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Capital Power reports strong third quarter 2025 results, advancing flexible generation[1] growth and contracting success

CFO Sandra Haskins announces retirement after 23 years of leadership and financial excellence

EDMONTON, Alberta – October 29, 2025 – Capital Power Corporation (TSX: CPX) today released financial results for the quarter ended September 30, 2025.

Strategic highlights

- Executed a new long-term contract for Midland Cogeneration Venture (MCV)[2] through to 2040, with improved economic terms, adding 10 years of incremental contracted revenue
- Commissioned 170 MW of battery storage in Ontario contracted through to 2047
- MCV entered into a term sheet with a leading colocation data centre developer for the potential development of a 250 MW data centre adjacent to the facility. The proposed project is subject to due diligence, execution of definitive agreements, and the requisite regulatory approvals

Financial highlights

- Generated AFFO of $369 million and net cash flows from operating activities of $404 million
- Generated adjusted EBITDA of $477 million and net income of $153 million
- Negotiated a two-year, $600 million revolving credit facility maturing in 2027

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, & Treasurer will transition to Interim SVP Finance & CFO. A search for a new SVP Finance & CFO is underway, and a successor will be announced in due course. Sandra will support a smooth leadership transition by remaining in an advisory capacity until the end of Q1 2026.

“Our third quarter results reflect the continued execution of our strategy to strengthen our U.S. platform and expand our contracted cash flows,” said Avik Dey, President and Chief Executive Officer. “The MCV contract is a prime example of the critical role natural gas will continue to play in meeting the needs of grids. With scale, diversification, and unmatched operational and commercial excellence and a surging demand for reliable power, we are well positioned to deliver sustained value for shareholders.”

“Capital Power delivered multiple projects through to 2040 and beyond in the third quarter, demonstrating our strong execution on high-value growth opportunities and financial discipline. Our established track record of securing and delivering long-term partnership contracts enhances cash flow stability, which we only expect to continue. Additionally, our two Ontario battery storage assets further strengthens our balance sheet and the new $600 million credit facility enhances our liquidity,” said Sandra Haskins, Senior Vice President, Finance and Chief Financial Officer. "These actions reinforce our commitment to stable, contracted cash flows and long-term value creation for shareholders.”

“On behalf of the entire executive team and Board of Directors, I also want to express our gratitude to Sandra Haskins for her exceptional service and dedication over the past 23 years," continued Avik Dey. "Sandra has been instrumental in driving our company forward, building a strong culture, and delivering outstanding results. While we will greatly miss her leadership, we wish Sandra only the best in this well-deserved next chapter ahead."

[1] References to flexible generation are defined as natural gas generation assets and energy storage
[2] Jointly owned with 50% working interest with Manulife Investment Management

Reaffirming 2025 Guidance

Capital Power is reaffirming revised guidance ranges across Adjusted EBITDA, AFFO and Sustaining Capital for 2025 despite updates to planned outages and delays on Alberta projects.

To ensure portfolio reliability, and best position the assets to capitalize on stronger market fundamentals beyond 2026, our updated Alberta maintenance schedule is planned as follows:

- Genesee 3 (G3) unit is advancing its planned outage to Q4 2025. This strategic decision ensures that G3 is fully available in 2026 to provide system support and mitigate the impact of concurrent outages elsewhere in the fleet.
- The recently commissioned Genesee 1 (G1) and Genesee 2 (G2) units are scheduled for incremental maintenance that require us to extend the previously scheduled outages in Q2 2026 to balance reliability and growing dispatch requirements heading into 2027, which is typical for newly installed turbines.
- Shepard Energy Centre, Joffre Cogeneration, and Clover Bar Energy Centre have routine planned outages scheduled in 2026.
- In 2026, we expect approximately a 40% increase in outage days for our Canada flexible generation portfolio.

As part of its ongoing Alberta fleet optimization, Capital Power remains focused on dispatching as much of its existing capacity at the Genesee site as possible. Further to that, incremental performance testing of Capital Power's technical solution for generation above the Most Single Severe Contingency limit (MSSC) will continue including additional tuning, operational refinement, and extended runtime evaluations. Furthermore, Capital Power will also continue its proactive engagement with the AESO pursuant to the Phase 2 Large Load Allocation process to potentially unlock as much as the full nameplate capacity of the G1 and G2 units. Capital Power will update on the timing and quantum of incremental capacity above the MSSC that can be dispatched from the Genesee site once it is able to do so.

2025 Annual Guidance

Priority	2025 targets	Status at September 30, 2025
Execution of major turnarounds	Sustaining capital expenditures of **$215 million to $245 million**[3]	**$134 million**[1,2]
Generate financial stability and strength	AFFO[3,4] of **$950 million to $1,100 million**	**$822 million**[1]
	Adjusted EBITDA[3,4] of **$1,500 million to $1,650 million**	**$1,166 million**[1]

1 For the nine months ended September 30, 2025.

2 Includes our share of equity-accounted investments sustaining capital expenditures of $49 million net of partner contributions of $8 million.

3 The Company provided updated guidance for 2025 based on the Company's year-to-date results, expectations for the remainder of the year and the expected results from the acquisition of Hummel Station, LLC and Rolling Hills Generating, LLC for the periods subsequent to the close of the transaction on June 9, 2025.

4 AFFO and adjusted EBITDA are non-GAAP financial measures. See Non-GAAP Financial Measures and Ratios.

Operational and Financial Highlights[1]

($ millions, except per share amounts)	Three months ended September 30,		Nine months ended September 30,	
	2025	**2024**	**2025**	**2024**
Electricity generation (Gigawatt hours) [2]	13,374	11,001	31,952	28,413
Generation facility availability [3]	93 %	94 %	92 %	94 %
Revenues and other income	1,213	1,030	2,642	2,923
Adjusted EBITDA [4]	477	401	1,166	1,013
Net income	153	178	172	459
Net income attributable to shareholders of the Company	154	179	173	459
Basic earnings per share ($)	0.94	1.32	1.02	3.39
Diluted earnings per share ($) [5]	0.94	1.32	1.01	3.38
Net cash flows from operating activities	404	236	757	706
Adjusted funds from operations [4]	369	315	822	642
Adjusted funds from operations per share ($) [4]	2.37	2.42	5.53	5.00
Purchase of property, plant and equipment and other assets, net	147	231	576	675
Dividends per common share, declared ($)	0.6910	0.6519	1.9948	1.8819

[1] The operational and financial highlights in this press release should be read in conjunction with the Management's Discussion and Analysis and the unaudited condensed interim financial statements for the nine months ended September 30, 2025.
[2] Gigawatt hours (GWh) of electricity generation reflects the Company's share of facility output.
[3] Facility availability represents the percentage of time in the period that the facility was available to generate power regardless of whether it was running and therefore is reduced by planned and unplanned outages.
[4] The consolidated financial highlights, except for adjusted EBITDA, AFFO and AFFO per share were prepared in accordance with GAAP. See Non-GAAP Financial Measures and Ratios.
[5] Diluted earnings per share was calculated after giving effect to outstanding share purchase options.

Significant Events

York Energy 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, under budget and with an excellent safety record. The projects are contracted until 2047 with the 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 unprecedented, growing demand for electricity.

MCV new contract 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 United States, 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 power purchase agreement (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)[1] annually representing an 85% increase over current contract pricing.

[1] Jointly owned with 50% working interest with Manulife Investment Management.

MCV data center

In September 2025, MCV[1] entered into a term sheet with a leading colocation data centre developer for the potential development of a data centre adjacent to the facility. Subject to due diligence, execution of formal agreements, and the requisite regulatory approvals, the proposed project would see 250 MW of power sold under a PPA agreement of up to 15-years.

[1] Jointly owned with 50% working interest with Manulife Investment Management.

Virtual power purchase agreement cancellation

As a result of delayed commissioning on Halkirk 2 Wind, Saputo Inc. (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.

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

On June 30, 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 US dollars. Interest is floating and is based on the type of draw, plus margin.

Analyst conference call and webcast

Capital Power will be hosting a conference call and live webcast with analysts on October 29, 2025 at 9:00 am (MT) to discuss the third quarter financial results. The webcast can be accessed at: https://edge.media-server.com/mmc/p/pfzzokqy/. Conference call details will be sent directly to analysts.

An archive of the webcast will be available on the Company's website at www.capitalpower.com following the conclusion of the analyst conference call.

Non-GAAP Financial Measures and Ratios

Capital Power uses (i) earnings before, income tax expense, depreciation and amortization, net finance expense, foreign exchange gains or losses, gains or losses on disposals and other transactions, unrealized changes in fair value of commodity derivatives and emission credits, other expenses from our joint venture interests, acquisition and integration costs, and other items that are not reflective of the Company's facility operating performance (adjusted EBITDA), and (ii) AFFO as specified financial measures. Adjusted EBITDA and AFFO are both non-GAAP financial measures.

Capital Power also uses AFFO per share as a specified performance measure. This measure is a non-GAAP ratio determined by applying AFFO to the weighted average number of common shares used in the calculation of basic and diluted earnings per share.

These terms are not defined financial measures according to GAAP and do not have standardized meanings prescribed by GAAP and, therefore, are unlikely to be comparable to similar measures used by other enterprises. These measures should not be considered alternatives to net income, net income attributable to shareholders of Capital Power, net cash flows from operating activities or other measures of financial performance calculated in accordance with GAAP. Rather, these measures are provided to complement GAAP measures in the analysis of our results of operations from management's perspective.

Adjusted EBITDA

During the second quarter of 2025, the Company amended the composition of adjusted EBITDA to exclude acquisition and integration costs, as these costs are not reflective of facility operating performance. The Company has applied this change to all historical amounts reported. Capital Power uses adjusted EBITDA to measure the operating performance of facilities and categories of facilities from period to period. Management believes that a measure of facility operating performance is more meaningful if results not related to facility operations are excluded from the adjusted EBITDA measure such as impairments, foreign exchange gains or losses, gains or losses on disposals and other transactions, unrealized changes in fair value of commodity derivatives and emission credits, acquisition and integration costs, and other items that are not reflective of the long-term performance of the Company's underlying operations.

A reconciliation of adjusted EBITDA to net income is as follows:

($ millions)	**Three months ended September 30,**		**Nine months ended September 30,**	
	2025	**2024**	**2025**	**2024**
Net income	**153**	**178**	**172**	**459**
Depreciation and amortization	157	124	421	366
Unrealized changes in fair value of commodity derivatives and emission credits	(13)	(78)	176	(286)
Other non-recurring items	–	–	4	4
Acquisition and integration costs	4	–	41	10
Impairment	–	27	–	27
Foreign exchange loss (gain)	7	(5)	(16)	9
Net finance expense	92	65	217	160
Loss on disposals and other transactions	5	5	12	20
Other items[1]	37	32	110	91
Income tax expense	35	53	29	153
Adjusted EBITDA	**477**	**401**	**1,166**	**1,013**

[1] Includes finance expense, depreciation expense and unrealized changes in fair value of derivative instruments from equity-accounted investments.

AFFO and AFFO per share

AFFO and AFFO per share are measures of our ability to generate cash from our operating activities to fund growth capital expenditures, repayment of debt, and payment of common share dividends. During the second quarter of 2025, the Company amended the composition of AFFO and AFFO per share to exclude acquisition and integration costs, as these costs are not reflective of cash generated from facility operations. The Company has applied this change to all historical amounts reported.

AFFO represents net cash flows from operating activities adjusted to:

- remove timing impacts of cash receipts and payments that may impact period-to-period comparability which include deductions for net finance expense and current income tax expense, the removal of deductions for interest paid and income taxes paid and removing changes in operating working capital,
- include our share of AFFO of joint venture interests and exclude distributions received from our joint venture interests which are calculated after the effect of non-operating activity joint venture debt payments,
- include cash from off-coal compensation received annually through to 2030,
- remove the tax equity financing project investors' shares of AFFO associated with assets under tax equity financing structures so only Capital Power's share is reflected in the overall metric,
- deduct sustaining capital expenditures and preferred share dividends,
- exclude the impact of fair value changes in certain unsettled derivative financial instruments that are charged or credited to our bank margin account held with a specific exchange counterparty,
- exclude acquisition and integration costs, and
- exclude other typically non-recurring items affecting cash flows from operating activities that are not reflective of the long-term performance of the Company's underlying business.

A reconciliation of net cash flows from operating activities to AFFO is as follows:

($ millions)	Three months ended September 30,		Nine months ended September 30,	
	2025	**2024**	**2025**	**2024**
Net cash flows from operating activities per condensed interim consolidated statements of cash flows	**404**	**236**	**757**	**706**
Add (deduct):				
Interest paid	87	73	202	132
Change in fair value of derivatives reflected as cash settlement	—	2	7	(17)
Realized gain on settlement of interest rate derivatives	—	(28)	(17)	(42)
Distributions received from joint ventures	(9)	(13)	(47)	(24)
Miscellaneous financing charges paid [1]	4	1	(2)	(6)
Income taxes (recovered) paid	(11)	(3)	(14)	17
Change in non-cash operating working capital	(77)	63	(23)	(7)
	(7)	95	105	53
Net finance expense [2]	(81)	(56)	(192)	(136)
Current income tax recovery (expense) [3]	16	(7)	72	(29)
Sustaining capital expenditures [4]	(44)	(35)	(85)	(96)
Preferred share dividends paid	(7)	(6)	(20)	(24)
Cash received for off-coal compensation [5]	50	50	60	50
Remove tax equity interests' respective shares of AFFO	(1)	(1)	(4)	(4)
AFFO from joint ventures	38	40	101	99
Acquisition and integration costs [6]	3	—	41	7
Other non-recurring items [7]	(3)	(1)	(14)	16
AFFO	**369**	**315**	**822**	**642**
Weighted average number of common shares outstanding (millions)	155.3	130.3	148.6	127.8
AFFO per share ($)	**2.37**	**2.42**	**5.53**	**5.00**

[1] Included in other cash items on the condensed interim consolidated statements of cash flows to reconcile net income to net cash flows from operating activities.

[2] Excludes unrealized changes on interest rate derivative contracts, amortization, accretion charges, and non-cash implicit interest on tax equity investment structures.

[3] Excludes current income tax expense related to the partial divestiture of Quality Wind and Port Dover and Nanticoke Wind as the amount is classified as an investing activity.

[4] Includes sustaining capital expenditures net of partner contributions of $2 million and $8 million for the three and nine months ended September 30, 2025, respectively, compared with $2 million and $8 million for the three and nine months ended September 30, 2024, respectively.

[5] Reflects annual off-coal compensation payments received from the Government of Alberta (GoA). For the nine months ended September 30, 2025, an additional payment was received for the settlement of previously disputed off-coal compensation payments as described in the Company's 2024 annual consolidated financial statements.

[6] For the three and nine months ended September 30, 2025, net of current income tax recoveries of $1 million and $2 million, respectively, compared with $3 million for the three and nine months ended September 30, 2024.

[7] For the three months ended September 30, 2025, other non-recurring items reflect costs related to the termination of the Halkirk 2 Wind VPPA of $5 million (see Significant Events), net of current income tax recoveries of $8 million related to other non-recurring items recognized in the current and prior periods. For the nine months ended September 30, 2025, other non-recurring items reflect costs related to the termination of the Halkirk 2 Wind VPPA and end-of-life of Genesee coal operations of $5 million each, net of current income tax recoveries of $24 million related to other non-recurring items recognized in the current and prior periods. For the three and nine months ended September 30, 2024, other non-recurring items reflects costs related to the end-of-life of Genesee coal operations of $1 million and $5 million, respectively, and a provision of $18 million for the discontinuation of the Genesee carbon capture and storage project related to the termination of sequestration hub evaluation work, net of current income tax recoveries of $2 million and $7 million for the three and nine months ended September 30, 2024, related to other non-recurring items recognized in the prior and current periods, respectively.

Forward-looking information

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

Material forward-looking information in this MD&A includes expectations regarding:

- our priorities and long-term strategies, including our corporate, and decarbonization strategies,
- our 2025 performance targets, including sustaining capital expenditures, adjusted funds from operations (AFFO) and adjusted earnings before interest, taxes, depreciation, and amortization (EBITDA),
- future revenues, expenses, earnings, adjusted EBITDA and AFFO,
- the future pricing of electricity and market fundamentals in existing and target markets,
- our future cash requirements including interest and principal repayments, capital expenditures, dividends and distributions,
- our sources of funding, adequacy and availability of committed bank credit facilities and future borrowings, various aspects around existing, planned and potential development projects and acquisitions. This includes expectations around timing, generation capacity, costs of technologies selected, environmental and sustainability benefits, and commercial and partnership arrangements,
- our 2025 estimated capital expenditures for previously announced growth projects,
- the performance of future projects and the performance of such projects in comparison to the market,
- the timing of 2026 planned maintenance outages at the Company's Alberta facilities,
- the increase in outage days in 2026 expected for the Company's Canadian flexible generation portfolio,
- plans and results related to the acquisition of Hummel Station, LLC (Hummel Station) and Rolling Hills Generating, LLC (Rolling Hills),
- the return to operation of the out of service unit at the Rolling Hills facility,
- re-bidding the Halkirk 2 Wind facility into future requests for proposals and the financial impact of the VPPA cancellation,
- anticipated pricing trends, growth opportunities, market conditions, and future power demand in the Pennsylvania-New Jersey-Maryland market,
- legislative developments regarding carbon pricing in Pennsylvania and Ohio,
- future growth and emerging opportunities in our target markets,
- market and regulation designs and regulatory and legislative proposals and changes, regulatory updates, initiatives, projects and the impact thereof on the Company's core markets and business, and
- the impact of climate change, including our assumptions relating to our identification of future risks and opportunities from climate change, our plans to mitigate transition and physical climate risks, and opportunities resulting from those risks.

