# Annual Information Form

# Capital Power Corporation

## For the year ended December 31, 2020

February 23, 2021

## TABLE OF CONTENTS

*Remainder of page intentionally left blank*

## PRESENTATION OF INFORMATION

Unless otherwise noted, the information contained in this Annual Information Form (AIF) is given at or for the period ended December 31, 2020. Amounts are expressed in Canadian dollars unless otherwise indicated. All financial information presented in millions of Canadian dollars is rounded to the nearest million unless otherwise stated. Unless otherwise indicated, all financial information is presented in accordance with Canadian generally accepted accounting principles (GAAP). The Company uses adjusted EBITDA and adjusted funds from operations (AFFO) as financial performance measures, which are not defined financial measures according to GAAP and do not have standardized meanings prescribed by GAAP. For further discussion of such terms, see the Company's Integrated Annual Report dated February 18, 2021 for the year ended December 31, 2020.

Certain capitalized terms used herein, and if not defined where first used, are defined under "Definitions of Certain Terms".

This AIF provides material information about the business and operations of Capital Power Corporation.

The "Risks and Risk Management" section of the Company's Integrated Annual Report dated February 18, 2021 for the year ended December 31, 2020 is incorporated herein by reference and can be found on SEDAR at www.sedar.com.

## FORWARD-LOOKING INFORMATION

Forward-looking information or statements included in this AIF are provided to inform the Company's shareholders, potential investors and other stakeholders about management's assessment of Capital Power's future plans and operations. This information may not be appropriate for other purposes. The forward-looking information in this AIF is generally identified by words such as "will", "anticipate", "believe", "plan", "intend", "target", and "expect" or similar words suggesting future outcomes.

Forward-looking information in this AIF includes, among other things, information relating to: (i) expectations regarding the timing of, funding of, generation capacity of, costs for, technology selected for or commercial arrangements regarding existing, planned and potential development projects and acquisitions; (ii) expectations regarding revenues generated by existing facilities or facilities in development, including expected impacts to net income, adjusted EBITDA, net cash flows from operating activities and AFFO; (iii) expectations regarding future growth and emerging opportunities in Capital Power's target markets including the focus on certain technologies; (iv) expectations regarding availability of fuel supply; (v) expectations regarding the timing or outcome of applications for permits or licenses, or other regulatory proceedings; (vi) the expected impact of the GHG Regulations and other regulations announced by the Government of Canada and other environmental regulations on Capital Power's power facilities, including compliance costs and the useful lives of power facilities and any conversions; (vii) expectations regarding proposed new environmental regulations, including the timing of such regulations coming into force, and the impact of current and new environmental regulations on Capital Power's business, including, but not limited to, Capital Power's compliance costs; (viii) expectations regarding the timing for Capital Power to receive the majority of benefits from certain projects subject to tax equity financing arrangements; (ix) expectations regarding the timing of collective bargaining, or the timing, effect or implementation of collective agreements; (x) expectations regarding new power market or energy resource regulations, including the timing of such regulations coming into force, and the impact of current and new power market or energy resource regulations on Capital Power; (xi) the timing, imposition and impact of taxes on Capital Power; (xii) expectations related to Capital Power's future cash requirements including interest and principal repayments, capital expenditures and dividends and distributions; (xiii) expectations governing the operation of the dividend reinvestment plan for holders of Common Shares; (xiv) expectations for Capital Power's sources of funding, adequacy and availability of committed bank credit facilities and future borrowings; (xv) expectations regarding power requirements and demand in Capital Power's target markets; (xvi) expectations around matters related to the line loss rule proceedings and adjustments (including timing of payments to the AESO and recovery from appropriate parties) and potential impacts to the Company arising from the foregoing; (xvii) expectations regarding Capital Power's intention to acquire Common Shares pursuant to its normal course issuer bid; (xviii) the timing, expected capital costs, project returns (including expected AFFO per share) and environmental benefits (including the expected reduction in emission levels) of gas conversion and repowering at the Genesee units (including Genesee units 1 and 2 being hydrogen-ready, and being off-coal in 2023); (xix) statements relating to our growth and sustainability strategy and sustainability targets, including reduction of emissions and emissions intensity and being net carbon neutral by 2050, completion of the Genesee Carbon Conversion Centre and commercial application of carbon conversion technologies; and (xx) the impact of the COVID-19 pandemic and the decline in oil prices.

These statements are based on certain assumptions and analyses made by the Company considering its experience and perception of historical and future trends, current conditions and expected future developments, and other factors it believes are appropriate. The material assumptions used to develop these forward-looking statements relate to: (i) electricity, other energy and carbon prices, (ii) performance, (iii) business prospects and opportunities including expected growth and capital projects, (iv) status of and impact of policy, legislation and regulations, (v) effective tax rates, (vi) the development and performance of technology, and (vii) assumptions around matters related to the line loss rule proceeding and adjustments (including assumptions related to timing for payments to the AESO and recovery from appropriate parties).

Whether actual results, performance or achievements will conform to the Company's expectations and predictions is subject to several known and unknown risks and uncertainties which could cause actual results and experience to differ materially from the Company's expectations. Such material risks and uncertainties include: (i) power facility availability and performance including maintenance expenditures, (ii) changes in electricity and carbon prices in markets in which Capital Power operates, (iii) regulatory and political environments including changes to environmental, climate, financial reporting, market structure and tax legislation, (iv) acquisitions and developments including timing and costs of regulatory approvals and construction, (v) ability to fund current and future capital and working capital needs, (vi) changes in energy commodity market prices and use of derivatives, (vii) changes in market prices and availability of fuel, (viii) ability to realize the anticipated benefits of acquisitions, (ix) limitations inherent in the Company's review of acquired assets, (x) changes in the performance and cost of technologies and the development of new technologies, new energy efficient products, services and programs, and (xii) the risks and uncertainties discussed under the heading "Risks and Risk Management" in the Company's Integrated Annual Report dated February 18, 2021 for the year ended December 31, 2020.

Readers are cautioned not to place undue reliance on any such forward-looking statements, which speak only as of the date made. The Company does not undertake or accept any obligation or undertaking to release publicly any updates or revisions to any forward-looking statements to reflect any change in the Company's expectations or any change in events, conditions or circumstances on which any such statement is based, except as required by law.

*Remainder of page intentionally left blank*

## DEFINITIONS OF CERTAIN TERMS

Certain terms used in this AIF have the following meanings:

"**150 Mile House**" means the 150 Mile House waste heat facility as further described in "Business of Capital Power – Ontario and BC Contracted Facilities – 150 Mile House"

"**ABCA**" *Business Corporations Act* of the Province of Alberta

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

"**AESO**" means the Alberta Electric System Operator

"**AFFO**" means adjusted funds from operations

"**Affordable Clean Energy Rule**" means the Affordable Clean Energy Rule issued by the United States Environmental Protection Agency

"**AIF**" means Annual Information Form

"**AISC**" means Air Issues Steering Committee, a committee of the Canadian Electricity Association, Generation Council

"**Arlington Valley**" means the Arlington Valley facility as further described in "Business of Capital Power – US Contracted Facilities – Arlington Valley"

"**Ascend**" means Ascend Performance Materials LLC

"**AUC**" means the Alberta Utilities Commission

"**Balancing Pool**" means the Alberta Balancing Pool, an Alberta provincial government entity established to, among other things, hold certain PPAs

"**BC**" means the Province of British Columbia

"**BC Hydro**" means the British Columbia Hydro and Power Authority

"**BCUC**" means the British Columbia Utilities Commission

"**Bear Branch Solar**" means the Bear Branch solar project as further described in "Business of Capital Power – Projects Under Construction or in Advanced Stages of Development – Bear Branch Solar"

"**Beaufort**" means the Beaufort solar facility as further described in "Business of Capital Power – US Contracted Facilities – Beaufort"

"**Bloom**" means the Bloom wind facility as further described in "Business of Capital Power – US Contracted Facilities – Bloom"

"**Board**" means the board of directors of Capital Power Corporation

"**Buckthorn Wind**" means the Buckthorn wind facility as further described in "Business of Capital Power – US Contracted Facilities – Buckthorn"

"**C2CNT**" means a company that has developed and is now applying at scale an innovative technology that captures and transforms carbon dioxide ($CO_2$) into a useful and high-value product called carbon nanotubes

"**CNTs**" means carbon nanotubes

"**CAISO**" means the California Independent System Operator

"**Capital Power**", "**CPC**" or the "**Company**" means Capital Power Corporation together with its subsidiaries on a consolidated basis, including its interest in Capital Power L.P., except where otherwise noted or the context otherwise indicates

"**Cardinal Point**" means the Cardinal Point wind facility as further described in "Business of Capital Power – US Contracted Facilities – Cardinal Point"

"**CASA**" means the Clean Air Strategic Alliance, an Alberta multi-stakeholder partnership composed of representatives selected by industry, government and non-government organizations, committed to a comprehensive air quality management system for the province

"**CBCA**" means the *Canada Business Corporations Act*

"**CCIR**" means the Carbon Competitiveness Incentive Regulation (Alberta Regulation 255/2017) made pursuant to the *Climate Change and Emissions Management Act* of the Province of Alberta

“**Clean Air Act**” means the Clean Air Act of 1963 (42 U.S.C. § 7401)

"**Clean Power Plan**" means the Clean Power Plan issued by the United States Environmental Protection Agency to regulate $CO_2$ for existing power facilities under the Clean Air Act

"**Clover Bar**" means the Clover Bar Energy Centre as further described in "Business of Capital Power – Alberta Commercial Facilities – Clover Bar"

"**$CO_2$**" means carbon dioxide

"**$CO_2e$**" means carbon dioxide equivalent

"**Common LP Units**" means common limited partnership units in the capital of the Partnership

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

"**COSIA**" means Canada's Oil Sands Innovation Alliance

"**CPLP**" or the "**Partnership**" means Capital Power L.P. and its subsidiaries on a consolidated basis, except where otherwise noted or the context otherwise indicates

"**CPLPGP**" means Capital Power GP Holdings Inc., the general partner of CPLP

"**CPLPHI**" means Capital Power LP Holdings Inc., a subsidiary of the Company and the limited partner of CPLP

"**CPLP Trust Indenture**" means the Trust Indenture dated April 14, 2010 between CPLP and Computershare Trust Company of Canada as supplemented and amended from time to time as further described in "Capital Structure – Debt Issuance"

"**CTG NOx Policy**" means the $NO_x$ emission policy for CTG Units

"**CTG Units**" means coal to natural gas converted units

"**CTI**" means critical transmission infrastructure

"**DBRS**" means DBRS Limited

"**Decatur**" means the Decatur Energy Center as further described in "Business of Capital Power – US Contracted Facilities – Decatur"

"**DRIP**" means dividend reinvestment plan

"**DSW**" means the Desert Southwest Region of the Western Area Power Administration

"**East Windsor**" means the East Windsor Cogeneration Centre as further described in "Business of Capital Power – Ontario and BC Contracted Facilities – East Windsor"

"**EBITDA**" means earnings before interest, income tax, depreciation and amortization

"**ECCC**" means Environment and Climate Change Canada, the lead department of the Government of Canada for a wide range of environmental issues

"**Enchant Solar**" means the Enchant solar project as further described in "Company History – 2020 – Enchant Solar project proceeding"

"**ENMAX**" means ENMAX Corporation collectively with its subsidiaries

"**EoUL**" means end of useful life

"**EPA**" means electricity purchase agreement or energy purchase agreement, as applicable

"**EPC**" means Emission Performance Credits

"**EPCOR**" means EPCOR Utilities Inc. collectively with its subsidiaries

"**EPDC**" means EPCOR Power Development Corporation

"**EPS**" mean emissions performance standards

"**ESG**" means environmental, social and governance

"**EUA**" means the *Electric Utilities Act* of the Province of Alberta

"**Exchangeable LP Units**" means exchangeable common limited partnership units in the capital of the Partnership

"**FERC**" means the Federal Energy Regulatory Commission of the United States of America

"**FIT**" means Feed-In-Tariff

"**FMCC**" means Ford Motor Company of Canada

"**FPA**" means the Federal Power Act of the United States of America

"**Framework**" means the Pan-Canadian Framework on Clean Growth and Climate Change

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

"**GE**" means General Electric Inc.

"**Genesee 1 and 2**" means, collectively, the Genesee 1 and Genesee 2 facilities as further described in "Business of Capital Power – Alberta Contracted Facilities – Genesee 1 and 2"

"**Genesee 3**" means the Genesee 3 facility as further described in "Business of Capital Power – Alberta Commercial Facilities – Genesee 3"

"**Genesee 4 and 5**" means the Genesee 4 and 5 facilities that have been discontinued as described in "Company History – Discontinuation of Genesee 4 and 5"

"**GGPPA**" means the *Greenhouse Gas Pollution Pricing Act* (S.C. 2018, c. 12, s. 186)

"**GHG**" means greenhouse gases

"**GHG Regulations**" means the Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations (SOR/ 2012-167) made pursuant to the *Canadian Environmental Protection Act*, 1999

"**Goreway**" means the Goreway facility as further described in "Business of Capital Power – Ontario and BC Contracted Facilities – Goreway"

"**GP Units**" means general partnership units in the capital of the Partnership

"**GWh**" means gigawatt hour(s)

"**Halkirk**" means the Halkirk wind facility as further described in "Business of Capital Power – Alberta Commercial Facilities – Halkirk"

"**Heartland Generation**" means Heartland Generation Ltd.

"**Hornet Solar**" means the Hornet solar project as further described in "Business of Capital Power – Projects Under Construction or in Advanced Stages of Development – Hornet Solar"

"**HSE**" means health, safety and environment

"**HSE Policy**" means the Health, Safety and Environment Policy of the Company

"**Hunter's Cove Solar**" means the Hunter's Cove solar project as further described in "Business of Capital Power – Projects Under Construction or in Advanced Stages of Development – Hunter's Cove Solar"

"**IESO**" means Independent Electric System Operator

"**Integrated Annual Report**" means the Company's Integrated Annual Report dated February 18, 2021

"**IPO**" means the July 2009 initial public offering by Capital Power Corporation of 21.75 million Common Shares at a price of $23.00 per share, pursuant to an underwriting agreement with a group of underwriters, for proceeds, net of underwriter and issue costs, of approximately $475 million

"**Island Generation**" means the Island Generation facility as further described in "Business of Capital Power – Ontario and BC Contracted Facilities – Island Generation"

"**ISO**" means Independent System Operator

"**ISO-NE**" means the Independent System Operator for New England

"**Joffre**" means the Joffre cogeneration facility as further described in "Business of Capital Power – Alberta Commercial Facilities – Joffre"

"**K2**" means the K2 wind facility located in the Township of Ashfield-Colborne-Wawanosh, Ontario

"**Kingsbridge 1**" means the Kingsbridge 1 wind facility as further described in "Business of Capital Power – Ontario and BC Contracted Facilities – Kingsbridge 1"

"**Keephills 3**" means the Keephills 3 coal-fired generating facility located 70 km west of Edmonton, Alberta

"**Lehigh**" means Lehigh Hanson, Inc.

"**LFM**" means loss factor calculation methodology

"**Macho Springs**" means the Macho Springs wind facility as further described in "Business of Capital Power – US Contracted Facilities – Macho Springs"

"**Mitsubishi**" means Mitsubishi Power, Ltd.

"**MSA**" means the Market Surveillance Administrator for the Province of Alberta

"**MTN**" means medium term note

"**MW**" means megawatt(s)

"**MWh**" means megawatt hour(s)

"**NCDAQ**" means the North Carolina Department of Air Quality

"**New Frontier**" means the New Frontier wind facility as further described in "Business of Capital Power – US Contracted Facilities – New Frontier"

"**New Indenture**" means the Trust Indenture dated May 3, 2016 between CPC and Computershare Trust Company of Canada as further described in "Capital Structure – Debt Issuance"

"**NGCC**" means natural gas combined cycle

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

"**$NO_x$**" means oxides of nitrogen

"**NOVA**" means Nova Chemicals Corporation

"**OBPS**" means output-based pricing system

"**PCG**" means the People, Culture, and Governance Committee of the Company (formerly Corporate Governance, Compensation and Nominating Committee)

"**PDN**" means the Port Dover and Nanticoke wind facility as further described in "Business of Capital Power – Ontario and BC Contracted Facilities – Port Dover and Nanticoke"

"**PG&E**" means Pacific Gas and Electric Company

"**PJM**" means Pennsylvania, New Jersey and Maryland

"**PMRU**" means Prairie Mines & Royalty ULC, a subsidiary of Westmoreland

"**PPA**" means power purchase agreement or power purchase arrangement, as applicable

"**Preferred Shares**" means all of the Series 1 Shares, Series 3 Shares, Series 5 Shares, Series 7 Shares, Series 9 Shares and Series 11 Shares that are issued and outstanding

"**PSD**" means Prevention of Significant Deterioration

"**QF**" means a qualifying facility and is a term used to describe a category of cogeneration or small power generating facility that meets certain ownership, operating, and efficiency criteria established by FERC pursuant to the US Public Utility Regulatory Policies Act of 1978 (see "Regulatory Overview – United States")

"**Quality**" means the Quality wind facility as further described in "Business of Capital Power – Ontario and BC Contracted Facilities – Quality"

"**RECs**" means renewable energy credits

"**RTOs**" mean Regional Transmission Organizations

"**RESA**" means a Renewable Energy Support Agreement

"**REP**" means Alberta's Renewable Electricity Program being administered by the AESO that proposes to add 5,000 MW of renewable energy capacity by 2030

"**Reorganization**" means the series of transactions concurrent with the completion of the IPO pursuant to which CPLP acquired substantially all of the power generation assets of EPCOR, which transactions consisted of:

(i) the formation of CPLP by CPC, as the initial general partner with one GP Unit, and Capital Power LP Holdings Inc., a wholly-owned subsidiary of CPC, as the initial limited partner with one Common LP Unit;

(ii) the sale by EPCOR of all of the outstanding common shares of EMCC Limited to CPC in exchange for a cash payment of approximately $468 million out of the net proceeds of the IPO;

(iii) the contribution by EMCC Limited of substantially all of its assets to CPLP in exchange for 21.75 million GP Units of CPLP, and the acquisition by EMCC Limited of CPC's GP Unit in CPLP, pursuant to which EMCC Limited (subsequently re-named Capital Power GP Holdings Inc.) became the sole general partner of CPLP; and

(iv) the sale by EPDC of substantially all of its assets (consisting primarily of assets related to Genesee 1 and 2, the Genesee coal mine joint venture and certain interests in partnerships) to CPLP in return for 56.625 million Exchangeable LP Units of CPLP and approximately $896 million in cash (financed by CPLP by way of a long-term debt obligation to EPCOR) and the concurrent subscription by EPDC for 56.625 million Special Voting Shares for a nominal amount and acquisition of the Special Limited Voting Share

"**Roxboro**" means the Roxboro facility as further described in "Business of Capital Power – US Contracted Facilities"

"**Savona**" means the Savona waste heat facility as further described in "Business of Capital Power – Ontario and BC Contracted Facilities – Savona"

"**SEDAR**" means the System for Electronic Document Analysis and Retrieval, which can be accessed via the Internet at www.sedar.com

"**S&P**" means S&P Global Ratings, Inc.

"**Series 1 Shares**" means the cumulative rate reset preference shares, series 1 issued by the Company

"**Series 3 Shares**" means the cumulative rate reset preference shares, series 3 issued by the Company

"**Series 5 Shares**" means the cumulative rate reset preference shares, series 5 issued by the Company

"**Series 7 Shares**" means the cumulative minimum rate reset preference shares, series 7 issued by the Company

"**Series 9 Shares**" means the cumulative minimum rate reset preference shares, series 9 issued by the Company

"**Series 11 Shares**" means the cumulative minimum rate reset preference shares, series 11 issued by the Company

"**Shepard**" means the Shepard Energy Centre as further described in "Business of Capital Power – Alberta Commercial Facilities – Shepard"

"**$SO_2$**" means sulphur dioxide

"**Southport**" means the Southport facility as further described in "Business of Capital Power – US Contracted Facilities – Southport"

"**Special Voting Shares**" means the special voting shares that existed in the capital of Capital Power Corporation prior to being removed from its authorized capital effective on May 4, 2016, after such removal was approved by the Company's common shareholders in a special resolution on April 22, 2016

"**Special Limited Voting Share**" means the special limited voting share in the capital of Capital Power Corporation

"**Strathmore Solar**" means the Strathmore solar project as further described in "Business of Capital Power – Projects Under Construction or in Advanced Stages of Development – Strathmore Solar"

"**TCM Rule**" means the AESO's Transmission Constraints Management Rule

"**TEI**" means tax equity investor partner

"**TIER**" means the *Technology Innovation and Emissions Reduction Regulation*, A.R. 133/2019

"**TransAlta**" means TransAlta Corporation and, where the context requires, TransAlta Corporation and/ or its subsidiaries

"**TransCanada**" means TransCanada Pipelines Limited

"**US**", "**U.S.**" or "**United States**" means the United States of America

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

"**VaR**" means Value-at-Risk

"**Wells Fargo**" means Wells Fargo Bank, N.A.

"**Westmoreland**" means Westmoreland Coal Company

"**Whitla 1**" means Phase 1 of the Whitla wind facility as further described in "Business of Capital Power – Alberta Contracted Facilities – Whitla 1"

"**Whitla 2**" means Phase 2 of the Whitla wind project as further described in "Business of Capital Power – Projects Under Construction or in Advanced Stages of Development – Whitla 2"

"**Whitla 3**" means Phase 3 of the Whitla wind project as further described in "Business of Capital Power – Projects Under Construction or in Advanced Stages of Development – Whitla 3"

"**York**" means the York Energy Centre as further described in "Business of Capital Power – Ontario and BC Contracted Facilities – York"

*Remainder of page intentionally left blank*

# CORPORATE STRUCTURE

## Capital Power Corporation

The Company was incorporated under the CBCA on May 1, 2009. The Company's articles were amended on May 6, 2009, June 16, 2009, July 7, 2009, December 10, 2010, December 14, 2012, March 11, 2013, May 4, 2016, September 28, 2016, July 31, 2017 and May 9, 2019 to, among other things, create the classes of shares described in this AIF. See "Capital Structure".

The principal business office and registered office of the Company is located at Suite 1200, 10423 – 101 Street NW, Edmonton, Alberta, Canada, T5H 0E9.

For a description of the Company's inter-corporate relationships with its subsidiaries, see "Inter-Corporate Relationships" below.

## Capital Power L.P.

CPLP is a limited partnership established under the laws of the Province of Ontario. The general partner of CPLP is CPLPGP which is wholly-owned by the Company (subject to the one special limited voting share of CPLPGP held by EPCOR) and is incorporated pursuant to the ABCA. Capital Power elects the board of directors of CPLPGP, the general partner of CPLP.

Capital Power indirectly holds all of the GP Units (subject to the one special limited voting share of CPLPGP held by EPCOR) and all of the Common LP Units, representing 100% of the total outstanding partnership interests in CPLP.

## Inter-Corporate Relationships

The following table provides the name and the jurisdiction of incorporation, continuance, formation or organization of the subsidiaries of the Company other than those subsidiaries that, as at December 31, 2020, had aggregate total assets or revenues that did not exceed 20% of Capital Power's consolidated assets or consolidated revenues. Unless otherwise noted, the Company directly or indirectly owns 100% of the voting securities of the subsidiaries listed below, or of the general partner of those subsidiaries that are limited partnerships.

| Subsidiaries | Jurisdiction of Incorporation, Continuance, Formation or Organization |
|---|---|
| Capital Power L.P. | Ontario |
| CP Energy Marketing L.P. | Alberta |
| Capital Power (Alberta) Limited Partnership | Alberta |
| Capital Power (Genesee) L.P. | Alberta |
| Decatur Energy Centre, LLC | Delaware |
| Halkirk I Wind Project LP | Alberta |
| Capital Power (G3) Limited Partnership | Alberta |
| CP Bloom Wind LLC | Delaware |
| Arlington Valley, LLC | Delaware |
| Goreway Station Partnership | Ontario |
| Capital Power (Whitla) L.P. | Alberta |
| Cardinal Point LLC | Delaware |

# GENERAL DEVELOPMENT OF THE BUSINESS

## Overview

Capital Power is a growth-oriented North American independent power producer headquartered in Edmonton, Alberta. Capital Power develops, acquires, owns and operates power generation from a range of energy sources. Its asset portfolio includes ownership in several operating facilities in Canada and the United States and projects in various stages of construction and development. The significant events and conditions that have influenced the general development of Capital Power's business over the past three years are summarized below. Certain of these events and conditions and operational information on Capital Power's facilities are discussed in greater detail under the heading "Business of Capital Power".

## Company History

### 2021

#### *Chair of the Board Transition*

In February 2021 the Company announced that after 12 successful years as Chair of the Board, and after reaching his term limit, Donald Lowry would retire from the Board at the 2021 annual general meeting (AGM). The Company also announced that the Board has appointed Jill Gardiner as successor Chair, effective immediately following the AGM and subject to Ms. Gardiner being re-elected by the shareholders. Capital Power would like to express its gratitude to Mr. Lowry for his significant contributions and leadership and is looking forward to working with Ms. Gardiner.

The Company also announced that the Board has appointed Barry Perry to the Board effective March 1, 2021. Mr. Perry will stand for election at the 2021 AGM.

### 2020

#### *Expiry of Genesee 1 and 2 PPA*

Until December, 31, 2020, Genesee 1 and 2 were subject to a PPA with the Balancing Pool. Under the terms of the PPA, the Balancing Pool was entitled to the power produced by Genesee 1 and 2, up to their committed capacity (381 MW for each unit). Generation in excess of committed capacity was managed as part of Capital Power's Alberta electricity portfolio optimization activities. Upon expiry of the PPA on December 31, 2020, both units became part of the Company's Alberta commercial facilities portfolio and are managed as part of Capital Power's Alberta electricity portfolio optimization activities. See "Business of Capital Power – Portfolio Optimization".

#### *Acceleration of plans to repower Genesee*

On December 3, 2020, Capital Power announced an update to the execution of its growth and sustainability strategy involving the repowering of Genesee 1 and 2 and being off-coal in 2023.

Capital Power is proceeding with its plans to repower Genesee 1 and 2, located west of Edmonton near Warburg, Alberta.  A summary of the Company's plans for the project are as follows:

- Expected capital cost of $997 million with project returns expected to exceed the Company's hurdle rates and contributing approximately $0.70 in AFFO per share on average in the first five full years.

- Provides additional 560 MW of net capacity totaling 1,360 MW.

- Simple cycle units will be completed first, allowing the units to run in simple cycle mode before the expected completion of the combined cycle mode of unit 1 in 2023 and unit 2 in 2024, avoiding any material downtime.

- Utilizing best-in-class air cooled J-series NGCC technology from Mitsubishi.

- 30% hydrogen-ready when repowering completed and upgradable to 95% in the future at minimal cost.

- Carbon conversion ready.

- Dual-fuel upgrades will only continue at Genesee 3, which will be 100% natural gas-fueled by 2023.

- Reduces the carbon intensity of Genesee 1 and 2 to 0.35 tonnes $CO_2e$/MWh, below the Alberta Technology Innovation and Emissions Reduction (TIER) regulation benchmark of 0.37 tonnes $CO_2e$/MWh.

- Following gas conversion and repowering, physical carbon dioxide emissions at the Genesee facility will be approximately 3.4 million tonnes per year lower than 2019 emission levels, with an additional estimated indirect 2.5 million-tonne annual reduction from displacement of less efficient units in the Alberta market.

See also "Company History – 2019 – Accelerated Plan for Genesee Natural Gas Capability", "Business of Capital Power – Alberta Contracted Facilities – Genesee 1 and 2" and "Business of Capital Power – Alberta Commercial Facilities – Genesee 3".

***Enchant Solar project proceeding***

On December 3, 2020, Capital Power announced that, subject to successful permitting and regulatory approvals, it is moving forward with the Enchant Solar project. This project is located within the municipal district of Taber, Alberta. The project will add 75 MW in the second half of 2022 at an expected capital cost between $100 million to $105 million.

Enchant Solar will generate carbon credits that can be used to hedge against Capital Power's carbon compliance costs from its Alberta thermal generation facilities. The Company expects a portion of the output from Enchant Solar to be sold under renewable offtake contracts and is actively pursuing contracting opportunities. Annual adjusted EBITDA and AFFO is expected to average approximately $11 million and $12 million, respectively, over the first five years of the project.

***C2CNT and Genesee Carbon Conversion Centre***

In December 2020, Capital Power exercised its option to increase its equity interest in C2CNT from 25% to 40% with the additional investment to occur during the first quarter of 2021. The design phase of the Genesee Carbon Conversion Centre is underway, and commercial operations of the 2,500 tonne carbon nanotube facility are expected to commence in the first half of 2022.

See also "Company History – 2019 – Capital Power Increases Interest in C2CNT", "Company History – 2018 – Capital Power Invests in C2CNT" and "Business of Capital Power – Alberta Commercial Facilities – Genesee 3".

***25-year PPA executed for Strathmore Solar project***

In November 2020, Capital Power executed a 25-year PPA with a large Canadian company for all the energy and renewable energy credits generated by its Strathmore Solar project. Strathmore Solar is a 40.5

MW project located in Strathmore, Alberta. The Company expects that construction will begin in the second quarter of 2021, and commercial operations are expected to commence in January 2022.

See also "Company History – 2020 – Strathmore Solar Project" and "Business of Capital Power – Projects Under Construction or in Advanced Stages of Development – Strathmore Solar".

***20-year PPAs for three North Carolina solar development projects***

On October 19, 2020, the Company announced the execution of 20-year PPAs with Duke Energy Carolinas for three solar development projects located in North Carolina totaling 160 MW. The solar projects consist of Hornet Solar (75 MW), Hunter's Cove Solar (50 MW), and Bear Branch Solar (35 MW) (collectively, the "NC solar projects"). Construction of the NC solar projects is expected to begin in late 2021 or early 2022, and commercial operations are expected to commence in the fourth quarter of 2022.

The initial build assumption includes $260 million (US$198 million) to construct the NC solar projects. The Company expects to finance the NC solar projects using debt and tax equity. The investment is expected to meet the Company's after-tax hurdle rate with the average accretion expected to be neutral to AFFO in the first five years. The solar projects are expected to generate approximately $23 million (US$17 million) of adjusted EBITDA and $5 million (US$4 million) of AFFO annually on average in the first five years.

