MEG ENERGY

Sustainable. Innovative. Responsible.

Annual Information Form

February 27 | **2023** | For the year ended December 31, 2022

TSX | MEG

Certain financial measures in this Annual Information Form ("AIF") are non-GAAP financial measures or ratios, supplementary financial measures and capital management measures. These measures are not defined by IFRS and, therefore, may not be comparable to similar measures provided by other companies. These non-GAAP and other financial measures should not be considered in isolation or as an alternative for measures of performance prepared in accordance with IFRS. Please refer to the "Non-GAAP and Other Financial Measures" section of this AIF for further descriptions of the measures noted below.

1. *Non-GAAP financial measures and ratios:*

    - *Cash operating netback*
    - *Bitumen realization*
    - *Net transportation and storage expense*
    - *Bitumen realization after net transportation and storage expense*
    - *Operating expenses net of power revenue*
    - *Per barrel figures associated with non-GAAP financial measures*

2. *Supplementary financial measures and ratios:*

    - *Non-energy operating costs*
    - *Energy operating costs*
    - *Per barrel figures associated with supplementary financial measures*

3. *Capital management measures:*

    - *Net debt*

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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", "forecast", "future", "strategy" 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 – Contingent Resources. Readers are cautioned that the term Reserves Life Index or RLI (as defined herein) may be misleading, particularly if used in isolation. This measure is used for consistency with other oil and gas companies and does not reflect the actual life of the reserves. 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, including expected 2023 average production;
- the Corporation's strategy and opportunities;
- the Corporation's capital expenditure programs and future capital requirements, including the expectation that the Corporation's 2023 capital investment plan will be fully funded with internally generated cash flow;
- the Corporation’s execution on its capital allocation strategy;
- 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 (as defined herein) 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 and potential government-imposed production curtailments;
- potential future markets for the Corporation's products;
- the planned construction of the Corporation's facilities;
- the anticipated timing and effect of turnaround activities;
- the Corporation's drilling plans;
- the Corporation's plans for, and results of, exploration and development activities;
- the receipt of regulatory approvals associated with potential expansions at the Christina Lake Project;
- the Corporation's treatment under governmental regulatory and royalty regimes and tax laws;
- the Christina Lake Project achieving payout in the first quarter of 2023 and the associated increase to royalty rates;
- the Corporation's execution on its environmental, social, and governance ("ESG") commitments, including its 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, leases, 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 SOR (as defined herein);
- 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;
- future sources of insurance for the Corporation's property and operations;
- 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;
- the impact of increasing activism related to climate change, public opposition to the ongoing development of fossil fuels and the adoption of increasingly stringent targets and supporting legislation by governments in response to these shifting societal attitudes; and
- the Corporation's ability to obtain financing and insurance 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:

- a reduction in global crude oil and other petroleum product prices or a widening of differentials between differing grades of crude oil;
- 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 or other third-party claims;
- the effect of any diluent supply constraints and increases in the cost thereof;
- operational hazards including 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 and eMSAGP (each as defined herein) bitumen recovery processes;
- changes to royalty regimes;
- the failure of the Corporation to meet specific requirements in respect of its mineral leases;
- claims made by Indigenous peoples;
- 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, including rising interest rates and potential global recession;
- volatility of commodity inputs;
- inflationary pressures and increased supply costs;
- variations in foreign exchange rates and interest rates;
- hedging strategies;
- national or global financial crises;
- public health crises such as the COVID-19 pandemic, including continued weakness and volatility of crude oil and other petroleum products prices from decreased global demand resulting from the COVID-19 pandemic and in particular, the pace of relaxation of "zero-tolerance" COVID-19 policies in China;

- environmental risks and hazards and the cost of compliance with current and future environmental legislation and regulations, including GHG regulations, potential climate change legislation and potential land use regulations;
- 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 capital, both foreign and domestic;
- increased activism and public opposition to fossil fuel development and the continuation or acceleration of the global energy transition away from fossil fuels;
- uncertainties associated with climate change, including both physical risks from changing or extreme weather patterns, transitional risks associated with the consequences of a global transition (or acceleration thereof) to a less carbon-intensive economy, and technological, reputational and other risks;
- a failure to meet ESG related goals including: (i) the mid-term target of reducing absolute GHG emissions (Scope 1 and Scope 2) by 0.63 megatonnes by 2030; and (ii) the goal to achieve net zero Scope 1 and Scope 2 GHG emissions by 2050;
- failure to obtain or retain key personnel;
- unavailability of, or increased cost of skilled labour or technical professionals;
- potential conflicts of interest;
- changes to tax laws and government incentive programs, including a potential windfall profits tax;
- 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 Facility and the indentures governing our Notes (as defined herein) and future indebtedness;
- any requirements 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; 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 Phase 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) 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.

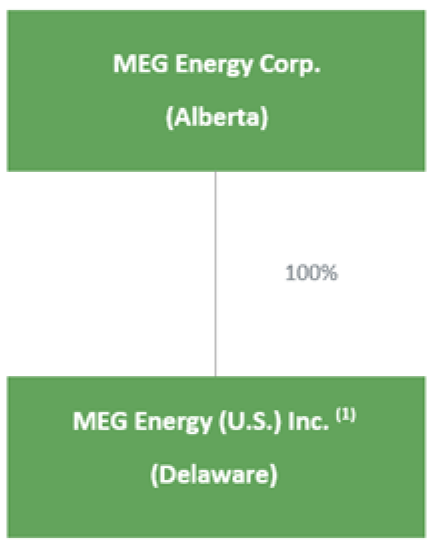
This cautionary statement qualifies all forward-looking information contained in this Annual Information Form.

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.



Note:
(1) MEG US is a guarantor under the Notes and the Credit Facility.

THREE YEAR DEVELOPMENT

The following describes significant events and conditions that have influenced the development of the Corporation's business during the last three financial years:

2020

Continuing debt reduction initiatives. On January 31, 2020, MEG completed a private offering of US$1.2 billion in aggregate principal amount of 7.125% notes due in 2027 (2020 Notes). The net proceeds of the offering, together with cash on hand, were used to fully redeem US$800 million in aggregate principal amount of senior unsecured notes due

March 2023 and partially redeem US$400 million in aggregate principal amount of senior unsecured notes due March 2024 (2013 Notes). Concurrently, MEG redeemed US$100 million ($132 million) of the Second Lien Notes due 2025.

Response to COVID-19. On March 17, 2020, Alberta's Chief Medical Officer of Health declared a public health emergency in an effort to combat the spread of COVID-19 and on March 27, 2020 MEG's business activities were declared an essential service by the Alberta Government. At the onset of the global pandemic, MEG established a COVID-19 task force comprised of members of senior management and employees as well as third party expert consultants to promptly implement measures to protect the health and safety of MEG's work force and the public, as well as to ensure continuity of operations. MEG directed the vast majority of its office staff and certain non-essential field staff to work from home, and implemented mandatory self-quarantine policies, travel restrictions, screening protocols, enhanced cleaning and sanitation measures, social distancing measures, revised shift schedules and increased appropriate personal protective equipment. Flexibility and adaptability continue to be integral to the MEG's response to the pandemic.

Turnaround Activities. MEG conducted a turnaround at the Phase 1 and 2 facilities, which began in early June 2020 and was completed mid-August 2020. The 2020 turnaround was extended in duration to 75 days and expanded in scope, relative to base budget, in order to minimize staff levels at site during COVID-19 and maximize utilization of MEG's internal resources thereby lowering overall cash costs. MEG also made the decision to advance turnaround activities from 2021 to significantly reduce 2021 turnaround requirements.

2021 Capital Budget. On December 7, 2020, MEG announced its 2021 capital investment plan, including a capital budget of $260 million. MEG focused on production optimization and continued debt reduction. Concurrently, MEG announced expected 2021 annual average production of 86,000 – 90,000 bbls/d. MEG subsequently announced successive revisions to guidance on May 3, 2021, July 22, 2021, and November 8, 2021, with the last revision to guidance on November 8, 2021, reflecting 2021 capital expenditures of $335 million and annual average production of 92,500 – 93,500 bbls/d.

2021

Continuing debt reduction initiatives. On February 2, 2021, MEG successfully closed a private offering of US$600 million in aggregate principal amount of 5.875% senior unsecured notes due in 2029 (2021 Notes). The net proceeds of the offering, together with cash on hand, were used to fully redeem the 2013 Notes.

On August 23, 2021, MEG redeemed an additional US$100 million in aggregate principal amount of its 6.50% senior secured second lien notes due 2025 (Second Lien Notes). On November 29, 2021, MEG issued a notice to redeem US$225 million aggregate principal amount of the Second Lien Notes at a redemption price of 101.625% plus accrued and unpaid interest up to the redemption date, which occurred on January 18, 2022. Inclusive of these redemptions, MEG redeemed US$579 million of the original US$750 million principal balance of the Second Lien Notes, leaving US$171 million principal balance outstanding. The Corporation has repaid US$2.6 billion of outstanding indebtedness since 2016 and remains committed to continued debt reduction as a key component of its ongoing capital allocation strategy.

ESG Initiatives. MEG remains committed to its long-term goal of reaching net zero Scope 1 and Scope 2 GHG emissions by 2050. In the third quarter of 2021, MEG adopted a mid-term target of reaching a 30% reduction in bitumen GHG emissions intensity (Scope 1 and Scope 2) from 2013 levels by 2030. MEG, along with five other oil sands operators that collectively represent about 95% of Canada's operated oil sands production, formed the Oilsands Pathways to Net Zero ("Pathways") Alliance to work collectively with the federal and Alberta governments to achieve net zero GHG emissions from oil sands operations by 2050. The Pathways Alliance proposes to reduce oil sands production emissions in three phases: Phase 1 (2021-2030), Phase 2 (2031-2040) and Phase 3 (2041-2050). In Phase 1, Pathways will focus on building out a $C0_2$ capture network in the oil sands producing region of northern Alberta. A key aspect of this network is a proposed CO_2 transportation line to gather CO_2 from more than 20 oil sands facilities and move it to a proposed sequestration hub in the Cold Lake area of Alberta for storage. The carbon transportation line would also be available to other industries in the region interested in capturing and storing CO_2.

Revisions to Guidance and Capital Budget. MEG announced successive revisions to guidance on May 3, 2021, July 22, 2021, and November 8, 2021, with the last revision to guidance on November 8, 2021, reflecting, among other items, annual average production of 92,500 – 93,500 bbls/d.

2022 Capital Budget, Further Debt Reduction. On November 29, 2021, MEG announced its 2022 capital investment plan, including a capital budget of $375 million. Concurrently, MEG announced expected 2022 annual average production of 94,000 – 97,000 bbls/d.

2022

Continuing Debt Reduction. On March 3, 2022, the Corporation issued a notice to fully redeem the remaining $171 million principal balance outstanding of its Second Lien Notes at a redemption price of 101.625% plus accrued and unpaid interest to, but not including the redemption date. The redemption was completed on April 4, 2022. Inclusive of the redemption, MEG redeemed in full the original US$750 million aggregate principal amount of the Second Lien Notes.

Extension of Revolving Credit Facility. On June 24, 2022, the Corporation amended and restated its revolving credit facility and its letters of credit facility guaranteed by Export Development Canada ("EDC") and extended the maturity date of each facility by 2.3 years to October 1, 2026. Total credit available under the two facilities was reduced from $1.3 billion to $1.2 billion and is comprised of $600 million under the revolving credit facility and $600 million under the EDC facility.

Normal Course Issuer Bid. In anticipation of reaching its previously announced near-term net debt target of US$1.7 billion, on March 3, 2022, the Corporation filed an application with the Toronto Stock Exchange ("TSX") for a normal course issuer bid ("NCIB") which allowed MEG to initiate a share buyback program to buyback over a twelve-month period up to approximately 10% of the Corporation's public float.

Advanced Capital Allocation Strategy. The Corporation started the year allocating all free cash flow to debt reduction. In the second quarter, upon reaching net debt of US$1.7 billion, the Corporation initiated the allocation of approximately 25% of free cash flow to share buybacks with the remainder applied to debt reduction. At the end of the third quarter, net debt declined to US$1.2 billion and free cash flow allocated to share buybacks was raised to approximately 50% with the remainder applied to debt reduction. This allocation will remain in place until net debt reaches US$600 million, which is expected to occur beyond 2023 at current oil prices. In 2022, the Corporation returned $382 million to shareholders by buying 20.7 million shares and repurchased US$1.0 billion of debt.

Continued Pathways Alliance Progress. MEG and its Pathways Alliance partners continued to make significant progress in advancing the early work required to build one of the world's largest carbon capture and storage ("CCS") facilities. The Pathways Alliance progressed engagement with more than 20 Indigenous communities along the proposed CO2 storage corridor, completed pre-engineering for the CO2 pipeline and is conducting field programs to support regulatory applications and engineering studies related to the CO2 capture facilities. On October 4, 2022 the Pathways Alliance was one of 19 CCS proposals chosen to proceed to the next stage of evaluation by the Alberta government. The Pathways Alliance partners have identified $24.1 billion of investments in CCS and other emissions projects as part of the first phase of its goal to reduce emissions by 22 million tonnes per year by 2030 and reach net zero emissions from the oil sands by 2050. Pathways Alliance work continues with the Federal and Alberta governments on the appropriate co-investment mechanisms, in addition to the planned Federal Investment Tax Credit.

2023 Capital Budget. On November 28, 2022, MEG announced its 2023 capital investment plan, including a capital budget of $450 million. Concurrently, MEG announced expected 2023 annual average production of 100,000 – 105,000 bbls/d including a planned Q2 turnaround which is anticipated to reduce full year production by approximately 6,000 bbls/d.

PROJECTS OVERVIEW

BUSINESS OVERVIEW

MEG is an energy company focused on sustainable *in situ* thermal oil production in the southern Athabasca oil region of Alberta, Canada. MEG is actively developing innovative enhanced oil recovery projects that utilize steam-assisted gravity drainage ("SAGD") extraction methods to improve the responsible economic recovery of oil as well as lower carbon emissions. MEG transports and sells thermal oil (known as Access Western Blend or "AWB") to customers throughout North America and internationally.

MEG owns a 100% working interest in approximately 410 square miles of mineral leases. In the GLJ report, which is dated effective December 31, 2022 (the "GLJ Report"), GLJ estimated that the leases it had evaluated contained approximately 1.94 billion barrels of gross proved plus probable ("2P") bitumen reserves at the Christina Lake Project, where MEG has regulatory approval in place for 210,000 bbls/d of production. At a steam-oil ratio of 2.2, MEG has developed oil processing capacity of approximately 110,000 bbls/d at its Christina Lake central plant facility, prior to any impact from scheduled maintenance activity or outages. The typical average annual production decline rate at the Christina Lake Project is approximately 10% to 15% and at an annual production level of approximately 103,700 bbls/d, MEG has a 2P reserve life index of greater than 50 years.

The Corporation has been able to realize production growth over time at the Christina Lake Project while minimizing SOR and associated greenhouse gas ("GHG") emissions intensity through the application of proprietary technologies, including MEG's proprietary reservoir technology eMSAGP, which reduces the amount of steam required to produce a barrel of bitumen. MEG also uses cogeneration, also known as combined heat and power generation, to create steam and power from a single heat source. The application of eMSAGP and cogeneration have enabled MEG to lower its GHG emissions intensity more than 15% below the *in situ* industry volume weighted average calculated based on data reported to Environment Canada, the Alberta Energy Regulator and the Alberta Electric System Operator. In addition, in 2022, as part of a broader development strategy, MEG introduced enhanced completion designs and optimized inter-well spacing all focused on reducing SOR. MEG achieved an average SOR of 2.36 in 2022 compared to the *in situ* industry volume weighted average of 3.0. [1]

The Corporation delivers its production to market via a long-term transportation services agreement on the Access Pipeline which connects to the Edmonton, Alberta sales hub and via additional pipelines and storage facilities to customers in high value markets. MEG has 100,000 bbls/d of bitumen blend transportation capacity on the Flanagan South and Seaway pipeline systems providing pipeline transportation directly to U.S. Gulf Coast ("USGC") refineries and export terminals. Additionally, MEG is a shipper on the Trans Mountain Expansion Project which, when in service, will provide MEG with 20,000 bbls/d of bitumen blend pipeline transportation capacity to Canada's West Coast. MEG also has proprietary and contracted oil storage capacity of approximately 2.1 million barrels in Alberta and strategic locations in the U.S., with marine export capacity at Beaumont, Texas in the USGC. This combination of pipeline access, storage capacity and marine export capability advances MEG's strategy of having diversified, long-term and reliable market access to world oil prices for its production.

The following table sets forth certain summary information from the GLJ Report with respect to MEG's assets as of December 31, 2022:

Asset	**Proved Reserves (MMbbls)**	**Probable Reserves (MMbbls)**	**Proved plus Probable Before Tax PV-10% (MM$)**
Christina Lake Project	1,208	731	17,884
Total[(1)]	**1,208**	**731**	**17,884**

Note:
(1) Proved and probable reserves include the Corporation's total interest before royalties.

As of December 31, 2022, MEG employed 429 full time permanent employees and 1 part-time permanent employee. MEG also engages a number of contractors and service providers.

CHRISTINA LAKE PROJECT

The Christina Lake Project is situated on 80 square miles of mineral leases in the southern Athabasca 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 Canadian Natural Resources Limited's Jackfish SAGD project. MEG owns a 100% working interest in the mineral 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.

[1] Annual 2022 data as per the Alberta Energy Regulator ST53.

Reserves and Resources

GLJ Report

In the GLJ Report, GLJ assigned proved and probable developed reserves to the existing wells and producing facility at the Christina Lake Project. Proved and probable undeveloped reserves are assigned to future planned wells to maintain existing project production along with wells associated with processing plant debottlenecking and brownfield expansions at the Christina Lake Project. Contingent resources were also assigned to the Christina Lake Project. See "Independent Reserves Evaluation" and Appendix D - Contingent Resources 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 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 and the McMurray Formation is variably saturated with water, bitumen and natural gas. Bitumen from the McMurray Formation has an average API gravity of approximately 8 degrees.

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 ranges in thickness from 9 to 56 metres with an average approximate thickness of 19 metres. Bitumen saturation is between 60% and 85%. Reservoir sands have average porosity of 33%. Absolute permeability of the sand is 3,000 to 5,000 millidarcies. Initial reservoir pressure is 2,100 kPa and *in situ* reservoir temperature is 12^{o}C. Bitumen viscosity at reservoir temperature is typically greater than 1,000,000 centipoise.

Production Overview

Phase 1 production commenced in 2008 with an initial bitumen production design capacity of approximately 3,000 bbls/d. Phase 2 production commenced 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 production commenced 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 increase overall bitumen production capacity over time to approximately 110,000 bbls/d, primarily through the deployment of eMSAGP, several debottlenecking and expansion projects and enhanced completion designs, optimized inter-well spacing, short-cycle high return redevelopment projects and steam allocation techniques.

