipeline system in the Edmonton/Fort Saskatchewan corridor. The diluent system is also connected to the Enbridge CRW condensate pool 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.

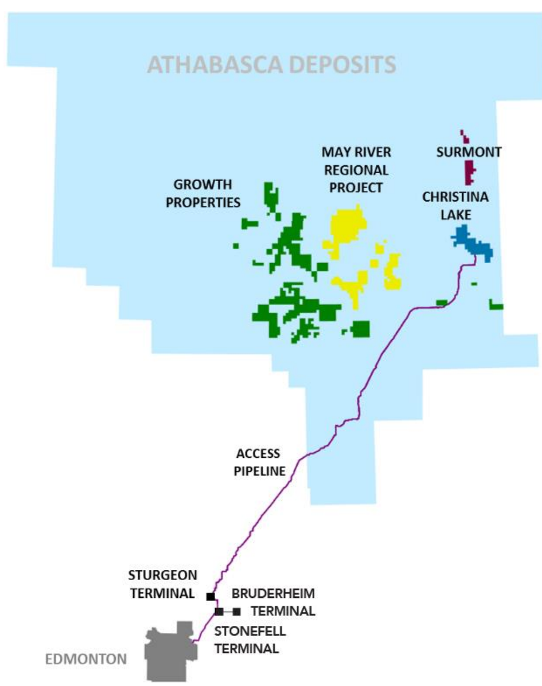
The Stonefell Terminal is connected to the Access Pipeline System and has a storage and terminalling capacity of 900,000 barrels. MEG has entered into a long-term lease for use of the Stonefell Terminal. Stonefell Terminal provides MEG with the ability to: (i) sell and deliver AWB to a variety of markets; (ii) access multiple sources of diluent; and (iii) store both bitumen blend and diluent in periods of market and transportation disruptions or constraints. Stonefell Terminal is directly connected by pipeline to the Bruderheim Terminal. This combination of facilities allows for the loading of bitumen blend for transport by rail.

In the fourth quarter of 2018, MEG executed a binding agreement to access 30,000 bbls/d of rail loading capacity at the Bruderheim Terminal, operated by Bruderheim Energy Terminal Ltd., a wholly-owned subsidiary of Cenovus. This three-year agreement, with a one-year extension at MEG's option, balances both free-on-board rail sales and delivered rail sales dependent on customer needs, asset availability and market conditions.

On March 22, 2018 the Corporation announced that it had successfully closed its previously announced sale of the Corporation's 50% interest in the Access Pipeline and its 100% interest in the Stonefell Terminal for cash proceeds of C$1.52 billion and other consideration of C$90 million. As part of the transaction, MEG entered into a TSA dedicating MEG's Christina Lake production and condensate transport to Access Pipeline for an initial term of 30 years In addition, commercial parameters have been established for the conversion of Access Pipeline's 16" unutilized pipeline to transport natural gas liquids. Under the TSA, MEG has secured a market-based toll on transported volumes related to MEG's bitumen production up to approximately 113,000 barrels per day and an incentive toll structure where the tolls on additional barrels are reduced by as much as 60% as incremental production is brought on stream.

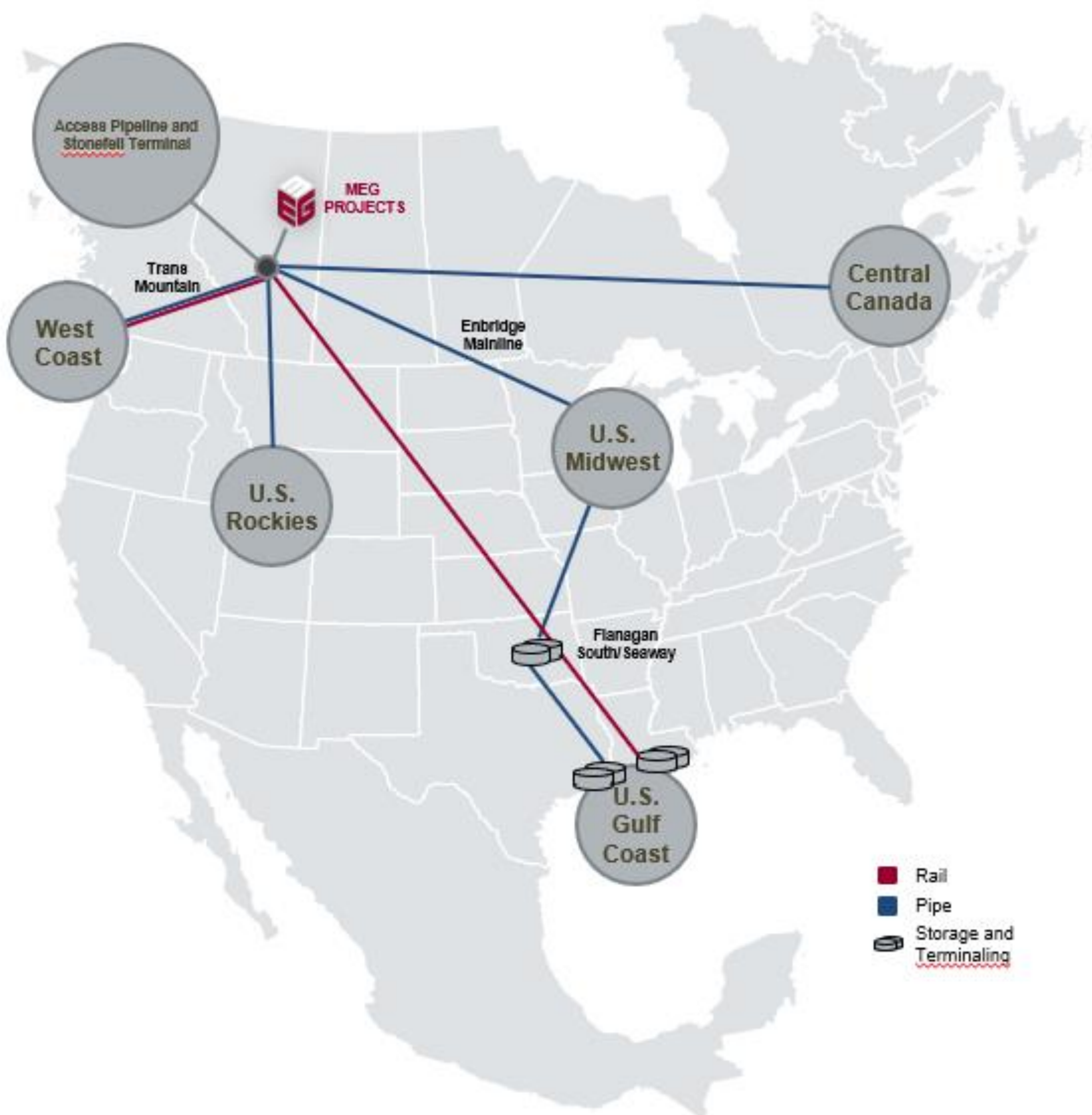
The transaction also includes a Stonefell Lease Agreement which is a 30-year arrangement that secures MEG's operational control and exclusive use of 100% of the Stonefell Terminal's 900,000-barrel blend and condensate storage facility. MEG will pay a fixed lease fee, plus operating expenses under the terms of its lease for the Stonefell Terminal. The Stonefell Terminal is connected to the Access Pipeline System.

### Access Pipeline System, Stonefell Terminal and Bruderheim Terminal




MEG uses multiple facilities to transport and sell AWB to refiners throughout North America and beyond. MEG has contracted for 50,000 bbls/d (expanding to 100,000 bbls/d in mid-2020) of transportation capacity on the Flanagan South and Seaway pipeline systems providing pipeline transportation directly to U.S. Gulf Coast refineries. In addition, MEG is a shipper on the Trans Mountain Expansion Project which, when in service, will provide MEG with 20,000 bbls/d of committed tidewater access on Canada's West Coast.  This combination of pipeline access, along with continuing options for rail, advances MEG's strategy of having broadening and reliable market access to world oil prices for its production.

