

Annual Information Form
Capital Power Corporation

For the year ended December 31, 2025

March 4, 2026

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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, 2025. 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 the non-GAAP financial measures, adjusted EBITDA, adjusted funds from operations (AFFO) and normalized earnings attributable to common shareholders, as well as the non-GAAP ratios, AFFO per share and normalized earnings per share, as financial performance measures, which are not standardized financial measures according to GAAP and do not have standardized meanings prescribed by GAAP. For further discussion of such terms and for reconciliations of these non-GAAP financial measures, see the Company's 2025 Integrated Annual Report for the year ended December 31, 2025, which is available under the Company's profile on SEDAR+ at sedarplus.ca and on the Company's website at capitalpower.com.

The "Non-GAAP Financial Measures and Ratios" and "Risks and Risk Management" of the Company's 2025 Integrated Annual Report for the year ended December 31, 2025 are incorporated herein by reference and can be found on SEDAR+ at www.sedarplus.ca.

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.

FORWARD-LOOKING INFORMATION

Forward-looking information or statements (collectively, forward-looking information) 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 forward-looking 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.

Material forward-looking information in this AIF includes, among other things, information relating to:

(i) expectations regarding the timing of, funding of and costs of, generation capacity of, costs of technologies selected for, environmental and sustainability benefits, commercial and partnership arrangements regarding existing, planned and potential development projects and acquisitions (including East Windsor Expansion, Maple Leaf Solar, Hornet Solar and Bear Branch Solar project); (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 and data centres; (iv) expectations regarding the feasibility of developing and advancing nuclear energy in Alberta, including the expected timing of completion of feasibility assessments, capital costs, project returns, production and environmental benefits; (v) expectations regarding availability of fuel supply; (vi) expectations regarding the timing or outcome of applications for permits or licenses, or other regulatory proceedings; (vii) the expected impact of the Canada – Alberta MOU (including its implementation), the Budget 2025, the Federal Plan, Canada's NDC, Clean Electricity Regulations (including any suspension), the Alberta Sovereignty Act, and other regulations announced by the Government of Canada, the provinces of Canada, the US, including US states, and the US EPA, and other environmental regulations that apply to Capital Power's power facilities, including compliance costs and the useful lives of power facilities and any conversions; (viii) 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; (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) the timing, expected proceeds and benefits of selling interests in renewable power assets; (xiii) expectations related to Capital Power's future cash requirements including interest and principal repayments, capital expenditures and dividends and distributions; (xiv) expectations governing the operation of the dividend reinvestment plan for holders of Common Shares; (xv) expectations regarding the ability of profit sharing arrangements to support partner communities; (xvi) the impact, cost and benefits of any organizational reviews (including the expected operational efficiency resulting from the Voluntary Departure Program); (xvii) expectations for Capital Power's sources of funding, adequacy and availability of committed bank credit facilities and future borrowings; (xviii) expectations regarding power requirements and demand in Capital Power's target markets; (xix) expectations around matters related to the line loss rule proceedings recovery of payments from appropriate parties and potential impacts to the Company arising from the foregoing; (xx) the timing, expected capital costs, project returns, production and environmental benefits (including the expected reduction in emission levels) of gas conversion at the Genesee units; (xxi) expectations regarding the eligibility of certain projects for the Clean Technology ITC; (xxii) expectations regarding the outcome of the ongoing litigation in respect of the Genesee Repowering Project; (xxiii) the outcomes resulting from the MOU with Apollo Funds; (xxiv) the outcome resulting from the MOU with the data centre developer; (xxv) the anticipated benefits, outcomes, projected timing, and terms of strategic agreements; (xxvi) the Company's 2030 targets, including dividend growth; (xxvii) the Company's 2026 financial guidance, including annual dividend growth; (xxviii) various aspects around existing, planned and potential development projects and acquisitions. This includes expectations around timing, funding, and commercial and partnership arrangements; and (xxix) the anticipated benefits of the Arlington Valley tolling agreement extension, including in respect of adjusted EBITDA.

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, including its review of purchased businesses and assets. The material factors and assumptions used to develop these forward-looking statements relate to: (i) electricity, and other energy and carbon prices; (ii) the Company's performance; (iii) the Company's business prospects (including potential re-contracting of facilities) and opportunities including expected growth and capital projects; (iv) the energy needs of certain jurisdictions; (v) the status and impact of policy, legislation and regulations; (vi) effective tax rates; (vii) the development and performance of technology; (viii) the outcome of claims and disputes; (ix) foreign exchange rates; and (x) other matters discussed under the "Our Strategy" section in the Company's 2025 Integrated Annual Report pertaining to Performance Targets for 2025.

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) identifying and completing acquisitions contemplated by the MOU with Apollo Funds and the timing thereof, and completing documentation with Apollo Funds in respect of the contemplated investment partnership; (ii) completing documentation with the data centre developer in respect of the ESA, and the data centre developer's development and completion of a data centre contemplated in any ESA; (iii) changes in electricity, natural gas and carbon prices in markets in which the Company operates and the use of derivatives; (iv) regulatory and political environments including changes to environmental, climate, financial reporting, market structure and tax legislation; (v) disruptions, or price volatility within the Company's supply chains; (vi) generation facility availability, wind capacity factor and performance including maintenance expenditures; (vii) ability to fund current and future capital and working capital needs, including in respect of the funding commitments under the MOU with Apollo Funds; (viii) acquisitions and developments including timing and costs of regulatory approvals and construction; (ix) changes in market prices and availability of fuel, (x) ability to realize the anticipated benefits of acquisitions; (xi) limitations inherent in the Company's review of acquired assets, (xii) changes in general economic and competitive conditions, including inflation and recession; (xiii) changes in the performance and cost of technologies and the development of new technologies, new energy efficient products, services and programs; and (xiv) the risks and uncertainties discussed under the heading "Risks and Risk Management" in the Company's 2025 Integrated Annual Report for the year ended December 31, 2025.

Readers are cautioned not to place undue reliance on any such forward-looking information, which speak only as of the date made and that other events or circumstances, although not listed above, could cause Capital Power's actual results to differ materially from those estimated or projected and expressed in, or implied by the forward-looking information. The Company does not undertake or accept any obligation or undertaking to release publicly any updates or revisions to any forward-looking information 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.

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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 – Canada Flexible Generation – 150 Mile House"

"**AAQOs**" means Ambient Air Quality Objectives

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

"**AEPA**" means Alberta Environment and Protected Area

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

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

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

"**AI**" means artificial intelligence

"**AIF**" means Annual Information Form

"**AMIL. BGS6 Load Zone**" means the Ameren Illinois Basic Generation Service 6 Load Zone

"**Arlington Valley**" means the Arlington Valley facility as further described in "Business of Capital Power – U.S. Flexible Generation – 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 – U.S. Renewables – Beaufort"

"**BESS**" means battery energy storage system

"**Bloom Wind**" means the Bloom wind facility as further described in "Business of Capital Power – U.S. Renewables – Bloom Wind"

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

"**Buckthorn Wind**" means the Buckthorn wind facility as further described in "Business of Capital Power – U.S. Renewables – Buckthorn Wind"

“**Budget 2025**” means Canada’s 2025 federal budget released on November 4, 2025

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

"**Canada – Alberta MOU**" means the memorandum of understanding entered into as of November 27, 2025, between Canada and Alberta

"**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 – U.S. Renewables – 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* RSC, 1985 c. C-44

"**CCS**" means carbon capture and storage

"**CCUS**" means carbon capture, utilization and storage

"**CERs**" means Clean Electricity Regulations

"**CES**" means the Clean Energy Standard

"**Clover Bar**" means the Clover Bar Energy Centre as further described in "Business of Capital Power – Canada Flexible Generation – Clover Bar"

"**Clydesdale Solar**" means the Clydesdale solar project (formerly Enchant Solar) as further described in "Business of Capital Power – Canada Renewables – Clydesdale Solar"

"**CO₂**" means carbon dioxide

"**CO₂e**" means carbon dioxide equivalent

“**COD**” means commercial operation date

"**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

"**COP28**" means the 28th United Nations Climate Change Conference

"**COP29**" means the 29th United Nations Climate Change Conference

“**COP30**” means the 30th United Nations Climate Change Conference

"**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/Redemption"

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

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

"**DBRS**" means DBRS Limited

"**Decatur**" means the Decatur Energy Center as further described in "Business of Capital Power – U.S. Flexible Generation – 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 – Canada Flexible Generation – East Windsor"

"**East Windsor Expansion**" means the East Windsor Expansion project as further described in "Business of Capital Power - Projects Under Construction or in Advanced Stages of Development – East Windsor Generation Facility Expansion"

"**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

"**Enbridge**" means Enbridge Inc. collectively with its subsidiaries

"**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

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

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

"**EPEA**" means the *Environmental Protection and Enhancement Act*, RSA 2000, c E-12

"**EPS**" mean emissions performance standards

"**ERCOT**" means the Electric Reliability Council of Texas

"**ESA**" means an Energy Service Agreement

"**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

"**Fitch**" means Fitch Ratings, Inc.

"**Flexible Generation**" means natural gas generation assets and energy storage

"**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

"**Frederickson**" means the Frederickson 1 facility as further described in "Business of Capital Power – U.S. Flexible Generation – Frederickson"

"**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 – Canada Flexible Generation – Genesee Generating Station – Genesee Repower 1 & 2"

"**Genesee 3**" means the Genesee 3 facility as further described in "Business of Capital Power – Canada Flexible Generation – Genesee 3"

"**Genesee CCS Project**" means the Genesee carbon capture and storage project as further described in "Generative Development of the Business – Company History – 2024 – Discontinuation of \$2.4 billion Genesee CCS Project"

"**Genesee Generating Station**" means, collectively, Genesee 1 and 2 and Genesee 3

"**Genesee Mine**" means the surface strip mine located near Warburg, Alberta

"**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 – Canada Flexible Generation – Goreway"

"**Goreway BESS**" means the Goreway Battery Energy Storage System as further described in "Business of Capital Power – Canada Flexible Generation – Goreway Battery Energy Storage System"

"**Goreway Uprate Project**" means the Goreway turbine efficiency as further described in "Business of Capital Power – Canada Flexible Generation – Goreway – Goreway Power Station - Upgrade Project"

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

"**Green Financing**" means green bonds and green loans issued under the Green Framework

"**Green Framework**" means the Green Financing Framework

"**GW**" means gigawatt

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

"**Halkirk 1**" means phase 1 of the Halkirk wind project as further described in "Business of Capital Power – Canada Renewables – Halkirk 1"

"**Halkirk 2**" means phase 2 of the Halkirk wind project as further described in "Business of Capital Power – Canada Renewables – Halkirk 2"

"**Harquahala**" means the Harquahala facility as further described in "Business of Capital Power – U.S. Flexible Generation – Harquahala"

"**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"

"**HRCO**" means heat rate call option

"**HSSE**" means health, safety, security and environment (formerly health, safety and environment)

"**HSSE Management System**" means the Health, Safety, Security and Environment Management System of the Company

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

"**Hummel Facility**" means the Hummel Station Facility as further described in "Business of Capital Power – U.S. Flexible Generation – Hummel"

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

"**Integrated Annual Report**" means the Company's 2025 Integrated Annual Report

"**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

"**IRP**" means Integrated Resource Plan

"**Island Generation**" means the Island Generation facility as further described in "Business of Capital Power – Canada Flexible Generation – Island Generation"

"**ISO**" means Independent System Operator

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

"**ITC**" means Investment Tax Credit

"**Joffre**" means the Joffre cogeneration facility as further described in "Business of Capital Power – Canada Flexible Generation – Joffre"

"**Kingsbridge 1**" means the Kingsbridge 1 wind facility as further described in "Business of Capital Power – Canada Renewables – Kingsbridge 1"

"**La Paloma**" means the La Paloma facility as further described in "Business of Capital Power – U.S. Flexible Generation – La Paloma"

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

"**LNG**" means liquified natural gas

"**Macho Springs**" means the Macho Springs wind facility as further described in "Business of Capital Power – U.S. Renewables – Macho Springs"

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

"**Midland Cogen**" means the Midland Cogeneration Venture as further described in "Business of Capital Power – U.S. Flexible Generation – Midland Cogeneration"

"**MISO**" means Midcontinent Independent System Operator

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

"**Moody's**" means Moody's Investors Service, Inc.

"**MOU**" means Memorandum of Understanding

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

"**MSSC**" means Most Severe Single Contingency

"**MTN**" means medium term note

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

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

"**New Frontier**" means the New Frontier wind facility as further described in "Business of Capital Power – U.S. Renewables – 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/Redemption"

"**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 – Canada Renewables – Port Dover & Nanticoke"

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

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

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

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

"Prudential Notes" means 10-year Series C Senior Notes with Prudential Capital Group that mature in September 2026

"Quality" means the Quality wind facility as further described in "Business of Capital Power – Canada Renewables – Quality"

"RECs" means renewable energy credits

"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 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.

"RESA" means a Renewable Energy Support Agreement

"Rolling Hills Facility" means the Rolling Hills Generating Facility as further described in "Business of Capital Power – U.S. Flexible Generation – Rolling Hills"

"RTO" means Regional Transmission Organization

"Savona" means the Savona waste heat facility as further described in "Business of Capital Power – Canada Flexible Generation – Savona"

"SEDAR+" means the System for Electronic Data Analysis and Retrieval, which can be accessed via the internet at www.sedarplus.ca

"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 9 Shares" means the cumulative minimum rate reset preference shares, series 9 of the Company and redeemed on September 30, 2022

"**Series 11 Shares**" means the cumulative minimum rate reset preference shares, series 11 of the Company and redeemed on June 30, 2024

"**Shepard**" means the Shepard Energy Centre as further described in "Business of Capital Power – Canada Flexible Generation – Shepard"

"**SO₂**" means sulphur dioxide

"**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 or in the capital of Capital Power GP Holdings Inc., as applicable. See "Material Contracts – Social Objectives Agreement"

"**Strathmore Solar**" means the Strathmore solar project as further described in "Business of Capital Power – Canada Renewables – Strathmore Solar"

"**Subordinated Notes**" means the Fixed-to-Fixed Subordinated Notes, Series 1, due September 9, 2082 issued by the Company

"**tCO₂e**" means metric tonnes of carbon dioxide equivalent

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

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

"**TransAlta**" means TransAlta Corporation

"**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

"**VPPA**" means Virtual Power Purchase Agreement

"**WEIM**" means the Western Energy Imbalance Market, which is a real-time energy market established to manage variations in demand and generation across a wider footprint including DSW, CAISO and the Pacific Northwest

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

"**Whitla Wind**" means phases 1, 2 and 3 of the Whitla wind facility as further described in "Business of Capital Power – Canada Renewables – Whitla Wind"

"**York**" means the York Energy Centre as further described in "Business of Capital Power – Canada Flexible Generation – York"

"**York BESS**" means the York Battery Energy Storage System as further described in "Business of Capital Power – Canada Flexible Generation – York Battery Energy Storage System"

"**York Uprate Project**" means the York turbine efficiency as further described in "Business of Capital Power – Canada Flexible Generation – York – York - Upgrade Project"

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, May 9, 2019, and September 7, 2022 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 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 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, 2025, had aggregate total assets or revenues that did not exceed 20% of Capital Power's consolidated assets or consolidated revenue. 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.

<u>Subsidiaries</u>	<u>Jurisdiction of Incorporation, Continuance, Formation or Organization</u>
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 Center, LLC	Delaware
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
CP Energy Marketing (US) Inc.	Delaware
Capital Power Investments LLC	Delaware
CP Halkirk 2 L.P.	Alberta
CXA La Paloma, LLC	Delaware
Hummel Station, LLC	Pennsylvania
Rolling Hills Generating, LLC	Ohio

Notes:

- (1) The Company indirectly owns 100% of the Class B Units of CP Bloom Wind LLC. The Class A Units of Bloom Wind LLC are held by a tax equity investor.

- (2) The Company indirectly owns 100% of the Class B Units of Cardinal Point LLC. The Class A Units of Cardinal Point LLC are held by tax equity investors.

GENERAL DEVELOPMENT OF THE BUSINESS

Overview

Capital Power (TSX: CPX) is one of North America's leading independent power producers, with approximately 12 GW of generation capacity across 35 facilities. Our portfolio includes natural gas, renewables and battery energy storage solutions. We deliver power generation at utility-scale through a flexible and resilient fleet built to meet growing electricity demand. Backed by deep expertise and an investment-grade credit rating, we provide safe, reliable power communities can depend on. We are Powering Change by Changing Power™.

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

2026

Kevin MacIntosh appointed Chief Financial Officer

On February 19, 2026, Capital Power announced the appointment of Kevin MacIntosh as Chief Financial Officer of the Company, effective March 16, 2026. Mr. MacIntosh has over 30 years of experience as a finance leader working in large, complex organizations within the global energy industry and brings expertise across multi-jurisdictional operations, cross-border transactions, energy trading and diverse regulatory landscapes. Scott Manson, who has served as Interim CFO, will continue to support the onboarding process and assist Mr. MacIntosh until the end of April 2026.

Arlington Valley tolling agreement extension and increased summer capacity

In January 2026, Capital Power extended its summer tolling agreement for the Arlington Valley facility with the current counterparty, an investment-grade utility. The agreement extends the existing 2031 agreement through October 2038, providing 13 years of contracted revenue and positioning Capital Power for continued growth and value creation in the U.S. southwest. The 6-month contract structure enables the facility to capture increasing merchant value during the winter months, while retaining the stability of contracted summer revenues. The facility is expected to realize a full year adjusted EBITDA uplift of approximately US\$70 million annually by 2032, inclusive of the uprate. The uprate is expected to contribute approximately US\$8M per year adjusted EBITDA over the life of the asset, starting in 2027.

As part of this agreement, the facility will undergo a 35 MW capacity uprate to summer capacity; 10 MWs will be added in 2026 and an additional 25 MWs in 2027. This investment will strengthen Arlington's ability to provide reliable power during Arizona's peak summer demand.

2025

\$4.2 billion (US \$3.0 billion) investment partnership with Apollo Funds

In December 2025, Capital Power entered into a MOU with Apollo Global Management (Apollo Funds) to form an investment partnership to pursue the acquisition of merchant U.S. natural gas generation assets, with total potential committed equity of up to US\$3 billion (including US\$750 million from Capital Power). The partnership combines Apollo Funds' capital strength with Capital Power's operating and commercial expertise to accelerate Capital Power's U.S. natural gas growth strategy and expand earnings.

The MOU contemplates a partnership with Capital Power operating acquired assets and receiving management and performance fees.

Alberta data centre MOU

In December 2025, the Company entered into a binding MOU with an investment grade data centre developer for a 250 MW Electricity Supply Agreement (ESA). The long-term ESA (10+ years) has an anticipated start date in 2028 and would be backed by Capital Power's Alberta-based power generation portfolio. If a final agreement between the parties cannot be reached, a termination fee will be paid to Capital Power.

\$600 million offering of medium term notes and redemption of January 2026 medium term notes

On November 14, 2025, Capital Power completed a public offering in Canada of unsecured medium term notes (Notes) in the aggregate principal amount of \$600 million. The Notes have an interest rate of 4.231% and mature on January 14, 2033. Capital Power used the net proceeds to repay, redeem and refinance existing indebtedness, which included fully funding the redemption of the Company's January 2026 Notes (as defined below), as well as project level debt at Goreway Power Station, Capital Power's credit facilities, and for general corporate purposes.

See also "Capital Structure – Debt Issuance/Redemption".

On November 5, 2025, Capital Power issued a notice of redemption in respect of all of its outstanding 4.986% medium term notes, due January 23, 2026 (January 2026 Notes), for redemption on November 23, 2025 (Redemption Date) in accordance with the trust indenture governing the January 2026 Notes. The aggregate principal amount of January 2026 Notes outstanding was C\$300 million. The redemption price was C\$1,000 per C\$1,000 principal amount of the January 2026 Notes redeemed, plus accrued and unpaid interest to, but excluding, the Redemption Date. As November 23, 2025 was not a business day, payment of the redemption price occurred on November 24, 2025.

CFO update

On October 29, 2025, Sandra Haskins, SVP Finance & CFO announced her plans to retire from her role on December 31, 2025 after a 23-year tenure. Sandra has played a pivotal role in shaping the strategic direction and successful growth of Capital Power. Scott Manson, Chief Accounting Officer has transitioned to Interim SVP Finance & CFO. On February 19, 2026, Capital Power announced the appointment of Kevin MacIntosh as Chief Financial Officer of the Company, effective March 16, 2026. Sandra will support a smooth leadership transition by remaining in an advisory capacity until the end of Q1 2026.

York and Goreway Battery Energy Storage Systems commissioned and contracted to 2047

On September 22, 2025, 120 MW York BESS and 50 MW Goreway BESS projects successfully achieved commercial operations. A leader of Ontario's BESS development, Capital Power delivered both projects on time and under budget. The projects are contracted until 2047 with the Ontario Independent Electricity System Operator (IESO) (part of their Expedited Long-Term 1 RFP process) and will add approximately \$35 million in annual adjusted EBITDA over the contract term. These facilities enhance our portfolio of Flexible Generation sources that provide grid stability, support the integration of renewable resources, and meet the province's growing demand for electricity.

Midland Cogeneration Venture (MCV) with Consumers Energy to 2040

In September 2025, Capital Power successfully executed a new long-term contract with improved economic terms for MCV with Consumers Energy, extending to 2040 and providing 10 years of incremental contracted revenue, subject to customary regulatory approvals. MCV is the largest natural gas-fired combined electric and steam generation facility in the U.S., and a cornerstone of reliable power generation in Michigan. MCV will receive payments for 1,240 MW, approximately 75% of the facility's capacity starting in June 2030 under the new PPA, creating long-term revenue stability throughout the contract term. The contract is expected

to generate a gross increase in full year adjusted EBITDA for the facility of approximately \$140 million (US\$100 million) annually representing an 85% increase over current contract pricing. MCV is jointly owned, with Capital Power owning a 50% working interest and the remaining 50% owned by Manulife Investment Management.

MCV data centre

In September 2025, MCV entered into a term sheet with a leading data centre developer for the potential development of a data centre adjacent to the facility. While the parties are no longer exclusive, the Company is continuing its discussions with the developer to execute a long term PPA for 250MW of power for up to 15 years.

Virtual power purchase agreement cancellation

The Company previously announced that on March 27, 2024, it had entered into a 15-year VPPA with Saputo Inc. (Saputo). As a result of delayed commissioning on Halkirk 2 Wind, Saputo elected to terminate the VPPA with Capital Power, resulting in a \$5 million penalty paid in the third quarter of 2025. The termination also resulted in an unrealized mark-to-market loss of \$8 million upon unwinding of the VPPA in the third quarter of 2025. Despite the contract with Saputo representing 45% of plant output, Capital Power expects the financial impact to be minimal due to forecasted merchant pricing exceeding the Saputo VPPA pricing. Halkirk 2 Wind achieved commercial operation in December 2025.

\$1.5 billion credit facility and \$600 million revolving credit facility

On June 6, 2025, the Company terminated its \$300 million unsecured club credit facility, increased the capacity of its committed credit facility from \$700 million to \$1.5 billion, and extended the term from 2029 to 2030. On August 8, 2025, the Company entered into a 2-year revolving credit agreement with a total commitment of \$600 million, maturing in 2027. The funds can be drawn in Canadian or U.S. dollars. Interest is floating and is based on the type of draw, plus margin.

Acquisition of Hummel Facility and Rolling Hills

On June 9, 2025, Capital Power completed its previously announced acquisition of 100% of the equity interests in:

- Hummel Station, LLC, owner of the 1,124 MW Hummel combined cycle natural gas facility in Shamokin Dam, Pennsylvania (the Hummel Acquisition), and
- Rolling Hills Generating, LLC., owner of the 1,023 MW Rolling Hills Generation plant, a combustion turbine natural gas facility in Wilkesville, Ohio (the Rolling Hills Acquisition and, together with the Hummel Acquisition, the Acquisition).

The Acquisition expands the Company's operations into the PJM interconnection market and adds to its U.S. Flexible Generation fleet.

The total purchase price of the Acquisition was \$3.0 billion (US\$2.2 billion) in total cash consideration, including working capital and other closing adjustments. Capital Power partially financed the acquisition with net proceeds from an offering of common shares and a private offering of senior notes. The offering of common shares for total gross proceeds of approximately \$667 million, closed on April 22, 2025 and consisted of a bought deal offering of 11,902,500 common shares (inclusive of the full exercise of a 1,552,500 common shares over-allotment option) of Capital Power for gross proceeds of \$517 million and 3,455,000 common shares on a private placement basis for gross proceeds of approximately \$150 million, with Alberta Investment Management Corporation. Capital Power also financed the Acquisition with the net proceeds from a senior notes offering of \$1.7 billion (US\$1.2 billion), which closed on May 28, 2025 and consisted of a private placement offering of \$966 million (US\$700 million) aggregate principal amount of 5.257% senior notes due 2028 and \$690 million (US\$500 million) aggregate principal amount of 6.189% senior notes due 2035 issued by Capital Power (US Holdings) Inc., a U.S. wholly-owned subsidiary of the

Company. The balance of the Acquisition was funded with additional cash on hand and a drawdown on the Company's existing revolving credit facilities.

2024

Renewable Power Asset Sell-Down

On December 20, 2024, the Company announced the closing of the previously announced sale of a 49% interest in each of the Quality Wind facility in British Columbia and the Port Dover and Nanticoke Wind facility in Ontario.