These statements are based on certain assumptions and analyses made by the Company in light of its experience and perception of historical trends, current conditions, 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:

- electricity and other energy and carbon prices,
- performance,
- business prospects (including potential re-contracting of facilities) and opportunities including expected growth and capital projects,
- the status and impact of policy, legislation and regulations,
- effective tax rates,
- the development and performance of technology,
- the outcome of claims and disputes,
- foreign exchange rates, and
- other matters discussed under the Performance Outlook and Risks and Risk Management sections of the MD&A.

Whether actual results, performance or achievements will conform to our expectations and predictions is subject to a number of known and unknown risks and uncertainties which could cause actual results and experience to differ materially from our expectations. Such material risks and uncertainties are:

- changes in electricity, natural gas and carbon prices in markets in which we operate and the use of derivatives,
- regulatory and political environments including changes to environmental, climate, financial reporting, market structure and tax legislation,
- disruptions, or price volatility within our supply chains,
- generation facility availability, wind capacity factor and performance including maintenance expenditures,
- ability to fund current and future capital and working capital needs,
- acquisitions and developments including timing and costs of regulatory approvals and construction,
- changes in the availability of fuel,
- ability to realize the anticipated benefits of acquisitions,
- limitations inherent in our review of acquired assets,
- changes in general economic and competitive conditions, including inflation and recession,
- changes in the performance and cost of technologies and the development of new technologies, new energy efficient products, services and programs, and
- risks and uncertainties discussed under the Risks and Risk Management section of the MD&A.

See Risks and Risk Management in our 2024 Integrated Annual Report, for further discussion of these and other risks.

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

Territorial Acknowledgement

In the spirit of reconciliation, Capital Power respectfully acknowledges that we operate within the ancestral homelands, traditional and treaty territories of the Indigenous Peoples of Turtle Island, or North America. Capital Power's head office is located within the traditional and contemporary home of many Indigenous Peoples of the Treaty 6 Territory and Métis homeland. We acknowledge the diverse Indigenous communities that are located in these areas and whose presence continues to enrich the community.

About Capital Power

Capital Power is a growth-oriented power producer with approximately 12 GW of owned power generation at 32 power generation facilities and two BESS facilities across North America. We prioritize safely delivering reliable and affordable power communities can depend on, building lower-carbon power systems, and creating balanced solutions for our energy future. We are Powering Change by Changing Power™.

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CAPITAL POWER CORPORATION

Management’s Discussion and Analysis

This Management’s Discussion and Analysis (MD&A), prepared as of October 28, 2025, should be read in conjunction with the unaudited condensed interim consolidated financial statements of Capital Power Corporation and its subsidiaries for the nine months ended September 30, 2025, the audited consolidated financial statements and the 2025 Performance Targets, Powering the Energy Expansion and Business Report sections of the Integrated Annual Report of Capital Power Corporation for the year ended December 31, 2024 (the 2024 Integrated Annual Report), the Annual Information Form of Capital Power Corporation dated February 25, 2025, and the cautionary statements regarding Forward-Looking Information which begin on page 10.

Effective January 1, 2025, the Company reassessed its reportable segments due to changes in internal reporting for performance results provided to the Company's Chief Operating Decision Maker (CODM). These operating segments are now grouped by both business activity and geographical areas into flexible generation and renewables and Canada and U.S. Prior to 2025, these segments were based on geographical areas. Comparative segment information has been restated to conform to the current period’s presentation. References to flexible generation are defined as natural gas generation assets and energy storage.

In this MD&A, any reference to the Company or Capital Power, except where otherwise noted or the context otherwise indicates, means Capital Power Corporation together with its subsidiaries.

In this MD&A, financial information for the nine months ended September 30, 2025 and September 30, 2024 is based on the unaudited condensed interim consolidated financial statements of the Company for such periods which were prepared in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board and are presented in Canadian dollars unless otherwise specified. In accordance with its terms of reference, the Audit Committee of the Company’s Board of Directors reviews the contents of the MD&A and recommends its approval by the Board of Directors. The Board of Directors approved this MD&A as of October 28, 2025.

FORWARD-LOOKING INFORMATION

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

Material forward-looking information in this MD&A includes expectations regarding:

- our priorities and long-term strategies, including our corporate, and decarbonization strategies,
- our 2025 performance targets, including sustaining capital expenditures, adjusted funds from operations (AFFO) and adjusted earnings before interest, taxes, depreciation, and amortization (EBITDA),
- future revenues, expenses, earnings, adjusted EBITDA and AFFO,
- the future pricing of electricity and market fundamentals in existing and target markets,
- our future cash requirements including interest and principal repayments, capital expenditures, dividends and distributions,
- our sources of funding, adequacy and availability of committed bank credit facilities and future borrowings, various aspects around existing, planned and potential development projects and acquisitions. This includes expectations around timing, generation capacity, costs of technologies selected, environmental and sustainability benefits, and commercial and partnership arrangements,
- our 2025 estimated capital expenditures for previously announced growth projects,
- the performance of future projects and the performance of such projects in comparison to the market,
- the timing of 2026 planned maintenance outages at the Company's Alberta facilities,
- the increase in outage days in 2026 expected for the Company's Canadian flexible generation portfolio,
- plans and results related to the acquisition of Hummel Station, LLC (Hummel Station) and Rolling Hills Generating, LLC (Rolling Hills),
- the return to operation of the out of service unit at the Rolling Hills facility,
- re-bidding the Halkirk 2 Wind facility into future requests for proposals and the financial impact of the virtual power purchase agreement (VPPA) cancellation,
- anticipated pricing trends, growth opportunities, market conditions, and future power demand in the Pennsylvania-New Jersey-Maryland (PJM) market,
- legislative developments regarding carbon pricing in Pennsylvania and Ohio,
- future growth and emerging opportunities in our target markets,
- market and regulation designs and regulatory and legislative proposals and changes, regulatory updates, initiatives, projects and the impact thereof on the Company's core markets and business, and
- the impact of climate change, including our assumptions relating to our identification of future risks and opportunities from climate change, our plans to mitigate transition and physical climate risks, and opportunities resulting from those risks.

These statements are based on certain assumptions and analyses made by the Company in light of its experience and perception of historical trends, current conditions, 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:

- electricity and other energy and carbon prices,
- performance,
- business prospects (including potential re-contracting of facilities) and opportunities including expected growth and capital projects,
- the status and impact of policy, legislation and regulations,
- effective tax rates,
- the development and performance of technology,
- the outcome of claims and disputes,
- foreign exchange rates, and
- other matters discussed under the Performance Outlook and Risks and Risk Management sections of this MD&A.

Whether actual results, performance or achievements will conform to our expectations and predictions is subject to a number of known and unknown risks and uncertainties which could cause actual results and experience to differ materially from our expectations. Such material risks and uncertainties are:

- changes in electricity, natural gas and carbon prices in markets in which we operate and the use of derivatives,
- regulatory and political environments including changes to environmental, climate, financial reporting, market structure and tax legislation,
- disruptions, or price volatility within our supply chains,
- generation facility availability, wind capacity factor and performance including maintenance expenditures,
- ability to fund current and future capital and working capital needs,
- acquisitions and developments including timing and costs of regulatory approvals and construction,
- changes in the availability of fuel,
- ability to realize the anticipated benefits of acquisitions,
- limitations inherent in our review of acquired assets,
- changes in general economic and competitive conditions, including inflation and recession,
- changes in the performance and cost of technologies and the development of new technologies, new energy efficient products, services and programs, and
- risks and uncertainties discussed under the Risks and Risk Management section of this MD&A.

See Risks and Risk Management in our 2024 Integrated Annual Report, for further discussion of these and other risks.

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

OVERVIEW OF BUSINESS AND CORPORATE STRUCTURE

Capital Power is a growth-oriented power producer with approximately 12 GW of owned power generation at 32 power generation facilities and two battery energy storage (BESS) facilities across North America. We prioritize safely *delivering* reliable and affordable power communities can depend on, *building* lower-carbon power systems, and *creating* balanced solutions for our energy future. We are Powering Change by Changing Power™.

The Company's power generation operations and assets are owned by Capital Power L.P. (CPLP), Capital Power L.P. Holdings Inc., and Capital Power (US Holdings) Inc., all wholly owned subsidiaries of the Company.

PERFORMANCE OUTLOOK

The following discussion should be read in conjunction with the forward-looking information section of this MD&A which identifies the material factors and assumptions used to develop forward-looking information and their material associated risk factors.

We measure our operational and financial performance in relation to our corporate strategy through financial and non-financial targets approved by the Board of Directors. The measurement categories include corporate measures and measures specific to certain groups within Capital Power. The corporate measures are company-wide and include adjusted EBITDA, AFFO and safety. The group-specific measures include facility operating margin and other operations measures, committed capital, construction and sustaining capital expenditures on budget and on schedule, and facility site safety.

The 2025 targets and forecasts, which were updated in the second quarter of 2025, are based on numerous assumptions including power and natural gas price forecasts, facility performance, and planned outages. Capital Power is reaffirming the revised guidance ranges across Adjusted EBITDA, AFFO and Sustaining Capital for 2025 despite updates to planned outages and delays on Alberta projects (see Significant Events and Capital expenditures and investments).

To ensure portfolio reliability, and best position the assets to capitalize on stronger market fundamentals beyond 2026, our updated Alberta maintenance schedule is planned as follows:

- Genesee 3 (G3) unit is advancing its planned outage to Q4 2025. This strategic decision ensures that G3 is fully available in 2026 to provide system support and mitigate the impact of concurrent outages elsewhere in the fleet.
- The recently commissioned Genesee 1 (G1) and Genesee 2 (G2) units are scheduled for incremental maintenance that require us to extend the previously scheduled outages in Q2 2026 to balance reliability and growing dispatch requirements heading into 2027, which is typical for newly installed turbines.
- Shepard Energy Centre, Joffre Cogeneration, and Clover Bar Energy Centre have routine planned outages scheduled in 2026.
- In 2026, we expect approximately a 40% increase in outage days for our Canada flexible generation portfolio.

As part of its ongoing Alberta fleet optimization, Capital Power remains focused on dispatching as much of its existing capacity at the Genesee site as possible. Further to that, incremental performance testing of Capital Power's technical solution for generation above the Most Single Severe Contingency limit (MSSC) will continue including additional tuning, operational refinement, and extended runtime evaluations. Furthermore, Capital Power will also continue its proactive engagement with the AESO pursuant to the Phase 2 Large Load Allocation process to potentially unlock as much as the full nameplate capacity of the G1 and G2 units. Capital Power will update on the timing and quantum of incremental capacity above the MSSC that can be dispatched from the Genesee site once it is able to do so.

Operational priorities and performance targets for Capital Power in 2025 include a balanced approach to the energy transition:

Priority	2025 targets	Status at September 30, 2025
Deliver		
Execution of major turnarounds	Sustaining capital expenditures of **$215 million to $245 million** [3]	**$134 million** [1,2]
Generate financial stability and strength	AFFO [3,4] of **$950 million to $1,100 million**	**$822 million** [1]
	Adjusted EBITDA [3,4] of **$1,500 million to $1,650 million**	**$1,166 million** [1]
Portfolio optimization and integration	Re-contract/contract flexible generation Maximize facility asset life and value	In Q3 2025, the Company executed a new long-term contract with improved economic terms for Midland Cogeneration, extending to 2040 and providing 10 years of incremental contracted revenue (see Significant Events). Discussions with counterparties for other flexible generation facilities are in progress.

Priority	2025 targets	Status at September 30, 2025
Build		
Expand flexible generation portfolio	Continue construction on Ontario growth and commercial initiative projects Continue to explore opportunities to build or acquire flexible generation facilities	Construction is underway and the projects remain on track to meet their targeted completion dates (see Capital Expenditures and Investments). Reached commercial operation of the 40 MW uprate project at Goreway in Q2 2025. The Ontario BESS projects achieved commercial operations in Q3 2025. East Windsor Expansion environmental permits have been received and all major equipment is on site. Site civil work and foundations are advanced. In Q2 2025, the Company completed the acquisition of two U.S. flexible generation assets in the PJM market, Hummel Station and Rolling Hills (see Significant Events).
Grow renewables portfolio	Continue construction on Alberta and North Carolina growth and commercial initiative projects Continue to explore opportunities to build or acquire renewables facilities	Construction for Hornet Solar commenced during the first quarter of 2025. Bear Branch Solar and Maple Leaf Solar commenced construction in the second quarter of 2025. These projects remain on schedule for targeted completion (see Capital Expenditures and Investments).
Create		
Balanced energy solutions	Evaluate Small Modular Reactors (SMRs) in Alberta	Pre-feasibility study work for the Alberta SMR project with Ontario Power Generation (OPG) remains on track. The first funded phase of the pre-feasibility study for the Alberta SMR project with OPG has been completed. We continue to evaluate the development opportunity through this project.
	Provide integrated energy solutions to commercial and industrial customers	Discussions with counterparties are in progress to provide integrated energy solutions.

1 For the nine months ended September 30, 2025.

2 Includes our share of equity-accounted investments sustaining capital expenditures of $49 million net of partner contributions of $8 million.

3 The Company provided updated guidance for 2025 based on the Company's year-to-date results, expectations for the remainder of the year and the expected results from the acquisition of Hummel Station, LLC and Rolling Hills Generating, LLC for the periods subsequent to the close of the transaction on June 9, 2025.

4 AFFO and adjusted EBITDA are non-GAAP financial measures. See Non-GAAP Financial Measures and Ratios.

The Board of Directors has approved a 6% increase in the common share dividend for 2025 and we continue to anticipate a long-term targeted dividend growth of 2% – 4% after 2025, as previously announced at our Investor Day Presentation in May 2024. The reduction of our targeted dividend growth after 2025 aligns with our strategy to reinvest cash flows and to fund future growth opportunities. Each annual increase is premised on the assumptions listed under Forward-Looking Information and subject to approval by the Board of Directors of Capital Power at the time of the increase.

See Liquidity and Capital Resources for discussion of expected sources of funding.

NON-GAAP FINANCIAL MEASURES AND RATIOS

Capital Power uses (i) earnings before income tax expense, depreciation and amortization, net finance expense, foreign exchange gains or losses, gains or losses on disposals and other transactions, unrealized changes in fair value of commodity derivatives and emission credits, other expenses from our joint venture interests, acquisition and integration costs, and other items that are not reflective of the Company's facility operating performance (adjusted EBITDA), and (ii) AFFO as specified financial measures. Adjusted EBITDA and AFFO are both non-GAAP financial measures.

Capital Power also uses AFFO per share as a specified performance measure. This measure is a non-GAAP ratio determined by applying AFFO to the weighted average number of common shares used in the calculation of basic and diluted earnings per share.

These terms are not defined financial measures according to GAAP and do not have standardized meanings prescribed by GAAP and, therefore, are unlikely to be comparable to similar measures used by other enterprises. These measures should not be considered alternatives to net income, net income attributable to shareholders of Capital Power, net cash flows from operating activities or other measures of financial performance calculated in accordance with GAAP. Rather, these measures are provided to complement GAAP measures in the analysis of our results of operations from management's perspective.

Adjusted EBITDA

During the second quarter of 2025, the Company amended the composition of adjusted EBITDA to exclude acquisition and integration costs, as these costs are not reflective of facility operating performance. The Company has applied this change to all historical amounts reported. Capital Power uses adjusted EBITDA to measure the operating performance of facilities and categories of facilities from period to period. Management believes that a measure of facility operating performance is more meaningful if results not related to facility operations are excluded from the adjusted EBITDA measure such as impairments, foreign exchange gains or losses, gains or losses on disposals and other transactions, unrealized changes in fair value of commodity derivatives and emission credits, acquisition and integration costs, and other items that are not reflective of the long-term performance of the Company's underlying operations.

A reconciliation of adjusted EBITDA to net income is as follows:

($ millions)	**Three months ended September 30,**		**Nine months ended September 30,**	
	2025	**2024**	**2025**	**2024**
Net income	**153**	**178**	**172**	**459**
Depreciation and amortization	157	124	421	366
Unrealized changes in fair value of commodity derivatives and emission credits	(13)	(78)	176	(286)
Other non-recurring items	–	–	4	4
Acquisition and integration costs	4	–	41	10
Impairment	–	27	–	27
Foreign exchange loss (gain)	7	(5)	(16)	9
Net finance expense	92	65	217	160
Loss on disposals and other transactions	5	5	12	20
Other items [1]	37	32	110	91
Income tax expense	35	53	29	153
Adjusted EBITDA	**477**	**401**	**1,166**	**1,013**

[1] Includes finance expense, depreciation expense and unrealized changes in fair value of derivative instruments from equity-accounted investments.

AFFO and AFFO per share

AFFO and AFFO per share are measures of our ability to generate cash from our operating activities to fund growth capital expenditures, repayment of debt, and payment of common share dividends. During the second quarter of 2025, the Company amended the composition of AFFO and AFFO per share to exclude acquisition and integration costs, as these costs are not reflective of cash generated from facility operations. The Company has applied this change to all historical amounts reported.

AFFO represents net cash flows from operating activities adjusted to:

- remove timing impacts of cash receipts and payments that may impact period-to-period comparability which include deductions for net finance expense and current income tax expense, the removal of deductions for interest paid and income taxes paid and removing changes in operating working capital,
- include our share of AFFO of joint venture interests and exclude distributions received from our joint venture interests which are calculated after the effect of non-operating activity joint venture debt payments,
- include cash from off-coal compensation received annually through to 2030,
- remove the tax equity financing project investors' shares of AFFO associated with assets under tax equity financing structures so only Capital Power's share is reflected in the overall metric,
- deduct sustaining capital expenditures and preferred share dividends,
- exclude the impact of fair value changes in certain unsettled derivative financial instruments that are charged or credited to our bank margin account held with a specific exchange counterparty,
- exclude acquisition and integration costs, and
- exclude other typically non-recurring items affecting cash flows from operating activities that are not reflective of the long-term performance of the Company's underlying business.