See also "Business of Capital Power – Projects Under Construction or Advanced Stages of Development – Hornet Solar", "Business of Capital Power – Projects Under Construction or Advanced Stages of Development – Hunter's Cove Solar" and "Business of Capital Power – Projects Under Construction or Advanced Stages of Development – Bear Branch Solar".

***10-year tolling agreement extension for Decatur***

On August 4, 2020, the Company announced the execution of a 10-year tolling agreement extension through December 2032 for Decatur with the current counterparty. Decatur is a natural gas-fired combined cycle facility located in Decatur, Alabama that began commercial operations in 2002. Decatur sells capacity and energy to a regional entity with an A-rated credit rating under a tolling agreement with an original term of 10 years that was to expire in December 2022.

On September 28, 2020, Decatur executed an amendatory interconnect agreement (the Amendatory Interconnect Agreement) that will permit Decatur to transmit all capacity and energy to the current counterparty.

Under the terms of the toll extension, Decatur began receiving payments for 34 MW of additional capacity upon execution of the toll extension, which then subsequently increased to 72 MW upon execution of the Amendatory Interconnect Agreement. As a result, adjusted EBITDA is expected to increase by $11 million (US$8 million) in 2021 and $27 million (US$20 million) in 2022. In 2023, the first year of the additional 10-year term, adjusted EBITDA is expected to be $73 million (US$54 million) per year and then decline by approximately 4% on average per annum over the term.

See also "Business of Capital Power – US Contracted Facilities – Decatur".

***Strathmore Solar project***

On July 30, 2020, the Company announced its plans to move forward with developing the Strathmore Solar project, the Company's first solar development project in Canada. Strathmore Solar is a proposed 40.5 MW solar project, located in Strathmore, Alberta. The Company expects that construction will begin in the second quarter of 2021, and commercial operations are expected to commence in January 2022. All of the energy and renewable energy credits generated by its Strathmore Solar project will be sold under a 25-year PPA with a large Canadian company.

See also "Company History – 2020 – 25-year PPA executed for Strathmore Solar project" and "Business of Capital Power – Projects Under Construction or in Advanced Stages of Development – Strathmore Solar".

***Executive appointments***

On July 30, 2020, Capital Power and the Board announced the following executive position appointments:

- B. Kathryn Chisholm, Senior Vice President, Planning, Stakeholder Relations and Chief Sustainability Officer;
- Bryan DeNeve, Senior Vice President, Business Development and Commercial Services;
- Sandra Haskins, Senior Vice President, Finance and Chief Financial Officer;
- Chris Kopecky, Senior Vice President and Chief Legal Officer; and
- Jacquie Pylypiuk, Senior Vice President, People, Culture and Technology.

Darcy Trufyn continues to serve as the Senior Vice President, Operations, Engineering and Construction. Mark Zimmerman, who previously served as the Senior Vice President, Corporate Development and Commercial Services, stepped down from his role effective July 30, 2020.

***Phase 3 of Whitla wind project***

On June 23, 2020, the Company announced that it was moving forward with developing Whitla 3, the third phase of the Whitla wind project, which will add 54 MW in late 2021. The Company has initiated the permitting process for Whitla 3 with the AESO and has filed its AUC application. Subject to regulatory approvals, construction of Whitla 3, with an estimated capital cost of $92 million, is expected to begin in the second quarter of 2021 and will be constructed concurrently with the Whitla 2 (97 MW) project to capture synergies. Construction of both projects is expected to be completed by the end of 2021. Whitla 3 will consist of 15 Vestas V-136 3.6 MW wind turbines, the same technology in operation at Whitla 1 and the future Whitla 2.

Whitla 3 will generate carbon credits that can be used to hedge against the Company's carbon compliance costs from its Alberta thermal generation facilities. The Company is in active discussions with commercial and industrial customers for renewable offtake contracts for both Whitla 2 and Whitla 3.

See also "Business of Capital Power – Projects Under Construction or Advanced Stages of Development – Whitla 3".

***Wind facility long-term service agreement extensions and Whitla 2 and 3 turbine supply***

In late April 2020, the Company signed agreements with Vestas setting the terms for 10-year long-term service agreement (LTSA) extensions for the maintenance of nine of the Company's wind facilities and the supply of turbines for the Whitla 2 and 3 projects.

The agreement for the 10-year extension on the series of LTSAs with Vestas covers a wider scope of services for all of our Vestas-equipped wind facilities while reducing costs by an estimated 26% compared to current service and maintenance agreements. The new LTSAs were executed in October 2020 and will take effect between 2021 and 2023. The Company expects to realize ongoing annual savings on the Company's wind facilities covered under these LTSAs, which would increase adjusted EBITDA and AFFO by approximately $8 million and $6 million per year, respectively. Additionally, the LTSA extensions include provisions intended to identify and encourage potential indigenous training, employment and economic opportunities at Canadian facilities.

### *Acquisition of Buckthorn Wind*

On April 1, 2020, the Company announced that it had successfully completed the acquisition of Buckthorn Wind from private investors. The equity purchase price was in the range of US$60 million to US$69 million, pending the realization of future market performance, and the Company stepped into a tax equity partnership with a tax equity balance of approximately US$74 million (subject to final adjustments). The Company had previously announced the acquisition of Buckthorn Wind on March 16, 2020 and that the acquisition was to be 100% debt financed.

Buckthorn Wind has two hedge agreements with an investment grade U.S. financial institution, a 20-year (through early 2038) fixed-price contract for differences (CFD) for 55% of the project's as-generated energy output and RECs, and a 13-year (through early 2031) financial hedge for approximately 83% of the remaining 45% of the facility's energy output. Buckthorn Wind also has a tax equity investor that receives the tax benefits and a portion of adjusted EBITDA and cash flow until the flip-date that is projected to occur in the late 2020s. Prior to the flip-date and based on an equity purchase price of US$60 million, the Company expects average annual adjusted EBITDA and AFFO to be approximately $18 million and $1 million, respectively. After the flip-date during the CFD, the average annual adjusted EBITDA and AFFO is expected to be approximately $9 million and $6 million, respectively.

See also "Business of Capital Power – US Contracted Facilities – Buckthorn Wind".

### *Commercial operation and tax equity financing for Cardinal Point*

On March 16, 2020, Cardinal Point began commercial operations and subsequently the Company received approximately US$157 million in net tax equity financing on March 26, 2020 from two U.S. financial institutions in exchange for Class A interests of a subsidiary of the Company. The Company operates Cardinal Point under a 12-year fixed-price financial hedge contract with an investment grade U.S. financial institution covering 85% of the facility's output. The expected adjusted EBITDA and AFFO in the first full year of operations is US$40 million and US$4 million, respectively.

See also "Business of Capital Power – US Contracted Facilities – Cardinal Point".

### *Discontinuation of Genesee 4 and 5*

During the first quarter of 2020, the Company and its partner for the Genesee 4 and 5 project determined that they would no longer be pursuing the project. Arbitration has commenced between the Company and its partner around the costs of exiting the series of agreements previously entered into. As a result of the decision to no longer pursue the project, the Company has determined that $13 million of capital expenditures incurred by the Company were purely related to the development of Genesee 4 and 5. The Company therefore recorded an impairment on these capital costs during the first quarter of 2020.

### *Capital Power updates plans for President and Chief Executive Officer role*

On February 24, 2020, the Company announced that Brian Vaasjo will remain as President and Chief Executive Officer of the Company for an additional three years. The February 20, 2020 announcement followed the Company's previous announcement on July 29, 2019 that Mr. Vaasjo had advised the Board of his intention to retire in 2020.

The July 29, 2019 announcement activated an established Chief Executive Officer succession plan developed by the Board. The Board's search for a new President and Chief Executive Officer was conducted through the remainder of 2019 and into early 2020, with the intention that the Board would announce a successor in due course. With the February 24, 2020 announcement that Mr. Vaasjo will continue as President and Chief Executive Officer for three more years, the Board's search for a replacement President and Chief Executive Officer ended.

**2019**

***Genesee Carbon Conversion Centre***

On December 5, 2019, the Company announced plans to build the Genesee Carbon Conversion Centre, the first-ever commercial scale production facility of CNTs at its Genesee facility, and to exercise options to increase its interest to 40% in C2CNT at the end of 2020.

Lehigh, a subsidiary of Heidelberg Cement A.G., a worldwide construction materials company, will be conducting testing for the utilization of CNTs in concrete. The Company plans to start commercial scale production of CNTs at its Genesee facility, assuming the use of CNTs in concrete testing and preliminary marketing of the product is successful. Assuming required permits are approved, construction is expected to commence in the first quarter of 2021, with operations expected to commence in the first half of 2022. The Genesee Carbon Conversion Centre could generate 2,500 tonnes of CNTs per year.

See also "Company History – 2020 – C2CNT and Genesee Carbon Conversion Centre" and "Company History – 2018 – Capital Power Invests in C2CNT".

***Whitla 2 Proceeding***

On December 5, 2019, the Company announced that it is moving forward with the second phase of the Whitla wind project, Whitla 2, which will add 97 MW in 2021 at an expected capital cost of $165 million. The Company is in active discussions with potential commercial and industrial customers for renewable offtake contracts from Whitla 2.

See also "Business of Capital Power – Projects Under Construction or Advanced Stages of Development – Whitla 2".

***Whitla 1 Begins Commercial Operations***

On December 1, 2019, Whitla 1, located in the County of Forty Mile, Alberta, began commercial operations. Construction of the facility began in September 2018 and was completed on schedule and on budget within its $315 million to $325 million target, excluding foreign exchange impacts which were partially economically hedged. In December 2017, Whitla 1 was one of four successful wind projects that was awarded a 20-year contract by the AESO in the first round of the REP, which attracted global competition.

See also "Business of Capital Power – Alberta Contracted Facilities – Whitla 1".

***Capital Power Assumes 100% Ownership and Control of Genesee 3 Generating Station***

On August 2, 2019, the Company announced it had entered into an agreement to divest its 50% share of Keephills 3 to TransAlta, and to acquire TransAlta's 50% share of Genesee 3. The transaction closed on October 1, 2019, with a net cost to the Company of $10 million, subject to working capital and other closing adjustments. Previously both facilities had been owned and operated under 50/50 joint venture agreements between the Company and TransAlta. Following the close of the transaction, Genesee 3 is fully owned and operated by the Company and Keephills 3 is fully owned and operated by TransAlta.

Keephills 3 and Genesee 3 are the only supercritical coal facilities in Alberta, with a net capacity of 463 MW and 466 MW, respectively. The swap of interests in the facilities is aligned with the Company's strategic plan to deliver responsible energy for tomorrow. As a result of the transaction, the Company gained full control of the Genesee site, providing strategic freedom and latitude to make decisions that further optimize value for all three Genesee units.

See also "Business of Capital Power – Alberta Commercial Facilities – Genesee 3".

***Accelerated Plan for Genesee Natural Gas Capability***

During 2019, the Company announced that it was proceeding with a project that will maximize the flexibility to utilize natural gas as fuel at Genesee, which previously burned primarily coal. The total cost of the project to completely transform the Genesee units to dual-fuel capability was estimated at $70 million with expenditures of $10 million incurred in 2019, $43 million incurred in 2020 and expected costs of $17 in 2021. The project involves adding new gas pipeline infrastructure within the Genesee site and modifications to the Genesee 1 and 2 boilers. The rated capacity of the units will remain the same. The Company has since announced on December 3, 2020, that it will only be moving forward with dual fuel capability on Genesee 3 given the decision to repower units 1 and 2.

After Genesee 3 has been transformed to 100% dual-fuel capability, the units can utilize up to 100% natural gas or coal, or a mix of the two. The amount of coal used at any given time, versus natural gas, will be driven by several factors including natural gas and coal prices and carbon costs.

Once Genesee 1 and 2 are burning 100% natural gas under the repowering plan, the Genesee coal mine will be closed and Genesee 3 will burn 100% natural gas by 2023.

The Genesee units are already the most efficient coal generating units in Alberta and best performing from an emissions intensity perspective. Under the Genesee Performance Standard program, which commenced in 2016, a 12% improvement in efficiency and performance of the units is targeted by 2021, which improvements will benefit both natural gas and coal operations. See also "Business of Capital Power – Alberta Contracted Facilities – Genesee 1 and 2" and "Business of Capital Power – Alberta Commercial Facilities – Genesee 3".

Capital Power is seeking regulatory approval to repower both units to NGCC units as a longer-term option for baseload power generation. The repowered assets will utilize best in class NGCC technology, setting a new standard for gas generation efficiency in the province.

See also "Company History – 2020 – Acceleration of plans to repower Genesee". As a result of the repowering, Genesee will cease utilizing coal in 2023.

***Acquisition of Goreway Power Station***

On April 29, 2019, the Company announced that it had entered into an agreement to acquire Goreway Power Station Holdings Inc., which owned the Goreway Power Station (Goreway), an 875 MW natural gas combined cycle generation facility located in Brampton, Ontario.

On June 4, 2019, the Company completed the acquisition of 100% of the ownership interests in Goreway. The purchase price consisted of (i) $405 million of total cash consideration, including working capital and other closing adjustments of $18 million, and (ii) the assumption of $590 million of project level debt. Financing of the Goreway acquisition consisted of a combination of debt from the Company's existing credit facilities and equity offerings.

The Goreway facility has a 20-year Accelerated Clean Energy Supply Contract expiring in June, 2029 with the Ontario IESO. Goreway is strategically located in the Greater Toronto Area load centre making it an important asset in Ontario's electric system and, in combination with the Company's other Ontario natural gas assets, will provide operating and market synergies over time. The acquisition of Goreway supports the Company's growth strategy and fully meets the Company's investment criteria.

See also "Business of Capital Power – Ontario and BC Contracted Facilities – Goreway".

### *Capital Power Increases its Equity Interest in C2CNT*

In May 2019, the Company committed to increase its equity interest in C2CNT from 5% to 9% by March of 2020 and in August 2020, further increased its equity interest from 16% to 25%.

The Company had the right to provide notice to exercise a final option before the end of 2020 for an additional 15% equity interest in C2CNT. In December, 2020, Capital Power exercised its option to increase its equity interest in C2CNT from 25% to 40% with the additional investment to occur during the first quarter of 2021. See also "Company History – 2020 – C2CNT and Genesee Carbon Conversion Centre".

The investment supports the Company's pursuit of innovative and leading-edge technology to reduce greenhouse gases.

Lehigh agreed to conduct testing for the utilization of CNTs in concrete at their cost. Lehigh also made a modest financial contribution to C2CNT development.

See also "Company History – 2018 – Capital Power Invests in C2CNT".

### *Heat Rate Call Option at Arlington Valley*

During the first quarter of 2019, the Company entered into a heat rate call option agreement (HRCO) with an investment grade counterparty covering the periods outside of Arlington Valley's existing summer tolling agreements. The HRCO commenced on April 1, 2019 and terminates December 31, 2025, covering (i) April and November-December 2019 and (ii) January-May and October-December 2020-2025. Pursuant to the HRCO the counterparty has the right to call the plant in exchange for fixed monthly premiums plus reimbursements for fuel at an indexed price, variable operating and maintenance expense and start charges. Adjusted EBITDA and AFFO from the Arlington Valley facility during the period covered by the HRCO are expected to be consistent with the guidance provided at the time the acquisition was announced.

See also "Business of Capital Power – US Contracted Facilities – Arlington Valley".

## 2018

### *New Frontier Begins Commercial Operations*

On January 9, 2019, the Company announced that its New Frontier wind project, located in North Dakota, began commercial operation on December 21, 2018. The construction of the 99 MW facility was completed on-schedule and below its original cost estimate of approximately $182 million (US$145 million).

In addition, on December 31, 2018, the Company received approximately $125 million (US$92 million) in net tax equity financing from an investment grade US financial institution in exchange for Class A interests of a subsidiary of the Company.

The Company will operate New Frontier under a 12-year fixed-price financial hedge contract, as further described in "Business of Capital Power – US Contracted Facilities – New Frontier".

### *Sale of Minority Interest in K2*

On November 7, 2018, the Company announced that it entered into an agreement for the sale of its minority owned one-third interest of 90 MW in K2 to a consortium of investors led by Axium Infrastructure for $216 million. The transaction closed on December 31, 2018.

***Acquisition of Arlington Valley***

On September 6, 2018, the Company announced that it entered into an agreement to acquire 100% of the ownership interests in Arlington Valley, LLC, which owned the Arlington Valley facility, a 580 MW combined cycle natural gas generation facility. The Company acquired Arlington Valley from funds managed by Oaktree Capital Management, L.P. and its co-investors for $399 million (US$303 million) in total cash consideration, including preliminary working capital and other closing adjustments of $3 million (US$3 million). The transaction closed on November 30, 2018.

Arlington Valley sells capacity and electricity to an investment grade load serving utility (credit ratings of A2/A- from Moody's and S&P, respectively) under a tolling agreement during the summer months through 2025. Arlington Valley is adjacent to the Palo Verde hub allowing for additional capacity and energy to be sold into the DSW or CAISO wholesale markets during the months outside the summer tolling months.

The acquisition of Arlington Valley supports the Company's US growth strategy and fully meets the Company's investment criteria. Arlington Valley is a well-positioned asset in the attractive DSW power market with growing demand and a low investment risk environment.

See also "Business of Capital Power – US Contracted Facilities – Arlington Valley".

***Capital Power Invests in C2CNT***

On May 29, 2018, the Company announced that it acquired an equity interest in C2CNT, a company that developed and is applying at scale an innovative technology that captures and transforms $CO_2$ into CNTs, a useful and high-value product.

This technology can utilize $CO_2$ from a number of sources including emissions from thermal power generation to produce CNTs. CNTs are stronger than steel and lighter than aluminum and can be used in a wide range of applications including batteries, tires, polymers and structural materials such as concrete. When used as an additive in concrete for example, tensile strength is increased which reduces the amount of material required. As concrete production is an emissions intensive process, use of CNTs in that material can significantly reduce emissions.

The C2CNT technology was developed by a team of scientists, led by Professor Stuart Licht, at George Washington University. The technology uses electrolysis to separate carbon from oxygen. The carbon can then be repurposed into CNTs, and the oxygen is available for other uses.

Dr. Licht and his team were among five finalists competing in the natural gas track of the NRG COSIA Carbon XPRIZE competition. As part of the XPRIZE competition, C2CNT started testing their technology at demonstration scale at the Alberta Carbon Conversion Technology Centre located at the Shepard Energy Centre in Calgary that the Company co-owns with ENMAX.

See also "Company History – 2020 – C2CNT and Genesee Carbon Conversion Centre", "Company History – 2019 – Genesee Carbon Conversion Centre", "Company History – 2019 – Capital Power Increases Equity Interest in C2CNT" and "Business of Capital Power – Alberta Commercial Facilities – Shepard".

***Genesee Royalty Rate Agreement***

During the second quarter, the Company entered into an agreement with Genesee Royalty Limited Partnership establishing a fixed royalty rate structure in place of the previous structure which was based on coal regulations from the 1980s. The new structure provides improved royalty cost certainty in the future.

See also "Business of Capital Power – Alberta Commercial Facilities – Genesee 3".

***Bloom Tax Equity Agreement Amendment***

As part of the enactment of the U.S. Tax Cuts and Jobs Act of 2017 in the fourth quarter of 2017, and the resulting reduction in the U.S. Federal corporate tax rate (effective January 1, 2018), a change in tax law provision was triggered in the tax equity agreement for Bloom. As a result, in May of 2018, the Company re-negotiated certain commercial terms within that agreement. The re-negotiated terms resulted in an interest rate increase on the tax equity financing balance. As well, a one-time reduction to the tax equity financing balance by $44 million (US $33 million) was recorded relating to additional tax benefits used by the tax equity partner. The overall impact of the re-negotiated terms resulted in a one-time, non-cash increase in net income after tax of $15 million (US $11 million). Under the re-negotiated agreement and considering the reduction in the U.S. Federal corporate tax rate, the Company has maintained its original expected returns for Bloom.

See also "Business of Capital Power – US Contracted Facilities – Bloom".

***Completion of Contracts for Cardinal Point***

On April 30, 2018, the Company announced that the construction of Cardinal Point would proceed once all applicable regulatory approvals were received. Cardinal Point is a 150 MW facility constructed in the McDonough and Warren Counties, Illinois. Final costs of the project were US$237 million, at the lower end of the expected range. Commercial operation of the facility commenced on March 16, 2020. The Company operates Cardinal Point under a 12-year fixed-for-floating financial swap agreement with an investment grade U.S. financial institution covering approximately 85% of the facility's output. The hedge offers a fixed-price for a fixed notional quantity of energy, and settles at the AMIL.BGS6 Load Zone. In addition, Cardinal Point has secured three 15-year, fixed-price contracts with three Illinois utilities for the sale and purchase of approximately 95% of the forecast RECs generated by the facility. The fixed-for-floating swap and REC agreements secure long-term revenues, allowing Cardinal Point to secure tax equity financing.

See "Business of Capital Power – US Contracted Facilities – Cardinal Point".

## BUSINESS OF CAPITAL POWER

### Overview

Capital Power is a growth-oriented North American wholesale power producer with a strategic focus on sustainable energy headquartered in Edmonton, Alberta. We build, own and operate high-quality, utility-scale generation facilities that include renewables such as wind, solar and waste heat, and thermal such as natural gas and coal. We have also made significant investments in carbon capture and utilization to reduce carbon impacts and are committed to be off coal in 2023.

Capital Power owns over 6,500 megawatts (MW) of gross power generation capacity at 28 facilities across North America. In addition, approximately 425 MW of owned renewable generation capacity and 560 MW of incremental natural gas combined cycle capacity, from the repowering of Genesee 1 and 2, is in advanced development in Alberta and North Carolina.

As of December 31, 2020, Capital Power's power generation fleet had a capacity weighted average facility age of 14 years and is diversified across three Canadian provinces and eight states in the US.

Capital Power owns approximately 2,600 MW of power generation capacity in Alberta, with ownership interests in nine facilities. As of January 1, 2021, most of the power generated by Capital Power's Alberta power facilities is sold on a merchant, or non-contracted, basis as part of Capital Power's portfolio optimization activities. See "Business of Capital Power – Portfolio Optimization and Company History – Expiry of Genesee 1 and 2 PPA".

Capital Power sells some of the power generated by its Alberta power facilities and most of the power generated by its power facilities outside of Alberta, on a contracted basis to arm's length third parties. See

"Business of Capital Power – Alberta Contracted Facilities", "Business of Capital Power – Ontario and BC Contracted Facilities", and "Business of Capital Power – US Contracted Facilities".

As part of its growth strategy, Capital Power continually seeks opportunities to acquire or develop contracted, larger scale, natural gas-fired and renewable power generation facilities in Alberta, the rest of Canada, and the US, and has focused its merchant power business on Alberta. Capital Power considers Environmental, Social and Governance (ESG) integral to achieving total value creation. As such, as we execute our strategy, our decisions include consideration for ESG factors, which helps drive innovation and better decisions in the interests of our many different stakeholders.

Capital Power's sustainability targets, including ambitious carbon emissions-reduction targets, reflect our commitment to being an investment, employer, supplier and neighbour of choice. These targets, detailed below, include an ambitious target to be net carbon neutral before 2050.

- Achieve net carbon neutrality before 2050
- Construct all new natural gas generation units to be carbon capture and/or hydrogen-ready
- Reduce Scope 1 $CO_2$ emissions at Genesee by 50% by 2030 from 2005 levels
- Reduce Scope 1 $CO_2$ emissions by 10% by 2030 from 2005 levels, based on our 2019 fleet
- Reduce Scope 1 $CO_2$ emission intensity by 65% by 2030 from 2005 levels
- Invest in carbon capture and utilization technology to help us achieve net carbon neutrality before 2050 and eventually physically decarbonize our natural gas fleet (ongoing)
- Complete the Genesee Carbon Conversion Centre in the first half of 2022
- Enhanced sustainable sourcing plan (2021)
- Enhanced water management plan (2021)
- Target of at least 30% women on the Board and Executive team

## Generation Facility Summary

The following table provides details of Capital Power's generation facilities that are in service, under construction or in advanced stages of development as at December 31, 2020:

| Category | Facility Name and Location | Type of Generating Facility | Year Commissioned or Target Date | Facility Generation Capacity (MW) | Capital Power Interest (MW) |
|---|---|---|---|---|---|
| **Alberta Commercial Facilities** | Genesee 3, Alberta[(1)] | Supercritical coal and natural gas co-fired | 2005 | 516 | 516 |
| | Joffre, Alberta | Gas-fired, combined cycle cogeneration | 2001 | 480 | 192 |
| | Clover Bar, Alberta | Natural gas-fired, simple cycle | Unit 1 - 2008<br>Unit 2 & 3 - 2009 | 43<br>200 | 43<br>200 |
| | Clover Bar Landfill, Alberta | Land fill gas-fired | 2005 | 1.6 | 1.6 |
| | Halkirk, Alberta | Wind turbine | 2012 | 150 | 150 |
| | Shepard, Alberta | Natural gas-fired, combined cycle | 2015 | 860 | 430 |

| Category | Facility Name and Location | Type of Generating Facility | Year Commissioned or Target Date | Facility Generation Capacity (MW) | Capital Power Interest (MW) |
|---|---|---|---|---|---|
| | ***Total Alberta Commercial Facilities*** (2) (3) | | | | **1,532.6** |
| **Alberta Contracted Facilities** | Genesee 1 and 2, Alberta(1)(6) | Coal and natural gas co-fired | Genesee 1 -1994<br>Genesee 2 -1989 | 430<br>430 | 430<br>430 |
| | Whitla 1 | Wind Turbine | 2019 | 202 | 202 |
| | ***Total Alberta Contracted Facilities***(2) (3) | | | | **1,062** |
| **Ontario and BC Contracted Facilities** | Kingsbridge 1, Ontario | Wind turbine | 2001 & 2006 | 40 | 40 |
| | Island Generation, BC | Natural gas-fired, combined cycle | 2002 | 275 | 275 |
| | 150 Mile House, BC | Waste heat | 2008 | 5 | 5 |
| | Savona, BC | Waste heat | 2008 | 5 | 5 |
| | East Windsor, Ontario | Natural gas | 2009 | 84 | 84 |
| | Quality, BC | Wind turbine | 2012 | 142 | 142 |
| | York, Ontario | Natural gas | 2012 | 400 | 200 |
| | PDN, Ontario | Wind turbine | 2013 | 105 | 105 |
| | Goreway, Ontario | Natural gas | 2009 | 875 | 875 |
| | ***Total Ontario and BC Contracted Facilities***(2) | | | | **1,731** |
| **US Contracted Facilities** | Roxboro, North Carolina | Coal, tire-derived fuel and wood waste power facility | 1987 | 46(4) | 46 |
| | Southport, North Carolina | Coal, tire-derived fuel and wood waste combined heat and power facility | 1987 | 88(4) | 88 |
| | Arlington Valley, Arizona | Natural gas | 2002 | 580 | 580 |
| | Decatur, Alabama | Natural gas | 2002 | 792 | 792 |
| | Macho Springs, New Mexico | Wind turbine | 2011 | 50 | 50 |
| | Beaufort, North Carolina | Solar | 2015 | 15 | 15 |
| | Bloom, Kansas | Wind turbine | 2017 | 178 | 178 |
| | Buckthorn Wind, Texas | Wind turbine | 2018 | 100.5 | 100.5 |
| | New Frontier, North Dakota | Wind turbine | 2018 | 99 | 99 |
| | Cardinal Point, Illinois | Wind turbine | 2020 | 150 | 150 |
| | ***Total US Contracted Facilities***(2) | | | | **2,098.5** |

| Category | Facility Name and Location | Type of Generating Facility | Year Commissioned or Target Date | Facility Generation Capacity (MW) | Capital Power Interest (MW) |
|---|---|---|---|---|---|
| **Facilities Under Construction or in Advanced Stages of Development** | Whitla 2, Alberta | Wind turbine | 2021 | 97 | 97 |
| | Whitla 3, Alberta | Wind turbine | 2021 | 54 | 54 |
| | Strathmore Solar, Alberta | Solar | 2022 | 40.5 | 40.5 |
| | Enchant Solar, Alberta | Solar | 2022 | 75 | 75 |
| | Bear Branch Solar, North Carolina | Solar | 2022 | 35 | 35 |
| | Hornet Solar, North Carolina | Solar | 2022 | 75 | 75 |
| | Hunter's Cove Solar, North Carolina | Solar | 2022 | 50 | 50 |
| | Repowering of Genesee 1 and 2, Alberta | Natural Gas | Genesee 1 - 2023<br>Genesee 2 - 2024 | 280[7]<br>280[7] | 280[7]<br>280[7] |
| | ***Total Under Construction or in Advanced Stages of Development*** | | | | **986.5** |
| **Total Capital Power[5]** | | | | | **7,410.6** |

**Notes:**

(1) MW noted are gross capacity. All others listed are net capacity.
(2) Represents Capital Power's owned capacity as at the date of this AIF.
(3) Based on the nature of future cash flows, the Alberta assets are combined as one cash-generating unit (CGU) for impairment testing purposes. The cash flow of Genesee 1 and 2 remained contracted through 2020 and management continued to present facility results for Genesee 1 and 2 within the Alberta Contracted grouping in 2020.
(4) Generation capacity utilizing current blended fuel mixture (wood product, tire-derived product and coal) versus the nameplate capacity of 54 MW and 109 MW for Roxboro and Southport respectively. See also "US Contracted Facilities – Roxboro" and "US Contracted Facilities – Southport".
(5) Represents Capital Power's owned capacity, capacity under construction or in advanced stages of development as at the date of this AIF.
(6) The power purchase arrangement for Genesee 1 and 2 expired on December 31, 2020. Commencing in 2021, these facilities will be reported within the Alberta commercial facilities grouping.
(7) Represents additional capacity to be developed at the Genesee 1 and 2 facilities.