Capital Expenditures

As a result of an unplanned electrical event subsequent to the Christina Lake Phase 2B facility turnaround in the second quarter of 2022, the Corporation's 2022 annual average bitumen production guidance was decreased from the original 2022 guidance of 94,000 – 97,000 bbls/d to 92,000 – 95,000 bbls/d. Capital expenditures were $376 million in 2022 compared to $331 million during 2021. The $376 million invested in 2022 was primarily focused on sustaining and maintenance activities and a turnaround at the Phase 2B facility which took place in the second quarter of 2022. No turnaround activity took place in 2021.

MEG's 2022 capital expenditures summary is as follows:

2022 Capital Expenditures Summary		**$ millions**
Sustaining and maintenance	$	311
Turnaround		46
Field infrastructure, corporate and other		19
Total	**$**	**376**

In 2022, the Corporation produced an annual average of 95,338 bbls/d of bitumen from Christina Lake compared to 93,733 bbls/d in 2021. The Corporation's average annual SOR was 2.36 for the year ended December 31, 2022, as compared to 2.43 for the year ended December 31, 2021. 2023 annual average bitumen production is expected to be in the range of 100,000 bbls/d to 105,000 bbls/d including a planned Q2 turnaround which is anticipated to reduce full year production by approximately 6,000 bbls/d.

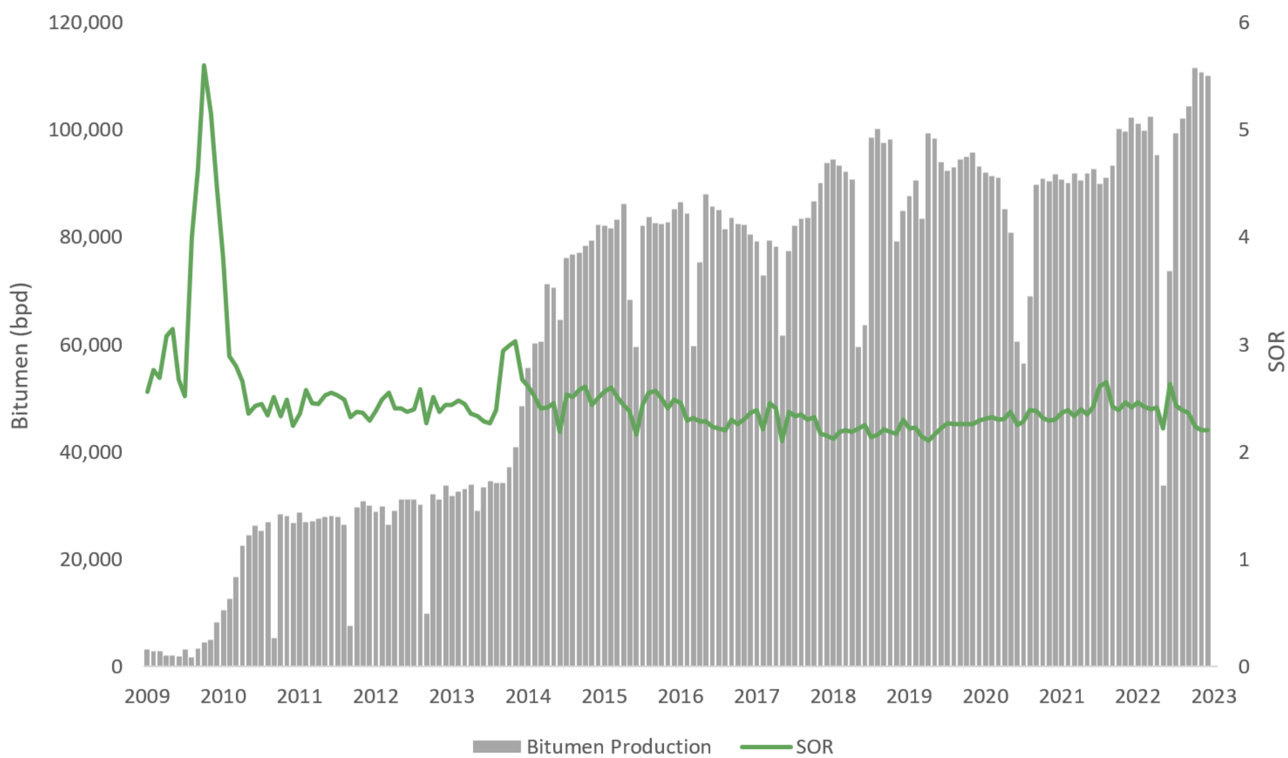
The table below summarizes MEG's unaudited operating costs, production levels and SORs for each quarter of 2022.

	MEG - Operating Costs 2022				
	First Quarter	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Annual Average**
Operating Expenses net of Power Revenue(1) ($/bbl)					
Non-energy operating costs(2)	4.74	5.65	4.49	4.34	4.73
Energy operating costs(2)	6.80	10.40	6.12	6.71	7.29
Power revenue	(2.56)	(3.08)	(5.16)	(5.22)	(4.11)
Operating Expenses net of Power Revenue(1)	**8.98**	**12.97**	**5.45**	**5.83**	**7.91**
Production (bbls/d)	101,128	67,256	101,983	110,805	95,338
SOR	2.43	2.46	2.39	2.22	2.36

(1) Non-GAAP financial measure - please refer to the "Non-GAAP and Other Financial Measures" of this AIF.
(2) Supplementary financial measure - please refer to the "Non-GAAP and Other Financial Measures" of this AIF.

Phase 2 and Phase 2B of the Christina Lake Project each include an 85 MW cogeneration facility (together 170 MW) which generate steam and power from the efficient use of natural gas and which are both operating near capacity. The capacity of the cogeneration units and heat recovery steam generator 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 42% of the Phase 1, Phase 2 and Phase 2B steam generation capacity is provided by the cogeneration units and the heat recovery steam generator. The remainder is provided by conventional steam generators including once-through steam generators.

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. At a steam oil ratio of 2.2, MEG has developed oil processing capacity of approximately 110,000 bbls/d at its Christina Lake central plant facility, prior to any impact of scheduled maintenance activity or outages.

On November 28, 2022, MEG announced its 2023 capital investment plan and guidance, including a capital budget of $450 million and expected 2023 annual average bitumen production of 100,000 – 105,000 bbls/d including a planned Q2 turnaround which is anticipated to reduce full year production by approximately 6,000 bbls/d.

Approximately 52%, or $235 million, of the program is allocated towards new well pads, gathering systems, and redevelopment drilling which will generate short-cycle production, improve resource recovery and reduce capital intensity.

An additional $140 million is directed toward facility and field infrastructure. Investments in areas, such as high-pressure steam deployment, gas and water processing, reliability improvements, well work, and sulphur recovery, which will enhance facility utilization.

Turnaround activities, planned for the second quarter of 2023, comprise $55 million.

SURMONT PROJECT

The Surmont Project comprises 32 square miles of lands in the southern Athabasca 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 resources. Other *in situ* thermal recovery projects are already operating in this area. The Surmont Project is adjacent to an *in situ* thermal project operated by ConocoPhillips Canada. MEG owns a 100% working interest in its mineral 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 and received regulatory approval for the Surmont Project in September 2019. In December 2021, these approvals were cancelled at MEG's request as Surmont is no longer in MEG's near-term development plan.

Geology

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 to 50 metres with an average thickness of 24 metres. Bitumen saturation is between 60% 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.

GLJ Report

Due to changes in the short-to-medium term strategic plan for the Corporation, in the 2019 GLJ Report the previously attributed probable undeveloped reserves attributable to the Surmont Project were reclassified to contingent resources.

MAY RIVER REGIONAL PROJECT

The May River Regional Project properties are situated on 129 square miles of lands in the southern Athabasca region of Alberta. MEG owns a 100% working interest in the mineral 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, 2022, MEG had drilled and cored 118 stratigraphic test wells (core holes) and recorded 77 square miles of 3D seismic data over the Corporation's leases in the May River Regional Project area. The May River Regional Project would be expected to use SAGD and eMSAGP development techniques similar to the Christina Lake Project.

On February 21, 2017 the Corporation filed regulatory applications with the AER for the May River Regional Project. In October 2019, MEG requested that the regulatory review of the May River Regional Project be placed on hold. In December 2021, MEG requested the regulatory review of the May River Regional Project be withdrawn and cancelled as the May River Regional Project is not currently in MEG's near-term development plans.

Geology

The McMurray Formation at the May River Regional Project has similar reservoir properties to those at the Christina Lake Project. The reservoir is at an average depth of 444 to 518 metres. The reservoir sand ranges in thickness from 10 to 40 metres with an average thickness of 20 metres. Bitumen saturation is between 60% and 85%. Initial reservoir pressure is between 1,825 kPa to 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 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 re-pressurization. MEG has water source opportunities from non-potable subsurface formations at the May River Regional Project.

GROWTH PROPERTIES

The Growth Properties are situated on approximately 170 square miles of lands in the southern Athabasca region of Alberta and includes the Duncan, East Kirby and West Kirby mineral leases. MEG owns a 100% working interest in the mineral 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, 2022, MEG has drilled 15 and cored 12 stratigraphic test wells over the Corporation's leases in the Growth Properties. MEG does not have plans to develop the Growth Properties at this time.

2023 CAPITAL INVESTMENT

The Corporation announced a 2023 capital budget of $450 million. The budget is designed primarily to sustain production guidance of 100,000 bbls/d to 105,000 bbls/d in 2023.

2023 Capital Investment Summary		$ millions
Well Pads & Redevelopment	$	235
Facility & Field Infrastructure		140
Turnaround		55
Corporate & Other		20
Total	**$**	**450**

ENVIRONMENTAL STRATEGY

In 2022, MEG continued resource development at Christina Lake by applying enhanced thermal in situ technologies using SAGD extraction as the basis. MEG's inherent sustainability advantages include a large resource base, low production decline and a low sustaining cost. The localized nature of the Corporation's asset permits MEG to economically develop the resource while minimizing environmental impacts. MEG is not engaged in oil sands mining or fracking activities. SAGD is a commercially proven technology that has numerous environmental advantages over mining operations, including:

- Reduced environmental footprint – in SAGD, production wells with a horizontal length of between 800 to over 1000 metres are drilled from multi-well pads with minimal impact to the land. The surface area of a standard six-well production pad is approximately 9% of the surface of the development area accessed by the six horizontal well pairs on the pad and production pad footprint continues to be reduced by the deployment of reduced footprint production pad configurations;

- Water use – MEG does not use potable water in its thermal operation processes. MEG recycles approximately 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 which would not otherwise be suitable 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; and

- Reduced air emissions – MEG conserves the gas produced from the reservoir and supplements with natural gas to use as fuel to generate steam. This mixed gas stream has very similar properties to natural gas, resulting in lower overall 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 some 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 fuel, 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 and sulphur dioxide emissions per unit of natural gas burned. MEG also conserves produced and production lift gases in addition to vapour capture as fuel for use in steam generation, and has extensive fugitive emissions detection and management programs in place to monitor and reduce emissions;

- Minimizing 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 turbines generate electricity that is used in its operations, with surplus power sold into the Alberta electricity grid. The heat from the turbines 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 energy costs. The increased efficiency of the cogeneration system helps reduce the overall provincial GHG footprint as any excess power that is sold into the Alberta electricity grid displaces other power sources that have a higher carbon intensity; and

- GHG management – MEG's low SOR results in effective GHG management and emission intensity reductions. Further deployment of proprietary reservoir technologies (including eMSAGP and cogeneration) and, as part of a broader development strategy, the deployment of enhanced completion designs, optimized inter-well spacing, short-cycle high return redevelopment projects and steam allocation techniques offers the potential for MEG to further decrease emissions intensity. In addition, MEG conserves greater than 99.5% of processed and produced methane, making MEG's methane emissions amongst the lowest in the oil and gas sector due to the use of active fugitive monitoring and a responsive repair program. MEG's methane emissions intensity is less than 1% of the estimated global average. [2]

Technology Development

To manage emissions and 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 provide stable base load power back to the provincial electricity grid. Generating power production below the electricity GHG performance benchmark has enabled MEG to earn emissions performance credits that can further offset GHG compliance cost burden.

MEG continued to advance certain reservoir recovery technologies throughout 2022. eMSAGP was used on a commercial scale to 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 intensity. MEG has also worked to develop enhanced well designs, optimized inter-well spacing and steam allocation techniques that are lowering SOR and associated GHG intensity while increasing production.

2022 Environmental Performance Measures and Trends

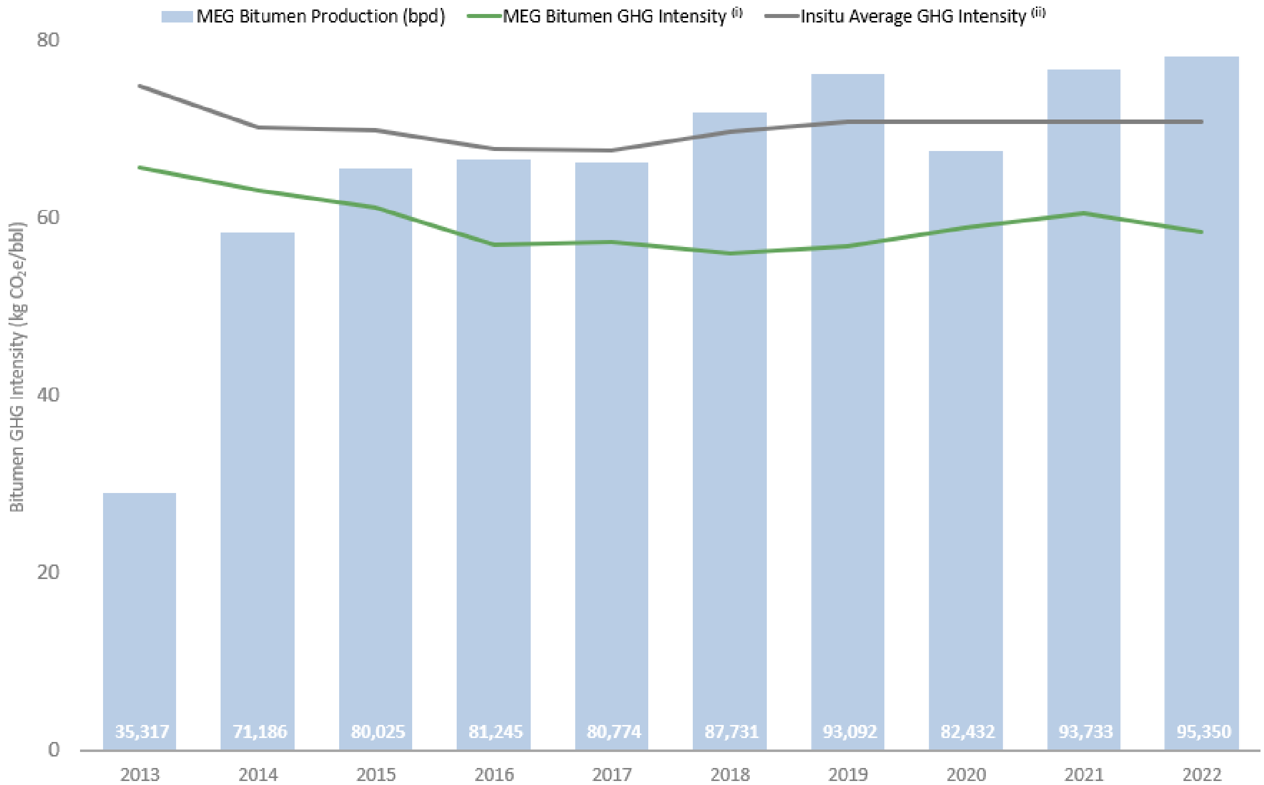
GHG Intensity Performance

MEG conserves greater than 99.5% of produced and processed methane. MEG's Christina Lake facility is a gas conserving facility whereby flaring and venting is virtually eliminated in normal operating conditions.[3]

MEG's bitumen GHG intensity includes the associated emissions intensity reduction benefits of cogeneration. In 2022, MEG's bitumen intensity decreased from 2021 due to enhanced well designs, optimized inter-well spacing, a focus on short cycle, high return redevelopment projects and steam allocation techniques. The application of eMSAGP and cogeneration have enabled MEG to maintain a bitumen GHG intensity of more than 15% below the in situ industry average.

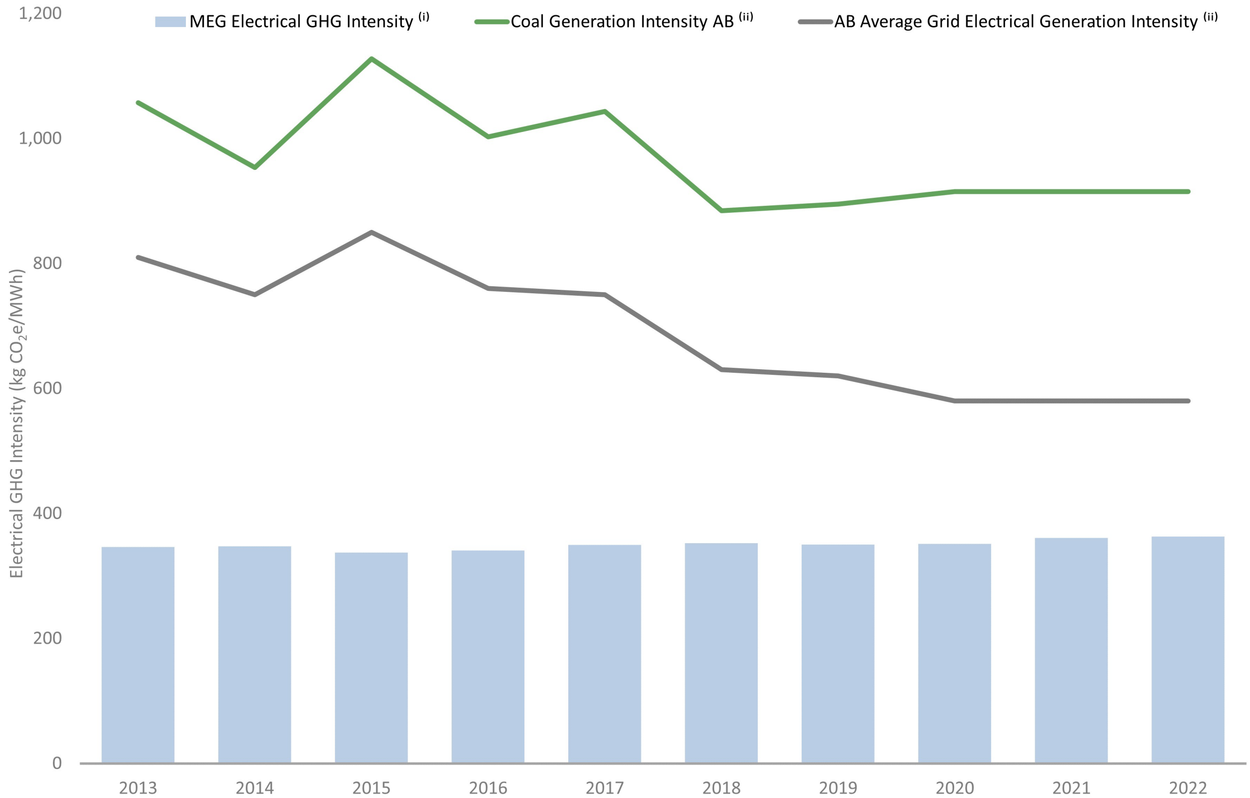
[2] World Oil Supply and Demand, 1971 - 2019

[3] Schneising, O. et al (2020) - Remote sensing of methane leakage from natural gas and petroleum systems revisited. Atmospheric Chemistry and Physics.