On November 26, 2024, Capital Power announced that it agreed to sell a 49% interest in two operating Canadian wind facilities to Axiom Infrastructure Inc. The 246 MW portfolio includes the Quality Wind facility in British Columbia and the Port Dover and Nanticoke Wind facility in Ontario. Total pre-tax cash proceeds to Capital Power from the transaction are expected to be approximately \$340 million, inclusive of working capital.

The two wind facilities are fully contracted with investment grade counterparties and have a remaining weighted average contract life of approximately 11 years. Capital Power will continue to manage and operate the assets on behalf of the newly formed partnership under a long-term asset management agreement.

\$460 million bought offering of common shares

On December 17, 2024, the Company completed a public offering of 7,820,000 common shares (inclusive of the full exercise of a 1,020,000 common shares over-allotment option), at an issue price of \$58.80 per common share for total gross proceeds of approximately \$460 million (the Offering) less issue costs of \$18 million.

Genesee Repowering Achieves Commercial Operation

On December 13, 2024, Unit 2 achieved combined cycle commercial operations. This milestone marked a significant phase in the Genesee Repowering project, resulting in Units 1 and 2 becoming Canada's most efficient natural gas combined cycle facility. Unit 1 received COD on November 18, 2024 and Unit 2 received COD on December 13, 2024 for combined cycle operation achieving 466 MWs per unit. The advancement of this industry-leading project increases overall capacity at the Genesee Generating Station by 512 megawatts (MW) and reduces CO₂ emissions (scope 1) by 3.4 million tonnes annually – representing a ~60% increase in capacity while reducing emissions (scope 1) by ~40%. A plan is in place for each unit to further unlock additional MWs. See also "Regulatory Overview – AESO Most Severe Single Contingency (MSSC)".

Voluntary Departure Program

On October 24, 2024, Capital Power announced the rollout of the voluntary departure program (VDP) aimed to reduce its workforce of Canada-based corporate employees by at least 25% (approximately 130 positions). The VDP is the result of a strategic organizational review to optimize the organization to scale and grow efficiently, inclusive of decentralizing corporate functions, reducing headcount in certain areas and expanding in key growth areas.

The Company achieved a reduction in Canada-based corporate workforce of approximately 40% (165 positions) incurring a total cost of \$49 million in connection with the VDP. This includes \$10 million related to employee benefit costs that would have been otherwise incurred in future periods. The Company believes this initiative will enhance operational efficiency, aligns the workforce with the organization's strategic objectives and in respect to employees, provides them a choice in the change process.

\$600 million medium term notes offering

On September 16, 2024, Capital Power completed a public offering in Canada of unsecured medium term notes in the aggregate principal amount of \$600 million. The offering consisted of \$600 million of 4.831% medium term notes maturing on September 16, 2031. Capital Power used the net proceeds to repay, redeem and refinance existing indebtedness, including indebtedness under Capital Power's credit facilities, and for general corporate purposes.

See also "Capital Structure – Debt Issuance/Redemption".

\$350 million Green Hybrid Subordinated Notes, Series 1 exchange

On August 15, 2024, the Company announced the approval of amendments to the indenture governing the \$350 million 7.95% Fixed-to-Fixed Rate Subordinated Notes, Series 1, due September 9, 2082 (Series 1 Notes). These changes allowed for the exchange of all outstanding principal amount of Series 1 Notes for an equal principal amount of new 7.95% Fixed-to-Fixed Rate Subordinated Notes, Series 3, due September 9, 2082 (Series 3 Notes) issued under a supplemental indenture dated August 15, 2024 to the trust indenture dated as of June 5, 2024.

The Series 3 Notes have the same economic terms as the Series 1 Notes, including interest rates and maturity dates, but without the provision for delivery of preferred shares upon the occurrence of certain bankruptcy and related events. Holders will continue to receive interest accrued on the exchanged Series 1 Notes.

This note exchange was completed on August 15, 2024, following the execution of the necessary supplemental indentures. The Series 3 Notes will rank equally in right of payment with the \$450 million 8.125% Fixed-to-Fixed Subordinated Notes, Series 2, due June 5, 2054. S&P Global Ratings and Morningstar DBRS confirmed the instrument rating of the Series 3 Notes at BB and BB with a Stable trend, respectively.

Partnership with Maskwacis First Nations

On July 19, 2024, the Company signed a three-year partnership and equity option agreement with the Louis Bull Tribe, Ermineskin Cree Nation, Montana First Nation and Samson Cree Nation of Maskwacis located in Alberta. Following the three-year agreement, the Company is offering the four First Nations an opportunity to acquire a combined total of 25% of Halkirk 2 Wind. As part of the Company's commitment to reconciliation, the agreement provides an equitable profit-sharing model that supports a pathway to future, long-term equity ownership in the project that can support these nations with sustainable income throughout the lifetime of its operations.

See also "Business of Capital Power – Canada Renewables – Halkirk 2".

Executes 25-year contracts for Hornet Solar and Bear Branch Solar projects in North Carolina

In June 2024, the Company successfully executed 25-year power purchase agreements with Duke Energy Carolinas for the Hornet Solar and Bear Branch Solar projects located in North Carolina totalling 107.5 MW. Hornet Solar began construction in August 2024, and Bear Branch commenced construction in June 2025. Targeted commercial operations for both projects is expected in the second half of 2026.

Genesee Generating Station is off coal

On June 18, 2024, the Company reached a significant milestone for the Genesee Repowering project with the announcement that the Genesee Generating Station is off coal and 100% natural gas-fueled, resulting in the facility being off coal more than 5 years ahead of the Alberta government mandate. With cessation of coal mining, the activities at the Genesee Mine are now wholly directed to land reclamation. This is expected to continue for the next 3 to 4 years.

As part of the Genesee Repowering project, the facility completed simple cycle commissioning for Units 1 and 2 on May 3, 2024 and June 28, 2024, respectively, and Unit 3 transitioned fully to natural gas.

\$450 million Subordinated Notes offering

On June 5, 2024, the Company completed a public offering of Fixed-to-Fixed Subordinated Notes, Series 2, in the aggregate principal amount of \$450 million (the Subordinated Notes). The Subordinated Notes have a fixed interest rate of 8.125% and mature on June 5, 2054.

The Company used the net proceeds from the sale of the Subordinated Notes to repay certain amounts drawn on the Company's credit facilities (which include amounts drawn for the acquisition of a 50% interest in New Harquahala Generating Company, LLC, and a 100% interest in CXA La Paloma, LLC, and related expenses, development purposes and in respect of ongoing operations), to redeem all of the Company's outstanding Cumulative Minimum Rate Reset Preference Shares, Series 11, (the Preferred Shares, Series 11) and for general corporate purposes.

See also "Capital Structure – Debt Issuance/Redemption".

Redemption of Preferred Shares, Series 11

On May 15, 2024, the Company announced its intention to redeem all of its 6 million issued and outstanding Preferred Shares, Series 11 on June 30, 2024 (Redemption Date) at a price of \$25.00 per share (Redemption Price) for an aggregate total of \$150 million, less any tax required to be deducted and withheld by the Company. As June 30, 2024 was not a business day payment of the Redemption Price for the share redemption occurred on July 2, 2024.

Discontinuation of \$2.4 billion Genesee CCS Project

On May 1, 2024, Capital Power announced that it was discontinuing its pursuit of the Genesee CCS Project. Through its development of the project, Capital Power confirmed CCS is a technically viable technology and potential pathway to decarbonization for thermal generation facilities including Genesee. However, at the time, the project was not economically feasible and as a result Capital Power turned its time, attention, and resources to other opportunities to serve its customers with balanced energy solutions. As part of its discontinuation of the project, Capital Power incurred a pre-tax cost of \$18 million, related to termination of sequestration hub evaluation work.

Completion of acquisition of 100% interest in La Paloma Facility and 50% interest in Harquahala Facility

On February 9, 2024, the Company closed the previously announced acquisition of 100% of the equity interests in CXA La Paloma, LLC (La Paloma), owner of the 1,062 MW La Paloma natural gas-fired generation facility in Kern County, California (La Paloma Acquisition). On February 16, 2024, the Company announced closing of the previously announced acquisition by a 50/50 partnership between Capital Power Investments, LLC and an affiliate of a fund managed by BlackRock's Diversified Infrastructure business (BlackRock) of 100% of the equity interests in New Harquahala Generating Company, LLC (Harquahala Acquisition and, together with the La Paloma Acquisition, the Acquisitions) which owns the 1,092 MW Harquahala natural gas-fired generation facility in Arizona. Concurrently, approximately US\$442 million of combined term loans, letter of credit loans and revolving loans related to the Harquahala facility were closed as part of the transaction.

La Paloma and Harquahala are essential infrastructure assets, which support the reliability of California and Arizona's electricity grids and add further growth opportunities in the attractive Western Electricity Coordinating Council (WECC) market while balancing the Company's geographical footprint across North America. La Paloma is contracted under various resource adequacy contracts through 2029 with multiple investment grade utilities and load serving entities. Harquahala is 100% contracted under a tolling agreement through 2031 with an investment grade utility.

The Acquisitions were previously announced on November 20, 2023. The net purchase price for the Acquisitions attributable to Capital Power was US\$1.1 billion, subject to working capital adjustments. Capital Power partially financed the Acquisitions with the net proceeds of an offering of subscription receipts (the Subscription Receipts) for approximately \$400 million, which closed on November 28, 2023 and consisted of a \$300 million bought public offering and a \$100 million private placement with Alberta Investment Management Corporation. Capital Power also financed the Acquisitions with the net proceeds from a public offering of \$850 million principal amount of unsecured medium term notes in Canada which closed on December 15, 2023. Capital Power is responsible for the operation, maintenance and asset management of the facilities relating to the Acquisitions and will receive an annual management fee for the Harquahala facility.

Upon closing of the La Paloma Acquisition, each Subscription Receipt was automatically exchanged in accordance with their terms, without payment of additional consideration and without further action on the part of the holders thereof, for one common share of Capital Power.

The Acquisitions are expected to generate average annual Adjusted EBITDA of approximately \$265 million (US\$197 million) for the 2024-2028 period and are estimated to be, on average, 8% accretive to AFFO per share over the same period.

See also "General Development of the Business – Company History – 2023 – Announcing acquisitions of two contracted combined cycle U.S. gas generation facilities and concurrent equity offerings" and "General Development of the Business – Company History".

Partnered with Ontario Power Generation to advance new nuclear in Alberta

On January 15, 2024, the Company announced that it had entered into an agreement with Ontario Power Generation (OPG) to jointly assess the development and deployment of grid-scale small modular reactors (SMRs) to provide clean, reliable nuclear energy for Alberta.

Pursuant to the agreement, the two companies were to examine the feasibility of developing SMRs in Alberta, including possible ownership and operating structures. SMRs are being pursued by jurisdictions in Canada and around the world to power the growing demand for clean electricity and energy security.

Capital Power and OPG planned to complete the feasibility assessment within two years, while continuing to work on the next stages of SMR development. In 2024, Capital Power qualified for \$13 million in funding to support certain activities to be undertaken as part of the feasibility assessment.

As of the date of this AIF, the pre-feasibility study work for the Alberta SMR project with OPG remains on track. The first funded phase of the pre-feasibility study for the Alberta SMR project with OPG has been completed. Capital Power's partnership with OPG on the project continues to progress as planned, and recently, the parties extended their commitment for another two years to continue with the collaboration. Capital Power continues to evaluate the development opportunity through this project.

2023

Acquisition of 50.15% interest in Frederickson 1 Generating Station

On December 28, 2023, Capital Power successfully completed the previously announced acquisition of a 50.15% ownership interest in the Frederickson 1 Generating Station, a 265 MW natural gas-fired combined cycle generation facility located in Pierce County, Washington. The facility was acquired from Atlantic Power & Utilities for \$137 million (US\$100 million) of cash consideration, including working capital and other closing adjustments. The other 49.85% is owned by Puget Sound Energy. Capital Power financed the acquisition using cash on hand and our existing credit facilities.

See also "Business of Capital Power – U.S. Flexible Generation – Frederickson".

\$850 million medium term notes offering

On December 15, 2023, Capital Power completed a previously announced public offering in Canada of unsecured medium term notes in the aggregate principal amount of \$850 million. The offering consisted of \$400 million of 5.378% medium term notes maturing on January 25, 2027 and \$450 million of 5.973% medium term notes maturing on January 25, 2034. The offering closed on December 15, 2023.

See also "Capital Structure – Debt Issuance/Redemption".

Announcing acquisitions of two contracted combined cycle U.S. gas generation facilities and concurrent equity offerings

On November 20, 2023, Capital Power announced that it had entered into two separate definitive agreements with CSG Investments Inc., a subsidiary of Beal Financial Corporation, to acquire (i) 100% of the equity interest in CXA La Paloma, LLC which owns the 1,062 MW La Paloma natural gas fired generation facility in Kern County, California (La Paloma Acquisition); and (ii) under a new formed 50/50 partnership with an affiliate of BlackRock's Diversified Infrastructure business, 100% of the equity interest in New Harquahala Generation Company, LLC which owns the 1,092 MW natural gas-fired generation facility in Maricopa County, Arizona (Harquahala Acquisition and together with the La Paloma Acquisition, the Acquisitions).

Concurrent with the announcement of the Acquisitions, Capital Power announced it had entered into an agreement with a syndicate of underwriters to issue 8,231,000 subscription receipts, on a bought deal basis, at an issue price of \$36.45 per subscription receipt, for total gross proceeds of approximately \$300 million. Additionally, Capital Power entered into a subscription agreement to issue 2,745,000 subscription receipts to Alberta Investment Management Corporation on a private placement basis for gross proceeds of approximately \$100 million. The concurrent equity offering closed on November 28, 2023.

See also "General Development of the Business – Company History – 2024 – Completion of acquisition of 100% interest in La Paloma Facility and 50% interest in Harquahala Facility" and "Business of Capital Power – U.S. Flexible Generation – Harquahala" and "Business of Capital Power – U.S. Flexible Generation – La Paloma".

Reinstatement of Dividend Reinvestment Plan

On August 1, 2023, the Company reinstated the DRIP. Eligible shareholders were entitled to participate in the DRIP commencing with the Company's third quarter 2023 cash dividend. Shareholders that were enrolled in the DRIP upon suspension in December 2021, and remained enrolled with the plan administrator, automatically resumed participation in the DRIP upon reinstatement. New Common Shares issued under the reactivated DRIP were issued at a discount rate of 1% to the average closing price on the Toronto Stock Exchange for the 10 trading days immediately preceding the applicable dividend payment date.

Secured 1 gigawatt supply of solar modules

On July 5, 2023, Capital Power announced that it had secured its first order for approximately 1 gigawatt of responsibly produced, ultra-low carbon thin film solar modules. The modules, which will be delivered between 2026 and 2028, will support Capital Power's growing development portfolio.

Contracts executed for Natural Gas and Batteries from Ontario's IESO bids

On June 29, 2023, Capital Power announced that it had executed two long-term contracts for the East Windsor Expansion project and the York BESS project. The York BESS project achieved commercial operations in September 2025 while the East Windsor Expansion project has been updated to begin commercial operations in 2026 due to delays in municipal and provincial permitting processes. In addition, Capital Power was selected as a successful proponent for the Goreway Battery Energy Storage System project as part of Category 2 of the IESO's Expedited Long-Term RFP.

See also "Business of Capital Power – Canada Flexible Generation – York Battery Energy Storage System", "General Development of the Business – Company History – 2025 – York and Goreway Battery Energy Storage Systems commissioned and contracted to 2047" and "Business of Capital Power – Projects Under Construction or in Advanced Stages of Development – East Windsor Generation Facility Expansion".

Maple Leaf Solar project awarded 25-year contract

On June 29, 2023, Capital Power announced that it had entered into a 25-year PPA for 100% of the output from its Maple Leaf Solar project with Duke Energy Progress as part of the 2022 Duke Energy Solar Procurement Program.

See also "Business of Capital Power – Projects Under Construction or in Advanced Stages of Development – Maple Leaf Solar".

Two successful bids in Ontario IESO's Expedited Long-Term RFP

On May 16, 2023, Capital Power announced that it had been selected as a successful proponent in the Ontario IESO's Expedited Long-Term RFP. The two successful submissions included the York Battery Energy Storage System and East Windsor Generation Facility Expansion. Subsequently, on June 23, 2023, Capital Power executed long-term contracts with the IESO.

See also "General Development of the Business – Company History – 2023 – Contracts executed for Natural Gas and Batteries from Ontario's IESO bids", "Business of Capital Power – Canada Flexible Generation – York Battery Energy Storage System", "General Development of the Business – Company History – 2025 – York and Goreway Battery Energy Storage Systems commissioned and contracted to 2047", and "Business of Capital Power – Projects Under Construction or in Advanced Stages of Development – East Windsor Generation Facility Expansion".

Executive appointments

On April 19, 2023, Capital Power and the Board of Directors announced that it had selected Avik Dey to be the new President and Chief Executive Officer and become a member of the Board of Directors, effective May 8, 2023.

Approval of normal course issuer bid

On March 1, 2023, the Toronto Stock Exchange approved the Company's normal course issuer bid to purchase and cancel up to 5.8 million of its outstanding Common Shares during the one-year period from March 3, 2023 to March 2, 2024.

23-year clean electricity supply agreement with Public Services and Procurement Canada

On February 3, 2023, Capital Power announced that it had entered into a 23-year clean electricity supply agreement with Public Services and Procurement Canada (PSPC) to meet the power needs of all federal government buildings in Alberta. Capital Power provides approximately 250,000 MWh of clean electricity per year, which was initially through Canada-sourced REC's until Halkirk 2 was completed. Halkirk 2 successfully reached commercial operations on December 15, 2025, resulting in the asset providing renewable energy to PSPC for the remainder of the term, representing approximately 65% of Halkirk 2's output.

15-year renewable energy agreement with Shaw Communications Inc.

On January 17, 2023, Capital Power announced that it had entered into a 15-year Virtual Power Purchase Agreement with Shaw Communications Inc. for the purchase of approximately 30 MW of renewable energy from the Clydesdale Solar facility. The renewable energy is bundled with 100% of the associated greenhouse gas offsets and environmental attributes generated from Shaw Communications' share of the facility's generation output.

BUSINESS OF CAPITAL POWER

Overview

Capital Power (TSX: CPX) is one of North America’s leading independent power producers, with approximately 12 GW of generation capacity across 35 facilities. Our portfolio includes natural gas, renewables and battery energy storage solutions. We deliver power generation at utility-scale through a flexible and resilient fleet built to meet growing electricity demand. Backed by deep expertise and an investment-grade credit rating, we provide safe, reliable power communities can depend on. We are Powering Change by Changing Power™. See – 2025 Integrated Annual Report, “About Us”.

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 across North America. In the ordinary course of business, Capital Power evaluates multiple potential acquisitions, development projects, joint ventures, partnership opportunities, and other strategic initiatives at various stages of review, including preliminary due diligence and the submission of non-binding expressions of interest, initial bids, or indicative offers. While certain opportunities may be material, their evaluation does not imply a commitment to pursue or complete any particular transaction. Such ongoing assessment activity is a standard and recurring component of Capital Power’s business practices and reflects Capital Power’s disciplined approach to shareholder value creation and to maintaining a competitive position in evolving power markets.

Generation Facility Summary

As of December 31, 2025, Capital Power’s owned power generation fleet had a capacity weighted average facility age of ~17 years and is diversified across three Canadian provinces and twelve states in the US. 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, 2025:

Category	Facility Name and Location	Type of Generation Facility	Year Commissioned or Target Date	Net Facility Generation Capacity (MW) ⁽¹⁾	Capital Power Interest (MW) ⁽¹⁾
Canada Flexible Generation	Genesee Generating Station, Alberta	Natural gas-fired combined cycle	Units 1 & 2 – 2024 ⁽²⁾ Unit 3 – 2005 ⁽²⁾	1,857	1,857
	Clover Bar, Alberta	Natural gas-fired, simple cycle	Unit 1 – 2008 Unit 2 & 3 – 2009	243	243
	Clover Bar Landfill Gas, Alberta	Land fill gas-fired	2005	2	2
	Joffre, Alberta	Gas-fired, combined cycle cogeneration	2001	480	192
	Shepard, Alberta	Natural gas-fired, combined cycle	2015	881	440
	Island Generation, BC	Natural gas-fired, combined cycle	2002	275	275
	York, Ontario ⁽³⁾	Natural gas	2012	462	231
	York, Ontario	BESS	2025	120	120
	East Windsor, Ontario	Natural gas	2009	92	92
	Goreway, Ontario ⁽⁴⁾	Natural gas	2009	915	915
	Goreway, Ontario	BESS	2025	50	50
	150 Mile House, BC	Waste heat	2008	5	5
Savona, BC	Waste heat	2008	5	5	

Category	Facility Name and Location	Type of Generation Facility	Year Commissioned or Target Date	Net Facility Generation Capacity (MW) ⁽¹⁾	Capital Power Interest (MW) ⁽¹⁾
	Total Canada Flexible Generation Facilities⁽⁵⁾				4,424
Canada Renewables	Quality, BC	Wind turbine	2012	142	72
	Halkirk 1, Alberta	Wind turbine	2012	150	150
	Halkirk 2, Alberta ⁽⁶⁾	Wind turbine	2025	122	122
	Whitla Wind, Alberta ⁽⁷⁾	Wind turbine	Phase 1 – 2019 Phases 2&3 – 2021	202 151	202 151
	Strathmore Solar, Alberta	Solar	2022	41	41
	Clydesdale Solar (formerly Enchant Solar), Alberta	Solar	2022	75	75
	Kingsbridge 1, Ontario	Wind turbine	2001 & 2006	39	39
	PDN, Ontario	Wind turbine	2013	105	54
		Total Canada Renewables Facilities⁽⁵⁾			
U.S. Flexible Generation	Decatur, Alabama	Natural gas	2002	885	885
	Arlington Valley, Arizona	Natural gas	2002	600	600
	Midland Cogen, Michigan	Natural Gas	1990	1,633	817
	Frederickson 1, Washington	Natural Gas	2002	265	133
	Harquahala, Arizona	Natural Gas	2004	1,092	546
	La Paloma, California	Natural Gas	2003	1,062	1,062
	Hummel Facility, Pennsylvania ⁽⁸⁾	Combined-cycle natural gas	2018	1,124	1,124
	Rolling Hills Facility, Ohio ⁽⁸⁾	Combustion turbine natural gas	2003	1,023	1,023
		Total U.S. Flexible Generation Facilities⁽⁵⁾			
U.S. Renewables	Beaufort, North Carolina	Solar	2015	15	15
	Bloom Wind, Kansas	Wind turbine	2017	178	178
	Macho Springs, New Mexico	Wind turbine	2011	50	50
	New Frontier, North Dakota	Wind turbine	2018	99	99
	Cardinal Point, Illinois	Wind turbine	2020	150	150
	Buckthorn Wind, Texas	Wind turbine	2018	101	101
		Total U.S. Renewables Facilities⁽⁵⁾			
	Maple Leaf, North Carolina	Solar	2027	73	73
	Bear Branch, North Carolina	Solar	2026	35	35

Category	Facility Name and Location	Type of Generation Facility	Year Commissioned or Target Date	Net Facility Generation Capacity (MW) ⁽¹⁾	Capital Power Interest (MW) ⁽¹⁾
Facilities Under Construction or in Advanced Stages of Development	Hornet Solar, North Carolina	Solar	2026	73	73
	East Windsor, Ontario ⁽⁹⁾	Natural Gas	2026	106	106
	Total Under Construction or in Advanced Stages of Development⁽¹⁰⁾				287

Notes:

- (1) MW listed are net capacity.
- (2) The generating capacities of Units 1, 2 and 3 are 666 MW, 666 MW and 525 MW, respectively. However, there is currently a system limit in place, called the Most Severe Single Contingency (MSSC), that sets the maximum amount of supply loss the Alberta grid can reliably withstand when operating in an interconnected (466 MW limit) or islanded condition (425 MW limit). This means generation from each of Units 1, 2 and 3 is currently limited to a maximum of 466 MW or 425 MW, as applicable. The Company is exploring, with the AESO, ways to enable an increase to the generating output of each facility above the MSSC.
- (3) The York Energy Centre upgrade project was completed in July 2025. See also "Business of Capital Power – Canada Flexible Generation – York – York - Upgrade Project".
- (4) The Goreway Power Station upgrade project was completed in May 2025. See also "Business of Capital Power – Canada Flexible Generation – Goreway – Goreway Power Station - Upgrade Project".
- (5) Represents Capital Power's owned capacity as at the date of this AIF.
- (6) Halkirk 2 achieved commercial operations on December 15, 2025. See also "Business of Capital Power – Canada Renewables – Halkirk 2".
- (7) Whitla Wind consists of 3 phases. Phase 1 (202 MW) is owned by Capital Power (Whitla) L.P. and phases 2 and 3 (151 MW) are owned by Whitla 2 Wind Generation L.P. For contracting purposes, phases 2 and 3 are contracted together, while phase 1 is contracted separately. For operational reporting, the Company combines all phases of the Whitla Wind project as a single facility referred to as Whitla Wind.
- (8) The Hummel Facility and the Rolling Hills Facility were acquired on June 9, 2025. See also "General Development of the Business – Company History – 2025 – Acquisition of Hummel Facility and Rolling Hills Facility".
- (9) Refers to East Windsor Expansion. See also "Business of Capital Power - Projects Under Construction or in Advanced Stages of Development – East Windsor Generation Facility Expansion".
- (10) Represents Capital Power's owned capacity, capacity under construction or in advanced stages of development as at the date of this AIF.