## Revenue and Volume

The following table shows Capital Power's revenues and other income from its generation business by category:

| | Revenues and other income (unaudited $ millions) | |
|---|---|---|
| **Category** | **Twelve Months Ended December 31, 2020** | **Twelve Months Ended December 31, 2019** |
| Alberta commercial facilities | 772 | 725 |
| Alberta contracted facilities | 301 | 261 |
| Ontario and BC contracted facilities | 391 | 293 |
| U.S. contracted facilities | 463 | 449 |
| Corporate | 55 | 188 |

| Category | Revenues and other income (unaudited $ millions) Twelve Months Ended December 31, 2020 | Twelve Months Ended December 31, 2019 |
|---|---|---|
| Sub Total | 1,982 | 1,916 |
| Unrealized changes in fair value of commodity derivatives and emission credits | (45) | 47 |
| **Total** | **1,937** | **1,963** |

The following table shows Capital Power's power generation volumes from its generation business by category:

| Category | Electricity Generation (GWh) Twelve Months Ended December 31, 2020 | Twelve Months Ended December 31, 2019 |
|---|---|---|
| Alberta commercial facilities | 8,763 | 9,049 |
| Alberta contracted facilities | 6,763 | 6,288 |
| Ontario and BC contracted facilities | 1,938 | 2,061 |
| U.S. contracted facilities | 6,342 | 7,129 |
| **Total** | **23,806** | 24,527 |

## Alberta Commercial Facilities

As of December 31, 2020, the Alberta commercial facilities consisted of ownership interests in six facilities representing approximately 1,533 MW of power generation capacity. The facilities generate electricity from coal, natural gas, wind and landfill gas. The output of the Alberta facilities is managed on a portfolio basis by Capital Power's Commodities team. Output from these facilities is sold into the deregulated Alberta power market. The PPA for Genesee 1 and 2 expired on December 31, 2020. Commencing in 2021, these facilities will be reported within the Alberta commercial facilities grouping. At the date of this AIF, the Alberta commercial facilities consist of ownership interests in eight facilities representing approximately 2,393 MW of power generation capacity.

Capital Power seeks to maximize earnings from the Alberta commercial facilities by achieving high availability and production levels from the facilities and by actively managing the portfolio's commodity price exposure relative to market price views.

### *Genesee 3*

Genesee 3 is a 516 MW supercritical coal power facility located adjacent to Genesee 1 and 2 near Warburg, Alberta, which was commissioned in 2005. Genesee 3 is 100% owned and operated by Capital Power as of October 1, 2019. Genesee 3 uses supercritical technology to achieve greater fuel efficiency and lower $CO_2$, $NO_x$ and $SO_2$ emissions per MW than conventional subcritical pulverized coal technologies.

To comply with new CASA $SO_2$ emission limits, Genesee 3 reduced its $SO_2$ emissions from 0.76 tonnes per hour to 0.36 tonnes per hour by installing a dry sorbent injection (DSI) system. The DSI system injects hydrated lime into the flue gas stream where it captures and removes $SO_2$. The DSI system has proved successful in reducing Genesee's emissions below the required level.

*Commercial Arrangement: Merchant Facility*

Genesee 3 is managed as part of Capital Power's Alberta electricity portfolio optimization activities.

*Fuel Supply*

Coal required for the Genesee power facilities is supplied by the adjacent Genesee coal mine. The coal is provided to the Genesee power facilities under long-term, cost of service supply agreement with the Genesee coal mine, a 50/50 joint venture between Capital Power and PMRU. PMRU is the operator. Capital Power is also a party to various agreements with PMRU in relation to the operation of the Genesee coal mine. See "Company History – 2017 – Amendment of the Genesee Coal Mine Joint Venture Agreement".

In 2014 and 2015, Capital Power received approval from the AER to add approximately 10,000 acres of surface land holdings as well as amended Alberta *Water Act* approvals for the Genesee coal mine. Capital Power believes the recoverable coal reserves to which it holds the rights exceed the estimated requirements for the life of Genesee 1, 2 and 3. The explored portions of the coal rights held by the Genesee coal mine joint venture are surface mineable, which reduces extraction costs. Once Genesee 1 and 2 are burning 100% natural gas under the repowering plan, the Genesee coal mine will be closed and Genesee 3 will burn 100% natural gas by 2023.

By 2022, the Company intends that the Genesee 3 facility will fully accommodate both coal and natural gas for fuel supply and will be off-coal in 2023. See "Company History 2020 – Acceleration of plans to repower Genesee". When natural gas is more economic than coal, natural gas for Genesee is purchased in the Alberta wholesale market to meet dispatch requirements. A natural gas transportation agreement with TransCanada provides firm and interruptible transport services to the site and a new pipeline was completed and commissioned in 2020 of sufficient size to handle all of the current Genesee natural gas needs. This new natural gas pipeline to Genesee also holds significant expansion potential should the gas needs at Genesee materially increase with future development.

***Joffre***

Joffre is a 480 MW natural gas combined-cycle cogeneration power facility located at NOVA's petrochemical complex near Red Deer, Alberta. Joffre began commercial operations in May 2001. Joffre is owned by Capital Power, Heartland Generation and NOVA in a joint venture, with ownership interests of 40%, 40% and 20%, respectively.

The facility produces both steam and electricity for NOVA's host petrochemical complex. On average, 125 MW of the net electricity output of the cogeneration facility is required on site by the host petrochemical complex with the balance being sold to the wholesale electricity market. Heartland Generation operates the facility and dispatches the power that is surplus to the needs of the host petrochemical complex for sale to the Alberta Power Pool on behalf of the owners.

*Commercial Arrangement: Energy Supply Agreement and Merchant Facility*

An energy supply agreement dated June 30, 1999, as amended, among a subsidiary of Capital Power, Heartland Generation and NOVA sets forth the terms regarding the sale of electricity, steam and feedwater to NOVA. NOVA makes cost-of-service payments comprised primarily of a natural gas fuel cost payment, an operating and maintenance payment, and a capital payment calculated on a return-on-rate basis. The uncommitted capacity of the facility is bid into the wholesale electricity market by Heartland Generation and Capital Power's share of output is incorporated into the Alberta electricity portfolio optimization activities. The agreement terminates upon decommissioning of the site by NOVA.

*Fuel Supply*

Capital Power procures and manages its 40% ownership share of the fuel for the facility. Any cost for fuel procured for generation required by the host petrochemical complex is passed through at cost to NOVA. Natural gas transportation agreements with TransCanada provide firm and interruptible transport services to the Joffre site.

***Clover Bar***

Clover Bar is a 243 MW natural gas power facility located in Edmonton, Alberta. Clover Bar is comprised of a GE LM 6000 natural gas-fired turbine with a generation capacity of approximately 43 MW, which began commercial operations in March 2008, and two GE LMS 100 natural gas-fired turbines with a combined generation capacity of approximately 200 MW, which began commercial operations in 2009. The turbines are simple cycle units with quick-start capability and permitted to meet the need for peaking, mid-merit and baseload capacity in Alberta.

Clover Bar unit #1 (LM6000) is scheduled for a hot gas path overhaul in Q1 of 2022 based on forecasted usage.

*Commercial Arrangement: Merchant Facility*

The units are dispatched to take advantage of price volatility in the Alberta electricity market and to provide ancillary services and, as such, are part of Capital Power's Alberta electricity portfolio optimization activities.

*Fuel Supply*

Natural gas for Clover Bar is purchased in the Alberta wholesale market to meet dispatch requirements. A natural gas transportation agreement with TransCanada provides firm transport service to the Clover Bar site for most of the capacity.

***Halkirk***

Halkirk is a 150 MW wind facility located near Halkirk, Alberta, that began commercial operations on December 1, 2012. Halkirk is comprised of 83 Vestas V-90 turbines each with a generation capacity of 1.8 MW.

*Commercial Arrangement: Merchant Facility for Energy (Power Purchase Agreement for RECs)*

The electricity generated by Halkirk is managed as part of Capital Power's Alberta electricity portfolio optimization activities. RECs produced by Halkirk are sold to PG&E under the terms of a 20-year fixed price agreement. On January 29, 2019, PG&E filed for voluntary reorganization proceedings under Chapter 11 of the U.S. Bankruptcy Code in California and subsequently had its credit rating downgraded to "D", representing default. On June 20, 2020, the United States Bankruptcy Court for the Northern District of California, San Francisco Division, confirmed PG&E's plan of reorganization under Chapter 11 (the "Plan") and the Plan became effective on July 1, 2020, at which point PG&E emerged from creditor protection. As part of the Plan, PG&E assumed all its obligations under the fixed-price agreement with Halkirk and paid the pre-Chapter 11 petition debt it owned to Halkirk in full on August 7, 2020. At this time, PG&E has continued to fulfill its obligations to Halkirk under the fixed price agreement.

***Shepard***

Shepard is an 860 MW natural gas fired combined-cycle power facility located in Calgary, Alberta, that began commercial operations in March, 2015. Shepard is owned by Capital Power and ENMAX in a joint venture, and each has a 50% interest. Shepard features combined-cycle technology that has two combustion turbines to generate electricity and makes use of waste heat through a steam turbine for further electricity production. This configuration makes Shepard's gas-fuelled facility one of the cleanest and most efficient combined cycle facilities in Alberta.

*Commercial Arrangement: Merchant Facility*

Capital Power and ENMAX have also entered into various commercial agreements including a 20-year tolling agreement that took effect April 1, 2015. Under the terms of the tolling agreement, ENMAX will pay Capital Power a fixed capacity charge for 50% of Capital Power's owned capacity from April 2018 to 2035. The remaining non-tolled portion of Capital Power's share of Shepard's generation is managed as part of Capital Power's Alberta electricity portfolio optimization activities.

*Fuel Supply*

Natural gas for Shepard is purchased in the Alberta wholesale market to meet dispatch requirements. A natural gas transportation agreement with TransCanada provides firm transport service to the Shepard site. Capital Power is required to procure natural gas for Capital Power's non-tolled capacity.

***Additional Alberta Facilities***

Capital Power has a 100% interest in Clover Bar Landfill Gas Facility, recently repowered under a life extension project to a 1.6 MW facility located in Edmonton, Alberta. The landfill gas collection system was commissioned in 1992 to provide gas to the process facility for cleaning and flaring and under the life extension work is expected to operate until 2023.

The facility creates carbon offset credits through both the flare and electrical generation under a renewed carbon offset program until Q3 of 2023. The environmental approval has been extended to Q1 of 2021. Flaring and/or use of the landfill gas for power generation creates carbon offset credits through the collection and combustion of methane. Electrical output from the facility is sold into the Alberta wholesale electricity market at spot price.

## Alberta Contracted Facilities

***Genesee 1 and 2***

Genesee 1 and 2, are coal-fired power facilities with 860 MW of combined generation capacity located west of Edmonton near Warburg, Alberta. Both units are 100% owned and operated by Capital Power and are located on land owned by Capital Power. Genesee 1 and 2 were commissioned in 1994 and 1989, respectively.

*Commercial Arrangement: Power Purchase Arrangement*

Until December, 31, 2020, Genesee 1 and 2 were subject to a PPA with the Balancing Pool. Under the terms of the PPA, the Balancing Pool was entitled to the power produced by Genesee 1 and 2, up to their committed capacity (381 MW for each unit). Generation in excess of committed capacity was managed as part of Capital Power's Alberta electricity portfolio optimization activities. Upon expiry of the PPA on December 31, 2020, both units became part of the Company's Alberta commercial facilities portfolio and are managed as part of Capital Power's Alberta electricity portfolio optimization activities.

*Fuel Supply*

Genesee 1 and 2 are managed as part of Capital Power's Alberta electricity portfolio optimization activities.

### *Whitla 1*

Whitla 1 is a 202 MW wind facility located in the County of Forty Mile, Alberta that began commercial operations on December 1, 2019. Whitla 1 is comprised of 56 Vestas V136 turbines, each with a generation capacity of 3.6 MW.

*Commercial Arrangement: Renewable Energy Support Agreement (RESA) Swap Arrangement*

In December 2017, Whitla 1 was awarded a 20-year contract by the AESO in the first round of the Renewable Electricity program which attracted global competition. The RESA contract is in effect a contract-for-differences covering the facility's entire output for 20 years, and additionally will provide the AESO with all the renewable attributes generated by the facility.

## Ontario and BC Contracted Facilities

The Ontario and BC contracted facilities consist of generation facilities for which Capital Power sells all output of the facilities to provincial government entities, either the Ontario IESO or BC Hydro, as applicable, pursuant to long-term contracts. The Ontario and BC contracted facilities consist of ownership interests in nine facilities representing approximately 1731 MW of power generation capacity. The facilities generate electricity from natural gas, wind and waste heat.

### *Kingsbridge 1*

Kingsbridge 1 is a 40 MW wind facility located in the Township of Ashfield-Colborne-Wawanosh, Ontario. Kingsbridge 1 consists of one Vestas V-90 turbine with a generation capacity of 1.8 MW commissioned in 2013, 21 Vestas V-80 turbines each with a generation capacity of 1.8 MW commissioned in 2006 and one Vestas V-47 turbine with a generation capacity of 0.7 MW commissioned in 2001.

*Commercial Arrangement: Energy Supply Contracts*

Kingsbridge 1 operates under the terms of two energy supply contracts with the Ontario IESO. The energy supply contract for the turbine commissioned in 2001 is a standard offer agreement under the Ontario IESO's Renewable Energy Standard Offer Program which terminates in March 2027. The energy supply contract for the remaining turbines terminates in March 2026.

### *Island Generation*

Island Generation is a 275 MW natural gas combined-cycle power facility located at Campbell River, BC, that was commissioned in 2002 and acquired by Capital Power in October 2010. The facility is comprised of a GE GT24B gas turbine and a GE steam turbine.

*Commercial Arrangement: Electricity Purchase Agreement*

Island Generation is fully contracted to April 2022 under a tolling arrangement with BC Hydro. BC Hydro has full dispatch rights and is responsible for the fuel supply to the facility.

### *150 Mile House*

150 Mile House is a 5 MW waste heat facility located at a gas pipeline compressor station near 150 Mile House, British Columbia owned by Westcoast Energy Inc., a subsidiary of Enbridge. Enbridge operates the facility. The facility began commercial operation in 2008.

*Commercial Arrangement: Electricity Purchase Agreement*

The facility operates under a 20-year EPA with BC Hydro, with original terms expiring in 2028.

***Savona***

Savona is a 5 MW waste heat facility located at gas pipeline compressor station near Savona, British Columbia owned by Westcoast Energy Inc., a subsidiary of Enbridge. Enbridge operates the facility. The facility began commercial operation in 2008.

*Commercial Arrangement: Electricity Purchase Agreement*

The facility operates under a 20-year Electricity Purchase Agreement with BC Hydro, with original terms expiring in 2028.

***East Windsor***

East Windsor is an 84 MW natural gas facility located in Windsor, Ontario. The project encompasses approximately 1.5 acres of industrial land, located adjacent to the existing powerhouse owned by FMCC and is equipped with modern emission controls that meet all federal and provincial air quality standards. The facility began commercial operation in 2009.

*Commercial Arrangement: Combined Heat and Power Contract*

The facility is fully contracted with the Ontario IESO until 2029 and had a long-term steam agreement to supply FMCC's Windsor engine facility that terminated in May of 2020. The company is currently exploring options for the use of steam at East Windsor.

*Fuel Supply*

Capital Power procures and delivers the fuel for the facility. Natural gas transportation contracts and natural gas storage contracts are in place to provide firm delivery of natural gas.

***Quality***

Quality is a 142 MW wind facility located near Tumbler Ridge, BC that began commercial operations in November 2012. Quality is comprised of 35 Vestas V-90 turbines each with a generation capacity of 1.8 MW and 44 Vestas V-100 turbines each with a generation capacity of 1.8 MW.

*Commercial Arrangement: Electricity Purchase Agreement*

Quality has a 25-year EPA with BC Hydro which expires in 2037.

***York***

York is a 400 MW natural gas facility located northwest of Newmarket, Ontario in the Township of King. This facility is the largest quick-response gas-fired peaking facility in Ontario. The facility provides power during periods of peak demand.

The facility is jointly owned, with Capital Power having a 50% interest.

*Commercial Arrangement: Peaking Generation Contract*

The facility is fully contracted with the Ontario IESO until 2032.

*Fuel Supply*

Capital Power procures and delivers the fuel for the facility. Natural gas transportation contracts and natural gas storage contracts are in place to provide firm delivery of natural gas, most costs for which are passed through to the Ontario IESO.

***PDN***

PDN is a 105 MW wind facility located in the counties of Norfolk and Haldimand, Ontario that began commercial operations in November 2013. The facility is comprised of 58 Vestas V-90 turbines each with a generation capacity of 1.8 MW.

*Commercial Arrangement: Electricity Purchase Agreement*

PDN has a 20-year PPA with the Ontario IESO which expires in 2033.

***Goreway***

Goreway is an 875 MW natural gas combined cycle generation facility located strategically in Brampton, Ontario, within the Greater Toronto Area load centre. The Goreway facility utilizes best-in-class gas-fired generation equipment including three upgraded GE 7FB.04 combustion turbines, three Deltak heat recovery steam generators and a single Siemens steam turbine. The commercial operational date of the facility was June, 2009 and Capital Power acquired Goreway in June, 2019.

*Commercial Arrangement: Accelerated Clean Energy Supply Contract*

Goreway has a 20-year Accelerated Clean Energy Supply Contract expiring in June 2029 with the Ontario IESO.

*Fuel Supply*

Capital Power procures and delivers the fuel for the facility. Natural gas transportation contracts and natural gas storage contracts are in place to provide firm delivery of natural gas.

**<u>US Contracted Facilities</u>**

***Roxboro***

Roxboro, a 46 MW biomass power facility located in Roxboro, North Carolina, was commissioned in 1987 and acquired by Capital Power in conjunction with the Capital Power Income L.P. divestiture in November 2011. Particulate emissions are controlled using engineered fabric filters, which capture particulate matter in order to comply with state and federal environmental regulations. Roxboro will cease operations after March 31, 2021 and is in the planning stages for decommissioning.

*Commercial Arrangement: Power Purchase Agreement*

Roxboro sells all its electrical output under a PPA with Carolina Power & Light Company doing business as Progress Energy Carolinas, Inc., a subsidiary of Duke Energy Corporation that expires at the end of March 2021.

*Commercial Arrangement: REC*

Roxboro has a 10-year fixed price agreement with Duke Energy Progress to sell RECs generated from tire-derived fuel and wood biomass. The agreement expires at the end of March 2021.

*Fuel Supply*

Roxboro's fuel requirements are satisfied with a mixture of wood residuals, tire-derived fuel and a small amount of coal. Coal is sourced from regional coal suppliers; tire-derived fuel and wood residuals are sourced from multiple local suppliers. Capital Power has a contract with Central Carolina Holdings LLC for 60% of the tire-derived fuel requirements of both Roxboro and Southport. Tire-derived fuel receives an additional REC when purchased from Virginia. Wood residuals are procured at fixed prices indexed to the distance from the facility and are subject to a fuel charge.

***Southport***

Southport, an 88 MW biomass cogeneration heat and power facility located in Southport, North Carolina, was commissioned in 1987 and acquired by Capital Power in November 2011. Particulate emissions are controlled using engineered fabric filters, which capture particulate matter in order to comply with state and federal environmental regulations. Southport will cease operations after March 31, 2021 and is in the planning stages for decommissioning.

*Commercial Arrangement: Power Purchase Agreement*

Southport provides all its electrical output under a PPA with Carolina Power & Light Company doing business as Progress Energy Carolinas, Inc., a subsidiary of Duke Energy Corporation that expires at the end of March 2021. Southport also sells steam to Archer Daniels Midland Company pursuant to a contract that expires at the end of March 2021.

*Commercial Arrangement: REC*

Southport has a 10-year fixed price agreement in place with Duke Energy Progress for RECs generated from tire-derived fuel and biomass. The facility also has a steam supply contract with a nearby Archer Daniels Midland facility to provide varying amounts of 150 psig process steam producing thermal RECs, which are sold under a 10-year fixed price thermal REC agreement with Duke Energy Corporation. These agreements expire at the end of March 2021.

*Fuel Supply*

Southport's fuel requirements are satisfied with a mixture of wood residuals, including green wood and rail ties, tire-derived fuel and a small amount of coal. Coal is sourced from regional coal suppliers; tire-derived fuel and wood residuals are sourced from multiple local suppliers. Capital Power has a contract with Central Carolina Holdings LLC for 60% of the tire-derived fuel requirements of both Southport and Roxboro. Tire-derived fuel receives an additional REC when purchased from Virginia. Wood residuals are procured at fixed prices indexed to the distance from the facility and subject to a fuel charge.

***Decatur***

Decatur is a 792 MW output natural gas-fired combined cycle power generation facility located in Decatur, Alabama, that Capital Power acquired on June 13, 2017. The facility is a 3X1 combined cycle facility comprised of two Siemens SGT6-5000F combustion turbine generators and 1 Siemens 501F D2 combustion turbine generator, three Nooter Eriksen heat recovery steam generators, and a single Toshiba steam turbine generator. Emissions are controlled through selective catalytic reduction and a dry-low $NO_x$ combustion system.

The facility is located on property owned by Ascend and there is an agreement in place to provide demineralized water to Ascend.

*Commercial Arrangement: Conversion Services Agreement*

Decatur operates under a tolling agreement with a regional entity and is fully contracted until the end of 2022. On August 4, 2020, the Company announced the execution of a 10-year tolling agreement extension through December 2032 for Decatur with the current counterparty. Under the terms of the extension, Decatur began receiving payments for 34 MW of additional capacity upon execution of the toll extension, which then subsequently increased to 72 MW upon execution of the Amendatory Interconnect Agreement.

*Fuel Supply*

Fuel procurement and delivery are the responsibility of the tolling agreement counterparty.

***Macho Springs***

Macho Springs is a 50 MW wind facility located in Luna County, New Mexico, that began commercial operations in November 2011 and was acquired by Capital Power in December 2014. The facility is comprised of 28 Vestas V-100 turbines each with a generation capacity of 1.8 MW. MetLife Capital, Limited Partnership is both a TEI and non-recourse term loan provider to Macho Springs. The TEI received the majority of the earnings, tax benefits and cash flows from Macho Springs until it reached its target yield, after which time the project reverted such that Capital Power receives 80% of the earnings, tax benefits, and cash flows. The reversion occurred on September 30, 2018.

*Commercial Arrangement: Electricity Purchase Agreement*

Macho Springs has a 20-year PPA with Tucson Electric Power which expires November 15, 2031.

***Beaufort***

Beaufort is a 15 MW photovoltaic solar facility located near Chocowinity, Beaufort County, North Carolina, that began commercial operations December 2015. The project entered into a sale-leaseback transaction with Wells Fargo to monetize the state and federal investment tax credits for which it is eligible. Under the transaction, Wells Fargo purchased the project's equipment, and leases it back to Beaufort, LLC for ten years. At the conclusion of the lease, Capital Power has the option to re-purchase the project for fair market value.

*Commercial Arrangement: Electricity Purchase Agreement*

Beaufort has a 15-year PPA with Duke Energy Progress, LLC which expires December 22, 2030.

***Bloom***

Bloom is a 178 MW wind facility consisting of 54 Vestas V117-3.3 MW turbines. Bloom is located on 15,000 acres of privately owned lands approximately 20 miles south of Dodge City in Ford and Clark Counties, Kansas.

*Commercial Arrangement: Financial Proxy Revenue Swap Agreement*

Capital Power owns and operates Bloom under a 10-year, fixed revenue contract with Allianz Risk Transfer, a subsidiary of Allianz SE, covering most of the facility's output (approximately 93%, based on actuals since commercial operations commenced). Under the contract, Capital Power swaps the market revenue of the facility's proxy generation for a fixed annual payment until April 2026. Surplus energy above the proxy volume is sold unhedged as merchant. In addition, the project secured tax equity financing from Goldman Sachs Alternative Energy Investing Group as TEI, which funded an initial 65% of Bloom costs when the facility achieved commercial operation in June 2017. The TEI will receive the majority of the tax benefits and approximately 33% of cash distributions until it has reached its target yield, after which time the project will revert so that Capital Power will receive the majority of the tax benefits and cash flows.

***Arlington Valley***

Arlington Valley is a 580 MW combined cycle natural gas generation facility located approximately 50 miles southwest of Phoenix, Arizona. The facility was commissioned in 2002 and acquired in late 2018.

*Commercial Agreement: Tolling Agreement and Heat Rate Call Option*

Arlington Valley sells capacity and electricity to an investment grade load serving utility (credit ratings of A2/A- from Moody's and S&P, respectively) under a tolling agreement during the summer months through 2025. For the non-summer months through 2025, Arlington Valley entered into a Heat Rate Call Option with another investment grade counterparty to produce energy when called upon. When not called under the Heat Rate Call Option, Arlington Valley may sell energy into the DSW or the CAISO wholesale markets during the non-summer months.

***New Frontier***

New Frontier is a 99 MW greenfield wind project in McHenry County, North Dakota. It is located approximately 25 miles southeast of Minot. The facility consists of 29 Vestas V126-3.45MW wind turbines on 87-meter towers. The project commenced commercial operation in December 2018. In addition, the project secured net tax equity financing of $125 million (US$92 million) from an investment grade US financial institution on December 31, 2018.

*Commercial Arrangement: Financial Swap Agreement*

Meadowlark Wind I LLC, the New Frontier project company, has entered into a financial hedge agreement with an investment grade U.S. financial institution that covers approximately 87% of the facility's output. The hedge is fixed-price for a fixed notional quantity of energy and settles at the MISO Minnesota Hub. The financial hedge has a twelve-year term that began on March 1, 2019. The remainder of the energy output is sold unhedged as merchant.

***Buckthorn Wind***

*Commercial Arrangement: Contract for Differences (CFD)/REC off-take and Financial Swap Agreement*

Buckthorn Wind is a 100.5 MW wind facility located approximately 60 miles south of Dallas in Erath County, Texas. The facility began commercial operations in January 2018 and operates in the liquid Electric Reliability Council of Texas (ERCOT) North region, which is situated between most of the wind generation in ERCOT-West and the Dallas load center. The ERCOT-North region has strong fundamentals with high likelihood of baseload generation requirements and is one of the fastest growing regions in the United States. Buckthorn Wind has two financial hedges with an investment grade US financial institution, the first of which is a 20-year (through early 2038) fixed-price contract for differences for 55% of the project's as-generated energy output and RECs, the second of which is a 13-year (through early 2031) financial swap agreement for approximately 85% of the remaining 45% of energy output. Both financial hedges are fixed-price (the second hedge for a fixed notional quantity of energy) and settle at the ERCOT North Hub. Capital Power acquired Buckthorn Wind from private investors in April 2020.

The Buckthorn Wind facility is comprised of 29 Vestas wind turbines.

***Cardinal Point***

Cardinal Point is a 150 MW facility located in the McDonough and Warren Counties, Illinois. Commercial operation of the facility began on March 16, 2020. In addition, the Company received approximately $221 million (US$157 million) in tax equity financing on March 26, 2020, net of issue costs of $3 million (US$2 million) associated with the financing, from two U.S. financial institutions in exchange for Class A interests of a subsidiary of the Company.

*Commercial Arrangement: Financial Swap Agreement*

Commencing January 1, 2021, Capital Power will operate Cardinal Point under a 12-year financial swap agreement with an investment grade U.S. financial institution covering approximately 85% of the facility's output. The hedge is fixed-price for a fixed notional quantity of energy, and settles at the AMIL.BGS6 Load Zone. The remainder of the energy output is sold unhedged as merchant. In addition, the project has secured three 15-year, fixed-price REC contracts with three Illinois utilities for approximately 95% of the forecast RECs, with the balance marketed on a merchant basis. Prior to January 1, 2021 the energy output of Cardinal Point is unhedged.

**Projects Under Construction or in Advanced Stages of Development**

As of the date of this AIF, the following projects are under construction or in advanced stages of development:

***Whitla 2***

Whitla is a fully permitted 300 MW wind development in the County of Fort Mile, Alberta. Phase 1 of the Whitla development, Whitla 1, is a 202 MW wind facility that reached commercial operation on December 1, 2019. See "Business of Capital Power – Alberta Contracted Facilities – Whitla 1". Whitla 2 is a 97 MW facility with a target in-service date in the fourth quarter of 2021.

*Commercial Arrangement: Merchant Facility*

The Company is in active discussions with potential commercial and industrial customers for renewable offtake contracts from Whitla 2.

***Whitla 3***

Whitla 3 is a proposed 54 MW wind project, located in the County of Forty Mile, Alberta, and is the third phase of the Company's Whitla wind facility. Whitla 3 will consist of 15 Vestas V-136 3.6 MW wind turbines, the same technology in operation at Whitla 1 and to be installed for Whitla 2. Whitla 3 has an estimated capital cost of $92 million and is expected to be constructed concurrently with the Whitla 2 project beginning in summer 2021 with a commercial operation date in December 2021.

Whitla 3 will generate carbon credits that can be used to hedge against the Company's carbon compliance costs from its Alberta thermal generation facilities. The Company is in active discussions with commercial and industrial customers for renewable offtake contracts for Whitla 2 and will now include Whitla 3.

The Company has initiated the permitting process for Whitla 3 with the AESO and filed its AUC application in September 2020.

***Strathmore Solar***

Strathmore Solar is a proposed 40.5 MW solar project, located in Strathmore, Alberta. The Company expects that construction will begin in the second quarter of 2021, with a COD in January 2022. All of the energy and renewable energy credits generated by its Strathmore Solar project will be sold under a 25-year PPA with a large national Canadian company.

***Enchant Solar***

Enchant Solar is a proposed 75 MW solar project located within the municipal district of Taber, Alberta. Subject to permitting and regulatory approvals the project is expected to reach commercial operations in the second half of 2022 at an expected capital cost between $100 million to $105 million.

***Bear Branch Solar***

Bear Branch Solar is a proposed 35 MW solar project, located in Stokes County, North Carolina. Construction of the project is expected to begin in late 2021 or early 2022, with commercial operations expected in the fourth quarter of 2022. The Company will operate Bear Branch Solar under a 20-year power purchase agreement with Duke Energy Carolinas.

***Hornet Solar***

Hornet Solar is a proposed 75 MW solar project, located in Gaston and Lincoln Counties, North Carolina. Construction of the project is expected to begin in late 2021 or early 2022, with commercial operations expected in the fourth quarter of 2022. The Company will operate Hornet Solar under a 20-year power purchase agreement with Duke Energy Carolinas.

***Hunter's Cove Solar***

Hunter's Cove Solar is a proposed 50 MW solar project, located in Rutherford County, North Carolina. Construction of the project is expected to begin in late 2021 or early 2022, with commercial operations expected in the fourth quarter of 2022. The Company will operate Hunter's Cove Solar under a 20-year power purchase agreement with Duke Energy Carolinas.

***Repowering of Genesee 1 and 2***

The repowering of Genesee 1 and 2 will provide an additional 560 MW of net capacity totaling 1360 MW. The upgraded units will use best-in-class air cooled J-series NGCC technology from Mitsubishi and will be 30% hydrogen ready when repowering is completed and upgradable to 95% in the future at minimal cost. The units will also be carbon conversion ready. The project has an expected capital cost of $997 million with project returns expected to exceed the Company's hurdle rates and contributing approximately $0.70 in AFFO per share on average in the first five full years.