**MEG Marketing Network**




## 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 portions of 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 Carbon Competitiveness Incentive Regulation which replaced the Specified Emitters Regulation on January 1, 2018). The GLJ Report does not 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 Corporation’s production enhancement program which uses a combination of proprietary reservoir technologies (including eMSAGP) and processing plant enhancements, debottlenecking and brownfield expansions of the Christina Lake Project; and (iv) probable undeveloped reserves in respect of Phases 1, 2, 2B and sub-phases associated with the Corporation’s production enhancement program which uses a combination of proprietary reservoir technologies (including eMSAGP) and processing plant enhancements, debottlenecking and brownfield expansions of the Christina Lake Project and in respect of Phase 1 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, 2018 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, 2018 (Forecast Prices and Costs)

| | Bitumen | |
|---|---|---|
| **Reserves Category** | **Gross[1] (MMbbls)** | **Net[2] (MMbbls)** |
| **Proved Reserves[3]** | | |
| Proved Developed Producing | 266.6 | 221.5 |
| Proved Developed Non-Producing | 7.3 | 5.2 |
| Proved Undeveloped | 1094.1 | 808.5 |
| **Total Proved Reserves** | 1,368.0 | 1,035.2 |
| **Total Probable Reserves[4]** | 1,440.7 | 1,043.4 |
| **Total Proved Plus Probable Reserves[5]** | 2,808.7 | 2,078.6 |

**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, 2018 Before Income Taxes (Forecast Prices and Costs) | | | | | |
|---|---|---|---|---|---|---|
| | Before Income Taxes Discounted at %/Year | | | | | Unit Value Before Income Taxes Discounted at 10%/Year[1] $/bbl |
| **Reserves Category** | **0% (MM$)** | **5% (MM$)** | **10% (MM$)** | **15% (MM$)** | **20% (MM$)** | |
| **Proved Reserves** | | | | | | |
| Proved Developed Producing | 8,319 | 6.823 | 5.708 | 4,871 | 4.230 | 25.77 |
| Proved Developed Non-Producing | 257 | 186 | 139 | 106 | 83 | 26.63 |
| Proved Undeveloped | 40,706 | 16,002 | 7,658 | 4,234 | 2,578 | 9.47 |
| **Total Proved Reserves[2]** | 49,282 | 23,012 | 13,506 | 9,211 | 6,890 | 13.05 |
| **Total Probable Reserves** | 59,390 | 17.893 | 6,539 | 2,689 | 1,144 | 6.27 |
| **Total Proved Plus Probable Reserves[2]** | 108,672 | 40,905 | 20,045 | 11,900 | 8,034 | 9.64 |

**Notes:**

(1) Unit values have been calculated using MEG's net reserves after deducting royalties.

(2) Totals may not add due to rounding.

| Reserves Category | Net Present Value of Future Net Revenue as of December 31, 2018 After Income Taxes (Forecast Prices and Costs) (Discounted at %/Year) 0% (MM$) | 5% (MM$) | 10% (MM$) | 15% (MM$) | 20% (MM$) |
|---|---|---|---|---|---|
| **Proved Reserves** | | | | | |
| Proved Developed Producing | 8,043 | 6,657 | 5,606 | 4,806 | 4,188 |
| Proved Developed Non-Producing | 185 | 140 | 108 | 85 | 69 |
| Proved Undeveloped | 29,493 | 11,525 | 5,478 | 3,010 | 1,820 |
| **Total Proved Reserves** | 37,721 | 18,322 | 11,193 | 7,901 | 6,076 |
| **Total Probable Reserves** | 43,149 | 12,780 | 4,501 | 1,721 | 626 |
| **Total Proved Plus Probable Reserves**[(1)] | 80,870 | 31,102 | 15,694 | 9,622 | 6,702 |

**Note:**

(1) Totals may not add due to rounding.

**Future Net Revenue (undiscounted) as of December 31, 2018 (Forecast Prices and Costs)**

| Reserves Category | Revenue (MM$) | Royalties (MM$) | Operating Costs (MM$) | Development Costs (MM$) | Aband. And Reclam. Costs [(1)] (MM$) | Future Net Revenue Before Income Taxes (MM$) | Income Taxes (MM$) | Future Net Revenue After Income Taxes (MM$) |
|---|---|---|---|---|---|---|---|---|
| **Proved Reserves** | | | | | | | | |
| Proved Developed Producing | 15,442 | 2,785 | 3,256 | 610 | 472 | 8,319 | 276 | 8,043 |
| Proved Developed Non-Producing | 479 | 134 | 70 | 13 | 7 | 257 | 72 | 185 |
| Proved Undeveloped | 97,818 | 25,345 | 15,756 | 13,564 | 2,447 | 40,706 | 11,213 | 29,493 |
| **Total Proved Reserves**[(2)] | 113,740 | 28,264 | 19,082 | 14,187 | 2,925 | 49,282 | 11,561 | 37,721 |
| **Total Probable Reserves** | 138,920 | 38,768 | 21,453 | 16,904 | 2,405 | 59,390 | 16,242 | 43,149 |
| **Total Proved Plus Probable Reserves**[(2)] | 252,660 | 67,032 | 40,534 | 31,091 | 5,330 | 108,672 | 27,803 | 80,870 |

**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, 2018 (Forecast Prices and Costs)**

| Reserves Category | Production Group | Future Net Revenue Before Income Taxes (discounted at 10%/yr) MM$ | Unit Value[(1)] ($/bbl) |
|---|---|---|---|
| **Total Proved Producing Reserves** | Bitumen | 5,708 | 25.77 |
| **Total Proved Reserves** | Bitumen | 13,506 | 13.05 |
| **Total Proved Plus Probable Reserves** | Bitumen | 20,045 | 9.64 |

**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, 2018 against such reserves as of December 31, 2017 based on the forecast price and cost assumptions set forth in Note 1 of the table.

| | Total Bitumen Reserves[(1)] | | |
|---|---|---|---|
| | Gross Proved (Mbbls) | Gross Probable (Mbbls) | Gross Proved Plus Probable (Mbbls) |
| **December 31, 2017** | 1,398,726 | 1,437,462 | 2,836,188 |
| Discoveries | 0 | 0 | 0 |
| Extensions and Improved Recovery | 0 | 0 | 0 |
| Technical Revisions | 1,315 | 3,263 | 4,578 |
| Acquisitions | 0 | 0 | 0 |
| Dispositions | 0 | 0 | 0 |
| Economic Factors | 0 | 0 | 0 |
| Production | -32,022 | 0 | -32,022 |
| **December 31, 2018** | 1,368,019 | 1,440,725 | 2,808,744 |

**Note:**

(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".

### *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, 2019 pricing models. A summary of selected price forecasts is set forth below.

## Forecast Prices used in Preparing Reserves Data GLJ (January 1, 2019)

| 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) |
|---|---|---|---|---|---|---|---|---|---|
| 2019 | 2.0 | 0.75 | 56.25 | 1.85 | 47.67 | 67.67 | 37.65 | 62.07 | 58.90 |
| 2020 | 2.0 | 0.77 | 63.00 | 2.29 | 58.44 | 79.22 | 51.21 | 73.82 | 70.05 |
| 2021 | 2.0 | 0.79 | 67.00 | 2.67 | 65.82 | 83.54 | 59.51 | 78.15 | 74.16 |
| 2022 | 2.0 | 0.81 | 70.00 | 2.90 | 67.90 | 85.49 | 61.62 | 79.85 | 75.78 |
| 2023 | 2.0 | 0.82 | 72.50 | 3.14 | 70.12 | 87.80 | 63.82 | 81.87 | 77.69 |
| 2024 | 2.0 | 0.83 | 75.00 | 3.23 | 72.73 | 90.30 | 66.45 | 84.34 | 80.04 |
| 2025 | 2.0 | 0.83 | 77.50 | 3.34 | 75.76 | 93.33 | 69.48 | 87.31 | 82.85 |
| 2026 | 2.0 | 0.83 | 80.41 | 3.41 | 79.28 | 96.86 | 73.01 | 90.77 | 86.13 |
| 2027 | 2.0 | 0.83 | 82.02 | 3.48 | 81.24 | 98.81 | 74.96 | 92.68 | 87.95 |
| 2028 | 2.0 | 0.83 | 83.66 | 3.54 | 83.22 | 100.80 | 76.95 | 94.63 | 89.80 |
| 2029 | 2.0 | 0.83 | 85.33 | 3.61 | 84.88 | 102.82 | 78.49 | 96.52 | 91.60 |
| 2030 | 2.0 | 0.83 | 87.04 | 3.68 | 86.58 | 104.87 | 80.06 | 98.45 | 93.43 |

The Corporation realized an average price of $36.25/bbl of bitumen for the year ended December 31, 2018.