A reconciliation of net cash flows from operating activities to AFFO is as follows:

($ millions)	Three months ended September 30,		Nine months ended September 30,	
	2025	**2024**	**2025**	**2024**
Net cash flows from operating activities per condensed interim consolidated statements of cash flows	**404**	**236**	**757**	**706**
Add (deduct):				
Interest paid	87	73	202	132
Change in fair value of derivatives reflected as cash settlement	–	2	7	(17)
Realized gain on settlement of interest rate derivatives	–	(28)	(17)	(42)
Distributions received from joint ventures	(9)	(13)	(47)	(24)
Miscellaneous financing charges paid [1]	4	1	(2)	(6)
Income taxes (recovered) paid	(11)	(3)	(14)	17
Change in non-cash operating working capital	(77)	63	(23)	(7)
	(7)	95	105	53
Net finance expense [2]	(81)	(56)	(192)	(136)
Current income tax recovery (expense) [3]	16	(7)	72	(29)
Sustaining capital expenditures [4]	(44)	(35)	(85)	(96)
Preferred share dividends paid	(7)	(6)	(20)	(24)
Cash received for off-coal compensation [5]	50	50	60	50
Remove tax equity interests' respective shares of AFFO	(1)	(1)	(4)	(4)
AFFO from joint ventures	38	40	101	99
Acquisition and integration costs [6]	3	–	41	7
Other non-recurring items [7]	(3)	(1)	(14)	16
AFFO	**369**	**315**	**822**	**642**
Weighted average number of common shares outstanding (millions)	155.3	130.3	148.6	127.8
AFFO per share ($)	**2.37**	**2.42**	**5.53**	**5.00**

1 Included in other cash items on the condensed interim consolidated statements of cash flows to reconcile net income to net cash flows from operating activities.

2 Excludes unrealized changes on interest rate derivative contracts, amortization, accretion charges, and non-cash implicit interest on tax equity investment structures.

3 Excludes current income tax expense related to the partial divestiture of Quality Wind and Port Dover and Nanticoke Wind as the amount is classified as an investing activity.

4 Includes sustaining capital expenditures net of partner contributions of $2 million and $8 million for the three and nine months ended September 30, 2025, respectively, compared with $2 million and $8 million for the three and nine months ended September 30, 2024, respectively.

5 Reflects annual off-coal compensation payments received from the Government of Alberta (GoA). For the nine months ended September 30, 2025, an additional payment was received for the settlement of previously disputed off-coal compensation payments as described in the Company's 2024 annual consolidated financial statements.

6 For the three and nine months ended September 30, 2025, net of current income tax recoveries of $1 million and $2 million, respectively, compared with $3 million for the nine months ended September 30, 2024.

7 For the three months ended September 30, 2025, other non-recurring items reflect costs related to the termination of the Halkirk 2 Wind VPPA of $5 million (see Significant Events), net of current income tax recoveries of $8 million related to other non-recurring items recognized in the current and prior periods. For the nine months ended September 30, 2025, other non-recurring items reflect costs related to the termination of the Halkirk 2 Wind VPPA and end-of-life of Genesee coal operations of $5 million each, net of current income tax recoveries of $24 million related to other non-recurring items recognized in the current and prior periods. For the three and nine months ended September 30, 2024, other non-recurring items reflects costs related to the end-of-life of Genesee coal operations of $1 million and $5 million, respectively, and a provision of $18 million for the discontinuation of the Genesee carbon capture and storage project related to the termination of sequestration hub evaluation work, net of current income tax recoveries of $2 million and $7 million for the three and nine months ended September 30, 2024, related to other non-recurring items recognized in the prior and current periods, respectively.

FINANCIAL HIGHLIGHTS

($ millions, except per share amounts)	Three months ended September 30,		Nine months ended September 30,	
	2025	2024	2025	2024
Revenues and other income	1,213	1,030	2,642	2,923
Net income	153	178	172	459
Net income attributable to shareholders of the Company	154	179	173	459
Basic earnings per share ($)	0.94	1.32	1.02	3.39
Diluted earnings per share ($) [1]	0.94	1.32	1.01	3.38
Adjusted EBITDA [2]	477	401	1,166	1,013
AFFO [2]	369	315	822	642
AFFO per share ($) [2]	2.37	2.42	5.53	5.00
Net cash flows from operating activities	404	236	757	706
Purchase of property, plant and equipment and other assets, net	147	231	576	675
Dividends per common share, declared ($)	0.6910	0.6519	1.9948	1.8819
Dividends per Series 1 preferred share, declared ($)	0.1638	0.1638	0.4914	0.4914
Dividends per Series 3 preferred share, declared ($)	0.4288	0.4288	1.2863	1.2863
Dividends per Series 5 preferred share, declared ($)	0.4144	0.4144	1.2433	1.2433
Dividends per Series 11 preferred share, declared ($) [3]	N/A	N/A	N/A	0.7188

	As at	
	September 30, 2025	December 31, 2024
Loans and borrowings including current portion	6,670	4,976
Total assets	15,345	12,930

[1] Diluted earnings per share was calculated after giving effect to outstanding share purchase options.

[2] The consolidated financial highlights, except for adjusted EBITDA, AFFO and AFFO per share were prepared in accordance with GAAP. See Non-GAAP Financial Measures and Ratios.

[3] On June 30, 2024, Capital Power redeemed all of its 6 million issued and outstanding 5.75% cumulative minimum rate reset preference shares, Series 11.

Revenues and other income for the three months ended September 30, 2025, were higher than the corresponding period in 2024 primarily due to increased revenues from the U.S. flexible generation segment due to the Hummel Station and Rolling Hills facilities which were acquired in June 2025 (see Significant Events). Revenues and other income for the nine months ended September 30, 2025 were lower than the prior year due to losses on unrealized changes in fair value of commodity derivatives and emission credits, partially offset by the Hummel Station and Rolling Hills facilities acquired in June 2025 and increased revenues from La Paloma which was acquired in February 2024.

Net income for the three and nine months ended September 30, 2025, was lower than the same periods last year due to the impacts of:

- changes in adjusted EBITDA described below,
- unfavorable changes in unrealized changes in fair value of commodity derivatives,
- higher depreciation and amortization primarily due to the acquisition of the Hummel Station and Rolling Hills facilities in the second quarter of 2025, and the commissioning of Genesee Repower 1 and 2 in the fourth quarter of 2024,
- increased other administrative expenses including acquisition and integration costs, and
- increased net finance expense due to increased long term borrowings in the current year.

Basic and diluted earnings per share changes were driven by the same factors as net income, and the changes from period to period in the weighted average number of common shares outstanding.

Adjusted EBITDA for the three months ended September 30, 2025 was higher than the same period last year due to:

- higher contributions for the U.S. flexible generation segment due to the Hummel Station and Rolling Hills facilities which were acquired in June, 2025 (see Significant Events), partially offset by lower results from La Paloma due to lower generation from reduced demand related to the weather, and lower results from Decatur Energy due to lower generation and facility availability resulting from a planned plant outage in August 2025.

Adjusted EBITDA for the nine months ended September 30, 2025, was higher than the corresponding period in 2024 largely due to the net impact of:

- higher contributions for the U.S. flexible generation segment due to the Hummel Station and Rolling Hills facilities which were acquired in June, 2025 (see Significant Events), and the full year results from La Paloma and Harquahala which were acquired in February 2024, partially offset by lower results from Midland Cogeneration due to lower revenue from a capacity rate reduction in the power purchase agreement (PPA) contract and increased fuel costs resulting in a lower dispatch,
- lower emissions costs in the Canada flexible generation segment driven by the repowering of Genesee Generating Station to be off coal,
- lower corporate expenses driven by lower salary costs that resulted from a reorganization late in 2024, and
- partially offset by lower contributions from the Canada renewables segment due to the sell down of Quality Wind and Port Dover and Nanticoke facilities in the fourth quarter of 2024.

See Consolidated Net Income and Results of Operations for further discussion of the key drivers of the changes in revenues and other income, net income and net income attributable to shareholders of the Company and adjusted EBITDA.

AFFO for the three months ended September 30, 2025, was higher than the corresponding period in 2024 primarily due to:

- higher adjusted EBITDA described above, and
- current income tax recovery due to lower overall consolidated net income before tax,
- partially offset by higher finance expense from increased loans and borrowings.

AFFO for the nine months ended September 30, 2025, was higher than the corresponding period in 2024 primarily due to:

- higher adjusted EBITDA and current income tax recovery described above,
- lower sustaining capital expenditures due mainly to a credit received for parts at La Paloma during 2025, and
- settlement received for disputed off-coal compensation payments in 2025,
- partially offset by higher finance expense described above.

See Liquidity and Capital Resources for discussion of key drivers of changes in net cash flows from operating activities.

Purchases of property, plant and equipment and other assets is discussed in Liquidity and Capital Resources.

SIGNIFICANT EVENTS

York Energy 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, under budget and with an excellent safety record. 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 unprecedented, 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 United States, 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)[1] annually representing an 85% increase over current contract pricing.

[1] Jointly owned with 50% working interest with Manulife Investment Management.

MCV[1] data centre

In September 2025, MCV entered into a term sheet with a leading colocation data centre developer for the potential development of a data centre adjacent to the facility. Subject to due diligence, execution of formal agreements, and the requisite regulatory approvals, the proposed project would see 250 MW of power sold under a PPA agreement up to 15-years.

[1] Jointly owned with 50% working interest with Manulife Investment Management.

Virtual power purchase agreement cancellation

As a result of delayed commissioning on Halkirk 2 Wind, Saputo Inc. (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.

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

On June 30, 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 US dollars. Interest is floating and is based on the type of draw, plus margin.

Acquisition of Hummel Station 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.

Both the Hummel Station and Rolling Hills facilities sell their 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 will be sold through the annual auction and potential interim balancing auctions as required.

The Hummel Station 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.

Similar to the Hummel Station facility, 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.

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, with a full unit restoration target date of December 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.

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, described in further detail below. The balance of the Acquisition was funded with additional cash on hand and a drawdown on the Company's existing revolving credit facilities.

On July 22, 2025, PJM posted their Base Residual Auction (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.

$1.7 billion (US$1.2 billion) senior notes offering

On May 28, 2025, Capital Power 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.

$667 million bought deal offering of common shares

On April 22, 2025, the Company completed its bought deal offering of 11,902,500 common shares of Capital Power, which included 1,552,500 common shares issued pursuant to the full exercise of the over-allotment option, at an offering price of $43.45 per common share (the Offering Price), for total gross proceeds of approximately $517 million (the Public Offering).

Concurrently, the Company issued 3,455,000 common shares at the Offering Price to Alberta Investment Management Corporation on a private placement basis for gross proceeds of approximately $150 million.

The net proceeds of the offerings were used to partially finance the Acquisition.

SUBSEQUENT EVENT

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, & Treasurer will transition to Interim SVP Finance & CFO. A search for a new SVP Finance & CFO is underway, and a successor will be announced in due course. Sandra will support a smooth leadership transition by remaining in an advisory capacity until the end of Q1 2026.

CONSOLIDATED NET INCOME AND RESULTS OF OPERATIONS

The primary factors contributing to the change in consolidated net income for the three and nine months ended September 30, 2025, compared with 2024 are presented below followed by further discussion of these items.

($ millions)	Three months		Nine months	
Consolidated net income for the periods ended September 30, 2024		**178**		**459**
Increase (decrease) in adjusted EBITDA [1]:				
Canada flexible generation	(6)		25	
Canada renewables	(9)		(34)	
U.S. flexible generation	88		136	
U.S. renewables	(4)		(3)	
Corporate	7	76	29	153
Change in unrealized net gains or losses related to the fair value of commodity derivatives and emission credits		(65)		(462)
Increase in depreciation and amortization expense		(33)		(55)
Decrease in impairments		27		27
Increase in foreign exchange (loss) or gain		(12)		25
Increase in net finance expense from equity accounted investments		(5)		(19)
Increase in net finance expense		(27)		(57)
Decrease in loss on disposals and other transactions		–		8
Acquisition and integration costs		(4)		(31)
Decrease in income before tax		(43)		(411)
Decrease in income tax expense		18		124
Decrease in net income		(25)		(287)
Consolidated net income for the periods ended September 30, 2025		**153**		**172**

[1] Adjusted EBITDA is a non-GAAP financial measure. See Non-GAAP Financial Measures and Ratios.

Results by facility category and other

	Three months ended September 30,							
	2025	2024	2025	2024	2025	2024	2025	2024
	Electricity generation (GWh) [1]		Facility availability (%) [2]		Revenues and other income ($ millions) [3]		Adjusted EBITDA ($ millions) [3]	
Total electricity generation, average facility availability and facility revenues	13,374	11,001	93	94	836	638		
Canada flexible generation								
Genesee Generating Station, Alberta [4]	2,670	2,114	96	83	138	125		
Clover Bar Energy Centre, Alberta	98	203	55	94	12	17		
Joffre, Alberta	167	164	98	100	14	15		
Shepard, Alberta	724	807	100	100	36	39		
Island Generation, British Columbia	–	300	100	100	1	3		
York Energy, Ontario [5]	16	19	100	100	N/A	N/A		
East Windsor, Ontario	11	5	98	93	7	8		
Goreway, Ontario	1,336	901	100	100	84	77		
EnPower, British Columbia	6	5	99	100	1	–		
BESS, Ontario [6]	1	N/A	96	N/A	6	N/A		
Alberta portfolio optimization	N/A	N/A	N/A	N/A	234	236		
	5,029	4,518	95	93	533	520	181	187
Canada renewables								
Quality Wind, British Columbia [5]	39	84	97	87	N/A	11		
Halkirk 1 Wind, Alberta	92	96	97	95	7	8		
Halkirk 2 Wind, Alberta [7]	–	N/A	–	N/A	–	N/A		
Whitla Wind, Alberta	215	234	96	96	10	12		
Strathmore Solar, Alberta	28	24	97	97	2	1		
Clydesdale Solar, Alberta	53	55	97	97	3	4		
Kingsbridge 1 Wind, Ontario	11	11	96	97	1	1		
Port Dover and Nanticoke Wind, Ontario [5]	18	37	97	97	N/A	6		
	456	541	97	95	23	43	18	27
Total Canada	**5,485**	**5,059**	**96**	**93**	**556**	**563**	**199**	**214**
U.S. flexible generation								
Decatur Energy, Alabama	685	1,287	67	100	39	44		
Arlington Valley, Arizona	917	832	100	97	39	36		
Midland Cogeneration, Michigan [5]	1,341	1,436	97	95	N/A	N/A		
Frederickson 1, Washington	264	258	100	97	7	6		
Harquahala, Arizona [5,8]	897	860	99	98	N/A	N/A		
La Paloma, California [8]	642	901	95	94	193	194		
Hummel Station, Pennsylvania [9]	2,143	N/A	100	N/A	130	N/A		
Rolling Hills, Ohio [9]	661	N/A	86	N/A	79	N/A		
PJM portfolio optimization and other U.S. trading [9]	N/A	N/A	N/A	N/A	9	6		
	7,550	5,574	93	96	496	286	307	219
U.S. renewables								
Beaufort Solar, North Carolina	8	5	99	94	1	1		
Bloom Wind, Kansas	121	137	92	92	10	11		
Macho Springs Wind, New Mexico	14	19	94	95	2	2		
New Frontier Wind, North Dakota	71	77	88	90	5	4		
Cardinal Point Wind, Illinois	56	65	89	75	4	7		
Buckthorn Wind, Texas	69	65	89	96	5	6		
	339	368	91	88	27	31	15	19
Total U.S.	**7,889**	**5,942**	**91**	**95**	**523**	**317**	**322**	**238**
Corporate [10]					5	5	(44)	(51)
Unrealized changes in fair value of commodity derivatives and emission credits					129	145		
Consolidated revenues and other income and adjusted EBITDA					**1,213**	**1,030**	**477**	**401**

	Nine months ended September 30,							
	2025	2024	2025	2024	2025	2024	2025	2024
	Electricity generation (GWh) [1]		Facility availability (%) [2]		Revenues and other income ($ millions) [3]		Adjusted EBITDA ($ millions) [3]	
Total electricity generation, average facility availability and facility revenues	31,952	28,413	92	94	1,959	1,756		
Canada flexible generation								
Genesee Generating Station, Alberta [4]	7,882	6,530	93	91	356	468		
Clover Bar Energy Centre, Alberta	314	497	71	69	28	48		
Joffre, Alberta	498	518	99	93	43	56		
Shepard, Alberta	2,081	2,179	99	91	98	125		
Island Generation, British Columbia	74	334	100	100	5	9		
York Energy, Ontario [5]	47	37	86	100	N/A	N/A		
East Windsor, Ontario	21	19	98	97	25	24		
Goreway, Ontario	2,823	2,252	96	94	275	225		
EnPower, British Columbia	20	14	100	95	2	1		
BESS, Ontario [6]	1	N/A	96	N/A	6	N/A		
Alberta portfolio optimization	N/A	N/A	N/A	N/A	747	714		
	13,761	12,380	93	91	1,585	1,670	554	529
Canada renewables								
Quality Wind, British Columbia [5]	141	264	98	94	N/A	36		
Halkirk 1 Wind, Alberta	313	311	96	94	24	30		
Halkirk 2 Wind, Alberta [7]	–	N/A	–	N/A	–	N/A		
Whitla Wind, Alberta	781	897	97	96	38	45		
Strathmore Solar, Alberta	71	62	96	97	4	3		
Clydesdale Solar, Alberta	134	139	97	97	9	11		
Kingsbridge 1 Wind, Ontario	71	58	95	94	6	5		
Port Dover and Nanticoke Wind, Ontario [5]	99	182	92	97	N/A	28		
	1,610	1,913	97	96	81	158	78	112
Total Canada	**15,371**	**14,293**	**94**	**93**	**1,666**	**1,828**	**632**	**641**
U.S. flexible generation								
Decatur Energy, Alabama	2,626	2,625	88	99	96	92		
Arlington Valley, Arizona	2,326	2,467	89	93	151	121		
Midland Cogeneration, Michigan [5]	3,613	4,178	95	94	N/A	N/A		
Frederickson 1, Washington	529	641	95	79	19	18		
Harquahala, Arizona [5,8]	1,268	1,193	89	91	N/A	N/A		
La Paloma, California [8]	1,310	1,495	89	94	403	302		
Hummel Station, Pennsylvania [9]	2,659	N/A	100	N/A	164	N/A		
Rolling Hills, Ohio [9]	821	N/A	89	N/A	100	N/A		
PJM portfolio optimization and other U.S. trading [9]	N/A	N/A	N/A	N/A	26	26		
	15,152	12,599	92	94	959	559	567	431
U.S. renewables								
Beaufort Solar, North Carolina	21	19	99	97	2	2		
Bloom Wind, Kansas	436	495	91	95	30	33		
Macho Springs Wind, New Mexico	93	101	95	96	12	12		
New Frontier Wind, North Dakota	277	273	91	89	17	16		
Cardinal Point Wind, Illinois	347	373	84	82	26	29		
Buckthorn Wind, Texas	255	260	92	96	20	19		
	1,429	1,521	90	91	107	111	73	76
Total U.S.	**16,581**	**14,120**	**91**	**95**	**1,066**	**670**	**640**	**507**
Corporate [10]					36	8	(106)	(135)
Unrealized changes in fair value of commodity derivatives and emission credits					(126)	417		
Consolidated revenues and other income and adjusted EBITDA					**2,642**	**2,923**	**1,166**	**1,013**

1 Gigawatt hours (GWh) of electricity generation reflects the Company's share of facility output and includes GWh discharged from BESS.