**Portfolio Optimization**

Capital Power's commodity portfolio is comprised of exposures resulting from ownership of generation assets or financial interest in generation assets as well as transactions with other market participants. These exposures include electricity, natural gas and environmental commodities. All commodity risk management and optimization activities are centrally managed by Capital Power's Commodities teams. Portfolio optimization includes activities undertaken to both manage Capital Power's exposure to commodity risk and enhance earnings. Overall commodity exposure within the portfolio is managed within limits established under Capital Power's risk management policies and procedures.

Capital Power manages output from its commercial facilities, contracted facilities with residual commodity exposure and any acquired PPAs on a portfolio basis. Capital Power transacts physical and financial forward contracts that are generally non-unit specific, reducing exposure to plant specific operating characteristics. Capital Power also takes specific and limited positions in the power, natural gas and environmental commodities markets outside of Alberta to manage portfolio risk and develop and maintain capability to support Capital Power's growth strategy and to a lesser extent generate profits.

The Commodities teams:

- manage price and volume risk in Capital Power's commodity portfolio;
- set generation unit offer strategy for electricity and ancillary services;
- acquire and schedule delivery of natural gas supply used to generate electricity; and

- ensure compliance with existing and emerging market based environmental regulations by transacting in environmental commodities markets to proactively manage compliance risks and costs.

Capital Power controls its commodity management and optimization activities by measuring and reporting commodity portfolio risk and validating transactions. Capital Power uses mark-to-market valuation and VaR techniques to assess the risk of its commodity portfolio. The VaR methodology is a statistically-defined, probability-based approach that takes into consideration market volatilities and risk diversification by recognizing offsetting positions and correlations between exposures. This technique utilizes historical data and back testing to assess market risk arising from possible future changes in commodity prices. In addition, Capital Power subjects the portfolio to stress testing by using pre-defined scenarios to estimate maximum potential losses under abnormal market conditions.

**Competitive Environment**

Capital Power typically competes with other independent power producers, financial entities, utilities, hedge funds, public and private investors, infrastructure funds, etc. in the energy and environmental commodities markets and for asset development and acquisition.

Capital Power's competitive environment is determined in large part by the types of power markets in which it operates. Capital Power has generation assets in the Alberta deregulated wholesale power market and in regulated and deregulated wholesale power markets in BC, Ontario, North Carolina, Alabama, Kansas, New Mexico, North Dakota, Texas, Illinois and Arizona. For an overview of the structure of these markets, see "Regulatory Overview".

In deregulated wholesale markets, Capital Power competes with other power producers by leveraging its operational excellence and market intelligence, enabling it to offer energy, capacity and ancillary services into the market at a competitive price and with high availability. Capital Power also competes for long-term PPAs, offtakes, tolls, hedges, etc., to supply credit-worthy counterparties.

Within Alberta, between its merchant generation facilities and the generation it controls through joint venture agreements, Capital Power controls dispatchable merchant generation capacity in Alberta representing approximately 11.8% of the market (approximately 7.3% as of December 31, 2020, prior to the expiry of the Genesee 1 and 2 PPA at the end of 2020).

In regulated, bi-lateral and centrally-planned markets, Capital Power competes for long-term PPAs to supply credit-worthy counterparties, typically the incumbent utility or a government agency by: (i) developing projects that meet counterparty requirements (for generation type, location and capacity); (ii) securing suitable sites; and (iii) focusing on being a low-cost developer and efficient operator. Capital Power also competes to acquire contracted assets or development projects. Capital Power expects to compete for contracted opportunities across Canada and the US.

***Environmental Social and Governance Disclosure***

Capital Power's ESG reporting practices reflect our belief in the importance of transparency and the resilience of our business strategy as we transition to a low-carbon economy. We undertake a number of voluntary initiatives that go beyond legislative and regulatory disclosure requirements. Some examples include combining our financial and ESG reporting in a single Integrated Annual Report which aligns to the Global Reporting Initiative and Sustainability Accounting Standards Board. Additionally, we voluntarily report on climate change and water security-related disclosures through the Carbon Disclosure Project and our annual Climate Change Disclosure Report, recognizing the recommendations of the Financial Stability Board's Task Force on Climate-related Financial Disclosures.

We measure and report our performance on an ongoing and comprehensive basis and, in 2020, 20% of Executive short-term incentive pay was based on the company meeting its ESG targets. The Board receives quarterly reports on ESG metrics, which are also reported in the 2020 Integrated Annual Report.

In 2020, and in early 2021, we received the following recognition for our ESG activities:

- Received strong ESG disclosure scores: "A-" for Climate Change Disclosure and "B" for Water Security Assessment from the Carbon Disclosure Project
- Exceeded our 30% gender diversity goal with 44% and 43% women on the Board and Executive respectively
- Named one of World's Most Ethical Companies by Ethisphere in 2020
- Named 2020 Best ESG Responsible Energy Producer in Canada by Capital Finance International
- CCGG 2019 Gavel Award Winner for Best Disclosure of Corporate Governance and Executive Compensation Practices
- 2020 Finalist for two S&P Global Platts Energy awards: "*Excellence – Power*" and "*Lifetime Achievement*," out of 300 nominees from 43 countries around the world
- Inclusion in Bloomberg's 2021 Gender Equality Index recognizing our commitment to support gender equality and transparently disclose our progress

## Environmental Regulation

Many of Capital Power's operations are subject to extensive federal, provincial, and state laws, regulations and guidelines relating to the generation of electricity, protection of the environment, and the health and safety of employees. These laws, regulations and guidelines apply to air emissions, water usage, wastewater discharges, wildlife and habitat protection, hazardous material handling, the storage, treatment, and disposal of waste and other materials, and remediation of sites and land-use responsibility.

Capital Power's thermal assets are emitters of various air pollutants including $CO_2$, $NO_x$, $SO_2$, mercury, and particulate matter. Capital Power is required to comply with all licenses and permits and federal, provincial and state requirements, including programs to reduce or offset air emissions. Compliance with new regulatory requirements may require Capital Power to incur significant capital expenditures or additional operating expenses, or cause operations at certain facilities to end prior to the end of their useful economic lives. Failure to comply with such regulations could result in fines, penalties or the curtailment of operations.

Capital Power complies with regulatory requirements while working to reduce its environmental impact. The following outlines current environmental regulations and corporate initiatives that have or may have a significant impact on Capital Power's operations.

### *Canadian Federal Government*

*Greenhouse Gas Regulation – Coal Generation*

The GHG Regulations apply a performance standard of 0.420 tonnes of $CO_2$ emissions per gross output in MWh per year (t CO2/MWh), which is intended to represent the intensity level of natural gas combined cycle technology. On February 17, 2018, the federal government published the final amendments to the Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations. Under these amendments, coal units will have to meet the performance standard of 0.42 t CO2/MWh on December 31, 2029. Alberta's date for the phase out of use of coal for electricity generation is December 31, 2030.

*Greenhouse Gas Regulation – Natural Gas Generation*

On February 17, 2018, the Government of Canada enacted Regulations Limiting Carbon Dioxide Emissions from Natural Gas-fired Generation of Electricity. Under the regulations, coal units converted to natural gas (coal-to-gas, or CTG) units were granted 0, 5, 8 or 10 years of additional operational life beyond their coal-fired end-of-useful-life (EoUL) established under previously established regulations for coal-fired generation. The duration of additional operational life for CTG Units is based on their environmental efficiency as measured in tonnes of carbon dioxide per MWh. Boilers that meet more stringent efficiency requirements are permitted to operate up to 10 years post EoUL**.**

For gas turbines, large units are subject to a 0.42 tonne of carbon dioxide per MW (tCO2/MWh) standard, while small units are subject to a 0.550 tCO2/MWh standard (gross basis). Small units are those that are rated equal to or less than 150 MW; large units are rated greater than 150 MW. The regulation included provisions grandfathering existing units such that Clover Bar, Joffre, Shepard and Island Generation are not impacted by the standards.

*Pan-Canadian GHG Framework*

The *Greenhouse Gas Pollution Pricing Act (GGPPA)* sets out a federal carbon pricing system based on a two-pronged approach: (1) an economy-wide charge on fossil fuels that are consumed within a province or territory, which will be administered by the Canada Revenue Agency and (2) an output-based pricing system that applies to large industrial facilities (OBPS Regulations), which is administered by ECCC. The GGPPA among other things, list the jurisdictions in which the federal fuel charge will apply and the rates at which it will apply.

Under the Framework, provinces and territories are enabled to design their own pricing systems that are equivalent to the federal standard. Under the GGPPA, the federal carbon price started at $20 per tonne in 2019 and increases by $10 per tonne per year until reaching $50 per tonne in 2022. To minimize uncertainty, the federal price will remain in effect at least until 2022.

The governments of Alberta, Saskatchewan, Manitoba and Ontario have put forward constitutional challenges of the GGPPA. The Supreme Court of Canada's hearing of these appeals was heard on September 22 and 23, 2020. The timing for its ruling on the matter is unknown.

British Columbia, Alberta, Quebec, Nova Scotia, Prince Edward Island, Newfoundland and Labrador, and the Northwest Territories have all implemented, or are implementing, carbon pollution pricing systems which were found to be meeting the federal benchmark and were not subject to the federal carbon pricing system in 2019. Alberta's TIER regime, which applies to large power generation, was deemed compliant with federal standards for 2020.

On September 20, 2020, the Minister of the Environment and Climate Change informed the governments of Ontario and New Brunswick that their carbon pollution pricing systems for industrial facilities meet the federal government's minimum stringency benchmark requirements for equivalent pricing carbon pollution for the sources that they cover. As a result, the Government of Canada will not apply its OPBS in both provinces. The Government of Canada will cease to apply the federal carbon pricing system for industry in Ontario and New Brunswick at a date to be determined in consultation with each of the two provincial governments. The federal OBPS remains in effect in Ontario for Capital Power's Ontario facilities until the transition to Ontario's carbon pricing framework for industrial facilities.

The Government of Alberta repealed its economy-wide carbon tax on May 30, 2019. The Government of Canada therefore added Alberta to the list of provinces that would be subject to the federal carbon pricing system of the GGPPA in order to implement the fuel charge. For Alberta, the rates became effective on January 1, 2020, with future increases taking effect in April of each year for liquid, gaseous and other solid fuels. Capital Power facilities are exempt from the federal fuel charge since they are covered by TIER.

On July 2, 2020, ECCC released the Carbon Pollution Pricing: Considerations for Protocol Development in the Federal Greenhouse Gas Offset System discussion paper (Discussion Paper). The Discussion Paper outlines the main elements of the federal GHG Offset System, with a focus on protocol development. ECCC released the list of Recognized Offset Programs and Protocols. The list includes the five protocols from Alberta.

*December 2020 Federal Climate Plan and Proposals*

On December 11, 2020, the Government of Canada released its updated climate plan (the Federal Plan). The Federal Plan sets out a range of measures and proposed policies across multiple sectors that are intended to enable Canada to meet and exceed its current 2030 greenhouse gas reduction commitments under the Paris Agreement, and also set Canada on a path to achieving net-zero by 2050. Among other things, the Federal Plan proposes to increase the carbon price by $15 per tonne per year after 2022 until achieving a price of $170 per tonne in 2030; review standards used to assess equivalence of provincial carbon frameworks; make investments to advance smart renewable energy and grid modernization projects to enable the clean grid of the future; work with provinces and territories to help build key intertie projects; and make funding available and develop strategies to support further deployment of various decarbonization technologies including carbon capture, utilization and storage and hydrogen.

Management has initiated an assessment of the potential impacts the proposed elements of the Federal Plan may have for Capital Power's existing facilities and prospective interests in its Canadian markets, and intends to participate in forthcoming processes, which have yet to be scheduled, to discuss the key elements proposed as part of the Federal Plan.

***Alberta***

*Off-Coal Agreement*

On November 24, 2016, Capital Power announced it had reached an agreement with the Government of Alberta relating to the 2030 phase-out of coal emissions. Under the agreement, as compensation for the capital that Capital Power invested in coal generating assets that will be stranded effective December 31, 2030, Capital Power is to receive cash payments from the Government of Alberta of $52.4 million annually for 14 years, commencing July 31, 2017, for a total of $734 million. The Government of Alberta conducted an audit on the calculation of net book values driving the compensation payments and has withheld $2 million from the 2017, 2018 and 2019 payments. The Company is disputing the withholding but has reduced the amounts recorded related to the compensation stream to reflect the uncertainty. This has resulted in a reduction of $1 million to the government compensation amount for each of 2019, 2018 and 2017. Capital Power is required to cease coal-fired emissions from Genesee 1, Genesee 2 and Genesee 3 by the end of 2029. In December 2020, Capital Power announced its plan to cease coal-fired operations by the end of 2023, six years earlier than required by the Federal regulations.

*Climate Change Strategy*

On January 1, 2020, the Government of Alberta replaced the Carbon Competitiveness Incentive Regulation (CCIR) with the Technology Innovation and Emissions Reduction Regulation (TIER) for large industrial emitters. Under TIER, the carbon price for large emitters was $30 per tonne in 2020. On November 5, 2020, Alberta Environment and Parks announced that the 2021 carbon price under TIER will be $40 per tonne of carbon dioxide equivalent ($CO_2e$).

To meet TIER requirements, facilities can physically reduce their emissions or:

- use credits from facilities that have reduced their emissions to below their respective targets;
- use emission offsets from organizations that are not regulated by TIER, but which have voluntarily reduced their emissions; or
- pay into the TIER Fund at $30/ $tCO_2e$ in 2020.

Specific to the electricity industry, the benchmark is set at 0.37 tCO2e/MWh.

If a facility's emissions exceed 0.37t$CO_2$e/MWh, the resulting compliance obligation can be met through the use of Emission Performance Credits (EPCs) or offsets, or through payment to the Technology Innovation and Emissions Reduction Fund. TIER imposes limits on the use of EPCs and offsets within each compliance year, which were 60% in 2020. TIER also phases in legislated expiry periods for credit vintages starting in the 2020 compliance period until reaching a go-forward 8-year vintage expiry period in 2022. Vintages 2016 and older can only be used for up to 40% of the total compliance obligation of a facility for 2020 and 2021 compliance and will expire after the 2021 compliance submission in June 2022.

Capital Power's 2020 TIER compliance obligation must be paid in Spring 2021. The Company intends to purchase fund credits at the 2020 compliance year cost of $30 per tonne in order to meet substantially all of its 2020 obligation. The offsets and emission performance credits in inventory will be saved for use in future years when the carbon price associated with the TIER Fund is expected to increase. Therefore, the approximate total cost of compliance for Capital Power for the 2020 reporting period, split by Capital Power's generating assets for the 2020 reporting period (under TIER), is comprised as follows:

- Genesee 1 and 2 are expected to pay approximately $4.0 million. This figure is net of the compliance obligation that was recoverable from the PPA buyer under the terms of the PPA.
- Genesee 3 is expected to be approximately $52.3 million.
- Genesee Mine has opted into the TIER program and the cost for 2020 is expected to be approximately $0.1 million.
- Clover Bar is expected to be approximately $2.1 million.
- Shepard Energy Center is expected to be approximately $0.1 million (representing Capital Power's 50% interest).

Under the operating approvals for Genesee 3, Capital Power was required to offset its emissions to the equivalent of a natural gas combined cycle facility. This requirement is now met through regulation under the current TIER program. Capital Power also voluntarily offsets 100% of its Scope 2 emissions at the Calgary and Edmonton offices by retiring offsets and RECs against those emissions.

Capital Power has been acquiring offsets for over a decade and has entered into more than 85 offset purchase agreements across North America. Capital Power invested approximately $42 million in Alberta Compliance offsets in 2020.

*Air Emission Regulations*

The Federal and Alberta governments both support coal-to-gas conversion to reduce emissions, maintain reliability, and help avoid stranded assets. Air emissions from the Alberta electricity sector are managed by the 2003 CASA Framework, which when developed did not anticipate CTG Units. In 2018, to address this gap, the Alberta government developed NOx standards for CTG Units based on recommendations made by CASA.

On February 20, 2018 the Government of Alberta issued the CTG $NO_x$ Policy. According to the CTG $NO_x$ Policy, CTG subcritical units' $NO_x$ emissions would be limited to 50% of their 2003 CASA baseline emissions. Converted Genesee 1 and 2 units to natural gas must meet 1.06 kg/MWh (net basis). No $NO_x$ emission reductions would be required for supercritical units until the federal EoUL of the converted units. To demonstrate compliance with the $NO_x$ emission standards, units will have an annual emission intensity test. Exceeding the maximum annual emission intensity would be considered an environmental non-compliance.

The CASA 5-Year Electricity Framework Review began in July 2018. The review is undertaken by a multi-stakeholder committee comprised of representatives from the electricity industry, cogeneration operators, the Government of Alberta, and non-governmental organizations. The intent of the review is to evaluate the current regulatory framework for air pollutants, and seek consensus on recommendations to the

Government of Alberta for appropriate actions to control emissions. The CASA 5-year review has reached non-consensus on $NO_x$ standards for new gas-fired turbines. The non-consensus $NO_x$ standards report was forwarded at the end of 2018 to Alberta Environment and Parks for consideration.

***BC***

The Government of BC announced plans, effective April 1, 2018, to escalate its $30 per tonne carbon tax by $5 per tonne per year until it matched the Federal carbon tax floor of $50 per tonne in 2022. In early 2020, the BC Government suspended scheduled escalation of the carbon tax as part of BC's COVID-19 pandemic relief policies, and advised that BC's carbon tax rate will remain at $40 per tonne until further notice. Capital Power's operations in BC do not have any carbon tax exposure.

***Ontario***

On July 4, the Government of Ontario published their final Greenhouse Gas Emissions Performance Standards (EPS). The first compliance period is not in effect until the federal government removes Ontario from the GGPPA, which will exempt Ontario from being subject to the output-based pricing system.

The EPS was created under the Emissions Performance Standards Regulation. The EPS includes excess emissions units (EEUs) and emissions performance units (EPUs) as compliance instruments which can be used to satisfy a facility's compliance obligation. EEUs must be distributed to facilities beginning in the first year after the first compliance period. The cost EEU will match the federal carbon price. The EPS did not consider offsets.

On December 16, 2020, the Government of Ontario started consultation with stakeholders regarding the transition of Ontario industrial facilities from the Federal OBPS to the provincial EPS. Capital Power is participating in this process.

Capital Power's Ontario facilities have power purchase contracts with provisions that trigger amendments as a result of changes in GHG cost, the effect of which will enable recovery of most of the imposed federal or provincial carbon compliance costs.

***United States***

*Greenhouse Gas Regulation*

The US EPA's Cross-State Air Pollution Rule requires 28 eastern states to reduce $SO_2$ and $NO_x$ emissions from power facilities to enable downwind states to meet federal air quality standards. Risk to the Company's operating assets is minimal given North Carolina's removal from the ozone program in 2016, which has led to decreased compliance costs for Southport and Roxboro. Also, with the ceasing of operations and decommissioning of Roxboro and Southport, risk to Capital Power's assets will be minimized further. The North Carolina facilities and Decatur will continue to purchase allowances for annual $SO_2$ and $NO_x$ emissions, which totaled approximately $16,000 for 2020.

On July 8, 2019, the US EPA published the final Affordable Clean Energy Rule (ACE) to repeal and replace the Clean Power Plan (CPP). Under ACE, states are required to conduct a unit specific evaluation of the potential for heat rate improvements at existing fossil fuel facilities, which will then be used to establish emission standards for units within their state. States have discretion to consider additional factors such as remaining useful life, even if consideration of these factors would result in the application of the performance standard in a less stringent manner than would otherwise be required. The final rule prohibits state plans from allowing averaging or trading among units for compliance purposes.

ACE took effect on September 6, 2019 and directed states to submit compliance plans within 3 years. An assortment of parties, including twenty-five states, environmental and public health NGOs, and a number of utility companies subsequently challenged ACE in the D.C. Circuit Court. On January 19, 2021, the Court issued a ruling that struck down the validity of ACE and remanded it back to the US EPA. President

Biden subsequently directed the US EPA to review ACE, and the US EPA is now expected to promulgate new $CO_2$ standards for existing power plants under the Clean Air Act.

*Regional Greenhouse Gas Initiative (RGGI)*

The RGGI is a regional cap-and-trade program to reduce $CO_2$ emissions from power facilities in nine northeastern states. The original Memorandum of Understanding among the participating states established a programmatic review every four years, including evaluating of the cap level.

RGGI's Final Model Rule extends the program through 2030 and includes a lower cap starting in 2021 and an annual decline in the regional cap through 2030, which will result in a 30 percent reduction from the 2020 cap), full bank adjustment for pre-2021 vintage allowances, emissions containment reserve and trigger price, and the elimination of certain offset categories. The cost containment reserve will continue to make allowances available when prices are high. The emissions containment reserve will divert allowances from the auction if prices are low.

New Jersey and Virginia have undertaken a process to implement a cap-and-trade program starting in 2020, with the intent of linking with RGGI.

On June 17, 2019, New Jersey DEP finalized the two rules to rejoin RGGI and to distribute RGGI auction proceeds. The first rule establishes an initial CO2 emissions cap of 18 million short tons in 2020 that will decline to 12.6 million short tons by 2030, a 30 percent decline that is consistent with the RGGI Model Rule. The second rule establishes a framework for the state to distribute proceeds from RGGI actions.

On May 27, 2019, Virginia finalized regulations establishing an initial carbon cap consistent with the current RGGI budget. While the regulations are "trading ready" to allow RGGI and the Virginia programs to be linked, the Virginia legislative assembly passed a provision to the state's budget prohibiting Virginia from participating in the program. It is unclear what the next steps will be.

*Air Emissions Regulation*

Roxboro and Southport have been assessed civil penalties for failure to submit Prevention of Significant Deterioration (PSD) permits for $SO_2$ emission increases under the New Source Review provisions of the Clean Air Act, and for failure to operate best available control technology at the plants. The plants underwent a $NO_x/SO_2$ Boiler Control Retrofit and Increased Wood/Biomass Firing Project completed in 2011. The project air permit application was submitted in 2008, and projected emissions at that time did not indicate PSD permitting would be required. However, following a detailed analysis of continuous emissions monitoring data (CEMS) from the plants for calendar year 2015 it was ultimately determined in conjunction with the North Carolina Department of Air Quality (NCDAQ) that $SO_2$ emission increases as a result of fuel blend changes which increased tire derived fuel throughput, in fact exceeded the PSD permitting threshold. PSD permit applications were submitted NCDAQ in 2017, subsequently amended and resubmitted. Roxboro and Southport facilities finalized a Special Order of Consent (SOC) agreement with the North Carolina Department of Air Quality. The SOC includes a revised $SO_2$ lb/mmBtu limit at both facilities through the duration of the existing PPA.

## Health, Safety and Environment

### *Health, Safety and Environment Policy*

If not properly managed, Capital Power's activities with respect to the construction, operation, and maintenance of power generation and related facilities can present significant risks to human health, safety, and the environment. The Health, Safety and Environment Policy (the Policy) is intended to create, implement, and maintain a Health, Safety and Environment (HSE) Management System that enables minimization of occupational injury and illness, and negative impacts to the environment, in a socially responsible and sustainable manner by ensuring:

- the promotion of a zero-injury safety culture including the promotion and maintenance of the physical, psychological, and social well-being of all employees;
- environmental responsibility;
- compliance with all applicable laws and regulatory requirements;
- proactive identification and management of health, safety and environment-related risks;
- the continuous review and improvement of the Policy and the HSE Management System;
- appropriate goals are established, and performance is monitored in respect of those goals;
- contractors align with the Policy; and
- employees, contractors and third parties understand their HSE responsibilities and possess the required competencies and training to perform their job responsibilities, including hazard identification, hazard control and monitoring of hazard control effectiveness.

Every Capital Power employee and contractor is responsible for Capital Power's environmental performance, and the health and safety of themselves and their fellow workers.

Capital Power manages its HSE risks through a company-wide HSE Management System and measures its HSE performance against recognized industry and internal performance measures. Compliance audits are conducted by internal and external auditors to verify that the HSE management program meets the regulatory requirements for the business.

Board approved HSE objectives are established annually to promote Capital Power's HSE stewardship and are measured through the HSE Performance Index. The Index measures performance by using a combination of leading and lagging performance indicators. Where lagging indicators measure the "end-results", leading indicators recognize and focus attention on proactive activities and continuous improvement.

***Health, Safety and Environment Initiatives***

To manage HSE risks and promote a zero-injury and environmentally responsible culture, Capital Power engages in the following activities:

- Conducts regular HSE audits of its operations and construction activities, tracking items of non-compliance and reporting on progress to the HSE Committee of the Board.
- Requires, and encourages the reporting of hazards, near miss events and incidents. These events are tracked and analysed for trends, and preventative actions are taken because of those trends.
- Delivers ongoing HSE training to all employees of Capital Power. Training is required for all employees in field or operating positions and the completion of such training is tracked and monitored by Capital Power.
- Regularly reviews HSE regulatory updates to ensure awareness of upcoming regulatory changes.

Specific environmental initiatives and achievements include the following activities:

- Capital Power launched the Genesee Performance Strategy, committing up to $50 million in capital investment to the initiative to reduce carbon emissions at the Genesee facilities by 12% by 2021.

- Capital Power participated in Alberta's REP through the Whitla 1 wind project.

- Capital Power is moving forward with Whitla 2 and Whitla 3 wind projects.

- Capital Power is moving forward with Strathmore Solar and Enchant Solar in Alberta, as well as, Hornet Solar, Hunter's Cove Solar and Bear Branch Solar in North Carolina.

- Shepard is being used as the test site for the natural gas track of the prestigious $20 million NRG COSIA Carbon XPRIZE, a global competition to develop breakthrough technologies that remove carbon dioxide from the atmosphere and convert it into valuable products. C2CNT, in which Capital Power owns 40% of the equity, is a contestant in the XPRIZE. The winners of the XPRIZE are expected to be announced before the end of 2021.

- Capital Power plans to complete the first of three phases of the Genesee Carbon Conversion Centre, the largest commercial scale production facility of CNTs at its Genesee facility in the first half of 2022.

- Capital Power continues to serve on the Board of the West Central Airshed Society. This Society monitors and promotes effective management of air quality within the Airshed zone. The zone is approximately 62 thousand square kilometres and spans from just west of Edmonton to the BC border.

- Capital Power co-chairs the AISC. The AISC is a committee of the Canadian Electricity Association, Generation Council and is comprised of Generation Council company representatives. The committee serves to monitor, engage with, and respond to federal government initiatives and policies regarding climate change and air quality issues. The AISC worked closely with the Government of Canada on the reduction of $CO_2$ emissions from coal-fired generation of electricity regulations, the Canadian Ambient Air Quality Standards, and the Base Level Industrial Emissions Requirements.

- Capital Power continues to reclaim land from previously mined areas and return it to productive farmland and wildlife habitat.

- A long-term regional biomonitoring program encompassing the Genesee facilities is one of the largest programs of its kind in Canada. Since 2004, its air, water and wildlife studies have found no significant changes in land, natural water bodies or ambient air quality.

- Capital Power continues to advance its dual-fuel capability project with plans to increase natural gas capability at Genesee 3 to 100% by 2022 for the unit. In parallel, the Company continues to pursue repowering of Genesee 1 and 2 that would transition both units to 100% natural gas by 2023/2024. Once Genesee 1 and 2 are burning 100% natural gas under the repowering plan, the Genesee coal mine will be closed and Genesee 3 will burn 100% natural gas by 2023.

- Capital Power minimizes the amount of coal ash going to the landfill by selling it for use in cement production.

Specific health and safety initiatives and achievements include the following activities:

- Achievement of an HSE Performance Index of 1.08. This is the 7th consecutive year the Index has finished at or above the target of 1.0.

- In Q1 and Q2 2020, Company wide implementation of the "See It - Say It - Solve It" Attention to Prevention Campaign to increase event reporting. The purpose is to raise awareness on the importance of hazard identification and near misses so action can be taken proactively, to avoid injuries, and make our HSE program stronger. The roll out included all plant and office locations.

The program included easy to fill out booklets, several campaign toolbox talks, information posters and a formal presentation to all employees led by our HSE advisors.

- An update to the Event Management Standard which is designed to be a concise and user-friendly guide on how to react and who to notify, when a near miss or incident occurs. The standard was implemented in Q3 of 2020, supported by a rollout plan that included a company wide communication and department specific meetings.

- In 2020, the Corporate Safety Calendar program was developed by the HSE department. The calendar identifies a three-year cycle of mandatory monthly HSE topics applicable to the safe operation of the Company. The topics are prepared and communicated from the HSE department directly to supervisors with the requirement to communicate the topic to all affected employees during regular scheduled monthly HSE meetings.

- Establishment of a single standardized corporate HSE training matrix that identifies and assigns regulatory and site specific HSE training requirements by position. These were completed for all positions within the Company. The matrix is managed and maintained by the HSE department.

- Development and implementation of an online HSE Management System. This new platform makes it easy for stakeholders at any level of the organization to understand how HSE is managed by the Company, their specific roles and HSE responsibilities, and how to access specific HSE documents in an easy to use and interactive platform. The HSE Policy was updated at the same time which has been posted in the HSE Management System, in prominent locations at all Capital Power sites and offices, and on the external Capital Power website.

- Development of a mandatory Investigation 101 training program for leadership. The training is being rolled out through the end of 2020 and into 2021. Applying formal investigation training demonstrates continuous improvement which will reflect positively throughout the Company as it will improve the identification of causes and effective corrective actions to prevent reoccurrence.

- A Significant Event Review Committee which reviews incident investigations and conducts root cause analysis of recordable injury and serious near miss events. The Committee ensures investigations are completed in a timely manner and completed at a level appropriate for the incident, action plans are identified, and learnings are shared across the organization.

- All of Capital Power's offices, operating facilities and construction sites have HSE representatives or an established health and safety committee.

- Capital Power has updated its corporate, operations/construction and site-specific orientations for all operational facilities and offices. All employees and contractors have completed the new updated orientations applicable to them in 2020.

- HSE Improvement Plans were implemented at all facilities and for the construction and engineering group.

- Capital Power has formalized its Contractor HSE Management Process to include all four phases of construction and provides the opportunity to manage contractor performance from pre-qualification (supported by ISNetworld) right through to job completion. To ensure the standard was embedded into site work practices, HSE completed compliance audits during 2020 across all operated facilities.

- A Work Readiness-Warmup and Stretching Program was developed to help prevent musculoskeletal disorders (MSDs). The program was fully implemented in 2020.