### *Undeveloped Reserves*

Through the GLJ Report, GLJ has assigned the Christina Lake property proved undeveloped reserves of 1,094 MMbbls and the Christina Lake and Surmont properties probable undeveloped reserves of 1,409 MMbbls. The Corporation's proved undeveloped reserves and probable undeveloped reserves are expected to be developed as wells and plant capacity become available. The Corporation continually reviews the economic ranking of these undeveloped reserves within the Corporation's overall portfolio of development projects. See "Projects Overview – Christina Lake Project" and "Projects Overview – Surmont Project".

Probable undeveloped oil and gas reserves are those reserves that are less certain to be recovered than proved reserves and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Proved and probable undeveloped reserves have been estimated by GLJ in accordance with procedures and standards contained in the COGE Handbook. Recognition of probable reserves requires sufficient drilling of stratigraphic wells to establish reservoir suitability for SAGD.

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

| Period | First Attributed (MMbbls) | Total at Year-end (MMbbls) |
|---|---|---|
| December 31, 2016 | 0 | 1,248 |
| December 31, 2017 | 0 | 1,165 |
| December 31, 2018 | 0 | 1,094 |

## Probable Undeveloped Bitumen Reserves

| Period | First Attributed (MMbbls) | Total at Year-end (MMbbls) |
|---|---|---|
| December 31, 2016 | 0 | 1,475 |
| December 31, 2017 | 0 | 1,405 |
| December 31, 2018 | 0 | 1,409 |

### *Significant Factors or Uncertainties*

The Corporation does not anticipate that any significant 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$) | Total Proved Plus Probable Future Development Costs Using Escalated Dollars Costs (MM$) |
|---|---|---|
| 2019 | 304 | 304 |
| 2020 | 465 | 418 |
| 2021 | 225 | 249 |
| 2022 | 251 | 700 |
| 2023 | 140 | 1,467 |
| 2024 | 228 | 2,236 |
| 2025 | 247 | 1,152 |
| 2026 | 325 | 521 |
| 2027 | 269 | 624 |
| 2028 | 368 | 650 |
| 2029 | 298 | 575 |
| 2030 | 222 | 511 |
| Remainder | 10,844 | 21,683 |
| Total, undiscounted | 14,187 | 31,091 |

# 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, 2018, all of which are in Alberta, Canada:

| | Bitumen Production Wells as of December 31, 2018 | |
|---|---|---|
| | Gross | Net |
| **Christina Lake** | | |
| Producing SAGD Well Pairs | 173 | 173 |
| Non-producing SAGD Well Pairs | 36 | 36 |
| Producing Infill Wells | 97 | 97 |
| Non-producing Infill Wells | 11 | 11 |
| **Total** | 317 | 317 |

**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 855 stratigraphic test wells, 315 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 2018.

The following table sets out the Corporation's producing and non-producing gas wells, all of which are in Alberta, as of December 31, 2018:

### Gas Production Wells as of December 31, 2018

| | Gas Production Wells as of December 31, 2018 | |
|---|---|---|
| | **Gross** | **Net** |
| Producing | 0 | 0 |
| Non-producing | 127 | 115.7 |
| **Total** | 127 | 115.7 |

## 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, 2018. 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** |
| 575,814 | 575,814 |

## Additional Information Concerning Abandonment and Reclamation Costs

The Corporation follows IFRS 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, removal of equipment from leased acreage and returning such land to a condition equivalent to its original condition. Under the standard, the estimated cost of each decommissioning obligation is recorded in the period a well or related asset is drilled, constructed or acquired. The obligation 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, 2018, the estimated total undiscounted amount required to settle the decommissioning obligations in respect of the Corporation's facilities and certain wells (including producing, non-producing, observation, water source and water disposal wells), net of estimated salvage recoveries, was $719.4 million. This obligation is estimated to be settled in periods up to 2067. The 14.1% discounted present value of this amount is $73.6 million ($103.1 million discounted at 10%). Over the next three years, the Corporation expects to incur approximately $17.7 million in decommissioning expenditures.

In the GLJ Report, abandonment and reclamation costs for total proved plus probable reserves were estimated to be $5.330 billion, undiscounted, and $282 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 3,156 producing wells, including infill wells and 1,586 injection wells anticipated to be required to develop the assigned reserves over the life of the projects.

## Tax Horizon

As of December 31, 2018, the Corporation had approximately $7.7 billion of available tax pools and had recognized a deferred income tax asset of $237 million. In addition, as of December 31, 2018, the Corporation had $73 million 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, 2018. The following table summarizes the net capital investment made by MEG on its properties for the year ended December 31, 2018:

### Summary of Net Capital Investment

| ($000) | Year ended December 31 2018 |
|---|---|
| Total cash capital investment | **618,820** |
| Capitalized cash-settled stock-based compensation | **3,429** |
| **Net capital investment** | **$ 622,249** |

## Exploration and Development Activities

MEG conducted a series of drilling programs on its oil sands leases in 2018. The following table sets forth the number of exploratory and development wells which MEG completed during the year ended December 31, 2018:

### Exploration and Development Activities

| | **2018 Wells (Gross & Net)** |
|---|---|
| Exploration Wells | 0 |
| Stratigraphic Test Wells | 38 |
| SAGD Wells | 86 |
| Observation Wells | 16 |
| Infill Wells | 9 |
| Water Source Wells | 0 |
| Water Disposal Wells | 0 |
| **Total Completed Wells**[1] | 149 |

**Note:**

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

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

## Production Estimates

The following table sets forth the estimated volume of net working interest production of gross proved reserves and gross probable reserves in 2019, before royalties, as set out in the GLJ Report.  GLJ has incorporated an estimate of the Alberta Government production curtailments into the Corporation's production forecast for 2019. See – "Pricing and Marketing – Crude Oil, Bitumen and Bitumen Blend"

### Production Estimates

| Reserves | Bitumen Production (bbls/d)[(1)(2)] |
|---|---|
| Total Proved Reserves | 91,411 |
| Total Probable Reserves | 54 |
| Total Proved Plus Probable Reserves | 91,465 |

**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, 2018 | Three months ended June 30, 2018 | Three months ended September 30, 2018 | Three months ended December 31, 2018 |
| Average Daily Production Bitumen (bbls/d) | 93,207 | 71,325 | 98,751 | 87,582 |
| Bitumen Realization Bitumen ($/bbl) | 35.31 | 47.20 | 49.58 | 13.90 |
| Royalties Bitumen ($/bbl) | 1.03 | 1.64 | 2.01 | 0.15 |
| Net Operating Costs[(1)] Bitumen ($/bbl) | 5.98 | 5.64 | 4.34 | 4.55 |
| Transportation[(2)] Bitumen ($/bbl) | 5.99 | 8.28 | 9.11 | 10.28 |
| Realized gain (loss) on commodity risk management | (2.15) | (13.11) | (10.16) | 6.81 |
| Cash Operating Netback[(3)] Bitumen ($/bbl) | 20.16 | 18.53 | 23.96 | 5.73 |

**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 production for the year ended December 31, 2018 from Phases 1, 2 and 2B of the Christina Lake Project was 87,731 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 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 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*, *Environmental Protection and Enhancement Act, Water Act, Public Lands Act, Pipeline 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,* ("CEAA, 2012"), the *Canadian Environmental Protection Act, 1999* ("CEPA")*,* the *Fisheries Act*, the *Navigation Protection Act,* the *Species at Risk 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.

In 2016, the Government of Canada commenced reviews of various environmental and regulatory processes under federal legislation, including expert panel reviews of the federal environmental assessment process and the National Energy Board. As a result of the reviews, the Government has introduced Bill C-69 and Bill C-68, which propose to enact the *Impact Assessment Act* ("IAA") to replace the CEAA, 2012 and to enact the *Canadian Energy Regulator Act* to replace the NEB Act, and to amend the *Navigation Protection Act* and the *Fisheries Act*. If enacted as proposed the legislation will, among other things, result in a broader assessment of impacts caused by certain federally regulated projects, increased opportunities for public participation and increased Indigenous participation throughout all phases of the federal impact assessment process, including a new early planning phase. The proposed IAA only requires federal impact assessments for certain designated projects. It is uncertain whether the list of designated projects under the proposed IAA will be similar to the current list of designated projects under the CEAA, 2012, which does not include in situ oil sands projects as designated projects. The proposed legislation in Bill C-69 and Bill C-68 must still be passed by Parliament in order to become law.