Revenue and Volume

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

Category	Revenues and other income (unaudited \$ millions)	
	Twelve Months Ended December 31, 2025	Twelve Months Ended December 31, 2024
Canada Flexible Generation ⁽¹⁾	2,181	2,193
Canada Renewables ⁽¹⁾⁽²⁾	111	214
U.S. Flexible Generation ⁽¹⁾⁽³⁾	1,416	757
U.S. Renewables	146	146
Corporate	40	19
Sub Total	3,894	3,329

Revenues and other income
(unaudited \$ millions)

Category	Twelve Months Ended December 31, 2025	Twelve Months Ended December 31, 2024
Unrealized changes in fair value of commodity derivatives and emission credits	(174)	447
Total	3,720	3,776

Notes:

- (1) Canada Flexible Generation does not include York, Canada renewables does not include PDN and Quality, and U.S. Flexible Generation does not include Midland Cogen and Harquahala, as they are accounted for under the equity method. Capital Power's share of the facility's net income is included in income from joint ventures on our consolidated statements of income.
- (2) Halkirk 2 achieved commercial operations on December 15, 2025. See also "Business of Capital Power – Canada Renewables – Halkirk 2".
- (3) The Hummel Facility and the Rolling Hills Facility were acquired on June 9, 2025. See also "General Development of the Business – Company History – 2025 – Acquisition of Hummel Facility and Rolling Hills Facility".

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

Electricity Generation (GWh)

Category	Twelve Months Ended December 31, 2025	Twelve Months Ended December 31, 2024
Canada Flexible Generation	18,721	15,976
Canada Renewables ⁽¹⁾	2,252	2,617
U.S. Flexible Generation ⁽²⁾	21,670	17,139
U.S. Renewables	1,973	2,089
Total	44,616	37,821

Notes:

- (1) Halkirk 2 achieved commercial operations on December 15, 2025. See also "Business of Capital Power – Canada Renewables – Halkirk 2".
- (2) The Hummel Facility and the Rolling Hills Facility were acquired on June 9, 2025. See also "General Development of the Business – Company History – 2025 – Acquisition of Hummel Facility and Rolling Hills Facility".

CANADA

As of December 31, 2025, Canadian commercial facilities consisted of ownership interests in 21 facilities representing approximately 5102 MW of power generation capacity ownership. The facilities generate electricity from natural gas, wind, solar, waste heat, and landfill gas, with some newly added BESS facilities this year. The output of the Canadian facilities is managed on a portfolio basis by Capital Power's Supply & Trading team. Output from these facilities is sold into their respective jurisdictional markets.

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

Canada Flexible Generation

Genesee Generating Station

Genesee Repower 1 & 2

Genesee Repower 1 & 2 is Canada's most efficient natural gas combined cycled facility⁽¹⁾ with a net capacity totaling 1332 MW. The repowered units achieved commercial operation in December 2024 and are 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.

Note:

(1) Repowered Units 1 and 2 at Genesee Generating Station use Mitsubishi M501JAC turbines and Vogt heat recovery steam generators in combined cycle mode and are the most efficient combined cycle units currently operating in Canada.

Commercial Arrangement: Merchant Facility

Genesee Repower 1 & 2 is managed as part of Capital Power's Alberta electricity portfolio optimization activities.

Fuel Supply

Natural gas for Genesee Repower 1 & 2 is purchased in the Alberta wholesale market to meet dispatch requirements. A natural gas transportation agreement with TransCanada currently 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 natural gas needs for Genesee Generating Station. This new natural gas pipeline also holds significant expansion potential should the gas needs at Genesee materially increase with future development.

Genesee 3

Genesee 3 is a 525 MW supercritical natural gas fueled 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. It has clean air technologies that include fabric filters that stop 99.8% of particulate matter from reaching the atmosphere. Upon its conversion to natural gas, the heat rate of the unit was increased by 1.5% and the net output capability was increased to 480 MW.

Commercial Arrangement: Merchant Facility

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

Fuel Supply

Genesee 3 is 100% natural gas fueled. Natural gas for Genesee 3 will be provided as part of TransCanada's firm and interruptible transport services as noted in "Business of Capital Power – Canada Flexible Generation – Genesee Generating Station – Genesee Repower 1 & 2 – Fuel Supply".

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.

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.

Clover Bar Landfill Gas

Capital Power owns and operates Clover Bar Landfill Gas facility, which was recently repowered under a life extension project to a 2 MW facility located in Edmonton, Alberta. The landfill gas collection system was commissioned in 1992 to provide gas to the process facility for cleaning, generation, and flaring.

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, TransAlta, 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. TransAlta operates the facility and dispatches the surplus power from 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, TransAlta 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 TransAlta 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.

Shepard

Shepard is an 881 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.

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 October 2026 under a tolling arrangement with BC Hydro. BC Hydro has full dispatch rights and is responsible for the fuel supply to the facility. For discussion of the Company's efforts with respect to renewal of the tolling arrangement with BC Hydro, see also "Regulatory Overview – British Columbia".

York

York is a 462 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. A 38 MW uprate was completed in 2025.

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 April 2035.

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.

York – Uprate Project

The York Uprate Project was developed around a turbine efficiency package, plus inlet cooling that provides a 38 MW increase in the total plant capacity. The uprate consists of improved turbine hot gas path parts and combustors together with an air inlet fogging system to improve hot weather performance. In Q1 2025, Capital Power completed equipment upgrades at the York Energy Centre that provide an additional 38 MW of electricity generating capacity. The upgrades were completed under the Ontario IESO Same Technology Upgrade Solicitation, which called for capacity increases from existing facilities. The upgrades improved efficiency, increased generation capacity and reduced NOx emissions at the York Energy Centre.

The uprate was accepted by the IESO in their call for same technology uprates to extend the PPA under similar terms until 2035. The project was completed in July 2025.

York Battery Energy Storage System

The York BESS facility provides 120 MW of nameplate capacity with at least four hours of storage (480 MWh) to the Ontario grid. Construction began in August 2024, and it became commercially operational in September 2025. The facility is located adjacent to the existing natural gas facility in the Township of King, and Tesla was selected as the preferred supplier. The York BESS is one of Capital Power's first-ever battery energy storage system projects, delivered alongside a second Ontario site (Goreway BESS, as further described below). This facility enhances Capital Power's portfolio of Flexible Generation sources that provides grid stability, supports the integration of renewable resources, and meets the province's unprecedented, growing demand for electricity.

Commercial Arrangement

This project is fully contracted with the Ontario IESO until 2047 (part of their Expedited Long-Term 1 RFP process). The York BESS facility connects to the 230KV system via the York substation.

See also "General Development of the Business – Company History – 2025 – York and Goreway Battery Energy Storage Systems commissioned and contracted to 2047".

East Windsor

East Windsor is a 92 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. In 2021 the company agreed with the IESO to operate the facility as a simple cycle generator with no steam host.

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.

Goreway

Goreway is a 915 MW natural gas combined-cycle generation facility located strategically in Brampton, Ontario, within the Greater Toronto Area load centre. The Goreway facility utilizes 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

The facility is fully contracted with the Ontario IESO until April 2035.

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.

Goreway Power Station – Upgrade Project

The Goreway Uprate Project was developed around a turbine efficiency package that will provide a 40 MW increase in the total plant capacity. The uprate consists of improved turbine hot gas path parts and higher output first stage compressor components, together with a peak firing software change. In 2025, Capital Power completed the upgrade to the station with more advanced technology and materials to increase efficiency, operational flexibility and electricity generation capacity by 40 MW, resulting in a new nameplate capacity of 915 MW.

The uprate was accepted by the IESO in their call for same technology uprates to extend the existing PPA under similar terms until 2035. The project was completed in May 2025.

Goreway Battery Energy Storage System

The Goreway BESS facility provides 50 MW of nameplate capacity with at least four hours of storage (200 MWh) to the Ontario grid. It became commercially operational in August 2025. The facility is located on an unused portion of the natural gas facility property in Brampton, and Tesla was selected as the preferred supplier. This facility also enhances Capital Power's portfolio of flexible generation sources that provides grid stability, supports the integration of renewable resources, and meets the province's unprecedented, growing demand for electricity.

Commercial Arrangement

This project is fully contracted with the Ontario IESO until 2047 (part of their Expedited Long-Term 1 RFP process). The Goreway BESS facility connects to the 230KV system downstream of the existing substation utilizing the existing Goreway grid connection.

See also "General Development of the Business – Company History – 2025 – York and Goreway Battery Energy Storage Systems commissioned and contracted to 2047".

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 owned by the Company and located at gas pipeline compressor station, owned by Westcoast Energy Inc., a subsidiary of Enbridge, near Savona, British Columbia, which Enbridge operates. 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.

Canada Renewables

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. The facility is jointly owned in a 51/49 partnership with Axiom Infrastructure Inc. and is operated by Capital Power.

Commercial Arrangement: Electricity Purchase Agreement

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

Halkirk 1

Halkirk 1 is a 150 MW wind facility located near Halkirk, Alberta, that began commercial operations on December 1, 2012. Halkirk 1 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 1 is managed as part of Capital Power's Alberta electricity portfolio optimization activities. RECs produced by Halkirk 1 are sold to PG&E under the terms of a 20-year fixed price agreement.

Halkirk 2

Halkirk 2 is a 122 MW wind facility located near Halkirk, Alberta, that successfully reached commercial operations on December 15, 2025. Halkirk 2 is comprised of 27 Vestas V-150 turbines each with a generation capacity of 4.5 MW.

In August 2024, Capital Power announced it entered into a participation and equity option agreement with Louis Bull Tribe, Samson Cree Nation, Montana First Nation and Ermineskin Cree Nation related to the project.

Commercial Arrangement: A partially Contracted Facility (Power Purchase Agreement for Energy and RECs)

In February 2023, the Company entered into a 23-year clean energy supply agreement with Public Service and Procurement Canada for approximately 250,000 MWh of renewable electricity and RECs per year to be sourced from the project. This represents approximately 65% of Halkirk 2's capacity.

Whitla Wind

Whitla Wind is a 353 MW wind facility located in the County of Forty Mile, Alberta that consists of 3 phases. Phase 1 began commercial operations on December 1, 2019 and is comprised of 56 Vestas V136 turbines, each with a generation capacity of 3.6 MW. Phases 2 and 3 reached commercial operation on December 1, 2021 and added 151 MW of generation capacity comprised of an additional 42 3.6 MW Vestas V136 turbines.

Commercial Arrangement: Renewable Energy Support Agreement (RESA) Swap Arrangement and Power Purchase Agreements

In December 2017, phase 1 of Whitla Wind 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 phase 1 of Whitla Wind's entire output for 20 years, and additionally will provide the AESO with all the renewable attributes generated by phase 1 of the project.

On September 15, 2021, the Company executed a 15-year renewable power purchase agreement with Dow Chemical Canada ULC, a subsidiary of Dow, for 25 MW of capacity and the associated environmental attributes from phases 2 and 3 of Whitla Wind.

On March 18, 2022, the Company announced a 10-year agreement starting April 1, 2022, with MEGlobal, a subsidiary of EQUATE Petrochemical Company K.S.C.C., for 126MW of capacity and the associated environmental attributes from phases 2 and 3 of Whitla Wind.

Strathmore Solar

Strathmore Solar is a 41 MW solar project, that began commercial operation in March 2022. Strathmore Solar consists of 109,174 photovoltaic panels located on 320 acres of leased industrial land.

Commercial Arrangement – Power Purchase Agreement

All of the energy and renewable energy credits generated by the Strathmore Solar project are sold under a 25-year PPA with TELUS Communications expiring at the end of 2046.

Clydesdale Solar (formerly Enchant Solar)

Clydesdale Solar is a fully permitted 75 MW solar project located within the municipal district of Taber, Alberta. Construction began in the fall of 2021 and began commercial operation on December 13th, 2022.

Commercial Arrangement: Renewable Energy Agreement and Virtual Power Purchase Agreement (VPPA)

The Company executed a 15-year renewable energy agreement to sell 51% of the electricity generated from Clydesdale Solar to Labatt Brewing Company Ltd. of Canada, along with bundled RECs.

In addition, Capital Power entered into a 15-year VPPA with Shaw Communications Inc. for the purchase of approximately 30 MW of renewable energy from the facility. The renewable energy is bundled with 100% of the associated greenhouse gas offsets and environmental attributes generated from Shaw's share of the facility's generation output.

Kingsbridge 1

Kingsbridge 1 is a 39 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, 20 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 single 0.7 MW 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 was successfully renewed in 2025 through the Ontario Medium-Term 2 Energy RFP, which now terminates at the end of April 2031.

Port Dover & Nanticoke

Port Dover & Nanticoke (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. The facility is jointly owned in a 51/49% partnership with Axiom Infrastructure Inc. and is operated by Capital Power.

Commercial Arrangement: Electricity Purchase Agreement

PDN has a 20-year feed-in-tariff contract with the Ontario IESO which expires in 2033.

UNITED STATES

U.S. Flexible Generation

Decatur

Decatur is an 885 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 three Siemens SGT6-5000F combustion turbine generators, 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 leased 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 with an A-rated credit rating and is fully contracted until the end of 2032.

Fuel Supply

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

Arlington Valley

Arlington Valley is a 600 MW combined-cycle natural gas generation facility located approximately 50 miles southwest of Phoenix, Arizona. The facility was commissioned in 2002 and acquired by Capital Power November 30, 2018.

Commercial Agreement: Tolling Agreement and Heat Rate Call Option

On January 7, 2026 Capital Power announced the extension of its summer tolling agreement for the Arlington facility with the current counterparty, an investment-grade utility. The agreement extends the existing 2031 agreement through October 2038 providing 13 years of contracted revenue. As part of this agreement, the facility will undergo a 35 MW capacity uprate to summer capacity; 10 MWs will be added in 2026 and an additional 25 MW in 2027.

On January 4, 2022, Capital Power announced the execution of a 6-year tolling agreement extension through October 2031 for its Arlington Valley facility with the current counterparty. Under the extension, the tolling agreement will be six months of the year from 2026 to 2031 as compared to four summer months through 2025.

Arlington Valley currently sells capacity and electricity to an investment grade load serving utility (credit ratings of A3/BBB+ 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 produces power to support a HRCO with another investment grade counterparty when called upon. When not called to support the heat rate call option, Arlington Valley may sell energy into the DSW or the CAISO wholesale markets.

Starting in 2026, Arlington Valley's energy and capacity will be sold into the DSW wholesale market during the six non-toll months.

Fuel Supply

Natural gas to the Arlington Valley facility is supplied through the El Paso Natural Gas Company gas interconnection or the Transwestern Natural Gas interconnection. During the summer months fuel

procurement and delivery are the responsibility of the tolling agreement counterparty. During non-summer months fuel procurement is managed by Capital Power's Supply and Trading team.

Midland Cogeneration

Midland Cogeneration is a 1,633 MW natural gas combined-cycle cogeneration facility located in Midland, Michigan that began operations in 1990 and was acquired by Capital Power on September 23, 2022. Midland Cogeneration is jointly owned, with Capital Power owning a 50% working interest and the remaining 50% owned by Manulife Investment Management.

Commercial Arrangement: PPA & Steam and Electrical offtakes

Midland has a PPA in place for 1,240 MW of capacity and energy with Consumers Energy, an investment grade load serving utility (credit ratings of Baa1/A- from Moody's and S&P, respectively) which is set to expire in 2030. In September 2025, Capital Power executed a new long-term contract with improved economic terms for Midland Cogeneration with Consumers Energy, extending the term to 2040 and providing 10 years of incremental contracted revenue, subject to customary regulatory approvals. Midland Cogeneration will receive payments for 1,240 MW, approximately 75% of the facility's capacity starting in June 2030 under the new PPA, creating long-term revenue stability throughout the contract term. In addition, Midland has steam and electricity supply agreements with investment grade agriscience companies located adjacent to the facility which provide stable revenue and a pass through of costs through 2035.

Fuel Supply

Midland has had a long-term asset management and gas supply agreement with a large North American natural gas producer and energy manager since 2008, with the current arrangements expiring in 2027. The agreements provide for 100% of the facility's gas requirements with contract pricing tied to the Consumers City Gate index, which coincides with the fuel cost pass through mechanisms in the facility's PPA and steam and electric supply agreements with behind-the-meter customers. Midland also has contracted for gas transportation and storage services with Consumers Energy until 2030 that provide firm deliveries, load balancing, and optimization opportunities for the facility. In addition to the gas interconnection with Consumers Energy, Midland is also interconnected with Great Lakes Gas Transmission Company providing additional gas supply reliability and flexibility but at a premium to the Consumers City Gate index.

Frederickson

Frederickson is a 265 MW natural gas combined-cycle cogeneration facility located near Tacoma in Pierce County, Washington that began operations in 2002 and was acquired by Capital Power on December 28, 2023. Capital Power has a 50.15% undivided ownership interest under a joint venture with Puget Sound Energy, whereby the parties are tenants in common. The facility consists of a 1X1 combined-cycle facility comprised of one GE 7FA combustion turbine, one Nooter Eriksen heat recovery steam generator, and a single GE steam turbine.

See also "General Development of the Business – Company History – 2023 – Acquisition of 50.15% interest in Frederickson 1 Generating Station".

Commercial Arrangement

Fredrickson has one long term unit contingent toll agreement with a credit-worthy counterparty and has recently concluded another. The tolling agreement with Morgan Stanley Group Inc. terminated in September 2025 and as of October 2025, the tolling agreement with Puget Sound Energy is active and will expire in October 2030. Each of the tolling agreements set the terms for energy purchases and entitles the tolling agreement counterparty to the facility's share of the committed capacity.

Fuel Supply

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

Harquahala

Harquahala is a 1,092 MW gas combined cycle facility located 60 miles West of Phoenix in Maricopa County, Arizona. It became commercially operational in 2004 and Capital Power's ownership interest was acquired in a transaction that closed on February 16, 2024. The facility consists of three (3) 501G powered 1 x 1 combined cycle gas turbines. Harquahala is electrically connected to the Hassayampa common bus and connects directly to the Palo Verde pricing hub. Harquahala is a FERC-approved exempt wholesale generator that is authorized to sell power at market-based rates. Capital Power is a 50% owner and operator of Harquahala under a partnership arrangement with an affiliate of a fund managed by BlackRock's Diversified Infrastructure business.

See also "General Development of the Business – Company History – 2024 – Completion of acquisition of 100% interest in La Paloma Facility and 50% interest in Harquahala Facility".

Commercial Arrangement

Harquahala revenues are fully contracted through a long-term tolling PPA with an investment grade counterparty through 2031. The PPA provides for the sale of nearly all capacity of Harquahala from January 1, 2024 to December 31, 2031, on a year-round basis and all of the electric energy associated with that capacity sold under the PPA. The PPA is based on a fixed capacity payment for Harquahala, subject to certain availability guarantees, along with a variable energy payment and a start charge. The PPA counterparty is responsible for carbon and other environmental costs pursuant to the PPA.

Energy management services for the Harquahala facility are currently provided by third party service providers. As of January 1, 2025, operation, maintenance, and asset management services are all provided by Capital Power, with those activities having been transitioned from third party service providers over the course of 2024.

Fuel Supply

Natural gas to the Harquahala facility is supplied through the El Paso Natural Gas Company gas interconnection. Fuel procurement, scheduling and delivery are the responsibility of the PPA counterparty.

La Paloma

La Paloma is a 1,062 MW gas combined cycle facility located 30 miles West of Bakersfield in Kern County, California. It became commercially operational in 2003 and Capital Power's 100% equity interest was acquired in a transaction that closed on February 9, 2024. The facility consists of four (4) combined cycle gas turbines. The La Paloma facility is electrically connected to the CAISO and procures fuel at the Kern pricing hub. The La Paloma facility is a FERC-approved exempt wholesale generator that is authorized to sell power at market-based rates.

Commercial Arrangement

The La Paloma facility sells its energy and capacity into the California power market. La Paloma sells into the CAISO through merchant day ahead/real time markets as part of a must-offer obligation when providing contracted capacity. La Paloma has secured bi-lateral Resource Adequacy (RA) contracts for a portion of available capacity with multiple counterparties. The La Paloma facility has currently sold its capacity pursuant to RA agreements with various investment grade utilities and off takers. The La Paloma facility can sell energy margin forward either through forward swaps or structured products which lock in the spark spread margin. The La Paloma facility is required to acquire carbon allowances through California's cap and trade program. It procures carbon allowances monthly at market rates and passes these costs through its energy offers in the CAISO market.

Operations, maintenance, and energy management services for the La Paloma facility are currently provided by third party service providers. Asset management services for La Paloma were transitioned from a third-party service provider to Capital Power in 2024. In June 2025, an updated Contractual Service Agreement was negotiated between Capital Power and GE Steam Power, a subsidiary of GE Vernova, to provide contracted gas turbine maintenance services to the La Paloma facility until 2040.

See also "General Development of the Business – Company History – 2024 – Completion of acquisition of 100% interest in La Paloma Facility and 50% interest in Harquahala Facility".

Fuel Supply

Fuel procurement and delivery are the responsibility of the energy manager. Procurement occurs in the spot markets since there are no fuel supply agreements in place.

Hummel

The Hummel Facility is a 1,124 MW combined-cycle natural gas facility in Shamokin Dam, Pennsylvania. It became commercially operational in 2018 and Capital Power's 100% equity interest in Hummel Station, LLC the owner of the facility was acquired in a transaction that closed on June 9, 2025.

Commercial Arrangement

The Hummel Facility sells its energy, ancillary services and capacity into the PJM market on a merchant basis. Energy margins are earned through a combination of day-ahead and real-time sales while capacity is sold through the annual auction and potential interim balancing auctions as required.

Fuel Supply

The Hummel Facility benefits from a strategically advantageous location with respect to gas supply. It is connected to the UGI Sunbury pipeline (Sunbury), which links to the Transco interstate pipeline in central Pennsylvania. The Hummel Facility holds firm gas transport capacity on Sunbury, providing access to competitively priced Marcellus shale gas. The Hummel Facility sources gas at the Leidy gas point which trades in the spot market at a discount to most other regional gas hubs.

Rolling Hills

The Rolling Hills Facility is a 1,023 MW combustion turbine natural gas facility in Wilkesville, Ohio. It became commercially operational in 2003 and Capital Power's 100% equity interest in Rolling Hills Generating, LLC the owner of the facility was acquired in a transaction that closed on June 9, 2025. Currently, one unit at the Rolling Hills Facility is out of service as a result of a Generator Step Up (GSU) transformer fire on or about September 12, 2024. The unit has been out of service while awaiting procurement of a replacement GSU. Unit 3 returned to service on December 23, 2025. Lost revenues associated with the unit were negotiated as part of the purchase price, and the Company has insurance coverage for the cost of the replacement GSU.

Commercial Arrangement

The Rolling Hills Facility sells its energy, ancillary services and capacity into the PJM market on a merchant basis. Energy margins are earned through a combination of day-ahead and real-time sale while capacity is sold through the annual auction and potential interim balancing auctions as required.

Fuel Supply

The Rolling Hills Facility is well positioned with respect to its gas supply as it has access to low-cost Marcellus Basin gas. It is connected to the Texas Eastern Transmission Corporation (TETCO) interstate pipeline and procurement occurs in the spot market. The facility sources its gas from the TETCO East Louisiana hub, which typically trades in the spot market at a discount compared to other regional gas hubs.

U.S. Renewables

Beaufort

Beaufort is a 15 MW photovoltaic solar facility located near Chocowinity, Beaufort County, North Carolina, that began commercial operations in 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. This lease concluded in 2025 and Capital Power has exercised its option to re-purchase the project at 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 Wind

Bloom Wind is a 178 MW wind facility consisting of 54 Vestas V117-3.3 MW turbines. Bloom Wind 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 Wind 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 June 30, 2027. 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 Wind 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.

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.

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.

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 operates 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 was unhedged.

Buckthorn Wind

Buckthorn Wind is a 101 MW wind facility located approximately 60 miles southwest of Dallas in Erath County, Texas and comprised of 29 Vestas wind turbines. The facility began commercial operations in January 2018 and operates in the liquid ERCOT North region, which is situated between most of the wind generation in ERCOT-West and the Dallas load center.

Commercial Arrangement: Contract for Differences / REC offtake and Financial Swap Agreement

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.

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:

Maple Leaf Solar

Maple Leaf is a 73 MW solar energy project, located in the Town of Selma, North Carolina. In June 2023, Capital Power announced a 25-year, fixed price renewable power purchase agreement for 100% of the output from the project with Duke Energy Progress. Construction began in Q2 of 2025 with an estimated capital cost of US\$165 million and an expected commercial operations date in Q1 2027. See also "General Development of the Business – Company History – 2023 – Maple Leaf Solar project awarded 25-year contract".

Bear Branch Solar

Bear Branch Solar is a 34.5 MW solar energy project located in Stokes County, North Carolina. The project signed a 25-year, fixed price renewable power purchase agreement with Duke Energy Carolinas in 2024. The project is currently under construction and is expected to reach commercial operations in Q3 of 2026.

Hornet Solar

Hornet Solar is a 73 MW solar energy project located in Stanley, North Carolina. The project signed a 25-year, fixed price renewable power purchase agreement with Duke Energy Carolinas in 2024. The project is currently under construction and is expected to reach commercial operation in Q2 2026.