**COVID-19 Pandemic Response and Planning**

Capital Power began preparation for the possibility of a pandemic as the COVID-19 outbreak unfolded in Asia and Europe by activating the Crisis Management Plan on March 6, 2020. COVID-19 was subsequently declared a pandemic by the World Health Organization, on March 11, 2020. Strategies and actions have been premised on the basis that the pandemic has an indefinite end, even with the development of a vaccine. Highlights of the response and ongoing planning includes the following:

- remote work was enacted March 13, 2020 with physical access to Capital Power sites restricted to critical infrastructure workers only;
- COVID-19 specific hazard assessments were completed for all work locations including our generating facilities, office locations, and work from home;
- fleet wide protocols and procedures were developed including signage, enhanced cleaning, site access screening protocols and temperature checks, COVID-19 specific personal protective equipment, a suspected case procedure including contact tracing, and return to work protocols for employees and contractors;
- altered shift changes to minimize staff interactions between critical infrastructure workers;
- COVID-19 health assessment tools including a dashboard that tracks key factors such as the effectiveness of proactive COVID-19 measures, staff wellness, and a regional health overview;
- developed remote capability and took the step to isolate the control rooms, the heart of each plant, and installed hospital-grade UV equipment to sterilize the rooms;
- the introduction of a Telemedicine program that provides 24/7 virtual healthcare support to employees and their families;
- provision of masks to employees and their families;
- COVID-19 education and awareness campaigns; and
- ongoing communication updates from senior management.

There have been no material COVID-19 related impacts to operations at any plant and no transmission of infection at any facility.

**Personnel**

As at December 31, 2020, the total number of persons employed by Capital Power is 827. As at December 31, 2020, approximately 674 full-time, part-time, temporary and casual employees work in Capital Power's Canadian operations and 153 are employed in Capital Power's US operations.

There are three Canadian labour unions, in four bargaining units, which together represent approximately 36% of Capital Power's Canadian labour force and approximately 30% of Capital Power's overall work force. The bargaining units are:

- the Civic Service Union 52, which represents administrative, technical, professional and information technology employees located in the Edmonton corporate office and Genesee power facility;
- the International Brotherhood of Electrical Workers Local 1007, which represents electrical, instrument and mechanical tradesmen, coal facility operators, equipment and crane operators, utility workers, tool servicemen and related employees at the Genesee power facility;

- the UNIFOR Local 829, which represents power engineers at the Genesee power facility; and
- the UNIFOR Local 1123, which represents shift engineers, electrical and instrumentation technicians and mechanical maintenance technicians at Island Generation.

Bargaining with UNIFOR 829 has started and will continue into Q1 of 2021. Bargaining with IBEW 1007 will start in Q1 of 2021. The following table provides a summary of the status of Capital Power's collective agreements in force. For clarity, Capital Power's collective agreements remain in force until they are replaced with new collective agreements reached through the bargaining process.

| Bargaining Unit | Location | Effective Date | Expiry date |
|---|---|---|---|
| CSU 52 | Edmonton, AB | December 23, 2018 | December 18, 2021 |
| IBEW Local 1007 | Edmonton, AB | December 22, 2018 | December 19, 2020 |
| UNIFOR Local 829 | Edmonton, AB | December 23, 2018 | December 19, 2020 |
| UNIFOR Local 1123 | Campbell River, BC | May 1, 2015 | April 30, 2021 |

## REGULATORY OVERVIEW

The following is an overview of the principal electrical power regulatory regimes to which Capital Power's current operations are subject. Environmental regulations affecting Capital Power's operations are discussed under "Business of Capital Power – Environmental Regulation".

### Alberta

Since January 1, 1996, new generation capacity initiatives in Alberta have been paid for by independent power producers and are subject to market forces, rather than rate payors. Regulated generating units, including those owned and operated by Capital Power, became subject to PPAs that were auctioned by the Government of Alberta to buyers in 2000. The Balancing Pool assumed the responsibilities of "PPA Buyer" for those generating units that were subject to a PPA not acquired in the initial 2000 auction, including Genesee 1 and 2. Power from PPA generating units and merchant generation is cleared through a wholesale electricity market. Power is dispatched in accordance with an economic merit order administered by AESO, based on offers by generators to sell power. The MSA is an independent entity responsible for monitoring the behaviour of market participants, including AESO and the Balancing Pool, investigating behaviour that may not be consistent with the fair, efficient and openly competitive operation of the market and enforcing compliance with all applicable legislation, regulations, and AESO and AUC rules. The AUC oversees electricity industry matters including approvals for construction and operation of new power facility and transmission facilities, and regulated rates for transmission, distribution and sale of electricity and natural gas to end-use consumers. The AUC is also responsible for approving AESO rules, for considering complaints and objections filed in respect of AESO rules, and for determining penalties and sanctions on any participant found to have contravened market rules.

The *Responsible Energy Development Act* created a single regulator, the AER, which became operational in June 2013. The AER is responsible for all oil, gas, oil sands and coal mining projects in Alberta, combining certain responsibilities previously assigned to the Energy Resources Conservation Board and Alberta Environment. The AER oversees energy development projects from the application through the reclamation phases of project development. Capital Power's coal mining related activities are subject to oversight by the AER.

Updates on the Government of Alberta's climate policy, discussed above can be found in the "Business of Capital Power – Environmental Regulation – Alberta – Climate Change Strategy" section including details on how that policy will impact the electricity sector in Alberta.

***Alberta Announcement Cancelling a Transition to a Capacity Market***

On November 23, 2016, the Government of Alberta announced that it would transition Alberta's electricity market design from an energy-only market to a capacity market. On July 24, 2019, that transition was cancelled.

Along with the cancellation, the Government of Alberta tasked the AESO to provide its advice on the existing market power mitigation framework and also whether changes to the existing market pricing framework were required. On April 23, 2020, the Government of Alberta announced acceptance the AESO's advice to maintain the current market power mitigation framework, and on August 28, 2020, announced acceptance of the AESO's advice to maintain the current pricing framework, including the existing offer cap, price cap, and price floor.

***Transmission Issues***

Under amendments to the EUA introduced in 2009 as Bill 50, the Government of Alberta was empowered to designate certain transmission projects as critical infrastructure, and to approve the need for such facilities. Bill 50 identified and described five projects deemed as CTI projects, including two North-South transmission reinforcement projects that would increase transmission capacity between the Edmonton and Calgary regions. These two projects are known as the West Alberta Transmission Line and the East Alberta Transmission Line. Another CTI project was the Fort McMurray West line, a 500kV line between the Genesee area and Fort McMurray that would increase transfer capability out of the Fort McMurray region. The AUC remains responsible for reviewing and approving other aspects of CTI projects.

Amendments to the EUA enacted in December 2012 repealed Bill 50, but grandfathered the existing CTI projects. The West Alberta Transmission Line and the East Alberta Transmission Line were both commissioned in December 2015. The Fort McMurray West line came into service in spring of 2019. The existing CTI projects increased the capacity and reliability of the transmission system and alleviated the potential for transmission congestion to arise between the areas of Alberta where Capital Power's generating stations are located and the loads drawing on the system.

The Alberta Government has also implemented changes to enhance the scrutiny by the AUC of the costs associated with new power lines. Amendments to the Transmission Regulation, and a Transmission Deficiency Regulation, which include provisions for approved cost estimate, a cost oversight management function and improved cost reporting, were approved in September 2014. Both the CTI projects referred to above and additional transmission work required to carry electricity within Alberta are costly. The increased scrutiny of these costs should ensure that the costs associated with transmission facilities are reasonable in the circumstances. If the costs are too high, some customers may choose to leave the system by producing their own electricity on-site.

***Transmission Line Losses***

In Alberta, the costs associated with transmission losses on the Alberta Interconnected Electric System are charged to generators in accordance with a methodology established by the AESO. The AESO established a line loss methodology in January 2006, which was updated in January 2008. Under that line loss methodology, the AESO calculated location-specific loss factors for generators or groups of generators by way of charges or credits within a range prescribed by the Transmission Regulation. All of Capital Power's generating facilities are assigned loss factors pursuant to the line loss methodology.

The line loss methodology was subsequently challenged and found not to comply with the requirements of the Transmission Regulation. In a January 2015 decision, the AUC ruled that the line loss rule did not comply, and that retroactive relief should be given to those who overpaid as a result, dating back to January 1, 2006.

Subsequent proceedings and decisions of the AUC resulted in the AUC establishing a payment process whereby Capital Power and other generators are being issued three separate tranches of invoices (for charges or credits as applicable) for the years 2014-2016 in October 2020 (which was to be settled prior to the end of 2020), 2010-2013 (which is to be settled by March 1, 2021), and 2006-2009 (which is expected to be settled by May 31, 2021).

Based on current AUC decisions, Capital Power would incur additional charges related to historical periods and, as such, has recorded $20 million pertaining to the estimated net liability for its currently held Alberta assets. This amount reflects an increase of $5 million recorded during 2020 to reflect updated information published by the AESO.

The invoicing process results in gross billings to Capital Power of which those amounts not attributable to Capital Power will then be recoverable from the appropriate parties. Capital Power believes that it should not be ultimately liable for certain line loss liabilities. The Company will therefore continue to pursue legal and regulatory measures to mitigate any potential exposure. See "Legal Proceeding and Regulatory Actions – Milner Power Inc. (Milner) Loss Factor Complaint" and "Risk Factors".

***Transmission Constraint Management***

As described above, power in Alberta is dispatched in accordance with an economic merit order administered by the AESO, based upon offers by generators to sell power. Where real-time transmission constraints preclude the offer that would otherwise have been dispatched, the AESO's TCM Rule is applied to dispatch the next available offer that is unaffected by the constraint, which then sets the price.

In April 2015, the AUC approved a new TCM Rule that it had directed the AESO to develop to address concerns with the previous rule. The new TCM Rule took effect in November 2015. Since that time, the AESO's reporting has indicated that the frequency of congestion, and related costs under the new TCM rule, have been negligible. The new TCM Rule has not had any material or adverse implications to date for the dispatch of Capital Power's facilities.

**BC**

BC's electricity is produced and delivered primarily by BC Hydro, a Crown corporation that is regulated by the BCUC. With significant interconnection to adjoining Western Electricity Coordinating Council markets, BC exports electricity through BC Hydro's trading arm and wholly owned subsidiary, Powerex Corporation.

Since 2003, the BC Government has taken steps to diversify the market and to promote new generation by independent power producers (IPPs). Under the direction of the BC Government, BC Hydro acquires electricity supply on a competitive basis from IPPs. Procurement of energy from IPPs is generally completed through calls for power, open offers and bilateral arrangements.

Capital Power has ownership interests in four facilities in BC. Island Generation is a combined cycle facility located near Campbell River which provides reliability services to Vancouver Island under a long-term tolling agreement with BC Hydro. Quality was commissioned in 2012 and provides renewable energy to BC Hydro under a long-term Electricity Purchase Agreement. The Savona and 150 Mile House waste heat facilities both produce zero-emissions energy and operate along Enbridge's Westcoast Energy BC Gas Pipeline. Both waste-heat facilities provide power to BC Hydro under long-term Electricity Supply Agreements.

Because of BC Hydro's market control in generation, distribution and trading, future opportunities for IPPs in BC may be limited.

***General Election***

BC held a provincial general election on October 24, 2020. Incumbent Premier and BC NDP Leader, John Horgan was re-elected with a majority government. The BC NDP's election platform included commitments to legislate net-zero emissions by 2050, make strategic investments in made-in-BC carbon capture technology, and ramp-up industrial emissions reductions.

Prior to the election, the BC Government appointed former Deputy Finance Minister, Peter Milburn, to investigate cost overruns and geotechnical issues associated with the Site C dam. A report on these issues is forthcoming.

**Ontario**

Ontario has a "hybrid market" for electricity and related products administered by the IESO. The IESO Administered Market produces hourly prices for energy and operating reserve, but most existing resources are either contracted or rate-regulated. Hydro One operates approximately 97% of Ontario's transmission network. The electricity sector is regulated by the Ontario Energy Board. Under the *Electricity Act, 1998* the Minister of Energy, Northern Development and Mines is required to issue a long-term energy plan during the period prescribed by regulation. In June, 2020 the Minister of Energy, Northern Development and Mines issued notice of its intent to revoke the regulatory requirement to publish and long-term energy plan and provided notice of its intention to embark on designing a revised electricity planning framework at some point in the future. It is expected that the Minister of Energy, Northern Development and Mines will provide further details of its plans to review the planning framework in 2021. The IESO remains responsible for operating and administering the Ontario wholesale market, planning and forecasting supply needs, and ensuring the reliability of the electric system in Ontario. In accordance with this mandate the IESO launched and its Resource Adequacy stakeholder engagement in September, 2020. Consultations on the proposed Resource Adequacy framework are expected to continue throughout 2021.

Capital Power has ownership interests in three thermal gas facilities and two wind projects in Ontario. The York Energy Centre was commissioned in 2012 and is the largest quick-response gas-fired facility in Ontario, operating under contract with the IESO. East Windsor began commercial operations in 2009 and operates under contract with the IESO. Goreway began commercial operations in 2009 and operates under contract with the IESO.

Capital Power's two wind projects are located in Southern Ontario. Kingsbridge 1 was developed pursuant to Ontario's Renewable Energy Supply program, which allowed for long-term PPAs for wind facilities. PDN began commercial operations in November 2013. The PDN facility was awarded a PPA pursuant to a FIT program. The FIT program, originating from the 2009 Ontario *Green Energy Act*, provides standard program rules, standard contracts and standard pricing for classes of renewable energy.

***IESO Market Renewal***

The IESO is continuing work under its Market Renewal Program (MRP) which is a series of coordinated market reforms expected to result in a fundamental redesign of Ontario's electricity market. The IESO's stated goal for the MRP is to improve how electricity is priced, scheduled and procured to meet Ontario's electricity system needs. The Company is actively participating in the MRP stakeholder process and collaborating with the IESO. The PPAs for the Goreway, York Energy, East Windsor, Port Dover and Nanticoke and Kingsbridge 1 facilities contain provisions for renegotiation should there be a change in market rules. The intent of these provisions is to preserve the underlying supplier economics as contemplated under the respective PPAs. The Company does not believe that implementation of the MRP will have a material adverse effect on its financial condition and results of operations.

**<u>United States</u>**

Capital Power's operations are subject to extensive regulation by US governmental agencies. Capital Power's projects are subject to US federal laws and regulations that govern, among other things, transactions by and with purchasers of power, including utility companies, the development and construction of generation facilities, the ownership and operations of generation facilities, and access to transmission. Generation facilities are also subject to US federal, state and local laws and regulations that govern, among other things, the geographical location, zoning, land use and operation of a project.

***US Energy Industry Regulatory Matters***

*FERC Jurisdiction*

Unless otherwise exempt, any person that owns or operates facilities used for the wholesale sale or transmission of electric energy in interstate commerce is a public utility subject to FERC's jurisdiction. FERC has extensive ratemaking jurisdiction and other authority with respect to interstate wholesale sales and transmission of electric energy under the FPA and with respect to certain interstate sales, transportation and storage of natural gas under the *US Natural Gas Act* of 1938, as amended, and the US *Natural Gas Policy Act* of 1978, as amended. FERC also maintains certain reporting requirements for public utilities and regulates, among other things, the disposition and acquisition of certain assets and securities, the holding of certain interlocking directorate positions, and the issuance of securities by public utilities.

FERC mandates open access for transmission service in the US. A series of orders issued by FERC since 1996 have: i) unbundled utilities' transmission and generation services; ii) required those utilities to offer eligible entities open access to utility transmission facilities on a basis comparable to the utilities' own use of the facilities; and iii) set out standards for RTOs.  RTOs are voluntary organizations operated by ISOs independent of market participants. RTOs perform planning, operations, and transmission services on a regional instead of utility specific basis. ISOs/RTOs serve two thirds of the wholesale power markets in the US. The six FERC-approved RTOs in the United States include: ISO-NE, New York ISO, PJM Interconnection, the Midwest ISO, the Southwest Power Pool and the California ISO. In addition, FERC approval is required for wholesale sales of power at market based or cost-based rates. This approval is granted if FERC finds that the seller and its affiliates: lack market power in generation and transmission; cannot erect other barriers to market entry; and comply with certain affiliate restrictions. This authorization is subject to revocation by FERC if such companies fail to continue to satisfy FERC's current or future criteria for market based rate authority or to modification if FERC restricts the ability of wholesale sellers of power to make sales at market based rates. All of Capital Power's power marketer affiliates are currently authorized by FERC to make wholesale sales of power at market-based rates.

*Independent System Operators*

FERC has the authority to enforce the statutes it is responsible for implementing and the regulations it issues under those statutes. It is empowered to impose civil penalties of up to US $1 million per day per violation for violations of the US Natural Gas Act of 1938, US Natural Gas Policy Act of 1978 and Part II of the FPA, with the potential of criminal fines and imprisonment for violations. FERC is also responsible for certification of power facility facilities operating in the wholesale markets. The North American Electric Reliability Corporation establishes and enforces reliability standards applicable to all owners, operators and users of the bulk power system. These standards are reviewed by FERC and thus are subject to FERC's enforcement authority.

**North Carolina**

Most of North Carolina is not part of an RTO or ISO. Thus, in most areas of the state, all transactions are bilateral and must be scheduled through the incumbent utility. Capital Power has three facilities in North Carolina, Southport, Roxboro and Beaufort, which are all in the non-RTO part of North Carolina. All three facilities are QFs under the US Public Utilities Regulatory Policies Act of 1978 that incentivizes energy efficiency through use of cogeneration and renewable energy. They are contracted with Duke Energy Progress, LLC.

Southport and Roxboro's contracts with Duke will both expire March 31, 2021, after which the facilities will cease operations.

**New Mexico**

Most of New Mexico is not part of an RTO or ISO. Thus, in most areas of the state, all transactions are bilateral and must be scheduled through the incumbent utility. Capital Power owns one facility in New Mexico, Macho Springs, which is a 50 MW wind-powered facility located in Luna County, New Mexico. Macho Springs is located in the El Paso Electric Company balancing authority area; the non-RTO part of the state. Macho Springs is interconnected with transmission facilities owned by El Paso Electric Company, and all of the output is sold to Tucson Electric Power pursuant to a long-term PPA. Macho Springs is an exempt wholesale generator that is authorized to sell energy, capacity, and ancillary services at market-based rates.

**Alabama**

Capital Power owns Decatur, a 792 MW natural gas fired facility located in Decatur, Alabama. The state is not part of an RTO or ISO. Decatur operates in the Southeast Electric Reliability Council region. Energy and capacity markets in the area are bilateral, where vertically integrated utilities supply their own load, or purchase power from third parties under contracts. Decatur is a FERC approved exempt wholesale generator that is authorized to sell energy, capacity and ancillary services at market-based rates.

Decatur sells capacity to a regional entity under a contract which expires December 31, 2032.

**Kansas**

Capital Power owns Bloom, a 178 MW wind-powered facility located in Clark and Ford County, Kansas. The state is part of the Southwest Power Pool, which is an RTO that oversees the bulk electric grid and wholesale power market in the Central U.S. on behalf of a large group of utilities and transmission companies in 14 states. Southwest Power Pool formally became an RTO in 2004 and implemented its integrated marketplace in 2014, which includes a day-ahead energy market, a real-time energy market, and an operating reserve market. Bloom is a FERC approved exempt wholesale generator that is authorized to sell energy, capacity and ancillary services at market-based rates.

Bloom sells its output under a financial proxy revenue swap agreement over a 10-year term into mid-2027 with Allianz Risk Transfer, as further described in "Business of Capital Power – US Contracted Facilities – Bloom".

**Arizona**

Capital Power owns Arlington Valley, a 580 MW gas-fired combined-cycle generation facility located in Arlington, Arizona. The state is not part of an RTO or ISO. Thus, in most areas of the state, most transactions are bilateral and must be scheduled through the incumbent utility. Arlington Valley is a FERC approved exempt wholesale generator that is authorized to sell power at market-based rates.

Arlington Valley sells capacity and electricity to an investment grade, load-serving entity under a summer tolling agreement through 2025 and sells capacity and energy to a credit-worth counterparty under a non-summer Heat Rate Call Option through 2025.

**Illinois**

Capital Power owns Cardinal Point Wind, a 150MW generation facility located in McDonough and Warren Counties, Illinois. The state is part of MISO, an RTO that operates the transmission system and a centrally dispatched market in portions of 15 states in the Midwest and the South – extending from Michigan and Indiana to Montana and from the Canadian border to the southern extremes of Louisiana and Mississippi. Cardinal Point is a FERC approved exempt wholesale generator that is authorized to sell energy, capacity and ancillary services at market-based rates.

Cardinal Point operates under a fixed-price financial hedge contract over 12-year term with an investment grade US financial institution, as further described in "Business of Capital Power – US Contracted Facilities – Cardinal Point".

**North Dakota**

Capital Power owns New Frontier Wind, a 99 MW generation facility located in McHenry County, North Dakota. The state is part of MISO, an RTO that operates the transmission system and a centrally dispatched market in portions of 15 states in the Midwest and the South – extending from Michigan and Indiana to Montana and from the Canadian border to the southern extremes of Louisiana and Mississippi. New Frontier is a FERC approved exempt wholesale generator that is authorized to sell energy, capacity and ancillary services at market-based rates.

New Frontier operates under a fixed-price financial hedge contract over a 12-year term with an investment grade US financial institution, as further described in "Business of Capital Power – US Contracted Facilities – New Frontier".

## RISK FACTORS

A discussion of the risk factors relating to Capital Power and its business and operations can be found in the section entitled "Risks and Risk Management" in the Company's Integrated Annual Report for the year ended December 31, 2020 which section is incorporated herein by reference and is available on SEDAR.

*Remainder of page intentionally left blank*

## COMMON AND PREFERRED DIVIDENDS

### Common Dividends

For the three most recently completed financial years, the Company has declared the following: (i) on July 30, 2020, the Company announced a 6.8% dividend increase for its Common Shares effective for the third quarter 2020 dividend for an annualized dividend of $2.05 per Common Share, (ii) on July 29, 2019, the Company announced a 7.3% dividend increase for its Common Shares effective for the third quarter 2019 dividend for an annualized dividend of $1.92 per Common Share, (iii) on July 27, 2018, the Company announced a 7.2% dividend increase for its Common Shares effective for the third quarter 2018 dividend for an annualized dividend of $1.79 per Common Share.

The payment of dividends is not guaranteed, however, and the amount and timing of any future dividends will be at the discretion of the Board after taking into account such factors as the Company's financial condition, results of operations, distributions from subsidiaries, current and anticipated cash needs, the requirements of any future financing agreements and other factors that the Board may deem relevant.

The Company reactivated its dividend reinvestment plan effective July 30, 2020. See "Common and Preferred Dividends – Dividend Reinvestment Plan".

The following dividends have been declared on the Common Shares for the three most recently completed financial years:

| **Dividends Declared** | |
|---|---|
| **Declaration Date** | **Dividend per Share** |
| 15 Feb 18 | $0.4175 |
| 27 Apr 18 | $0.4175 |
| 30 Jul 18 | $0.4475 |
| 26 Oct 18 | $0.4475 |
| 15 Feb 19 | $0.4475 |
| 26 Apr 19 | $0.4475 |
| 29 Jul 19 | $0.480 |
| 25 Oct 19 | $0.480 |
| 21 Feb 20 | $0.480 |
| 1 May 20 | $0.480 |
| 30 Jul 20 | $0.5125 |
| 30 Oct 20 | $0.5125 |
| 18 Feb 21 | $0.5125 |

**Preferred Dividends**

From issuance, the Series 1 Shares paid fixed cumulative dividends of $1.15 per share per annum, yielding 4.60% per annum, payable on the last business day of March, June, September and December of each year, as and when declared by the Board, for the initial five-year period ending December 31, 2015.

On December 31, 2015, the annual fixed dividend rate on the Series 1 Shares was reset pursuant to their terms to 3.06% for the five year period ending December 31, 2020. The fixed cumulative dividends was $0.765 per share per annum during this five year period.

On December 31, 2020, the annual fixed dividend rate on the Series 1 Shares was reset pursuant to their terms to 2.621% for five-year period ending December 31, 2025. The fixed cumulative dividends will be $0.65525 per share per annum during this five-year period.

The following dividends have been declared on the Series 1 Shares for the three most recent completed financial years:

| **Dividends Declared** | |
|---|---|
| **Declaration Date** | **Dividend per Share** |
| 15 Feb 18 | $0.19125 |
| 27 Apr 18 | $0.19125 |
| 30 Jul 18 | $0.19125 |
| 26 Oct 18 | $0.19125 |
| 15 Feb 19 | $0.19125 |
| 26 Apr 19 | $0.19125 |
| 29 Jul 19 | $0.19125 |
| 25 Oct 19 | $0.19125 |
| 21 Feb 20 | $0.19125 |
| 1 May 20 | $0.19125 |
| 30 Jul 20 | $0.19125 |
| 30 Oct 20 | $0.19125 |
| 18 Feb 21 | $0.1638125 |

The Series 3 Shares pay fixed cumulative dividends of $1.15 per share per annum, yielding 4.60% per annum, payable on the last business day of March, June, September and December of each year, as and when declared by the Board, for the initial five-year period ending December 31, 2018.

On December 31, 2018, the annual fixed dividend rate on the Series 3 Shares was reset pursuant to their terms to 5.453% for the next five-year period ending December 31, 2023. The fixed cumulative dividends will be $1.36325 per share per annum during this five-year period.

The following dividends have been declared on the Series 3 Shares for the three most recent completed financial years:

| **Dividends Declared** | |
|---|---|
| **Declaration Date** | **Dividend per Share** |
| 15 Feb 18 | $0.2875 |
| 27 Apr 18 | $0.2875 |
| 30 Jul 18 | $0.2875 |
| 26 Oct 18 | $0.2875 |
| 15 Feb 19 | $0.3408125 |
| 26 Apr 19 | $0.3408125 |
| 29 Jul 19 | $0.3408125 |
| 25 Oct 19 | $0.3408125 |
| 21 Feb 20 | $0.3408125 |
| 1 May 20 | $0.3408125 |
| 30 Jul 20 | $0.3408125 |
| 30 Oct 20 | $0.3408125 |
| 18 Feb 21 | $0.3408125 |

The Series 5 Shares pay fixed cumulative dividends of $1.125 per share per annum, yielding 4.50% per annum, payable on the last business day of March, June, September and December of each year, as and when declared by the Board, for the initial five-year period ending June 30, 2018.

On June 30, 2018, the annual fixed dividend rate on the Series 5 Shares was reset pursuant to their terms to 5.238% for the next five-year period ending December 31, 2023. The fixed cumulative dividends will be $1.3095 per share per annum during this five-year period.

The following dividends have been declared on the Series 5 Shares for the three most recent completed financial years:

| **Dividends Declared** | |
|---|---|
| **Declaration Date** | **Dividend per Share** |
| 15 Feb 18 | $0.28125 |
| 27 Apr 18 | $0.28125 |
| 30 Jul 18 | $0.327375 |
| 26 Oct 18 | $0.327375 |
| 15 Feb 19 | $0.327375 |
| 26 Apr 19 | $0.327375 |
| 29 Jul 19 | $0.327375 |
| 25 Oct 19 | $0.327375 |
| 21 Feb 20 | $0.327375 |
| 1 May 20 | $0.327375 |
| 30 Jul 20 | $0.327375 |
| 30 Oct 20 | $0.327375 |
| 18 Feb 21 | $0.327375 |

The Series 7 Shares pay fixed cumulative dividends of $1.50 per share per annum, yielding 6.00% per annum, payable on the last business day of March, June, September and December of each year, as and when declared by the Board, for the initial five-year period ending December 31, 2021.

The following dividends have been declared on the Series 7 Shares for the three most recently completed financial years:

| **Dividends Declared** | |
|---|---|
| **Declaration Date** | **Dividend per Share** |
| 15 Feb 18 | $0.375 |
| 27 Apr 18 | $0.375 |
| 30 Jul 18 | $0.375 |
| 26 Oct 18 | $0.375 |
| 15 Feb 19 | $0.375 |
| 26 Apr 19 | $0.375 |
| 29 Jul 19 | $0.375 |
| 25 Oct 19 | $0.375 |
| 21 Feb 20 | $0.375 |
| 1 May 20 | $0.375 |
| 30 Jul 20 | $0.375 |
| 30 Oct 20 | $0.375 |
| 18 Feb 21 | $0.375 |

The Series 9 Shares pay fixed cumulative dividends of $1.4375 per share per annum, yielding 5.75% per annum, payable on the last business day of March, June, September and December of each year, as and when declared by the Board, for the initial five-year period ending September 30, 2022.

The following dividends have been declared on the Series 9 Shares since the date of issuance of such shares:

| **Dividends Declared** | |
|---|---|
| **Declaration Date** | **Dividend per Share** |
| 15 Feb 18 | $0.359375 |
| 27 Apr 18 | $0.359375 |
| 30 Jul 18 | $0.359375 |
| 26 Oct 18 | $0.359375 |
| 15 Feb 19 | $0.359375 |
| 26 Apr19 | $0.359375 |
| 29 Jul 19 | $0.359375 |
| 25 Oct 19 | $0.359375 |
| 21 Feb 20 | $0.359375 |
| 1 May 20 | $0.359375 |
| 30 Jul 20 | $0.359375 |
| 30 Oct 20 | $0.359375 |
| 18 Feb 21 | $0.359375 |

The Series 11 Shares pay fixed cumulative dividends of $1.4375 per share per annum, yielding 4.15% per annum, payable on the last business day of March, June, September and December of each year, as and when declared by the Board, for the initial five-year period ending June 30, 2024.

The following dividends have been declared on the Series 11 Shares since the date of issuance of such shares:

| **Dividends Declared** | |
|---|---|
| **Declaration Date** | **Dividend per Share** |
| 16 May 19 | $0.1772(1) |
| 29 Jul 19 | $0.359375 |
| 25 Oct 19 | $0.359375 |
| 21 Feb 20 | $0.359375 |
| 1 May 20 | $0.359375 |
| 30 Jul 20 | $0.359375 |
| 30 Oct 20 | $0.359375 |
| 18 Feb 21 | $0.359375 |

**Note:**
(1) Initial quarterly dividend represents the period from May 16, 2019 (the date of issuance of the Series 11 Shares) to June 30, 2019.

## Dividend Reinvestment Plan

On January 1, 2012, the Company launched a DRIP, under which eligible shareholders were able to elect to participate commencing with the Company's first quarter 2012 cash dividend on its Common Shares. The DRIP provides eligible shareholders with an alternative to receiving their quarterly cash dividends on Common Shares. Under the DRIP, eligible shareholders that so elect accumulate additional Common Shares by reinvesting their quarterly cash dividends on the applicable dividend payment date in new Common Shares issued from treasury. Participation in the DRIP is optional. Those shareholders who did not enrol, or have not enrolled, in the DRIP are still entitled to receive their quarterly cash dividends on their Common Shares.