## 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/$m^3$, 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/$m^3$, 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.

On December 3, 2018 the Government of Alberta enacted rules to enable a temporary curtailment of crude oil and bitumen production (the "Curtailment Rules"). The Curtailment Rules came into force on January 1, 2019 and terminate December 31, 2019. The Curtailment Rules give the Minister the authority to make an Order to set the maximum combined provincial production amount of crude oil and bitumen on a monthly basis. The Minister also has the authority to make an Order to set the curtailment amount for each operator. The AER is responsible for ensuring that operators comply with the Curtailment Rules and their individual ministerial orders. Operators that do not comply will be subject to AER enforcement action.

## 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.

## 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, 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. Under the Modernized Royalty Framework, which does not apply to oil sands production, new royalty rules for oil, natural gas and NGLs came into effect in 2017, but include grandfathering, under the old royalty rules, all wells drilled before 2017 for a ten year period. Following the Government of Alberta’s royalty review the royalty structure and rates for oil sands remain generally unchanged, with some minor adjustments to allowable costs and transparency.

The oil sands royalty framework, effective January 1, 2009, establishes royalty rates for bitumen that are linked to price. The Alberta oil sands royalty payable is based on these price-sensitive royalty rates and applied to production volumes. The applicable royalty rates change 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.

On February 3, 2012, the Government of Alberta and the Government of Canada released the Joint Canada-Alberta Implementation Plan for Oil Sands Monitoring (“Monitoring Plan”). In December 2017, the two governments reaffirmed this joint commitment to Oil Sands Monitoring in a signed Memorandum of Understanding and a subsequent Letter of Agreement in September 2018 with Indigenous communities. The Oil Sands Monitoring Program 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. Funding for the monitoring program is collected from industry through the Oil Sands Monitoring Program Regulation to an aggregate amount of up to $50 million a year.

The federal *Species at Risk Act* and provincial *Wildlife Act* regulate threatened and endangered species and may limit the pace and amount of development in areas identified as critical habitat for species of concern such as Woodland Caribou. In Alberta, the Alberta Caribou Action and Range Planning Project has been established to develop action and range plans for sustaining Alberta’s caribou populations. On December 19, 2017, Alberta’s Draft Provincial Woodland Caribou Range Plan was released. The federal and/or provincial implementation of measures to protect species at risk such as Woodland Caribou and their critical habitat in areas of the Corporation’s current or future operations may limit the Corporation’s pace and amount of development in affected areas.

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"). In December, 2015, UNFCCC members agreed to a 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. Canada ratified the Paris Agreement in October 2016.

***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.

On December 9, 2016, the Canadian federal government adopted the Pan Canadian Framework on Clean Growth and Climate Change (the “Framework”) in response to the Paris Agreement. Under the Framework, the federal government introduced a carbon pricing program that includes, at a minimum, a floor price on carbon emissions of $10 per tonne in 2018, rising by $10 per tonne each year to $50 per tonne in 2022. The Framework allows provinces to implement either a carbon tax or use a broad market-based mechanism and includes a federal backstop in the event jurisdictions do not meet the floor carbon price.

The federal *Greenhouse Gas Pollution Pricing Act* (“GGPPA”), came into force on June 21, 2018 and is similar in structure to Alberta’s current approach to carbon pricing in that it includes a levy on fossil fuels and an output-based pricing system for industrial facilities. The GGPPA applies, in whole or in part, in provinces that voluntarily adopt the federal standard or that do not have a carbon pricing system in place that meets the federal standard by January 1, 2019. On October 23, 2018the federal government confirmed that Alberta’s current approach to carbon pricing is equivalent to the federal standard and as a result the GGPPA currently does not apply in Alberta.

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 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 other than the *Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector)* under the CEPA in April 2018. Under the CEPA, federal rules will not apply if equivalent requirements are made under the provincial *Methane Emission Reduction Regulation* under the *Environmental Enhancement and Protection Act*.

***Government of Alberta 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 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 is implementing to address climate change: (i) the complete phase-out of coal-fired sources of electricity by 2030; (ii) an Alberta economy-wide carbon price on GHG emissions of $30 per tonne; (iii) 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 (iv) reducing methane emissions from oil and gas activities by 45% by 2025.

Certain details regarding how the Plan will be implemented including, the carbon levy under the *Climate Leadership Act*, the *Carbon Competitiveness Incentive Regulation* (“CCIR”) and the *Methane Emission Reduction Regulation* have been released. The *Oil Sands Emissions Limit Act* came into force on December 14, 2016; however, it does not obligate oil sands producers until a regulatory system is designed and implemented under the regulations. Certain details regarding how the Plan will be implemented have not been released and uncertainties exist with respect to the implementation of the Plan and the effects that the Plan, including the oil sands emission limit, may have on the industry and the Corporation.

In Alberta, the *Climate Change and Emissions Management Act* 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 Reporting Regulation* ("SGRR"), which imposes GHG emissions reporting requirements and the CCIR, which came into force on January 1, 2018. The CCIR replaces the *Specified Gas Emitters Regulation* (“SGER”) for compliance years 2018 and thereafter.

Various elements of the SGER are included in the CCIR, as the CCIR remains an emissions intensity-based regime requiring large emitters to reduce their emissions intensity below a prescribed level, or otherwise achieve this through a true-up obligation whereby credits can be applied against such required level, together with or as an alternative to physical abatement, with penalties for failure to achieve compliance. However, the CCIR has fundamental differences with SGER as the facility specific baselines in SGER have now largely been replaced in the CCIR with product specific benchmarks.

The CCIR applies to facilities in Alberta that have produced 100,000 or more tonnes of GHG emissions in 2003 or any subsequent year. A facility’s emissions allowance, or output based allocation (“OBA”), is calculated based on the applicable benchmarks for the product it produces. In the case of in situ oil sands a top quartile production-based approach is used to determine the established benchmark. Exported electricity also has an established benchmark. A facility must ensure that its net emissions do not exceed the OBA for the facility. The net emissions for a facility are calculated as the total regulated emissions (“TRE”) minus the sum of any emission offsets, emission performance credits (“EPC”) or fund credits. A facility is required to compare its TRE with its OBA to determine the quantity of emission offsets, EPCs and/or fund credits required to meet the facility’s “true up obligation”, which is the amount by which a facility’s TRE in a reporting period exceeds the facility’s OBA for such reporting period. As was the case under the SGER, a facility can earn EPCs if its TRE is less than the facility’s OBA. EPCs may be banked for use in future compliance, transferred to another regulated facility or sold.

There are four compliance options for facilities that are subject to the CCIR: (i) improve emissions intensity at the facility; (ii) purchase or use banked EPCs; (iii) purchase emission offsets in the open market, which are generated from Alberta based projects; and/or (iv) purchase fund credits by contributing to the Climate Change and Emissions Management Fund ("Fund") run by the Alberta government. Currently the contribution costs to the Fund are set at $30 per tonne although this is subject to change by Ministerial order. Under the CCIR there are no limits on purchasing fund credits to meet a facility's true up obligation; however, the CCIR includes limits on the use of EPCs and emission offsets for compliance purposes, and adds expiry periods for EPCs and emission offsets according to the vintage year.

Annual compliance reports for facilities subject to the CCIR are due on March 31. A facility that exceeds one megatonne of annual emissions is considered a forecasting facility and must also submit an annual forecasting report on November 30 and quarterly interim compliance reports on May 15, August 15 and November 15. In 2018 and 2019 there is a compliance phase-in period, which applies to facilities in both compliance and crediting positions.

The SGRR imposes GHG emissions reporting requirements on facilities that have GHG emissions of 10,000 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.

The *Climate Leadership Act* came into force on January 1, 2017 and establishes an Alberta carbon pricing regime in the form of a carbon levy on various types of fuel. Under the *Climate Leadership Act*, facilities subject to the SGER and the CCIR are exempt from the carbon levy.