East Windsor Generation Facility Expansion

The East Windsor Expansion project is a new 106 MW natural gas generator. It will be located on Capital Power owned land adjacent to the existing East Windsor facility and will connect to the 115KV system at the same connection point as the existing facility. General Electric has been selected as the turbine supplier. Construction is at an advanced stage and the facility is expected to reach commercial operations in 2026.

Once completed, this facility will be contracted with the Ontario IESO until 2040.

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 Supply & Trading team. 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 to manage portfolio risk and develop and maintain capability to support Capital Power's growth strategy and to generate profits.

The Supply & Trading team:

- manages price and volume risk in Capital Power's commodity portfolio;
- sets generation unit offer strategy for electricity and ancillary services;
- acquires and schedules delivery of natural gas supply used to generate electricity; and
- ensures 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, Alabama, Arizona, California, Illinois, Kansas, Michigan, New Mexico, North Carolina, North Dakota, Ohio, Pennsylvania, Texas, and Washington. 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 experience 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 13.3% of the total merchant generation capacity in the market.¹³

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 reporting and disclosure practices reflect our commitment to transparency and accuracy. This commitment is demonstrated through integrating our sustainability and financial disclosures in Capital Power's seventh Integrated Annual Report, being published in March 2026. The Integrated Annual Report aligns to the Sustainability Accounting Standards Board standards, as well as the recommendations of the Task Force on Climate-related Financial Disclosures framework (which are now part of the International Financial Reporting Standards Foundation) to disclose information pertaining to climate-related risks and opportunities.

We measure and report our performance on an ongoing and comprehensive basis. In 2025, 15% of the CEO's short-term incentive scorecard was based on ESG targets, and 12.75% of the rest of the executive team's short-term incentive scorecard was based on ESG targets. The Board receives quarterly sustainability updates and has oversight of our Integrated Annual Report.

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 CO₂, NO_x, SO₂ 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 additional capital expenditures or operating expenses, or

¹³ Source: Market Surveillance Administrator, Market Share Offer Control Report, June 2025, MSOC (albertamsa.ca)

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.

Health, Safety, Security, and Environment

Health, Safety, Security, and Environment Policy (HSSE Policy)

At Capital Power, we work in environments where risks are real and constantly changing. The high-energy hazards and critical infrastructure we manage require constant attention, strong systems, and a culture deeply committed to protecting people, reducing environmental impacts, safeguarding assets, and maintaining operational excellence.

We Believe:

- No matter how skilled our workforce is or how well we maintain our equipment, errors and failures can happen. Our systems need to be designed to anticipate human error, absorb shocks, and enable safe recovery – minimizing harm and maximizing resilience.
- Incidents are rarely due to negligence or bad intentions. We see blame as a barrier to progress and aim to create an open environment where challenges are identified, understood, and addressed at the system level.
- Decisions are made in complex, high-pressure environments with sometimes imperfect information. We will listen to those closest to the work and co-create solutions that reflect real conditions, not just procedural ideals.
- Learning should be proactive and ongoing. We will report all incidents, leverage insights and adapt quickly to maintain safe and reliable performance.
- How leaders and teams respond to issues – whether safety concerns, operational upsets, or improvement ideas – sets the tone for trust, transparency, and continuous improvement.

Our Commitments:

- We will uphold rigorous risk management practices that prioritize the prevention of serious injury, environmental harm, and security threats.
- We will design and maintain HSSE systems that are practical, risk-informed, and human-centered.
- We will engage and empower people at all levels to contribute to HSSE performance and innovation.
- We will comply with all applicable laws, regulations, and industry standards as a minimum baseline.
- We will continuously measure, monitor, and improve our HSSE performance to achieve operational excellence.

At Capital Power, safety and environmental responsibility are core values. We are all responsible for our environmental performance, and the health, safety, and security of ourselves and our fellow workers.

HSSE Governance and Performance Oversight

Capital Power manages HSSE risks through a company-wide HSSE Management System and measures results against recognized industry and internal standards. Compliance audits, conducted by internal and external auditors, verify that the program meets regulatory requirements.

Board-approved HSSE objectives are established annually and tracked through the HSSE Performance Index (Index), which uses five leading indicators to focus on proactive activities and continuous improvement. In 2025, Capital Power achieved an HSSE Performance Index of **1.14**, marking the twelfth consecutive year at or above the target and demonstrating strong results against leading indicators.

To support these objectives, Capital Power:

- Tracks and analyzes hazards, near-miss events, and incidents to identify trends and implement preventative actions.
- Delivers ongoing HSSE training for employees in field and operating roles, with completion monitored for compliance.
- Reviews regulatory updates regularly to maintain awareness of upcoming changes.

HSSE Initiatives

In 2025, Capital Power advanced the transformation of its HSSE Management System framework to align with an evolving and dynamic operating model. This risk-based approach is designed to strengthen resiliency and scalability while maintaining strong risk controls:

- The framework provides flexibility within defined boundaries, enabling alternative solutions that deliver equivalent levels of protection.
- Mandatory controls are clearly defined where there is potential for high-consequence events, supported by risk control measures aligned with contemporary industry practices.
- Transformation efforts focus on optimizing local expertise and decision-making while ensuring consistent protection standards across operations.

Specific environmental initiatives and achievements include the following activities:

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

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

- Advanced the integration and understanding of Human and Organizational Performance (HOP) principles to strengthen safety through collaboration, learning, and reliability across operations.
- Continued to focus on energy-based safety, sharpening attention on high-energy hazards and critical controls.
- Maintained HSSE representation or health and safety committees at all applicable offices, operating facilities, and construction sites in compliance with regulatory requirements.
- Continued to optimize learning opportunities through the Significant Event Review Committee and fleet-wide learning review meetings, supported by lessons-learned bulletins to drive continuous improvement across our growing fleet.
- Met or exceeded leading indicator targets specific to health and safety, including completion of required HS training, focused inspections, and in-field leadership discussions.

People

As at December 31, 2025, the total number of persons employed by Capital Power is 731. As of December 31, 2025, approximately 502 full-time, part-time, temporary and casual employees work in Capital Power's Canadian operations and 229 are employed in Capital Power's US operations.

There are four Canadian labour unions, in six bargaining units, and two labour unions in two bargaining units in the USA which together represent approximately 31% of Capital Power's Canadian labour force, 21% of Capital Power's US work force and approximately 28% 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 International Brotherhood of Electrical Workers Local 769, which represents hourly operators and maintenance employees at Harquahala facility;
- the Power Workers Union Local 1000, which represents power engineers and maintenance employees at Goreway;
- the Power Workers Union Local 1000, which represents plant technicians at East Windsor Cogeneration Centre;
- the UNIFOR Local 829, which represents power engineers at the Genesee power facility;
- the UNIFOR Local 592, which represents power engineers and maintenance employees at Island Generation; and
- the Utility Workers Union of America local 564, which represents hourly operators and maintenance employees at Midland Cogeneration Venture.

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 14, 2025	December 8, 2029
IBEW Local 1007	Edmonton, AB	December 17, 2023	December 13, 2025
IBEW Local 769	Arizona, United States	January 23, 2026	January 23, 2029
PWU Local 1000	Brampton, ON	December 5, 2023	December 4, 2026
PWU Local 1000	Windsor, ON	June 6, 2024	June 5, 2027
UNIFOR Local 829	Edmonton, AB	December 19, 2025	December 9, 2028
UNIFOR Local 592	Campbell River, BC	May 1, 2025	April 30, 2028
UWUA Local 564	Michigan, United States	March 2, 2025	March 10, 2030

REGULATORY OVERVIEW

The following is an overview of the principal electricity and 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".

Canada

Federal Government

Canada – Alberta MOU

On November 27, 2025, Alberta and the federal government signed a MOU outlining several key measures relevant to Capital Power, the electricity sector, and Alberta's broader economy. These include:

Clean Electricity Regulations (CERs): Suspension of the CER in Alberta immediately, pending a new carbon pricing agreement (including the electricity sector) under Alberta's TIER program by April 1, 2026. The CER will remain in abeyance once the agreement and other measures are finalized. Having the CER in abeyance will mark a significant achievement as it addresses the real challenges facing the development of efficient natural gas-fired projects that are necessary to meet immediate demand growth.

Carbon Pricing: Plans to design and commit globally competitive, long-term carbon prices, levy recycling protocols, and sector-specific stringency factors for large oil & gas and electricity emitters under Alberta's TIER system.

- Minimum *effective* credit price: \$130/tonne; agreement by April 1, 2026.
- Include financial mechanisms in the agreement for long-term certainty and emissions reductions.
- Ensure Alberta's carbon market functions reliably and adapts to electricity, oil & gas, and other large emitters (e.g., fertilizer, cement).

Greenwashing Provisions: Canada committed to amend the *Competition Act* (as outlined in Budget 2025) to remove "greenwashing" provisions that create investment uncertainty.

Interties: Canada and Alberta will immediately engage with British Columbia in trilateral discussions on pipeline development and related projects, including interties, ensuring B.C.'s economic interests are considered.

Data Centres: Supports for increasing electrical generation for consumer and industrial use on Alberta's grid, including meeting AI data centre needs, while targeting net-zero GHG emissions for the electricity sector by 2050. By July 1, 2026, Alberta committed to implement a policy framework to incentivize large investments in data centre development, including Canadian sovereign computing.

Nuclear & CCUS: By January 1, 2027, Alberta will collaborate with Canada on a nuclear generation strategy to build and operate competitive nuclear power serving Alberta and interconnected markets by 2050. Canada committed to collaborate with Alberta on policy supports enabling deployment of nuclear technology, CCUS, and energy storage to decarbonize the electricity system while ensuring reliability and affordability.

Investment Tax Credits: Extend federal ITCs and policy supports to encourage large-scale CCUS investments, including Pathways and enhanced oil recovery, to attract significant domestic and foreign capital.

Oil and Gas Emissions Cap: Canada committed to not implement the previously proposed oil and gas emissions cap which has not yet been put into effect.

Pipeline Collaboration and Indigenous Consultation: The MOU commits Alberta and the federal government to collaborate on pipeline development to the west coast, with a specific emphasis on ensuring meaningful consultation and engagement with Indigenous communities throughout the planning and implementation process. Alberta will act as the proponent for advancing the project to the Major Projects office by July 1, 2026.

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 is based on their environmental efficiency as measured in tonnes of carbon dioxide per MWh. Boilers, such as Genesee Unit 3, that meet more stringent efficiency requirements are permitted to operate up to 10 years post EoUL.

For gas turbines, large units (over 150 MW) are subject to a 0.42 tCO₂e /MWh standard, while smaller units (25-150 MW) are subject to a 0.550 tCO₂e /MWh standard (gross basis). The regulation included provisions providing legacy treatment to existing units such that Clover Bar, Joffre, Shepard and Island Generation are not impacted by the standards.

Clean Electricity Regulations

On December 17, 2024, the Government of Canada released the final version of the *Clean Electricity Regulations* (CER). The Regulations have been published in Gazette II and are established under the *Canadian Environmental Protection Act, 1999* (CEPA). The CER are part of a broader suite of policies intended to meet the federal government's objective of achieving a net-zero electricity system by 2050.

Starting in 2035, where applicable, the CER will apply to grid connected units that are greater than 25MW and generate electricity using fossil fuels. The regulations set an annual emission limit (AEL) for each unit based on a prescribed emission intensity and the unit's capacity. The prescribed emission intensity will be 65 tCO₂/GWh for the period between January 1, 2035 and December 31, 2049; and 0 tCO₂/GWh thereafter. Compliance flexibility by way of using offsets is permitted. The CER will grant an allowance of an additional 35 tCO₂/MWh over the prescribed emission intensity to 2050 and 42 tCO₂/GWh after. The offsets must be registered within the Canadian system and issued no more than eight years prior to being remitted. The same offset can be applied to the CER and federal carbon pricing or a provincial carbon price that has cross recognition with Canadian offset credits. Additional compliance flexibility will be allowed through banking of AEL credits for use in future years and the transfer of unused AEL credits between units operating in the same jurisdiction so long as the unit is not a coal facility or existing / planned cogeneration facility. Existing units, planned units, or units regulated under the coal-to-gas regulations will not have to comply with the AEL until the end of their prescribed life (EoPL) where the EoPL is defined as 25 years after the unit's commissioning date for existing units, 2049 for planned units, and the end of life assigned to coal-to-gas converted units under the *Regulations Limiting Carbon Dioxide Emissions from Natural Gas-fired Generation of Electricity*. Planned units are defined as a unit that is commissioned between January 1, 2025 and December 31, 2034 where construction begins prior to December 31, 2027.

As a result of the Canada – Alberta MOU, management will be participating and monitoring the progress for the CERs to be held in abeyance in the Province of Alberta.

While all of Capital Power's natural gas generation facilities in Canada, including the repowered Genesee 1 and 2 units, qualify as existing units under the CER, subject to further details, the MOU will allow Alberta facilities to operate beyond the EoPL. As such, each unit will have to achieve compliance with the AEL at the end of their respective EoPL, 25 years after COD.

Federal Climate Competitiveness Strategy

On December 11, 2020, the Government of Canada released its climate plan (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/tCO₂e per year starting in 2023 until achieving a price of \$170/tCO₂e in 2030.

In Budget 2025, the federal government released their Climate Competitiveness Strategy, which outlined plans to strengthen industrial carbon pricing (with further details outlined in the Canada – Alberta MOU) and improve certainty over the long-term. The strategy also outlined the need for greater clarity on GHG Regulations, committing to changes to the greenwashing provisions, oil and gas emissions cap, and the *Canadian Environmental Protection Act*.

Pan-Canadian GHG Framework

The *Greenhouse Gas Pollution Pricing Act* (GGPPA) sets out a federal carbon pricing system. For industrial emitters it sets out an output based pricing system (OBPS), which is administered by Environment and Climate Change Canada (ECCC). On October 11, 2022, the Government of Canada established the carbon price for the 2023-2030 period. Starting at \$65/tCO₂e in 2023, the schedule increases the carbon price by \$15/tCO₂e per year until achieving a price of \$170/tCO₂e in 2030. In 2025, the carbon price was set at \$95/tCO₂e. Under the Framework, provinces and territories are enabled to design their own pricing systems that are equivalent to the federal standard. Alberta (TIER) and Ontario (EPS) both have their own industrial

carbon pricing systems which the Federal Government has assessed as meeting the objectives of the OBPS. These programs will be reviewed during an interim assessment in 2026 to confirm each provincial frameworks continue to meet benchmark criteria for the 2027-2030 period.

Within the Canada – Alberta MOU, the government has committed to creating an industrial carbon price pathway to achieve an effective carbon price of \$130/tonne at an indeterminate time. The deadline for an agreement is April 1, 2026.

Management continues to engage both federal and provincial governments on the future of industrial carbon pricing in Canada, with advocacy focusing on long-term certainty, predictability and competitiveness.

Canada's Enhanced Nationally Determined Contribution

On April 22, 2021, Canada announced that it will increase its emissions reduction target to be 40-45% below 2005 levels by 2030, compared to the previous target of 30%. The 40-45% emissions reduction was subsequently incorporated in *the Canadian Net-Zero Emissions Accountability Act*, which received Royal Assent on June 29, 2021, and was reflected in Canada's enhanced Nationally Determined Contribution (NDC) that was submitted to the United Nations on July 12, 2021.

COP28 concluded on December 12, 2023, with an agreement that sets the stage for a transition process. This process is expected to involve significant emissions reductions and increased financing to support climate change mitigation and adaptation globally. The agreement highlights the importance of substantial, ongoing reductions in greenhouse gas emissions, in alignment with 1.5 °C pathways. It also encourages parties to participate in global efforts, taking into account their individual national circumstances. Canada and the US maintained their respective NDCs at 40-45% below 2005 levels by 2030 and 50–52% below 2005 levels by 2030, respectively. The following efforts are the most relevant to the electricity sector:

- Tripling renewable energy capacity globally and doubling the global average annual rate of energy efficiency improvements by 2030.
- Accelerating efforts globally towards net zero emission energy systems, utilizing zero- and low-carbon fuels well before or by around mid-century.
- Transitioning away from fossil fuels in energy systems, in a just, orderly and equitable manner, accelerating action in this critical decade, so as to achieve net zero by 2050 in keeping with the science.
- Accelerating zero- and low-emission technologies, including renewables, nuclear, abatement and removal technologies such as carbon capture and utilization and storage, particularly in hard-to-abate sectors, and low-carbon hydrogen production.

COP29 concluded on November 22, 2024, with an agreement to increase annual funding goals to at least US\$300 billion annually, with an overall climate financing target to reach “at least US\$1.3 trillion by 2035”. The new goal of at least US\$300 billion annually by 2035 is triple the amount of the previous target, aiming to mobilize much-needed finance for developing countries to cut emissions and address the mounting impacts of climate change. No changes were made to Canada’s NDC but indicated an aim to submit the next NDC that are aligned with emission trajectories in-line with mid-century net-zero objectives.

COP30, held in Belém, Brazil, reinforced and advanced the commitments made at COP28 and COP29, particularly regarding global ambition on emissions reductions, climate finance, adaptation, and the energy transition. In addition, COP30 marked the formal submission of the next round of Nationally Determined Contributions (NDCs) for 2035, launched new initiatives to accelerate implementation, and included enhanced commitments on adaptation finance and Indigenous participation. The summit maintained the global focus on tripling renewable energy capacity and doubling energy efficiency by 2030, while emphasizing the need for practical action and accountability to achieve climate goals.

Federal Financial Support for Clean Electricity Projects

The 2023 Federal Budget (Budget) was tabled on March 28, 2023 and included proposals for a number of new and expanded programs and initiatives to support investment across a range of zero and low-emitting technologies to advance the federal government's clean electricity and net-zero objectives. The Budget measures of particular note for Capital Power were the following: (i) reaffirmation of the role and mandate for the Canada Growth Fund (CGF) to support de-risking of large scale decarbonization through instruments such as carbon contracts for differences, (ii) direction by the federal government that the Canada Infrastructure Bank will have a new priority focus on clean electricity, (iii) enhancements to the 50% refundable ITC for carbon capture, utilization and storage, (iv) updates to the 30% refundable Clean Technology ITC that will be available to taxable entities for investments in eligible technologies, (v) a new 15% refundable Clean Electricity ITC that will be available for non-taxable entities for investments in eligible technologies, and (vi) updates to the Clean Hydrogen ITC.

The 2023 Fall Economic Statement (2023 FES), tabled on November 21, 2023, provided additional direction regarding the CGF's mandate in noting that the CGF will allocate \$7 billion of its total \$15 billion of capital to issue all forms of CCFDs and offtake agreements to support de-risking of investments in decarbonization technologies.

Legislation to implement the CCUS and Clean Technology ITCs were also introduced in November 2023 and progressed in 2024's Budget and Fall Economic Statement. Bill C-59 (which includes the CCUS ITC and Clean Technology ITC) received Royal Assent on June 20, 2024. Capital Power's Halkirk 2 Wind, Goreway BESS and York BESS projects are expected to be eligible for the Clean Technology ITC and an accrual of \$73 million, based on the respective project-to-date spend, was recorded in 2024.

In Budget 2025, the government proposed the final implementation of the 15% Clean Electricity Investment Tax Credit, which may include a domestic content requirement that will be engaged upon in 2026. The government also extended the full value of the CCUS ITC by 5-years to 2035.

Greenwashing Provisions

Bill C-59 introduced amendments to Section 74.01 of the *Competition Act* (Act) to address greenwashing. The Act now targets environmental claims that promote the environmental, social, and ecological benefits of using or supplying a product if the claim is not based on an adequate and proper test. More broadly, it also targets environmental claims that promote the environmental and ecological benefits of a business or business activity that are not based on adequate and proper substantiation in accordance with an internationally recognized methodology. Both of these sections place the burden of proof on the entity making the environmental claim to demonstrate compliance with these provisions.

As part of Budget 2025 and the Canada – Alberta MOU, the federal government has committed to updating the greenwashing provisions of the *Competition Act* arising from Bill C-59 to mitigate the concerns regarding investment uncertainty. Changes are expected to progress in 2026.

Artificial Intelligence Strategy

As part of Budget 2025, a new Office of Digital Transformation will lead AI and emerging tech adoption across the government. Budget 2025 proposes \$925.6 million over five years to build sovereign public AI infrastructure, boosting compute capacity for public and private research. The Minister of Artificial Intelligence and Digital Innovation will engage industry to identify promising AI infrastructure projects and formalize support through MOUs.

Alberta

Since January 1, 1996, new generation capacity initiatives in Alberta have been paid for by independent power producers and are compensated subject to market forces, rather than ratepayers. Power from merchant generation is cleared through a wholesale electricity market. Power is dispatched in accordance with an economic merit order administered by the Alberta Electric System Operator (AESO), based on

offers by generators to sell power. The Market Surveillance Administrator (MSA) is an independent entity responsible for monitoring the behaviour of market participants, including AESO, 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, AESO and AUC rules. The AUC oversees electricity industry matters including approvals of the construction and operation of new power and transmission facilities, regulated rates for transmission, distribution and the 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. Capital Power's development projects are subject to oversight by the AUC.

The *Responsible Energy Development Act* created a single regulator, the AER, which began operations in June 2013. The AER is responsible for all oil, gas, oilsands and coal mining projects in Alberta. 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.

Alberta Electric System Operator Restructured Energy Market (REM)

On March 11, 2024, the Government of Alberta and the AESO announced plans to restructure the energy market (REM) to address long-term reliability, affordability, and decarbonization objectives. The AESO initiated a series of consultations on high-level design details on September 10, 2024, and completed its high-level design for REM on August 27, 2025.

The final design introduces increased price caps (with the offer cap rising to \$1,500/MWh upon implementation of the REM, increasing to \$2,000/MWh in 2032; and a price cap during scarcity events set at \$3,000/MWh), a new real-time ramping product (R30), and the adoption of locational marginal pricing (LMP) for congestion management. The AESO has started consultation on REM rules which are expected to be approved by the Minister of Affordability and Utilities later this year. Details of several administrative parameters, such as the cost of new entry for reference units, will be determined closer to implementation which is expected to start in mid-2027. The high-level design is supportive of providing added value for dispatchable, reliable generation and Management will continue to actively participate in the rules and implementation process.

Alberta Bill 52 – Energy and Utilities Statutes Amendment Act, 2025

On May 12, 2025, the Government of Alberta passed the *Energy and Utilities Statutes Amendment Act* to enable the AESO to implement the REM. The Act makes necessary changes to the rules approval process to allow the REM rules to be enacted by the Minister through regulation (instead of the AUC). The bill also removed the congestion free policy from the AESO's policy obligations for transmission planning. Other changes in the Act remove barriers to allow hydrogen blending in the natural gas distribution system for residential and commercial heating to support new technologies while ensuring the safety and reliability of the system; and streamline the process to connect with other jurisdictions, reducing red tape and enabling critical improvements.

Interim Market Power Mitigation Rules

Two interim regulations to address the Government of Alberta's concerns with market power in the wholesale electricity market were announced on March 11, 2024 when plans were announced to restructure the energy market. Details of the interim regulations are:

- The *Market Power Mitigation Regulation* sets out a secondary price cap in Alberta's market where offers of generators with 5% or higher market share are limited once a hypothetical reference combined cycle unit reaches twice its expected fixed cost (capital recovery and fixed operating) recovery for the month. When the threshold is reached, the offer cap for affected generators will decline to the greater of \$125/MWh or 25 times the natural gas price.
- The *Supply Cushion Regulation* enables the AESO to develop procedures to direct or keep on generating assets that cycle offline and cannot re-connect within an hour in the event it anticipates

its supply cushion in the market to be less than 932 MW. In the event a generator is directed on, it will be compensated for its startup costs and minimum generation costs in the event the market prices do not cover the costs.

The expedited rules based on the interim regulations were approved by the AUC on June 19, 2024, and came into effect on July 1, 2024. The AUC approved the final rules on February 19, 2025 requiring the AESO to provide more transparency on the use of the supply cushion procedures.

Transmission Policy Changes

On October 23, 2023, the Government of Alberta released a discussion paper identifying different features of the existing transmission policy framework that are being reviewed to ensure the affordability, reliability and decarbonization of Alberta's electricity system. On July 11, 2024, the Alberta Minister of Affordability and Utilities announced policy direction on long-standing transmission policy. On a go forward basis, the policy direction is to move away from the current zero-congestion transmission planning standard to an optimally planned transmission planning standard where costs of transmission are evaluated against the benefits. This will result in congestion becoming more pertinent to Alberta's market and will see changes to how the AESO plans the transmission system.

On December 10, 2024 the Government of Alberta issued a direction letter to the AESO outlining further decisions on transmission policy – specifically outlining that to improve location signals when siting new generation, the existing Generator Unit Owner's Contribution will be replaced with a non-refundable Transmission Reinforcement Payment (TRP) whose proceeds will be used to offset transmission costs. There will be no upper limit on the TRP and will be implemented through changes to the AESO's tariff. To restore the inertia, the AESO has been directed to develop plans and file them with the AUC by December 31, 2026 to restore the Alberta-BC path to approximately 950 MW, procure and maintain high levels of ancillary services to allow full import flows, and replace the Alberta-Saskatchewan inertia which is nearing the end of its useful life – in doing so there is an expectation that the AESO will increase its path rating.

On July 15, 2025 the Government of Alberta directed the AESO to adopt LMP and allocate financial transmission rights (FTRs) to incumbent generators. The AESO started consultations on FTRs in holding stakeholder sessions in September to discuss the long-term potential for FTRs in the Alberta market and in October to discuss the allocation of the transition rights.