(i) Data for 2022 is preliminary.
(ii) Alberta Oil Sands Greenhouse Gas Emission Intensity Analysis, AEP. 2020-22 is estimated.

MEG uses cogeneration to meet the electrical demand at the Christina Lake facility, while the excess power is sold into the Alberta market. The electrical intensity of MEG's generation is approximately 60% lower than that of coal-fired electricity generation and approximately 40% below that of the Alberta electricity grid.

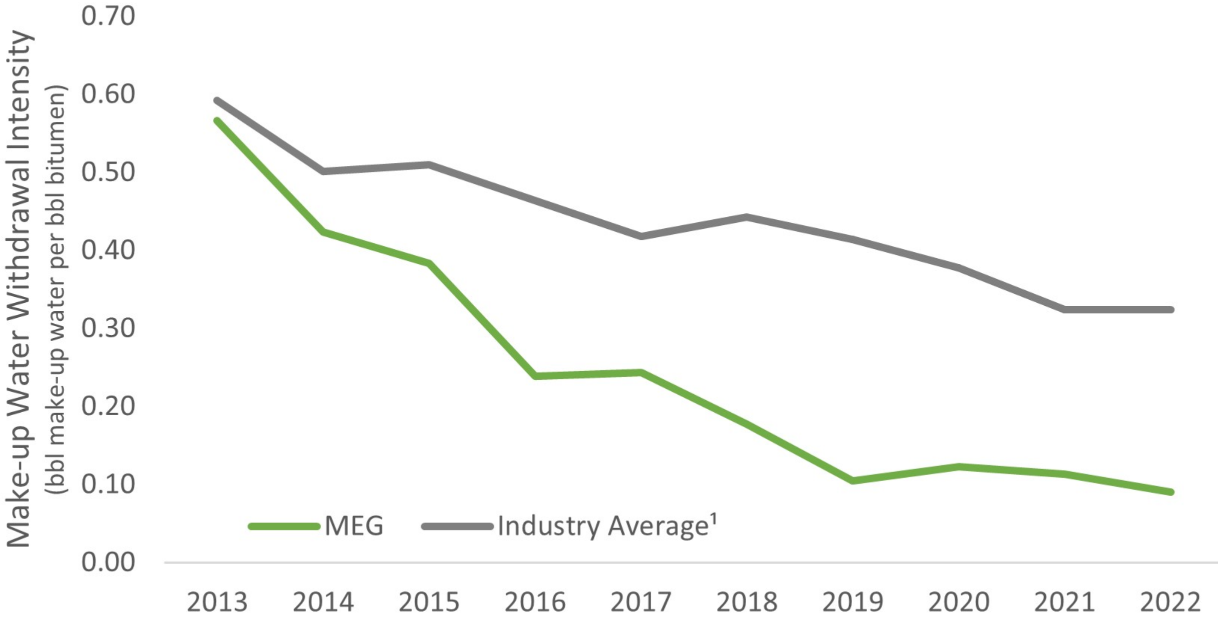


(i) Data for 2022 is preliminary.
(ii) National Inventory Report (2022 Edition). Data for 2021/22 are estimated.

Make-up Water Use

In 2022, MEG's make-up water withdrawal intensity (a ratio between a barrel of make up water used per barrel of bitumen produced) remained well below the industry volume weighted average due the application of eMSAGP and continued optimization of recycling technology.[4] MEG recycles the vast majority 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 thermal operations.

[4] The *in situ* industry volume weighted average is sourced from the annual AER Water Use Report.



1 In Situ Industry average make-up water intensity obtained from the AER Water Use Report. 2022 data is extrapolated from previous year.

Land Disturbance

In 2022, MEG continued implementation of its third-generation production pad design which can reduce pad size by up to 40% from prior well pad designs. The third-generation production pad design involves running injection and producer wells across from each other as opposed to side-by-side. This design allows for simplistic pad expansions with minimal footprint impact. In addition, MEG continues to optimize production pad design, the design of access roadways and gathering lines to reduce right of way widths and overall footprint.

MEG is committed to minimizing total land disturbance in its operations and in 2022 continued restoration and reclamation activities within the Christina Caribou Range that overlaps Boreal Woodland Caribou habitat. This restoration program assists in the species recovery efforts being undertaken by the Province of Alberta. To date, MEG has completed a total of approximately 10,000 hectares of restoration in high quality caribou habitat.

Further work in 2022 included obtaining reclamation certification of three gas well sites and seven exploration core hole sites, as well as the continuation of a large civil reclamation scope of an exhausted borrow pit. MEG also continues to maintain compliance with obligations to remove inactive infrastructure from operations.

ENVIRONMENTAL, SOCIAL AND GOVERNANCE ACTIVITIES

The Corporation remains committed to its long-term goal of reaching net zero Scope 1[1] and Scope 2[2] GHG emissions by 2050. In early 2023, the Corporation replaced its mid-term target of reaching a 30% reduction in bitumen GHG emissions intensity (Scope 1 and Scope 2) from 2013 levels by 2030, with a mid-term target of reducing its absolute GHG emissions (Scope 1 and Scope 2) by 0.63 megatonnes per annum by year-end 2030, representing a reduction of approximately 30% absolute Scope 1 and Scope 2 emissions from 2019 levels.

MEG, along with its Pathways Alliance ("Alliance") peers, is progressing pre-work on the proposed foundational carbon capture and storage project, which will transport CO2 via pipeline from multiple oil sands facilities to be stored safely and permanently in the Cold Lake region of Alberta. In the fourth quarter of 2022, the Corporation and its Alliance peers reached a significant milestone entering into a carbon sequestration evaluation agreement with the Government of Alberta and starting the detailed evaluation of the proposed Cold Lake area geological storage hub. The Corporation

[1] Scope 1 refers to direct GHG emissions from sources that are owned or controlled by the Corporation.
[2] Scope 2 refers to indirect GHG emissions that result from the generation of purchased electricity, heating, cooling or steam consumed at assets owned or controlled by the Corporation.

and its Alliance peers continue to work closely with the federal and provincial governments to land on policy that supports the progress of these large decarbonization projects while ensuring Canada remains globally competitive and continues to attract investment. In addition to Climate Change and GHG Emissions, the Corporation continues to progress each of the other three priority ESG topics: Health and Safety, Indigenous Relations, and Water and Wastewater Management.

Additional information regarding MEG's ESG actions, including the Corporation's 2021 ESG Report and its 2022 ESG Performance Data Supplement is available in the "Sustainability" section of MEG's website at www.megenergy.com. The Corporation's ESG Report, the 2022 ESG Performance Data Supplement and the content of MEG's website are expressly not incorporated by reference in this AIF.

MARKETING OVERVIEW

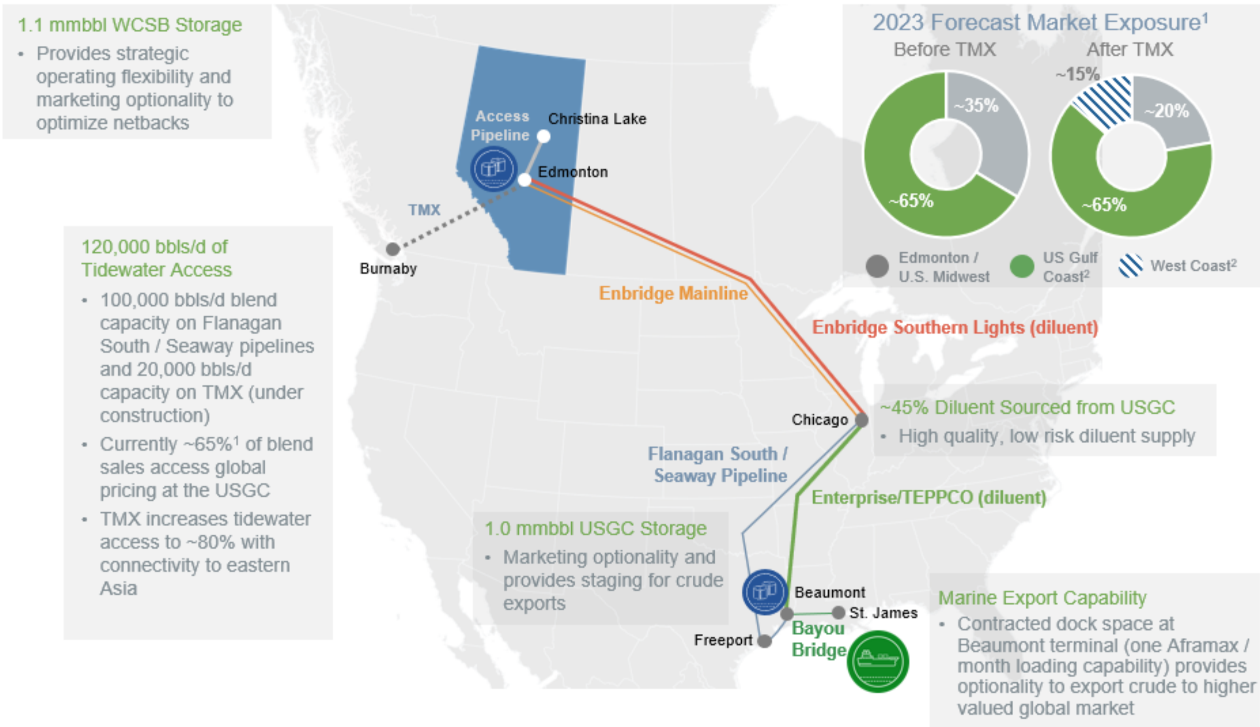
The Corporation employs a marketing strategy that delivers and sells its production to oil markets throughout North America and internationally. MEG owns, leases and contracts for services on multiple facilities to transport, store and deliver AWB to customers. MEG has 100,000 bbls/d of contracted AWB transportation capacity on the Flanagan South and Seaway pipeline systems ("FSP") providing pipeline transportation directly to USGC refineries and export terminals. MEG is also a shipper on the Trans Mountain Expansion Project ("TMX") which, when in service, will provide MEG with 20,000 bbls/d of contracted AWB transportation capacity to Canada's West Coast. MEG has proprietary and contracted oil storage capacity of approximately 2.1 million barrels in Alberta and strategic locations in the U.S., with marine export capacity at Beaumont, Texas in the USGC. This combination of pipeline access, storage capacity and marine export capacity comprises MEG's strategy of having diversified, long-term and reliable market access to world oil prices for its production.

MEG has 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 export pipelines. The Access Pipeline is comprised of an AWB blend pipeline system and diluent pipeline system. The AWB blend pipeline system runs from the Christina Lake Project to Edmonton. The diluent pipeline system runs from the Edmonton area to MEG's Christina Lake Project and allows MEG to effectively manage its local and import sourced diluent supply for purposes of blending with its Christina Lake production. The diluent system receives volumes from numerous local diluent production streams and fractionation facilities as well as imported diluent volumes from inbound pipelines and rail terminals. The diluent system is well connected to key pipeline and storage systems in the Edmonton/Fort Saskatchewan corridor, including the Enbridge TEPPCO and Southern Lights import pipelines for access to Mont Belvieu supply. This system provides a range of diluent supply alternatives and helps to mitigate diluent supply and price risk.

In the Edmonton area, MEG has approximately 1.1 million barrels of storage and terminalling capacity, including approximately 900,000 barrels of capacity contracted at the Stonefell Terminal. The Stonefell Terminal is connected to the Access Pipeline System and provides the Corporation 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.

MEG has contracted pipeline capacity, storage capacity and marine export capacity in the USGC area. Specifically, MEG has contracted for approximately 1.0 million barrels of storage capacity, along with marine export capacity, at Beaumont, Texas. MEG has also contracted capacity on the Bayou Bridge pipeline to access USGC refineries and export facilities beyond Texas.

MEG Marketing Network Schematic



1. Assumes mid point of 2023 production guidance, 1.44 blend ratio and 5% apportionment.
2. Assumes 20,000 bbl/d of contracted capacity on TMX (scheduled to come in service in Q4 2023).

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. All of the Corporation's properties are located in the Province of Alberta and are described elsewhere in this AIF. See "Projects Overview". This statement of reserves and other oil and gas information comprises MEG's 51-101F1.

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 AIF. 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 - Contingent Resources to this AIF.

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 Technology Innovation and Emissions Reduction Regulation which came into force on October 29, 2019). 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 - Contingent Resources 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

Reserves are estimated remaining quantities of crude oil, natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on analysis of drilling, geological, geophysical and engineering data, the use of established technology and specified economic conditions, which are generally accepted as being reasonable. Reserves can be classified into proved, probable and possible, according to the degree of certainty associated with the estimates. Most relevant are the categories of **proved** and **probable**:

a. **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.

b. **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.

Each **reserves** category 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. The developed category may be subdivided as follows:

    - **Developed producing reserves** are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

    - **Developed non-producing reserves** are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

- **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. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned.

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. As described above, 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, and as set out above, each of these categories may be further divided into **developed** and **undeveloped** categories.

In the GLJ Report, GLJ assigned proved and probable developed reserves to the existing wells and producing facility at the Christina Lake Project. Proved and probable undeveloped reserves are assigned to future planned wells to maintain existing project production along with wells associated with processing plant debottlenecking and brownfield expansions at the Christina Lake Project. Contingent resources were also assigned to the Christina Lake Project. See "Independent Reserves Evaluation" and Appendix D - Contingent Resources 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, 2022, as evaluated by GLJ in the GLJ Report, reflecting the Corporation's 100% working interest in the Christina Lake 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, 2022 (Forecast Prices and Costs)

	Bitumen	
Reserves Category	**Gross[(1)] (MMbbls)**	**Net[(2)] (MMbbls)**
Proved Reserves[(3)]		
Proved Developed Producing	262.4	195.5
Proved Developed Non-Producing	7.2	5.2
Proved Undeveloped	938.8	718.9
Total Proved Reserves	**1,208.5**	**919.5**
Total Probable Reserves[(4)]	**730.8**	**528.9**
Total Proved Plus Probable Reserves[(5)]	**1,939.3**	**1,448.4**

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, 2022 Before Income Taxes (Forecast Prices and Costs)					
	Before Income Taxes Discounted at %/Year					Unit Value Before Income Taxes Discounted at 10%/Year[(1)]
Reserves Category	**0% (MM$)**	**5% (MM$)**	**10% (MM$)**	**15% (MM$)**	**20% (MM$)**	**$/bbl**
Proved Reserves						
Proved Developed Producing	9,933	8,233	6,977	6,034	5,310	35.69
Proved Developed Non-Producing	274	200	150	115	90	28.92
Proved Undeveloped	36,292	14,501	6,762	3,549	2,017	9.41
Total Proved Reserves[(2)]	**46,498**	**22,933**	**13,889**	**9,697**	**7,416**	**15.10**
Total Probable Reserves	**43,055**	**10,968**	**3,995**	**1,946**	**1,142**	**7.55**
Total Proved Plus Probable Reserves[(2)]	**89,553**	**33,902**	**17,884**	**11,643**	**8,558**	**12.35**

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, 2022 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	8,783	7,387	6,336	5,538	4,919
Proved Developed Non-Producing	211	154	115	88	69
Proved Undeveloped	27,669	10,935	5,010	2,565	1,407
Total Proved Reserves	**36,663**	**18,476**	**11,461**	**8,191**	**6,394**
Total Probable Reserves	**33,069**	**8,383**	**3,037**	**1,472**	**860**
Total Proved Plus Probable Reserves[1]	**69,732**	**26,859**	**14,498**	**9,662**	**7,255**

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

Reserves Category	Future Net Revenue (undiscounted) as of December 31, 2022 (Forecast Prices and Costs) 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	21,003	4,921	4,327	1,183	640	9,933	1,149	8,783
Proved Developed Non-Producing	572	158	112	21	8	274	63	211
Proved Undeveloped	97,305	22,131	21,004	15,358	2,521	36,292	8,623	27,669
Total Proved Reserves[2]	**118,881**	**27,209**	**25,443**	**16,562**	**3,170**	**46,498**	**9,835**	**36,663**
Total Probable Reserves	**97,455**	**24,886**	**16,892**	**10,767**	**1,856**	**43,055**	**9,986**	**33,069**
Total Proved Plus Probable Reserves[2]	**216,336**	**52,095**	**42,335**	**27,329**	**5,026**	**89,553**	**19,821**	**69,732**

Notes:
(1) Total abandonment and reclamation costs included for the Christina Lake Project processing facility, infrastructure, SAGD and observation wells, both known and existing, and to be incurred as a result of future development activity.
(2) Totals may not add due to rounding.

Reserves Category	Production Group	Future Net Revenue by Production Group as of December 31, 2022 (Forecast Prices and Costs) — Future Net Revenue Before Income Taxes (discounted at 10%/yr) MM$	Unit Value[1] ($/bbl)
Total Proved Producing Reserves	Bitumen	6,977	35.69
Total Proved Reserves	Bitumen	13,889	15.10
Total Proved Plus Probable Reserves	Bitumen	17,884	12.35

Notes:
(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, 2022 against such reserves as of December 31, 2021, 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, 2021	**1,271,056**	**738,474**	**2,009,530**
Discoveries	—	—	—
Extensions and Improved Recovery	—	—	—
Technical Revisions [2]	(27,792)	(7,625)	(35,417)
Acquisitions	—	—	—
Dispositions	—	—	—
Economic Factors	—	—	—
Production	(34,799)	—	(34,799)
December 31, 2022	**1,208,466**	**730,849**	**1,939,315**

Notes:

(1) The pricing assumptions used in the GLJ Report with respect to values of future net revenue as well as the inflation rates used for operating and capital costs are set forth below under "GLJ Price Forecast".

(2) The decrease in 2022 is a net outcome of mapping updates from drilling results, development plan updates and field performance.