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-a-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 recent 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 or State and Country of Residence | Position(s) Held | Director Since | Principal Occupation During the Preceding Five Years |
|---|---|---|---|
| Derek W. Evans......................... Alberta, Canada | President, Chief Executive Officer and a Director | August 10, 2018 | President, Chief Executive Officer and a Director of the Corporation since August 2018. Director of Franco-Nevada Corporation since August 2008. Formerly President, Chief Executive Officer and Director of Pengrowth Energy from 2009 to March 2018. |
| 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 | Chief Operating Officer | N/A | Chief Operating Officer of the Corporation since August 27, 2018, prior to which he served as Senior Vice President, Operations, Resource and Technology Development of the Corporation from November 2017 to August 2018, Senior Vice President, Reservoir and Geosciences of the Corporation from November 2011 until November 2017 and Vice President, Reservoir & Production of the Corporation from September 2004 until November 2011. |
| Grant Borbridge ........................ Alberta, Canada | Senior Vice President, Legal and General Counsel and Corporate Secretary | N/A | Senior Vice President, Legal and General Counsel of the Corporation since November 2017, prior to which he served as Vice President, Legal and 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. |

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|---|---|---|---|
| Aidan Mills ................................ Alberta, Canada | Vice President, Downstream | N/A | Vice President, Downstream of the Corporation since June 2018 prior to which he served as Vice President Marketing of the Corporation since March 2017. Formerly Senior Marketing Advisor at RimRock Oil & Gas from November 2016 to March of 2017, Managing Director, Commodities for Goldman Sachs from June 2014 to October 2016 and VP Commodity Marketing and Supply at Husky Energy from 2009 to 2014. |
| John Nearing ............................ Alberta, Canada | Vice President, Finance and Corporate Services | N/A | Vice President, Finance and Corporate Services since November 2017, prior to which he served as Vice President, Finance & Controller of the Corporation since December 2013, prior to which he served as Controller of the Corporation since December 2011. |
| 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. |
| Jeffrey J. McCaig(5) ................... Alberta, Canada | Chairman of the Board | March 1, 2014 | Director of the Corporation since March 2014. 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. Director of Bantrel Company since 2000, becoming its Chairman in December 2007. Formerly a Director of Potash Corporation of Saskatchewan from January 2001 to May 2017. |
| Harvey Doerr(3)(4)(5).................... Calgary, Canada | Director | June 9, 2010 | Director of the Corporation since June 2010. Interim President and Chief Executive Officer of the Corporation from June 1, 2018 to August 10, 2018. Chairman of Velvet Energy Ltd. since 2011 and Director of Seven Generations Energy Ltd. since 2016. Formerly a director of Newalta Corporation from May 2014 to July 2018. |
| Robert B. Hodgins(1)(2)(5)............ Alberta, Canada | Director | September 23, 2010 | Director of the Corporation since September 2010. Independent businessman and director of AltaGas Ltd., Enerplus Corporation and GranTierra Energy Inc. |

| | | | |
|---|---|---|---|
| Timothy E. Hodgson[(1)(5)] ..................<br>Toronto, Ontario | Director | June 28, 2016 | Director of the Corporation since June 2016. Managing Partner of Alignvest Management Corporation and Chairman of the Board of Alignvest II Acquisition Corp. Director of Hydro One Limited since August 2018. Formerly Chairman of Alignvest Acquisition Corp. from 2015 to 2017. Formerly Special Advisor to Governor Carney at the Bank of Canada from 2010 to 2012. |
| William R. Klesse[(4)(5)] ........................<br>San Antonio, Texas | Director | June 28, 2016 | Director of the Corporation since June 2016. Formerly CEO and Chairman of Valero Energy Corporation from 2005 to 2014. |
| David B. Krieger[(3)(5)] ..................<br>Houston, U.S.A. | Director | February 27, 2004 | Director of the Corporation since February 2004. Managing Director, Warburg Pincus LLC since 2006. |
| James D. McFarland[(1)(2)(3)(4)(5)] ...<br>Alberta, Canada | Director | June 9, 2010 | Director of the Corporation since June 2010. Director of Arrow Exploration Corp. since September 2018. Director of Valeura Energy Inc. since April 2010 and President and CEO until his retirement in 2017. Director of Pengrowth Energy Corporation since 2010. |
| Diana J. McQueen[(2)(3)(4)(5)] ........<br>Alberta, Canada | Director | October 6, 2015 | Director of the Corporation since October 2015. Self-employed consultant since September 2015. Director of Canada WaterNEXT Innovations Inc. Formerly held various Alberta provincial cabinet roles during 2011 to 2015, including Minister of Energy, Minister of Environment and water, and Minister of Municipal Affairs. |

**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. Ms. McQueen is the Chairman of the Governance and Nominating Committee.
(4) Member of the HSE & Reserves Committee. HSE & Reserves Committee was established June 14, 2018. Mr. Klesse is the Chairman of the HSE & Reserves Committee.
(5) Independent director.

As of December 31, 2018, the directors and executive officers of the Corporation, as a group, beneficially owned or held control or direction over, directly or indirectly, 17,365,825 Common Shares, representing approximately 5.85% of the issued and outstanding Common Shares. These Common Shares include a total of 15,986,580 Common Shares which are owned of record and beneficially by WP X LuxCo S.a.r.l. ("WPX Luxco") a subsidiary of Warburg Pincus LLC.

## Corporate Cease Trade Orders or Bankruptcies

Other than as described below, to the Corporation's knowledge, none of its current directors or executive officers (nor any personal holding company of such persons) 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 (including the Corporation) 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") that was issued while the director or officer 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 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 the Corporation's knowledge, other than as described below, none of its directors or executive officers (nor any personal holding company of such persons) 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 the ten years before the date of this Annual Information Form, a director or executive officer of any company (including the Corporation) 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 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 the ten years before the date of 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.

Derek Evans was a director (until his resignation in January 2016) of a private oil and gas company that sought protection under the Companies' Creditors Arrangement Act (Canada) in May 2016.

## 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 (or a subsidiary of the Corporation) and any director or officer of the Corporation(or a subsidiary 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 recommendations 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 nomination 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. Hodgins, Hodgson and McFarland. 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. 296,841,071 Common Shares, and no Preferred

Shares, were issued and outstanding as of December 31, 2018. 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 25, 2017, shareholders passed a resolution extending the term of the Rights Plan until the annual meeting of shareholders of the Corporation to be held in 2020.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, 2018.

| | | Monthly Price Range | |
|---|---|---|---|
| | Volume (Shares) | High | Low |
| | | ($) | ($) |
| January | 35,447,407 | 6.18 | 4.91 |
| February | 30,658,383 | 6.43 | 4.98 |
| March | 23,615,610 | 5.17 | 4.28 |
| April | 41,224,702 | 6.76 | 4.49 |
| May | 70,698,082 | 9.92 | 6.51 |
| June | 54,093,471 | 11.24 | 8.41 |
| July | 47,210,243 | 11.51 | 8.25 |
| August | 48,859,793 | 9.13 | 6.98 |
| September | 32,292,919 | 8.4 | 6.78 |
| October | 86,078,552 | 11.7 | 9.93 |
| November | 34,489,025 | 10.43 | 7.69 |
| December | 31,305,792 | 8.89 | 7.25 |

## 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 future 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.

### Credit Ratings Received by the Corporation as at the Date of this Annual Information Form

| | **Moody's Investors Service** ("Moody's") | **S&P Global Ratings** ("S&P") | **Fitch Ratings** (“Fitch”) |
|---|---|---|---|
| Issuer Credit Rating | B3 (Stable) | B+ (Negative) | B (Stable) |
| Senior Secured Debt (Term Loan & Revolving) | Ba3 | BB | BB |
| Second Lien Secured Debt (Secured Notes) | B3 | BB | BB |
| Senior Unsecured Debt (High Yield Notes) | Caa2 | BB- | B |

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 to pay its financial obligations (its creditworthiness). Long-term credit ratings are intended to provide an independent measure of the credit quality of long-term debt. Fitch’s credit ratings provide an opinion on the relative ability of an entity to meet financial commitments or counterparty obligations.

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 "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 rating of “Ba” by Moody’s is within the fifth highest of nine categories and is assigned to debt securities which are judged to be speculative and subject to substantial credit risk. 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.