On September 24, 2025 the AESO published its Optimal Transmission Planning (OTP) recommendation paper which outlined its approach to updating how transmission planning will be performed going forward as a result of the transmission policy changes. The paper provided details on how the AESO will assess benefits and costs for transmission development and how this will inform future transmission projects. Further consultation is expected into 2026 with the AESO planning to put forward its first long-term transmission plan under the OTP framework in 2027.

Management is active in all transmission policy and planning consultations.

AESO Independent Systems Operator (ISO) tariff redesign

On March 5, 2025, the AESO kicked off an engagement to redesign its ISO tariff, which outlines the rates, terms and conditions for market participants who receive access to the transmission system. The scope of the engagement will include addressing ancillary service cost allocation, system access charges for generators and amendments to the connection process with a filing with the AUC in 2026; and demand rates, tariffs for imports and exports, and additional considerations are to be filed with the Commission in 2027. New rates are expected to take effect in 2029 following the AUC review process. Management will participate as appropriate in the AESO's engagement over the next two years.

AESO Data Centre Connections, Requirements, and Engagement

On March 20, 2025, the AESO provided an industry update on how data centre projects introduce technical and operational challenges and its plans for a path forward. This included near- and longer-term actions

that the AESO is taking to provide projects with a reasonable opportunity to connect to the grid in a manner that is fair, efficient, and competitive.

On June 4, 2025, the AESO shared details on Phase I of their large load connection plan, updating industry with details on how data centre projects in Alberta will be provided with an opportunity to connect to the grid. For Phase I, the AESO instated a 1,200 MW interim connection limit that was allocated to qualified data centre projects, including those applied for by Capital Power, with contracting awarded in October 2025. While the interim connection limit restricts the scale of data centre projects, Management views data centre-driven electricity demand growth in Alberta as a positive long-term development for all power producers.

In August and September 2025, the AESO consulted on connection requirements for transmission connected data centres with the intention to provide clear expectations to developers while safeguarding reliability. On September 26, 2025 the AESO announced pre-engagement on its Phase II of its Large Load Integration Program which will explore changes necessary to create a long-term framework for large loads including data centres. This will include iterative engagements on the AESO's connection processes, planning, operations, markets, tariff and reliability. Capital Power has been selected to participate in the Phase II working group and will be actively providing feedback on the first issue – enabling accelerated connections including for projects that align with the government of Alberta's objective to "bring your own generation".

Alberta Bill 8 –Utilities Statutes Amendment Act, 2025

The government of Alberta passed Bill 8 on December 8, 2025. The bill provides updates to the *Electric Utilities Act* to accelerate large-scale data centre development and modernize the province's electricity system in response to AI-driven power demand. The bill would allow data centres to bring their own generation, fast-tracking approvals and prioritizing grid connection for projects that self-supply power. The required transmission upgrades for these connections would be paid for by the data centres themselves, not Alberta ratepayers. The government positions this as a strategy to strengthen grid reliability and affordability while attracting major digital infrastructure investment. Bill 8 also advances REM implementation, building on reforms passed earlier in 2025.

Alberta Bill 12 – Financial Statutes Amendment Act 2025

On August, 27, 2025 the Alberta government announced that it would be developing a 2% levy on grid connected data centre investments of 75 MW or greater. This would be a levy on the investments in computer hardware and is designed to be creditable against provincial corporate income taxes (meaning once a data centre becomes profitable and pays corporate income taxes, the net burden of the levy disappears). As part of Bill 12, approved on December 9, 2025, the government provided more details on its proposed levy structure where the levy would be graduated: 2% on grid-dependent projects; 1% on grid-connected projects that bring additional generation; and 0% on fully self-supplied (off-grid) projects.

Management continues to monitor and assess how this impacts Alberta's competitiveness in attracting data centres.

AESO ISO Fast Frequency Response Plus (FFR+) procurement

In June 2025, the AESO launched a new engagement on FFR+, a proposed ancillary service designed to support full import flows on Alberta's BC and Montana interties. FFR+ builds on the existing Fast Frequency Response framework by incorporating additional non-market reliability services such as system strength, fast net demand response, and blackstart capability.

In July 2025, the AESO convened a stakeholder engagement session to solicit feedback on design options for the Fast Frequency Response Plus (FFR+) product. In August, the AESO published an Addendum to its FFR+ rationale, outlining several new design options informed by stakeholder input and solicited stakeholder feedback and concurrently invited expressions of interest for participation in a forthcoming procurement for the FFR+ product. The AESO anticipates releasing the formal call for procurement in mid-

2026. Management will continue to monitor this and evaluate opportunities through the procurement process.

AESO Most Severe Single Contingency (MSSC)

The AESO introduced a limit on the MSSC on June 27, 2023 at 466 MW (interconnected) or 425 MW (islanded). This is a system limit that sets the maximum amount of supply loss the Alberta grid can reliably withstand. The generating capacities of repowered Genesee Units 1 and 2 are 666 MW each and Unit 3 is 525 MW. However, due to the MSSC, generation from each of the Units is currently limited to 466 MW or 425 MW, as applicable. The Company is exploring, with the AESO, a technical solution to enable an increase to the generating output of each repowered unit above the MSSC. Performance testing is underway to determine the incremental MWs achievable through this technical solution. Once performance testing is complete, implementation is contingent upon regulatory approval. Management continues to advocate for an overall increase to the limit to allow each unit to operate at its fully capability.

Alberta Utilities Commission Inquiry into the Ongoing Economic, Orderly and Efficient Development of Electricity Generation in Alberta

On August 3, 2023 the Government of Alberta announced that it had directed the AUC to pause approvals of renewable generation projects until February 29, 2024 and had also directed the AUC to initiate an inquiry into the ongoing economic, orderly and efficient development of electricity generation in Alberta. As an outcome of the inquiry, additional clarity was provided on policies for siting renewable generation. This includes: an "agriculture first" approach to land-use where renewable projects have to demonstrate that they co-exists with agricultural use; a buffer zone for renewable development around specific viewscales where wind projects will not be permitted and where other projects will be required to undertake a visual impact assessment; creation of standards for reclamation security; and plans for an engagement on use of Crown lands for renewable development. On December 6, 2024, the *Electric Energy Land Use and Visual Assessment Regulation* was introduced to formalize the February policy direction. This includes a map that depicts the pristine viewscales, visual impact assessment zones and agricultural lands identifies specific locations where projects may not be permitted or face additional scrutiny. Amendments to the *Conservation and Reclamation Regulation* were also announced, requiring reclamation security for wind and solar operations. Capital Power does not have any active or outstanding applications impacted by the AUC inquiry outcomes.

Government of Alberta Response to CERs under Alberta "Sovereignty Act"

On November 27, 2023, the Government of Alberta introduced a resolution under *the Sovereign Alberta Within a United Canada Act ("the Sovereignty Act")* that outlines a series of measures that Alberta would propose to pursue to ensure the CERs are not implemented in Alberta due to its intrusion on provincial jurisdiction over electricity generation and potential risk to reliability and affordability of electricity.

As tabled, the resolution would:

- Enable Cabinet to order all provincial entities not to recognize the constitutional validity of, enforce, or cooperate in the implementation of the CERs in any manner, to the extent legally permissible. This order would not apply to private companies or individuals.
- Ask the Government to work with the AESO, AUC and others to implement various reforms to Alberta's electrical system to ensure grid affordability and reliability.
- Instruct the government to work with industry, regulators and other groups to study the feasibility of establishing a provincial Crown corporation for the purpose of bringing and maintaining more reliable and affordable electricity onto the grid in the event that private generators find it too risky to do so under the CERs.
- Urge the government to use all legal means necessary to oppose the implementation and enforcement of the CERs in Alberta.

The Government's announcement regarding the resolution noted that any future Crown corporation, in the event one was established, would work with industry and other stakeholders to bring on needed electricity

onto the grid, either through building new generation or purchasing existing generation assets that private industry would otherwise not build or shut down due to the uncertainty and penalties established by the CER. The Crown corporation could also be used as a means of assisting and partnering with industry to de-risk investments in nuclear power and other emerging generation technologies if needed.

On May 1, 2025, the Province of Alberta announced their intention to challenge the constitutionality of the Clean Electricity Regulations in the Alberta Court of Appeal. This court challenge remains in place despite the Canada – Alberta MOU.

Management understands that the measures outlined in the resolution are intended as a "last resort" and would only be pursued at a point in the future after Alberta has explored all other measures to address its concerns with the CERs, and then only after consultations involving industry and other stakeholders. On this basis, Management does not currently believe there will be any immediate impact for Capital Power's Alberta operations or the Alberta electricity market. Management will continue to engage with the Government of Alberta on market design, CERs and the MOU to mitigate any potential impacts.

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 was to receive cash payments from the Province of Alberta of \$52.4 million annually for 14 years, commencing July 31, 2017, for a total of \$734 million. The Government of Alberta subsequently conducted an audit on the calculation of net book values used in determining the compensation payments and withheld approximately \$2.7 million from each of the payments from 2017 through 2024. The Company disputed the amounts withheld, which resulted in a decrease in the amount previously recorded of approximately \$5 million recorded in net income through loss on disposals and other transactions. The respective deferred revenue and government grant receivable amounts were likewise adjusted to reflect total payments over the 14-year term of \$706 million. At December 31, 2025, the remaining government grants receivable balance relating to off-coal compensation from the Government of Alberta was \$231 million.

Under the Off-Coal Agreement, Capital Power is required to cease coal-fired emissions from Genesee 1, Genesee 2 and Genesee 3 by the end of 2029. On June 18, 2024, Capital Power announced that the Genesee Generating Station is 100% natural gas-fueled, resulting in the facility being off coal over five years ahead of the Alberta government mandate. As part of the Genesee Repowering project, the facility completed simple cycle commissioning for Unit 1 and Unit 2 on May 3, 2024, and June 28, 2024, respectively, and Unit 3 has transitioned to natural gas. The project completed combined cycle commissioning in Q4 2024 with Unit 1 achieving COD on November 18, 2024 and Unit 2 on December 13, 2024.

Technology Innovation and Emissions Reduction (TIER) Regulation

On January 1, 2020, the Government of Alberta replaced the *Carbon Competitiveness Incentive Regulation* with the TIER for large industrial emitters. Under TIER, facilities can physically reduce their emissions to the target or:

- use emission performance credits (EPCs) 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 the prevailing carbon price under TIER which in 2025 was \$95 per tonne. On May 12, 2025, the Government of Alberta announced that it would freeze the TIER fund price at \$95 per tonne with no additional increases.

For electricity, TIER is based on a high-performance benchmark emission intensity. In 2025 this is 0.3478 tCO₂e/MWh and is set to decrease to 0.3404 tCO₂e/MWh in 2026.

TIER imposes limits on the use of EPCs and offsets within each compliance year, which are 80% for 2025, increasing to 90% in 2026. TIER also imposes expiry periods on TIER eligible carbon credits. New offsets with 2023 vintages and later expire after five years while offset and EPCs with 2017-2022 vintages will continue to expire after eight years.

On June 17, 2022, the Alberta Environment and Protected Areas (AEPA) launched the formal review of the TIER Regulation with Alberta's intention to meet the minimum federal GHG benchmark criteria in order to preserve provincial jurisdiction of the carbon pricing framework for large emitters. The key changes proposed relate to committing Alberta to adopt the federal carbon price schedule through 2030, introducing a 2% per year reduction to facility-specific and high-performance benchmarks until 2030, aligning the Electricity Grid Displacement Factor used as the basis for offsets with the electricity TIER benchmark by 2030, and increasing the credit usage cap from 60% to 90% by 2026. On November 22, 2022, the Government of Canada announced that Alberta's TIER framework for industrial emissions will remain in effect from 2023 to 2030. On December 15, 2022, the AEPA released the *TIER Amendment Regulation*. As part of the TIER amendments, the electricity benchmark declines by 2% per year starting on January 1, 2023 reaching 0.3108 tCO₂e/MWh in 2030.

The TIER amendment Regulation also includes sequestration credits and capture recognition tonnes (CCUS credits) as new compliance instruments. Capture recognition credits enable large emitters and opt-in facilities to reduce sequestered emissions from total regulated emissions at carbon capture sites. Under the CCUS credits, facilities capturing CO₂ on site can claim the CCS reductions once captured. Sequestration credits enable recognition under the federal *Clean Fuel Regulations*.

Capital Power's 2025 TIER compliance obligation must be paid in the second quarter of 2026. The Company intends to retire offsets and EPCs for approximately 80% of the 2025 compliance obligation and purchase fund credits at the \$95/tCO₂e 2025 cost for the remaining 20% of our obligation. The rest of our offsets and EPCs in inventory will be saved for compliance or market sales 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 2025 reporting period, split by Capital Power's generating assets for the 2025 reporting period (under TIER), is comprised as follows:

- Genesee Repower 1 and 2 are expected to pay approximately \$3.65 million.
- Genesee 3 is expected to be approximately \$60.34 million.
- Genesee Mine has applied to opt-out of the TIER program and, pending decision, the cost for 2025 is expected to be approximately \$0 million.
- Clover Bar is expected to be approximately \$6.32 million.
- Shepard Energy Center is expected to be approximately \$3.4 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 from power consumed by all our facilities by retiring offsets and RECs against those emissions.

Capital Power has been acquiring offsets for over a decade and has entered into more than 100 offset purchase agreements across North America. Capital Power invested approximately \$30 million in Alberta Compliance offsets in 2025.

On May 12, 2025, the Alberta government announced that it is indefinitely freezing the TIER carbon price at \$95/tonne. On December 3, 2025, the government also finalized a new compliance option – Direct Investment – whereby onsite emissions reductions can enable compliance for a portion of a proponent's obligation.

The Canada – Alberta MOU outlines plans to establish a new Industrial Carbon pricing framework under TIER by April 1, 2026.

Alberta's Emissions Reduction and Energy Development Plan

On April 19, 2023, the Government of Alberta released Alberta's Emissions Reduction and Energy Development Plan (ERED). The ERED included an aspiration of achieving a carbon neutral economy – net zero – by 2050 in Alberta but did not specify any other targets. It noted Alberta's plan for emissions reduction will rely heavily on technology such as carbon capture and storage, hydrogen, and small modular reactors and be balanced with a commitment to maintaining affordability, reliability and energy security. The Government of Alberta sees a continued role for natural gas-fired generation in the province for decades to come. The ERED is consistent with the Company's expectations for decarbonization of Alberta's electricity system. The Company will continue to engage with the Government of Alberta on matters relating to decarbonization and Alberta's electricity system.

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 NO_x 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.

In September 2021, AEPA released the draft Ambient Air Quality Objectives (AAQOs) for nitrogen dioxide, SO₂ for consultation. The draft AAQOs will not impact the current *Environmental Protection and Enhancement Act* (EPEA) approvals for the Genesee repowering units, which were approved as an amendment to the existing Genesee permits but will be a consideration in the EPEA renewal process which will commence in 2024 prior to expiry of the current permits in 2026. Management is assessing the potential impacts, if any, of the draft AAQOs on Genesee and Cloverbar Energy Centre future EPEA renewals. AEPA has not released the final AAQOs.

Water Amendment Act (Bill 7) – Alberta Environment Water Availability Engagement

In October 2025, the Government of Alberta tabled the *Water Amendment Act* (Bill 7), following consultation through the Water Availability Engagement, in which Capital Power participated. Bill 7 proposed updates to Alberta's water management framework, including streamlined licensing, greater flexibility for amending water licenses, expanded provisions for water reuse and alternative sources, and enhanced transparency and reporting requirements.

These proposed legislative changes are relevant to Capital Power's North Saskatchewan River water diversion licenses for Genesee and the Clover Bar facilities. Capital Power continues to monitor the legislative process and assess potential impacts, ensuring that any new requirements support responsible water management and operational certainty for its Alberta sites.

Alberta Carbon Capture Incentive Program

On November 28, 2023, the Government of Alberta announced the Alberta Carbon Capture Incentive Program (ACCIP) which will support and accelerate the development of new CCUS infrastructure in Alberta by providing hard-to-abate industries with a grant of up to 12 per cent for new eligible CCUS capital costs. ACCIP will be available to power generation projects and is expected to build on the previously announced Federal CCUS ITC. The grant will be paid in three installments over three years starting after one year of operation. Applicants must meet reporting requirements by providing project reports between the grant instalment payments. A portion of ACCIP funding will come from Alberta's existing TIER fund.

Capital costs eligible for the grant include the costs to convert existing equipment to monitor and track CO₂ for CCUS; and the purchase and installation of approved equipment for an eligible CCUS project, provided an eligible storage or use of the CO₂ exists (any utilization which permanently sequesters CO₂ will be eligible).

The Canada – Alberta MOU outlines the potential to further enhance the ACCIP program to enable large-scale carbon capture projects in the province. Management will continue to monitor what an enhanced program might look like.

Alberta Nuclear Engagement Panel

On August 25, 2025, the Alberta government announced an expert panel tasked with gathering feedback on how nuclear power could be integrated into Alberta's energy mix. In the first phase, the panel gathered initial input from Albertans, Indigenous communities and stakeholders to help identify information needs, engagement interest and preferences. Capital Power met on multiple occasions with members of the panel to provide insights. On December 8, 2025, the government commenced the second phase, which is focused on engaging with Indigenous communities and organizations to better understand their perspectives on potential nuclear development and provide additional opportunities for industry and the public to share feedback. Management will continue to monitor the engagement and outcome of the panel.

British Columbia

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 imports and 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.

BC Hydro 2025 Integrated Resource Plan (IRP)

BC Hydro filed a new IRP with the BC Utilities Commission on October 31, 2025. The IRP did not identify any ongoing or future role for natural gas-fired generation facilities, including the Island Generation facility on Vancouver Island. There was no mention of new or continued reliance on natural gas generation in the plan. This is consistent with the BC Government's *Clean BC Regulation* that sets out that by 2030 100% of the electricity generated in BC and supplied to the integrated grid is to be generated from clean or renewable sources.

The 2025 IRP does set out that BC Hydro plans to prepare for the deployment of up to 400 MW of utility scale batteries by 2031 and BC Hydro initiated a request for expressions of interest in capacity on June 4, 2025 which management is monitoring. To meet growing energy needs, BC Hydro plans to acquire up to 5,000 GWh/year of new clean or renewable energy by fiscal 2034, with procurement processes beginning in fiscal 2026. This will continue BC Hydro's calls for power that started in 2024.

British Columbia Output-Based Carbon Pricing System

The Government of BC announced plans, effective April 1, 2018, to escalate its \$30/tCO₂e carbon tax by \$5/tCO₂e per year until it matched the federal carbon tax floor of \$50/tCO₂e in 2022. On April 1, 2022, BC's carbon tax rate rose from \$45 to \$50/ tCO₂e. Since then the carbon tax has increased in alignment with the federal carbon tax, increasing \$15/tCO₂e each April 1. Capital Power's operations in BC do not have any carbon tax exposure. As part of its 2023 budget, the Government of BC announced the transition to a provincial OBPS beginning in April 2024. The OBPS will ensure emissions reductions for industry continue while also providing flexible options, such as carbon offsets, to meet compliance obligations.

Net-Zero New Industry Intentions

On July 5, 2023, the BC Climate Action Secretariat (CAS) released the Net-Zero New Industry Intentions Paper (Paper). BC is proposing to amend the *Greenhouse Gas Industrial Reporting and Control Act* and its regulations to implement the Net-Zero New Industry Policy (Policy). The Paper did not discuss the benchmarks for any industrial sector. Under the Policy, new facilities will be required to develop net-zero plans to achieve net-zero emissions in 2050 (2030 for LNG projects) and every year thereafter. The net-zero plan would have to be approved by the CAS before a facility is permitted to proceed.

Ontario

Ontario's electricity market is often referred to as a "hybrid market" as it has a competitive wholesale market but leverages contracts to meet long-term reliability. The competitive wholesale market for energy and operating reserve opened in May 2002. The IESO held their first capacity auction to support short term supply balancing in 2020. Most generating facilities remains under contract with the IESO or are rate regulated. Hydro One operates approximately 98% of Ontario's transmission network.

The Ministry of Energy provides the overall regulatory framework and planning for energy in Ontario, while the Ontario Energy Board provides overall regulatory oversight of the electricity sector. The IESO is responsible for the administration of the wholesale electricity markets, operation and reliability of the grid, resource adequacy planning, administration of contracts for electricity resources, and promotion of electricity conservation.

Market Renewal Program (MRP)

Ontario's MRP is a set of coordinated market and IESO system reforms intended to improve market transparency, competitiveness, and real-time unit scheduling. It introduces LMP, market power mitigation, and a financially binding day-ahead market. MRP design work is complete and the IESO Board unanimously approved the market rule amendments associated with MRP on October 18, 2024. The IESO transitioned to the new market on May 1, 2025. Management is now monitoring the impact the MRP has on the Company's generating contracts and continues to work with the IESO to minimize any adverse outcomes. Management may, if necessary, leverage provisions within the contracts that are intended to protect suppliers from adverse effects resulting from market rule changes.

On November 7, 2024, a consortium of market participants that own non-quick start natural gas generating units, including the Company, submitted an application to the Ontario Energy Board (OEB) appealing the MRP market rule amendments. The application requests the OEB to review the amendments for consistency to the *Electricity Act 1998* and to determine if MRP unjustly discriminates against a class of market participants. The OEB issued their decision in March 2025, finding that the rule amendments are not discriminatory.

Ontario Bill 40 – Protect Ontario by Securing Affordable Energy for Generations Act, 2025

On June 3, 2025 the Ontario government tabled legislation to support major growth in Ontario's energy system to meet rising demand. The legislation is proposed to enable the IESO and the Ontario Energy Board (OEB) to prioritize projects that promote economic growth and create jobs, support made-in-Canada

energy technology for security and increase support for hydrogen. Management will continue to monitor changes and opportunities resulting from the legislation and the subsequent integrated energy plan.

Data centre requirements

As part of the Bill 40 changes, the Ontario Government has proposed requirements for data centres to address recent growth in data centre connection interest. Under the proposed changes, approval from the Minister of Energy and Mines will be required for data centre projects to connect to the provincial electricity grid. Management participated in the engagement, which ran through November 2025, and continues to monitor changes for opportunities.

Ontario's integrated energy plan

On June 12, 2025, Ontario released the province's inaugural integrated energy plan titled "Energy for Generations: Ontario's Integrated Plan to Power the Strongest Economy in the G7". The plan builds on energy policy and key initiatives including energy efficiency, Indigenous partnerships, and affordable, secure, reliable, and clean electricity. The plan also consolidates broad energy policy goals around Ontario becoming an energy superpower, streamlining permitting of large-scale energy infrastructure projects, and continued support for investment in nuclear and transmission. The plan further reaffirms the critical role natural gas plays in Ontario's energy system and the government's commitment to the IESO's competitive procurements for electricity generation. Management will continue to monitor changes and opportunities resulting from the integrated energy plan and related legislation.

Foreign procurement

The Ministry of Energy and Mines is undertaking a consultation on the development of regulations that may limit foreign participation in Ontario's energy sector. This would place limitations targeting identified foreign actors that may pose a threat to Ontario's energy infrastructure and may include restrictions on procurement of strategic assets based on country-of-origin, restrictions on foreign ownership of strategic assets, or establishing preferential criteria and scoring for Canadian proponents in energy sector procurements. Management will continue monitoring the impact this legislation may have on Capital Power projects in Ontario (third reading as of December 8, 2025).

MT2 procurement

In spring 2025, the IESO concluded their second medium-term procurement (MT2 RFP), extending contracts with 27 proponents. Capital Power was successful in securing a contract extension for Kingsbridge 1, with a price higher than the weighted average. The procurement offered 5-year flexible deemed energy or capacity contracts to assets coming off existing IESO contracts between May 1, 2026 and April 30, 2029.

Ontario's Affordable Energy Future: The Pressing Case for More Power

On October 22, 2024, the Ministry of Energy and Electrification released the government's vision for energy in a report titled "Ontario's Affordable Energy Future: The Pressing Case for More Power". The report highlights the important role electricity plays in Ontario's economy and the government's plans to address rapidly growing energy demand while keeping costs affordable. The report also articulates the important role electrification will have in reducing provincewide emissions and how critical natural gas generation is in supporting the energy transition and grid reliability.

The government's Powering Ontario Growth Plan remains at the forefront of the government's efforts to maintain a reliable, affordable, and clean energy system. The Powering Ontario Growth Plan was released in July 2023. The plan includes several critical initiatives like predevelopment work to site new large-scale nuclear generation at the Bruce generating facility, development of three small modular reactors at the Darlington site, advancement of large hydroelectric storage projects, optimization of hydroelectric generating assets, rollout of energy efficiency programs, and new transmission development. The plan also includes the IESO's procurements for new energy generation.

Bill 214: Affordable Energy Act

The Minister of Energy and Electrification introduced *Bill 214: the Affordable Energy Act, 2024* on October 23, 2024, and the Bill received Royal Assent on December 4, 2024. The overall purpose of the Bill is to enact certain parts of the government's energy vision into legislation. For example, the Bill expands the purpose of the *Energy Act, 1998* and the IESO to include the promotion of electrification and the facilitation of energy efficiency by using electricity to reduce Ontario's overall emissions. The Bill also creates a legislative requirement for the Ministry to carry out integrated energy plans every five years. Lastly, the Bill includes amendments to the *Ontario Energy Board Act, 1998* that will allow the Lieutenant Governor in Council to amend the distribution system code or the transmission system code on matters related to cost allocation or recovery.