2 Facility availability represents the percentage of time in the period that the facility was available to generate power regardless of whether it was running and therefore is reduced by planned and unplanned outages.

3 The financial results by facility category, except for adjusted EBITDA, were prepared in accordance with GAAP. See Non-GAAP Financial Measures and Ratios.

4 Genesee repowered units 1 and 2 simple cycle commissioned May 3, 2024 and June 28, 2024, respectively and dual cycle commissioned November 18, 2024 and December 13, 2024, respectively. Genesee Units 1, 2 and 3 are now presented together as the Genesee Generating Station. 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) (see Regulatory and Government Matters), 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.

5 Quality Wind, York Energy, Port Dover and Nanticoke Wind, Midland Cogeneration and Harquahala are accounted for under the equity method. Capital Power's share of each facility's net income is included in income from equity-accounted investments on our consolidated statements of income. Capital Power's share of each facility's adjusted EBITDA is included in adjusted EBITDA above. Quality Wind and Port Dover and Nanticoke Wind were partially divested on December 20, 2024. Revenues and other income and adjusted EBITDA are included up until December 20, 2024, for Capital Power's full ownership. The equivalent of Capital Power's share of all of the equity-accounted facilities revenue and adjusted EBITDA was $135 million and $62 million, and $405 million and $175 million, for the three and nine months ended September 30, 2025 respectively, compared with $116 million and $61 million, and $325 million and $115 million for three and nine months ended September 30, 2024, respectively. The facilities revenues and adjusted EBITDA are not included in the above results.

6 York Energy and Goreway BESS projects commenced commercial operations on August 29, 2025 (see Significant Events).

7 Halkirk 2 Wind commenced partial operations in the fourth quarter of 2024 with commercial operations expected in the first quarter of 2026 (see Capital Expenditures and Investments and Significant Events).

8 Harquahala and La Paloma were acquired February 16, 2024 and February 9, 2024, respectively.

9 Hummel Station and Rolling Hills facilities were acquired June 9, 2025. Trading activity related to the optimization of these assets is included in PJM portfolio optimization and other U.S. trading.

10 Corporate revenues are partially offset by interplant category eliminations.

Power and natural gas energy pricing

	Three months ended September 30,		Nine months ended September 30,	
	2025	**2024**	**2025**	**2024**
Power prices				
PJM - Western Hub (US$/MWh) [1]	36.04	N/A	37.01	N/A
PJM - AEP Dayton Hub (US$/MWh) [1]	43.47	N/A	44.77	N/A
PJM realized power price average (US$/MWh) [1,2]	39.58	N/A	40.75	N/A
Alberta AESO ($/MWh)	51.30	55.36	43.90	66.56
Alberta realized power price average ($/MWh) [2]	72.68	75.53	73.45	78.72
Natural gas prices				
PJM - Transco Leidy (US$/GJ) [1]	2.16	N/A	2.19	N/A
PJM - Tetco ELA (US$/GJ) [1]	2.83	N/A	2.84	N/A
Alberta AECO ($/GJ)	0.63	0.65	1.43	1.24

1 Pricing for the nine months ended September 30, 2025 is from the date of acquisition of Hummel Station and Rolling Hills facilities in June 2025 (see Significant Events).

2 Realized power price is the average aggregate price realized through selling power generation into the spot market, the Company's commercial contracted sales and portfolio optimization activities. When long-term forward portfolio optimization hedges are transacted, they reflect the market's expectations for future period pricing. Ultimately, spot pricing may vary from expected forward pricing due to a number of factors resulting in realized power prices in a given period that can differ materially from spot pricing.

Canada flexible generation

Alberta spot price averaged $51 per MWh for the third quarter and $44 per MWh for the first nine months of 2025, compared to $55 per MWh and $67 per MWh in the same periods last year. Mild temperatures across the province throughout the majority of the period and improved thermal supply resulted in lower Alberta settled and captured pricing by our Alberta portfolio year-over-year.

Generation for the three and nine months ended September 30, 2025 increased compared to the same periods in the previous year while availability remained consistent due to the following net effect:

- increased generation at Genesee Generation Station due to incremental capacity gained from the repowering of units 1 & 2 which achieved commercial operations in the fourth quarter of 2024,
- increased availability and generation year-over-year at Goreway due to tighter market conditions with increased load demand, increased exports and colder weather early in 2025 compared to 2024,
- partially offset by lower dispatch and generation at Clover Bar Energy Centre, Joffre and Shepard due to lower year-over-year power pricing.

Lower revenues and other income for the nine months ended September 30, 2025, compared to the same period in 2024 were primarily due to reduced power pricing realized by the Alberta portfolio slightly offset by higher generation as listed above.

Adjusted EBITDA was favorable year-over-year due to lower emissions costs from reduced intensity driven by a shift to natural gas versus coal consumption at the Genesee Generating Station, which more than offset the lower power prices and higher gas prices realized in the Alberta portfolio in 2025 compared to 2024.

Canada renewables

While availability was consistent year-over-year, generation and revenues and other income and adjusted EBITDA were lower in 2025 primarily due to the renewable asset sell-down of the Quality Wind and Port Dover and Nanticoke facilities in the fourth quarter of 2024. Lower Alberta power prices further reduced revenues and other income and adjusted EBITDA at Halkirk and lower generation from lower wind resource in Alberta overall.

U.S. flexible generation

Generation for the three and nine months ended September 30, 2025 increased compared to the same periods in 2024 due to the following net effect:

- acquisition of the Hummel Station and Rolling Hills facilities in June 2025 (see Significant Events),
- full year of generation at the Harquahala and La Paloma facilities in 2025 that were acquired in February 2024, slightly offset by a planned outage at La Paloma in 2025,
- partially offset by the impact of higher fuel costs on MCV's position in the merit curve, resulting in lower dispatch.

Year-to-date and quarter-to-date availability compared to the same quarter last year is impacted by standard fall maintenance outages.

Revenues and other income and adjusted EBITDA for the three months ended September 30, 2025 were higher than the prior year due to the acquisition of Hummel Station and Rolling Hills facilities in June 2025 (see Significant Events). Results for the nine months ended September 30, 2025 were higher than prior year due to the acquisition, higher captured prices at La Paloma and Arlington as a result of various outages in the area, increased energy revenues at MCV, partially offset by a contracted reduction in the MCV power purchase capacity rate, and a favorable foreign exchange with a stronger U.S. currency.

U.S. renewables

The results of U.S. renewables remained relatively stable year-over-year.

Corporate

Corporate results include (i) costs of support services such as treasury, finance, internal audit, legal, people services, enterprise risk management, asset management, and environment, health and safety, and (ii) business development expenses. Cost recovery revenues are primarily intercompany revenues that are offset by interplant category transactions.

Net corporate revenues and other income for the three months ended September 30, 2025 were consistent with the same period in 2024. Net corporate revenues and other income for the nine months ended September 30, 2025, were higher compared to the same period in 2024, primarily due to insurance proceeds and government grant revenues received in 2025. Adjusted EBITDA for the three months ended September 30, 2025 was higher compared with the same period in 2024 primarily due to lower business development project fees in the current period. Adjusted EBITDA for the nine months ended September 30, 2025 was higher than the comparative period due to insurance proceeds received in 2025, lower salary costs that resulted from a reorganization late in 2024, and the lower business development project fees previously discussed, offset partially by higher share-based compensation in 2025 compared with the same period of last year as a result of increased valuations in 2025.

Unrealized changes in fair value of commodity derivatives and emission credits

($ millions)	Three months ended September 30,			
	2025	**2024**	**2025**	**2024**
Unrealized changes in fair value of commodity derivatives and emission credits	**Revenues and other income [1]**		**Income before tax [1]**	
Unrealized (losses) gains on Alberta power derivatives	(12)	38	(12)	35
Unrealized gains on U.S. power derivatives	126	129	87	109
Unrealized gains (losses) on natural gas derivatives	18	(15)	(80)	(58)
Unrealized (losses) gains on emission derivatives	(3)	(7)	9	(18)
Unrealized gains on emission credits held for trading	–	–	9	10
	129	**145**	**13**	**78**

($ millions)	Nine months ended September 30,			
	2025	**2024**	**2025**	**2024**
Unrealized changes in fair value of commodity derivatives and emission credits	**Revenues and other income [1]**		**Income before tax [1]**	
Unrealized (losses) gains on Alberta power derivatives	(129)	332	(128)	328
Unrealized gains on U.S. power derivatives	14	124	13	104
Unrealized losses on natural gas derivatives	(8)	(31)	(22)	(120)
Unrealized losses on emission derivatives	(3)	(8)	(31)	(25)
Unrealized losses on emission credits held for trading	–	–	(8)	(1)
	(126)	**417**	**(176)**	**286**

[1] Revenues and other income and adjusted EBITDA include realized changes in the fair value of commodity derivatives and emission credits but exclude unrealized changes in these values. The unrealized changes are also excluded from our adjusted EBITDA metric.

When a derivative instrument settles, the unrealized fair value changes recorded in prior periods for that instrument are reversed from this category. The gain or loss realized upon settlement is then reflected in adjusted EBITDA for the relevant facility category.

During the three and nine months ended September 30, 2025, we recognized unrealized losses on Alberta power derivatives of $12 million and $128 million, respectively, mainly due to impacts of increasing forward prices on net forward sale contracts. During the comparable periods in September 30, 2024, we recognized unrealized gains of $35 million and $328 million, respectively, mainly due to the impacts of decreasing forward prices on net forward sale contracts.

During the three and nine months ended September 30, 2025, we recognized unrealized gains on U.S. power derivatives of $87 million and $13 million, respectively, mainly due to decreasing forward pricing on net forward sale contracts in California, partially offset by unrealized losses on contracts at our Hummel Station, Rolling Hills and U.S. renewable facilities. During the comparable periods in September 30, 2024, we recognized unrealized gains of $109 million and $104 million, respectively, mainly due to the impact of decreased forward prices on forward sale contracts associated with the majority of the Company's U.S. renewables facilities and La Paloma.

During the three and nine months ended September 30, 2025, we recognized unrealized losses on natural gas derivatives of $80 million and $22 million, respectively, due to impacts of decreasing forward pricing on net forward buy contracts in the U.S. During the comparable periods in September 30, 2024, we recognized unrealized losses of $58 million and $120 million, respectively, due to the impacts of decreased forward pricing on forward purchase contracts.

During the nine months ended September 30, 2025, we recognized unrealized losses of $31 million on emissions derivatives due to the impact of decreased forward pricing on our U.S. emissions derivatives on forward net purchases. During the three and nine months ended September 30, 2024 we recognized unrealized losses on emissions derivatives of $18 million and $25 million, respectively, mainly due to decreased forward prices on forward purchases.

Consolidated other expenses and non-controlling interests

($ millions)	Three months ended September 30,		Nine months ended September 30,	
	2025	2024	2025	2024
Net finance expense	(92)	(65)	(217)	(160)
Depreciation and amortization	(157)	(124)	(421)	(366)
Impairment	–	(27)	–	(27)
Foreign exchange (loss) gain	(7)	5	16	(9)
Loss on disposals and other transactions	(5)	(5)	(12)	(20)
Other items from equity-accounted investments [1]	(37)	(32)	(110)	(91)
Income tax expense	(35)	(53)	(29)	(153)
Net loss attributable to non-controlling interests	(1)	(1)	(1)	–

[1] Includes finance expense, depreciation expense and fair value changes on derivatives from equity-accounted investments.

Net finance expense

Higher net finance expense for the three and nine months ended September 30, 2025 compared with the same periods in the prior year largely reflects higher interest due to the increased loans and borrowings outstanding from draws on the $600 million credit facility, $1.7 billion senior notes issued during 2025 (see Significant Events) and the $450 million and $600 million notes issued during the second half of 2024. This was further impacted by lower capitalized interest during 2025 due to higher construction activity for the Genesee repowering project in 2024.

Depreciation and amortization

Higher depreciation and amortization for the three and nine months ended September 30, 2025 was due to the Goreway uprate which achieved commercial operation in the second quarter of 2025, the acquisitions of the Hummel Station and Rolling Hills facilities in the second quarter of 2025, and La Paloma in the first quarter of 2024 and the commissioning of Genesee Repower 1 and 2 in the fourth quarter of 2024.

Foreign exchange (loss) gain

The Company recognized foreign exchange losses for the three months ended September 30, 2025 due to an increase in the USD to CAD exchange rates during the period, compared to gains in the same quarter last year due to a decrease in rates in the prior year. Foreign exchange gains were recognized for the nine months ended September 30, 2025 due to a decrease in the USD to CAD exchange rates during the period. Comparatively, exchange rates during the period ending September 30, 2024 were increasing resulting in foreign exchange losses.

Other items from equity-accounted investments

Other items from equity-accounted investments includes Capital Power's share of finance expense, depreciation expense and unrealized changes in fair value of derivative instruments from our York Energy, Quality Wind, Port Dover and Nanticoke Wind, Midland Cogeneration and Harquahala equity-accounted investments. Other items from equity-accounted investments increased compared with 2024 primarily due to Quality Wind and Port Dover and Nanticoke Wind becoming equity-accounted investments upon Capital Power's partial divestiture of these assets in the fourth quarter of 2024.

Income tax expense

Income tax expense for the three and nine months ended September 30, 2025, decreased compared with the corresponding periods in 2024 primarily due to lower overall consolidated net income before tax.

FINANCIAL POSITION

The following highlights changes in the consolidated statements of financial position from December 31, 2024 to September 30, 2025 were as follows:

($ millions)	September 30, 2025	December 31, 2024
Assets		
Current assets	1,451	1,948
Non-current assets:		
Property, plant and equipment	11,155	8,061
Equity-accounted investments	1,081	1,096
Intangible assets and goodwill	637	744
Right-of-use assets	138	118
Derivative financial instruments	430	412
Government grant receivable	315	380
Deferred tax assets	37	26
Other assets	101	145
Total assets	15,345	12,930
Liabilities and equity		
Current liabilities	1,960	1,353
Non-current liabilities:		
Derivative financial instruments	615	494
Loans and borrowings	5,960	4,819
Lease liabilities	155	134
Deferred tax liabilities	915	863
Provisions	425	373
Deferred revenue and other liabilities	307	323
Total liabilities	10,337	8,359
Share capital	5,009	4,301
Deficit	(222)	(74)
Other reserves	229	349
Equity attributable to shareholders of the Company	5,016	4,576
Non-controlling interests	(8)	(5)
Total equity	5,008	4,571
Total liabilities and equity	15,345	12,930

Net working capital decreased from December 31, 2024 to September 30, 2025 by $1,104 million, mainly driven by:

- reduction in cash balances as described in Liquidity and Capital Resources,
- reclassifying the current portion of loans and borrowing from non-current,
- partially offset by deferred payments on capital project costs for the construction of Halkirk 2 Wind.

The Company has $1.9 billion of available liquidity from credit facilities if needed to meet obligations as they become due (2024 - $1.0 billion) (see Liquidity and Capital Resources).

Property, plant and equipment increased from December 31, 2024 to September 30, 2025 primarily due to the additions of the Hummel Station and Rolling Hills facilities. Intangible assets and goodwill decreased from December 31, 2024 to September 30, 2025 primarily due to amortization and the use of emissions credits for compliance purposes.

Non-current loans and borrowings increased from December 31, 2024 to September 30, 2025 due to draws on the credit facility obtained in the current quarter and the $1.7 billion of senior notes issued in the second quarter of 2025 (see Significant Events), partially offset by reclassifying the current portion of loans and borrowings.