On July 25, 2014, the Company announced a reduction in the discount percentage for the DRIP, reducing the discount rate from a 5% discount to the average market price to a discount rate of 3%, effective the third quarter 2014 dividend. Subsequently, on March 25, 2015, the Company announced the suspension of the DRIP following the April 2015 dividend payment.

On July 30, 2020, the Company reinstated the DRIP. Eligible shareholders may elect to participate in the Plan commencing with the Company's third quarter 2020 cash dividend. Shareholders that were enrolled in the DRIP upon suspension in June 2015, and remained enrolled with the plan administrator, automatically resumed participation in the DRIP. New Common Shares issued under the reactivated DRIP will be issued at a discount rate of 3% to the average closing price on the TSX for the 10 trading days immediately preceding the applicable dividend payment date.

The Company reserves the right to limit the amount of new equity available under the DRIP on any particular dividend payment date. No assurances can be made that new Common Shares will be made available under the DRIP on a quarterly basis, or at all. Accordingly, participation may be prorated in certain circumstances. If on any dividend payment date the Company determines not to issue any equity under the DRIP, or the availability of new Common Shares is prorated in accordance with the terms of the DRIP, then participants are entitled to receive from the Company the full amount of their regular quarterly cash dividend for each share in respect of which the dividend is payable but cannot be reinvested under the DRIP in accordance with the applicable election.

Since the Company's DRIP was introduced and as of the date of this AIF, 5,559,001 Common Shares have been issued pursuant to the DRIP at a weighted average price of $24.21. To date, no pro-ration has occurred.

## CAPITAL STRUCTURE

The Company's authorized share capital consists of an unlimited number of Common Shares, an unlimited number of Preference Shares issuable in series, and one Special Limited Voting Share. As of December 31, 2020, there were 106,180,990 Common Shares, 5 million Series 1 Shares, 6 million Series 3 Shares, 8 million Series 5 Shares, 8 million Series 7 Shares, 6 million Series 9 Shares, 6 million Series 11 Shares and one Special Limited Voting Share outstanding.

### Common Shares

Holders of Common Shares are entitled to one vote for each Common Share held on a ballot vote at all meetings of shareholders of the Company except meetings at which or in respect of matters on which only holders of another class of shares are entitled to vote separately as a class. Holders of Common Shares are entitled to receive, subject to the rights of the holders of another class of shares, any dividend declared by the Company and the remaining property of the Company on the liquidation, dissolution or winding-up of the Company, whether voluntary or involuntary.

#### *Normal Course Issuer Bid*

On February 23, 2021, the Company announced that the Toronto Stock Exchange had approved the Company's normal course issuer bid to purchase and cancel up to 10,661,112 of its outstanding Common Shares during the one year period from February 26, 2021 to February 25, 2022.

Pursuant to the rules of the Toronto Stock Exchange, the maximum number of Common Shares that may be purchased during the same trading day on the Toronto Stock Exchange is 87,397 Common Shares (being 25% of the average daily trading volume of Common Shares for the six months preceding the date of the normal course issuer bid notice to the Toronto Stock Exchange, which was equal to 349,589 Common Shares), subject to certain exceptions for block repurchases.

On February 24, 2020, the Company announced that the Toronto Stock Exchange had approved the Company's normal course issuer bid to purchase and cancel up to 10,513,532 of its outstanding Common Shares during the one year period from February 26, 2020 to February 25, 2021. As of the date of this AIF, the Company has purchased 461,832 Common Shares at a weighted average price of $22.67.

Pursuant to the rules of the Toronto Stock Exchange, the maximum number of Common Shares that may be purchased during the same trading day on the Toronto Stock Exchange is 76,972 Common Shares (being 25% of the average daily trading volume of Common Shares for the six months preceding the date of the Toronto Stock Exchange's acceptance of the normal course issuer bid, which was equal to 307,889 Common Shares), subject to certain exceptions for block repurchases.

Purchases are made on behalf of the Company by a registered broker through the facilities of the Toronto Stock Exchange at prevailing market prices pursuant to the rules of the Toronto Stock Exchange governing normal course issuer bids and/or through alternative Canadian trading platforms or as otherwise may be permitted by applicable securities regulatory authorities.

**Preference Shares**

The Preference Shares may at any time and from time to time be issued in one or more series. Subject to the CBCA, the Board may fix, before the issue thereof, the number of Preference Shares of each series, the designation, rights, privileges, restrictions and conditions attaching to the Preference Shares of each series, including, without limitation, any voting rights, any right to receive dividends (which may be cumulative or non-cumulative and variable or fixed) or the means of determining such dividends, the dates of payment thereof, any terms and conditions of redemption or purchase, any conversion rights, any rights on the liquidation, dissolution or winding up of the Company, and any sinking fund or other provisions.

The Preference Shares of each series will, with respect to the payment of dividends and the distribution of assets in the event of the liquidation, dissolution or winding up of the Company, whether voluntary or involuntary, rank on a parity with the Preference Shares of every other series and be entitled to preference over the Common Shares and any other shares ranking junior to the Preference Shares with respect to priority in payment of dividends and the distribution of assets in the event of the liquidation, dissolution or winding up of the Company.

On May 16, 2019, the Company issued 6 million Series 11 Shares at a price of $25.00 per Series 11 Share for aggregate gross proceeds of $150 million.

The Series 11 Shares pay fixed cumulative dividends of $1.4375 per share per annum, yielding 5.75% per annum, payable on the last business day of March, June, September and December of each year, as and when declared by the Board, for the initial five-year period ending June 30, 2024. The dividend rate will reset on June 30, 2024 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 4.15%, provided that in any event, such rate shall not be less than 5.75%. The Series 11 Shares are redeemable by Capital Power, at its option, on June 30, 2024 and every five years thereafter.

The holders of the Series 11 Shares will have the right, at their option, to convert all or any part of their Series 11 Shares into Cumulative Floating Rate Preference Shares, Series 12 (Series 12 Shares), subject to certain conditions, on June 30, 2024 and every five years thereafter. Holders of the Series 12 Shares will be entitled to receive a cumulative quarterly floating dividend at a rate equal to the sum of the then 90-day Government of Canada Treasury Bill yield plus 4.15%, as and when declared by the Board.

On August 9, 2017, the Company issued 6 million Series 9 Shares at a price of $25.00 per Series 9 Share for aggregate gross proceeds of $150 million.

The Series 9 Shares pay fixed cumulative dividends of $1.4375 per share per annum, yielding 5.75% per annum, payable on the last business day of March, June, September and December of each year, as and when declared by the Board, for the initial five-year period ending September 30, 2022. The dividend rate will reset on September 30, 2022 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 4.12%, provided that in any event, such rate shall not be less than 5.75%. The Series 9 Shares are redeemable by Capital Power, at its option, on September 30, 2022 and every five years thereafter.

The holders of the Series 9 Shares will have the right to convert all or any part of their Series 9 Shares into Cumulative Floating Rate Preference Shares, Series 10 (Series 10 Shares), subject to certain conditions, on September 30, 2022 and every five years thereafter. Holders of the Series 10 Shares will be entitled to receive a cumulative quarterly floating dividend at a rate equal to the sum of the then 90-day Government of Canada Treasury Bill yield plus 4.12%, as and when declared by the Board.

On October 4, 2016, the Company issued 8 million Series 7 Shares at a price of $25.00 per Series 7 Share for aggregate gross proceeds of $200 million.

The Series 7 Shares pay fixed cumulative dividends of $1.50 per share per annum, yielding 6.00% per annum, payable on the last business day of March, June, September and December of each year, as and when declared by the Board, for the initial five-year period ending December 31, 2021. The first quarterly dividend of $0.3616 per share was paid on December 30, 2016 (for the initial period October 4, 2016 to December 31, 2016). The dividend rate will reset on December 31, 2021 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 5.26%, provided that, in any event, such rate shall not be less than 6.00%. The Series 7 Shares are redeemable by the Company, at its option on December 31, 2021 and every five years thereafter.

The holders of Series 7 Shares will have the right to convert all or any part of their Series 7 Shares into Cumulative Floating Rate Preference Shares, Series 8 (Series 8 Shares), subject to certain conditions, on December 31, 2021 and five years thereafter. Holders of Series 8 Shares will be entitled to receive quarterly floating rate cumulative dividends, as and when declared by the Board, at a rate equal to the sum of the then 90-day Government of Canada treasury bill rate and 5.26%.

On March 14, 2013, the Company issued 8 million Series 5 Shares at a price of $25.00 per Series 5 Share for aggregate gross proceeds of $200 million.

The Series 5 Shares paid fixed cumulative dividends of $1.125 per share per annum, yielding 4.50% per annum, payable on the last business day of March, June, September and December of each year, as and when declared by the Board, for the initial five-year period ending June 30, 2018. The first quarterly dividend of $0.3329 per share was paid on June 28, 2013. The dividend rate reset on June 30, 2018 and will reset every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 3.15%. The Series 5 Shares are redeemable by the Company, at its option, on June 30 of every fifth year after June 30, 2018.

The holders of Series 5 Shares had the right to convert all or any part of their Series 5 Shares into an equal number of Cumulative Floating Rate Preference Shares, Series 6 (Series 6 Shares), subject to certain conditions, on June 30, 2018. Following the conversion deadline on June 15, 2018, approximately 236,824 Series 5 Shares were tendered for conversion, which was less than the one million shares required for conversion into Series 6 Shares, as prescribed by the Company's articles of incorporation (as amended). Accordingly, 8,000,000 Series 5 Shares remain outstanding and there were no Series 6 Shares issued as at June 30, 2018. Effective June 30, 2018, the annual fixed dividend rate for the Series 5 Shares for the next five-year period was reset to 5.238% with a fixed cumulative dividend of $1.3095 per share per annum.

The holders of Series 5 Shares will have the right to convert their Series 5 Shares into Series 6 Shares, subject to certain conditions, again on June 30, 2023 and on June 30 of every fifth year thereafter. The holders of Series 6 Shares will be entitled to receive quarterly floating rate cumulative dividends, as and when declared by the Board, at a rate equal to the sum of the then 90-day Government of Canada treasury bill rate and 3.15%.

On December 18, 2012, the Company issued 6 million Series 3 Shares at a price of $25.00 per Series 3 Share for aggregate gross proceeds of $150 million.

The Series 3 Shares paid fixed cumulative dividends of $1.15 per share per annum, yielding 4.60% per annum, payable on the last business day of March, June, September and December of each year, as and when declared by the Board, for the initial five-year period ending December 31, 2018. The first quarterly dividend of $0.3151 per share was paid on March 28, 2013 (for the initial period from December 18, 2012 to March 31, 2013). The dividend rate reset on December 31, 2018 and will reset every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 3.23%. The Series 3 Shares are redeemable by the Company, at its option, on December 31 of every fifth year after December 31, 2018.

The holders of Series 3 Shares had the right to convert all or any part of their Series 3 Shares into an equal number of Cumulative Floating Rate Preference Shares, Series 4 (Series 4 Shares), subject to certain conditions, on December 31, 2018. Following the conversion deadline on December 17, 2018, approximately 47,270 Series 3 Shares were tendered for conversion, which was less than the one million shares required for conversion into Series 4 Shares, as prescribed by the Company's articles of incorporation (as amended). Accordingly, 6,000,000 Series 3 Shares remain outstanding and there were no Series 4 Shares issued as at December 31, 2018. Effective December 31, 2018, the annual fixed dividend rate for the Series 3 Shares for the next five-year period was reset to 5.453% with a fixed cumulative dividend of $1.36325 per share per annum.

The holders of Series 3 Shares will have the right to convert their Series 3 Shares into Series 4 Shares, subject to certain conditions, again on December 31, 2023 and on December 31 of every fifth year thereafter. The holders of Series 4 Shares will be entitled to receive quarterly floating rate cumulative dividends, as and when declared by the Board, at a rate equal to the sum of the then 90-day Government of Canada treasury bill rate and 3.23%.

On December 16, 2010, the Company issued 5 million Series 1 Shares at a price of $25.00 per Series 1 Share for aggregate gross proceeds of $125 million.

The Series 1 Shares paid fixed cumulative dividends of $1.15 per share per annum, yielding 4.60% per annum, payable on the last business day of March, June, September and December of each year, as and when declared by the Board, for the initial five-year period ending December 31, 2015. The first quarterly dividend of $0.3308 per share was paid on March 31, 2011 (for the initial period December 16, 2010 to March 31, 2011). The dividend rate reset on December 31, 2015 and will reset every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 2.17%. The Series 1 Shares are redeemable by the Company, at its option, on December 31 of every fifth year after December 31, 2015.

The holders of Series 1 Shares had the right to elect to convert all or any part of their Series 1 Shares into Cumulative Floating Rate Preference Shares, Series 2 (Series 2 Shares), subject to certain conditions, on December 31, 2015. Following the conversion deadline on December 16, 2015, approximately 930,800 Series 1 Shares were tendered for conversion, which was less than the one million shares required for conversion into Series 2 Shares, as prescribed by the Company's articles of incorporation (as amended). Accordingly, 5,000,000 Series 1 Shares remain outstanding and there were no Series 2 Shares issued as at December 31, 2015. Effective December 31, 2015, the annual fixed rate for the Series 1 Shares for the next five-year period was reset to 4.60%.

The holders of Series 1 Shares again had the right to elect to convert all or any part of their Series 1 Shares into Series 2 Shares, subject to certain conditions, on December 31, 2020. Following the conversion deadline on December 16, 2020, 687,245 Series 1 Shares were tendered for conversion, which was less than the one million shares required for conversion into Series 2 Shares, as prescribed by the Company's articles of incorporation (as amended). Accordingly, 5,000,000 Series 1 Shares remain outstanding and there were no Series 2 Shares issued as at December 31, 2020. Effective December 31, 2020, the annual fixed rate for the Series 1 Shares for the next five-year period was reset to 2.621%.

The holders of Series 1 Shares will have another opportunity to convert their Series 1 Shares into Series 2 Shares, subject to certain conditions, again on December 31, 2025 and on December 31 of every fifth year thereafter. The holders of Series 2 Shares will be entitled to receive quarterly floating rate cumulative dividends, as and when declared by the Board, at a rate equal to the sum of the then 90-day Government of Canada treasury bill rate and 2.17%.

**Special Limited Voting Share**

The authorized number of Special Limited Voting Shares is limited to one. The Special Limited Voting Share is held by EPCOR. The holder of the Special Limited Voting Share is entitled to receive notice of, to receive materials relating to, and to attend any meeting of Capital Power's shareholders; however, the holder of the Special Limited Voting Share is not, in such capacity, entitled to vote at any shareholder meeting except as provided by law or as described below.

The articles of the Company provide that any amendment to the articles of the Company to change the place in which the "Head Office" (as defined in the articles) is located to a place other than the City of Edmonton in the Province of Alberta or to change in any way the definition of "Head Office" and the related definitions set out in the articles, or any merger, amalgamation, arrangement, reorganization, liquidation or sale of all or substantially all of the property of the Company or similar transaction pursuant to which the resulting corporation or other successor to the Company or its business is not required to: (i) have its Head Office located in the City of Edmonton; (ii) have a definition of "Head Office" as set out in the articles; or (iii) have a Special Limited Voting Share in the capital of the resulting corporation or other successor to the Company having the same rights and restrictions as those relating to the Special Limited Voting Shares issued to the holder of the Special Limited Voting Share, must be approved by the holder of the Special Limited Voting Share, voting separately as a class, in addition to approval of the holders of the Common Shares. In addition, the jurisdiction of incorporation of the Company may not be changed, by continuance or otherwise; no amendment to the articles to increase the maximum number of authorized Special Limited Voting Shares may be made; the rights, privileges, restrictions and conditions of the Special Limited Voting Share may not be amended; no exchange or creation of a right of exchange or right to acquire Special Limited Voting Shares may be effected; and no transaction, including any amendment to the articles, to effect an exchange, reclassification or cancellation of the Special Limited Voting Share may be undertaken, without approval by the holder of the Special Limited Voting Share, voting separately as a class.

The articles of the Company define "Head Office" to mean the office or offices at which: (i) the majority of the Company's senior "Executive Officers", which consist of the persons carrying out as a substantial part of their duties any of the functions of the chief executive officer, chief operating officer, chief financial officer, president, any executive vice-president, senior vice-president or general counsel of the Company, which majority shall include the chief executive officer, are located and from which they carry out the majority of their functions; and (ii) the majority of the "Executive Officers" are located and from which they carry out the majority of their functions (such majority including the Chief Executive Officer and the senior Executive Officers referred to in clause (i) above). The term "Executive Officers" is defined in the articles to include the senior Executive Officers referred to above; and (to the extent different from such senior Executive Officers) the persons, whether employed by the Company or any of its subsidiary entities, carrying out as a substantial part of their duties any of the functions of the chief executive officer, chief operating officer, chief financial officer, president, any executive vice-president or senior vice-president or general counsel, with respect to a substantial portion of the businesses carried on by the Company and its subsidiary entities, taken as a whole. The articles further require that the registered office of the Company be located in the City of Edmonton.

The Special Limited Voting Share carries no right for the holder to receive dividends. The holder of the Special Limited Voting Share has the right to receive, subject to any payment or distribution to holders of Preference Shares, in preference to the holders of Common Shares, the amount of $1.00 from the remaining property and assets of the Company upon the voluntary or involuntary liquidation, dissolution or winding-up of the Company.

EPCOR is also the holder of one special limited voting share of CPLPGP. The rights, privileges, restrictions and conditions of the special limited voting share of CPLPGP are substantially similar to those of the Special Limited Voting Share of the Company mutatis mutandis.

**Debt Issuance**

On October 9, 2020 Capital Power Corporation redeemed all of its outstanding 5.276% medium-term notes, due November 16, 2020, in the aggregate principal amount of C$251,181,000. The redemption price was an aggregate amount of $257,614,750.13, including applicable early redemption premiums, as well as accrued and unpaid interest to and including the day immediately preceding the redemption date.

On October 1, 2020, Capital Power Corporation issued $350 million of senior unsecured medium-term notes due on October 1, 2032 with interest payable semi-annually at a rate of 3.147%, pursuant to the New Indenture as supplemented by a fourth supplemental Trust Indenture dated June 1, 2020.

On May 15, 2020, Capital Power Corporation filed a short form base shelf prospectus allowing for the offering of the following securities that may be issued pursuant to prospectus supplement, in one or more issuances in an aggregate principal amount not to exceed $3 billion: (i) common shares of the Company, (ii) preference shares of the Company, (iii) subscription receipts exchangeable for common shares and/or other securities of the Company; and (iv) debt securities of the Company. In addition, Capital Power Corporation filed a prospectus supplement to issue medium term notes due not less than one year from the date of issue, at prices and on terms determined at the time of issue, in an aggregate principal amount not to exceed $2 billion. All issuances may be made during the 25-month period that the prospectus remains valid. Any medium-term notes issued under the base shelf prospectus and prospectus supplement filed in 2020 will be issued pursuant to the terms of the New Indenture.

On November 8, 2019, Capital Power Corporation issued $275 million of senior unsecured medium-term notes due on February 8, 2030 with interest payable semi-annually at a rate of 4.424%, pursuant to the New Indenture, as supplemented by a third supplemental Trust Indenture dated November 8, 2019.

On June 12, 2019, Capital Power Corporation closed $325 million private placement of senior notes. The senior notes consist of five tranches, two with 10-year terms, two with 12-year terms and one with a 15-year term. The two 10-year senior notes have an aggregate principal amount of $210 million that matures in June 2029 with a coupon rate of 4.56%. The two 12-year senior notes have an aggregate $65 million principal amount and matures in June 2031 with a coupon rate of 4.72%. The 15-year senior note has a $50 million principal amount and matures in June 2034 with a coupon rate of 4.96%. The Note Purchase Agreement dated as of June 12, 2019, by and among CPC (as issuer) and the Purchasers (as defined therein) prohibits the Company from making distributions if an event or condition has occurred and is continuing that would, with the lapse of time or giving of notice or both, constitute an event of default under the terms of the Note Purchase Agreement.

On January 23, 2019, Capital Power Corporation issued $300 million of senior unsecured medium-term notes due in 2026 with interest payable semi-annually at a rate of 4.986% commencing on July 23, 2019, pursuant to the New Indenture, as supplemented by a second supplemental Trust Indenture dated January 23, 2019.

On September 18, 2017, Capital Power Corporation issued $450 million of senior unsecured medium-term notes due in 2024 with interest payable semi-annually at a rate of 4.284% commencing on March 18, 2018, pursuant to the New Indenture, as supplemented by a first supplemental Trust Indenture dated September 18, 2017.

On September 13, 2016, Capital Power Corporation closed $160 million, 10-year Series C Senior Notes with Prudential Capital Group that mature in September 2026 (the Prudential Notes). The Prudential Notes bear an interest rate of 3.85% which will be paid semi-annually and rank pari-passu with the Company's other senior unsecured borrowings. The Note Purchase Agreement dated as of September 13, 2016, by and among CPC (as issuer) and the Purchasers (as defined therein) (the Prudential Agreement) prohibits the Company from making distributions if an event of default has occurred and is continuing or would reasonably be expected to result from the distribution.

On May 3, 2016, the Company executed the New Indenture to support the issuance of senior unsecured medium-term notes from time to time.

Effective December 18, 2015, the Company and CPLP completed the amendment of the Trust Indenture dated April 14, 2010 between CPLP and Computershare Trust Company of Canada as supplemented and amended from time to time (the CPLP Trust Indenture) and the exchange of all issued and outstanding $300 million principal amount 5.276% senior unsecured MTNs of CPLP due November 16, 2020 and all issued and outstanding $250 million principal amount 4.85% senior unsecured MTNs of CPLP due February 21, 2019 (the CPLP MTNs) for an equal principal amount of newly issued MTNs of Capital Power having financial and other terms that are the same as those attached to the CPLP MTNs and benefiting from a guarantee provided by CPLP (the Note Exchange Transaction). Upon the completion of the Note Exchange Transaction, CPLP was released and discharged from all obligations under or in respect of the CPLP Trust Indenture and the CPLP MTNs.

The New Indenture and the CPLP Trust Indenture (the Trust Indentures) do not limit the aggregate principal amount of MTNs that may be issued thereunder. Additional MTNs maturing at varying dates and bearing interest at different rates, in each case as determined by the Company, may be issued under the Trust Indentures. Under the Trust Indentures, the Company is restricted from incurring additional indebtedness, making distributions or redeeming or repurchasing partnership interests or subordinated debt unless it has a debt-to-capitalization ratio of not more than 75% at the time of (and after giving effect to) such actions.

On June 15, 2011, Capital Power U.S. Financing LP (US Financing LP), an indirect subsidiary of CPLP, closed a US$295 million private placement of senior notes (Senior Notes). The Senior Notes consist of two notes with 10 and 15-year terms. The 10-year Senior Note has a principal amount of US$230 million that matures in June 2021 with a coupon rate of 5.21%. The 15-year Senior Note has a US$65 million principal amount and matures in June 2026 with a coupon rate of 5.61%. The Senior Notes prohibit CPLP from making distributions if an event of default has occurred and is continuing or would reasonably be expected to result from the distribution. On January 28, 2016, a Second Amending Agreement to the Note Purchase Agreement dated June 15, 2011 among US Financing LP, as issuer, CPLP, as parent guarantor, the Company, as additional guarantor, and each of the purchasers thereunder (the Note Purchase Agreement) was executed after receipt of the Note Holders' consent thereto. Pursuant to the Note Purchase Agreement, as amended, the Company has provided an additional parental guarantee of the obligations of US Financing LP under the Senior Notes and the Note Purchase Agreement. In addition, the Company has been substituted as the obligor for financial and reporting covenants (including the covenant to maintain a credit rating) under the Note Purchase Agreement and has also been substituted and/or added as the (or an) obligor for certain other covenants under the Note Purchase Agreement. The existing parental guarantee provided by CPLP remains in place.

***Credit Facilities***

Capital Power currently has two committed credit facilities under credit agreements among CPLP, CPLPHI and Capital Power (US Holdings) Inc. (as borrowers) and the Company (as covenantor) and various lenders as described below. Capital Power's credit facilities include: (i) an extendible syndicated facility of up to $700 million, with an accordion feature to increase the facility size by up to $300 million; and (ii) an extendible revolving club credit facility of up to $300 million (both credit agreements were amended May 2019 and currently have an expiration date of July 9, 2024). Confirmation of Guarantees from the Company, CPLP, Capital Power (US Holdings) Inc., Capital Power LP Holdings Inc. and Capital Power U.S. Financing L.P. in respect of their affiliate guarantees were provided to the lenders to ensure that any obligations of the borrowers remain pari passu with the Company's other senior unsecured borrowings. Similar guarantees were also provided per both Note Purchase Agreements and the Prudential Agreement (as defined above under "Capital Structure – Debt Issuance") to meet the pari passu covenants in those agreements.

In May 2019, Capital Power LP Holdings Inc. obtained a short-term credit facility of $250 million from an existing lender (the Side Car Facility) with terms, covenants, costs and intercorporate guarantees consistent with the Company's other credit facilities. The Side Car Facility had a term of 12 months; however it was paid out in full prior to expiry in November of 2019.

Capital Power has Canadian dollar revolving letter of credit demand facilities with various lenders that were increased by $100 million in September 2019 and now total $320 million. In addition, two U.S. dollar revolving letter of credit demand facilities were put in place in September and November 2019 totalling $100 million.

The syndicated and club credit facilities, require CPC to meet certain financial covenants, including maintaining a consolidated senior debt to consolidated capitalization ratio of not more than 0.65 to 1.0 as at the end of any fiscal quarter. In addition, in the event that CPC is assigned a credit rating by S&P that is less than BBB- or by DBRS that is less than BBB (low) (in each case assigned with a stable outlook), then CPC must also maintain a ratio of consolidated EBITDA (to consolidated interest expense (each as defined in each of the credit agreements) of not less than 2.5 to 1.0 as at the end of each fiscal quarter. The syndicated and club credit facilities also prohibit CPC from making distributions if an event of default has occurred and is continuing or would reasonably be expected to result from the distribution.

Financial covenant calculations and financial reporting obligations are based on the Company's consolidated financial results (rather than CPLP financial reports).

## Ratings

The following credit rating agencies have assigned the following credit ratings to the preferred shares of the Company and debt obligations of the Company:

### *Preferred Share Ratings*

As at the date of this AIF, the Company has received a rating of Pfd-3 (low) with a stable trend for its preferred shares from DBRS and a rating of P-3 from S&P. Ratings are intended to provide investors with an independent measure of credit quality of an issue of securities.

The Company's preferred shares have been given a rating of P-3 by S&P. Such P-3 rating is the third highest of eight ratings used by S&P in its Canadian preferred share rating scale. According to S&P, a P-3 rating indicates that, although the obligation is less vulnerable to non-payment than other speculative issues, it faces major ongoing uncertainties or exposure to adverse business, financial, or economic conditions, which could lead to the obligor's inadequate capacity to meet its financial commitment on the obligation. S&P further subcategorizes each rating by the designation of "high" and "low" to indicate where an entity falls within the rating category.

The Company's preferred shares have been given a rating of Pfd-3 (low) with a stable trend by DBRS. The Pfd-3 (low) rating is the third highest of six rating categories used by DBRS for preferred shares. According to DBRS, preferred shares rated Pfd-3 (low) are of adequate credit quality. While protection of dividends and principal is still considered acceptable, the issuing entity is more susceptible to adverse changes in financial and economic conditions, and there may be other adverse conditions present which detract from debt protection. DBRS further subcategorizes each rating by the designation of "high" and "low" to indicate where an entity falls within the rating category. The absence of either a "high" or "low" designation indicates the rating is in the middle of the category. The rating trend indicates the direction in which DBRS considers the rating is headed should present tendencies continue, or in some cases, unless challenges are addressed.

The rating by each of DBRS and S&P is not a recommendation to buy, sell or hold any securities of the Company in as much as such rating does not comment as to market price or suitability for a particular investor. There is no assurance that any rating will remain in effect for any given period of time or that any rating will not be revised upward or downward or withdrawn entirely by either DBRS or S&P in the future if, in the judgment of either or both, circumstances so warrant. The ratings by DBRS and S&P may not reflect the potential impact of all risks related to the value of any of the securities of the Company. In addition, real or anticipated changes in the ratings assigned to the Company and its preferred shares may affect the market price or value of the securities of the Company.

### *Debt Ratings*

Capital Power Corporation currently has a BBB (low) credit rating with a stable outlook for its Senior Unsecured Debt from DBRS and a BBB- Corporate Credit rating with a stable outlook from S&P. Credit ratings are intended to provide investors with an independent measure of credit quality of an issue of securities.

The BBB (low) Corporate Credit rating category is the fourth highest rating of DBRS's ten rating categories, which range from a high of AAA to a low of D. With the exception of the AAA and D categories, DBRS uses "high" or "low" designations to indicate the relative standing of the securities being rated within a particular rating category, while the absence of either a high or low designation indicates the rating is in the middle of the category. According to the DBRS rating system, long-term debt rated BBB is of adequate credit quality. The capacity for the payment of financial obligations is considered acceptable, however, may be vulnerable to future events.

The BBB- Corporate Credit rating assigned by S&P is the fourth highest rating of S&P's ten rating categories, which range from a high of AAA to a low of D. With the exception of the AAA and D categories, S&P may modify a rating using a plus (+) or minus (-) sign to show relative standing within the major rating categories. An obligation rated BBB exhibits adequate protection parameters. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitment on the obligation. An S&P rating outlook assesses the potential direction of a long-term credit rating over the intermediate term (typically six months to two years). In determining a rating outlook, consideration is given to any changes in the economic and/or fundamental business conditions. An outlook is not necessarily a precursor of a rating change or future S&P credit action.

The credit rating by each of DBRS and S&P is not a recommendation to buy, sell or hold any securities of the Company in as much as such rating does not comment as to market price or suitability for a particular investor. There is no assurance that any rating will remain in effect for any given period of time or that any rating will not be revised upward or downward or withdrawn entirely by either DBRS or S&P in the future if, in the judgment of either or both, circumstances so warrant. The credit ratings by DBRS and S&P may not reflect the potential impact of all risks related to the value of any of the securities of the Company. In addition, real or anticipated changes in the credit ratings assigned to the Company and its indebtedness may affect the market price or value of the securities of the Company.