GLJ Price Forecasts

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, 2023 pricing models. A summary of selected price forecasts used in arriving at pricing forecasts is set forth below.

Forecast Prices used in Preparing Reserves Data GLJ (January 1, 2023)

Forecast	Oil Sands Inflation (%)	Exchange Rate (US$/Cdn$)	West Texas Intermediate Crude Oil at Cushing Oklahoma Current (US$/bbl)	AECO/NIT Spot Current (Cdn$/MMBtu)	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)
2023	—	0.735	75.00	4.36	65.65	99.32	54.54	98.94	95.51
2024	2.0	0.745	75.00	4.77	68.46	99.33	58.19	96.26	92.92
2025	2.0	0.755	75.43	4.47	73.42	98.58	64.87	95.45	92.14
2026	2.0	0.765	76.94	4.49	79.66	101.88	71.99	96.09	92.76
2027	2.0	0.775	78.48	4.53	81.91	102.58	74.71	96.75	93.39
2028	2.0	0.775	80.05	4.62	85.03	104.63	78.15	98.68	95.26
2029	2.0	0.775	81.65	4.71	86.83	106.72	79.86	100.65	97.17
2030	2.0	0.775	83.28	4.80	88.55	108.85	81.47	102.66	99.10
2031	2.0	0.775	84.95	4.89	90.34	111.03	83.13	104.72	101.09
2032	2.0	0.775	86.65	4.99	92.53	113.25	85.31	105.35	101.70
2033	2.0	0.775	88.38	5.09	94.38	115.52	87.02	107.46	103.73

The Corporation realized an average price of $91.95/bbl of bitumen for the year ended December 31, 2022.

Undeveloped Reserves

Through the GLJ Report, GLJ has assigned the Christina Lake Project proved undeveloped reserves of 939 MMbbls and probable undeveloped reserves of 676 MMbbls. The Corporation's proved undeveloped reserves and probable undeveloped reserves are expected to be developed over time, with a majority of proved and probable undeveloped reserves expected to be developed beyond two years as wells and plant capacity become available, which is typical of SAGD oil sands developments. 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".

As set out above in this section, 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, 2020	—	1,008
December 31, 2021	—	984
December 31, 2022	—	939

Probable Undeveloped Bitumen Reserves

Period	First Attributed (MMbbls)	Total at Year-end (MMbbls)
December 31, 2020	—	692
December 31, 2021	—	691
December 31, 2022	—	676

Reserves Life Index

The following Reserves Life Index values were calculated using the relevant reserves volumes by category estimated by GLJ divided by the Corporation's current production of approximately 103,700 bbls/d:

Reserves Category	Bitumen (MMbbls)	RLI (years)
Proved Developed Producing (PDP)	262.4	7.0
Total Proved (1P)	1,208.5	32.1
Total Proved plus Probable (2P)	1,939.3	51.6

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".

	Total Proved Future Development Costs Using Forecast Escalated Costs (MM$)	Total Proved Plus Probable Future Development Costs Using Escalated Dollars Costs (MM$)
2023	413	435
2024	438	428
2025	608	677
2026	513	598
2027	283	456
2028	366	427
2029	364	546
2030	354	483
2031	427	416
2032	656	665
2033	389	530
2034	426	373
Remainder	11,325	21,296
Total, undiscounted	**16,562**	**27,329**

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, 2022, all of which are in Alberta, Canada:

	Bitumen Production Wells as of December 31, 2022(1)	
	Gross	Net
Christina Lake		
Producing SAGD Well Pairs	231	231
Non-producing SAGD Well Pairs	40	40
Producing Infill Wells	97	97
Non-producing Infill Wells	35	35
Total	**403**	**403**

Notes:
(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 890 stratigraphic test wells, 304 observation wells, 18 water source wells, and 6 water disposal wells on or adjacent to its mineral leases. These wells did not produce any bitumen volumes in 2022.

The following table sets out the Corporation's producing and non-producing gas wells, all of which are in Alberta, as of December 31, 2022:

Gas Production Wells as of December 31, 2022

	Gas Production Wells as of December 31, 2022	
	Gross	**Net**
Producing	—	—
Non-producing	92	83
Total	**92**	**83**

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, 2022. All properties are located in Alberta and although no underlying leases are expected to expire in the next year, the Corporation may determine to release select leases in the May River and Growth Properties areas as part of its continuing lease rationalization program.

Mineral Leases without Attributed Reserves

	Undeveloped Acreage (acres)	
	Gross	**Net**
Mineral leases without attributed reserves	235,025	235,025

ADDITIONAL INFORMATION CONCERNING ABANDONMENT AND RECLAMATION COSTS

The Corporation follows IFRS to account for and report the estimated cost of future site abandonment and reclamation. This standard requires liability recognition for retirement obligations associated with long-lived assets, which would include abandonment of 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.

The Corporation's decommissioning obligation is the estimated cost of future abandonment and reclamation of the Corporation's existing long-lived assets. As of December 31, 2022, the estimated total undiscounted amount required to settle the decommissioning obligations in respect of all the Corporation's facilities and wells, net of estimated salvage recoveries, was $830 million. This obligation is estimated to be settled in periods up to 2066. The 9.5% discounted present value of this amount is $166 million ($162 million discounted at 10%). Over the next three years, the Corporation expects to incur approximately $11 million in decommissioning expenditures.

The GLJ Report estimate of abandonment and reclamation costs is an estimate of the amount required to abandon and reclaim the entire development over the life of the reserves. In the GLJ Report, abandonment and reclamation costs for total proved plus probable reserves were estimated to be $5.0 billion, undiscounted, and $268 million, discounted at 10%. These costs include the abandonment, decommissioning and reclamation of the entire Christina Lake central processing facility, infrastructure, currently drilled SAGD and observation wells plus the future well pairs, infills and observation wells anticipated to be required to develop the assigned reserves over the life of the Christina Lake Project. These estimates do not include abandonment and reclamation costs or other liabilities outside of the Christina Lake Project, which the Corporation has included in determining its total decommissioning provision.

TAX HORIZON

As of December 31, 2022, the Corporation had approximately $5.5 billion of Canadian tax pools, including $4.1 billion of non-capital losses and $0.2 billion of capital losses. The Corporation recognized a deferred income tax liability of $24 million. 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.

OIL SANDS ROYALTY PAYOUT HORIZON

As of December 31, 2022, Christina Lake Oil Sands Royalty Project cumulative costs exceed cumulative revenues by approximately $105 million. Based on the price forecast in the GLJ Report, the Christina Lake Project is currently subject to pre-payout royalty rates. Based on GLJ's January 1, 2023 pricing models, the Corporation anticipates the Christina Lake Project to achieve payout in the first quarter of 2023. This estimate will be impacted by, among other factors, bitumen production, capital costs, commodity prices, foreign exchange rates, operating costs, and changes to government policy. Changes in these factors from estimates used by the Corporation could result in the Corporation paying post-payout royalty rates earlier or later than expected. See "Regulatory Matters - Royalties".

COSTS INCURRED

The Corporation did not acquire any property with reserves or resources in the year ended December 31, 2022. The capital expenditures made by MEG on its properties for the year ended December 31, 2022 were $376 million.

EXPLORATION AND DEVELOPMENT ACTIVITIES

MEG conducted a series of drilling programs on its mineral leases in 2022. The following table sets forth the number of exploratory and development wells which MEG completed during the year ended December 31, 2022:

Exploration and Development Activities

	2022 Wells (Gross & Net)
Exploration Wells	—
Stratigraphic Test Wells	15
SAGD Wells	20
Observation Wells	10
Infill Wells	6
Water Source Wells	—
Water Disposal Wells	—
Total Completed Wells[(1)]	**51**

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

See "Projects Overview" for a description of the Corporation's current 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 2023, before royalties, as set out in the GLJ Report.

Production Estimates

Reserves	Bitumen Production (bbls/d)[1]
Total Proved Reserves	101,678
Total Probable Reserves	1,999
Total Proved Plus Probable Reserves	**103,677**

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 using an average estimated facility runtime of 95%.

PRODUCTION HISTORY

The following table sets forth certain non-audited 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 per barrel of bitumen sales received for each quarter of MEG's most recently completed financial year:

	Production History			
	Three months ended March 31, 2022	Three months ended June 30, 2022	Three months ended September 30, 2022	Three months ended December 31, 2022
Average Daily Bitumen Production (bbls/d)	101,128	67,256	101,983	110,805
Average Daily Bitumen Sales (bbls/d)	100,186	73,091	95,759	113,582
Bitumen Realization[1] ($/bbl)	97.28	122.69	90.33	69.16
Royalties ($/bbl)	(5.24)	(8.67)	(7.47)	(5.15)
Operating expenses net of power revenue[1] ($/bbl)	(8.98)	(12.97)	(5.45)	(5.83)
Net transportation and storage expense[1][2] ($/bbl)	(12.97)	(19.40)	(15.58)	(14.41)
Realized gain (loss) on commodity risk management ($/bbl)	0.12	0.10	0.80	0.12
Cash Operating Netback[1][3] ($/bbl)	**70.21**	**81.75**	**62.63**	**43.89**

Notes:
(1) Non-GAAP financial measure - please refer to the "Non-GAAP and Other Financial Measures" section of this AIF.
(2) Net transportation and storage expense includes costs associated with moving the Corporation's blend from Christina Lake to a final sales location and optimizing the timing of delivery, net of third-party recoveries on diluent transportation arrangements.
(3) Cash operating netback on a per-unit basis is calculated by dividing related production revenue, less costs and royalties, by bitumen sales volumes.

The Corporation's average bitumen production for the year ended December 31, 2022, from Phases 1, 2 and 2B of the Christina Lake Project was 95,338 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 under circumstances such as environmental protection and project approval within federal jurisdiction. 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 thermal production 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. Federal and provincial legislation is a matter of public record and the Corporation continues to monitor for potential changes to legislation that may materially affect its operations.

REGULATORY FRAMEWORK

The Alberta Department of Energy has authority under specified provincial legislation to issue dispositions of and collect royalties from provincial Crown-owned mines and minerals development. The types of Crown-owned mines and minerals is defined under the Mines and Minerals Act ("MMA") that includes oil, gas, oil sands and coal. On December 10, 2012, the Government of Alberta enacted the Responsible Energy Development Act ("REDA").

REDA 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 for regulating energy resource activities under specified enactments, including the *Oil Sands Conservation Act.* The second phase was completed on November 30, 2013, when the AER assumed the ESRD's responsibilities for regulating 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, with the AER assuming jurisdiction over energy resource activities formerly under the jurisdiction of the ESRD, including those energy resources activities under the *Environmental Protection and Enhancement Act* (“EPEA”) and the *Water Act*.

The AER is now Alberta's single energy regulator, responsible for full life-cycle regulation of oil, natural gas, oil sands and coal resources in Alberta. The AER is responsible for applications, exploration, construction, development, abandonment, reclamation and remediation. The changes in Alberta's regulatory framework were 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 associated with oil sands projects, including cogeneration facilities, remain regulated by the AUC. The Alberta Electric System Operator remains 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, the Oil Sands Conservation Act, EPEA, 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 Impact Assessment Act ("IAA"), the Canadian Environmental Protection Act, 1999 ("CEPA"), the Fisheries Act, the Migratory Birds Convention Act, the Canadian Navigable Waters Act, the Species at Risk Act and where applicable, the Canadian Energy Regulator 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 in, among other things, remedial orders, administrative monetary penalties, or quasi-criminal environmental prosecutions.

In 2016, the Government of Canada commenced a review of federal environmental and regulatory processes under various acts. Bill C-69: An Act to enact the Impact Assessment Act and the Canadian Energy Regulator Act, to amend the Navigation Protection Act, renamed the Canadian Navigable Waters Act, and to make consequential amendments to other Acts came into force in August 2019. In addition, Bill C-68, which amended the Fisheries Act, came into force at the same time. The enactment of Bill C-69 and Bill C-68 into legislation has, among other things, resulted 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 IAA requires federal impact assessments for certain designated projects. The list of designated projects under the IAA exempts in situ oil sands projects as designated projects where such projects are located within a province where provincial legislation is in force to limit the amount of greenhouse gas emissions produced by oil sands sites and that limit has not been reached. In Alberta, the Oil Sands Emissions Limit Act came into force in December 2016 and limits the amount of greenhouse gas emissions produced by all oil sands sites combined in Alberta to 100 megatonnes in any year, which limit has not been reached.

In September 2019, in response to the enactment of the IAA, the Alberta Government filed a constitutional challenge to the province's Court of Appeal, arguing the IAA was an overreach of federal jurisdiction. In February 2021, the case was brought before the Alberta Court of Appeal. Interveners included the Governments of Ontario and Saskatchewan, Alberta First Nations, industry associations, environmental groups, and advocacy organizations. The Governments of Ontario and Saskatchewan allied with Alberta while various environmental and legal groups intervened in support of the federal government's position. In May 2022, the Alberta Court of Appeal found the IAA unconstitutional. The Federal Government appealed the decision to the Supreme Court of Canada, which is scheduled to be heard March 21 and 22, 2023.

On December 7, 2022, the Alberta Government enacted the Alberta Sovereignty within a United Canada Act ("ASUCA"). The purpose of the ASUCA is to afford the Alberta Government certain powers to prevent federal actions that are deemed by the Alberta Government to encroach provincial jurisdiction. These certain powers include permitting the Alberta Government to deem a federal initiative as unconstitutional and directing Alberta entities to not enforce federal laws. Since the ASUCA has been recently enacted, there is still uncertainty how the Alberta Government will apply this legislation.

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, resulting in a market-determined price for 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 and demand balance, the global price of oil and other contractual terms.

Subject to certain exemptions, exports from Canada must be made pursuant to short-term export contracts or long-term export licences obtained from the Canada Energy Regulator ("CER"). An export order for light crude oil, defined to include blended oils with a density less than 875.7 kg/m3, may be granted for up to one year. An export order for heavy crude oil, defined to include blended oils with a density greater than 875.7 kg/m3, may be granted for a period not exceeding two years. If a longer term for export is required, an export licence must be obtained from the CER, 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.

Russian Invasion of Ukraine

In response to Russian aggression in Ukraine, Canada, in coordination with its NATO allies, issued an array of sanctions targeting Russia, Belarus, and the separatist-controlled territories of Ukraine. These restrictions on trade and financial transactions have had significant consequences for the price of oil globally. Crude oil prices are expected to remain volatile for the next several years, in part due to the global economic sanctions imposed on Russia.

Effective March 10, 2022, persons in Canada, or Canadian citizens or entities operating outside Canada are prohibited from importing, purchasing or acquiring petroleum oil, petroleum gas, or other gaseous hydrocarbons from Russia or any person in Russia. Moreover, as of June 7, 2022 Canada amended the Special Economic Measures (Russia) Regulations to ban the supply of key services to certain Russian industries. Canadians and persons in Canada are now prohibited from providing a wide range of services, such as mining and oil & gas extraction support services, energy distribution, repairs and research & development, to Russia or to any person in Russia in specified industries.

On July 14, 2022, Canada further expanded its services ban to Russian operators of oil and gas pipelines including businesses that manufacture metal products, computers, electronics and optical devices, electrical equipment, machinery, motor vehicles, trailers and semi-trailers, transport equipment. Two additional categories of support services for manufacturing were added to the schedule. The July 14 amendments are subject to a 60-day wind down period for contracts entered into before that date.

While the Corporation does not have any operations or transactions impacted directly by Russian sanctions, the ongoing conflict in Ukraine and resultant sanctions imposed from time to time are expected to have a contained effect on the volatility of crude oil prices.

Canada-United States-Mexico Agreement

On July 1, 2020, the Canada-United States-Mexico Agreement ("CUSMA") entered into force, replacing the North American Free Trade Agreement ("NAFTA"). Under CUSMA, the rule of origin applicable to heavy oil containing diluent has been relaxed to allow up to 40% of non-originating diluent that is added for the purpose of transportation in pipelines without affecting the originating status of the product, which will allow Canadian products to more easily qualify for duty-free treatment when imported into the U.S. Further, CUSMA does not include the “energy proportionality clause” which was contained in NAFTA, and there are no more customs duties on US imports of Canadian heavy oil mixed with diluent in CUSMA.

The investor-state dispute settlement provisions of NAFTA will no longer be available to protect future investments of Canadians in the U.S. or U.S. investments in Canada. For three years after the termination of NAFTA, existing "legacy investments" will maintain their access to the investor-state dispute settlement under NAFTA Chapter 11.

The Comprehensive and Progressive Agreement for Trans-Pacific Partnership

In October 2015, Canada concluded negotiations for a free trade agreement between the members of the Trans-Pacific Partnership ("TPP"), which included 12 countries in the Asia-Pacific region. The TPP was expected to provide greater transparency and more predictable market access for cross-border trade in extractive industries such as oil and gas. All 12 countries signed the TPP Agreement in 2016. However, in 2017, the US withdrew from TPP and the remaining 11 countries began negotiations for a new deal without US involvement.

On March 8, 2018, Canada signed the CPTPP. The 11 signatories include Canada, Australia, Brunei, Chile, Japan, Malaysia, Mexico, New Zealand, Peru, Singapore and Vietnam. The CPTPP came into force in Canada on December 30, 2018. The CPTPP includes provisions to enhance environmental protection in the CPTPP region and to address global environmental challenges. Signatories to the CPTPP are expected to take measures to control emissions from substances that have significant impact on the ozone layer in a manner likely to result in adverse effects on human health and the environment. As of July 2022, Brunei and Chile have not yet ratified the agreement. In June 2022, the United Kingdom formally launched accession negotiations with the original 11 signatories. Later in 2021, both China and Taiwan applied to join the CPTPP. However, accession negotiations have not yet begun with either country. As of July 2022, the South Korean government has approved an entry plan into the CPTPP.

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 CER. 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 Ministry 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 First Nations reserves and national parks.

In order to produce oil from oil sands owned by the Province of Alberta an operator must acquire an oil sands agreement. The new *Oil Sands Tenure Regulation, 2020* came into force on December 1, 2020, and repeals the *Oil Sands Tenure Regulation, 2010.* Leases are the only type of oil sands agreement issued under the Oil Sands Tenure Regulation, 2020, although permits granted under the Oil Sands Tenure Regulation, 2010 will be honoured until they expire, are converted to an oil sands lease, or are surrendered. The new regulations apply to all leases issued on or after December 1, 2020, to all permits issued under the 2010 Regulation, and those continued or discontinued from the

2010 or the previous 2000 Regulations. The new regulations no longer require a minimum level of evaluation for the continuance of a lease, however the Minister has established a minimum level of production.