IESO Resource Adequacy Framework and Procurements

On December 11, 2023, the IESO announced that it would be launching a series of long-term competitive procurements to secure up to 5,000 MW of non-emitting energy from new wind, solar, biofuel and hydro facilities. On August 28, 2024, the Honourable Stephen Lecce, the Minister of Energy and Electrification, announced that the government directed the IESO to target 5,000 MW of new generating capacity to be procured by 2034. At the same time the IESO was directed to accelerate procurement timelines pursue technology agnostic approaches. Combined with the non-emitting energy procurements, this is the largest competitive energy procurement in the province's history. The IESO released an updated electricity demand forecast on October 16, 2024. The forecast showed even higher annual demand growth, projected electricity demand to increase 75% by 2050, resulting from step changes in electric vehicle (EV) manufacturing, industrial growth, and data centre interconnection requests. On December 11, 2024, the IESO was directed to now procure up to 7500MW of new generating capacity by 2034. The Minister also requested the IESO to report back to the government on procurement options for long-lead energy resources like hydro generating facilities and long duration energy storage, and to provide contracting options for existing and new small scale electricity generation.

The Long-Term 2 RFP (LT2) is the first procurement, and launched in July 2025, the first window target 3,000 GWh of non-emitting energy and 600 MW of new capacity for a 2030 in-service-date. Subsequent procurements ("windows") are expected annually. Participating in the LT2 procurement requires municipal support for projects, and projects are not to be developed in speciality crop areas, with ground-mounted solar excluded from developing on prime agricultural lands. Projects located in Northern Ontario and projects with Indigenous community participation are to be prioritized.

In April 2025, the IESO's Annual Planning Outlook (APO) projected Ontario's net annual electricity demand to grow approximately 75% to 262 TWh by 2050 (up from 60% in the 2024 APO), driven by EV manufacturing, industrial expansion, emerging data centres, and broader electrification. Preliminary scenario analysis for the upcoming 2026 APO suggests the reference case may be revised slightly lower - to approximately 65% growth by 2050. The IESO concluded its second medium-term procurement (MT2) in 2025, awarding five-year contracts to 27 selected proponents — including Capital Power — for assets with contracts expiring between 2026 and 2029. Management believes Ontario's overall electricity needs and the IESO's commitment to awarding contracts through competitive procurements will continue to provide opportunities for the Company, including possible re-contracting opportunities for existing assets. Management remains involved in the IESO's engagements related to resource adequacy, the APO, and procurements.

Emissions Performance Standards (EPS)

The Ontario Minister of the Environment, Conservation and Parks (MECP) amended the EPS to meet stricter benchmark criteria set by the Federal Government and to extend the program to 2030, effective January 1, 2023.

Under the EPS, the carbon price will align with the minimum Federal carbon price of \$80/tCO₂e for the 2024 compliance period, increasing by \$15/tCO₂e per year to \$170/tCO₂e in 2030. The performance standard for generating electricity using fossil fuels declined from 0.370 tCO₂e/MWh to 0.310 tCO₂e/MWh effective

2023 and will remain at that level until 2030.

The contracts for the Company's York Energy, East Windsor and Goreway facilities have provisions that trigger amendments as a result of changes in GHG cost, the effect of which will limit the impact of changes to carbon compliance costs.

United States

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

U.S. Clean Air Act

In June 2025, the Environmental Protection Agency (EPA) released a draft rule that would repeal all greenhouse gas (GHG) standards for fossil fuel electric generating units, effectively kicking off a rulemaking process to overturn a previous rule that aimed to curb GHG emissions for coal-, gas-, and oil-fired power plants. This decision, once finalized, will remove the federal requirement for Capital Power to decarbonize future expansions to our thermal fleet. Given the need for notice and comment, and the statutory time period for states to develop implementation plans for existing sources under the *Clean Air Act*, it is unlikely that existing gas units could face any CO₂ regulation until the early to mid-2030s at the earliest from the U.S. federal government.

Maricopa County, Arizona, where the Arlington Valley and Harquahala natural gas facilities are located, does not meet the National Ambient Air Quality Standards set by the EPA under the *Clean Air Act* for two of the six principal pollutants. Maricopa County is currently classified as "moderate" nonattainment levels for these principal pollutants. EPA paused its planned reclassification of Maricopa County from moderate to serious ozone nonattainment in April 2025, following engagement with Arizona officials and business leaders, putting a hold on any changes in permitting requirements for existing, new and modified facilities. Maricopa County was previously facing additional offset sanctions at a 2:1 level for failure to submit a plan to EPA addressing moderate level air quality requirements, but an agreement was reached with EPA in the second quarter of 2025 that a sufficient moderate level plan was received, thus halting the threat of additional 2:1 sanctions. If Maricopa County continues to remain in nonattainment status, Capital Power will be challenged to construct additional turbines at Arlington Valley and Harquahala without offsetting emissions. Management continues to monitor developments.

EPA issued a final rule on February 12, 2026 rescinding the 2009 Endangerment Finding, which had determined that greenhouse gases endanger public health and welfare. This action also eliminated the legal basis for regulating GHG emissions from new motor vehicles under Clean Air Act §202(a). It is anticipated that this decision will face legal challenges in 2026.

The EPA has also proposed to terminate the Greenhouse Gas Reporting Program (GHGRP) and suspend reporting requirements until the current program ends in 2034. This proposal has not been finalized. Since its enactment in 2009, the GHGRP has required certain large GHG emission sources, including fuel and industrial gas suppliers and CO₂ injection sites, to report emissions data in a standardized way. While the termination of the program would remove the federal requirement for Capital Power to report emissions data, state-level requirements would remain in place. The 45Q Carbon Capture and Storage (CCS) tax credit requires emissions reporting data to claim tax credit eligibility, so a lack of a standardized reporting system could hinder Capital Power's ability to claim federal CCS tax credits for project construction. Management is currently engaging U.S. federal officials to gain clarity on how tax credit eligibility could be impacted without a formal reporting structure in place.

One Big Beautiful Bill (OBBB)

The U.S. Congress approved a budget reconciliation bill known as the One Big Beautiful Bill (OBBB), signed into law by President Donald Trump on July 4, 2025. The tax cuts are expected to provide a benefit of approximately \$200 million to Capital Power over the next seven years through reduced current and cash taxes from accelerated recognition of tax deductions. To pay for the cost of reauthorization, members of Congress are seeking cuts to other tax provisions including the Clean Energy Investment Tax Credit and production tax credit that were authorized in the 2022 *Inflation Reduction Act*. The OBBB language requires a clean energy project, as defined by the OBBB, to commence construction within one year of enactment to claim 100% of the existing tax credit benefits, and a placed-in-service date of December 31, 2027, to be eligible. There are also requirements on the percentage of a component, subcomponent, or critical mineral used in the project to be sourced domestically or from countries that are not considered foreign entities of concern.

Capital Power projects within the scope of this legislation include: Maple Leaf Solar, Bear Branch Solar, and Hornet Solar in North Carolina. The North Carolina projects are on schedule for construction completion and should not be negatively impacted by the OBBB. Management will continue to monitor and assess the implications of this legislative change on the Company's renewable growth projects.

U.S. tariffs / United States-Mexico-Canada Agreement (USMCA)

In 2025, President Trump issued tariffs which have created economic and political uncertainties, such as potential counter tariffs from other countries, including those imposed by the Government of Canada and Government of Ontario. Management has consulted external legal counsel and assessed potential scenarios under President Trump's tariff announcements that could impact the Company's operations, specifically Canadian electricity sales to the U.S., and the sales of renewable energy certificates from Canada to the U.S. While at this time, the Company does not expect significant impacts to Capital Power, this is an evolving risk that may impact future supply chain costs and sales of power to the U.S. Management will continue to monitor the situation as changes to the tariff framework are put into place.

Separately, the USMCA trade agreement is due for review by July 1, 2026, and all three parties must decide whether to extend the pact beyond its initial 16-year term. If one or more parties decline, annual reviews will be triggered until consensus is reached or until the agreement terminates in 2036. The USMCA review process has advanced, but no party has yet taken a formal position on whether to extend the agreement beyond 2036. The United States, Mexico, and Canada have all formally initiated the 2026 joint review process, which is the required precursor to any extension decision. While at this time, we do not expect significant impacts to Capital Power, this is an evolving risk that may impact future supply chain costs and sales of power to the U.S. Management will continue to monitor the situation as changes to the tariff framework are put into place.

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 *Federal Power Act* 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 Regional Transmission Organizations. RTOs are voluntary organizations operated by Independent System Operators independent of market participants. ss 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.

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 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.

PJM Market

The Hummel Facility is a 1,124 MW combined-cycle natural gas facility in Pennsylvania and the Rolling Hills Facility is a 1,023 MW combustion turbine natural gas facility in Ohio, both in PJM. PJM is a regional transmission organization that dispatches generation, operates a competitive wholesale electricity market and manages the reliability of a transmission grid spanning all or parts of 13 states and the District of Columbia, serving more than 65 million people. PJM is the largest centrally operating market in North America, with approximately 200 GW of installed capacity and peak demand of approximately 150 GW. PJM is currently experiencing substantial population growth and industrial development, including growth in data centre energy consumption, driven by the rapid expansion of digital infrastructure. According to PJM's 2025 load forecast, peak demand is expected to grow at annualized rates above 3% in the next ten years.

In PJM, both the day-ahead and real-time markets are nodal markets, where electricity prices are determined based on the supply and demand at each individual node on the grid, considering both the supply and demand as well as the physical constraints of the transmission system. In addition to its wholesale market, PJM operates a capacity market through the Reliability Pricing Model, which focuses on securing sufficient long-term resources to ensure grid reliability. PJM generally holds an annual Base Residual Auction (BRA) for capacity resources to meet expected energy demand needs for the future capacity year three years in advance; however, this schedule has been compressed due to delays beginning in 2019 around the Federal Energy Regulatory Commission's (FERC) Minimum Offer Price Rule and further delays in the wake of Winter Storm Elliot exposing vulnerabilities to PJM's reliability, causing PJM to reform its auction rules. The auctions are currently expected to be held every six months until PJM is back on the three-year forward schedule by May 2027. PJM has instituted a maximum capacity price of USD\$325/Megawatt-day (MWd) and a minimum capacity price of USD\$175/MWd for the next two auctions to increase market stability, otherwise known as the Price Collar. When participants offer resources into the auction, they are committing to be available to supply capacity or reduce demand in the energy market. If participants fail to meet these commitments during periods of grid system stress or emergencies, they face penalties for non-performance. If participants are on-line at full bid capacity during periods of grid system stress or emergency, they can earn incentives.

Annually, PJM performs a review of the capital additions required to provide reliable electric transmission services throughout its territory. PJM traditionally allocated the costs of constructing these facilities to those entities that benefited directly from the additions. Over the last several years, however, some of the costs of constructing large, new transmission facilities have been socialized across PJM without a direct relationship between the costs assigned to and benefits received by particular PJM members. To the extent

that any costs in the future are material and Capital Power is unable to recover them, such costs could have a material adverse effect on our results of operations, financial condition and cash flows.

PJM market is under pressure from various stakeholders including state consumer advocates, elected officials and public interest organizations to alleviate reliability and affordability concerns. If government officials at the state or federal level determine that market reform is needed to alleviate reliability and affordability concerns, then increased oversight over FERC, and by extension PJM, could facilitate or accelerate changes in market structures. This could disrupt competitive market dynamics and create uncertainty for market participants.

In January 2026, the White House and PJM State Governors issued a unified Statement of Principles urging PJM to extend the price collar and to use a Reliability Backstop Auction (RBA) as a targeted reliability tool – not as a recurring substitute for the Base Residual Auction. The Statement of Principles regarding PJM defines the RBA as a new, emergency procurement mechanism designed to guarantee long-term revenue certainty for new generation when the existing PJM capacity market cannot attract enough supply. The Principles frame the RBA as a targeted, reliability-driven intervention, not a replacement for the BRA. RBA remains a politically driven, emergency-use mechanism. The Principles emphasize that the RBA should be narrowly scoped, used only when reliability is at risk, and paired with reforms that support new investment rather than suppressing price signals. No final rulemaking or tariff filing has yet locked in a recurring RBA structure. Management continues to monitor these developments closely.

On July 22, 2025, PJM posted their BRA results for the 2026/2027 delivery year. The auction secured commitments for 134,311 MW of unforced capacity in the Regional Transmission Organization from annual, summer-period and winter-period matched resources and price-responsive demand. Prices for all locational deliverability areas (LDAs), including the LDAs where the Rolling Hills and Hummel facilities are located, cleared at the cap of US\$329/MW-day, further supporting the economics of the Acquisition. The July 2025 BRA results for the 2026/2027 Delivery Year remain unchanged. The auction cleared at the cap of \$329/MW-day across all LDAs, including the zones relevant to Rolling Hills and Hummel, and PJM has not issued any revisions or corrections to those results.

In February 2026, PJM's Board of Managers announced its intention to extend the capacity market price collar through 2030, subject to FERC approval which is anticipated. The White House National Energy Dominance Council and governors of PJM states have formally endorsed extending the collar as part of their "Statement of Principles Regarding PJM."

State Carbon Policy

Pennsylvania Regulatory Environment

Pennsylvania's carbon-pricing debate has moved decisively away from the Regional Greenhouse Gas Initiative (RGGI) after budget legislation on this matter was signed into law by Governor Shapiro in November of 2025. The state has now formally withdrawn from the RGGI, ending the policy pathway that the previous administration attempted to pursue through executive action. An alternative, made-in-Pennsylvania program, the *Pennsylvania Climate Emissions Reduction Act* (PACER), has been proposed but has not yet gained significant political traction. This program would allow Pennsylvania to retain control over the emissions cap and the auction process. Characterized as a "Cap-and-Invest" program, PACER is intended to keep revenue in Pennsylvania, with 70% of the proceeds being returned to consumers as rebates, and 30% invested in energy efficiency projects, clean energy initiatives, and support for low-income energy consumers. Management will continue to monitor this situation for further developments.

California Greenhouse Gas Regulation

California implemented GHG regulations under several authorities including the *Global Warming Solutions Act* of 2006. The initial target was to achieve 1990 statewide emission levels by 2020, representing approximately a 15% reduction in GHG emissions in California compared to a "business as usual" scenario. In September 2016, the target was revised to an emissions reduction goal of 40% below 1990 levels by

2030. In 2018, the target was again revised (CES) to a goal of 100% of electric load to be served by zero carbon resources by 2045. The CES is specific to the electricity sector.

The CES was signed in September 2018 and implements a goal of 100% of electric load to be served by zero-carbon resources, which includes hydro and nuclear resources as well as renewables, by 2045. In September 2022, legislators adopted two additional clean energy targets: (i) AB 1279 requires the state (not just the electricity sector) to reach net zero greenhouse gas emissions by 2045 at the latest and requires anthropogenic GHG emissions to be reduced to at least 85% below 1990 levels by 2045, and (ii) SB 1020 sets interim clean energy targets for sales to retail customers of 90% by 2035, 95% by 2040, and 100% by 2045. It also accelerates 100% of state agencies electricity sales be clean energy from 2045 to 2035. SB 1020 includes requirements for the California Public Utilities Commission (CPUC) to provide confidential PPA data to assist with transmission planning and the CPUC to provide an annual report on reliability in the context of the clean energy targets.

In the fourth quarter of 2023, the California legislature passed two bills that will require certain companies doing business in California to disclose their climate-related financial risks and their scope 1, 2, and 3 GHG emissions. These new laws were the first of their kind in the United States and have compliance deadlines of 2026, and 2027, respectively. The legislation requires the California Air Resources Board (CARB) to issue a formal rulemaking process prior to implementation of the laws, which is expected to occur later this year. CARB has indicated that Capital Power's La Paloma facility is not subject to these disclosure policies.

Washington State Carbon Market Legislation

In March 2024, the Washington legislature voted in favor of linking the statewide carbon trading market with California and Quebec. Further, in November 2024, voters in Washington considered a ballot initiative (Initiative 2117) that would have repealed the cap-and-invest program designed to reduce GHG emissions by 95% by 2050, if successful. The election results ultimately protected the cap-and-invest program, leaving California and Quebec to begin their own regulatory processes to determine whether to link with the Washington state market. Washington's cap-and-invest linkage effort has moved forward significantly and all three jurisdictions—Washington, California, and Québec—are now actively preparing for a formal linkage agreement expected in 2026, with potential operation of a fully linked market in 2026 or 2027.

On January 1, 2025, SB 6058 goes into effect in Washington, making it easier to link the state market with the California and Quebec markets. Immediately, the allowance purchase limit for a covered entity or an opt-in entity will increase from 10% to 25% of the allowances offered during a single auction. There will also be a subsequent rulemaking that is expected to begin in 2025 that will determine compliance periods and potentially revise the definition of an electricity importer. Once Washington formally links with another carbon market, the legislation also has provisions that changes holding limits for general market participants. Until Washington links with another jurisdiction, general market participants (GMPs) cannot own more than 10% of the total allowances to be issued in a calendar year ("vintage-year"). After linkage, there will no longer be a vintage-year holding limit for GMPs. The Washington State Department of Ecology will also have the ability to reduce monetary penalties, or the number of penalty allowances required to be submitted for violations throughout the first compliance period or until Ecology enters into a linkage agreement, whichever is sooner. The Frederickson 1 Generating Station is not likely to be financially impacted by these developments, as its carbon costs will be covered by Morgan Stanley or PSE through September 2030.

Michigan Legislation

On November 28, 2023, the Michigan Governor signed a legislative package that includes a goal of 100% clean energy in the state by 2040 and sets new renewable energy targets for the Michigan state. The legislation requires Midland Cogeneration to achieve GHG emission reductions that are the functional equivalent of deploying on site Carbon Capture and Storage with a 90% capture rate at the facility. Management is working towards a plan to achieve that clean energy goal and it must be submitted under the legislation to the Michigan Public Service Commission by 2030.

North Carolina

Most of North Carolina is not part of an RTO or ISO. Thus, in most areas of the state, transactions are bilateral and must be scheduled through the incumbent utility. Capital Power currently owns one facility in North Carolina: Beaufort, which is in the non-RTO part of North Carolina.

Beaufort is a 15 MW solar project contracted with Duke Energy Progress, LLC through 2030.

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, an 885 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 Wind, 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 Wind is a FERC approved exempt wholesale generator that is authorized to sell energy, capacity and ancillary services at market-based rates.

Bloom Wind 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 – U.S. Renewables – Bloom Wind".

Arizona

Capital Power owns Arlington Valley, a 600 MW gas-fired combined-cycle generation facility located in Arlington, Arizona, and 50% of Harquahala, a 1092 MW gas-fired combined-cycle generation facility, located in Harquahala, Arizona. Arizona is not part of a regional transmission organization or independent system operator and falls into the DSW market within the Western Electricity Coordinating Council. Planning and grid operations are managed by vertically integrated utilities, and in most areas of the state, transactions are bilateral and must be scheduled through the incumbent utility. Three major utilities, Arizona Public Service, Tucson Electric Power and Salt River Project serve the majority of Arizona's electricity demand. These utilities also participate in the WEIM, a real-time energy market established to manage variations in demand and generation across a wider footprint including DSW, CAISO and the Pacific Northwest. The WEIM is operated by CAISO. Arlington Valley and Harquahala are FERC approved exempt wholesale generators that are authorized to sell power at market-based rates.

Illinois

Capital Power owns Cardinal Point Wind, a 150 MW generation facility located in McDonough and Warren Counties, Illinois. Cardinal Point is in the portion of the state that 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.

Ohio

Capital Power owns Rolling Hills a 1,023 MW peaking flexible generation facility located in Wilkesville, Ohio. It provides capacity and energy to PJM Interconnection and American Electric Power. In 2025, Ohio passed HB 15 modernizing Ohio's energy framework by:

- Restructuring Ohio's competitive retail electric service law
- Reducing tangible personal property (TPP) taxes on new generation and energy-conversion equipment
- Streamlining permitting for new generation and transmission; and
- Increasing transparency and consumer protections.

These significant updates to Ohio energy law have no material impact on the existing operation of Rolling Hills.

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.

Texas

Capital Power owns Buckthorn Wind, a 101 MW wind facility located approximately 60 miles southwest of Dallas in Erath County, Texas. The state is almost entirely part of the ERCOT, an RTO that operates the transmission system and a centrally dispatched market in most of the state of Texas.

Michigan

Capital Power jointly owns Midland Cogen otherwise known as MCV, a 1633 MW gas fired combined electrical and steam generation facility located in Midland, Michigan. Midland Cogen is a major wholesale supplier of electrical energy to customers in Michigan and the midcontinent, and a supplier of bulk process steam energy to proximate agriscience production companies operating in the MISO region.

Washington

Frederickson is a 265 MW natural gas combined-cycle cogeneration facility near Tacoma in Pierce County. Contracts are bilateral and must be scheduled through the current utility. Frederickson is a FERC approved exempt wholesale generator that is authorized to sell power at market-based rates.

California

La Paloma is a 1,062 MW natural gas fired generation facility in Kern County, California. The state operates a competitive wholesale power market, managed by CAISO. The CAISO market represents approximately 80% of electricity demand in California. CAISO schedules the operation of the transmission lines of the

state's three large investor-owned utilities (IOUs), which retain ownership of the transmission lines. Independent power producers compete to sell their power to the IOUs and other entities such as municipal utilities, community choice aggregation programs, energy service providers and irrigation districts.

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 2025 Integrated Annual Report for the year ended December 31, 2025 which section is incorporated herein by reference and is available on SEDAR+.

COMMON AND PREFERRED DIVIDENDS

Common Dividends

For the three most recently completed financial years, the Company has declared the following: (i) on July 29, 2025, the Company announced a 6% dividend increase for its Common Shares effective for the third quarter 2025 dividend for an annualized dividend of \$2.764 per Common Share, (ii) on July 30, 2024, the Company announced a 6% dividend increase for its Common Shares effective for the third quarter 2024 dividend for an annualized dividend of \$2.6076 per Common Share, and (iii) on August 2, 2023, the Company announced a 6% dividend increase for its Common Shares effective for the third quarter 2023 dividend for an annualized dividend of \$2.46 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.

On December 10, 2025, Capital Power announced its 2030 targets alongside its 2026 financial guidance. The 2030 targets call for maintaining a 2-4% annual dividend growth target, while the 2026 financial guidance sets a dividend growth target of 2%.

On December 31, 2021, the Company suspended its DRIP for its Common Shares. Shareholders participating in the DRIP began receiving cash dividends on the January 31, 2022 payment date. On August 1, 2023, the Company reinstated the DRIP. Eligible shareholders were entitled to participate in the DRIP commencing with the Company's third quarter 2023 cash dividend. 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
28 Feb 23	\$0.58
28 Apr 23	\$0.58
2 Aug 23	\$0.615
31 Oct 23	\$0.615
27 Feb 24	\$0.615
30 Apr 24	\$0.615
30 Jul 24	\$0.6519
29 Oct 24	\$0.6519
25 Feb 25	\$0.6519
29 Apr 25	\$0.6519
29 Jul 25	\$0.6910
28 Oct 25	\$0.6910
3 Mar 26	\$0.6910

Preferred Dividends

The Series 1 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, 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.

On December 31, 2025, the annual fixed dividend rate on the Series 1 Shares was reset pursuant to their terms to 4.958% for five-year period ending December 31, 2030. The fixed cumulative dividends will be \$1.23950 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
28 Feb 23	\$0.1638125
28 Apr 23	\$0.1638125
2 Aug 23	\$0.1638125
31 Oct 23	\$0.1638125
27 Feb 24	\$0.1638125
30 Apr 24	\$0.1638125
30 Jul 24	\$0.1638125
29 Oct 24	\$0.1638125
25 Feb 25	\$0.1638125
29 Apr 25	\$0.1638125
29 Jul 25	\$0.1638125
28 Oct 25	\$0.1638125
03 Mar 26	\$0.3098750

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.

On December 31, 2023, the annual fixed dividend rate on the Series 3 Shares was reset pursuant to their terms to 6.860% for the next five-year period ending December 31, 2028. The fixed cumulative dividends will be \$1.71500 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
28 Feb 23	\$0.3408125
28 Apr 23	\$0.3408125
2 Aug 23	\$0.3408125
31 Oct 23	\$0.3408125
27 Feb 24	\$0.4287500
30 Apr 24	\$0.4287500
30 Jul 24	\$0.4287500
29 Oct 24	\$0.4287500
25 Feb 25	\$0.4287500
29 Apr 25	\$0.4287500
29 Jul 25	\$0.4287500
28 Oct 25	\$0.4287500
03 Mar 26	\$0.4287500

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 June 30, 2023. The fixed cumulative dividends will be \$1.3095 per share per annum during this five-year period.

On June 30, 2023, the annual fixed dividend rate on the Series 5 Shares was reset pursuant to their terms to 6.631% for the next five-year period ending June 30, 2028. The fixed cumulative dividends will be \$1.65775 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
28 Feb 23	\$0.327375
28 Apr 23	\$0.327375
2 Aug 23	\$0.4144375
31 Oct 23	\$0.4144375
27 Feb 24	\$0.4144375
30 Apr 24	\$0.4144375
30 Jul 24	\$0.4144375
29 Oct 24	\$0.4144375
25 Feb 25	\$0.4144375
29 Apr 25	\$0.4144375
29 Jul 25	\$0.4144375
28 Oct 25	\$0.4144375
3 Mar 26	\$0.4144375

The Series 9 Shares paid 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.