The Company made payments to each of DBRS and S&P in connection with obtaining the aforementioned ratings and over the past two years has made payments in respect of certain other services provided to the Company by each of DBRS and S&P.

*Remainder of page intentionally left blank*

# MARKET FOR SECURITIES

## Trading Price and Volume

The Company's Common Shares trade on the Toronto Stock Exchange under the symbol of CPX. The following table sets forth the reported high and low trading prices and volumes for the periods indicated:

### Toronto Stock Exchange 2020 CPX Trading Statistics

| Month | Share Price | | | Volume Traded |
|---|---|---|---|---|
| | High | Low | Close | |
| January | $36.40 | $33.90 | $36.21 | 5,871,147 |
| February | $38.88 | $32.96 | $33.55 | 7,489,488 |
| March | $37.61 | $20.23 | $27.15 | 18,420,894 |
| April | $28.81 | $23.24 | $26.94 | 11,383,724 |
| May | $27.24 | $23.72 | $26.73 | 9,321,378 |
| June | $29.92 | $26.13 | $27.98 | 8,778,384 |
| July | $28.89 | $26.57 | $28.33 | 6,320,718 |
| August | $30.28 | $28.41 | $28.62 | 5,946,451 |
| September | $30.22 | $28.14 | $29.39 | 9,380,510 |
| October | $31.05 | $29.13 | $29.36 | 6,158,692 |
| November | $33.45 | $29.35 | $33.24 | 6,130,475 |
| December | $36.47 | $32.71 | $34.98 | 7,895,544 |

The Company's Series 1 Shares began trading on the Toronto Stock Exchange on December 16, 2010 under the symbol of CPX.PR.A. The following table sets forth the reported high and low trading prices and volumes for the periods indicated:

**Toronto Stock Exchange 2020 CPX.PR.A Trading Statistics**

| Month | Share Price | | | Volume Traded |
|---|---|---|---|---|
| | High | Low | Close | |
| January | $13.57 | $12.50 | $12.58 | 143,623 |
| February | $12.92 | $11.81 | $11.92 | 79,746 |
| March | $11.60 | $6.51 | $8.66 | 134,544 |
| April | $9.35 | $7.90 | $8.91 | 170,400 |
| May | $9.28 | $8.64 | $8.91 | 55,609 |
| June | $9.92 | $8.81 | $9.00 | 59,960 |
| July | $9.99 | $8.89 | $9.51 | 69,971 |
| August | $10.75 | $9.55 | $10.70 | 81,074 |
| September | $10.85 | $9.31 | $9.42 | 73,844 |
| October | $10.30 | $9.57 | $10.10 | 104,266 |
| November | $11.61 | $10.10 | $11.48 | 55,994 |
| December | $12.21 | $11.32 | $11.78 | 75,833 |

The Company's Series 3 Shares began trading on the Toronto Stock Exchange on December 18, 2012 under the symbol of CPX.PR.C. The following table sets forth the reported high and low trading prices and volumes for the periods indicated:

**Toronto Stock Exchange 2020 CPX.PR.C Trading Statistics**

| Month | Share Price | | | Volume Traded |
|---|---|---|---|---|
| | High | Low | Close | |
| January | $19.23 | $18.60 | $19.02 | 80,858 |
| February | $19.63 | $18.70 | $19.00 | 69,442 |
| March | $19.21 | $12.01 | $14.35 | 121,090 |
| April | $15.14 | $14.00 | $14.75 | 127,741 |
| May | $15.57 | $14.00 | $14.36 | 63,623 |
| June | $15.98 | $14.30 | $14.51 | 91,361 |
| July | $15.78 | $14.41 | $15.30 | 70,307 |
| August | $16.60 | $15.35 | $16.54 | 52,643 |
| September | $16.90 | $15.29 | $15.68 | 69,394 |
| October | $16.00 | $14.87 | $15.65 | 254,627 |
| November | $17.50 | $15.50 | $17.27 | 138,637 |
| December | $18.76 | $17.30 | $18.45 | 228,516 |

The Company's Series 5 Shares began trading on the Toronto Stock Exchange on March 14, 2013 under the symbol of CPX.PR.E. The following table sets forth the reported high and low trading prices and volumes for the periods indicated:

**Toronto Stock Exchange 2020 CPX.PR.E Trading Statistics**

| Month | Share Price | | | Volume Traded |
|---|---|---|---|---|
| | High | Low | Close | |
| January | $18.40 | $17.95 | $18.24 | 79,902 |
| February | $18.51 | $17.56 | $17.90 | 114,631 |
| March | $18.00 | $11.03 | $13.76 | 166,445 |
| April | $14.81 | $13.00 | $14.70 | 113,826 |
| May | $14.55 | $13.56 | $13.65 | 104,782 |
| June | $15.49 | $13.70 | $14.25 | 65,621 |
| July | $15.34 | $14.00 | $14.81 | 59,199 |
| August | $16.10 | $14.78 | $15.93 | 98,715 |
| September | $16.63 | $14.90 | $15.40 | 49,654 |
| October | $15.67 | $14.47 | $15.19 | 326,909 |
| November | $16.82 | $15.19 | $16.59 | 191,893 |
| December | $18.20 | $16.58 | $17.49 | 174,384 |

The Company's Series 7 Shares began trading on the Toronto Stock Exchange on October 4, 2016 under the symbol of CPX.PR.G. The following table sets forth the reported high and low trading prices and volumes for the periods indicated:

**Toronto Stock Exchange 2020 CPX.PR.G Trading Statistics**

| Month | Share Price | | | Volume Traded |
|---|---|---|---|---|
| | High | Low | Close | |
| January | $26.25 | $25.85 | $25.85 | 51,453 |
| February | $26.17 | $25.51 | $25.54 | 51,013 |
| March | $25.79 | $18.03 | $23.29 | 233,269 |
| April | $24.50 | $22.25 | $23.61 | 148,336 |
| May | $23.91 | $22.11 | $23.65 | 114,743 |
| June | $24.70 | $23.60 | $24.20 | 94,255 |
| July | $24.83 | $24.30 | $24.75 | 63,713 |
| August | $25.65 | $24.65 | $25.48 | 49,964 |
| September | $25.55 | $24.50 | $25.00 | 99,629 |
| October | $25.35 | $24.85 | $24.93 | 98,473 |
| November | $25.25 | $24.73 | $25.25 | 83,165 |
| December | $25.50 | $25.01 | $25.21 | 71,823 |

The Company's Series 9 Shares began trading on the Toronto Stock Exchange on August 9, 2017 under the symbol of CPX.PR.I. The following table sets forth the reported high and low trading prices and volumes for the periods indicated:

**Toronto Stock Exchange 2020 CPX.PR.I Trading Statistics**

| Month | Share Price | | | Volume Traded |
|---|---|---|---|---|
| | High | Low | Close | |
| January | $25.89 | $25.47 | $25.55 | 74,801 |
| February | $25.99 | $25.50 | $25.50 | 50,339 |
| March | $25.50 | $17.00 | $21.36 | 186,185 |
| April | $23.89 | $21.35 | $22.75 | 76,742 |
| May | $23.00 | $21.08 | $22.99 | 39,991 |
| June | $23.88 | $22.95 | $23.50 | 39,624 |
| July | $23.75 | $23.34 | $23.70 | 50,113 |
| August | $24.85 | $23.62 | $24.55 | 72,983 |
| September | $24.89 | $23.00 | $23.66 | 139,982 |
| October | $24.80 | $23.50 | $24.40 | 70,988 |
| November | $25.05 | $24.17 | $24.91 | 47,943 |
| December | $25.46 | $24.96 | $25.20 | 84,132 |

The Company's Series 11 Shares began trading on the Toronto Stock Exchange on May 16, 2019 under the symbol of CPX.PR.K. The following table sets forth the reported high and low trading prices and volumes for the periods indicated:

**Toronto Stock Exchange 2020 CPX.PR.K Trading Statistics**

| Month | Share Price | | | Volume Traded |
|---|---|---|---|---|
| | High | Low | Close | |
| January | $25.93 | $25.51 | $25.61 | 85,402 |
| February | $25.95 | $25.37 | $25.68 | 65,076 |
| March | $25.55 | $16.95 | $21.85 | 268,777 |
| April | $23.71 | $21.01 | $22.65 | 170,712 |
| May | $23.00 | $21.00 | $22.65 | 68,095 |
| June | $23.77 | $22.80 | $23.50 | 70,371 |
| July | $24.00 | $23.25 | $23.90 | 91,597 |
| August | $24.90 | $23.76 | $24.65 | 72,082 |
| September | $24.95 | $23.40 | $24.50 | 110,241 |
| October | $25.05 | $24.06 | $24.41 | 103,296 |
| November | $25.33 | $24.30 | $25.33 | 105,658 |
| December | $25.50 | $25.00 | $25.40 | 78,666 |

## DIRECTORS AND OFFICERS

### Board of Directors

The name, place of residence, principal occupation, period of service as a member of the Board and membership in Board committees of each director of CPC are set forth in the following table as at December 31, 2020:

| **Name, Province / State and Country of Residence** | **Director Since** | **Office Held**(1)(2)<br>**Committee Membership**(3) | **Principal Occupation During Past Five Years** |
|---|---|---|---|
| Doyle Beneby<br>West Palm Beach, Florida, USA<br>Date of Birth: October 1959<br>Shares held:(4)<br>Nil | April 27, 2012 | Director<br>**Committees**:<br>Audit<br>PCG | Chief Executive Officer of Midland Cogeneration Venture from November 2018; prior thereto professional director from May 31, 2016; prior thereto, Chief Executive Officer, New Generation Power International, from October 2015; prior thereto, Chief Executive Officer, CPS Energy from July 2010. |
| Jill Gardiner<br>Vancouver, BC, Canada<br>Date of Birth: December 1958<br>Shares held:(4)<br>Common Shares – 8,686 | May 25, 2015 | Director<br>**Committees**:<br>Audit<br>PCG | Professional director from November 2010. |
| Kelly Huntington<br>Indianapolis, Indiana, USA<br>Date of Birth: September 1975<br>Shares held:(4)<br>Nil | June 3, 2015 | Director<br>**Committees**:<br>PCG<br>HSE | Senior Vice President and Chief Financial Officer, USIC, LLC, from November 2019; prior thereto Senior Vice President of Enterprise Strategy, OneAmerica Financial Partners, Inc., from July 2015; prior thereto, President & Chief Executive Officer, Indianapolis Power & Light Company, from June 2013 |
| Donald Lowry<br>Edmonton, Alberta, Canada<br>Date of Birth: September 1951<br>Shares held:(4)<br>Common Shares – 11,000<br>Series 1 Shares – 9,000<br>Series 5 Shares – 2,000 | July 9, 2009 | Director and Chair<br>**Committees**:(5)(6)<br>PCG<br>Audit<br>HSE | Professional director from March 2013. |

| Name, Province / State and Country of Residence | Director Since | Office Held[(1)(2)] Committee Membership[(3)] | Principal Occupation During Past Five Years |
|---|---|---|---|
| Series 7 Shares – 800<br>Series 11 Shares – 2,000 | | | |
| Jane Peverett<br>West Vancouver, BC, Canada<br>Date of Birth: September 1958<br>Shares held:[(4)]<br>Nil | March 1, 2019 | Director<br>**Committees:**<br>PCG<br>HSE | Professional director. |
| Robert L. Phillips<br>Anmore, BC, Canada<br>Date of Birth: January 1951<br>Shares held:[(4)]<br>Common Shares – 2,541 | April 26, 2019 | Director<br>**Committees:**<br>Audit<br>HSE | President of R.L. Phillips Investments Inc., a private investment firm since 2001. |
| Katharine B. Stevenson<br>Toronto, Ontario, Canada<br>Date of Birth: June 1962<br>Shares held:[(4)]<br>Common Shares – 8,000 | April 3, 2017 | Director<br>**Committees**:<br>Audit<br>PCG | Professional director. |
| Keith Trent<br>Charlotte, North Carolina, USA<br>Date of Birth: October 1959<br>Shares held:[(4)]<br>Nil | April 3, 2017 | Director<br>**Committees**:<br>Audit<br>HSE | Professional director from July 2015 and President of BK Trent LLC from January 1, 2016; prior thereto, Executive Vice President, Duke Energy, from 2005 to June 2015. |
| Brian Vaasjo<br>Edmonton, Alberta, Canada<br>Date of Birth: August 1955<br>Shares held:[(4)]<br>Common Shares – 148,903 | May 5, 2009 | Director, President and Chief Executive Officer | President and Chief Executive Officer, Capital Power Corporation from July 2009. |

**Notes:**

(1) The Board does not have an executive committee.
(2) Directors will hold office for a term expiring at the conclusion of the next annual meeting of shareholders of Capital Power or until their successors are elected or appointed and will be eligible for re-election.
(3) Board Committees: (i) Audit Committee, (ii) PCG Committee (formerly the CGC&N Committee); and (iii) HSE Committee.
(4) Represents, as of December 31, 2020, the number of Common Shares, Series 1 Shares, Series 3 Shares, Series 5 Shares, Series 7 Shares, Series 9 Shares, and Series 11 Shares as applicable, beneficially owned, or controlled or directed, directly or indirectly, by such persons.
(5) As Chair, Mr. Lowry attends committee meetings in an ex-officio, non-voting capacity.
(6) Having reached his term limit, Mr. Lowry will not be standing for re-election at the 2021 annual general meeting. On February 19, 2021 the Company announced that Mr. Lowry would retire from the Board and that the Board appointed Jill Gardiner as successor Chair, effective immediately following the meeting and subject to Ms. Gardiner being re-elected by the shareholders.

The Board has determined that all of the directors, except for Mr. Vaasjo, are independent within the meaning of applicable Canadian securities laws on the basis that they do not have any material direct or indirect relationship with the Company which could, in the view of the Board, be reasonably expected to interfere with the exercise of their independent judgment. Mr. Vaasjo is not considered independent as he is the President and Chief Executive Officer of the Company.

## Executive Officers

CPC's officers are appointed by and serve at the discretion of the Board. The following table sets forth the names, place of residence, and position with Capital Power of each person who is an executive officer of Capital Power as at December 31, 2020(2):

| **Name, Province / State and Country of Residence** | **Officer Since** | **Office Held** | **Principal Occupation During the last 5 Years** |
|---|---|---|---|
| Brian Vaasjo<br>Edmonton, Alberta, Canada<br>Date of Birth: August 1955<br>Shares held:(1)<br>Common Shares – 148,903 | May 1, 2009 | President and Chief Executive Officer, Director | President and Chief Executive Officer, Capital Power Corporation from July 2009 |
| Sandra Haskins<br>Edmonton, Alberta, Canada<br>Date of Birth: December 1959<br>Shares held:(1)<br>Common Shares – 3,315 | July 30, 2020 | Senior Vice President. Finance and Chief Financial Officer since July 30, 2020; prior thereto Vice President and Treasurer from February 16, 2018 to July 30, 2020; prior thereto Vice President Forecasting and Analytics from June 30, 2013 to February 16, 2018 | Senior Vice President, Finance and Chief Financial Officer since July 30, 2020; prior thereto Vice President and Treasurer from February 16, 2018 to July 30, 2020; prior thereto Vice President Forecasting and Analytics from June 30, 2013 to February 16, 2018 |

| Name, Province / State and Country of Residence | Officer Since | Office Held | Principal Occupation During the last 5 Years |
|---|---|---|---|
| Bryan DeNeve<br>Edmonton, Alberta, Canada<br>Date of Birth: July 1965<br>Shares held:[1]<br>Common Shares –45,355 | January 4, 2011 | Senior Vice President, Business Development and Commercial Services since July 30, 2020; prior thereto Senior Vice President, Finance and Chief Financial Officer since May 1, 2015; prior thereto Senior Vice President, Corporate Development and Commercial Services, since November 2012; prior thereto Senior Vice President, Commercial Services from January 2011 | Senior Vice President, Business Development and Commercial Services since July 30, 2020; prior thereto Senior Vice President, Finance and Chief Financial Officer, Capital Power Corporation since May 1, 2015 |
| B. Kathryn Chisholm, Q.C.<br>Edmonton, Alberta, Canada<br>Date of Birth: May 1963<br>Shares held:[1]<br>Common Shares – 25,018<br>Series 7 – 1,000 | May 1, 2009 | Senior Vice President, Planning, Stakeholder Relations and Chief Sustainability Officer since July 30, 2020; prior thereto Senior Vice President, Chief Legal and Sustainability Officer since July 27, 2018; prior thereto Senior Vice President, Chief Legal and Sustainability Officer and Corporate Secretary since April 5, 2018; prior thereto Senior Vice President, Legal and External Relations and Corporate Secretary, from November 2012; prior thereto Senior Vice President, General Counsel and Corporate Secretary from May 2009 | Senior Vice President, Planning, Stakeholder Relations and Chief Sustainability Officer since July 30, 2020; prior thereto Senior Vice President, Chief Legal and Sustainability Officer since April 5, 2018; prior thereto Senior Vice President, Legal and External Relations, Capital Power Corporation from November 2012 |

| Name, Province / State and Country of Residence | Officer Since | Office Held | Principal Occupation During the last 5 Years |
|---|---|---|---|
| Chris Kopecky<br>Boston, Massachusetts, USA<br>Date of Birth: June 1972<br>Shares held:[(1)]<br>Common Shares – Nil | July 30, 2020 | Senior Vice President, Chief Legal Officer since July 30, 2020; prior thereto Vice President, Business Development and Commercial from June 10, 2014 | Senior Vice President, Chief Legal Officer since July 30, 2020; prior thereto Vice President, Business Development and Commercial from June 10, 2014 |
| Darcy John Trufyn<br>Edmonton, Alberta, Canada<br>Date of Birth: July 1955<br>Shares held:[(1)]<br>Common Shares – 76,262 | October 9, 2009 | Senior Vice President, Operations, Engineering and Construction from November 2012; prior thereto Senior Vice President, Construction, Engineering and Project Management from October 2009 | Senior Vice President, Operations, Engineering and Construction, Capital Power Corporation from November 2012. |
| Jacquelyn Marie Pylypiuk<br>St. Albert, Alberta, Canada<br>Date of Birth: February 1969<br>Shares held:[(1)]<br>Common Shares – 7,797 | April 2015 | Senior Vice President, People, Culture and Technology since July 30, 2020; prior thereto Vice President, Human Resources | Senior Vice President, People, Culture and Technology since July 30, 2020; prior thereto Vice President, Human Resources, Capital Power Corporation, from April 2015 |

**Notes:**

(1) Represents as of December 31, 2020 the number of Common Shares, Series 1 Shares, Series 3 Shares, Series 5 Shares, Series 7 Shares, Series 9 Shares, and Series 11 Shares, as applicable, beneficially owned, or controlled or directed, directly or indirectly, by such persons.
(2) See also "Company History – 2020 – Executive Appointments"

As at December 31, 2020, the directors of the Company who are not also executive officers of the Company, as a group, beneficially owned, or controlled or directed, directly or indirectly, 30,227 Common Shares ($34.98 per share as at the close of trading on December 31, 2020 for a value of $1,057,340.46), which is less than 1% of the issued and outstanding Common Shares, 9,000 Series 1 Shares ($11.78 per share as at the close of trading on December 31, 2020 for a value of $106,020), which is less than 1% of the issued and outstanding Series 1 Shares, 2,000 Series 5 Shares ($17.49 per share as at the close of trading on December 31, 2020 for a value of $34,980), which is less than 1% of the issued and outstanding Series 5 Shares, 800 Series 7 Shares ($25.21 per share at the close of trading on December 31, 2020 for a value of $20,168) which is less than 1% of the issued and outstanding Series 7 Shares, and 2,000 Series 11 Shares ($25.40 per share at the close of trading on December 31, 2020 for a value of $50,800) which is less than 1% of the issued and outstanding Series 11 Shares.

As at December 31, 2020, the directors and executive officers of the Company, as a group, beneficially owned, directly or indirectly, or exercised control or direction over 336,697 Common Shares ($34.98 per share as at the close of trading on December 31, 2020 for a value of $11,777,661.06), which is less than

1% of the issued and outstanding Common Shares of the Company, 9,000 Series 1 Shares ($11.78 per share as at the close of trading on December 31, 2020 for a value of $106,020), which is less than 1% of the issued and outstanding Series 1 Shares, 2,000 Series 5 Shares ($17.49 per share as at the close of trading on December 31, 2020 for a value of $34,980), which is less than 1% of the issued and outstanding Series 5 Shares, 1,800 Series 7 Shares ($25.21 per share at the close of trading on December 31, 2020 for a value of $45,378) which is less than 1% of the issued and outstanding Series 7 Shares, and 2,000 Series 11 Shares ($25.40 per share at the close of trading on December 31, 2020 for a value of $50,800) which is less than 1% of the issued and outstanding Series 11 Shares. The information as to the beneficial ownership of the Common Shares, Series 1 Shares, Series 5 Shares, Series 7 Shares, and Series 11 not being within the knowledge of the Company, has been confirmed by the directors and executive officers individually.

**Corporate Cease Trade Orders, Bankruptcies, Penalties or Sanctions**

As at December 31, 2020, except as noted below, and to the knowledge of the Company, no director, executive officer or controlling security holder of the Company is, or within the ten years prior to the date hereof, has been, a director or executive officer of any other issuer that, while that person was acting in that capacity:

(i) was the subject of a cease trade or similar order or an order that denied the relevant company access to any exemption under securities legislation for a period of more than 30 consecutive days;

(ii) was subject to an event that resulted, after the person ceased to be a director or executive officer, in the corporation being the subject of a cease trade or similar order or an order that denied the relevant company access to any exemption under securities legislation for a period of more than 30 consecutive days; or

(iii) 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.

Keith Trent was a member of the management committee of Crescent Resources, LLC, a real estate joint venture between Duke Energy Corporation and Morgan Stanley Real Estate Fund. In 2009, subsequent to Mr. Trent having ceased to be a member of the management committee, Crescent Resources, LLC went into chapter 11 bankruptcy protection under the U.S. Bankruptcy Code.

Jane Peverett was a director of Postmedia Network Canada Corp. (Postmedia) between April 2013 and January 2016. On October 5, 2016, Postmedia completed a recapitalization transaction pursuant to a court approved plan of arrangement under the Canada Business Corporations Act under which, approximately US $268.6 million of debt was exchanged for shares that represented approximately 98% of the outstanding shares at that time. Additionally, Postmedia repaid, extended and amended the terms of outstanding debt obligations pursuant to the recapitalization transaction.

**Conflicts of Interest**

Certain directors and officers of the Company are associated with other reporting issuers or other corporations which may give rise to conflicts of interest. In accordance with corporate laws, directors who are a party to, are a director or officer of a party to, or have a material interest in any person who is a party to a material contract or material transaction or a proposed material contract or material transaction with the Company are required, subject to certain exceptions, to disclose that interest and generally abstain from voting on any resolution to approve the contract or transaction. In addition, the directors are required to act honestly and in good faith with a view to the best interests of the Company.

Robert Phillips is a director of West Fraser Timber Co. Ltd. ("West Fraser"). West Fraser, together with Capital Power, is a member of the PPA syndicate that is involved in the various disputes regarding the Milner Line Loss Litigation.

Conflicts, if any, will be subject to the procedures and remedies available under the CBCA. The CBCA provides that in the event that a director has an interest in a contract or proposed contract or agreement, the director shall disclose his interest in such contract or agreement and shall refrain from voting on any matter in respect of such contract or agreement unless otherwise provided by the CBCA.

## LEGAL PROCEEDINGS AND REGULATORY ACTIONS

Management is not aware of any existing or contemplated legal proceedings material to Capital Power to which it is a party or to which its property is subject except as described below.

### Milner Power Inc. (Milner) Loss Factor Complaint

Capital Power has participated in a proceeding before the AUC to re-hear a complaint originally filed by Milner in 2005 against the AESO's loss factor calculation methodology (LFM). The AUC initially rejected the complaint in 2005, but Milner appealed the decision in 2006. The Court of Appeal issued a ruling in 2010 directing the AUC to re-hear the complaint.

The LFM is used to calculate generator-specific line loss factors and forms the basis for certain transmission charges paid by Alberta generators. Milner alleged that the existing LFM, developed by the AESO in consultation with stakeholders in 2005 and implemented January 1, 2006, did not comply with applicable regulations. Milner advocated for the adoption, retroactively back to 2006 and on a go-forward basis, of an alternative LFM that would increase the line loss charges to Alberta generating units generally further away from load centres (including Genesee and Keephills) and proportionately decrease the charges to those that are closer in proximity to load (including Shepard). However, some facilities may see little to no impact.

In 2015, the AUC determined that the LFM did not comply with applicable regulations. The AUC also determined that it has the jurisdiction to direct retroactive adjustments to loss factor charges and credits back to January 1, 2006. Capital Power and other parties have challenged this and other determinations to the Alberta Court of Appeal.

On November 30, 2016, the AUC approved a new methodology for determining loss factors on a prospective basis effective January 2017.

A final AUC proceeding was held in 2017 to establish the methodology to be used in determining retroactive line loss adjustments. The AUC issued a decision in December 2017 and concluded that the prospective methodology be adapted for determining retroactive adjustments back to January 2006. Implementation activities by the AESO were held over the course of 2018 and 2019 and most of 2020.

With the outstanding phases of the AUC process relating to the Milner complaint largely complete, the Alberta Court of Appeal resumed the appeal process in June of 2018. A Court of Appeal hearing was held in June of 2018 to consider whether permission to appeal will be granted. On December 20, 2018, the Court of Appeal issued a decision rejecting the permission to appeal applications that sought to overturn the AUC's finding on jurisdiction to issue retroactive tariff adjustments. The Court of Appeal subsequently issued a decision on June 3, 2019 denying the applications that seek, among other things, to challenge the aspect of the AUC's 2017 decision that establishes the recipient of adjustment invoices.

On December 3, 2019 the AESO filed an application with the AUC seeking to have the AUC review and vary its December 2017 decision regarding the invoicing process for the historic line loss adjustments. In its December 2017 decision, the AUC had determined that the AESO implement a single settlement process for invoicing for the entire historic period of January 1, 2006 to December 31, 2016. In its review and variance application, the AESO requested that among other things, the AUC permit the AESO to implement "pay-as-you-go" settlement of line loss adjustment invoices on a year by year basis as the AESO completed its recalculations for each year, starting with 2006.

On January 10, 2020, the AUC issued a process letter to all interested parties pursuant to which all written submissions of interested parties and the AESO would be completed by February 21, 2020. Capital Power filed submissions opposing the AESO's requested relief.

On July 9, 2020, the AUC rendered its decision directing the AESO to issue three separate invoices for the various historic years instead of a single invoice for the entire period. The AESO's invoicing compliance plan was subsequently approved in September, 2020.

On October 22, 2020 the AESO issued the first invoices covering the years 2014-2016, and payment for the related amounts occurred at the end of 2020. Concurrently, the amounts invoiced to Capital Power but not attributable to the Company were invoiced to the appropriate parties for recovery.

In December 2020, the AESO issued the second batch of invoices covering the years 2010-2013 which are required to be settled by March 1, 2021. The third batch of invoices covering the years 2006-2009 are expected to be issued in March 2021 and are required to be settled by May 31, 2021. Based on current AUC decisions, Capital Power would incur additional charges related to historical periods and, as such, has recorded $20 million pertaining to the estimated net liability for its currently held Alberta assets. This amount reflects an increase of $5 million recorded during 2020 to reflect updated information published by the AESO.

In addition, in November 2020, the AESO filed a letter with the AUC requesting guidance on the treatment of interest relating to the historic invoice amounts, and particularly whether a simple interest or compound interest should apply. On January 26, 2021 the AUC issued a decision in this proceeding ordering the use of simple interest, as reflected in invoices issued by the AESO to that date.

See "Regulatory Overview – Alberta – Transmission Line Losses" and "Risk Factors".

## TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for the Common Shares and preferred shares is Computershare Trust Company of Canada at its principal offices in Calgary, Alberta and Toronto, Ontario.

## INTERESTS OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

No director, executive officer or principal holder of securities or any associate or affiliate of the foregoing has, or has had, within the three most recently completed financial years, any material interest in any transaction, or in any proposed transactions that has materially affected or will materially affect the Company or been indebted to the Company, except for routine indebtedness, other than as set forth in the AIF. See "Material Contracts".

EPCOR holds the one issued and outstanding Special Limited Voting Share. The Special Limited Voting Share confers on the holder the right to vote separately as a class in connection with certain amendments to the articles of the Company, including an amendment to change or permit the change of the location of the head office of the Company from the City of Edmonton, Alberta. EPCOR has undertaken to its sole shareholder, the City of Edmonton that it will not exercise, dispose of or otherwise relinquish any rights it has under the Special Limited Voting Share without the consent of the City of Edmonton.

## MATERIAL CONTRACTS

The following are the only material contracts, other than those contracts entered into in the ordinary course of business, which Capital Power has entered into since its incorporation on May 1, 2009 and within the most recently completed financial year.

- Master Separation Agreement between EPCOR and Capital Power dated June 25, 2009 (Master Separation Agreement)
- Social Objectives Agreement among EPCOR, 7166575 Canada Inc. and The City of Edmonton dated May 5, 2009, as amended on February 4, 2014 (Social Objectives Agreement)
- Amended and Restated Shareholder Rights Plan Agreement between CPC and Computershare Trust Company of Canada dated April 22, 2016 (Amended and Restated Rights Plan Agreement)

- Off-Coal Agreement between Capital Power, certain of its subsidiaries and the Province of Alberta dated November 24, 2016 (Off-Coal Agreement)

The following section provides a summary of these agreements. Copies of the above material agreements may be viewed on SEDAR at www.sedar.com.

**Master Separation Agreement**

The Master Separation Agreement contains the key provisions related to the separation of the business of the Company from EPCOR and the transfer of the power generation business from EPCOR to the Company pursuant to the Reorganization. All of the Company's and EPCOR's covenants and agreements in the Master Separation Agreement will survive indefinitely, subject to applicable laws. Certain of the principal provisions of the Master Separation Agreement relate to:

- The ownership and transfer of assets, including the separation of the Company's assets and assumption of liabilities from EPCOR through transfer agreements that the Company and / or CPLP have entered into with EPCOR. The assets constituting the business of Capital Power were transferred to the Company and CPLP on an "as is", "where is" basis without any representations or warranties, express or implied, as to its condition, quality, merchantability or fitness and the Company and / or CPLP, as applicable, bear the economic and legal risks if any conveyance proves to be insufficient to vest good and marketable title in such transferee;

- Capital Power indemnifying EPCOR, each of EPCOR's controlled subsidiaries, and each of their respective directors, officers, employees, consultants, advisers and agents from all losses they may suffer relating to, arising out of, or in respect of certain circumstances or events, whether such losses arise or accrue prior to, on or following the closing of the Reorganization, including Capital Power's business or future business or any liabilities arising out of or related to such business or Capital Power's assets; and

- EPCOR indemnifying Capital Power, each of Capital Power's controlled subsidiaries, and each of their respective directors, officers, employees, consultants, advisers and agents from all losses they may suffer relating to, arising out of, or in respect of certain circumstances or events, whether such losses arise or accrue prior to, on or following the closing of the Reorganization, including EPCOR's business or future business or any liabilities arising out of or related to such business or EPCOR's assets (excluding any liability arising out of the business of Capital Power).