Primary leases are issued for a 15-year term, and applications 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 of Energy. For the continuation of a primary lease, the lessee shall provide all production data in those sections to the Minister. If a lease is designated as "producing" it will continue for its productive life and will not be subject to escalating rentals. A lease designated as "non-producing" can be continued by payment of escalating rentals. An escalating rental is calculated based on the area of the lease location. An exception to the expiration of a lease is when producing wells are on multiple drilling spacing units or leases, in which case the eligible leases are continued.

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 government has established incentive programs to encourage exploration and development activity by improving earnings and cash flow within the industry. Such programs often provide for royalty rate reductions, credits and holidays, and are generally introduced when commodity prices are low. Such programs are often of limited duration and target specified oil and gas activities.

The oil sands royalty framework under the *Oil Sands Royalty Regulation, 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 based on the project's gross revenue multiplied by a 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 (i) the gross revenue royalty; or (ii) the net revenue royalty based on the net revenue royalty rate. The net revenue royalty rate is based on a formula which starts at 25% and increases for every dollar the WTI crude oil price, in Canadian dollars, 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-saline) water.

The Corporation may be affected by Alberta's frameworks for air quality, surface water quality and groundwater, under which parties may be required to comply with environmental limits and participate in regional monitoring. These frameworks are being created under the Alberta Land Stewardship Act ("ALSA") as legislative instruments equivalent to regulations and are binding on the Government of Alberta and provincial regulators, including those governing the oil and gas industry. The first of seven of these frameworks, the Lower Athabasca Regional Plan ("LARP") came into effect on September 1, 2012, and is currently in the implementation stage. The South Saskatchewan Regional Plan came into effect on September 1, 2014 (with amendments in 2017 and 2018), while other regional plans are at various stages of development, including the (i) North Saskatchewan Regional Plan; and (ii) Woodland Caribou Range Plan (draft plan issued in December 2017).

Future and existing operations in the region may be subject to more onerous environmental constraints and stringent operating parameters. While the LARP and South Saskatchewan Regional Plan have not had a significant effect on the Corporation, there can be no assurance that changes to the regional plans or that future laws or regulations will not adversely impact the Corporation's ability to develop or operate its projects. However, proposed Bill 206, Property Rights Statutes Amendment Act, 2020, includes a proposed amendment to the *ALSA* which would provide a right to claim compensation from the Crown for any damages or losses suffered by a statutory consent holder arising from the implementation of a regional plan, meaning statutory consent holders may be less likely to assert claims against the Corporation. Bill 206 received royal assent on December 15, 2022.

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 signed a renewed Memorandum of Understanding for the Monitoring Plan, and a subsequent Letter of Agreement in September 2018 with Indigenous communities. On December 15, 2021, several additional Indigenous communities signed the 2018 Letter of Agreement. The Oil Sands Monitoring Program is designed to provide an improved understanding of the long-term cumulative environmental effects of oil sands development. Under the Monitoring Plan, the federal and provincial governments increased air, water, land and biodiversity monitoring in the oil sands region. Funding for the monitoring program is collected from industry through the *Oil Sands Environmental Monitoring Program Regulation* to an aggregate amount of up to $50 million a year. Currently, the Oil Sands Environmental Monitoring Program Regulation is set to expire on January 31, 2023.

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. As noted above, Alberta’s Draft Provincial Woodland Caribou Range Plan was released in December 2017 but has not yet been finalized. 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 to 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 reports and monitors its GHG emissions. 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. Please see “Government of Canada Regulations” for further information.

Additionally, the Paris Agreement contemplated 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. No such market-based mechanism has been developed to date. Canada ratified the Paris Agreement in October 2016, and it came into force on November 4, 2016.

In 2020, MEG’s Board of Directors committed to supporting the Paris Agreement and approved the Corporation’s long-term goal of reaching net zero emissions (Scope 1 and Scope 2) by 2050. In furtherance of this long-term goal, on June 9, 2021, MEG, together with Canadian Natural Resources, Cenovus Energy, Imperial and Suncor Energy (and subsequently joined by ConocoPhillips Canada) announced the Oil Sands Pathways to Net Zero initiative. The Oil Sands Pathways to Net Zero initiative participants operate approximately 95 per cent of Canada’s operated oil sands production. The goal of this unique alliance, working collectively with the federal and Alberta governments, is to achieve net zero GHG emissions from the companies’ oil sands operations by 2050, to help Canada meet its climate goals, including its Paris Agreement commitments and 2050 net zero aspirations.

Following two weeks of negotiations between delegates from 197 countries, on Friday, November 13, 2021, COP26 concluded, culminating in the release of the final COP26 decision, now known as the Glasgow Climate Pact ("GCP"). The GCP reaffirms the long-term global goal to hold the increase in the global average temperature to well below 2˚C above pre-industrial levels and to pursue efforts to limit the temperature increase to 1.5˚C above pre-industrial levels. The federal government also made a number of announcements respecting Canada's climate change related ambitions during and immediately following COP26, indicating that regulatory oversight on climate change matters will likely continue to increase. These included reducing national GHG emissions to net-zero by 2050, new financial disclosure requirements concerning climate change, and increasing Canada's commitment from a 30% emissions reduction to a 40-45% reduction as compared to 2005 levels by 2030.

Government of Canada Regulations

Environment and Climate Change Canada coordinates the Government of Canada’s climate change initiatives that aim to reduce GHG emissions through a sector-by-sector regulatory approach in order to protect the environment and support economic prosperity. To date, Canada has implemented GHG emission reducing regulations for methane and upstream oil and gas, renewable fuels, transportation, short-lived climate pollutants, and coal- and natural gas-fired electricity. Regulations for the oil and gas sector have been developed within 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 do not apply if equivalent requirements are instituted by a province, for example, in Alberta, those made under the provincial Methane Emission Reduction Regulation under EPEA. Alberta, British Columbia and Saskatchewan have such equivalency agreements in place.

On June 29, 2021, the Canadian Net-Zero Emissions Accountability Act ("*NZEAA*") came into force. Under the *NZEAA*, the Government of Canada established a national greenhouse gas emissions target for 2050 that is net-zero, defined as "anthropogenic emissions… are balanced by anthropogenic removals of greenhouse gases from the atmosphere;" in other words, human caused emissions will be balanced by human caused greenhouse gas removals by 2050. On July 12, 2021, the Government of Canada announced its plan to reduce GHG emissions by 40-45% below 2005 levels by 2030 (referred to as the Nationally Determined Contribution or "NDC"), and formally submitted Canada's enhanced NDC to the UNFCC (the prior NDC targeted a 30% reduction by 2030). The *NZEAA* also requires a federal plan for achieving the 2030 target, with subsequent target plans for 2035, 2040, and 2045, as well as codifies the NDC as Canada's official 2030 emissions reduction target.

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. In December 2020, the federal government proposed increasing the price on carbon to $170 per tonne by 2030. To reach that level, the price imposed on carbon will rise from the 2022 rate of $50 per tonne by $15 per tonne each year. On January 1, 2023, the effective price imposed on carbon increased to $65 per tonne.

The federal *Greenhouse Gas Pollution Pricing Act* (“*GGPPA*”) came into force on June 21, 2018, and includes two key parts: (i) a fuel charge (“Part 1”); and (ii) an output-based pricing system for industrial facilities (“Part 2”). Schedule 4 of the *GGPA* establishes the $15 increase each per tonne of carbon emitted. 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. The Government of Alberta challenged the constitutionality of the federal carbon emission pricing system, and the Alberta Court of Appeal found the federal system to be unconstitutional. Appeals of this decision, along with appellate court decisions in both Ontario and Saskatchewan, which found the federal system to be constitutional, were heard by the SCC in September 2020. On March 25, 2021, the SCC ruled that the *GGPPA* is constitutional. As of November 11, 2022, the federal backstop applies in full in the Yukon, Nunavut and Manitoba, while partially applying in Alberta, Saskatchewan, Ontario and Prince Edward Island. Provincial systems in these latter four provinces meet the federal backstop requirements for the emission sources covered, but the *GGPPA* applies to certain sources not covered by the provincial systems.

On December 6, 2019, the federal government confirmed that Alberta’s approach to carbon pricing under the Alberta Technology Innovation and Emissions Reduction ("TIER") Regulation is equivalent to the federal standard and as a result Part 2 of the *GGPPA* does not apply in Alberta. This confirmation was further extended into 2021 by the federal government upon acceptance of the equivalency of the *GGPPA* to the TIER Regulation after the province adjusted the fund credit price to match that of the GGPPA. On December 21, 2022, the Government of Alberta released Ministerial Order 62/2022, which established for the year 2023 the 65$ per tonne charge on carbon emissions, in addition to the $15 increase each year up to $170 in 2030. The fuel charge under Part 1 of the *GGPPA* applies in Alberta as the Government of Alberta repealed the Alberta carbon levy under the *Climate Leadership Act*, however, the *GGPPA* includes provisions to exempt from the fuel charge under Part 1 of the *GGPPA* facilities subject to provincial regulations such as the TIER Regulation.

In March 2022, the Government of Canada launched a consultation through the publication of a discussion paper to solicit comments on clean electricity regulations (CER) under the Canadian Environmental Protection Act, 1999 (CEPA). The consultation is in support of the stated goals of the federal government to transition to a net-zero electricity supply by 2035 (NZ2035) and to achieve economy-wide net-zero emissions by 2050.

Environment and Climate Change Canada published a Proposed Framework for the CER, which was open for comment until August 17, 2022, and provided further potential details of the CER thereafter. As currently contemplated, a generation unit commissioned before 2025 would become subject to the CER's emission intensity performance standard at the end of its prescribed life, or on January 1, 2035. The definition of prescribed life would require further delineation, but could be defined as a period of fixed years starting with its commissioning date. Although the CER may exempt cogeneration units that generate electricity only for its own needs (i.e. self-consumption behind the industrial fence line), this would not exempt the Corporation's cogeneration facilities, which sells a portion of its generation to the electricity system. A regulated unit would be prohibited from operating when its quantified emissions performance exceeds the applicable standard over a period of time. Any residual emissions below the standard would be subject to financial compliance requirements, such as offset purchases or paying an amount that corresponds to the federal carbon price applicable in the given year. The contemplated CER would permit compliance to be achieved through a variety of technologies, such as abatement technologies.

The development of the CER continues, and may be subject to further federal consultations. See "Risk Factors – Environmental and Regulatory Risks – Cogeneration Regulation".

Government of Alberta Regulations

As noted above, the current Government of Alberta has repealed the carbon levy under the *Climate Leadership Act* and replaced the *Carbon Competitiveness Incentive Regulation* (“CCIR”) with the TIER Regulation. 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 and as a result, uncertainties exist for the industry and the Corporation with respect to the implementation of the 100 megatonnes per year province-wide limit on all oil sands emissions. The *Methane Emission Reduction Regulation* under the *EPEA* came into force on January 1, 2020, and includes requirements to address the primary sources of methane emissions from Alberta’s upstream oil and gas industry: fugitive emissions and venting.

In Alberta, the *Emissions Management and Climate Resilience Act* provides a framework for managing GHG emissions in the province. The accompanying regulations include the *Specified Gas Reporting Regulation* ("SGRR"), which imposes GHG emissions reporting requirements for facilities regulated under the TIER Regulation, which came into force on January 1, 2020.

Various elements of the CCIR are included in the TIER Regulation, as the TIER Regulation 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 prescribed level, together with or as an alternative to physical abatement, with penalties for failure to achieve compliance. However, the TIER Regulation has fundamental differences with the CCIR as the TIER Regulation includes facility-specific benchmarks and high-performance benchmarks in contrast to the product specific benchmarks under the CCIR.

The TIER Regulation applies to facilities in Alberta that produce 100,000 or more tonnes of GHG emissions per year. A facility's allowable emissions is calculated based on the applicable benchmarks for the product it produces. In the case of *in situ* oil sands facilities, emissions reduction obligations are determined based on the less stringent of a facility-specific benchmark or high-performance benchmark. The facility-specific benchmark is 90% of the historical emissions intensity of the facility based on 2013 to 2015 emissions intensity. The stringency of a facility-specific benchmark will increase by 1% annually beginning in 2021 until this benchmark meets the high-performance benchmark, which is calculated as the average emissions intensity of the most emissions-efficient *in situ* oil sands facilities. A facility must ensure that its net emissions do not exceed the allowable emissions 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 allowable emissions 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 allowable emissions for such reporting period. As was the case under the CCIR, a facility can earn EPCs if its TRE is less than the facility's allowable emissions. 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 TIER Regulation: (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 Technology Innovation and Emissions Reduction Fund ("Fund") run by the Alberta government. The contribution costs to the Fund are set at $50 per tonne for 2022 and subsequent years (increased from $30 in 2020 and from $40 in 2021), subject to change by Ministerial order. In December 2022 the TIER Regulations were updated to follow Federal Government pricing of $170 per tonne by 2030. Under the TIER Regulation there are no limits on purchasing fund credits to meet a facility's true up obligation; however, the TIER Regulation includes limits on the use of EPCs and emission offsets for compliance purposes and expiry periods for EPCs and emission offsets according to the vintage year.

Annual compliance reports for facilities subject to the TIER Regulation are due June 30 of the year following the compliance year. A facility that exceeds one megatonne of annual emissions is considered a forecasting facility and must also submit an annual forecasting report by November 30.

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.

No assurance can be given that environmental laws and regulations 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 U.S. Environmental Protection Agency ("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.

In early 2021, the U.S. rejoined the Paris Agreement and subsequently announced a 2030 target to reduce GHG emissions by 50 percent to 52 percent from 2005 levels. It is expected that this target will be met largely through clean energy incentives introduced under the *Inflation Reduction Act* as opposed to regulatory measures.

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, recent changes to Alberta's GHG regime, 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. If not appropriately harmonized, the costs of meeting new federal government requirements could be considerably higher than the costs of meeting Alberta's requirements.

See "Risk Factors".

ACCOUNTABILITY AND TRANSPARENCY

In 2015, the federal government's *Extractive Sector Transparency Measures Act* (the "*ESTMA*") came into effect, which imposed mandatory reporting requirements on certain entities engaged in the "commercial development of oil, gas or minerals", including exploration, extraction and holding permits. All companies subject to the *ESTMA* must report payments over $100,000 made to any level of a Canadian or foreign government (including Indigenous groups), including royalty payments, taxes (other than consumption taxes and personal income taxes), fees, production entitlements, bonuses, dividends (other than ordinary dividends paid to shareholders), infrastructure improvement payments and other prescribed categories of payments.

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. The term of each director is from the date of the meeting at which he or she is elected or appointed until the next annual meeting of shareholders or until a successor is elected or appointed.

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.
Ryan Kubik Alberta, Canada	Chief Financial Officer	N/A	Chief Financial Officer of the Corporation since July 2022. Prior thereto, Chief Financial Officer & Senior Vice President of Heritage Royalty from 2017 to 2022.
Darlene M. Gates Alberta, Canada	Chief Operating Officer	N/A	Chief Operating Officer of the Corporation since September 2021. Prior thereto, President of ExxonMobil Production Alaska.
Lyle S. Yuzdepski Alberta, Canada	Senior Vice President, General Counsel and Corporate Secretary	N/A	Senior Vice President, Legal, General Counsel and Corporate Secretary since January 2020. General Counsel and Corporate Secretary of the Mancal Group from January 2007 to January 2020. Formerly a partner at McCarthy Tétrault LLP.
Gary A. Bosgoed(1)(4)(5)	Director	July 1, 2022	President and CEO of Bosgoed Project Consultants Ltd. Formerly, Senior Vice President of WorleyParsons' Edmonton Office from 2012 to 2015. Currently a director of Capital Power Corporation.
Ian D. Bruce(1) Alberta, Canada	Director (Board Chair)	June 13, 2019	Director of the Corporation since June 2019. Chair of the Board of Cameco Corporation since May 2018 and a director since 2012. Former President and CEO of Peters & Co. Limited.
Robert B. Hodgins(1)(2)(4) Alberta, Canada	Director	September 21, 2010	Director of the Corporation since September 2010. Independent businessman and director of AltaGas Ltd., Enerplus Corporation and Gran Tierra Energy Inc. Senior Advisor (non-executive), Investment Banking of Canaccord Genuity Corp. until May 2022.
Kim Lynch Proctor(1)(2)(3)	Director	May 3, 2022	Independent businesswoman, experienced lawyer, accountant and executive. Currently a director of Paramount Resources Ltd. and serves on the Board of Trustees of Alaris Equity Partners Income Trust.
Susan M. MacKenzie(1)(2)(5) Alberta, Canada	Director	June 17, 2020	Director of the Corporation since June 2020. Corporate director since 2011. Currently a director of Enerplus Corporation and Precision Drilling Corporation.
Jeffrey J. McCaig(1)(3)(5) Alberta, Canada	Director	March 1, 2014	Director of the Corporation since March 2014. Currently Chairman of the Board of Trimac Transportation. Director of Michichi Capital Corp. since June 2022. 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.

Name, Province or State and Country of Residence	Position(s) Held	Director Since	Principal Occupation During the Preceding Five Years
James D. McFarland(1)(3)(5) Alberta, Canada	Director	June 9, 2010	Director of the Corporation since June 2010. Director of Valeura Energy Inc. since April 2010 and President and CEO until his retirement in 2017.
Diana J. McQueen(1)(3)(4) Alberta, Canada	Director	October 6, 2015	Director of the Corporation since October 2015. SVP Communications and Stakeholder Relations of Reconnaissance Energy Africa Ltd. since April 2021. Director of Total Helium Ltd. since November 2021. Self-employed consultant since September 2015. 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) Independent director.
(2) Member of the Audit Committee. Mr. Hodgins is the Chair of the Audit Committee.
(3) Member of the Human Capital & Compensation Committee. Mr. McFarland is the Chair of the Human Capital & Compensation Committee.
(4) Member of the Governance & Nominating Committee. Ms. McQueen is the Chair of the Governance & Nominating Committee.
(5) Member of the Health, Safety, Environment & Reserves Committee. Ms. MacKenzie is the Chair of the Health, Safety, Environment & Reserves Committee.

The Company's officers are appointed by and serve at the discretion of the Board. As of December 31, 2022, the directors and executive officers of the Corporation, as a group, directly or indirectly, beneficially owned or held control or direction over 1,692,502 Common Shares representing approximately 0.58% of the issued and outstanding Common Shares.

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.

Ian D. Bruce was a director of Laricina Energy Limited ("Laricina"), a junior oil sands private company, from 2013 to 2017. Laricina entered into *Companies' Creditors Arrangement Act* (*"CCAA")* under a protection order on March 26, 2015 and emerged on February 1, 2016, following completion of a restructuring.

Derek W. Evans was a director (until his resignation in January 2016) of Endurance Energy Ltd. (a private oil and gas company) that sought protection under the CCAA 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.