LIQUIDITY AND CAPITAL RESOURCES

($ millions)	Nine months ended September 30,		
Cash inflows (outflows)	**2025**	**2024**	**Change**
Operating activities	757	706	51
Investing activities	(3,477)	(1,846)	(1,631)
Financing activities	2,082	(129)	2,211

Operating activities

Cash flows from operating activities for the nine months ended September 30, 2025 were higher than the same period in 2024 mainly due to the net impact of:

- cash inflows from the contributions of Hummel Station and Rolling Hills in June 2025 (see Significant Events),
- lower cash taxes paid mainly due to tax depreciation and lower overall consolidated net income before tax,
- increased distributions received from equity-accounted investments,
- partially offset by increased interest paid mainly due to increased interest on loans and borrowings.

Investing activities

Cash flows used in investing activities for the nine months ended September 30, 2025 were higher than the same period in 2024 due to the acquisitions of the Hummel Station and Rolling Hills facilities in June 2025 (see Significant Events).

Financing activities

Cash flows from financing activities for the nine months ended September 30, 2025 were higher than the same period in 2024 due to the proceeds received from the $1.7 billion senior notes issued and increased share capital from the bought deal offering and private placement in the second quarter of 2025 (see Significant Events) and lower repayments of loans and borrowings.

Capital expenditures and investments

($ millions)	Pre-2025 actual	Nine months ended September 30,	Balance of 2025 estimated [1,2]	Actual or projected total [2]	Targeted completion
Repowering of Genesee 1 and 2 [3]	1,487	60	3 to 103	1,550 to 1,650	Achieved commercial operations fourth quarter of 2024 and the project is substantially complete
Halkirk 2 Wind [4]	298	17	16	333	First quarter of 2026 (previously fourth quarter of 2025)
Ontario growth projects	356	156	48	576	York and Goreway BESS completed in the third quarter of 2025 East Windsor Expansion in the second quarter of 2026
Maple Leaf Solar	12	37	34	230	First quarter of 2027
Bear Branch Solar	8	20	23	106	Fourth quarter of 2026
Hornet Solar	15	73	72	205	Third quarter of 2026
Commercial initiatives [5]	268	17	18		
Development sites and projects	63	(1)	–		
Subtotal growth projects		**379**	**214 to 314**		
Sustaining – plant maintenance		93			
Total capital expenditures [6]		**472**			
Emission credits held for compliance		18			
Capitalized interest		(31)			
Additions of property, plant and equipment and other assets		**459**			
Change in other non-cash investing working capital and non-current liabilities		117			
Purchase of property, plant and equipment and other assets, net		**576**			

1 The Company's 2025 estimated capital expenditures include only expenditures for previously announced growth projects and exclude other potential new development projects.

2 Projected capital expenditures to be incurred over the life of the ongoing projects are based on management's estimates. Projected capital expenditures for development sites are not reflected beyond the current period until specific projects reach the advanced development stage.

3 Projected costs for the project including incurred post-commercial operations date, remain subject to the dispute resolution with the contractor described under Contingent Liabilities, Other Legal Matters and Provisions.

4 Targeted completion date is management's estimate of the timeline to commission the site subject to the Alberta Utilities Commission's release of its work suspension order that resulted from the nacelle and rotor at one of the turbines that fell from the tower in November 2024. The commercial operation date required by the PPA for this project was not met. The agreement with Saputo was terminated and resulted in a termination fee of $5 million incurred in the third quarter of 2025 (see Significant Events).

5 Commercial initiatives include expected spending on various projects designed to either increase the capacity or efficiency of their respective facilities or to reduce emissions.

6 Capital expenditures include capitalized interest. Capital expenditures excluding capitalized interest are presented on the consolidated statements of cash flows as purchase of property, plant and equipment and other assets, net.

Financing activities

See Liquidity and Capital Resources for significant changes in current quarter and year-to-date financing activities.

The Company's credit facilities consisted of:

($ millions)		At September 30, 2025			At December 31, 2024		
	Maturity Timing	Total facilities	Credit facility utilization	Available	Total facilities	Credit facility utilization	Available
Committed credit facilities [1]	2030	2,100	174	1,926	1,000	–	1,000
Bilateral demand credit facilities	N/A	1,408			1,421		
Letters of credit outstanding			559			608	
		1,408	559	849	1,421	608	813
Demand credit facilities	N/A	25	–	25	25	–	25
		3,533	**733**	**2,800**	**2,446**	**608**	**1,838**

[1] Committed credit facilities include letters of credit, bankers' acceptances and bank loans outstanding.

In the third quarter of 2025, the Company entered into a 2-year revolving credit agreement with a total commitment of $600 million, maturing in 2027 (see Significant Events). The funds can be drawn in Canadian or US dollars. Interest is floating and is based on the type of draw, plus margin.

In the second quarter of 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. The available credit facilities provide adequate funding for ongoing development projects.

Capital Power has surety capacity to accommodate, as part of normal course of operations, the issuance of bonds for certain capital projects and contracts. At September 30, 2025 and December 31, 2024, $99 million of bonds were issued under these facilities.

Capital Power has the following corporate credit ratings which were affirmed in May 2025:

Rating Agency	Rating	Outlook	Definition
Standard and Poor's	BBB -	Stable	Exhibits adequate capacity to meet financial commitments; however, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitments.
DBRS Limited	BBB (low)	Stable	Adequate credit quality and the capacity for the payment of financial obligations is considered acceptable but the entity may be vulnerable to future events.
Fitch Ratings	BBB -	Stable	Expectation of default risk is low. The capacity for payment of financial commitments is considered adequate, but adverse business or economic conditions are more likely to impair this capacity.

The above credit ratings are investment grade credit ratings which enhance Capital Power's ability to re-finance existing debt as it matures and to access cost competitive capital for future growth.

During the second quarter of 2025, we obtained a credit rating by Fitch Ratings to support our long-term growth and broaden our access in the U.S. debt capital markets. Fitch assigned Capital Power a first-time issuer default rating of BBB- with a Stable outlook, reinforcing our investment-grade profile.

Off-statement of financial position arrangements

At September 30, 2025, Capital Power has $559 million of outstanding letters of credit for collateral support for trading operations, conditions of certain service agreements, and to satisfy legislated reclamation requirements and $99 million of surety bonds issued for certain capital projects and contracts.

If Capital Power were to terminate these off-statement of financial position arrangements, the penalties or obligations would not have a material impact on our financial condition, results of operations, liquidity, capital expenditures or resources.

Capital resources

($ millions)	As at	
	September 30, 2025	**December 31, 2024**
Loans and borrowings	6,670	4,976
Lease liabilities [1]	173	151
Less cash and cash equivalents	(204)	(865)
Net debt	6,639	4,262
Share capital	5,009	4,301
Deficit and other reserves	7	275
Non-controlling interests	(8)	(5)
Total equity	5,008	4,571
Total capital	**11,647**	**8,833**

[1] Includes the current portion presented within deferred revenue and other liabilities.

Capital Power uses a short-form base shelf prospectus to provide it with the ability, market conditions permitting, to obtain new debt and equity capital when required. Under the short-form base shelf prospectus dated June 12, 2024, Capital Power may issue an unlimited number of common shares, preferred shares, subscription receipts exchangeable for common shares and/or other securities of Capital Power and/or debt securities, including up to $3 billion of medium-term notes by way of a prospectus supplement. This prospectus expires in July 2026.

If the Canadian and U.S. financial markets become unstable, Capital Power's ability to raise new capital, to meet our financial requirements, and to refinance indebtedness under existing credit facilities and debt agreements may be adversely affected. Capital Power has credit exposure relating to various agreements, particularly with respect to our power purchase agreement, energy supply contract, trading and supplier counterparties. While Capital Power continues to monitor our exposure to significant counterparties, there can be no assurance that all counterparties will be able to meet their commitments. See Risks and Risk Management for additional discussion on recent developments pertaining to these risks and Capital Power's risk mitigation strategies.

CONTINGENT LIABILITIES, OTHER LEGAL MATTERS AND PROVISIONS

Refer to the Contractual Obligations, Contingent Liabilities, Other Legal Matters and Provisions discussion in our 2024 Integrated Annual Report for details on ongoing legal matters.

Contingent liabilities

Capital Power and our subsidiaries are subject to various legal claims that arise in the normal course of business. Management believes that the aggregate contingent liability of the Company arising from these claims is immaterial.

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.

RISKS AND RISK MANAGEMENT

For the nine months ended September 30, 2025, Capital Power's business, operational and climate-related risks and opportunities have remained consistent with those described in our 2024 Integrated Annual Report other than risks around tariffs imposed by the U.S. and Canada. See Regulatory and Government Matters for management's assessment of the impact of these tariffs. Future changes to tariffs imposed by both the U.S. and Canada may materially change management's current assessment.

Details around Capital Power's approach to risk management, including principal risk factors and the associated risk mitigation strategies, are described in our 2024 Integrated Annual Report. These factors and strategies have not changed materially in the nine months ended September 30, 2025.

In addition, the Company's acquisition of the Hummel Station and Rolling Hills facilities, expands the Company's operations into the PJM Interconnection market and presents new operational and market risks.

Market Exposure to the Hummel Station and Rolling Hills facilities

In PJM, the day-ahead and real-time markets are nodal markets which are based on the supply and demand of the energy market as a whole and of each individual node on the grid, taking into account the physical constraints of the transmission system. As a result, the nodal market incorporates local losses and congestion into the price that generators receive, exposing assets to basis risk compared to the major hub and/or zonal prices where hedges are typically available. Additionally, participants in the PJM capacity market must commit to being available to supply capacity or reduce demand in the energy market. However, there is no guarantee that the Hummel Station and Rolling Hills facilities will have the required capacity when needed the most, exposing them to potential penalties for non-performance if they fail to meet their commitments during periods of grid system stress or emergencies.

Merchant markets are cyclical and there is risk that future merchant revenues fall short of expectations. Given the current increase in capacity prices, PJM is making efforts to dampen capacity prices going forward, including but not limited to, proposing a lower price cap in future capacity auctions. Merchant exposure risk can be mitigated for resource adequacy through advanced contracting and risk on energy margin can be mitigated through heat rate call options and other products. Risk mitigation steps may shift risk from merchant energy to other risks, such as gas basis or operational risks. However, there remains a risk that future PJM market rule changes may not allow operators, including Capital Power with respect to the Hummel Station and Rolling Hills facilities, to earn market-based returns.

The PJM BRA results for the 2026/2027 year were posted on July 22, 2025 (see Significant Events). While the Hummel Station facility and the four operational units at the Rolling Hills facility are currently capable of meeting their capacity commitments, unforeseen circumstances may prevent the facilities from meeting their future capacity commitments (see Regulatory and Government Matters – PJM market).

ENVIRONMENTAL MATTERS

Capital Power recorded decommissioning provisions of $367 million at September 30, 2025 ($346 million at December 31, 2024) for our generation facilities and the Genesee mine as it is obliged to remove the facilities at the end of their useful lives and restore the facility and mine sites to their original condition. Decommissioning provisions for the Genesee mine were incurred over time as new areas were mined, and a portion of the liability is settled over time as areas are reclaimed prior to final pit reclamation. The timing of reclamation activities could vary and the amount of decommissioning provisions could change depending on potential future changes in environmental regulations.

At September 30, 2025, Capital Power has forward contracts to purchase environmental credits totaling $1,094 million and forward contracts to sell environmental credits totaling $958 million in future years. Included within these forward purchases and sales are net purchase amounts which will be used to comply with applicable environmental regulations and net sale amounts related to other emissions trading activities.

REGULATORY AND GOVERNMENT MATTERS

Refer to the Regulatory Matters discussion in the Company’s 2024 Integrated Annual Report for further details that supplement the recent developments discussed below:

United States

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 will face 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, and a reclassification to “serious” nonattainment levels can occur any time after February 3, 2025, which would result in 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.

The U.S. EPA proposed to rescind the 2009 Endangerment Finding, a legal precedent that determined the accumulation of greenhouse gases in the atmosphere endangers people’s health, and thus, the EPA is required to regulate such emissions under the Clean Air Act.

The EPA has also proposed to terminate the Greenhouse Gas Reporting Program (GHGRP) and suspend reporting requirements until the current program ends in 2034. 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; Greencastle in Indiana; and Nolin Hills in Oregon. 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)

During the first quarter of 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.

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. 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.

PJM market

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 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. 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 August 2025, PJM held a Critical Issue Fast Path workshop on large load additions. The conceptual proposal recommends the creation of a Non-Capacity-Backed Load (NCBL) option for large new loads, aiming to allow data centres to interconnect quicker without the need for multi-year capacity procurement obligations. It also creates economic incentives for data centres to contribute supply through demand response, providing a natural market-based solution rather than relying on the artificial reclassification of load under the NCBL option. PJM is targeting a December 2025 FERC filing, with changes going into effect for the 2028-2029 delivery year. Management will continue to monitor changes to the PJM market structure and report as needed.

Canada

Alberta

Alberta Electric System Operator (AESO) Restructured Energy Market (REM)

On August 27, 2025 the AESO released the final high-level design for REM. The final design introduces increased price caps for dispatchable assets (offer cap rising to $1,500/MWh and 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.

Connection for large load projects in Alberta

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 engagement on the AESO’s connection processes, planning, operations, markets, tariff and reliability. Management is actively involved in these data centre engagements and will continue to monitor as further details develop.

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

On May 12, 2025, the GoA 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 removes 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.

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.

Optimal transmission planning (OTP)

Following the Alberta government's July 2024 policy direction to shift from a zero-congestion to an OTP standard, the AESO launched stakeholder engagement in the second quarter of 2025. Management participated in two AESO-led sprints which focused on refining the OTP framework and introduced the Transmission Reinforcement Payment (TRP), which is intended to replace the Generating Unit Owner's Contribution (GUOC) – an upfront payment made by generators to fund transmission infrastructure. As part of this engagement, the AESO has been consulting on financial transmission rights (FTRs) to hedge congestion risk with the move to LMP. Management anticipates further details will be made available later this year as rule drafting is expected before year-end.

On July 15, 2025 the GoA directed the AESO to adopt LMP and allocate financial transmission rights (FTRs) to incumbent generators. The AESO started consultations on FTRs 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. The AESO has also started to consult OTP and in September published its recommended approach including how it will assess benefits and costs for transmission development. Further consultation on transmission reinforcement payments is anticipated to start in the fourth quarter of 2025 and will address the cost generators will be assessed to connect to the grid. Management is active in all transmission policy and planning consultations.

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, 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

Genesee repowered units 1 and 2 simple cycle commissioned May 3, 2024 and June 28, 2024, respectively and dual cycle commissioned November 18, 2024 and December 13, 2024, respectively. Genesee Units 1, 2 and 3 are presented together as the Genesee Generating Station. 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 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, a technical solution to enable an increase to the generating output of each facility 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.

Ontario

Market Renewal Program (MRP)

The IESO'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. 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.

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 will participate in the engagement, which will run through November 2025, and continue 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 to monitor changes.

M2T procurement

This spring, 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.

USE OF JUDGMENTS AND ESTIMATES

In preparing the condensed interim consolidated financial statements, management made judgments, estimates and assumptions that affect the application of Capital Power's accounting policies and the reported amount of assets, liabilities, income and expenses. Actual results may differ from these estimates. There have been no significant changes to Capital Power's use of judgments and estimates as described in our 2024 Integrated Annual Report.

FINANCIAL INSTRUMENTS

The classification, carrying amounts and fair values of financial instruments held at September 30, 2025 and December 31, 2024 were as follows:

($ millions)		September 30, 2025		December 31, 2024	
	Fair value hierarchy level [1]	Carrying amount	Fair value	Carrying amount	Fair value
Financial assets:					
Amortized cost					
Cash and cash equivalents	N/A	204	204	865	865
Trade and other receivables [2]	N/A	692	692	546	546
Government grant receivable [3]	Level 2	400	391	438	400
Fair value through profit or loss					
Derivative financial instruments [3]	See below	678	678	601	601
Fair value through other comprehensive income					
Derivative financial instruments [3]	See below	32	32	55	55
Financial liabilities:					
Amortized cost					
Trade and other payables	N/A	768	768	751	751
Loans and borrowings [3]	Level 2	6,670	7,008	4,976	5,244
Fair value through profit or loss					
Derivative financial instruments [3]	See below	862	862	621	621
Fair value through other comprehensive income					
Derivative financial instruments [3]	See below	22	22	20	20

[1] Fair values for Level 1 financial assets and liabilities are based on unadjusted quoted prices in active markets for identical instruments while fair values for Level 2 financial assets and liabilities are generally based on indirectly observable prices. Level 3 valuations are determined by appropriate subject matter experts and reviewed by the Company's commodity risk group and by management.

[2] Includes income taxes recoverable and excludes current portion of government grant receivable.

[3] Includes current and non-current portion.

Risk management and hedging activities

There have been no material changes in the nine months ended September 30, 2025 to our risk management and hedging activities as described in our 2024 Integrated Annual Report.