On September 30, 2022, the Company redeemed all of the issued and outstanding Series 9 Shares at a price of \$25.00 per share for an aggregate total of \$150 million.

No dividends have been declared on the Series 9 Shares for the three most recently completed financial years.

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.

On June 30, 2024, the Company redeemed all of the issued and outstanding Series 11 Shares at a price of \$25.00 per share (Redemption Price) for an aggregate total of \$150 million, less any tax required to be deducted and withheld by the Company. As June 30, 2024 was not a business day payment of the Redemption Price for the share redemption occurred on July 2, 2024.

The following dividends have been declared on the Series 11 Shares for the three most recently completed financial years:

Dividends Declared	
Declaration Date	Dividend per Share
28 Feb 23	\$0.359375
28 Apr 23	\$0.359375
2 Aug 23	\$0.359375
31 Oct 23	\$0.359375
27 Feb 24	\$0.359375
30 Apr 24	\$0.359375

Dividend Reinvestment Plan

On July 30, 2020, the Company reinstated the DRIP which was launched on January 1, 2012. 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.

Eligible shareholders were entitled to participate in the DRIP 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 upon reinstatement. New Common Shares issued under the reactivated DRIP were issued at a discount rate of 3% to the average closing price on the Toronto Stock Exchange for the 10 trading days immediately preceding the applicable dividend payment date.

Subsequently, on July 30, 2021, the Company announced a reduction in the discount percentage for the DRIP, reducing the discount rate from a 3% discount to the average market price to a discount rate of 1%, effective the third quarter 2021 dividend. On October 27, 2021, the Company announced the suspension of the DRIP following the October 2021 dividend payment.

On August 1, 2023, the Company reinstated the DRIP. Eligible shareholders were entitled to participate in the DRIP commencing with the Company's third quarter 2023 cash dividend. Shareholders that were enrolled in the DRIP upon suspension in December 2021, and remained enrolled with the plan administrator, automatically resumed participation in the DRIP upon reinstatement. New Common Shares issued under the reactivated DRIP were issued at a discount rate of 1% to the average closing price on the Toronto Stock Exchange for the 10 trading days immediately preceding the applicable dividend payment date.

Since the Company's DRIP was introduced and as of the date of this AIF, 10,693,949 Common Shares have been issued pursuant to the DRIP at a weighted average price of \$34.73. To date, no pro-ration has occurred.

CAPITAL STRUCTURE

The Company's authorized share capital consists of an unlimited number of Common Shares and an unlimited number of Preference Shares issuable in series, and one Special Limited Voting Share. As of December 31, 2025, there were 155,962,899 Common Shares, 5 million Series 1 Shares, 6 million Series 3 Shares, 8 million Series 5 Shares and one Special Limited Voting Share outstanding. As of February 23, 2026 the Special Limited Voting Share is no longer outstanding. See "Material Contracts – Social Objectives Agreement".

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.

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 paid 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.

On May 15, 2024, the Company announced its intention to redeem all of its 6,000,000 issued and outstanding Series 11 Shares at a price of \$25.00 per share for an aggregate total of \$150 million, less any tax required to be deducted and withheld by the Company. All of the Series 11 Shares were redeemed on June 30, 2024.

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 paid 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.

On August 19, 2022, the Company announced its intention to redeem all of its 6,000,000 issued and Series 9 Shares on September 30, 2022 at a price of \$25.00 per share for an aggregate total of \$150 million, less any tax required to be deducted and withheld by the Company. All of the Series 9 Shares were redeemed on September 30, 2022.

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 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 again had the right to elect to convert all or any part of their Series 5 Shares into Series 6 Shares, subject to certain conditions, on June 30, 2023. Following the conversion deadline on June 15, 2023, 44,106 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, 2023. Effective June 30, 2023, the annual fixed rate for the Series 5 Shares for the next five-year period was reset to 6.631%.

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, 2028 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 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 again had the right to elect to convert all or any part of their Series 3 Shares into Series 4 Shares, subject to certain conditions, on December 31, 2023. Following the conversion deadline on December 18, 2023, 7,157 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, 2023. Effective December 31, 2023, the annual fixed rate for the Series 3 Shares for the next five-year period was reset to 5.5%.

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, 2028 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 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 Shares, subject to certain conditions, on December 31, 2015. Following the conversion deadline on December 16, 2015, 5,000,000 Series 1 Shares remained outstanding and there were no Series 2 Shares issued. 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 once 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, 2025. Following the conversion deadline on December 16, 2025, 5,000,000 Series 1 Shares remained outstanding and there were no Series 2 Shares issued as at December 31, 2025. Effective December 31, 2025, the annual fixed rate for the Series 1 Shares for the next five-year period was reset to 4.958%.

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, 2030 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 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.

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*.

In connection with the amendment of the Social Objectives Agreement on February 23, 2026, the Special Limited Voting Shares of the Company and CPLPGP were assigned to the Company and CPLPGP, respectively, and are no longer outstanding. See "Material Contracts – Social Objectives Agreement".

Debt Issuance/Redemption

On November 5, 2025, Capital Power announced that it had issued a notice of redemption in respect of all of its outstanding 4.986% medium term notes, due January 23, 2026 (January 2026 Notes), for redemption on November 23, 2025 in accordance with the trust indenture governing the January 2026 Notes. The aggregate principal amount of January 2026 Notes outstanding as of the date hereof was C\$300,000,000. On November 14, 2025, the Company closed a public offering of unsecured medium term notes in the aggregate principal amount of \$600 million (the Notes). The Notes have a coupon rate of 4.231% and mature on January 14, 2033. The Company used the net proceeds to repay, redeem and refinance existing indebtedness, which included project related debt at Goreway Power Station, Capital Power's credit facilities, for general corporate purposes and fully funding the redemption of the Company's January 2026 Notes. The redemption price was C\$1,000 per C\$1,000 principal amount of the January 2026 Notes redeemed, plus accrued and unpaid interest to, but excluding, November 23, 2025 (Redemption Price). As November 23, 2025 was not a business day, payment of the Redemption Price occurred on November 24, 2025.

On May 28, 2025, the Company closed a private placement offering of \$966 million (US\$700 million) aggregate principal amount of 5.257% senior notes due 2028 and \$690 million (US\$500 million) aggregate principal amount of 6.189% senior notes due 2035 issued by Capital Power (US Holdings) Inc., a U.S. wholly-owned subsidiary of the Company. The notes are guaranteed by the Company and the Company's subsidiaries that guarantee the Company's revolving credit facilities. The net proceeds of the offering were used to fund a portion of the Acquisition (as defined above).

On September 16, 2024, the Company closed a public offering of unsecured medium term notes in the aggregate principal amount of \$600 million (the Notes). The Notes have a coupon rate of 4.831% and mature on September 16, 2031. The Company used the net proceeds to repay, redeem and refinance existing indebtedness, including indebtedness under the Company's credit facilities, and for general corporate purposes.

On August 15, 2024, the Company announced the approval of amendments to the indenture governing the \$350 million 7.95% Fixed-to-Fixed Rate Subordinated Notes, Series 1, due September 9, 2082 (Series 1 Notes). These changes allowed for the exchange of all outstanding principal amount of Series 1 Notes for an equal principal amount of new 7.95% Fixed-to-Fixed Rate Subordinated Notes, Series 3, due September 9, 2082 (Series 3 Notes). The Series 3 Notes have the same economic terms as the Series 1 Notes, including interest rates and maturity dates, but without the provision for delivery of preferred shares upon the occurrence of certain bankruptcy and related events. Holders will continue to receive interest accrued on the exchanged Series 1 Notes. This note exchange was completed on August 15, 2024, following the execution of the necessary supplemental indentures. The Series 3 Notes will rank equally in right of payment with the \$450 million 8.125% Fixed-to-Fixed Subordinated Notes, Series 2, due June 5, 2054. S&P Global Ratings and Morningstar DBRS confirmed the instrument rating of the Series 3 Notes at BB and BB with a Stable trend, respectively.

On June 12, 2024, Capital Power filed its short form base shelf prospectus. The prospectus was filed in reliance upon the "WKSI Blanket Orders", as the Company determined that it qualified as a "well-known seasoned issuer" (WKSI), which exempts qualifying issuers from certain disclosure requirements relating to such final short form base shelf prospectus. Capital Power may from time to time during the 25-month period that this short form base shelf prospectus remains valid offer and issue the following securities or any combination thereof: (i) Common Shares of the Company; (ii) preference shares of the Company; (iii) subscription receipts exchangeable for Common Shares or other securities of the Company; and (iv) debt securities of the Company. In addition, Capital Power 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 \$3 billion. All issuances may be made during the 25-month period that the prospectus remains valid.

On June 5, 2024, the Company closed a public offering of Fixed-to-Fixed Subordinated Notes, Series 2, in the aggregate principal amount of \$450 million (the Subordinated Notes), under a trust indenture dated June 5, 2024, between the Company and Computershare Trust Company of Canada, as trustee. The Subordinated Notes have a fixed interest rate of 8.125% and mature on June 5, 2054. The Company used the net proceeds from the sale of the Subordinated Notes to repay certain amounts drawn on the Company's credit facilities (which include amounts drawn for the acquisition of a 50% interest in New Harquahala Generating Company, LLC, and a 100% interest in CXA La Paloma, LLC, and related expenses, development purposes and in respect of ongoing operations), to redeem all of the Company's outstanding Series 11 Shares and for general corporate purposes.

On December 15, 2023, Capital Power issued \$850 million of senior unsecured MTNs. This offering consisted of \$400 million of 5.378% medium term notes maturing on January 25, 2027 and \$450 million of 5.973% medium term notes maturing on January 25, 2034. The offering closed on December 15, 2023, pursuant to the New Indenture as supplemented by an eighth supplemental trust indenture and a ninth supplemental trust indenture, respectively, each dated December 15, 2023.

On September 15, 2023, Capital Power issued \$350 million of senior unsecured MTNs due on September 15, 2028 with interest payable semi-annually at a rate of 5.816%, pursuant to the New Indenture as supplemented by a seventh supplemental trust indenture dated September 15, 2023.

On September 9, 2022, Capital Power closed a \$350 million offering of Fixed-to-Fixed Rate Subordinated Notes, Series 1 due September 9, 2082 (Subordinated Notes), under a trust indenture dated September 9, 2022, between the Company and Computershare Trust Company of Canada, as trustee. The Company intends to allocate an amount equal to the net proceeds from the sale of the Subordinated Notes to finance or refinance new or existing "green" investments that meet the eligibility criteria outlined in the Green Framework. Pending such allocation, the Company used the net proceeds from the sale of the Subordinated Notes to redeem the Company's outstanding Cumulative Minimum Rate Reset Preference Shares, Series 9, to repay certain amounts drawn on the Company's credit facilities and for general corporate purposes. Per the prospectus supplement dated August 18, 2022, the Company will pay interest on the Subordinated Notes in equal semi-annual instalments with the first payment on March 9, 2023, from, and including, the date of issue to but excluding September 9, 2032, the Subordinated Notes will bear interest at a rate of 7.95% per annum and on every fifth anniversary of such date thereafter the interest rate on the Subordinated Notes will reset.

In August 2023, the Company posted its Green Bond Report to its website which outlines the allocation of Green Financing proceeds by eligible category. The proceeds from the 2022 green bond offering to projects, which meet the eligible green criteria outlined in the Green Framework have been fully allocated.

On June 16, 2022, Capital Power executed a sixth supplemental trust indenture amending certain terms of the New Indenture for all series of MTNs issued after the date thereof.

On July 20, 2021, Capital Power executed a 12-year US\$150 million private placement of senior notes to partially refinance the 10-year US\$230 million senior notes that matured in June 2021. These Series I Senior Guaranteed Notes were issued on October 28, 2021 and mature in October 2033. They bear an interest rate of 3.24% which will be paid semi-annually and rank pari-passu with the Company's other senior unsecured borrowings. The Note Purchase Agreement, 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 October 9, 2020 Capital Power redeemed all of its outstanding 5.276% MTNs, due November 16, 2020, in the aggregate principal amount of \$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 issued \$350 million of senior unsecured MTNs 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 fifth supplemental trust indenture dated October 1, 2020.

On June 1, 2020, Capital Power executed a fourth supplemental trust indenture amending certain terms of the New Indenture for all series of MTNs issued after the date thereof.

On November 8, 2019, Capital Power issued \$275 million of senior unsecured MTNs 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 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 issued \$300 million of senior unsecured MTNs 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 issued \$450 million of senior unsecured MTNs 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 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 MTNs 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 L.P. (US Financing LP), an indirect subsidiary of CPLP, closed a US\$295 million private placement of senior notes (Senior Notes). The Senior Notes consisted of two notes with 10 and 15-year terms. The 10-year Senior Note had a principal amount of US\$230 million that matured 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 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. These include a \$1.5 billion extendible syndicated facility maturing in 2030 (increased from \$700 million on June 6, 2025) and a 2-year revolving facility with a total commitment of \$600 million, maturing in 2027 (entered into on August 8, 2025). Funds may be drawn in Canadian or US dollars, with floating interest based on the type of draw, plus margin. The Company's \$1.5 billion syndicated facility is a sustainability linked credit facility (SLC), with GHG emissions intensity as its sustainability performance target metric, aiming to reduce Scope 1 CO₂ emission intensity by 65% by 2030 from 2005 levels. The SLC includes terms that reduce or increase borrowing costs as the annual targets are met or missed. 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 for all Note Purchase Agreements and the Prudential Agreement (as defined above under "Capital Structure – Debt Issuance/Redemption") to meet the pari-passu covenants in those agreements.

The credit agreements also 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 that is not investment grade (investment grade means at least two Debt Ratings from the following Rating Agencies of not lower than "BBB-" from S&P, "BBB(low)" from DBRS, "Baa3" from Moody's and "BBB-" from Fitch (in each case 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 2-year revolving 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 Capital Power's consolidated financial results.

Capital Power also has existing Canadian dollar revolving letter of credit demand facilities with various lenders totalling CAD\$990 million, in addition, three U.S. dollar revolving letter of credit demand facilities totalling U.S.\$300 million.

Ratings

The following credit rating agencies have assigned the below credit ratings to the debt obligations and hybrid instruments of the Company:

Debt Ratings

Capital Power currently has a BBB (low) rating with a stable trend on its Issuer Rating and Senior Unsecured Debt from DBRS, a BBB- rating with a stable outlook on its Issuer Credit Rating and Senior Unsecured Debt from S&P, and a BBB- rating with a stable outlook on its Long-Term Issuer Default Rating (IDR) and Senior Unsecured Debt from Fitch. 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 BBB- Long-Term IDR assigned by Fitch Ratings is the lowest level within Fitch's 'BBB' investment-grade category, which is the fourth highest of Fitch's eleven rating categories, ranging from a high of AAA to a low of D. Fitch applies plus (+) or minus (-) modifiers to indicate relative standing within each major rating category. Under Fitch's rating system, BBB' ratings indicate that expectations of default risk are currently low. The capacity for payment of financial commitments is considered adequate, but adverse business or economic conditions are more likely to impair this capacity.

Hybrid Instrument Ratings

The hybrid instruments are rated two notches below the Company's corporate credit rating as they are deeply subordinated. The Preferred Shares and notes are hybrid securities that combine both debt and equity characteristics which are provided a degree of equity treatment from rating agencies without diluting the ownership interests of their common shareholders and debt treatment from tax authorities whereby the associated interest expense is deductible for income tax purposes. These ratings are intended to provide investors with an independent measure of credit quality of an issue of securities.

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 with a stable outlook from S&P.

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. Pfd-3 ratings generally correspond with issuers with a BBB category or higher reference point. 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 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.

Subordinated Notes Ratings

The fixed-to fixed rate subordinated notes, as described above under "Debt Issuance/Redemption", have been assigned a rating of BB by DBRS, BB by S&P, and BB by Fitch.

The BB rating category used by DBRS and, in DBRS's view, denotes speculative, non-investment grade credit quality. The capacity for the payment of financial obligations is uncertain and the entity is vulnerable

to future events. DBRS measures the characteristics against the attributes of common equity including its subordination to all other creditors, permanence in the capital structure, and tolerance for missed scheduled payments without causing a default or cross-default to debt instruments. DBRS assigned 50% equity treatment to the notes.

The BB rating category used by S&P and, according to the S&P rating system, is regarded as having significant speculative characteristics. While such obligations will likely have some quality and protective characteristics, these may be outweighed by large uncertainties or major exposure to adverse conditions. S&P classifies the notes as having intermediate equity content because of their subordination, permanence, and optional deferability features, in line with their hybrid capital criteria. S&P assigned 50% equity treatment to the notes.

The BB rating category used by Fitch and, according to the Fitch rating definition, indicates a speculative grade and an elevated vulnerability to default risk, particularly in the event of adverse changes in business or economic conditions over time; however, business or financial flexibility exists that supports the servicing of financial commitments. Fitch considers the notes to possess equity-like characteristics due to their subordination, permanence, and optional deferral features, while also exhibiting certain debt-like attributes. Fitch assigned 50% equity treatment to the notes.

The credit ratings by each of DBRS, S&P, and Fitch is not a recommendation to buy, sell or hold any securities of the Company. 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, S&P, or Fitch at any time in the future if, in the judgment of either or both, circumstances so warrant. The credit ratings by DBRS, S&P, or Fitch 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, S&P, and Fitch 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, S&P, and Fitch.

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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 2025 CPX Trading Statistics

Month	Share Price			Volume Traded
	High	Low	Close	
January	64.15	50.69	59.23	34.7M
February	54.48	50.65	52.67	26.1M
March	50.36	44.91	48.13	37.8M
April	52.34	43.90	47.55	34.2M
May	55.92	51.81	53.83	19.7M
June	57.17	54.80	56.08	21.8M
July	63.19	54.45	58.49	29.3M
August	61.22	56.51	59.14	18.6M
September	65.60	56.48	61.28	25.3M
October	73.05	67.17	71.00	16.2M
November	73.59	59.49	61.33	15.1M
December	65.53	58.55	58.55	18.4M

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 2025 CPX.PR. A Trading Statistics

Month	Share Price			Volume Traded
	High	Low	Close	
January	18.09	17.24	18.00	78,608
February	18.03	17.52	17.80	56,018
March	17.66	17.16	17.50	72,742
April	17.65	16.25	16.99	96,150
May	17.63	17.20	17.31	35,719
June	18.80	17.48	18.70	142,277
July	20.50	18.80	20.39	333,599
August	21.28	20.47	21.10	482,943
September	21.95	21.01	21.95	70,146
October	23.23	21.85	23.10	412,178
November	25.02	21.71	22.10	51,866
December	22.85	22.06	22.62	244,228

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 2025 CPX.PR. C Trading Statistics

Month	Share Price			Volume Traded
	High	Low	Close	
January	24.86	24.48	24.73	76,796
February	25.00	24.48	25.00	69,008
March	25.00	24.61	24.79	91,150
April	24.93	23.75	24.35	177,228
May	25.00	24.48	24.86	199,341
June	25.43	24.71	25.16	239,329
July	26.06	25.16	25.86	59,800
August	25.90	25.50	25.90	49,166
September	25.95	25.54	25.90	61,336
October	26.09	25.50	26.09	46,783
November	26.42	25.90	26.40	42,229
December	27.82	26.13	26.34	59,551

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 2025 CPX.PR. E Trading Statistics

Month	Share Price			Volume Traded
	High	Low	Close	
January	24.59	23.99	24.59	160,156
February	24.85	24.30	24.84	57,603
March	25.00	24.16	24.37	45,744
April	24.44	22.82	24.30	56,224
May	25.00	24.32	25.00	77,770
June	25.19	24.75	25.08	136,948
July	25.50	25.00	25.50	110,124
August	25.49	25.26	25.35	64,188
September	25.46	25.25	25.45	90,550
October	26.00	25.38	26.00	98,598
November	26.19	25.51	26.19	36,428
December	26.62	25.50	26.00	122,698

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 the date of this AIF:

Name, Province / State and Country of Residence	Director Since	Office Held⁽¹⁾⁽²⁾ Committee Membership⁽³⁾	Principal Occupation During Past Five Years
Gary Bosgoed Edmonton, Alberta, Canada Date of Birth: September 1958 <u>Shares held:</u> ⁽⁴⁾ Nil	June 1, 2022	Director Committees: HSE (Chair) PCG	President and Chief Executive Officer of Bosgoed Project Consultants Ltd. from July 2015
Avik Dey Edmonton, Alberta, Canada Date of Birth: February 1978 <u>Shares held:</u> ⁽⁴⁾ Common Shares - 3,794	May 8, 2023	Director	President and Chief Executive Officer, Capital Power Corporation from May 2023; prior thereto, Co-Head, Carlyle International Energy Partners from May 2022 to November 2022; prior thereto, Senior Vice President and Chief Financial Officer, NOVA Chemicals Corporation from May 2021 to May 2022; prior thereto, Managing Director and Head of Energy and Resources, Real Assets, Canada Pension Plan Investment Board from September 2014 to March 2021
Jill Gardiner Vancouver, British Columbia, Canada Date of Birth: December 1958 <u>Shares held:</u> ⁽⁴⁾ Common Shares – 11,326	May 25, 2015	Director and Chair Committees: ⁽⁵⁾ Audit PCG HSE	Professional Corporate Director

Name, Province / State and Country of Residence	Director Since	Office Held ⁽¹⁾⁽²⁾ Committee Membership ⁽³⁾	Principal Occupation During Past Five Years
<p>Carolyn Graham Edmonton, Alberta, Canada Date of Birth: June 1964</p> <p><u>Shares held:</u>⁽⁴⁾ Common Shares – 1,240</p>	<p>August 2, 2023</p>	<p>Director</p> <p>Committees: Audit PCG</p>	<p>Professional director since October 2022; prior thereto held the following positions at Canadian Western Bank: Senior Executive Vice President (EVP), Program Synergy from April 2022; EVP from November 2021; EVP and Chief Risk Officer from December 2020</p>
<p>Kelly Huntington Indianapolis, Indiana, USA Date of Birth: September 1975</p> <p><u>Shares held:</u>⁽⁴⁾ Nil</p>	<p>June 3, 2015</p>	<p>Director</p> <p>Committees: PCG (Chair) Audit</p>	<p>Senior Vice President and Chief Financial Officer from February 2023 and Senior Vice President from January 2023 to February 2023, MYR Group Inc.; prior thereto professional director from January 2022 to January 2023; prior thereto Senior Vice President and Chief Financial Officer, USIC, LLC, from November 2019 to January 2022</p>
<p>Barry Perry St John's, Newfoundland and Labrador, Canada Date of Birth: September 1964</p> <p><u>Shares held:</u>⁽⁴⁾ Common Share – 26,000</p>	<p>March 1, 2021</p>	<p>Director</p> <p>Committees: Audit (Chair) PCG</p>	<p>Professional director from March 2021; prior thereto President and Chief Executive Officer of Fortis Inc. from January 2015 to December 2020</p>
<p>Jane Peverett West Vancouver, British Columbia, Canada Date of Birth: September 1958</p> <p><u>Shares held:</u>⁽⁴⁾ Common Share – 2,000</p>	<p>March 1, 2019</p>	<p>Director</p> <p>Committees: Audit HSE</p>	<p>Professional director</p>
<p>Neil H. Smith Indian River Shores, Florida, USA Date of Birth: October 1964</p> <p><u>Shares held:</u>⁽⁴⁾ Nil</p>	<p>May 15, 2024</p>	<p>Director</p> <p>Committees: PCG HSE</p>	<p>Professional director since December 2024; prior thereto, Chief Executive Officer of Vanguard Renewables LLC from September 2021 to November 2024; prior thereto, President, Rev Renewables from July 2021</p>

Name, Province / State and Country of Residence	Director Since	Office Held ⁽¹⁾⁽²⁾ Committee Membership ⁽³⁾	Principal Occupation During Past Five Years
			to August 2021; prior thereto, Executive-in-Residence, LS Power from April 2021 to June 2021; prior thereto PJM Interconnect Board of Managers from May 2018 to April 2021
Keith Trent Lexington, Kentucky, USA Date of Birth: October 1959 <u>Shares held:</u> ⁽⁴⁾ Nil	April 3, 2017	Director Committees: Audit HSE	Professional director from July 2015 and President of BK Trent LLC from January 1, 2016
George Williams Naperville, Illinois, USA Date of Birth: September 1961 <u>Shares held:</u> ⁽⁴⁾ Nil	May 15, 2024	Director Committees: PCG HSE	Consultant at Power Contracting, LLC from December 2023; prior thereto Chairman and CEO of PMI Energy Solutions from February 2011 to November 2023

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, unless they resign earlier, or until their successors are elected or appointed and will be eligible for re-election.
- (3) Board Committees: (i) Audit Committee, (ii) PCG Committee; and (iii) HSE Committee.
- (4) Represents, as of December 31, 2025, the number of Common Shares, Series 1 Shares, Series 3 Shares and Series 5 Shares as applicable, beneficially owned, or controlled or directed, directly or indirectly, by such persons.
- (5) As Chair, Jill Gardiner attends committee meetings in an ex-officio, non-voting capacity.