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 Mr. Robert Hodgins (Chair), Ms. Kim Lynch-Proctor and Ms. Susan MacKenzie. Each member of the current Audit Committee and the post-Meeting Audit Committee is an independent director and is "financially literate" as such term is defined in National Instrument 52-110 – Audit Committees. Additionally, each of Mr. Hodgins and Ms. Lynch-Proctor are considered by the Board to be a "financial expert" based on their education, professional accounting designation and experience as a principal financial officer, principal accounting officer, controller, or experience in one or more positions that involve the performance of similar functions. The Audit Committee Charter 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. As of December 31, 2022, 291,081,189 Common Shares, and no Preferred Shares, were issued and outstanding. 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 "Effective Date"), the Corporation adopted the Rights Plan. At the annual and special meeting of shareholders of the Corporation held on June 17, 2020, shareholders passed a resolution extending the term of the Rights Plan until the annual meeting of shareholders of the Corporation to be held in 2023. 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 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.

DIVIDEND 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 prior to reaching the debt target of US$600 million, 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, debt repayment and return of capital initiatives. 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, 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 restrictions contained in the agreements governing certain 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 aggregate 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, 2022.

		Monthly Price Range	
	Volume (Shares)	**High ($)**	**Low ($)**
January	43,884,510	15.29	11.99
February	48,277,830	16.92	14.50
March	77,772,001	21.17	15.90
April	61,042,575	20.66	16.36
May	66,970,288	23.00	17.88
June	68,421,650	24.47	16.55
July	57,303,178	18.62	14.49
August	57,164,505	19.98	14.61
September	52,790,066	18.67	13.91
October	59,443,703	20.50	15.94
November	55,954,313	21.43	17.41
December	106,049,894	20.40	16.46

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 December 31, 2022

	Moody's Investors Service ("Moody's")	**S&P Global Ratings** ("S&P")	**Fitch Ratings** ("Fitch")
Issuer Credit Rating	B1 (Positive)	B+ (Stable)	B+ (Stable)
Senior Unsecured Debt (High Yield Notes)	B2	BB-	BB-

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

Moody's credit ratings are on a rating scale that ranges from Aaa to C, which represents the range from highest to lowest quality of such securities rated. A rating of "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 and the modifier 2 indicates a mid-range ranking. The "positive" rating outlook indicates the higher-than-average likelihood of a positive rating change over the medium term.

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 currently has the capacity to meet its financial commitments but adverse business, financial, or economic conditions will likely impair the obligor's capacity or willingness 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 shorter term (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. Securities with a BB credit rating are considered less vulnerable to non-payment than other speculative issues but face major ongoing uncertainties or exposure to adverse business, financial, or economic conditions that could lead to the obligor's inadequate capacity to meet its financial commitments on these obligations.

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 outlooks indicate the direction a rating is likely to move over a one to two-year period, reflecting financial or other trends that have not yet reached or been sustained the level that would cause a rating action, but which may do so if such trends continue. A “stable” outlook indicates neither an upward nor negative trend on the rating scale.

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.

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.

The Corporation has paid each of Moody's, S&P, and Fitch their customary fees in connection with the provision of the above ratings. The Corporation has not made any payments to Moody's, S&P or Fitch in the past two years for services unrelated to the provision of such ratings.

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

Risk Arising from Operations

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 or widening of differentials between various crude oil prices;
- increases in the price applied to carbon emissions;
- the negative impacts of the COVID-19 pandemic and the related global economic downturn;
- lower than expected reservoir performance, including, but not limited to, lower oil production rates and/or higher SOR, 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 enhanced completion designs, optimized inter-well spacing, short-cycle high return redevelopment projects and steam allocation techniques;
- 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, tankage, railways and railcars and barges that 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 availability and 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, tax and regulatory regimes in Canada, the United States and elsewhere;
- the ability to obtain further approvals and permits for MEG's future projects;
- the ability to attract or access capital as a result of changing investor priorities and trends, including as a result of climate change, ESG initiatives, the adoption of decarbonization policies and the general stigmatization of the oil and gas industry;
- the availability of pipeline capacity and other transportation and storage facilities for MEG's bitumen blend;
- refining markets for MEG's bitumen blend;
- increased royalty payments resulting from changes in regulatory regimes;
- inflationary pressures and increased supply costs;
- unavailability of, or increased cost of, skilled labour;
- unavailability of, or increased cost of, materials;
- 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 and Government of Alberta production curtailments, if any.

Status and Stage of Development

While the first three phases of the Christina Lake Project are operational, additional phases and other projects may not be completed on time (or at all), and the costs associated with additional phases may be greater than expected. At an SOR of 2.2, the Corporation has developed oil processing capacity of approximately 110,000 bbls/d at its Christina Lake central plant facility, prior to any impact of scheduled maintenance activity or outages through the phased construction of the Christina Lake Project as well as several low-cost debottlenecking and expansion projects and the application of its proprietary reservoir technologies. While the investment in Phase 2B brownfield growth project central processing plan is complete, ramp up in production from the brownfield project, 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, if and when approved, may be greater than the Corporation expects.

Additional phases of development of the Christina Lake Project 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 and/or a determination by MEG not to devote capital expenditures to a given project;
- 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;
- a determination not to proceed with, or to delay, development of a given project;
- labour disputes or disruptions, declines in labour productivity or the unavailability of, or increased cost 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 and regulations;
- 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, 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, Enbridge Mainline and Flanagan South and Seaway Pipelines. Any event that interrupts operations at the Christina Lake Project or the operations of these pipelines 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 all of MEG's 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.

A determination by MEG not to proceed with, or to delay, development of a given project may result in certain reserves pertaining to such project being reclassified. For example, the movement of the Surmont Project out of MEG's development plan in 2019 resulted in the reclassification of probable undeveloped reserves attributed to the Surmont Project to contingent resources.

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 MEG's control. The reserves, contingent resources and estimated financial information with respect to certain of MEG'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, 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.

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 depends 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, airstrips, terminals and vessels.

For example, the Christina Lake Project depends 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 MEG by limiting its ability to transport blended bitumen to end markets and increasing MEG's cost for both sourcing diluent and transporting its blended 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 could negatively impact the operation of the Christina Lake Project, 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. There is also a risk that MEG could face litigation initiated by third parties relating to climate change, including litigation pertaining to GHG emissions, the production, sale or promotion of fossil fuels and petroleum products and/or disclosure. Claims under any 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 MEG's thermal oil production properties and projects have experienced 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, well blowouts and spills. In addition, the geological characteristics and integrity of the bitumen reservoirs are inherently uncertain. The injection of steam into reservoirs under significant pressure may result in unforeseen damage to reservoirs that could result in steam blowouts or oil or gaseous leaks. A casualty occurrence might result in the loss of equipment or life, as well as injury, property damage or the interruption of MEG'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 MEG'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 thermal oil production 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 bitumen pricing and accordingly, MEG's results of operations, financial condition and prospects. In addition, the industry's 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 MEG's results of operations and financial condition.

SAGD and eMSAGP Bitumen Recovery Process

The recovery of bitumen using SAGD and eMSAGP processes is subject to uncertainty. Current SAGD and eMSAGP technologies for *in situ* extraction of bitumen or for reservoir injection require significant consumption of natural gas or other fuels to produce steam for use in the recovery process. There can be no assurance that MEG's operations will produce bitumen at the expected levels or on schedule. The quality and performance of the bitumen reservoir can also impact the SOR and the timing and levels of production. Current *in situ* thermal extraction technologies for the extraction of bitumen, including SAGD and eMSAGP, involve the injection of steam into the bitumen reservoir under significant pressure.

The amount of steam required in the production process can vary and impact costs significantly. In addition, the geological characteristics and integrity of the bitumen reservoirs are inherently uncertain. The injection of steam into reservoirs under significant pressure may cause fluid containment issues and unforeseen damage to reservoirs, resulting in large steam losses in parts of the reservoir where caprock may have been compromised or where there are connected reservoir thief zones such as bottom water and top gas and/or water. Should these adverse reservoir conditions be encountered, MEG's bitumen recovery levels may be negatively impacted.

Royalty Regimes

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 thermal oil production projects. See "Regulatory Matters".

The Government of Alberta implemented 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, which is subject to a separate royalty regime. Following the Government of Alberta's royalty review in 2016, the royalty structure and rates for oil sands production remain generally unchanged, with some minor adjustments to allowable costs and transparency. The Government of Alberta passed Bill 12, the *Royalty Guarantee Act* on July 18, 2019, ensuring that when a well is drilled, the royalty structure will remain in place for at least ten years, subject to certain listed exceptions. On July 23, 2020, Bill 22, the *Red Tape Reduction Implementation Act*, received Royal Assent. This bill amends the *Mines and Minerals Act (Alberta)* allowing the Alberta Minister of Energy to make changes to royalty rates without cabinet's approval. There can be no assurances that the Government of Alberta will not amend or repeal these Acts, or that the Government of Alberta or Canada will not adopt new royalty regimes, which may render MEG's projects uneconomic or otherwise adversely affect its results of operations, financial condition or prospects.

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

Tax Laws

Income tax laws and regulations and other laws and government incentive programs may in the future be changed or interpreted in a manner that has a material adverse effect on the Corporation's results of operations, financial condition and prospects. Tax authorities having jurisdiction over the Corporation may disagree with the manner in which we calculate our tax liabilities such that the Corporation's provision for income taxes may not be sufficient, or such authorities could change their administrative practices to the Corporation's detriment or to the detriment of our shareholders. In addition, all of our tax filings are subject to audit by tax authorities who may disagree with such filings in a manner that adversely affects the Corporation and its shareholders.

In Canada, in the 2022 Fall Economic Statement released by the Department of Finance, a new tax on share buybacks by public corporations was proposed. Under the proposal, which would come into force on January 1, 2024, a two percent corporate-level tax would apply on the "net value" of all types of share buybacks by public corporations in Canada. While there are few details available on the proposed tax, the Corporation will continue to monitor and assess any potential adverse impacts.

In addition, from time to time during periods of higher energy commodity prices various foreign governments have implemented or proposed the implementation of windfall taxes on energy companies. For example, in September 2022 the European Union approved a temporary 33% windfall tax on fossil fuel companies' profits made in 2022 and 2023 exceeding a four-year historical average by 20%. Although the Canadian federal government has not proposed such a tax, any decision to implement such a tax may have a material adverse effect on the Corporation's results of operations, financial condition and prospects.

Lease Expiries

The *Oil Sands Tenure Regulation, 2020* came into force on December 1, 2020, and repeals the *Oil Sands Tenure Regulation, 2010.* The 2020 regulations apply to all leases issued on or after December 1, 2020, to all permits issued under the 2010 Regulation, and those continued or discontinued from the 2010 or the previous 2000 Regulations. The new regulations no longer require a minimum level of evaluation for the issuance of a lease, however the Minister has established a minimum level of production. Certain of MEG's thermal oil production leases may expire and MEG may be required to surrender lands to the Province of Alberta. The initial term for MEG's thermal oil production leases, some of which began in or subsequent to 1996, is 15 years.

Claims Made by Indigenous Peoples

Indigenous Peoples have claimed indigenous title and rights to a substantial portion of western Canada. Certain Indigenous 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, indigenous 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.

On December 3, 2020, the Federal Government introduced Bill C-15, An Act respecting the United Nations Declaration on the Rights of Indigenous Peoples which requires the Federal Government to ensure all Canadian laws are consistent with the United Nations Declaration on the Rights of Indigenous People ("UNDRIP"), implement an action plan to achieve UNDRIP's objectives and table a report on the process of aligning the laws of Canada and on the action plan. On June 21, 2021, Bill C-15 received Royal Assent and came immediately into force. Additional processes may be created or legislation amended or introduced associated with project development and operations, further increasing uncertainty with respect to project regulatory approval timelines and requirements.

Recently in British Columbia, an indigenous group was able to establish that cumulative effects within its traditional territory had reached a "tipping point" resulting in infringement of their treaty rights. The court determined that British Columbia could not authorize new activities within this First Nation's traditional territory, pending consultation and negotiation with the First Nation. However, this decision does not create binding precedent in Alberta, negotiations are ongoing between the Government of British Columbia and the First Nation respecting future authorizations (an interim agreement allowing emergency authorizations has been reached) and the decision was not appealed by the Government of British Columbia. While the long-term impacts of this decision on aboriginal law in Canada overall and in Alberta are not yet fully understood, a similar claim, if successful, that encompasses the Christina Lake Project and/or MEG's other projects could have a significant adverse effect on MEG.

Unforeseen Title Defects

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

Future Acquisitions and Sufficiency of Funds

As part of a future growth strategy, MEG may continue to evaluate and, where appropriate, pursue acquisitions of additional mineral leases. Acquisitions of mineral 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 mineral 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 mineral leases, it may need to change its anticipated capital expenditure programs and the use of MEG'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, and potentially, the Surmont Project, the May River Regional Project and the Growth Properties. At present, cash flow from MEG's operations is largely dependent on the performance of a single project and commodity prices, and MEG'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. Specifically, changing investor priorities and trends, including as a result of climate change, ESG initiatives, the adoption of decarbonization policies and the general stigmatization of the oil and gas industry may limit MEG's ability to attract and access 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 MEG'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. In addition, a determination by MEG not to proceed with, or to delay, development of a given project may result in certain reserves pertaining to such project being reclassified. For example, the movement of the Surmont Project out of MEG's development plan in 2019 resulted in the reclassification of probable undeveloped reserves attributable to the Surmont Project to contingent resources.

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:

- the negative impacts of the COVID-19 pandemic, the proliferation of new COVID-19 variant strains, governmental policy and emergency response measures and any related economic downturn;
- global energy policy, including (without limitation) the ability of the Organization of Petroleum Exporting Countries ("OPEC") and OPEC Plus members, 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, including pipelines;
- the effect of worldwide environmental and/or energy conservation measures;
- the price and availability of alternative energy supplies; and
- the overall global economic environment.

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

The market prices for heavy oil (which includes bitumen blends) are lower than the established market prices for light and medium grades of oil, due principally to diluent prices and the higher transportation and refining costs associated with heavy oil. Also, the market for heavy oil is more limited than for light and medium grades of oil, making it more susceptible to supply and demand fluctuations. 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 or differentials widen, 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.

Public Health Crises and Related Impacts

The COVID-19 pandemic has affected, and may materially and adversely affect, MEG’s business, operating and financial results and liquidity. The severity, magnitude and duration of the COVID-19 pandemic, and the emergence of new variant strains of the COVID-19 virus, remains uncertain. While the full impact of the virus and the long-term worldwide reaction to it and impact from it remains uncertain, public health crises can result in volatility and disruptions in the supply, demand and pricing for petroleum products, global supply chains and financial markets, as well as declining trade and market sentiment and reduced mobility of people, all of which could affect commodity prices, interest rates, credit ratings, credit risk and inflation. Governmental reaction to the pandemic and restrictions and limitations applied by governments including travel restrictions, quarantines or site closures, as well as the pace of relaxation of such restrictions and limitations, particularly in large oil markets such as China, could adversely impact the Corporation in many ways, including the price the Corporation may achieve on sales of its products, ability of MEG’s employees and contractors to perform their duties, increase technology and security risk due to extended and company-wide telecommuting, disruptions in MEG’s supply chain (including necessary contractors), increase the risk that oil storage could reach capacity in Canada and the USGC as a result of decreased demand, lead to a disruption in MEG’s resource acquisition or permitting activities and cause disruption in MEG’s relationship with customers.

Additionally, the COVID-19 pandemic has significantly impacted economic activity and markets around the world, and COVID-19, variant strains or another similar outbreak could negatively impact MEG’s business in numerous ways, including, but not limited to, the following:

- MEG’s revenue may be reduced if the pandemic results in an economic recession to the extent it leads to a prolonged decrease in the demand for crude oil, bitumen and bitumen blends;

- MEG’s operations may be disrupted or impaired, thus lowering our production level, if a significant portion of MEG’s employees or contractors are unable to work due to illness or if operations are suspended or temporarily shut-down or restricted due to control measures designed to contain the pandemic; and

- MEG’s sole operating facility at Christina Lake is subject to risks relating to a temporary suspension or physical interruption of its operations in the event a significant number of employees or contractors at the Christina Lake facility become infected with COVID-19, as it could place MEG’s entire site workforce at risk.

In addition, the COVID-19 pandemic has increased volatility and caused negative pressure in the capital and credit markets. As a result, MEG may experience difficulty accessing the capital or financing needed to fund operations, which have substantial capital requirements, or refinance any upcoming debt maturities on satisfactory terms or at all. MEG anticipates funding capital expenditures with existing cash and cash generated by operations (which is subject to a number of variables, including many beyond MEG’s control) and, to the extent MEG’s capital expenditures exceed cash resources, from borrowings under the Credit Facility and other external sources of capital, MEG could be required to curtail operations and the development of its properties, which in turn could adversely affect MEG’s business, results of operations and financial position.

Russia Ukraine Conflict

In February 2022, Russian military forces invaded Ukraine. In response, Ukrainian military personnel and civilians are actively resisting the invasion. The outcome of the conflict is uncertain and is likely to have wide-ranging consequences on the peace and stability of the region and the world economy. Certain countries including Canada and the United States, have imposed strict financial and trade sanctions against Russia, which sanctions may have far reaching effects on the global economy. Russia is a major exporter of oil and natural gas. Disruption of supplies of oil and natural gas from Russia could cause a significant worldwide supply shortage of oil and natural gas and have a significant impact on worldwide prices of oil and natural gas. A lack of supply of energy and high prices of oil and natural gas could have a significant adverse impact on the world economy. The long-term impacts of the conflict and the sanctions imposed on Russia remain uncertain.

General Economic Conditions, Business Environment, Inflation and Other Risks

MEG’s business 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, MEG's ability to generate sufficient cash flow to meet its current and future obligations, MEG's ability to access external sources of debt and equity capital, general economic and business conditions, MEG'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 and royalties) against MEG (and its subsidiary), political and economic conditions in the geographic regions in which MEG and its subsidiary operate, difficulty or delays in obtaining necessary regulatory approvals, a significant decline in MEG's reputation, and such other risks and uncertainties, could individually or in the aggregate have a material adverse impact on MEG'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 MEG's results of operations, financial condition and prospects. There can be no assurance that any risk management steps taken by MEG with the objective of mitigating the foregoing risks will avoid future loss due to the occurrence of such risks. While MEG does not believe that inflation has had a material effect on MEG's business, financial condition or results of operations to date, if operation or labour costs were to become subject to significant inflationary pressures, MEG may not be able to fully offset such higher costs. Inability or failure to do so could harm MEG's business, financial condition and results of operations.