The derivative financial instruments assets and liabilities held at September 30, 2025 compared with December 31, 2024 and used for risk management purposes were measured at fair value and consisted of the following:

($ millions)		At September 30, 2025				
	Fair value hierarchy level	Commodity cash flow hedges	Commodity non-hedges	Interest rate cash flow hedges	Interest rate non-hedges	Total
Derivative financial instruments assets	Level 2	27	585	5	–	617
	Level 3	–	93	–	–	93
		27	678	5	–	710
Derivative financial instruments liabilities	Level 2	(2)	(590)	(20)	(2)	(614)
	Level 3	–	(270)	–		(270)
		(2)	(860)	(20)	(2)	(884)
Net derivative financial instruments assets (liabilities)		**25**	**(182)**	**(15)**	**(2)**	**(174)**

($ millions)		At December 31, 2024				
	Fair value hierarchy level	**Commodity cash flow hedges**	**Commodity non-hedges**	**Interest rate cash flow hedges**	**Foreign exchange cash flow hedges**	**Total**
Derivative financial instruments assets	Level 2	45	465	4	6	520
	Level 3	–	136	–	–	136
		45	601	4	6	656
Derivative financial instruments liabilities	Level 2	(4)	(329)	(16)	–	(349)
	Level 3	–	(292)	–	–	(292)
		(4)	(621)	(16)	–	(641)
Net derivative financial instruments assets (liabilities)		**41**	**(20)**	**(12)**	**6**	**15**

Commodity, interest rate and foreign exchange derivatives designated as accounting hedges

Unrealized gains and losses from fair value changes on commodity, interest rate and foreign exchange derivatives that qualify and are elected for hedge accounting are recorded in other comprehensive income (loss). When realized, they are reclassified to net income as revenues, energy purchases and fuel, finance expense or foreign exchange gains and losses as appropriate. For interest rate derivatives used to hedge the interest rate on a future debt issuance, realized gains or losses are deferred within accumulated other comprehensive income (loss) and recognized within finance expense over the life of the debt, consistent with the interest expense on the hedged debt. For foreign exchange derivatives hedging cash flow variability from foreign currency fluctuations on future capital expenditures, realized gains and losses are also deferred within accumulated other comprehensive income (loss) and then recorded in property, plant and equipment and amortized through depreciation and amortization over the hedged asset's estimated useful life.

Commodity, interest rate and foreign exchange derivatives not designated as accounting hedges

The change in fair values of commodity derivatives not designated as hedges is primarily due to changes in forward power, natural gas and REC prices and their impact within the Canada and U.S. flexible generation and renewables portfolios. Unrealized and realized gains and losses for fair value changes on commodity derivatives that do not qualify for hedge accounting are recorded in net income as revenues or energy purchases and fuel.

Unrealized and realized gains and losses on foreign exchange derivatives and interest rate derivatives that are not designated as hedges for accounting purposes are recorded in net income as foreign exchange gains or losses and net finance expense, respectively.

DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROL OVER FINANCIAL REPORTING

With the exception of the acquisitions of Hummel Station and Rolling Hills (see Significant Events), which are being integrated into Capital Power's systems of internal controls, there were no significant changes in Capital Power's disclosure controls and procedures and internal controls over financial reporting that occurred during the nine months ended September 30, 2025 that have materially affected or are reasonably likely to materially affect disclosures of required information and internal control over financial reporting.

In accordance with National Instrument 52-109, management's evaluation of and conclusions on the effectiveness of internal control over financial reporting did not include the internal controls of the acquired businesses of Hummel Station, LLC and Rolling Hills Generating, LLC. The financial results are included in the Company's September 30, 2025 consolidated financial statements because these entities were acquired by the Company through a business combination during the second quarter of 2025. The aggregate assets represent 20% of the Company's total assets as at September 30, 2025, and the aggregate liabilities represent 1% of the Company's total liabilities as at September 30, 2025. Gross revenue earned from the date of acquisition to September 30, 2025, represents 10% of the Company's gross revenue, and 17% for the quarter ended September 30, 2025.

SUMMARY OF QUARTERLY RESULTS

	Three months ended							
	Sep 2025	**Jun 2025**	**Mar 2025**	**Dec 2024**	**Sep 2024**	**Jun 2024**	**Mar 2024**	**Dec 2023**
Electricity generation (GWh)								
Canada flexible generation	5,029	3,933	4,799	3,596	4,518	3,417	4,445	4,312
Canada renewables	456	557	597	704	541	696	676	742
U.S. flexible generation	7,550	4,026	3,575	4,540	5,574	3,909	3,116	3,066
U.S. renewables	339	506	584	568	368	581	572	572
Total electricity generation	13,374	9,022	9,555	9,408	11,001	8,603	8,809	8,692
Facility availability (%)								
Canada flexible generation	95	91	94	87	93	88	93	95
Canada renewables	97	97	96	96	95	97	95	95
U.S. flexible generation	93	96	85	88	96	93	94	89
U.S. renewables	91	89	90	93	88	92	92	95
Total average facility availability	93	93	90	89	94	91	94	93
Revenues and other income ($ millions)								
Canada flexible generation	533	472	580	523	520	473	677	666
Canada renewables	23	28	30	56	43	54	61	70
U.S. flexible generation	496	213	250	198	286	138	135	84
U.S. renewables	27	37	41	37	31	38	40	39
Corporate [1]	5	19	14	9	5	2	3	27
Unrealized changes in fair value of commodity derivatives and emission credits	129	(328)	73	30	145	69	203	98
Total revenues and other income	**1,213**	**441**	**988**	**853**	**1,030**	**774**	**1,119**	**984**
Adjusted EBITDA [2]								
Canada flexible generation [3]	181	166	207	200	187	163	179	209
Canada renewables [3]	18	27	33	42	27	41	44	56
U.S. flexible generation [3]	307	141	119	123	219	128	84	46
U.S. renewables	15	27	31	26	19	29	28	29
Corporate	(44)	(39)	(23)	(61)	(51)	(38)	(46)	(24)
Total adjusted EBITDA [2]	**477**	**322**	**367**	**330**	**401**	**323**	**289**	**316**

1 Revenues are partially offset by interplant category revenue eliminations.

2 Adjusted EBITDA is a non-GAAP financial measure. See Non-GAAP Financial Measures and Ratios.

3 Canada flexible generation includes adjusted EBITDA from York Energy joint venture. Canada renewables include adjusted EBITDA from Quality Wind and Port Dover and Nanticoke Wind joint ventures. U.S. flexible generation includes adjusted EBITDA from Midland Cogeneration and Harquahala joint ventures.

Financial highlights

($ millions except per share amounts)	Three months ended							
	Sep 2025	Jun 2025	Mar 2025	Dec 2024	Sep 2024	Jun 2024	Mar 2024	Dec 2023
Revenues and other income	1,213	441	988	853	1,030	774	1,119	984
Net income (loss)	153	(131)	150	242	178	76	205	95
Net income (loss) attributable to shareholders of the Company	154	(132)	151	240	179	75	205	97
Basic earnings (loss) per share	0.94	(0.92)	1.03	1.76	1.32	0.51	1.58	0.74
Diluted earnings (loss) per share [1]	0.94	(0.92)	1.03	1.75	1.32	0.51	1.57	0.74
Adjusted EBITDA [2,3]	477	322	367	330	401	323	289	316
AFFO [2]	369	235	218	182	315	178	149	165
AFFO per share ($) [2]	2.37	1.55	1.57	1.38	2.42	1.37	1.21	1.39
Net cash flows from operating activities	404	143	210	438	236	136	334	(18)
Purchase of property, plant and equipment and other assets, net	147	141	288	395	231	226	218	244

1 Diluted earnings (loss) per share was calculated after giving effect to outstanding share purchase options.

2 The consolidated financial highlights, except for adjusted EBITDA, AFFO and AFFO per share were prepared in accordance with GAAP. See Non-GAAP Financial Measures and Ratios.

3 Includes adjusted EBITDA from the York Energy, Midland Cogeneration and Harquahala equity-accounted investments. Quality Wind and Port Dover and Nanticoke Wind were partially divested on December 20, 2024, and then became equity-accounted investments (see Significant Events in the Company's 2024 Integrated Annual Report). Due to the proximity to December 31, 2024, adjusted EBITDA relating to the equity-accounted investments period during the quarter was immaterial.

Quarterly revenues, net income and cash flows from operating activities are affected by seasonal weather conditions, fluctuations in U.S. dollar exchange rates relative to the Canadian dollar, power and natural gas prices, planned and unplanned facility outages and items outside the normal course of operations. Net income (loss) is also affected by changes in the fair value of our power, natural gas, interest rate and foreign exchange derivative contracts.

Factors impacting results for the previous quarters

Please refer to our 2024 Integrated Annual Report for significant events and items which affected results for the previous quarters.

SHARE AND PARTNERSHIP UNIT INFORMATION

Quarterly common share trading information

The Company's common shares are listed on the Toronto Stock Exchange under the symbol CPX and began trading on June 26, 2009.

	Three months ended							
	Sep 2025	**Jun 2025**	**Mar 2025**	**Dec 2024**	**Sep 2024**	**Jun 2024**	**Mar 2024**	**Dec 2023**
Share price ($/common share)								
High	66.06	57.92	64.95	68.73	50.88	41.99	39.43	39.88
Low	54.03	41.87	44.68	49.20	38.33	33.90	35.55	35.11
Close	65.35	54.80	47.83	63.72	49.17	38.99	38.21	37.84
Volume of shares traded (millions)	43.8	48.7	59.2	38.0	28.3	33.5	25.9	26.0

Outstanding share and partnership unit data

At October 24, 2025, the Company had 155.606 million common shares, 5 million Cumulative Rate Reset Preference Shares (Series 1), 6 million Cumulative Rate Reset Preference Shares (Series 3), 8 million Cumulative Rate Reset Preference Shares (Series 5), and one special limited voting share outstanding. Assuming full conversion of the outstanding and issuable share purchase options to common shares and ignoring exercise prices, the outstanding and issuable common shares at October 24, 2025 were 156.818 million. The outstanding special limited voting share is held by EPCOR.

At October 24, 2025, CPLP had 323.305 million general partnership units outstanding and 1,203.255 million common limited partnership units outstanding. All of the outstanding general partnership units and the outstanding common limited partnership units are held by the Company.

ADDITIONAL INFORMATION

Additional information relating to Capital Power Corporation, including the Company's annual information form and other continuous disclosure documents, is available on SEDAR+ at www.sedarplus.com.

Condensed Interim Consolidated Financial Statements of

CAPITAL POWER CORPORATION

(Unaudited, in millions of Canadian dollars)

Nine months ended September 30, 2025 and 2024

CAPITAL POWER CORPORATION

Condensed Interim Consolidated Financial Statements
Nine months ended September 30, 2025 and 2024

Condensed Interim Consolidated Financial Statements:

Condensed Interim Consolidated Statements of Income	46
Condensed Interim Consolidated Statements of Comprehensive Income	47
Condensed Interim Consolidated Statements of Financial Position	48
Condensed Interim Consolidated Statements of Changes in Equity	49
Condensed Interim Consolidated Statements of Cash Flows	51
Notes to the Condensed Interim Consolidated Financial Statements	52

CAPITAL POWER CORPORATION

Condensed Interim Consolidated Statements of Income
(Unaudited, in millions of Canadian dollars, except per share amounts)

	Three months ended September 30, 2025	Three months ended September 30, 2024	Nine months ended September 30, 2025	Nine months ended September 30, 2024
Revenues	$ 1,197	$ 1,013	$ 2,559	$ 2,863
Other income	16	17	83	60
Energy purchases and fuel	(632)	(456)	(1,381)	(1,342)
Gross margin	581	574	1,261	1,581
Other raw materials and operating charges	(55)	(54)	(161)	(151)
Staff costs and employee benefits expense	(48)	(51)	(142)	(150)
Depreciation and amortization	(157)	(124)	(421)	(366)
Other administrative expense	(54)	(51)	(188)	(150)
Impairment	–	(27)	–	(27)
Foreign exchange (loss) gain	(7)	5	16	(9)
Operating income	260	272	365	728
Net finance expense (note 4)	(92)	(65)	(217)	(160)
Income from equity-accounted investments	25	29	65	64
Loss on disposals and other transactions	(5)	(5)	(12)	(20)
Income before tax	188	231	201	612
Income tax expense	(35)	(53)	(29)	(153)
Net income	$ 153	$ 178	$ 172	$ 459
Attributable to:				
Non-controlling interests	$ (1)	$ (1)	$ (1)	$ –
Shareholders of the Company	$ 154	$ 179	$ 173	$ 459
Earnings per share attributable to shareholders of the Company:				
Basic (note 6)	$ 0.94	$ 1.32	$ 1.02	$ 3.39
Diluted (note 6)	$ 0.94	$ 1.32	$ 1.01	$ 3.38

See accompanying notes to the condensed interim consolidated financial statements

CAPITAL POWER CORPORATION

Condensed Interim Consolidated Statements of Comprehensive Income
(Unaudited, in millions of Canadian dollars)

	Three months ended September 30, 2025	Three months ended September 30, 2024	Nine months ended September 30, 2025	Nine months ended September 30, 2024
Net income	$ 153	$ 178	$ 172	$ 459
Other comprehensive income (loss):				
Items that may be reclassified subsequently to net income:				
Unrealized gain (loss) on derivative instruments[1] (note 7)	1	(8)	7	82
Reclassification of gains on derivative instruments to net income[2] (note 7)	(5)	(9)	(23)	(17)
Equity-accounted investments[3]	(1)	(9)	(7)	(3)
Net investment in foreign subsidiaries:				
Unrealized gains (losses)	78	(38)	(97)	30
Other comprehensive income (loss) for the period, net of tax	73	(64)	(120)	92
Total comprehensive income	$ 226	$ 114	$ 52	$ 551
Attributable to:				
Non-controlling interests	$ (1)	$ (1)	$ (1)	$ –
Shareholders of the Company	$ 227	$ 115	$ 53	$ 551

[1] For the three and nine months ended September 30, 2025, net of income tax expense of $1 and of $4, respectively. For the three and nine months ended September 30, 2024, net of income tax recovery of $2 and expense of $16, respectively.

[2] For the three and nine months ended September 30, 2025, net of reclassification of income tax expense of $2 and $7, respectively. For the three and nine months ended September 30, 2024, net of reclassification of income tax expense of $3 and $5, respectively.

[3] For the three and nine months ended September 30, 2025, net of income tax recovery of $1 and $3, respectively. For the three and nine months ended September 30, 2024, net of income tax recovery of $4 and $1, respectively.

See accompanying notes to the condensed interim consolidated financial statements

CAPITAL POWER CORPORATION

Condensed Interim Consolidated Statements of Financial Position
(Unaudited, in millions of Canadian dollars)

	September 30, 2025	December 31, 2024
Assets		
Current assets:		
Cash and cash equivalents	$ 204	$ 865
Trade and other receivables	588	507
Income taxes recoverable (note 5)	153	97
Inventories	226	235
Derivative financial instruments (note 7)	280	244
	1,451	1,948
Non-current assets:		
Property, plant and equipment (note 3 and 11)	11,155	8,061
Equity-accounted investments	1,081	1,096
Intangible assets and goodwill	637	744
Right-of-use assets	138	118
Derivative financial instruments (note 7)	430	412
Government grants receivable	315	380
Deferred tax assets	37	26
Other assets	101	145
Total assets	$ 15,345	$ 12,930
Liabilities and equity		
Current liabilities:		
Trade and other payables	$ 768	$ 751
Derivative financial instruments (note 7)	269	147
Loans and borrowings (note 8)	710	157
Provisions (note 11)	110	85
Deferred revenue and other liabilities	103	213
	1,960	1,353
Non-current liabilities:		
Derivative financial instruments (note 7)	615	494
Loans and borrowings (note 8)	5,960	4,819
Lease liabilities	155	134
Deferred tax liabilities	915	863
Provisions	425	373
Deferred revenue and other liabilities	307	323
Total liabilities	10,337	8,359
Share capital (note 9)	5,009	4,301
Deficit	(222)	(74)
Other reserves	229	349
Equity attributable to shareholders of the Company	5,016	4,576
Non-controlling interests	(8)	(5)
Total equity	5,008	4,571
Total liabilities and equity	$ 15,345	$ 12,930

See accompanying notes to the condensed interim consolidated financial statements

CAPITAL POWER CORPORATION

Condensed Interim Consolidated Statements of Changes in Equity
(Unaudited, in millions of Canadian dollars)

	Share capital (note 9)	Cash flow hedges[1]	Cumulative translation reserve[1]	Defined benefit plan actuarial losses[1]	Employee benefits reserve	Deficit	Equity attributable to shareholders of the Company	Non-controlling interests	Total
Balance, January 1, 2025	$ 4,301	$ 108	$ 240	$ (9)	$ 10	$ (74)	$ 4,576	$ (5)	$ 4,571
Net income	—	—	—	—	—	173	173	(1)	172
Other comprehensive loss	—	(23)	(97)	—	—	—	(120)	—	(120)
Total comprehensive income	—	(23)	(97)	—	—	173	53	(1)	52
Issue of share capital, net[2]	653	—	—	—	—	—	653	—	653
Common share dividends (note 9)	—	—	—	—	—	(299)	(299)	—	(299)
Preferred share dividends, net of tax[3] (note 9)	—	—	—	—	—	(22)	(22)	—	(22)
Dividends reinvested	55	—	—	—	—	—	55	—	55
Distributions to non-controlling interests	—	—	—	—	—	—	—	(2)	(2)
Balance, September 30, 2025	$ 5,009	$ 85	$ 143	$ (9)	$ 10	$ (222)	$ 5,016	$ (8)	$ 5,008

1 Accumulated other comprehensive income. Other reserves on the statements of financial position are the aggregate of accumulated other comprehensive income and the employee benefits reserve.