**Social Objectives Agreement**

Pursuant to the Social Objectives Agreement, the Company agreed to maintain its head office in the City of Edmonton in the Province of Alberta and to maintain at least 350 employees based in the City of Edmonton for a period of 25 years following completion of the IPO. In February 2014, the Social Objectives Agreement was amended by agreement among the Company, EPCOR, and the City of Edmonton to replace the requirement for the Company to maintain at least 350 employees in the City of Edmonton with a requirement for the Company to maintain two-thirds of its corporate shared service employees in the City of Edmonton. See "Capital Structure – Special Limited Voting Share".

**Amended and Restated Shareholder Rights Plan Agreement**

On November 20, 2012, the Board approved the adoption of a shareholder rights plan (2012 Rights Plan). The 2012 Rights Plan Agreement, dated November 20, 2012 between the Company and Computershare Trust Company of Canada, as rights agent, and the 2012 Rights Plan were confirmed and ratified by the Company's shareholders at its annual meeting of shareholders on April 26, 2013. On February 18, 2016, the Board resolved to continue the 2012 Rights Plan and to adopt an Amended and Restated Shareholder Rights Plan Agreement which was approved by shareholders at the April 22, 2016 annual meeting of shareholders of Capital Power (Rights Plan). The terms of the Rights Plan are the same in all material respects as the 2012 Rights Plan, but for certain minor amendments described below.

The following were the amendments to the 2012 Rights Plan contained within the Rights Plan, as amended and restated:

- The definition of "Expiration Time" in the Rights Plan, and the requirement for future shareholder approval to ratify the continued existence of the Rights Plan, were simplified to specify that requisite shareholder approval will be obtained to continue the rights plan at every third annual general meeting of shareholders or else the Rights Plan will terminate.

- The definition of "Permitted Lock-Up Agreement" was amended to include Convertible Securities (as such term is defined in the Rights Plan) as securities of Capital Power that may be the subject of a permitted lock-up agreement, in addition to the Voting Shares.

- The definition of "Permitted Bid" was amended to be the longer of 60 days or the minimum take-over bid deposit period prescribed by law. Under current securities regulations, this will not result in any change to the length of a permitted bid. Due to certain announced changes to securities law governing take-over bids, this language was added to contemplate changes to the law.

- Certain other amendments of a non-substantive, "housekeeping" nature were made to account for the fact that there are no longer any Exchangeable LP Units or Special Voting Shares outstanding. These changes provide greater clarity and consistency.

The Rights Plan authorizes the issuance of one right (Right) in respect of each Common Share (the Voting Shares). The Rights initially trade with and are represented by the certificates representing the Voting Shares, and until such time as the Rights separate from the Voting Shares and become exercisable, Rights certificates will not be distributed to shareholders.

Each Right is initially attached to and will trade with the Voting Shares in respect of which it was issued. The Rights will separate from the Voting Shares to which they are attached and become exercisable after the time (Separation Time) which (subject to the Board deferring the Separation Time) is the close of business ten trading days following the date of public announcement that a person has become an Acquiring Person (as defined below) or announces an intention to make a take-over bid that is not in compliance with the provisions of the Rights Plan.

Upon the occurrence of any transaction or event in which a person (an Acquiring Person), including associates and affiliates and others acting jointly or in concert, acquires (other than pursuant to a Permitted Bid (as defined in the Rights Plan) or another exemption available under the Rights Plan) Beneficial Ownership (as defined in the Rights Plan) of 20% or more of the outstanding Voting Shares of the Company (a Flip-in Event), any Rights held by an Acquiring Person will become void and the Rights held by all other holders of Rights will permit such holders to purchase Common Shares at a substantial discount to their then prevailing market price.

A bidder can make a take-over bid and acquire Common Shares of the Company without triggering a Flip-In Event under the Rights Plan if the take-over bid qualifies as a Permitted Bid. The Rights Plan also allows for a competing Permitted Bid (Competing Permitted Bid) to be made while a Permitted Bid is in existence, as long as the Competing Permitted Bid satisfies certain conditions.

With the consent by majority vote of Independent Shareholders (as defined in the Rights Plan) prior to the Separation Time, or the consent by majority vote of the independent holders of Rights after the Separation Time, the Board may redeem all of the outstanding Rights at a price of $0.00001 per right. With the consent by majority vote of Independent Shareholders prior to the Separation Time, the Board may waive the application of the Rights Plan to a Flip-in Event that occurs other than by means of a takeover bid made by way of a takeover bid circular sent to all holders of Voting Shares. Without the approval of shareholders or holders of Rights, the Board may waive the application of the Rights Plan to a Flip-in Event that occurs by means of a takeover bid made by way of a takeover bid circular sent to all holders of Common Shares.

The foregoing description of the Rights Plan is qualified entirely by the full text of the Rights Plan.

At the Company's Annual General Meeting held April 26, 2019, the shareholders voted to approve continuation of the Rights Plan. The Rights Plan will expire at the close of business on the date of the 2022 annual meeting of shareholders unless otherwise further extended by the shareholders at that time.

**Off-Coal Agreement**

On November 24, 2016, Capital Power and the Province of Alberta entered into the Off-Coal Agreement. The parties agreed that Capital Power's coal-fired electricity generation facilities will cease coal-fired emissions on or before December 31, 2030, and Capital Power is to receive cash payments from the Province of $52.4 million annually for 14 years, commencing July 31, 2017, for a total of $734 million. The Government of Alberta has conducted an audit on the calculation of net book values driving the compensation payments and has withheld $2 million from the 2017, 2018 and 2019 payments. The Company is disputing the withholding but has reduced the amounts recorded related to the compensation stream to reflect the uncertainty. Capital Power has also agreed to continue to participate in the Alberta electricity market, support the local communities surrounding the coal facilities through 2030, and fulfill its pension and other commitments to employees.

## INTERESTS OF EXPERTS

The Company's auditors are KPMG LLP, Chartered Professional Accountants, located at Suite 2200, 10175 – 101 Street, Edmonton, Alberta T5J 0H3. KPMG LLP has confirmed that they are independent with respect to the Company within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulations.

## AUDIT COMMITTEE

### Audit Committee Mandate

The responsibilities and duties of the Audit Committee are set out in the Committee's Terms of Reference, provided in Appendix A to this AIF.

### Composition of the Audit Committee

As at December 31, 2020, the Audit Committee was composed of Katharine Stevenson (Chair), Doyle Beneby, Jill Gardiner, Robert Phillips and Keith Trent. As Chair of the Board, Donald Lowry also attends Audit Committee meetings in an ex-officio, non-voting capacity. The Board has determined that all members of the Audit Committee are "independent" and "financially literate" as such terms are defined under applicable Canadian securities law and mandated under the Board terms of reference. See "Directors and Officers".

*Remainder of page intentionally left blank*

The Board based the determination regarding financial literacy on the education and breadth and depth of experience of each Audit Committee member, as summarized in the following table:

| AC Member | Relevant Education and Experience |
|---|---|
| Katharine Stevenson | • member of public company audit committees for 12 years<br>• previously chair of the audit committees of CAE Inc. and OSI Pharmaceuticals, Inc.<br>• formerly a senior financial executive/Global Treasurer of Nortel Networks from 1997 to 2005<br>• previously held progressively senior finance roles in corporate and investment banking at J.P. Morgan and Company from 1984 to 1995<br>• has earned her ICD.D designation from the Institute of Corporate Directors<br>• Director in Residence for the Institute of Corporate Directors Audit Committee Effectiveness Course, periodically in recent years |
| Doyle Beneby | • currently Chief Executive Officer of Midland Cogeneration Venture (the largest natural gas fired combined electrical energy and steam energy generating facility in the U.S.) since November 2018<br>• formerly served as Chief Executive Officer of New Generation Power International (an international independent renewable energy company) from 2015 to 2016<br>• formerly served as President and Chief Executive Officer of CPS Energy (the largest municipally-owned gas and electric utility company in the U.S.) from 2010 to 2015<br>• formerly served as Senior Vice President and Acting President of Exelon Corporation in 2009 and 2010<br>• has an MBA |
| Jill Gardiner | • member of the audit committee of Trevalli Mining Corporation<br>• past chair of the board of directors of Turquoise Hill Resources Ltd. and a past member and former chair of its Audit Committee<br>• previously a member (or chair) of the audit committees of Capstone Mining Corp., Timber Investments Ltd., The Banff Centre and SAIT Polytechnic<br>• previously spent over 20 years in the investment banking industry, most recently as Managing Director and Regional Head, British Columbia, for RBC Capital Markets<br>• has previously held various positions in corporate finance, mergers and acquisitions, and debt capital markets<br>• holds an MBA (with a major in finance and accounting) from Queen's University<br>• past lecturer in corporate finance at the University of Victoria |

| AC Member | Relevant Education and Experience |
|---|---|
| Robert Phillips | • acquired significant experience and exposure to accounting and financial reporting issues as the current President of R.L. Phillips Investments Inc., a private investment firm<br>• formerly President and Chief Executive Officer of the BCR Group of Companies, PTI Group Inc, and Dreco Energy Services Ltd.<br>• formerly Executive Vice President of MacMillan Bloedel Limited<br>• current Chair and member of the Audit Committee of Canadian Western Bank<br>• current director and former member of the Audit Committee of Canadian National Railway Company<br>• former director of Maxar Technologies Inc. and member of its Audit Committee<br>• former director and Chair of Precision Drilling Corporation and member of its Audit Committee<br>• fellow and director of the Institute of Corporate Directors and Chair of its Audit Committee |
| Keith Trent | • former General Counsel for Duke Energy overseeing the internal audit team<br>• previous profit/loss accountability for four of Duke Energy's electric utilities and for its commercial generation business<br>• former Chair of Duke Energy's Transaction and Risk Committee which provided financial and risk analysis for numerous transactions<br>• current director and member of the Audit Committee of Edison International<br>• former director and member of the Audit Committee of TRC, Inc. |

**Policies and Procedures for the Engagement of Audit and Non-audit Services**

Under its Terms of Reference, before Capital Power engages the external auditor for additional audit or non-audit services, the Audit Committee must pre-approve that engagement. If, for reasons of timing, pre-approval is not possible and it is not possible to wait until the next scheduled Audit Committee meeting, the Chair of the Audit Committee has the delegated authority to pre-approve non-audit services as long as the individual engagement fees are projected to be less than $100,000, subject to an annual maximum approval limit of $250,000. Any pre-approval must be reported to the Audit Committee for ratification at its next meeting. In 2020, the Chair of the Audit Committee did not pre-approve any non-audit services. In 2020, the committee pre-approved non-audit related services in an amount not to exceed $90,000 with respect to a post implementation assessment of the newly implemented Finance organizational structure at the Company.

*Remainder of page intentionally left blank*

**Auditor's Fees**

KPMG LLP has served as the Company's auditors since its incorporation. Fees accrued by KPMG LLP to the Company for the year ended December 31, 2020 in respect of the Company and the Company's subsidiaries were approximately $1.7 million as detailed below.

| | **Twelve Months Ended December 31, 2020 ($ Millions)** | **Twelve Months Ended December 31, 2019 ($ Millions)** |
|---|---|---|
| Audit Fees | 1.0 | 1.1 |
| Audit Related Fees | 0.1 | 0.1 |
| Tax fees | - | - |
| All Other fees | 0.6 | 0.4 |
| **Total** | **1.7** | **1.6** |

*Audit fees* – Audit fees billed are for professional services rendered for the audit and review of the financial statements of the Company or services provided in connection with statutory and regulatory filings and providing comfort letters associated with securities documents.

*Audit related fees* – Audit related fees are for assurance and related services that are reasonably related to the performance of the audit or review of the financial statements and are not reported under audit fees listed above.

*Tax fees* – Tax fees are tax-related services for review of tax returns, assistance with questions on tax audits, and tax planning.

*All other fees* – All other fees are fees for operational advisory and risk management services and non-securities legislative and regulatory compliance work.

**Other Committees**

Apart from the Audit Committee, the Board has established: (i) the PCG Committee to oversee matters relating to corporate governance, compensation and nomination; and (ii) the Health, Safety and Environment Committee to oversee matters relating to the impact of the Company's operations on the environment and on workplace health and safety. Mr. Lowry, the Chair of the Board, is a non-voting ex-officio member of all committees. The members of these committees as at December 31, 2020 were as follows:

PCG Committee

Ms. Jill Gardiner, Chair
Mr. Doyle Beneby
Ms. Kelly Huntington
Ms. Jane Peverett
Ms. Katharine Stevenson
Mr. Donald Lowry (ex-officio)

<u>Health, Safety and Environment Committee</u>

Mr. Keith Trent, Chair
Ms. Kelly Huntington
Ms. Jane Peverett
Mr. Robert Phillips
Mr. Donald Lowry (ex-officio)

The Board established an ad hoc CEO Search Committee in July 2019 (comprised of Doyle Beneby (chair), Jill Gardiner, Kelly Huntington, and Donald Lowry). The ad hoc committee met informally in 2019 (July-December) and in January and February of 2020. On February 24, 2020, the Company announced that Brian Vaasjo will remain as President and CEO for a period of three years. Following the announcement, the ad hoc committee was dissolved.

## ADDITIONAL INFORMATION

Additional information relating to the Company may be found on SEDAR at www.sedar.com and on the Company's website at www.capitalpower.com.

Additional financial information is provided in the Company's annual audited consolidated financial statements and Integrated Annual Report for the year ended December 31, 2020.

The "Risks and Risk Management" section of the Company's Integrated Annual Report for the year ended December 31, 2020 is incorporated herein by reference and is available on SEDAR.

The Company's material change reports are incorporated herein by reference and is available on SEDAR.

Additional information, including directors' and officers' remuneration and indebtedness, principal holders of the Company's securities and securities authorized for issuance under equity compensations plans, if applicable, is contained in the Company's information circular for its most recent annual meeting of securityholders that involved the election of directors.

**APPENDIX "A"**

**AUDIT COMMITTEE**

**TERMS OF REFERENCE**

---

## A. Overview and purpose

1. The Audit Committee (the "Committee"), except to the extent otherwise provided by law, is responsible to the Board of Directors (the "Board") of Capital Power Corporation (the "Corporation"). The Committee provides assistance to the Board in fulfilling its oversight responsibility to shareholders of the Corporation, the investment community and others in relation to the integrity of the Corporation's financial statements, financial reporting processes, systems of internal accounting and financial controls, the risk identification assessment conducted by the President and Chief Executive Officer (the "CEO") and their management team ("Management") (including fraud risk assessment) and the programs established by the CEO and Management and the Board in response to such assessment, the internal audit function and the external auditors' qualifications, independence, performance and reports to the Corporation. In addition, the Committee monitors, evaluates, advises or makes recommendations, in accordance with these terms of reference and any other directions of the Board, on matters affecting the financial and operational control policies and practices relating to the Corporation, including the external, internal or special audits thereof. Finally, the Committee monitors, evaluates, advises or makes recommendations, in accordance with these terms of reference and any other directions of the Board, on matters related to the raising of capital and capital allocation.

2. The CEO and Management are responsible for preparing the interim and annual financial statements of the Corporation and for maintaining a system of risk assessment and internal controls to provide reasonable assurance that assets are safeguarded and that transactions are authorized, recorded and reported properly. The Committee is responsible for reviewing the CEO and Management's actions and has the authority to investigate any activity of the Corporation. The primary responsibilities of the Committee include:

    a. assessing the processes related to identification of the risks and effectiveness of the Corporation's control environment, as they relate to the production of financial statements and other publicly disclosed financial information;

    b. overseeing and monitoring the Corporation's financial reporting;

    c. evaluating the Corporation's internal control systems for financial reporting;

    d. overseeing the audit of the Corporation's financial statements;

    e. overseeing and monitoring the qualifications, independence and performance of the Corporation's external auditors;

    f. maintaining direct lines of communication between the Corporation's external auditors, its internal auditing department, the CEO, Management and the Board;

    g. evaluating the internal and external, and any special, audit processes; and

    h. monitoring and evaluating the Corporation's financial risks.

3. The Committee will have unrestricted access to the Corporation's personnel and documents, including its internal auditors, and will be provided with the resources required to carry out its responsibilities. The Committee is authorized to retain, at the expense of the Corporation,

independent outside advisors and consultants as it sees fit to assist it in carrying out its duties and responsibilities.

4. The Committee will be the direct report for the external auditors, will evaluate their performance and will recommend their compensation to the Board.

**B. Structure and membership**

1. The Committee will be composed of such number of directors of the Corporation ("Directors") as may be specified by the Board from time to time, which number will be not less than three.

2. The Chair of the Board is an ex-officio and non-voting member of the Committee, unless appointed by the Board as a Committee Member.

3. At the first meeting of the Board following the Corporation's annual general meeting, committee members (the "Committee Members") and the chair of the Committee (the "Committee Chair") will be appointed by the Board on the recommendation of the People, Culture, and Governance Committee (the "PCG Committee").

4. All Committee Members will be independent and unrelated, as set forth in all applicable securities laws and regulations or the rules or guidelines of any stock exchange on which the securities of the Corporation are listed for trading (including, without limitation, National Instrument 52-110 *Audit Committees* or "NI 52-110", as implemented by the Canadian Securities Administrators and as amended or replaced from time to time), and have no relationship with the Corporation that may materially interfere with the ability of each Committee member to act with a view to the best interests of the Corporation.

5. All Committee Members will be financially literate (as such term is defined in NI 52-110). At least one member of the Committee will have a professional accounting designation or equivalent financial expertise as determined by the Board.

6. All members of the Board will be free to attend and participate at any meetings of the Committee, but only Committee Members will be entitled to vote on any question before the Committee. Other than members of the Board, entitlement to attend all or a portion of any Committee meeting will be determined by the Committee Chair or Committee Members

**C. Duties and responsibilities**

The Committee will:

1. Review the Corporation's annual audited financial statements including the notes thereto, management's discussion and analysis, earnings press releases and annual information forms before such documents are submitted to the Board for approval, including any report or opinion to be rendered in connection therewith, and make recommendations as to their approval by the Board.

2. Review, and make recommendations for subsequent approval by the Board, the Corporation's quarterly financial statements including the notes thereto, management's discussion and analysis and earnings press releases of the Corporation.

3. Review with the CEO and Management, the external auditors and**,** if necessary**,** internal and external legal counsel, any material litigation, claim, compliance issues, or regulatory or other contingency that could have a material effect upon the financial position or operating results of the Corporation and the manner in which these will be, or have been, disclosed in the Corporation's financial statements.

4. Review on a quarterly basis with the Corporation's chief financial officer (the "CFO") and General Counsel, and if necessary, external legal counsel, the status of all material litigation, claims, compliance issues, or regulatory or other contingencies faced by the Corporation.

5. Review, or establish procedures for the review of, all public disclosure documents containing audited, unaudited or forward-looking financial information before release by the Corporation, including any prospectus, management information circulars, offering memoranda, annual reports, management certifications, management's discussion and analysis, annual information forms and press releases.

6. As required, review Management's plans and strategies around investment practices, banking performance, treasury risk management, corporate finance and financial capital allocation, including, without limiting the generality of the foregoing, reviewing financing transactions such as offerings of debt or equity securities and obtaining, amending or extending credit facilities, and recommending the same to the Board.

7. Assess Management's procedures to ensure compliance by the Corporation with its loan and indenture covenants and restrictions, if any.

8. Monitor the appropriateness of the accounting policies and practices and financial reporting used by the Corporation, review any actual and prospective significant changes to such accounting policies and practices financial reporting to be adopted by the Corporation and review and assess any new or proposed developments in accounting and reporting standards that may affect or have an impact on the Corporation.

9. Review and recommend the nomination of the external auditors to the Board for appointment by the shareholders at the Corporation's annual general meeting. In connection therewith, the Committee will review the experience and qualifications of the external auditors' senior personnel who are providing audit services to the Corporation and the quality control procedures of the external auditors.

10. Review and discuss with the external auditors all relationships that the external auditors and their affiliates have with the Corporation and its affiliates in order to determine the independence of the Corporation's external auditors, including, without limitation (i) requesting, receiving and reviewing, at least annually, a formal written report from the external auditors delineating all relationships that may reasonably bear on the independence of the external auditors with respect to the Corporation; and (ii) discussing with the external auditors any disclosed relationships or services that the external auditors believe may affect the objectivity and independence of the external auditors. Following receipt and review of the external auditors' report and discussion with the external auditors, recommending that the Board, in response to the relationships or services disclosed in the report, take appropriate action to satisfy itself of the external auditors' independence.

11. Discussing with the Board whether, due to the passage of time or for other reasons, it would be appropriate to change the Corporation's external auditors or the audit engagement partner and, after consultation with appropriate Management, recommending either that the external auditors be changed or retained for each future fiscal year. This is achieved through annual reviews of the external auditors, with a comprehensive review conducted every 5 years. Annual reviews include evaluation of the external auditors based on audit quality indicators including metrics for fee competitiveness, involvement of partners/managers in the Corporation's audits, audit team turnover, use of topical specialists in the audit, and audit file inspection results by internal or external regulators.

12. Review and recommend to the Board for approval the compensation paid to the external auditors on an annual basis.

13. Review and pre-approve all non-audit services performed by the external auditors in relation to the Corporation and its subsidiaries. If, due to timing issues, the pre-approval of non-audit services

must be expedited and it is not practical to wait until the next scheduled Committee meeting, the Chair is delegated, on behalf of the Committee, to pre-approve the non-audit services when the individual engagement fees are projected to be less than $100,000, subject to an annual maximum approval limit of $250,000, and any such pre-approval will be reported to the Committee for ratification at its next meeting.

14. Oversee the work of the external auditor, including reviewing and approving the planning of the annual audit and reviewing the results thereof with the external auditors, including:

    a. approving the auditors' engagement letters;

    b. approving the scope of the audit, including materiality, audit reports required, area of audit risk, timetable and deadlines;

    c. reviewing with the external auditors the quality, not just the acceptability, of the accounting principles applied in the Corporation's financial reporting and the degree of aggressiveness or conservatism of the Corporation's accounting principles and underlying estimates;

    d. reviewing the post-audit management letter together with Management's responses;

    e. reviewing any other matters the external auditors bring to the attention of the Committee;

    f. resolving disagreements with Management regarding financial reporting;

    g. reviewing accruals, reserves and estimates which could have a significant effect on financial results;

    h. reviewing the use of any "pro forma" or "adjusted" information not in accordance with generally accepted accounting principles ("GAAP"); and

    i. reviewing interim review engagement reports.

    The Corporation's external auditors are ultimately accountable to the Board and the Committee as representatives of the shareholders of the Corporation, and will report directly to the Committee.

15. Review the rationale for any proposed change in auditors which is not initiated by the Committee or the Board.

16. Review reports from external auditors respecting their internal quality control procedures, peer reviews and investigations by governmental or professional authorities.

17. Obtain and review annually, prior to the completion of the external audit: (a) a report from the external auditors describing: (i) all critical accounting policies used by the Corporation in the preparation of its annual and interim financial statements; (ii) all alternative treatments of financial information within GAAP that have been discussed with Management; (iii) the ramifications of the use of such alternative treatments; and (iv) the treatment preferred by the external auditors; and (b) all other material written communications.

18. Obtain reasonable assurance from discussions with and/or reports from the CEO and Management and reports from external and internal auditors that the Corporation's accounting systems are reliable and that the prescribed internal controls are operating effectively.

19. Assess whether Management has implemented policies ensuring that the Corporation's financial risks are identified and that controls are adequate, in place and functioning properly. In connection therewith, as part of the financial risk assessment, Management will prepare tax compliance and planning strategies annually for review by the Committee, including a review of any tax reserves.

20. Monitor compliance with the Corporation's Ethics Policy (the "Ethics Policy") and ensure Management Compliance Certificates are received from Management quarterly.

21. Meet with the external auditors, at least annually and when requested by the external auditors, without Management representatives present.

22. Meet with the internal auditors, at least annually or as requested by the internal auditors, without Management representatives present.

23. Review and ensure that appropriate liaison and cooperation exists where necessary between the external auditors and the internal auditors, and provide a direct line of communication between the external and internal auditors, the Committee and the Board.

24. Review the responses of Management to information requests from government or regulatory authorities in respect of filing documents required under securities legislation, which may affect the financial reporting of the Corporation.

25. Review and approve the annual internal audit plan, including the charter, staffing, scope and objectives of the internal audit department, and the appointment, termination, and compensation of the chief audit person (Senior Manager, Internal Audit) and receive and review all financial internal audit reports issued in relation thereto.

26. Receive and review all follow-up action or status reports relating to the non-financial recommendations of the external auditor, and the internal auditor.

27. Obtain such information and explanations regarding the accounts of the Corporation as the Committee may consider necessary and appropriate to carry out its duties and responsibilities.

28. Annually review the performance, budget and independence of the internal audit function and direct the Chief Legal Officer to make any changes necessary.

29. Establish procedures for receiving, retaining and responding to complaints relating to accounting, internal accounting controls or auditing matters, on a basis that protects the confidentially of the complainant.

30. Review and approve the hiring policies regarding employees and former employees of the present and former external auditors.

31. Periodically assess procedures for the review of disclosure of financial information, extracted or derived from the Corporation's financial statements.

32. Review and monitor quarterly results of financial and commodity exposure management activities, including foreign currency and interest rate risk strategies, counterparty credit exposure and the use of derivative instruments, and ensure that they are appropriately reflected in the Corporation's financial reporting.

33. Monitor and evaluate the Corporation's insurance programs.

34. Review with Management and the external auditor any off balance sheet arrangements and special purpose vehicle structures.

35. Review disclosure made to the Committee by the CEO, the CFO and the General Counsel of a violation of applicable securities laws, a breach of a fiduciary duty under applicable laws or a similar violation by the Corporation or by any officer, director, employee or agent of the Corporation, which has been reported to the Committee, and determine whether an investigation is necessary regarding any such violation and report to the Board.

36. Receive, review and consider the annual and interim certificates provided by the CEO and CFO of the Corporation pursuant to National Instrument 52-109 *Certification of Disclosure in Issuers' Annual and Interim Filings*, as implemented by the Canadian Securities Administrators and as amended or replaced from time to time, along with reports from the Corporation's Disclosure Committee regarding the design and effectiveness of the Corporation's disclosure controls and internal controls over financial reporting.

37. Conduct all other matters required by law or stock exchange rules to be dealt with by an audit committee.

38. Review annually these terms of reference, the Ethics Policy, and the Corporation's policies regarding public disclosure of material information and insider trading (collectively, the "Disclosure Policy") and recommend any required material changes to the PCG Committee for further recommendation to the Board.

39. Conduct a regular, periodic survey relating to Committee effectiveness and performance.

40. The Committee Chair, as well as a member of Management independent from Internal Audit, will pre-approve the project scope of audits of areas which directly report to the Senior Manager, Internal Audit.

41. Report to the Board as required.

**D. Meetings**

1. The Committee will meet at least quarterly and may call other meetings as required.

2. The minutes of the Committee meetings will accurately record the decisions reached and will be distributed to Committee Members, and, as directed by the Committee, to other Board members, the CFO, and others.

3. Committee meetings may be called by the Committee Chair or by a majority of the Committee Members. In addition, the Committee Chair will call a meeting upon request of the external auditors. The Committee Chair will be a voting member and questions will be decided by a majority of votes.

4. Meetings may be called with 24 hours' notice, which may be waived, before or after the meeting, by Committee Members. Attendance at a meeting will be deemed to be waiver of notice of the meeting, except where the Committee member attends the meeting for the express purpose of objecting to the transaction of business on the grounds that the meeting has not been duly called. All Committee Members are entitled to receive notice of every meeting.

5. Meetings are chaired by the Committee Chair or in the Committee Chair's absence, by a member chosen by the Committee amongst themselves.

6. Agendas will be set by the Committee Chair with such assistance as the Committee Chair may request from the CEO, General Counsel, Corporate Secretary, CFO and auditors, and will be circulated with the materials for consideration at the meeting by the Committee Chair or the Corporate Secretary to all Committee and Board Members and, if directed by the Committee Chair, to the CEO, the General Counsel, Corporate Secretary, and CFO, no later than the day prior to the date of the meeting. However, it should be standard practice to deliver the agenda and draft materials for consideration at the meeting at least five business days prior to the proposed meeting except in unusual circumstances.

7. Except as provided in these terms of reference, the Chair of the meeting may establish rules of procedure to be followed at meetings.

8. Meetings may be conducted with the participation of a member by telephone, video, or other virtual meeting techniques which permits all persons participating in the meeting to hear and communicate with each other. A member participating in a meeting by those means is deemed to be present at the meeting.

9. The powers of the Committee may be exercised by vote at a meeting at which a majority of the Committee Members are present or by a resolution in writing signed by all Committee Members who would have been entitled to vote on the resolution at a meeting of the Committee. In the case of an equality of votes, the person acting as Chair of the Committee meeting will not be entitled to a second or casting vote.

10. A resolution in writing may be signed and executed in separate counterparts by Committee Members and the signing or execution of a counterpart will have the same effect as the signing or execution of the original. An executed copy of a resolution in writing or counterpart thereof transmitted by any means of recorded electronic transmission will be valid and sufficient.

11. Attendance at all or a portion of Committee meetings by staff, other directors, the auditors and others will be determined by the Committee.

12. The Corporate Secretary, or such other person as may be designated by the Committee, will keep minutes of the proceedings of all meetings of the Committee, which following Committee approval, will, subject to determination by the Committee otherwise, be available to any member of the Board. All minutes will be circulated to the Chair of the Board. With the exception of "in camera" items, minutes will be circulated to those receiving the agenda. Minutes will be retained by the Corporate Secretary.

13. The Committee may delegate its power and authority to individual Committee Members, where the Committee determines it is appropriate to do so in order for necessary decisions to be made between meetings of the Committee and where such delegation is permitted by law. Any such decisions will be reported to the Committee at its next meeting.