S&P's issuer credit ratings are on a rating scale that ranges from AAA to D, 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 B by S&P is within the sixth 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 of individual securities 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 commitments on the obligation.

Fitch’s issuer credit ratings are on a rating scale that ranges from AAA to D 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 B by Fitch is within the sixth highest of eleven categories and indicates that material default risk is present, but a limited margin of safety remains. Financial commitments are currently being met; however, capacity for continued payment is vulnerable to deterioration in the business and economic environment. Fitch’s "stable" outlook indicates a low likelihood of a rating change over a one to two year period.

Fitch’s ratings of individual securities are on a rating scale that ranges from AAA to C, 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 credit rating of BB is within the fifth highest of nine categories and indicates an elevated vulnerability to credit risk, particularly in the event of adverse changes in business or economic conditions over time; however, business or financial alternatives may be available to allow financial commitments to be met. A credit rating of B is within the sixth highest of nine categories and indicates that material credit risk is present.

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, the Corporation’s 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 Corporation’s production enhancement program which uses a combination of proprietary reservoir technologies (including eMSAGP) and processing plant enhancements, debottlenecking and brownfield expansions;
- 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 blend, 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 blend;
- refining markets for MEG's bitumen blend;
- 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 Development

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 been producing bitumen since May 2008, August 2009 and the fourth quarter of 2013, respectively.

While the first three phases of the Christina Lake Project are operational and production enhancement programs have been implemented successfully, additional phases, subsequent production enhancement 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 relatively 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 a steam line failure in May 2007 and in March 2016 a small fire occurred at the Corporation’s sulphur treatment facilities at the Christina Lake site which caused a one day suspension in production. 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.

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 has introduced the Modernized Royalty Framework, effective January 1, 2017, to incorporate a single royalty structure for crude oil, liquids and gas. The Modernized Royalty Framework does not apply to oil sands production. Following the Government of Alberta’s recent royalty review the royalty structure and rates for oil sands remain generally unchanged, with some minor adjustments to allowable costs and transparency. Regulatory changes to the oil sands royalty regime that will be implemented in respect of improving cost, revenue and collection information for oil sands operations were announced February 17, 2017. However, details of specific requirements are still to be determined, and accordingly, it is uncertain what the effects of these changes 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 currently have indefinite terms and 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 *Oil Sands Regulations 2010* under the *Mines and Minerals Act* (Alberta), has designated the minimum level of evaluation, or the MLE and the minimum level of production (MLP), to qualify for continuation. However, since the introduction of the *Oil Sands Tenure Regulations 2010*, Alberta Energy has been in the process of conducting a lease tenure review and it is possible that Alberta Energy may determine that continued leases will have specified terms that are not indefinite as a result of such review. The Corporation cannot predict the outcome of the lease tenure review and the resulting impact on MEG's oil sands leases. In order to assist lessees in adapting to the changing tenure environment, Alberta Energy has relaxed the MLE while such lease tenure review is ongoing and also provided extensions to lease terms. In 2018, Alberta Energy offered the ability for lessees to apply for further lease extensions to March 31, 2021 for leases that fall within designated caribou ranges. MEG received applicable lease expiry extensions to March 31, 2021 on 27 oil sands leases located at Surmont and the Growth Properties.

In view of the potentially changing tenure environment, MEG is actively evaluating all of its oil sands leases to determine the best continuation approach. In 2018, 9 sections on 3 of MEG’s oil sand leases expired in MEG’s Growth Properties. No reserves or contingent resources were associated with these lands. In 2018, MEG received indefinite continuations on 31 leases with 2018 and 2019 expiry dates. With these extensions and continuations, none of MEG's oil sands leases are scheduled to expire in 2019 or 2020.

Certain oil sands leases located in MEG’s Growth Properties (those outside of the Christina Lake, Surmont and May River Regional Projects) are scheduled to expire in 2021 and beyond. MEG is actively working on a lease continuation strategy for these lands in the context of the caribou extensions and the evolving lease tenure regulations.

### 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, and other similar claims that may be initiated, if successful, could have a significant adverse effect on MEG and the Christina Lake Project and MEG's other 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 and Sufficiency of Funds

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.

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 commodity prices, and the Corporation's primary alternate source of funds 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. Similarly, improvements in commodity pricing may result in a decreased need to raise additional capital.

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

### Fluctuations in Market Prices of Crude Oil, Bitumen Blend and Differentials

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, and differentials between world crude oil prices and Canadian heavy crude oil prices, have fluctuated widely during recent years and are subject to fluctuations in response to relatively minor 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 including curtailment orders;
- 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, or a widening of differentials, 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. These factors all contribute to price differentials. Future price differentials are uncertain and any widening in heavy oil differentials specifically 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 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 EDC Guaranteed L/C Facility and the 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 uses physical and financial instruments to hedge its exposure to fluctuations in commodity prices, exchange rates and interest rates. Engagement by the Corporation in such hedging activities will expose it 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 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, and 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 participants 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 (including any limit on oil sands emissions) 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-`a-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.

***IMO 2020***

The International Maritime Organization (“IMO”) is a specialized agency of the United Nations and the main regulatory body for the shipping industry. It is the global standard setting authority for environmental regulation of international shipping. On January 1, 2020 the global limit for sulphur in fuel used onboard ships will decrease from the current upper limit of 3.5 weight percent to 0.5 weight percent. Due to the sulphur content in heavy oils, such as bitumen, processing by complex refineries is required to meet the new IMO sulphur standards and the availability of refining capacity for bitumen may become scarce after the new limit comes into effect. The IMO sulphur regulation has the potential to materially adversely impact the crude marketing of bitumen and contribute to an increased widening of the light to heavy crude oil differential.

***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.

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 and AEP. 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, the Corporation's 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 depletion, depreciation and accretion, fair values, useful lives of assets, deferred income taxes, stock based compensation, estimates of reserves, derivative financial instruments, decommissioning obligations and onerous contracts. 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.

***Credit Ratings***

If commodity prices do not improve or worsen or if the Corporation is unable to increase its liquidity, the Corporation could experience downgrades to its credit ratings. In addition, in the event of any downgrade, certain of the Corporation's service providers, including its pipeline providers and condensate vendors, may require the Corporation to post collateral or provide other assurances of the Corporation's ability to perform its obligations under its contracts with such providers, which would negatively affect the Corporation's liquidity and the borrowing base under the Credit Facilities and, in turn, increase the risk of further downgrades.

### *Cybersecurity*

The Corporation's operations may be negatively impacted by a cybersecurity incident. MEG uses forms of information technology in its operations and such use creates various cybersecurity threats including the possibility of security breaches, operational disruptions and the release of non-public information (such as financial data, supplier and customer information and employee information). Although MEG has taken various steps to protect itself against such risks, its efforts may not always be successful, especially because of the rapidly changing nature of such cybersecurity threats. In the event of a cybersecurity incident, MEG's operations could be disrupted resulting in potential loss of customers, violation of laws and additional liabilities to the business.

## Risks Relating to Financing and the Corporation's Indebtedness

### *Restrictions Contained in Credit Facilities, Notes and Debt Service Obligations*

Upon the occurrence of any event of default under the Credit Facilities and the EDC Guaranteed L/C Facility, MEG's lenders and other secured parties 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 and other secured parties under the Credit Facilities and the EDC Guaranteed L/C Facility accelerate the payment of the indebtedness outstanding thereunder, MEG's assets may not be sufficient to repay in full that indebtedness and MEG's other indebtedness, including the Second Lien Notes.

The restrictions in the Credit Facilities, the EDC Guaranteed L/C Facility and the indentures governing the Notes may adversely affect MEG's ability to finance its future operations and capital needs and to pursue available business opportunities. Moreover, any new indebtedness MEG incurs may impose financial restrictions and other covenants on MEG that may be more restrictive than the Credit Facilities, the EDC Guaranteed L/C Facility and the indentures governing the Notes.

The Corporation's indebtedness could materially and adversely affect it in a number of ways. For example, it could:

- require the Corporation to dedicate a portion of its cash flow to service payments on its indebtedness, thereby reducing the availability of cash flow to fund working capital, capital expenditures, development efforts and other general corporate purposes;
- increase the Corporation's vulnerability to general adverse economic and industry conditions;
- limit the Corporation's flexibility in planning for, or reacting to, changes in its business and the industry in which it operates;
- place the Corporation at a competitive disadvantage compared to its competitors that have less debt;
- expose the Corporation to the risk of increased interest rates as the Credit Facilities and the EDC Guaranteed L/C Facility are at variable rates of interest; and
- limit the Corporation's ability to borrow additional funds to meet its operating expenses and for other purposes.