2 Net of share issue costs of $29, income tax recovery of $7, and share options exercised of $8.

3 Including income tax expense of $2.

See accompanying notes to the condensed interim consolidated financial statements

CAPITAL POWER CORPORATION

Condensed Interim Consolidated Statements of Changes in Equity
(Unaudited, in millions of Canadian dollars)

	Share capital (note 9)	Cash flow hedges[1]	Cumulative translation reserve[1]	Defined benefit plan actuarial losses[1]	Employee benefits reserve	Deficit	Equity attributable to shareholders of the Company	Non-controlling interests	Total
Balance, January 1, 2024	$ 3,524	$ 48	$ 22	$ (10)	$ 10	$ (404)	$ 3,190	$ (4)	$ 3,186
Net income	–	–	–	–	–	459	459	–	459
Other comprehensive income	–	62	30	–	–	–	92	–	92
Total comprehensive income	–	62	30	–	–	459	551	–	551
Issue of share capital, net[2]	387	–	–	–	–	–	387	–	387
Common share dividends (note 9)	–	–	–	–	–	(245)	(245)	–	(245)
Preferred share dividends, net of tax[3] (note 9)	–	–	–	–	–	(26)	(26)	–	(26)
Preferred share redemption	(150)	–	–	–	–	–	(150)	–	(150)
Dividends reinvested	50	–	–	–	–	–	50	–	50
Share options exercised	15	–	–	–	–	–	15	–	15
Distributions to non-controlling interests	–	–	–	–	–	–	–	(2)	(2)
Balance, September 30, 2024	$ 3,826	$ 110	$ 52	$ (10)	$ 10	$ (216)	$ 3,772	$ (6)	$ 3,766

1 Accumulated other comprehensive income. Other reserves on the statements of financial position are the aggregate of accumulated other comprehensive loss and the employee benefits reserve.

2 Net of share issue costs of $16 and income tax recovery of $3.

3 Including income tax expense of $2.

See accompanying notes to the condensed interim consolidated financial statements

CAPITAL POWER CORPORATION

Condensed Interim Consolidated Statements of Cash Flows
(Unaudited, in millions of Canadian dollars)

	Nine months ended September 30, 2025	Nine months ended September 30, 2024
Cash flows from operating activities:		
Net income	$ 172	$ 459
Non-cash adjustments:		
Depreciation and amortization	421	366
Net finance expense	217	160
Impairment	–	27
Fair value changes on commodity derivative instruments and emission credits held for trading	176	(286)
Foreign exchange (gains) losses	(16)	9
Income tax expense	29	153
Income from equity-accounted investments	(65)	(64)
Tax-equity attributes	(55)	(55)
Other	26	15
Change in fair value of derivative instruments, cash settlement	(7)	17
Distributions received from equity-accounted investments	47	24
Interest paid	(202)	(132)
Income taxes recovered (paid)	14	(17)
Other	(23)	23
Change in non-cash operating working capital	23	7
Net cash flows from operating activities	757	706
Cash flows used in investing activities:		
Purchase of property, plant and equipment and other assets, net[1]	(576)	(675)
Business acquisition, net of acquired cash (note 3)	(2,974)	(908)
Acquisition of equity-accounted investment	–	(316)
Government grants received	60	50
Other	13	3
Net cash flows used in investing activities	(3,477)	(1,846)
Cash flows from (used in) financing activities:		
Net proceeds from issue of loans and borrowings[2] (note 8)	1,809	1,042
Repayment of loans and borrowings	(78)	(754)
Capitalized interest paid	(31)	(44)
Issue of share capital[3]	646	6
Dividends paid (note 9)	(248)	(205)
Redemption of preferred shares (note 9)	–	(150)
Income taxes paid on preferred share dividends	(8)	(10)
Other	(6)	(12)
Distributions to non-controlling interests	(2)	(2)
Net cash flows from (used in) financing activities	2,082	(129)
Foreign exchange loss on cash held in foreign currency	(23)	(1)
Net decrease in cash and cash equivalents	(661)	(1,270)
Cash and cash equivalents, beginning of period	865	1,423
Cash and cash equivalents, end of period	$ 204	$ 153

[1] Reflects total additions, increased by $117 for changes in non-cash investing working capital and other non-current assets and liabilities (2024 – reduced by $118).

[2] Net of deferred debt issue costs of $15 (2024 - $8).

[3] Net of share issue costs of $29 (2024 - $8).
See accompanying notes to the condensed interim consolidated financial statements

1. Reporting entity

Capital Power Corporation (the Company or Capital Power) develops, acquires, owns, and operates utility-scale renewable and flexible generation (natural gas generation assets and energy storage) facilities and manages its related electricity and natural gas portfolios by undertaking trading and marketing activities.

The registered and head office of the Company is located at 10423 101 Street, Edmonton, Alberta, Canada, T5H 0E9. The common shares of the Company are traded on the Toronto Stock Exchange under the symbol "CPX".

Interim results will fluctuate due to plant maintenance schedules, the seasonal demands for electricity and changes in energy prices. Consequently, interim results are not necessarily indicative of annual results.

2. Basis of presentation and use of judgements and estimates

These condensed interim consolidated financial statements have been prepared by management in accordance with International Accounting Standards (IAS) 34, *Interim Financial Reporting*. The condensed interim consolidated financial statements do not include all of the information required for full annual financial statements and should be read in conjunction with the Company's 2024 annual consolidated financial statements prepared in accordance with International Financial Reporting Standards (IFRS) Accounting Standards as issued by the International Accounting Standards Board.

The accounting policies applied, the significant judgements made, and the key sources of estimation uncertainty are consistent with those described in the Company's 2024 annual consolidated financial statements, except as described in note 12.

These condensed interim consolidated financial statements were approved and authorized for issue by the Board of Directors on October 28, 2025.

3. Business combination

Acquisition of Hummel Station, LLC and Rolling Hills Generating, LLC

On June 9, 2025, the Company acquired 100% of the equity interests in:

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

The acquisition expands the Company's operations into the Pennsylvania-New Jersey-Maryland 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, which are expected to be finalized in the fourth quarter of 2025.

The valuation techniques used for measuring the fair value of material assets acquired include significant estimates associated with the depreciated replacement cost approach for property, plant and equipment, which includes estimates of replacement cost and reflects adjustments for physical deterioration as well as functional and economic obsolescence.

3. Business combination, continued

The preliminary allocation of the purchase price to the assets acquired and liabilities assumed based on their estimated fair values was as follows:

		June 9, 2025
Cash and cash equivalents	$	1
Trade and other receivables[1]		21
Inventories		15
Property, plant and equipment		3,003
Right-of-use asset		30
Other assets		12
Trade and other payables		(19)
Derivative financial instrument liabilities		(7)
Lease liabilities		(30)
Provisions		(52)
Fair value of net assets acquired	$	2,974

[1] The fair value of trade and other receivables approximates the carrying value.

The preliminary purchase price allocation reflects management's best estimate of the fair value of assets acquired and liabilities assumed based on the information obtained and analysis performed to date. Management continues to obtain specific information to support the valuation of working capital, property, plant and equipment, intangible assets and provisions. If new information obtained within one year after the acquisition date about facts and circumstances that existed at the acquisition date identifies adjustments to the above amounts, or any additional provisions that existed at the date of acquisition, then the accounting for the acquisition will be revised.

The Company assumed a provision to return a portion of amounts previously received by Hummel Station, LLC, from the Federal Energy Regulatory Commission (FERC) for reactive supply and voltage control from generation sources service overpayments in the estimated amount of $34 million, included in provisions. The payment will be due eighteen months after final acceptance from FERC is received. Provisions also include decommissioning provisions of $18 million.

Revenues and net income from the date of acquisition to September 30, 2025, were $268 million and $113 million, respectively. If the acquisition had occurred on January 1, 2025, consolidated revenues and consolidated net income would have been $3,109 million and $302 million, respectively..

For the nine months ended September 30, 2025, the Company incurred acquisition costs of $43 million which were recorded on the Company's consolidated statements of income primarily as other administrative expense.

4. Net finance expense

	Three months ended September 30,		Nine months ended September 30,	
	2025	2024	2025	2024
Interest expense				
Interest on loans and borrowings	$ 93	$ 72	$ 239	$ 200
Capitalized interest	(10)	(14)	(31)	(44)
Total interest expense	83	58	208	156
Other finance expense (income)				
Accretion on decommissioning provisions	4	3	9	8
Interest on lease liabilities	2	1	8	7
Interest on government grants receivable	(2)	(2)	(6)	(7)
Other	5	5	(2)	(4)
Net finance expense	$ 92	$ 65	$ 217	$ 160

5. Income tax

Income tax expense differs from the amount that would be computed by applying the federal and provincial income tax rates as a result of the following:

	Three months ended September 30,		Nine months ended September 30,	
	2025	2024	2025	2024
Net income before tax	$ 188	$ 231	$ 201	$ 612
Income tax at the statutory rate of 23%	43	53	46	141
Increase (decrease) resulting from:				
Non-deductible expenses and non-taxable income	4	(4)	–	3
Amounts attributable to non-controlling interests, equity-accounted investments, and tax-equity interests	(7)	–	(14)	(5)
Change in unrecognized tax benefits	–	2	–	(3)
Statutory and other rate differences	5	4	2	10
Other	(10)	(2)	(5)	7
Income tax expense	$ 35	$ 53	$ 29	$ 153

During the second quarter of 2025, there was a reclassification of $36 million from other assets to income taxes recoverable resulting from the filing of a portion of the expected Clean Technology investment tax credit claim with the Canada Revenue Agency for the 2024 taxation year.

6. Earnings per share

The earnings and weighted average number of common shares used in the calculation of basic and diluted earnings per share were as follows:

	Three months ended September 30, 2025	Three months ended September 30, 2024	Nine months ended September 30, 2025	Nine months ended September 30, 2024
Earnings for the period attributable to shareholders	$ 154	$ 179	$ 173	$ 459
Preferred share dividends[1]	(8)	(7)	(22)	(26)
Earnings available to common shareholders	$ 146	$ 172	$ 151	$ 433
Weighted average number of common shares	155,349,949	130,269,528	148,642,287	127,837,004
Basic earnings per share	$ 0.94	$ 1.32	$ 1.02	$ 3.39
Weighted average number of common shares	155,349,949	130,269,528	148,642,287	127,837,004
Effect of dilutive share purchase options	424,617	265,218	346,508	229,713
Diluted weighted average number of common shares	155,774,566	130,534,746	148,988,795	128,066,717
Diluted earnings per share	$ 0.94	$ 1.32	$ 1.01	$ 3.38

[1] Includes preferred share dividends declared and related taxes.

7. Derivative financial instruments and hedge accounting

Derivative financial and non-financial instruments are held for the purpose of energy and natural gas purchases, merchant trading or financial risk management.

The Company has elected to apply hedge accounting to certain derivatives used to manage commodity price risk relating to electricity prices, interest rate risk relating to future borrowings, and foreign exchange risk relating to future capital investment in U.S. dollars.

The derivative instruments assets and liabilities used for risk management purposes consist of the following:

	September 30, 2025					
	Energy and emission allowances		Interest rate		Foreign exchange	
	cash flow hedges	non-hedges	cash flow hedges	non-hedges	cash flow hedges	Total
Derivative instruments assets:						
Current	$ 19	$ 260	$ 1	$ –	$ –	$ 280
Non-current	8	418	4	–	–	430
Derivative instruments liabilities:						
Current	(1)	(260)	(8)	–	–	(269)
Non-current	(1)	(600)	(12)	(2)	–	(615)
Net fair value	$ 25	$ (182)	$ (15)	$ (2)	$ –	$ (174)
Net notional buys (sells) (millions):						
Megawatt hours of electricity	(3)	(77)				
Gigajoules of natural gas purchased[1]		524				
Gigajoules of natural gas basis swaps		58				
Metric tonnes of emission allowances		7				
Number of renewable energy credits		(8)				
Interest rate swaps			$ 1,418	$ 174		
Forward currency buys (U.S. dollars)					$ 10	
Range of remaining contract terms (years)	0.1 to 3.3	0.1 to 21.3	0.1 to 3.0	0.1 to 2.8	0.1 to 0.3	

[1] Added 179 Gigajoules as part of the acquisition of Hummel Station, LLC and Rolling Hills Generating, LLC (note 3).

7. Derivative financial instruments and hedge accounting, continued

	December 31, 2024					
	Energy and emission allowances		Interest rate		Foreign exchange	
	cash flow hedges	non-hedges	cash flow hedges	non-hedges	cash flow hedges	Total
Derivative instruments assets:						
Current	$ 28	$ 208	$ 2	$ –	$ 6	$ 244
Non-current	17	393	2	–	–	412
Derivative instruments liabilities:						
Current	(2)	(138)	(7)	–	–	(147)
Non-current	(2)	(483)	(9)	–	–	(494)
Net fair value	$ 41	$ (20)	$ (12)	$ –	$ 6	$ 15
Net notional buys (sells) (millions):						
Megawatt hours of electricity	(3)	(49)				
Gigajoules of natural gas purchased		197				
Gigajoules of natural gas basis swaps		63				
Metric tonnes of emission allowances		10				
Number of renewable energy credits		(11)				
Interest rate swaps			$ 800	$ 94		
Forward currency buys (U.S. dollars)					$ 84	
Range of remaining contract terms (years)	0.1 to 4.0	0.1 to 22.0	0.1 to 2.1	0.2 to 1.0	0.1 to 0.6	

7. Derivative financial instruments and hedge accounting, continued

Unrealized and realized pre-tax gains and (losses) on derivative instruments recognized in other comprehensive income (loss) and net income (loss) are as follows:

	Three months ended September 30, 2025		Three months ended September 30, 2024	
	Unrealized gains (losses)	Realized gains (losses)	Unrealized gains (losses)	Realized gains
Energy cash flow hedges	$ –	$ 6	$ 6	$ 8
Energy and emission allowances non-hedges	3	68	68	37
Interest rate cash flow hedges	(6)	4	(25)	4
Interest rate non-hedges	(1)	–	(1)	–
Foreign exchange cash flow hedges	1	(3)	(3)	–
Foreign exchange non-hedges	–	11	–	–

	Nine months ended September 30, 2025		Nine months ended September 30, 2024	
	Unrealized (losses) gains	Realized gains (losses)	Unrealized gains (losses)	Realized gains (losses)
Energy cash flow hedges	$ (18)	$ 23	$ 60	$ 11
Energy and emission allowances non-hedges	(169)	183	287	57
Interest rate cash flow hedges	4	10	(11)	11
Interest rate non-hedges	(1)	–	(1)	–
Foreign exchange cash flow hedges	(5)	(3)	27	–
Foreign exchange non-hedges	–	–	–	(2)

The following realized and unrealized gains and losses on derivative financial instruments are included in the Company's statements of income:

	Three months ended September 30,		Nine months ended September 30,	
	2025	2024	2025	2024
Revenues	$ 311	$ 285	$ 300	$ 644
Energy purchases and fuel	(234)	(172)	(263)	(289)
Foreign exchange gain (loss)	8	–	(3)	(2)
Net finance expense	3	3	9	10

Net after tax gains and losses related to derivative instruments designated as energy and interest rate cash flow hedges are expected to settle and be reclassified to net income in the following periods:

	September 30, 2025
Within one year	$ 43
Between one and five years	48
After five years	17
	$ 108

8. Loans and borrowings

Private offering of senior notes

On May 28, 2025, the Company closed a private offering of $1.7 billion (US$1.2 billion) aggregate principal amount of senior notes (the offering), guaranteed by the Company and certain of the Company's subsidiaries. The offering consisted 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.

Credit facilities

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 US dollars. Interest is floating and is based on the type of draw, plus margin.

On June 6, 2025, the Company amended the terms of its syndicated credit facility and terminated its $300 million unsecured club credit facility. The amendments to the syndicated credit facility included an increase to the maximum principal amount from $700 million to $1.5 billion, an extension of one year to June 2030, and a change to the modified consolidated net tangible assets to consolidated net tangible assets ratio covenant to be based on total assets. No amounts were drawn on the facilities at the time of the amendment.

On April 14, 2025, in anticipation of the acquisition (note 3), the Company entered into a commitment letter with TD Securities Inc. for fully underwritten $2 billion senior unsecured term loans. As the Company amended the terms of its syndicated credit facility, the commitment letter was no longer required and has been terminated.

9. Share capital

Issued and fully paid shares

On April 22, 2025, the Company completed a bought deal offering of 11,902,500 common shares and 3,455,000 common shares on a private placement basis, at an offering price of $43.45 per common share for total gross proceeds of approximately $667 million.

Common and preferred share dividends

	Dividends declared							
	For the three months ended September 30,				For the nine months ended September 30,			
	2025		2024		2025		2024	
	Per share	Total	Per share	Total	Per share	Total	Per share	Total
Common	$ 0.6910	$ 107	$ 0.6519	$ 86	$ 1.9948	$ 299	$ 1.8819	$ 245
Preference:								
Series 1	0.1638	1	0.1638	1	0.4914	3	0.4914	3
Series 3	0.4288	3	0.4288	2	1.2863	8	1.2863	8
Series 5	0.4144	3	0.4144	3	1.2433	9	1.2433	9
Series 11[1]	–	–	–	–	–	–	0.7188	4

[1] On June 30, 2024, the Company redeemed all of its issued and outstanding 5.75% cumulative rate reset preference shares, Series 11. The final quarterly dividend was paid on the redemption date.

	Dividends paid[2]							
	For the three months ended September 30,				For the nine months ended September 30,			
	2025		2024		2025		2024	
	Per share	Total	Per share	Total	Per share	Total	Per share	Total
Common[3]	$ 0.6519	$ 101	$ 0.6150	$ 80	$ 1.9557	$ 283	$ 1.8450	$ 231

[2] Preference share dividends are declared and paid in the same period.

[3] For the nine months ended September 30, 2025 common dividends consist of $228 million paid in cash and $55 million through the Company's dividend re-investment plan (nine months ended September 30, 2024, $181 million paid in cash and $50 million through the Company's dividend re-investment plan).