The successful operation of the Corporation’s business will depend upon the availability of, and competition for, skilled labour and supply of required goods and services. There is a risk that the Corporation may have difficulty sourcing the required labour and goods and services required in its operations. The risk could manifest itself through an inability to recruit new employees or contractors without a dilution of talent, to train, develop and retain high quality and experienced employees or contractors without unacceptably high attrition, and to satisfy an employee’s work/life balance and desire for competitive compensation. The labour market in Alberta is particularly tight due to a strengthening commodity price environment and increased field activities after a prolonged period of weak commodity prices, lack of work certainty, lower wages and COVID-19 which resulted in an exodus of skilled workers from the oil and gas industry. Labour, equipment and materials necessary for the Corporation’s operations may also be in short supply, subject to substantial cost inflation, and the Corporation may experience substantial delays in transportation of materials given the impacts of COVID-19 on global supply chains and logistics.

The nature of MEG's operations results in exposure to fluctuations in bitumen, diluent and gas prices. Natural gas is a significant component of MEG's cost structure, as it is used to generate steam for the SAGD process and to create electricity at MEG's cogeneration facility. Diluent, such as condensate, is also one of MEG'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 condensate and natural gas. As a result, MEG 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 from MEG's 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, MEG'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 MEG's debt is denominated in U.S. dollars. Fluctuations in exchange rates and interest rates may significantly increase or decrease the amount of debt and interest expense recorded on MEG's financial statements, which could have a significant effect on MEG's results of operations and financial condition.

Hedging Strategies

MEG uses physical and financial instruments to hedge its exposure to fluctuations in commodity prices, exchange rates and interest rates. MEG's engagement in such hedging activities could 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 MEG from realizing the full benefit of such increases or decreases. In addition, any future commodity hedging arrangements could cause MEG 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 MEG'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 in connection with the global financial crisis, 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. A new global financial crisis may exacerbate these market events and conditions.

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 OPEC and OPEC Plus 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 for a considerable period of time.

Climate Change Risks

Climate change may introduce new risks to MEG's business including both physical risks and transitional risks. Certain of these climate change risks include the following:

Transitional Risks

Transitional risks include a broader set of risks associated with a global transition to a less carbon-intensive economy. A negative impact from transitional risks could result in loss of customers, revenue loss, delays in obtaining regulatory approvals for pipelines and other projects, increased operating, capital, financing or regulatory costs, diminished shareholder confidence, continuing changes to laws and regulations affecting MEG's business or erosion or loss of public support towards the hydrocarbon-based energy sector.

Policy and Legal Risks

Negative consequences which could arise as a result of changes to the current and emerging regulatory environment include, but are not limited to, changes in environmental and emissions regulation of current and future projects by governmental authorities, which could result in changes to facility design and operating requirements, potentially increasing the cost of construction, operation and abandonment. Policy and legal risks are further discussed under the heading "Environmental and Regulatory Risks - Environmental Considerations" below.

Marketing Risks

Negative impacts from transitional risks and physical risks could result in constrained egress out of western Canada which could impact MEG's operating results. In terms of reputational risk, negative public perception of the Alberta oil sands could result in delays in obtaining regulatory approvals for pipelines and other projects increasing competition for market access. Future legislation or policies that limit the purchase of crude oil or bitumen produced from the oil sands may be adopted in domestic and/or foreign jurisdictions, which, in turn, may limit the world market for this crude oil, reduce its price and may result in stranded assets or an inability to further develop oil resources. In terms of physical risk, potential increases in extreme weather events may impede operation of pipelines, storage infrastructure as well as refineries.

Reputational Risks

Reputational risks include numerous factors which could negatively affect MEG's reputation, including general public perceptions of the energy industry, negative publicity relating to pipeline incidents, unpopular expansion plans or new projects, opposition from organizations and populations opposed to fossil fuels development, specifically oil sands projects and pipeline projects, including expansions thereof.

Negative public perceptions of the Alberta oil sands, where thermal oil operations are located, may impair the profitability of MEG's current or future oil sands projects. Further, with increasing public focus on climate change and GHG emissions, the scale of the global energy transition away from fossil fuels and the potential acceleration of the global energy transition, the reputations of oil and gas companies generally may become increasingly unfavourable. There are added social pressures which demand governments and companies to work to mitigate the risks associated with climate change, decrease GHG emissions and move towards decarbonization. Specifically, there is a reputational risk in connection with MEG's ability to meet increasing climate reporting and emission reduction expectations from key stakeholders. MEG has been actively preparing and adapting to manage and respond to investors' increasing expectations by proactively setting voluntary GHG and emission reduction targets, investing in energy efficiency and emissions reduction projects, integrating ESG across its business and linking executive compensation to progress on ESG goals and objectives.

Development of the Alberta oil sands has received considerable attention on the subjects of environmental impact, climate change, GHG emissions and Indigenous engagement. The influence of anti-fossil fuels activists (with a focus on oil sands) targeting equity and debt investors, lenders and insurers may result in policies which reduce support for or investment in the Alberta oil sands sector. Concerns about oil sands may, directly or indirectly, impair the profitability of MEG's current oil sands projects, and the viability of future oil sands projects, by creating significant regulatory uncertainty leading to uncertainty in economic modeling of current and future projects and delays relating to the sanctioning of future projects. In addition, evolving decarbonization policies of institutional investors, lenders and insurers could affect MEG's ability to access capital pools. Certain insurance companies have taken actions or announced policies to limit available coverage for companies which derive some or all of their revenue from the oil sands sector. As a result of these policies, premiums and deductibles for some or all of MEG's insurance policies could increase substantially. In some instances, coverage may become unavailable or available only for reduced amounts of coverage. As a result, MEG may not be able to extend or renew existing policies, or procure other desirable insurance coverage, either on commercially reasonable terms, or at all.

Technology Risks

MEG's mid-term and long-term goals related to reaching net-zero emissions (which is inherently uncertain due to the potentially long timeframe and certain factors outside of MEG's control, including the availability and cost effectiveness of current and future emissions reductions technologies) is subject to numerous risks and uncertainties. MEG's actions taken in implementing such a target may expose MEG to certain additional and/or heightened financial and operational risks.

Technological advancements and innovations associated with the global transition to a less carbon-intensive economy may impact the demand for MEG's products. This may include the advancement of alternative energy supplies and carbon performance of petroleum competitors.

Physical Risks

Physical risks associated with climate change may include chronic physical risks such as severe changes to seasonal weather patterns and the corresponding effects of seasonal conditions and temperatures or acute physical risks which include catastrophic events such as fires, lightning, extreme cold weather, or storms, any of which may impact MEG's operations.

ESG Related Goals

As a part of MEG's strategic priority to retain its position as a responsible leader in the energy industry, MEG has committed to various ESG targets, including the mid-term target of reducing its absolute GHG emissions (Scope 1 and Scope 2) by 0.6 megatonnes per annum by year-end 2030 and the goal to achieve net zero Scope 1 and Scope 2 GHG emissions by 2050. To achieve these goals, among others, and to respond to changing market demand, MEG may incur additional costs and invest in new technologies and innovation. It is possible that the return on these investments may be less than expected, and government regulatory and financial support to assist in achieving these goals may be less than expected, each of which may have an adverse effect on MEG's business, financial condition and reputation.

Generally speaking, MEG's ESG targets, including those related to GHG emissions, and others associated with diversity, relationships with stakeholders, including Indigenous stakeholders and wildlife habitat reclamation, depend significantly on MEG's ability to execute its current business strategy, each of which can be impacted by the numerous risks and uncertainties associated with MEG's business and other industry factors.

MEG recognizes that its ability to adapt to and succeed in a lower-carbon economy will be compared against its peers. Investors and other stakeholders increasingly compare companies based on ESG-related performance, including climate-related performance. Failure by MEG to achieve its ESG targets, or a perception among key stakeholders that MEG's ESG targets are insufficient, could adversely affect, among other things, MEG's reputation and ability to attract capital. The continued focus on climate change by investors may lead to higher costs of capital for MEG as the pressure to reduce emissions increases. MEG's ability to attract capital may also be adversely impacted if financial institutions and investors incorporate sustainability and ESG considerations as a part of their portfolios or adopt restrictive decarbonization policies.

There is also a risk that some or all of the expected benefits and opportunities of achieving some or all of MEG's various ESG targets may fail to materialize, may cost more to achieve or may not occur within anticipated or stated timeframes. In addition, there are risks that the actions taken by MEG in implementing these targets and ambitions relating to ESG focus areas, may have a negative impact on MEG's business, including adverse impacts on operations or increased costs and capital expenditures, which may in turn negatively impact future operating and financial results.

Environmental and Regulatory Risks

Environmental considerations

MEG's operations 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, MEG's competitive position within the thermal oil industry may be adversely affected, and many industry participants have greater resources than MEG to adapt to legislative changes.

No assurance can be given that future environmental approvals, laws or regulations will not adversely impact MEG's ability to develop and operate its oil sands projects, 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 future legislation that would progressively increase tax on air emissions (specifically greenhouse gases) or require, directly or indirectly, reductions in air emissions produced by energy industry participants, which MEG may be unable to mitigate.

All phases of the thermal oil 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. 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.

There has also been increased activism relating to climate change and public opposition to fossil fuels. The Federal Government and certain provincial governments in Canada have responded to these shifting societal attitudes by adopting ambitious emissions reduction targets and supporting legislation, including measures relating to carbon pricing, clean energy, field and emission standards, and alternative energy incentives and mandates. Concerns over climate change, fossil fuel extraction, GHG emissions, and water and land-use practices could lead governments to enact additional or more stringent laws and regulations applicable to the Corporation and other companies in the energy industry in general. 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 imposed more stringent environmental legislation that affects the thermal oil production industry. In addition, 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. Should there be changes to existing laws or regulations, the Corporation's competitive position within the thermal oil production industry may be adversely affected.

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 thermal oil production projects or increase or maintain production or control its costs of production. Changes to environmental regulations, including regulation relating to climate change, could impact the demand or pricing for the Corporation's products, or could require increased capital expenditures, operating expenses, abandonment and reclamation obligations and distribution costs, which may not be recoverable in the marketplace and which may result in current operations or future projects becoming less profitable or uneconomic.

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.

Any requirement to develop or implement new technology in response to future environmental standards could require a significant investment of capital and resources, and any delay in or failure to identify, develop and implement such technologies could prevent the Corporation from being able to operate profitably or being able to successfully compete with other companies.

No assurance can be given that environmental laws and regulations will not result in a curtailment of production, a cap on emissions 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, current and emerging in both Canada and the United States, including any limits on oil sands emissions and the Canadian Federal Government’s implementation of the Paris Agreement through the *Net-Zero Emissions Accountability Act*, *Greenhouse Gas Pollution Pricing Act (the "GGPA")*, the Clean Fuel Regulation (the "*Clean Fuel Standard")*, the Provincial Government's implementation of the TIER *Regulation* and any other federal or provincial carbon emission pricing system, may adversely affect MEG's business, operations and financial results. New or additional carbon taxes or similar costs could significantly increase operating costs or reduce output. 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.

On December 11, 2020, the Government of Canada released a document entitled A Healthy Environment and a Healthy Economy which outlined 64 new and updated policies and programs to achieve net zero by 2050. This included a proposal to increase the carbon price under the GGPA by $15 per year, starting in 2023, up to $170 per tonne of carbon pollution in 2030. The intent of the price adjustment is to incentivize cleaner fuel choices and discourage pollution-intensive investments.

On July 6, 2022, the Government of Canada enacted the *Clean Fuel Standard* under the *CEPA* as the enabling statute. The *Clean Fuel Standard* incentivizes producers and importers of gasoline and diesel to reduce the carbon intensity of liquid fossil fuels. As MEG's business and production facilities entails the production of crude oil, the Clean Fuel Standards is not applicable. Since the *Clean Fuel Standard* only considers those facilities producing gasoline or diesel, the cogeneration facilities used by MEG (for combined heat and power generation) also do not apply to the *Clean Fuel Standard*.

Future federal legislation, including the implementation of potential international requirements enacted under Canadian law, as well as provincial legislation and emissions reduction requirements and or production limits, 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 or caps on emissions or production 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.

Climate-Related Goals

The Corporation’s mid-term target of reducing its absolute GHG emissions (Scope 1 and Scope 2) by 0.6 megatonnes by year-end 2030 and long-term goal of reaching net-zero emissions (Scope 1 and Scope 2) (which is inherently uncertain due to the potentially long timeframe and certain factors outside of the Corporation’s control, including the application of future technologies) is subject to numerous risks and uncertainties. The Corporation’s actions taken in implementing such targets may expose the Corporation to certain additional and/or heightened financial and operational risks.

All of the Corporation's climate related goals, including those related to GHG emissions, and others associated with diversity, relationships with stakeholders, including Indigenous stakeholders and environmental performance depend significantly on the Corporation's ability to execute its current business strategy, which can be impacted by the numerous risks and uncertainties associated with the Corporation's business and other industry factors. There is a risk that some or all of the expected benefits and opportunities of achieving some or all of the Corporation's climate-related goals may fail to materialize, may cost more to achieve or may not occur within anticipated or stated timeframes. In addition, there are risks that the actions taken by the Corporation in implementing these goals, and in making efforts to achieve such goals, may have a negative impact on the Corporation's business, including adverse impacts on operations or increased costs and capital expenditures which may in turn negatively impact our future operating and financial results.

Cogeneration Regulation

The Canadian Federal Government has announced its intention to develop the Clean Electricity Regulations ("CER") under the *Canadian Environmental Protection Act,* 1999 in furtherance of a net zero electricity system by 2035. The CER would establish an emissions standard where a regulated generation unit would be prohibited from operating where its emissions performance exceeds an established intensity limit. In addition, emissions below the established intensity limit may also be subject to financial compliance requirements, such as offset purchases or paying an amount that corresponds to the federal carbon price applicable in the given year. As a result, compliance with the CER could require that the Corporation incur significant capital expense to capture CO_2 emissions for its cogeneration facilities to remain operational and additional expense in respect of emissions below the prescribed intensity limit. As a significant portion of the Corporation's SAGD steam supply is tied to cogeneration, compliance with the CER could have a material adverse effect on the Corporation's results of operations, financial condition and prospects.

The Alberta Utilities Commission ("*AUC*") regulates cogeneration facilities under the *Hydro and Electric Energy Act*. Effective from April 25, 2022, the AUC implemented a streamlined process for applications to construct new power plants one megawatt or greater and less than 10 megawatts. This streamlined process will likely result in more available resources for the AUC to determine other proceedings, which will likely benefit proponents such as the Corporation for constructing new power plants greater than 10 megawatts and require a full proceeding for approval.

In Alberta the *Oil Sands Emissions Limit Act* came into force in December 2016 and limits the amount of greenhouse gas emissions produced by all oil sands sites combined in Alberta to 100 megatonnes in any year, which limit has not been reached. While uncertainties remain until Alberta implements regulations, it is clear that this Act considers any emissions from cogeneration facilities to be excluded in the determination of greenhouse gas emissions from that oil sand site.

Any facilities with direct emissions of 100,000 tonnes of carbon in a year are subject to the *TIER* that regulates carbon emissions. Cogeneration facilities are eligible for emission offsets under the *TIER* if the electricity generated falls under the prescribed high-performance benchmark for electricity. In 2023, the effective benchmark for electricity is 0.3626 tonnes of carbon per megawatt. This benchmark is set to be more stringent each year, with the 2024 benchmark being 0.3478 tonnes of carbon per megawatt.

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

United States Climate Change Legislation

Environmental regulation of GHG 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 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, California's Air Resources Board (ARB) administers two regulatory programs that impact the crude or synthetic crude oil industry: the 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 relative to 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 thermal oil producers including 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 regulations implemented by the Government of Alberta. In such case, the costs of meeting new federal government requirements could be considerably higher than the costs of meeting Alberta's requirements. The Government of Alberta challenged the constitutionality of the federal carbon emission pricing system, and the Alberta Court of Appeal found the federal system to be unconstitutional. Appeals of this decision, along with appellate court decisions in both Ontario and Saskatchewan, which found the federal system to be constitutional, were heard by the Supreme Court of Canada ("SCC") in September 2020. On March 25, 2021, the SCC ruled that the federal carbon pricing system is constitutional. As of November 11, 2022, the federal backstop applies in full in the Yukon, Nunavut and Manitoba, while partially applying in Alberta, Saskatchewan, Ontario and Prince Edward Island. Provincial systems in these latter four provinces meet the federal backstop requirements for the emission sources covered, but the federal pricing system continues to apply to certain sources not covered by the provincial systems.

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. As of January 1, 2022, the AER (via Directive 088: Licensee Life-Cycle Management) is implementing new annual spend obligations for certain inactive inventories, albeit predominantly in the context of conventional oil and gas operations rather than thermal oil operations. This may increase the level of regulatory scrutiny on abandonment and reclamation obligations in the oil and gas sector overall in Alberta.

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 the Alberta Ministry of Environment and Parks. There can be no assurance such approvals, permits, leases and licenses will be granted or once granted 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.

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.

Consistent with the NZEAA, Prime Minister Trudeau announced on November 1, 2021, at the COP 26 climate conference that Canada would move to capping and reducing emissions from the oil and gas sector, by setting five-year targets to achieve net zero by 2050. In doing so, the Government of Canada is seeking the advice of the Net-Zero Advisory Body on how best to work with the oil and gas sector and affected communities to define pathways to net-zero that are achievable. The details of the Net-Zero Advisory Body's report, when released, and any subsequent final regulations published by the Government of Canada, could result in substantial costs to the Corporation and may adversely affect MEG's business, operations and 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 or continuation of operations at, the Christina Lake Project (as applicable), 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 and sufficient transportation, logistics and supply chain responsiveness. 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 technical and other 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 and/or the lack of sufficient transportation, logistics and supply chains 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, leases 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

The Corporation could experience downgrades to its credit ratings. In addition, in the event of any significant downgrade, certain of the Corporation's service providers, including its pipeline providers and condensate vendors, may require the Corporation to post incremental collateral or provide other assurances of the Corporation's ability to perform its obligations under its contracts with such providers, which could negatively affect the Corporation's financial liquidity.

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. Any increase in the number of personnel working remotely may enhance the risks associated with 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 Facility, Notes and Debt Service Obligations

MEG’s indebtedness contains certain restrictions, including mandatory prepayment obligations. For example, upon the occurrence of any event of default under the Credit Facility 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 Facility 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.

The restrictions in the Credit Facility, 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 Facility, 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 Facility 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 Facility, 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 indebtedness.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

During the year ended December 31, 2022, 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, 2022, 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”.

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, 2022 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 February 27, 2023 in respect of the Corporation's consolidated financial statements as at year ended December 31, 2022, and 2021 and its financial performance and its cash flows 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".

NON-GAAP AND OTHER FINANCIAL MEASURES

Certain financial measures in this AIF are non-GAAP financial measures or ratios, supplementary financial measures and capital management measures. These measures are not defined by IFRS and, therefore, may not be comparable to similar measures provided by other companies. These non-GAAP and other financial measures should not be considered in isolation or as an alternative for measures of performance prepared in accordance with IFRS.