The Corporation may not generate sufficient cash flow and may not have available to it future borrowings in an amount sufficient to enable it to make payments with respect to its indebtedness or to fund its other capital needs. In these circumstances, the Corporation may need to refinance all or a portion of its indebtedness on or before maturity. 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 favourable to it or at all, and the terms of the Credit Facilities, the EDC Guaranteed L/C Facility, certain other permitted obligations and the indentures governing the Notes may limit its ability to sell assets and also restrict the use of proceeds from such a sale.

### *Additional Indebtedness*

Despite MEG's current level of indebtedness, it may still be able to incur substantially more debt, which could further exacerbate the risks associated with MEG's substantial leverage.

# LEGAL PROCEEDINGS AND REGULATORY ACTIONS

Except as described below, during the year ended December 31, 2018, there were 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.

During the year ended December 31, 2018, there were no penalties or sanctions imposed against the Corporation by a court relating to 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 securities legislation or with a securities regulatory authority.

From time to time, the Corporation is the subject of litigation arising out of the normal course of operations. Damages claimed under such litigation may be material and the outcome of such litigation can be difficult to predict and may materially impact the Corporation's financial condition or results of operations. While the Corporation assesses the merits of each lawsuit and defends itself accordingly, the Corporation may be required to incur significant expenses or devote significant resources to defend itself against such litigation. See "Risk Factors"

MEG is the defendant in an action brought by Chemtrade Electrochem Inc. ("Chemtrade"), a wholly owned subsidiary of Chemtrade Logistics Income Fund (and successor entity to Canexus Corporation) in the Alberta Court of Queen's Bench. The claim was originally filed in 2014 in relation to legacy issues involving a unit train transloading facility. Amendments to the original claim were filed on December 12, 2017. MEG filed a statement of defence on January 8, 2018. Although the amended claim asserts a significant increase to damages claimed, MEG, in consultation with its legal advisors, continues to view this claim, and the recent amendments, as without merit and will defend against all claims asserted by Chemtrade. MEG may be required to incur significant expenses or devote significant resources to defend itself against the claim.

# 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, 2018 which can be found on SEDAR at www.sedar.com, no director or executive officer of the Corporation, or person or company that beneficially owns, or controls or directs, directly or indirectly, more than 10% of any class or series of the Corporation's outstanding voting securities, or associate or affiliate of those persons or companies, has any material interest, direct or indirect, in any transaction within the last three most recently completely financial years or during the current financial year 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 7$^{th}$, 2019 in respect of the Corporation's consolidated financial statements as of December 31, 2018 and December 31, 2017 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 the GLJ 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, 2018.

# GLOSSARY AND DEFINITIONS

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

"**2011 Notes**" means the 6.50% Senior Notes due 2021, issued pursuant to an indenture dated as of March 18, 2011, as supplemented, among MEG, the guarantor party thereto and Wilmington Trust, National Association, as trustee and which were redeemed on March 15, 2017 in conjunction with the issuance of the Second Lien Notes.

"**2012 Notes**" means the 6.375% Senior Notes due 2023, issued pursuant to an indenture dated as of July 19, 2012 among MEG, the guarantor party thereto and Wilmington Trust, National Association, as trustee.

"**2013 Notes**" means the 7.0% Senior Notes due 2024, issued pursuant to an indenture dated as of October 1, 2013 and a supplemental indenture dated November 6, 2013, among MEG, the guarantor party thereto and Wilmington Trust, National Association, as trustee.

"**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), as amended, including the regulations promulgated thereunder.

"**Access Pipeline**" means the 215-mile dual pipeline system, which connects the Christina Lake Project to 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.

"**AEP**" means Alberta Environment and Parks.

"**AER**" means the Alberta Energy Regulator.

"**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.

"**BMO Letter of Credit Agreement**" means the Credit Agreement dated as of December 15, 2014 between the Corporation and Bank of Montreal, as amended, modified or supplemented from time to time.

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

“**Bruderheim Terminal**” means the pipeline connected unit train transloading facility owned and operated by Bruderheim Energy Terminal Ltd., a wholly-owned subsidiary of Cenovus.

"**Christina Lake Project**" means MEG's in situ oil sands project located in the Province of Alberta as described in greater detail under the heading "Christina Lake Project" on page 10 of this AIF.

"**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$225.4 million principal amount term loan and a US$1.4 billion principal amount revolving credit facility, all as may be further amended or replaced from time to time.

"**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.

"**EDC Guarantee**" means the Performance Security Guarantee Issuance and Indemnity Agreement dated as of December 15, 2014 between the Corporation and Export Development Canada, as amended, modified or supplemented from time to time.

"**EDC Guaranteed L/C Facility**" means, collectively, the EDC Guarantee and the BMO Letter of Credit Agreement, as amended, modified or supplemented from time to time.

“**eMSAGP**” means the Corporation’s proprietary reservoir technology of enhanced Modified Steam and Gas Push, which involves the injection of non-condensable gas into the SAGD reservoir.

“**eMVAPEX**” means the Corporation’s proprietary recovery process known as enhanced modified vapour extraction which involves the injection of solvent into the SAGD reservoir.

"**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 AEP.

"**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, 2018, with a preparation date of February 6, 2019 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 "Growth Properties" on page 15 of this AIF.

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

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

“**IMO**” means the International Maritime Organization.

“**IMO 2020**” means the global limit, proposed by the IMO to come into effect on January 1, 2020, for sulphur content in fuel used onboard marine ships of 0.5 weight percent, a decrease from the current upper limit of 3.5 weight percent.

"**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 "May River Regional Project” on page 14 of this AIF.

"**McMurray Formation**" 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*.

"**Notes**" means, collectively, the 2011 Notes, the 2012 Notes, the 2013 Notes and the Second Lien Notes.

"**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.

“**Phase 1**” means the first phase of the Corporation’s Christina Lake Project which commenced production in 2008 with an initial bitumen production design capacity of approximately 3,000 bbls/d.

“**Phase 2**” means the second phase of the Corporation’s Christina Lake Project which commenced production in 2009 with an initial bitumen production design capacity of approximately 22,000 bbls/d which utilized existing central processing facilities associated with Phase 1, and primarily expanded well pad drilling and tie-ins to increase production.

“**Phase 2B**” means the third phase of the Corporation’s Christina Lake Project which commenced production in 2013 with an initial bitumen production design capacity of approximately 35,000 bbls/d

"**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.

"**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 Lien Notes**" means the 6.50% Senior Secured Lien Notes due 2025, issued pursuant to an indenture dated as of January 27, 2017 among MEG, Wilmington Trust, National Association, as trustee, and Computershare Trust Company of Canada, as collateral agent.

"**Shareholder Rights Plan Agreement**" means the shareholder rights plan agreement dated August 6, 2010, as amended and restated from time to time 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.

“**SIRs**” means supplemental information requests received the Corporation from the AER and AEP in the course of seeking regulatory approvals.

"**SOR**" means steam to oil ratio.

"**Stonefell Terminal**" means the terminalling and storage facility 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 "Surmont Project" on page 12 of this AIF.

"**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, contingent resources data as at December 31, 2018. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2018, estimated using forecast prices and costs. The contingent resources data are risked estimates of volume of contingent resources and related risked net present value of future net revenue as at December 31, 2018, 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, 2018, 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, 2018 | Canada | - | 20,045 | - | **20,045** |

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:

| Classification | Independent Qualified Reserves Evaluator or Auditor | Effective Date of Evaluation Report | Location of Resources Other than Reserves (Country or Foreign Geographic Area) | Risked Volume (Mboe) | Risked Net Present Value of Future Net Revenue (before income taxes, 10% discount rate – MM$) Audited | Evaluated | Total |
|---|---|---|---|---|---|---|---|
| Development Pending Contingent Resources (2C) | GLJ Petroleum Consultants | Dec. 31, 2018 | Canada | 1,722,020 | - | 5,837 | **5,837** |

| Classification | Independent Qualified Reserves Evaluator or Auditor | Effective Date of Evaluation Report | Location of Resources Other than Reserves (Country or Foreign Geographic Area) | Risked Volume (Mboe) |
|---|---|---|---|---|
| Development Unclarified Contingent Resources (2C) | GLJ Petroleum Consultants | Dec. 31, 2018 | Canada | 718,066 |

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, February 6, 2019

*"Originally Signed by"*
Caralyn P. Bennett, P. Eng.
Executive Vice President, Chief Strategy Officer

## 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 is the report 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 data and contingent resources data are based on judgments regarding future events, actual results will vary and the variations may be material.