9. Share capital, continued

Dividend Increase

On July 29, 2025, the Company's Board of Directors approved an increase of 6% in the annual dividend for holders of its common shares, from $0.6519 per common share to $0.6910 per common share. This increased common share dividend will commence with the third quarter 2025 quarterly dividend payment on October 31, 2025 to shareholders of record at the close of business on September 29, 2025.

10. Financial Instruments

Fair values

The Company classifies and measures its cash and cash equivalents, trade and other receivables, and trade and other payables at amortized cost and their fair values are not materially different from their carrying amounts due to their short-term nature.

The classification, carrying amount and fair value of the Company's other financial instruments are summarized as follows:

		September 30, 2025		December 31, 2024	
	Fair value hierarchy level	Carrying amount	Fair value	Carrying amount	Fair value
Financial assets[1]					
Government grants receivable[2]	Level 2	$ 400	$ 391	$ 438	$ 400
Financial liabilities[1]					
Loans and borrowings	Level 2	$ 6,670	$ 7,008	$ 4,976	$ 5,244

[1] Includes current portion.

[2] Government grants receivable includes $229 million related to off-coal compensation from the Government of Alberta (GoA). As described in the Company's 2024 annual consolidated financial statements, the GoA previously withheld approximately $2.7 million from each of the payments from 2017 to 2024, which the Company disputed. The annual payment amounts recorded by the Company were previously reduced by $1.5 million for 2017 to 2024. During the second quarter of 2025, the Company settled the disputed amounts with the GoA and received a cash payment of $10 million, which resulted in a decrease to the amount previously recorded of approximately $5 million, recorded through loss on disposals and other transactions.

Fair value hierarchy

Fair value represents the Company's estimate of the price at which a financial instrument could be sold or transferred between market participants in an orderly transaction at the measurement date. Fair value measurements recognized in the consolidated statements of financial position are categorized into levels within the fair value hierarchy based on the nature of the valuation inputs, and precedence is given to observable inputs over unobservable inputs. The determination of fair value requires judgment and is based on market information where available and appropriate. The valuation techniques used by the Company in determining the fair value of its financial instruments are the same as those used at December 31, 2024.

Fair value measurements are categorized into levels based upon the lowest level of significant input, as described in the Company's 2024 annual consolidated financial statements. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment.

The Company recognizes transfers between levels of the fair value hierarchy at the end of the reporting period during which the change has occurred. There were no transfers between Level 1 and Level 2.

The table below presents the Company's financial instruments measured at fair value on a recurring basis in the consolidated statements of financial position, classified using the fair value hierarchy described in the Company's 2024 annual consolidated financial statements.

10. Financial Instruments, continued

	September 30, 2025			
	Level 1	Level 2	Level 3	Total
Derivative financial instruments assets	$ –	$ 617	$ 93	$ 710
Derivative financial instruments liabilities	–	(614)	(270)	(884)

	December 31, 2024			
	Level 1	Level 2	Level 3	Total
Derivative financial instruments assets	$ –	$ 520	$ 136	$ 656
Derivative financial instruments liabilities	–	(349)	(292)	(641)

Fair values of derivative instruments are determined using valuation techniques, inputs, and assumptions as described in the Company's 2024 annual consolidated financial statements. It is possible that the assumptions used in establishing fair value amounts will differ from future outcomes and the impact of such variations could be material.

Valuation techniques used in Level 3 fair value measurements

The Company has various commodity, renewable energy agreements, and renewable energy credit (REC) contracts with terms that extend beyond a liquid trading period. Certain of these contracts include notional quantities based on future actual generation of underlying generation facilities. As forward market prices and actual generation are not available for the full period of these contracts, their fair values are derived using forecasts based on internal modelling and as a result, are classified as Level 3 fair value measurements. The fair values of the Company's commodity derivatives classified as Level 3 are determined by applying mark-to-forecast models. The valuation models used to calculate the fair values of the derivative financial instrument assets and liabilities within Level 3 are prepared by internal subject matter experts and are reviewed by the Company's commodity risk group and management. The valuation techniques and the associated inputs are assessed on a regular basis for ongoing reasonability.

The table below presents ranges for the Company's Level 3 inputs:

	September 30, 2025	December 31, 2024
REC pricing (per certificate) – Solar	$3 to $261	$3 to $201
REC pricing (per certificate) – Wind	$3 to $6	$3 to $8
Forward power pricing (per MWh) – Solar	$21 to $165	$15 to $113
Forward power pricing (per MWh) – Wind	$16 to $103	$15 to $142
Average monthly notional generation (MWh) – Solar	6,503 to 12,892	6,554 to 13,044
Average monthly notional generation (MWh) – Wind	16,077 to 61,348	16,540 to 60,060

The table below presents the change to the fair value of Level 3 derivative instruments based on a 10% change in the respective input:

	September 30, 2025	December 31, 2024
REC pricing – Solar	$ 1	$ 2
REC pricing – Wind	2	4
Forward power pricing – Solar	15	4
Forward power pricing – Wind	42	59
Generation – Solar	–	4
Generation – Wind	10	13

10. Financial instruments, continued

Continuity of Level 3 balances

The Company classifies financial instruments in Level 3 of the fair value hierarchy when there is at least one significant unobservable input used in the valuation model. In addition to these unobservable inputs, the valuation model for Level 3 instruments also relies on a number of inputs that are observable either directly or indirectly. Accordingly, the unrealized gains and losses shown below include changes in the fair value related to both observable and unobservable inputs. The following table summarizes the changes in the fair value of financial instruments classified in Level 3:

	September 30, 2025	December 31, 2024
At January 1[1]	$ (156)	$ (297)
Additions	(12)	27
Unrealized and realized (losses) gains included in net income[2]	(46)	137
Settlements	32	(15)
Transfers[3]	–	1
Foreign exchange gains (losses)	5	(9)
At end of period	$ (177)	$ (156)

[1] The fair value of derivative instruments assets and liabilities are presented on a net basis.

[2] Recorded in revenues.

[3] Relates to transfers from Level 3 to Level 2 when pricing inputs become readily observable. There were no transfers from Level 2 to Level 3.

Gains and losses associated with Level 3 balances may not necessarily reflect the underlying exposures of the Company. As a result, unrealized gains and losses from Level 3 financial instruments are often offset by unrealized gains and losses on financial instruments that are classified in other levels.

11. Commitments and contingencies

The Company and its subsidiaries are subject to various legal claims that arise in the normal course of business. Management believes that the aggregate contingent liability of the Company arising from these claims is immaterial.

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.

12. Segment information

The Company reassessed its reportable segments due to changes in internal reporting for performance results provided to the Company's Chief Operating Decision Maker (CODM). Comparative segment information has been restated to conform to the current period’s presentation.

The Company identifies its reportable segments both by business activity and by geographical areas and has four reportable segments described below:

- Flexible generation – Flexible generation refers to the ability of power-generating facilities to quickly adjust output based on grid demand. These dispatchable power sources include natural gas facilities and energy storage. Reportable segments associated with this activity include Canada flexible generation, and U.S. flexible generation. The Company actively trades in North American power, natural gas and environmental markets. The majority of the Company’s trading activities relate directly to assets or portfolios of assets within the flexible generation segments and accordingly are reported within these segments. Specifically, trading related to Alberta flexible generation portfolio of assets is included within Canada flexible generation, and trading to optimize U.S. facilities as well as other U.S. trading is included within U.S. flexible generation.
- Renewables – Renewable generation includes the Company's wind and solar facilities. Reportable segments associated with this activity include Canada renewables and U.S. renewables.

12. Segment information, continued

Corporate includes costs of support services such as treasury, finance, internal audit, legal, people services, enterprise risk management, asset management, and environment, health and safety.

The following tables provide each reportable segment's results in the format that the Company's CODM reviews in making operating decisions and assessing performance. The CODM assesses the performance of the operating segments based on adjusted EBITDA, which reflects earnings before net finance expense, income tax expense, depreciation and amortization, impairments, foreign exchange gains or losses, finance expense and depreciation from our joint venture interests, gains or losses on disposals, unrealized changes in fair value of commodity derivatives and emission credits, and other items that are not reflective of the long-term performance of the Company's underlying business. The tables below show the reconciliation of the total segment adjusted EBITDA to income before tax, as reported under IFRS.

	Three months ended September 30, 2025								
	Canada flexible generation[1]	Canada renewables[1]	U.S. flexible generation[1]	U.S. renewables	Corporate	Total	Equity-accounted investments[1]	Reclass adjustments	Consolidated IFRS financials
Revenues and other income	$ 538	$ 18	$ 778	$ 9	$ 5	$ 1,348	$ (135)	$ –	$ 1,213
Energy purchases and fuel	(327)	(2)	(354)	(3)	–	(686)	54	–	(632)
Other raw materials and operating charges	(20)	(6)	(32)	(5)	(1)	(64)	9	–	(55)
Staff costs and employee benefits expense	(10)	–	(8)	(1)	(33)	(52)	4	–	(48)
Other administrative expense	(14)	(5)	(18)	(4)	(19)	(60)	6	–	(54)
Remove unrealized changes in fair value of commodity derivatives	14	13	(59)	19	–	(13)	–	13	–
Remove other non-recurring items	–	–	–	–	4	4	–	(4)	–
Adjusted EBITDA[2]	181	18	307	15	(44)	477			
Depreciation and amortization									(157)
Foreign exchange loss									(7)
Losses on disposals and other transactions									(5)
Net finance expense									(92)
Income from equity-accounted investments									25
Income before tax									$ 188

12. Segment information, continued

	Three months ended September 30, 2024								
	Canada flexible generation[1]	Canada renewables[1]	U.S. flexible generation[1]	U.S. renewables	Corporate	Total	Equity-accounted investments[1]	Reclass adjustments	Consolidated IFRS financials
Revenues and other income	$ 550	$ 44	$ 462	$ 85	$ 5	$ 1,146	$ (116)	$ –	$ 1,030
Energy purchases and fuel	(310)	(1)	(179)	(1)	–	(491)	35	–	(456)
Other raw materials and operating charges	(24)	(8)	(23)	(6)	(1)	(62)	8	–	(54)
Staff costs and employee benefits expense	(13)	–	(8)	–	(33)	(54)	3	–	(51)
Other administrative expense	(14)	(6)	(12)	(6)	(22)	(60)	9	–	(51)
Remove unrealized changes in fair value of commodity derivatives	(2)	(2)	(21)	(53)	–	(78)	–	78	–
Adjusted EBITDA[2]	187	27	219	19	(51)	401			
Depreciation and amortization									(124)
Impairments									(27)
Foreign exchange gain									5
Loss on disposals and other transactions									(5)
Net finance expense									(65)
Income from equity-accounted investments									29
Income before tax									$ 231

12. Segment information, continued

	Nine months ended September 30, 2025								
	Canada flexible generation[1]	Canada renewables[1]	U.S. flexible generation[1]	U.S. renewables	Corporate	Total	Equity-accounted investments[1]	Reclass adjustments	Consolidated IFRS financials
Revenues and other income	$ 1,517	$ 76	$ 1,294	$ 124	$ 36	$ 3,047	$ (405)	$ –	$ 2,642
Energy purchases and fuel	(911)	(5)	(638)	3	–	(1,551)	170	–	(1,381)
Other raw materials and operating charges	(61)	(18)	(89)	(14)	(5)	(187)	26	–	(161)
Staff costs and employee benefits expense	(37)	(2)	(27)	(2)	(86)	(154)	12	–	(142)
Other administrative expense	(43)	(13)	(47)	(15)	(92)	(210)	22	–	(188)
Remove unrealized changes in fair value of commodity derivatives	85	40	74	(23)	–	176	–	(176)	–
Remove other non-recurring items[3]	4	–	–	–	41	45	–	(45)	–
Adjusted EBITDA[2]	554	78	567	73	(106)	1,166			
Depreciation and amortization									(421)
Foreign exchange gain									16
Losses on disposals and other transactions									(12)
Net finance expense									(217)
Income from equity-accounted investments									65
Income before tax									$ 201

12. Segment information, continued

	Nine months ended September 30, 2024								
	Canada flexible generation[1]	Canada renewables[1]	U.S. flexible generation[1]	U.S. renewables	Corporate	Total	Equity-accounted investments[1]	Reclass adjustments	Consolidated IFRS financials
Revenues and other income	$ 1,871	$ 278	$ 953	$ 138	$ 8	$ 3,248	$ (325)	$ –	$ 2,923
Energy purchases and fuel	(1,065)	(11)	(377)	(2)	–	(1,455)	113	–	(1,342)
Other raw materials and operating charges	(69)	(22)	(66)	(15)	(2)	(174)	23	–	(151)
Staff costs and employee benefits expense	(42)	(1)	(22)	(1)	(92)	(158)	8	–	(150)
Other administrative expense	(44)	(16)	(38)	(19)	(59)	(176)	26	–	(150)
Remove unrealized changes in fair value of commodity derivatives	(126)	(116)	(19)	(25)	–	(286)	–	286	–
Remove other non-recurring items	4	–	–	–	10	14	–	(14)	–
Adjusted EBITDA[2]	529	112	431	76	(135)	1,013			
Depreciation and amortization									(366)
Impairments									(27)
Foreign exchange loss									(9)
Loss on disposals and other transactions									(20)
Net finance expense									(160)
Income from equity-accounted investments									64
Income before tax									$ 612

[1] For internal reporting purposes, adjusted EBITDA from the Company's equity-accounted investments has been presented on a proportionate basis that reflects the Company's share of each investee's earnings on a line-by-line basis. These amounts are reported within Canada flexible generation for York Energy, Canada renewables for Quality Wind and Port Dover Nanticoke Wind (from the time of the sell-down on December 20, 2024 onwards), and U.S. flexible generation for MCV Partners LLC and Harquahala. Proportionate financial information is not, and is not intended to be, presented in accordance with IFRS. Under IFRS, these investments have been accounted for as joint ventures using the equity method.

[2] Adjusted EBITDA is not defined and has no standardized meaning under IFRS.

[3] Includes acquisition and integration costs of $41 million for the acquisition of Hummel Station, LLC and Rolling Hills Generating, LLC (note 3).

12. Segment information, continued

Additional geographic information

The Company's Canadian facilities are located in Alberta, British Columbia and Ontario and its U.S. facilities in Alabama, Arizona, California, Illinois, Kansas, Michigan, New Mexico, North Carolina, North Dakota, Ohio, Pennsylvania, Texas and Washington. The Company also holds a portfolio of wind and solar development sites in Canada and the U.S.

Select non-current assets within each geographic area are:

	At September 30, 2025			At December 31, 2024		
	Canada	U.S.	Total	Canada	U.S.	Total
Property, plant and equipment	$ 5,580	$ 5,575	$ 11,155	$ 5,457	$ 2,604	$ 8,061
Equity-accounted investments	395	686	1,081	397	699	1,096
Intangible assets and goodwill	435	202	637	519	225	744
Right-of-use assets	50	88	138	54	64	118
Other assets[4]	63	53	116	73	84	157
	$ 6,523	$ 6,604	$ 13,127	$ 6,500	$ 3,676	$ 10,176

[4] Includes current portion of finance lease receivable.

Major customer

For the three and nine months ended September 30, 2025, the Company recorded revenues of $180 million and $461 million, respectively, from the Alberta Electric System Operator, within the Canada flexible generation and Canada renewables segments (three and nine months ended September 30, 2024 - $176 million and $637 million, respectively) and $210 million and $265 million from PJM, within the U.S. flexible generation segment (three and nine months ended September 30, 2024 - nil). There were no other entities that accounted for more than 10 percent of the Company's total revenues.

Disaggregation of revenues from contracts with customers

The Company's revenues from contracts with customers are disaggregated by major type of revenues and operating segments:

	Three months ended September 30, 2025						
	Canada flexible generation	Canada renewables	U.S. flexible generation	U.S. renewables	Total from contracts with customers	Other sources	Total
Energy revenues	$ 454	$ 19	$ 351	$ 13	$ 837	$ 350	$ 1,187
Emission credit revenues	–	10	–	1	11	(1)	10
Total revenues[5]	$ 454	$ 29	$ 351	$ 14	$ 848	$ 349	$ 1,197

	Nine months ended September 30, 2025						
	Canada flexible generation	Canada renewables	U.S. flexible generation	U.S. renewables	Total from contracts with customers	Other sources	Total
Energy revenues	$ 1,293	$ 58	$ 652	$ 48	$ 2,051	$ 465	$ 2,516
Emission credit revenues	–	35	–	3	38	5	43
Total revenues[5]	$ 1,293	$ 93	$ 652	$ 51	$ 2,089	$ 470	$ 2,559

12. Segment information, continued

	Three months ended September 30, 2024						
	Canada flexible generation	Canada renewables	U.S. flexible generation	U.S. renewables	Total from contracts with customers	Other sources	Total
Energy revenues	$ 436	$ 30	$ 115	$ 10	$ 591	$ 410	$ 1,001
Emission credit revenues	–	10	–	1	11	1	12
Total revenues[5]	$ 436	$ 40	$ 115	$ 11	$ 602	$ 411	$ 1,013

	Nine months ended September 30, 2024						
	Canada flexible generation	Canada renewables	U.S. flexible generation	U.S. renewables	Total from contracts with customers	Other sources	Total
Energy revenues	$ 1,436	$ 116	$ 298	$ 37	$ 1,887	$ 914	$ 2,801
Emission credit revenues	–	32	–	3	35	27	62
Total revenues[5]	$ 1,436	$ 148	$ 298	$ 40	$ 1,922	$ 941	$ 2,863

[5] Included within trade and other receivables at September 30, 2025, were amounts related to contracts with customers of $312 million (2024 - $290 million).

13. Comparative figures

The comparative figures have been reclassified to conform with the presentation adopted for 2025.