Free Cash Flow

Free cash flow is a capital management measure and is defined in the Corporation's annual consolidated financial statements. Free cash flow is presented to assist management and investors in analyzing operating performance and cash flow generating ability. Free cash flow is presented to assist management and investors in analyzing performance by the Corporation as a measure of financial liquidity and the capacity of the business to repay debt and return capital to shareholders. Free cash flow is calculated as adjusted funds flow less capital expenditures. Funds flow from operating activities is an IFRS measure in the Corporation's annual consolidated statement of cash flow. Adjusted funds flow is calculated as funds flow from operating activities excluding items not considered part of ordinary continuing operating results. A reconciliation from funds flow from operating activities to adjusted funds flow to free cash flow is available in section 16 "Non-GAAP and Other Financial Measures" in MEG's annual 2022 MD&A.

Net Debt

Net debt is a capital management measure and is defined in the Corporation's consolidated financial statements. Net debt is an important measure used by management to analyze leverage and liquidity. Net debt is calculated as long-term debt plus current portion of long-term debt less cash and cash equivalents. A reconciliation from the Corporation's current and long-term debt to net debt is available in section 16 "Non-GAAP and Other Financial Measures" in MEG’s annual 2022 MD&A.

Cash Operating Netback

Cash operating netback is a non-GAAP financial measure, or ratio when expressed on a per barrel basis. Its terms are not defined by IFRS and, therefore, may not be comparable to similar measures provided by other companies. This non-GAAP financial measure should not be considered in isolation or as an alternative for measures of performance prepared in accordance with IFRS.

Cash operating netback is a financial measure widely used in the oil and gas industry as a supplemental measure of a company’s efficiency and its ability to generate cash flow for debt repayment, capital expenditures, or other uses. The per barrel calculation of cash operating netback is based on bitumen sales volumes.

Revenues, is an IFRS measure in the Corporation's consolidated statement of earnings (loss) and comprehensive income (loss), which is the most directly comparable primary financial statement measure to cash operating netback. A reconciliation from total revenues to cash operating netback is available in section 16 "Non-GAAP and Other Financial Measures" in MEG’s annual 2022 MD&A.

Bitumen realization

Bitumen realization is a non-GAAP financial measure, or ratio when expressed on a per barrel basis, and is used as a measure of the Corporation’s marketing strategy by isolating petroleum revenue and costs associated with its produced and purchased products and excludes royalties.

The term is not defined by IFRS and, therefore, may not be comparable to similar measures provided by other companies. This non-GAAP financial measure should not be considered in isolation or as an alternative for measure of performance prepared in accordance with IFRS. Bitumen realization per barrel is based on bitumen sales volumes.

Revenues, is an IFRS measure in the Corporation's consolidated statement of earnings (loss) and comprehensive income (loss), which is the most directly comparable primary financial statement measure to bitumen realization. A reconciliation from revenue to bitumen realization has been provided in section 16 "Non-GAAP and Other Financial Measures" in MEG’s annual 2022 MD&A.

Net Transportation and Storage Expense

Net transportation and storage expense is a non-GAAP financial measure, or ratio when expressed on a per barrel basis. Its terms are not defined by IFRS and, therefore may not be comparable to similar measures provided by other companies. This non-GAAP financial measure should not be considered in isolation or as an alternative for measures of performance prepared in accordance with IFRS. Per barrel amounts are based on bitumen sales volumes.

It is used as a measure of the Corporation’s marketing strategy by focusing on maximizing the realized AWB sales price after transportation and storage expense by utilizing its network of pipeline and storage facilities to optimize market access.

Transportation and storage expense is an IFRS measure in the Corporation's consolidated statements of earnings (loss) and comprehensive income (loss).

Other revenue is an IFRS measure in the Corporation's consolidated statement of earnings (loss) and comprehensive income (loss), which is the most directly comparable primary financial statement measure to transportation revenue. A reconciliation from other revenue to transportation revenue has been provided in section 16 "Non-GAAP and Other Financial Measures" in MEG's annual 2022 MD&A.

Bitumen Realization after Net Transportation and Storage Expense

Bitumen realization after net transportation and storage expense is a non-GAAP financial measure, or ratio when expressed on a per barrel basis. Its terms are not defined by IFRS and, therefore may not be comparable to similar measures provided by other companies. This non-GAAP financial measure should not be considered in isolation or as an alternative for measures of performance prepared in accordance with IFRS. Per barrel amounts are based on bitumen sales volumes.

It is used as a measure of the Corporation's marketing strategy by focusing on maximizing the realized AWB sales price after net transportation and storage expense by utilizing its network of pipeline and storage facilities to optimize market access. A reconciliation has been provided in section 16 "Non-GAAP and Other Financial Measures" in MEG's annual 2022 MD&A.

Operating expenses net of power revenue

Operating expenses net of power revenue is a non-GAAP financial measure, or ratio when expressed on a per barrel basis. Its terms are not defined by IFRS and, therefore, may not be comparable to similar measures provided by other companies. This non-GAAP financial measure should not be considered in isolation or as an alternative for measures of performance prepared in accordance with IFRS. Per barrel amounts are based on bitumen sales volumes.

It is used as a measure of the Corporation's cost to operate its facilities at the Christina Lake project after factoring in the benefits from selling excess power to offset energy costs.

Non-energy operating costs and energy operating costs are supplementary financial measures as they represent portions of operating expenses. Non-energy operating costs comprise production-related operating activities and energy operating costs reflect the cost of natural gas used as fuel to generate steam and power. Per barrel amounts are based on bitumen sales volumes.

Operating expenses is an IFRS measure in the Corporation's consolidated statement of earnings (loss) and comprehensive income (loss). Other revenue, is an IFRS measure in the Corporation's consolidated statement of earnings (loss) and comprehensive income (loss), which is the most directly comparable primary financial statement measure to power revenue. A reconciliation from other revenue to power revenue has been provided in section 16 "Non-GAAP and Other Financial Measures" in MEG's annual 2022 MD&A.

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 MD&A for the year ended December 31, 2022.

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:

"**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.

"**2020 Notes**" means the 7.125% Senior Notes due 2027, issued pursuant to an indenture dated as of January 31, 2020, among MEG, the guarantor party thereto and Wilmington Trust National Associate as trustee.

"**2021 Notes**" means the 5.875% Senior Notes due 2029, issued pursuant to an indenture dated as of February 2, 2021, among MEG, the guarantor party thereto and Wilmington Trust National Associate 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 "Contingent Resources Estimates" within Appendix D - Contingent Resources.

"**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 Amended and Restated Credit Agreement dated as of December 15, 2014, and amended and restated as of July 30, 2019 between the Corporation and Bank of Montreal, as amended, restated, modified or supplemented from time to time.

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

"**Christina Lake Project**" means MEG's *in situ* thermal energy project located in the Province of Alberta as described in greater detail under the heading "Christina Lake Project".

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

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

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

"**Credit Facility**" means the Corporation's senior secured credit facility comprised of a CAD$800 million revolving credit facility, as may be further amended, restated or replaced from time to time.

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

"**EDC**" means Export Development Canada.

"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.

"**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 Ltd., an independent qualified reserves and resources evaluator.

"**GLJ Report**" means the report of GLJ dated effective as of December 31, 2022, with a preparation date of January 30, 2023 assessing and evaluating the proved and probable reserves and contingent resources of the Corporation.

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

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

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

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

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

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

"**May River Regional Project**" means the mineral 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”.

"**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 equals 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 2020 Notes, the 2021 Notes and the Second Lien Notes.

“**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.

"**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.

"**Reserves Life Index**" or "**RLI**" is calculated by dividing the Corporation's 2P reserves by the GLJ Report's current annual production estimate.

"**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.

"**Scope 1**" direct GHG emissions from sources that are owned or controlled by an organization.

"**Scope 2**" indirect GHG emissions that result from the generation of purchased electricity, heating, cooling, or steam consumed at assets owned or controlled by an organization.

"**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.

"**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* thermal energy project described under the heading "Surmont Project" in this AIF.

"**TSX**" means the Toronto Stock Exchange.

"U.S." means the United States of America.

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
M$	thousand dollars (Canadian)
MM$	million dollars (Canadian)
$	dollars (Canadian)

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

APPENDIX A – FORM 51-101F2

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

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

1. We have evaluated the Company's reserves data and contingent resources data as at December 31, 2022. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2022, 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, 2022, 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, 2022, and identifies the respective portions thereof that we have evaluated and reported on to the Company's board of directors:

			Net Present Value of Future Net Revenue (before income taxes, 10% discount rate – MM$)			
Independent Qualified Reserves Evaluator or Auditor	**Effective Date of Evaluation Report**	**Location of Reserves (Country or Foreign Geographic Area)**	**Audited**	**Evaluated**	**Reviewed**	**Total**
GLJ Ltd.	Dec. 31, 2022	Canada	—	17,884	—	17,884

6. The following table sets 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:

					Risked Net Present Value of Future Net Revenue (before income taxes, 10% discount rate – MM$)		
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)**	**Audited**	**Evaluated**	**Total**
Development Pending Contingent Resources (2C)	GLJ Ltd.	Dec. 31, 2022	Canada	972,167	—	3,864	3,864

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 Ltd., Calgary, Alberta, Canada, February 10, 2023.

"Originally Signed by"
Tracy K. Bellingham, P. Eng.
Vice President, Corporate Evaluations

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 - Form 51-101F2 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) "*Ian Bruce*"
Ian Bruce
Chairman

(signed) "*Ryan Kubik*"
Ryan Kubik
Chief Financial Officer

(signed) "*Susan MacKenzie*"
Susan MacKenzie
Director

February 27, 2023

APPENDIX C

AUDIT COMMITTEE CHARTER AND RELATED INFORMATION

AUDIT COMMITTEE CHARTER

1. MANDATE

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

(a) the Corporation's financial statements, management's discussion and analysis, and accounting and financial reporting practices;

(b) the relationship with and assessment of the performance of the Corporation's external auditor;

(c) oversight of the adequacy and independence of the Corporation's internal audit activities;

(d) oversight of the adequacy of the Corporation's disclosure controls and procedures and internal control over financial reporting; and

(e) oversight of the Corporation's financial risk management activities including commodity price risk, credit risk and short-term investment management activities.

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. 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 Internal Audit

From time to time, the Committee may request assurance services be carried out by independent advisors. Examples of assurance services may include, but is not limited to: internal audits, compliance audits (both regulatory and contract compliance), financial audits, operational audits, environmental, health and safety audits, information technology audits and security reviews, investigations, and process reviews. Key findings of engagements shall be reviewed with the Committee.

3.2 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).

3.3 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; and

(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, or recommend to the Board for approval, 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.

3.4 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 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 recommendations from management and external auditors' regarding any matters, including internal control and management information systems and procedures.

3.5 Information Technology

The duties and responsibilities of the Committee as they relate to information technology security and risk shall be as follows:

(a) Review the Company's cybersecurity risk management activities, including the Company's programs, policies, practices and safeguards for information technology, cybersecurity and data security, and review periodic updates on such matters by management.

3.6 Commodity Price Risk Management

The Corporation's commodity price risk management activities are governed by a Commodity Price Risk Management Policy, which is approved by the Board of Directors. The Committee provides oversight of these commodity price risk management activities through execution of the following duties and responsibilities as described in the Commodity Price Risk Management Policy:

(a) On a quarterly basis, review the Corporation's commodity price risk management activity and results; and

(b) Authorize a commodity price risk management strategy that exceeds the hedging volume limits described in the Commodity Price Risk Management Policy.

3.7 Credit Risk Management

The Corporation's credit risk management activities are governed by a Credit Risk Management Policy, which is approved by the Board of Directors, and Credit Risk Management Practices, which are approved by the Committee. The duties and responsibilities of the Committee as they relate to credit risk management shall be as follows:

(a) On a quarterly basis, review the Corporation's credit risk exposure, including a review of compliance with the Credit Risk Management Policy and Credit Risk Management Practices; and

(b) Pursuant to this policy and these practices, the Committee is authorized to amend certain credit limits or modify certain practices.

3.8 Short-Term Investment Management

The Corporation's short-term investment management activities are governed by a Short-Term Investment Policy, which is approved by the Board of Directors, and Short-Term Investment Practices, which are approved by the Committee. The duties and responsibilities of the Committee as they relate to short term investment management shall be as follows:

(a) On a quarterly basis, review the Corporation's short-term investment portfolio, including a review of compliance with the Corporation's Short-Term Investment Policy and Short-Term Investment Practices.

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 full and unrestricted access to the employees and external auditors of the Corporation, and the books and records of the Corporation and its subsidiaries. The members of the Committee shall have the right 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.

5. REVIEW

In accordance with section 4(j), this charter shall be reviewed by the Committee every year to determine if further additions, deletions or other amendments are required.

Last reviewed and approved by the Committee on March 3, 2022.

Last approved by the Board on November 10, 2022.

COMPOSITION OF THE AUDIT COMMITTEE

As of the date of this Annual Information Form, the members of the Audit Committee are Mr. Robert Hodgins (Chair), Ms. Kim Lynch Proctor and Ms. Susan M. MacKenzie. 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 and has served as a director of various public and private entities since 2004 (including PrimeWest Energy Trust, Enerflex Systems Ltd., Enerflex Systems Income Fund, Caracal Energy plc, Fairborne Energy Trust and Calpine Power Income Fund) and is currently a director and Chair of the Governance and Nomination Committee and a member of the Human Resources Committee of Enerplus Corporation, a director and member of the Audit Committee of AltaGas Ltd., and a director and Chair of the Board and a member of the Audit Committee of Gran Tierra Energy Inc. Mr. Hodgins was a Senior Advisor (non-executive role), Investment Banking at Canaccord Genuity Corp. (an independent investment bank) Until May 2022. From 2002 to 2004, Mr. Hodgins served as the Chief Financial Officer of Pengrowth Energy Trust (predecessor to 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. He practiced corporate taxation from 1977-1987. 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. He is a member of the Institute of Corporate Directors and the National Association of Corporate Directors (US).

- Ms. Lynch Proctor is an independent businesswoman, an experienced lawyer, accountant and executive with over 20 years of experience. She was the Chief Financial Officer and General Counsel of KERN Partners, an energy focused private equity firm, from 2009 to 2016 and prior thereto a practicing lawyer and chartered professional accountant with Felesky Flynn LLP, Bennett Jones LLP, and Deloitte LLP, respectively, advising corporate clients on domestic and international transactions. Ms. Lynch Proctor is currently a director of Paramount Resources Ltd. and serves on the Board of Trustees of Alaris Equity Partners Income Trust and also serves on the Boards of several non-profit and municipal organizations, including the Calgary Police Commission. Ms. Lynch Proctor obtained both a Bachelor of Commerce and a Bachelor of Laws degree from the University of Calgary, a Master of Laws degree from New York University, is a Chartered Professional Accountant and holds an ICD.D designation from the Institute of Corporate Directors.

- Ms. MacKenzie is a corporate director with over 30 years of energy sector experience. Most recently she was Chief Operating Officer of Oilsands Quest Inc. from April to September 2010. Prior thereto, Ms. MacKenzie spent 12 years at Petro-Canada in progressive technical, operational and strategic roles, including Vice President Human Resources and Vice-President In Situ Oilsands Development and Operations. Her industry experience also includes 14 years with Amoco Canada in a variety of engineering and leadership roles in natural gas, conventional oil and heavy oil development and operations. Ms. MacKenzie holds a B. Eng. (Mechanical) from McGill University, an MBA from the University of Calgary, is a Life Member of the Association of Professional Engineers and Geoscientists of Alberta and an Institute of Corporate Directors - certified director. Ms. MacKenzie is currently a director of Enerplus Corporation (and was previously a member of its Audit Committee) and Precision Drilling Corporation. She is a past director of TransGlobe Energy Corporation, FortisAlberta Inc. (and was previously a member of its Audit Committee), Freehold Royalties Ltd. and the Calgary Women's Emergency Shelter and Safe Haven Foundation as well as numerous for-profit, not-for-profit, private and academic advisory boards.

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:

		2021		2022
Audit Fees	$	465,450	$	472,652
Audit Related Fees[1]		277,236		223,068
Tax Fees[2]		—		—
Other Fees		—		—
Total	**$**	**742,686**	**$**	**695,720**

Notes:

(1) Fees for assurance and related services by PricewaterhouseCoopers LLP in connection with their review of the Corporation's financial statements and other documents which are not otherwise reported under "Audit Fees".

(2) Fees for tax compliance and tax advice.

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 at the Christina Lake Project only, excluding contingent resources evaluated for the Surmont Project. 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.

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 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.

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".

Contingent Resources Estimates

The following tables includes the risked contingent resources (best estimate) contained in the GLJ Report with respect to the Christina Lake Project. The evaluation procedures employed by GLJ are based on GLJ's January 1, 2023 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. See “Reserves Estimates”.

SUMMARY OF RISKED OIL AND GAS CONTINGENT RESOURCES as of December 31, 2022 FORECAST PRICES AND COSTS

Resources Project Maturity Sub-Class	Contingent Resources - Best Estimate[1][2][3] (Bitumen) Gross (MMbbl)	Net (MMbbl)
CONTINGENT (2C) Development Pending	972.2	726.6

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. On an unrisked basis, there has been no material change between the contingent resources assigned to the Corporation’s Christina Lake Project in the 2021 GLJ Report and the 2022 GLJ Report.

SUMMARY OF RISKED NET PRESENT VALUE OF FUTURE NET REVENUE[1] (CONTINGENT RESOURCES – Best Estimate) as of December 31, 2022 FORECAST PRICES AND COSTS

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

Resources Project Maturity Sub-Class	Risked Net Present Value of Future Net Revenue (Bitumen)									
	Before Income Taxes Discounted at (%/Year) – MM$					After Income Taxes Discounted at (%/Year) – MM$				
	0%	5%	10%	15%	20%	0%	5%	10%	15%	20%
CONTINGENT (2C) Development Pending	37,548	11,464	3,864	1,380	472	28,720	8,589	2,766	895	232

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' are: resolution of the final conditions for development is being actively pursued, indicating there is a high chance of development.

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 Handbook Volume 2, Section 2.

MEG's contingent resources classified as 'development pending' are located at the Christina Lake Project. The following table summarizes the risked best estimate contingent resources for the Christina Lake Project:

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	972.2	95%	2,135	2031

Notes:

(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 2023. 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 Christina Lake Project in the 2021 GLJ Report and the 2022 GLJ Report.

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

Christina Lake Project – Specific Risks

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. As a result, all remaining contingencies preventing such contingent resources from being classified as reserves are "non-technical" contingencies.

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