(signed) "*Derek Evans*"
Derek Evans
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 7, 2019

# APPENDIX C

# AUDIT COMMITTEE CHARTER AND RELATED INFORMATION

## 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) On an annual basis, review with management the Corporation's significant tax matters with respect to income tax and other tax obligations.

(h) 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.

(i) Approve all audit or related services fees related to the Extractive Sector Transparency Measures Act. Review with management and with the external auditors the Extractive Sector Transparency Measures Act Report and approve the filing of the Extractive Sector Transparency Measures Act Report with Natural Resources Canada (NRCan).

(j) 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 where appropriate, the adequacy and effectiveness of the internal control and management information systems and procedures, including cybersecurity controls 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), Hodgson and McFarland. 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 Professional Accountant designation and was admitted as a member of the Institute of Chartered Accountants of Ontario in 1977 and Alberta in 1991.

- Mr. Hodgson is Managing Partner of Alignvest Management Corporation. He is also Chairman of the Board of Alignvest Acquisition II Corp. Prior to joining Alignvest, Mr. Hodgson was Special Advisor to Governor Carney at the Bank of Canada from 2010 to 2012, where he led the Bank's market infrastructure initiatives. While serving at the Bank, Mr. Hodgson sat on the Bank's Monetary Policy Review Committee and Financial Stability Committee. Additionally, he represented the Bank on the Heads of Agencies Committee, and on the Heads of Dealers Committee with the heads of the major Canadian investment banks. From 1990 to 2010, Mr. Hodgson held various positions in New York, London, Silicon Valley and Toronto with Goldman Sachs. In addition to his positions with Alignvest, Mr. Hodgson currently is a director of Hydro One Limited and sits on the boards of The Public Sector Pension Investment Board where he chairs the Investment Committee, KGS-Alpha Capital Markets and The Global Risk Institute. Mr. Hodgson holds a Masters of Business Administration from The Richard Ivey School of Business at Western University and a Bachelor of Commerce from the University of Manitoba. He is a Fellow of the Institute of Chartered Professional Accountants (FCPA) and a member of the Institute of Corporate Directors..

- Mr. McFarland is a co-founder and has been a director of Valeura Energy Inc. since April 2010 and served as President and CEO. until his retirement in December 2017. He has over 45 years of experience in the oil and gas industry. Prior thereto, Mr. McFarland served as President and CEO, director and co-founder of Verenex Energy Inc. from 2004 until 2009. From 1999 until 2004, he served as Managing Director of Southern Pacific Petroleum N.L. in Australia. From 1995 until 1998, Mr. McFarland served as President and Chief Operating Officer of Husky Oil Limited. From 1972 until 1995, he held various leadership positions in a 23 year career with Imperial Oil Limited and other Exxon affiliates in Canada, the U.S. and Western Europe. Mr. McFarland has been a director of various public and private entities and is currently a director of Pengrowth Energy Corporation, Valeura Energy Inc. and Arrow Exploration Corp. He also serves on the Program Committee of the World Petroleum Council. Mr. McFarland received a Bachelor of Science (Honours) (Chemical Engineering) from Queen's University at Kingston in 1970, a Master of Science (Petroleum Engineering) from the University of Alberta in 1974, completed the Executive Development Program at Cornell University in 1981 and the Governor General's Canadian Study Conference in 1987, received the designation of Professional Engineer in 1974 and is a member of 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:

| | 2017 | 2018 |
|---|---|---|
| Audit Fees | $ 314,692 | $ 333,900 |
| Audit Related Fees(1) | $ 469,103 | $ 556,644 |
| Tax Fees(2) | $ 110,088 | $ 116,347 |
| All Other Fees(3) | $ 3,780 | $ 3,780 |
| Total | $ 897,663 | $ 1,010,671 |

**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) 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, 2019 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, 2018**
**FORECAST PRICES AND COSTS**

| Resources Project Maturity Sub-Class | Contingent Resources – Best Estimate(1)(2)(3) Bitumen Gross (Mbbl) | Contingent Resources – Best Estimate(1)(2)(3) Bitumen Net (Mbbl) |
|---|---|---|
| CONTINGENT (2C) Development Pending .......................... | 1,722 | 1,289 |
| CONTINGENT (2C) Development Unclarified(4) .................... | 718 | 570 |

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 unrisked basis, there has been no material change between the contingent resources assigned to the Corporation's properties in the 2017 GLJ Report and the 2018 GLJ Report, except for the May River project that had a ~3% reduction from technical revisions.

**SUMMARY OF RISKED NET PRESENT VALUE OF FUTURE NET REVENUE(1)**
**(CONTINGENT RESOURCES – Best Estimate) as of December 31, 2018**
**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.**

| | Risked Net Present Value of Future Net Revenue (Bitumen) | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Before Income Taxes Discounted at (%/Year) | | | | | After Income Taxes Discounted at (%/Year) | | | | |
| Resources Project Maturity Sub-Class | 0 | 5 | 10 | 15 | 20 | 0 | 5 | 10 | 15 | 20 |

| | (MM$) | (MM$) | (MM$) | (MM$) | (MM$) | (MM$) | (MM$) | (MM$) | (MM$) | (MM$) |
|---|---|---|---|---|---|---|---|---|---|---|
| CONTINGENT (2C) Development Pending ................................................ | 60,587 | 18,246 | 5,837 | 1,771 | 335 | 53,642 | 15,843 | 4,885 | 1,348 | 130 |
| CONTINGENT (2C) Development Unclarified ................................................ | 20,548 | 5,550 | 1,484 | 290 | -64 | 17,618 | 4,483 | 1,065 | 114 | -142 |

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 unclarified', 'development on hold' and 'development pending'. Characteristics of the 'development pending' and 'development unclarified' 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 Unclarified: 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 unclarified' 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 Regional Projects:

| Project | Project Maturity Subclass | Project Evaluation Scenario Status | Risked Best Estimate Contingent Resource Gross (MMbbl) | Project C.O.C. (Chance of Commerciality) | Estimated Capital to Reach First Commercial Production (MM$)[(1,2)] | Timing of First Commercial Production[(1)] |
|---|---|---|---|---|---|---|
| **Christina Lake** | Development Pending | Development Study | 962 | 95% | $1,918 | 2027 |
| **Surmont** | Development Pending | Development Study | 327 | 93% | $179 | 2025 |
| **May River Regional Project** | Development Pending | Pre-Development Study | 434 | 93% | $2,488 | 2027 |
| | Development Unclarified | Pre-Development Study | 718 | 78% | $2,271 | 2029 |

**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 2019. See "Risk Factors".

(2) Capital presented is risked by chance of commerciality

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 the 2017 GLJ Report and the 2018 GLJ Report, except for the May River project that had a ~3% reduction from technical revisions.

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. The technical aspects of the regulatory approval have been completed and there are no remaining stakeholder statements of concerns. The Corporation anticipates receiving approval for the Surmont Project from the AER in 2019.

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. As of December 31, 2018, 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. On February 21, 2017 the Corporation filed regulatory applications with the AER for the May River Regional Project. As a normal part of the regulatory review process, the Company received SIRs from the AER and AEP in May 2017 and November 2017. MEG responded to the SIRs in September 2017 and January 2018. The May River Project Environmental Impact Assessment was deemed technically complete by the AER in February 2018. In accordance with AER requirements, MEG is actively working with stakeholders to address concerns raised on the May River Regional Project.

Management anticipates, consistent with the resource estimates contained in the GLJ Report, that the May River Regional Project can support an average of 164,000 bbls/d of bitumen production. The May River Regional Project is expected to use SAGD (and when mature enough, other proprietary technologies such as eMSAGP and eMVAPEX) similar to the Christina Lake Project.

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.

MEG Energy

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