The Board has determined that all the directors, except for Avik Dey, 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. Avik Dey 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 the date of this AIF:

Name, Province / State and Country of Residence	Executive Officer Since	Office Held	Principal Occupation During the last 5 Years
Avik Dey Edmonton, Alberta, Canada	May 8, 2023	President and Chief Executive Officer from May 8, 2023	President and Chief Executive Officer from May 2023; prior thereto, Co-Head, Carlyle International Energy Partners from May 2022 to November 2022; prior thereto,

Name, Province / State and Country of Residence	Executive Officer Since	Office Held	Principal Occupation During the last 5 Years
<p>Date of Birth: February 1978</p> <p><u>Shares held:</u>⁽¹⁾</p> <p>Common Shares – 3,794</p>			<p>Senior Vice President and Chief Financial Officer, NOVA Chemicals Corporation from May 2021 to May 2022; prior thereto, Managing Director and Head of Energy and Resources, Real Assets, Canada Pension Plan Investment Board from September 2014 to March 2021</p>
<p>Kevin MacIntosh Calgary, Alberta, Canada Date of Birth: March 1968</p> <p><u>Shares held:</u>⁽²⁾</p> <p>Common Shares – 4,588</p>	<p>March 16, 2026⁽³⁾</p>	<p>Chief Financial Officer from March 16, 2026</p>	<p>Vice President and Controller at Suncor Energy Inc. since 2019</p>
<p>May Wong Sturgeon County, Alberta, Canada Date of Birth: August 1981</p> <p><u>Shares held:</u>⁽¹⁾</p> <p>Common Shares – 995</p>	<p>August 29, 2023</p>	<p>Senior Vice President, Energy Markets and Low Carbon Solutions from December 4, 2024</p>	<p>Senior Vice President, Energy Markets and Low Carbon Solutions from December 2024; prior thereto, Senior Vice President, Strategy, Planning & Sustainability from August 2023; prior thereto Vice President, Strategy, Forecasting & Sustainability from May 2022; prior thereto Vice President, Market Assessment & Analytics from September 2019</p>
<p>Jason Comandante Calgary, Alberta, Canada Date of Birth: November 1979</p> <p><u>Shares held:</u>⁽¹⁾</p> <p>Common Shares – 10,582</p>	<p>August 29, 2023</p>	<p>Senior Vice President, Supply and Trading from October 20, 2025</p>	<p>Senior Vice President, Supply and Trading from October 2025; prior thereto, Senior Vice President, Head of Canada from August 29, 2023; prior thereto Vice President, Commercial Services, Canada West from July 2020</p>
<p>Pauline McLean Calgary, Alberta, Canada Date of Birth: August 1977</p> <p><u>Shares held:</u>⁽¹⁾</p> <p>Common Shares - 474</p>	<p>August 29, 2023</p>	<p>Senior Vice President, External Relations, Chief Legal Officer and Corporate Secretary from October 20, 2025</p>	<p>Senior Vice President, External Relations, Chief Legal Officer and Corporate Secretary from October 2025; prior thereto, Senior Vice President, External Relations & Chief Legal Officer from September 2023; prior thereto Vice President, Law, General Counsel & Corporate Secretary at Alberta Electric System Operator from October 2019</p>

Name, Province / State and Country of Residence	Executive Officer Since	Office Held	Principal Occupation During the last 5 Years
Steve Wollin Edmonton, Alberta, Canada Date of Birth: June 1966 <u>Shares held:</u> ⁽¹⁾ Common Shares – 1,915	August 29, 2023	Senior Vice President, Chief Operations Officer from December 4, 2024	Senior Vice President, Chief Operations Officer from December 2024; prior thereto, Senior Vice President, Operations from August 2023; prior thereto Vice President, Operations, Gas and Renewables from April 2018
Ferio Pugliese Calgary, Alberta, Canada Date of Birth: October 1968 <u>Shares held:</u> ⁽¹⁾ Nil	July 14, 2025	Senior Vice President, Chief Corporate Officer from July 14, 2025	Senior Vice President, Chief Corporate Officer from July 2025; prior thereto, Senior Vice President, Parkland Corporation from December 2020 to February 2025

Notes:

- (1) Represents as of December 31, 2025 the number of Common Shares, Series 1 Shares, Series 3 Shares and Series 5 Shares, as applicable, beneficially owned, or controlled or directed, directly or indirectly, by such persons.
- (2) Represents as of March 4, 2026 the number of Common Shares, Series 1 Shares, Series 3 Shares and Series 5 Shares, as applicable, beneficially owned, or controlled or directed, directly or indirectly, by such person.
- (3) Kevin MacIntosh has been appointed as the new Chief Financial Officer, effective March 16, 2026. See also "Company History - 2026 - Appointment of New Chief Financial Officer".
- (4) Sandra Haskins retired from her role as Senior Vice President, Finance and Chief Financial Officer on December 31, 2025. As at December 31, 2025, Sandra held 11,434 Common Shares of the Company. Scott Manson, Chief Accounting Officer, transitioned to Interim SVP Finance & Chief Financial Officer on Sandra Haskins' retirement and, at the date of this AIF, is acting as Interim Chief Financial Officer.

As at January 1, 2026, 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, 40,566 Common Shares (\$58.55 per share as at the close of trading on December 31, 2025 for a value of \$2,375,139.30), which is less than 1% of the issued and outstanding Common Shares.

As at January 1, 2026, the directors and executive officers of the Company, as a group, beneficially owned, directly or indirectly, or exercised control or direction over 58,920 Common Shares (\$58.55 per share as at the close of trading on December 31, 2025 for a value of \$3,449,766.00, which is less than 1% of the issued and outstanding Common Shares of the Company. The information as to the beneficial ownership of the Common Shares, 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, 2025, 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 company 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.

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 CBCA 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.

Jill Gardiner was a director of Trevali Mining Corporation (Trevali) between July 2019 and September 2022. On August 19, 2022, Trevali received an Initial Order for creditor protection from the British Columbia Supreme Court under the *Companies' Creditors Arrangement Act* (CCAA) for an initial period of ten days. The Initial Order was subsequently extended to October 6, October 18th, and finally December 16, 2022 to allow Trevali to restructure its business and financial affairs. On December 16, 2022, Trevali announced a winning bid under the Sales and Solicitation Process and disclosed that the company would be seeking Court approval of the proposed transaction. The transaction was approved by the Supreme Court of British Columbia on December 21, 2022 and was completed on June 27, 2023. On June 28, 2023 the Court appointed monitor was granted enhanced powers in the CCAA proceedings with respect to the Company's business and affairs. On June 6, 2025 the Supreme Court of British Columbia approved the settlement in this matter.

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.

Keith Trent is a director of Edison International. Edison International's subsidiary, Southern California Edison has an offtake agreement related to the La Paloma facility.

Jane Peverett is a director of Canadian Pacific Kansas City Limited ("CPKC"), NW Natural and Suncor Energy Inc. ("Suncor"). CPKC may provide transportation services to Capital Power. NW Natural may provide natural gas to Capital Power generators located in Oregon or Washington states in the future. Suncor sells electricity into the Alberta market.

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.

Claim Against Province of Alberta and Balancing Pool

In 2015, pursuant to a complaint regarding the AESO's 2005 loss factor calculation methodology (LFM), the AUC determined that the LFM did not comply with applicable regulations. The LFM is used to calculate generator-specific line loss factors and forms the basis for certain transmission charges paid by Alberta

generators. In December 2017 the AUC determined a revised LFM for determining retroactive adjustments back to January 2006. Implementation of the historic LFM adjustments by the AESO occurred over the course of 2018 – 2020 and, following a further decision of the AUC on July 9, 2020, the AESO was directed to and issued three separate invoices for the various historic years. The AUC directed the AESO to issue the adjustment invoices to the entities that held the applicable system transmission agreements with the AESO at the time the line losses occurred, however, the AUC expressly did not determine the matter of liability for payment given the fact some agreements had changed hands in the intervening periods.

In December 2016, Capital Power had entered into an agreement with the Province of Alberta pursuant to which the interests of Capital Power as the PPA Buyer in respect of the Sundance C PPA were wholly transferred to and assumed by the Balancing Pool. In January 2017, in furtherance of the agreement with the Province of Alberta and the transfer of the Sundance C PPA to the Balancing Pool, the system transmission agreements between Capital Power and the AESO relating to the Sundance C PPA were wholly transferred to and assumed by the Balancing Pool pursuant an assignment, assumption and novation agreement among Capital Power, the Balancing Pool and the AESO.

The AESO completed the primary invoicing process for all three tranches of historic line-loss adjustment invoices relating to the Sundance C PPA covering the years 2006-2016 and issued them to Capital Power. Capital Power forwarded the invoices to the Balancing Pool and demanded that it make payment of them. The Balancing Pool refused to make payment. Capital Power made payment to the AESO of the invoices under protest in December 2020, February 2021 and May 2021, respectively. The amounts invoiced to Capital Power but not attributable to the Company have been invoiced to the appropriate parties for recovery with significant portions received by the Company in December 2020, February 2021 and May 2021. A further invoice from the AESO was received in October 2021 to address trailing amounts and correct calculation errors uncovered during the invoicing process. Based on the information currently available, these did not significantly impact the net amounts paid by the Company.

The Balancing Pool and the Province of Alberta are disputing their liability to make payment for the line loss rule adjustment invoices related to the Sundance C PPA, the net amount of which, if recovered by Capital Power is approximately \$25 million and is recorded within other assets at December 31, 2025. The Company believes the various agreements governing the termination and transfer of the Sundance C PPA and related transmission agreements with the AESO had the effect of transferring all past liabilities for the Sundance C PPA to the Balancing Pool. Capital Power filed on January 11, 2021 and continues to pursue a statement of claim at the Alberta Court of Queen's Bench (now King's Bench) against the Balancing Pool and the Province of Alberta in which it is seeking, among other relief, recovery from the Balancing Pool and the Province of Alberta of all amounts Capital Power was compelled to pay to the AESO on account of the line loss rule adjustment invoices relating to the Sundance C PPA as well as interest and legal costs, including the portion invoiced to the Balancing Pool but not received by the Company pertaining to all tranches of invoices. This process remains ongoing. Capital Power expects to ultimately realize the full amount of the gross receivables related to the line losses upon resolution of the dispute before the Court.

Buckthorn Wind Personal Injury Litigation

Buckthorn Wind has been named, as one of several hundred defendants, in numerous personal-injury lawsuits relating to extreme winter weather in February 2021. The cases have been consolidated for pretrial purposes in a multi-district litigation proceeding captioned in, re Winter Storm Uri Litigation, Master Cause No. 2021-41903 in the District Court of Harris County, Texas. These lawsuits bring claims for negligence, tortious interference, private nuisance, conspiracy, and unjust enrichment, and allege that plaintiffs were harmed by defendants' alleged failure to provide power during the storm. Defendants include ERCOT, which operates Texas's electric grid and manages Texas's deregulated power market, along with numerous ERCOT market participants, including retail electric providers, transmission providers, electricity generators, and natural gas providers. The Company believes the claims made against it in these lawsuits are without merit and is taking all appropriate actions to defend itself.

Genesee Repowering

A dispute arose in 2024 between the Company and the contractor regarding construction work on the Genesee Repowering Project. The parties are participating in an arbitration process to resolve the claims by both parties. The Company has withheld payments pending the resolution of the dispute. Preliminary matters related to the arbitration process began late in the second quarter of 2025. While final project costs remain subject to the outcome of the arbitration, the Genesee Repowering Project achieved commercial operations in 2024 and is considered substantially complete.

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".

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 and February 23, 2026 (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.sedarplus.ca.

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. On February 23, 2026, the Social Objectives Agreement was amended and restated to, among other things, (i) remove EPCOR as a party, (ii) change the definition of "head office" to the office identified by the Company as either the Company head office or the Company Canadian head office and where a majority of the Company's "executive officers" have an office and a regular presence in the context of their leadership responsibilities, (iii) change the definition of "executive officers" for purposes of the head office definition to the Company's chief executive officer and the direct reports of the chief executive officer with leadership accountabilities and responsibilities extending across the business conducted in Canada of the Company, and (iv) change the requirement in respect of maintaining the shared services complement of employees in the City of Edmonton to no less than 50% of the total number of shared service employees required to support Capital Power's business in Canada. In connection with the amendment of the Social Objectives Agreement, EPCOR assigned the Special Limited Voting Share of each of the Company and CPLPGP to the Company and CPLPGP, respectively, and those shares are no longer outstanding.

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) and again at the April 26, 2019, April 29, 2022, and April 29, 2025 annual meetings of shareholders.

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 which is available on our website (www.capitalpower.com) and on SEDAR+ (www.sedarplus.ca).

The Rights Plan will expire at the close of business on the date of the 2028 annual meeting of shareholders, unless extended by a further vote of 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 would cease coal-fired emissions on or before December 31, 2030, and Capital Power would 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 subsequently conducted an audit on the calculation of net book values used in determining the compensation payments and withheld approximately \$2.7 million from each of the payments from 2017 through 2024. The Company disputed the amounts withheld, which resulted in a decrease in the amount previously recorded of approximately \$5 million recorded in net income through loss on disposals and other transactions. The respective deferred revenue and government grant receivable amounts were likewise adjusted to reflect total payments over the 14-year term of \$706 million. At December 31, 2025, the remaining government grants receivable balance relating to off-coal compensation from the Government of Alberta was \$231 million.

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, 2025, the Audit Committee was composed of Barry Perry (Chair), Carolyn Graham, Kelly Huntington, Jane Peverett and Keith Trent. As Chair of the Board, Jill Gardiner 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".

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
Barry Perry	<ul style="list-style-type: none"> • Chartered Professional Accountant • former Chief Executive Officer of Fortis Inc. • former Chief Financial Officer of Fortis Inc. • holds a Bachelor of Commerce from Memorial University of Newfoundland • member of the audit committees of Royal Bank of Canada and CPP Investments
Carolyn Graham	<ul style="list-style-type: none"> • Chartered Professional Accountant • Fellow of Institute of Chartered Professional Accountants of Alberta and recipient of Lifetime Achievement Award • former Chief Financial Officer of Canadian Western Bank, TSX listed, federally regulated Schedule 1 bank • former chair of audit committee for public REIT, as well as numerous non-profits • holds a Bachelor of Commerce from the University of Alberta
Kelly Huntington	<ul style="list-style-type: none"> • current Senior Vice President and Chief Financial Officer of MYR Group Inc. • former Senior Vice President and Chief Financial Officer of USIC • former Senior Vice President of Enterprise Strategy for OneAmerica Financial Partners which included responsibility for internal audit • former President & Chief Executive Officer, and Senior Vice President & Chief Financial Officer for Indianapolis Power and Light Company • has previously held a variety of positions in investment banking, private equity, financial analysis, investor relations and risk management • holds an MBA from Northwestern University's Kellogg School of Management, is a Chartered Financial Analyst, and has the NACD. DC designation
Jane Peverett	<ul style="list-style-type: none"> • Chartered Professional Accountant • former Chief Financial Officer of Union Gas and British Columbia Transmission Corporation • former chair of the audit committees of four publicly traded companies

AC Member	Relevant Education and Experience
Keith Trent	<ul style="list-style-type: none"> • former General Counsel for Duke Energy overseeing the internal audit team • previous profit/loss accountability for four of Duke Energy's electric utilities and for its commercial generation business • former chair of Duke Energy's transaction and risk committee which provided financial and risk analysis for numerous transactions • current director and former member of the audit committee of Edison International • 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 2025, the Audit Committee pre-approved non-audit related services in an amount not to exceed \$300,000, in relation to a high-level review of the Company's internal controls framework.

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, 2025 in respect of the Company and the Company's subsidiaries were approximately \$3.2 million as detailed below.

	Twelve Months Ended December 31, 2025 (\$ Millions)	Twelve Months Ended December 31, 2024 (\$ Millions)
Audit fees	3.1	2.1
Audit related fees	0.1	0.3
Tax fees	-	-
All other fees	-	-
Total	3.2	2.4

Audit fees – Audit fees billed are for professional services rendered for the audit and review of the financial statements of the Company and its subsidiaries 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. During fiscal year 2025, the services provided in this category included French translation work performed in relation to securities filings engagements. In fiscal year 2024, the services provided in this category included sustainability assurance engagements and French translation work performed in relation to securities filings engagements.

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, nomination, compensation and human capital; and (ii) the HSE Committee to oversee matters relating to the impact of the Company's operations on the environment and on workplace health and safety. Jill Gardiner, the Chair of the Board, is a non-voting ex-officio member of all committees. The members of these committees as at December 31, 2025 were as follows:

PCG Committee

Kelly Huntington, Chair
Gary Bosgoed
Carolyn Graham
Barry Perry
Neil H. Smith
George Williams
Jill Gardiner (ex-officio)

Health, Safety, and Environment Committee

Gary Bosgoed, Chair
Jane Peverett
Neil H. Smith
Keith Trent
George Williams
Jill Gardiner (ex-officio)

ADDITIONAL INFORMATION

Additional information relating to the Company may be found on SEDAR+ at www.sedarplus.ca 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, 2025.

The "Risks and Risk Management" section of the Company's 2025 Integrated Annual Report for the year ended December 31, 2025 is incorporated herein by reference and is available on SEDAR+.

The Company's material change reports are incorporated herein by reference and are 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 AS AT MARCH 3, 2026

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 the management team ("Management") (including fraud risk assessment) and the programs established by the CEO, 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 and 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 and 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. monitoring the Corporation's financial reporting;
 - c. evaluating the Corporation's internal controls over financial reporting;
 - d. overseeing the audit of the Corporation's financial statements;
 - e. 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;

- h. reviewing Management's updates on information security matters, including processes for identifying and managing data, cyber and other information technology related risk; and
 - i. 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.
- 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 (the "Committee Members").
- 2. The Chair of the Board (the "Chair") is an ex-officio and non-voting member of the Committee, unless appointed by the Board as a Committee Member.
- 3. At least once every calendar year, and as otherwise may be required, 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"). Any Committee Member may be removed or replaced at any time by the Board and shall cease to be a Committee Member upon ceasing to be a Director. Each Committee Member shall hold office until the Committee Member resigns or is replaced, whichever occurs first. The Board shall fill Committee Member vacancies by appointing a member from the Board. If a vacancy on the Committee exists, the remaining members shall exercise all the Committee's powers so long as a quorum exists and provided the Committee includes not less than three members.
- 4. Each Committee Member shall meet all applicable standards of independence under applicable laws, regulations, rules and guidelines, which determination of independence will be made by the Board.
- 5. All Committee Members will be financially literate (as defined in NI 52-110 and in the rules of any stock exchange on which the securities of the Corporation are listed for trading). At least one member of the Committee will be considered an audit committee financial expert 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 of the Committee Chair

The Committee Chair will:

- 1. ensure, to the extent possible, the Committee has sufficient information to properly discharge its duties and responsibilities;
- 2. report to the Board on the activities, decisions and recommendations of the Committee after each meeting;

3. set agendas with such assistance as the Committee Chair may request from the CEO, CLO, Corporate Secretary, CFO and auditors; and
4. in conjunction with a member of Management independent from Internal Audit, pre-approve the project scope of reviews of Internal Audit functions.
5. have the right to determine attendance by staff, the auditors, and others at all or a portion of Committee meetings. Attendance will normally include the CEO, CFO, the Corporate Secretary, Head of Internal Audit and appropriate staff.

D. Duties and Responsibilities of the Committee

The Committee will:

1. Review the Corporation's compliance with applicable laws and regulations as they relate to financial reporting and disclosure.
2. Review the Corporation's integrated annual report, including the annual audited financial statements, the notes thereto, management's discussion and analysis, the earnings press release and the Corporation's annual information form before release by the Corporation, including any report or opinion or independent external assurance to be rendered in connection therewith, and make recommendations as to their approval by the Board.
3. 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.
4. 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.
5. Review on a quarterly basis with the Corporation's Chief Financial Officer (the "CFO") and the Chief Legal Officer (the "CLO"), and if necessary, external legal counsel, the status of all material litigation, claims, compliance issues, or regulatory or other contingencies, including tax reassessments, faced by the Corporation.
6. 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, but not limited to, any prospectus, management information circulars, offering memoranda, annual reports, management certifications, management's discussion and analysis, annual information forms and press releases.
7. Review the process used by Management to measure publicly disclosed progress towards the achievement of material non-financial, sustainability related performance metrics to ensure accuracy and reasonableness.
8. 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.

9. Assess Management's procedures to ensure compliance by the Corporation with its loan and indenture covenants and restrictions, if any.
10. 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.
11. 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.
12. 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.
13. Discuss 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.
14. Review and recommend to the Board for approval the compensation paid to the external auditors on an annual basis.
15. 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.

16. 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 between Management and external auditors 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.

17. Review the rationale for any proposed change in auditors which is not initiated by the Committee or the Board.
18. Review reports from external auditors respecting their internal quality control procedures, peer reviews and investigations by governmental or professional authorities.
19. 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.
20. 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.
21. 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.

22. Monitor compliance with the Corporation's Code of Conduct (the "Code of Conduct") and ensure Management Compliance Certificates have been executed.
23. Meet with the external auditors, at least annually and when requested by the external auditors, without Management representatives present.
24. Meet with the internal auditors, at least annually or as requested by the internal auditors, without Management representatives present.
25. 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.
26. 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.
27. 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 a summary of all internal audit reports issued in relation thereto.
28. Receive and review all follow-up action or status reports relating to the non-financial recommendations of the external auditor, and the internal auditor.
29. 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.
30. Annually review the performance, budget and independence of the internal audit function and direct the Senior Vice President, Finance and Chief Financial Officer (or their delegate) to make any changes necessary.
31. Establish procedures for receiving, retaining and responding to complaints relating to accounting, internal accounting controls or auditing matters, on a basis that protects the confidentiality of the complainant.
32. Review and approve the hiring practices of the Corporation regarding current and former partners and current and former employees of the present and former external auditors.
33. Periodically assess procedures for the review of disclosure of financial information, extracted or derived from the Corporation's financial statements.
34. Review and monitor quarterly results of financial and commodity exposure management activities, counterparty credit exposure and the use of derivative instruments, as well as annually review foreign currency and interest rate risk strategies, and ensure that they are appropriately reflected in the Corporation's financial reporting.
35. Monitor and evaluate the Corporation's insurance programs.

36. Review with Management and the external auditor any off balance sheet arrangements and special purpose vehicle structures.
37. Review disclosure made to the Committee by the CEO, the CFO and the CLO of a violation of applicable securities laws, a breach of 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.
38. 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, including the adequacy of such controls and any remedial steps being undertaken to address any material weaknesses or significant deficiencies in internal controls over financial reporting.
39. Conduct all other matters required by law or stock exchange rules to be dealt with by an audit committee.
40. Review the Code of Conduct and recommend any required material changes to the Board.
41. Review annually these terms of reference.
42. Review, no less than every two years, the Corporation's Disclosure and Insider Trading Policy regarding public disclosure of material information and insider trading and recommend any required material changes to the Board.
43. Conduct an annual review and survey of the effectiveness and performance of the Committee including a review of its compliance with these terms of reference. In conducting its review, the Committee will take into consideration all applicable legislative and regulatory requirements, and any guidelines recommended by regulators or stock exchanges with which the Corporation has a reporting relationship.
44. Conduct annual reviews of practices relating to Directors' and officers' expenses and the reimbursement thereof.
45. Review, by the Committee Chair, confidential submissions received via the Corporation's Integrity Hotline to which the Committee Chair has direct access.
46. Receive from the Corporation's Chief Compliance Officer quarterly and annual reports outlining pertinent statistics related to investigation activities.
47. Review incidents or alleged incidents of accounting or auditing irregularities, material fraud, an ethical breach by a member of Management at the vice president level or above, or an incident which could result in criminal prosecution or civil or administrative action against Capital Power's directors or officers or which could cause significant damage to the Corporation's reputation as reported by senior management, internal audit, the external auditor, the Chief Compliance Officer, the law department, or otherwise.

48. Review the solvency and liquidity tests used to support dividend declarations by the Corporation.
49. Report to the Board as required.

E. Outside Experts and Advisors

1. The Committee is authorized, where deemed necessary and desirable, to engage independent counsel, outside experts, consultants and other advisors to assist it in carrying out its duties and responsibilities. The Committee shall set the compensation and oversee the work of any independent counsel and other advisors to be paid by the Corporation.

F. Meetings

1. 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. A majority of Committee Members will constitute a quorum. The Committee Chair will be a voting member and questions will be decided by a majority of votes.
2. The Committee will meet at least quarterly and may call other meetings as required.
3. 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.
4. Meetings are chaired by the Committee Chair or in the Committee Chair's absence, by a Committee Member chosen from among and by Committee Members present at the meeting.
5. At each meeting, an in camera session will be held with just the Committee Members in attendance.
6. Agendas 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, CLO, and CFO, no later than the day prior to the date of the meeting provided the meeting is held with 24 hours notice. 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. Notice of the time and place of a Committee meeting shall be given by the Committee to the Corporation's external auditor in the same manner notice is provided to Committee Members. The Committee shall provide the external auditor with meeting materials in advance of the meeting.
9. The external auditor will be provided the opportunity to attend every meeting related to quarterly and annual financial reporting.
10. Meetings may be conducted with the participation of Committee Members by telephone, video, or other virtual meeting techniques which permits all persons

participating in the meeting to hear and communicate with each other. A Committee Member participating in a meeting by those means is deemed to be present at the meeting.

11. 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, as applicable, will not be entitled to a second or casting vote.
12. 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.
13. 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. With the exception of "in camera" items, minutes will be circulated to those receiving the agenda. Minutes will be retained by the Corporate Secretary.
14. 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.