No securities regulatory authority has expressed an opinion about these securities and it is an offence to claim otherwise. This prospectus constitutes a public offering of these securities only in those jurisdictions where they may be lawfully offered for sale therein and only by persons permitted to sell such securities.

*These securities have not been, and will not be, registered under the United States Securities Act of 1933, as amended (the "**U.S. Securities Act**"), or the securities laws of any state of the United States (as such term is defined in Regulation S under the U.S. Securities Act) and may not be offered, sold or delivered, directly or indirectly, in the United States or to a U.S. person (as such term is defined in Regulation S under the U.S. Securities Act), except pursuant to an exemption from the registration requirements of the U.S. Securities Act and applicable state securities laws. This prospectus does not constitute an offer to sell or solicitation of an offer to buy any of these securities in the United States. See "Plan of Distribution".*

SUPPLEMENTED PREP PROSPECTUS

Initial Public Offering
and Secondary Offering (if the Over-Allotment Option is exercised)

October 8, 2025

ROCKPOINT
GAS STORAGE

ROCKPOINT GAS STORAGE INC.

C$704,000,000

32,000,000 Class A Shares

This prospectus qualifies the distribution to the public (the "**Offering**") of an aggregate of 32,000,000 class "A" common shares (the "**Class A Shares**") of Rockpoint Gas Storage Inc. (the "**Company**" or "**Rockpoint**"), an Alberta corporation, at a price of C$22.00 per Class A Share (the "**Offering Price**"). The Offering consists of an initial public offering of 32,000,000 Class A Shares by the Company from treasury and, if the Over-Allotment Option (as defined below) is exercised, a secondary offering (the "**Secondary Offering**") of up to 4,800,000 Class A Shares held by the Selling Shareholders (as defined below), who are affiliates of Brookfield Infrastructure (as defined below). See "Brookfield" and "Plan of Distribution". The Company will not receive any proceeds from the Secondary Offering.

Rockpoint was recently incorporated with nominal assets for the purpose of facilitating the Offering and acquiring approximately 40% of the limited partner units (each, a "**Swan OpCo Unit**") of Swan Equity Aggregator LP, an Ontario limited partnership ("**Swan OpCo**"), and approximately 40% of the common shares (each a "**BIF OpCo Share**", and together with a Swan OpCo Unit, an "**OpCo Interest**") of BIF II CalGas (Delaware) LLC, a Delaware limited liability company ("**BIF OpCo**", and together with Swan OpCo, the "**OpCos**"), from the Selling Shareholders in exchange for an aggregate of US$450,400,000 cash and 21,200,000 Class A Shares pursuant to the Business Transfer Agreement (as defined below) (the "**Reorganization**"). The OpCos and WGS LP (as defined below) own and operate, directly and indirectly, the largest independent pure play portfolio of natural gas storage facilities in North America with a total effective working gas storage capacity (as defined below) of approximately 279.2 Bcf. Each of the OpCos and WGS LP are currently subsidiaries of Brookfield (as defined below). Following the completion of the Offering, the Reorganization and other related transactions described under "Relationship with Brookfield — The Transactions" (collectively, the "**Transactions**"), the Company will hold an approximate 40% interest in the Business (as defined below) by virtue of its ownership of approximately 40% of the OpCo Interests, and Brookfield, through the Selling Shareholders, will own approximately 60% of the OpCo Interests, as well as approximately 39.8% of the outstanding Class A Shares, assuming the Over-Allotment Option is not exercised, and 100% of the Class B Shares (as defined below), comprising approximately 75.9% of the votes attached to all outstanding Shares (as defined below), as described further below. See "Our Business", "Relationship with Brookfield" and "Use of Proceeds".

There is currently no market through which the Class A Shares may be sold and purchasers may not be able to resell the Class A Shares purchased under this prospectus. This may affect the pricing of the Class A Shares in the secondary market, the transparency and availability of trading prices, the liquidity of the Class A Shares and the extent of issuer regulation. An investment in the Class A Shares is speculative and involves a high degree of risk. Prospective investors should carefully consider the information set out under "Risk Factors" and the other information in this prospectus before purchasing Class A Shares.

The Toronto Stock Exchange ("**TSX**") has conditionally approved the listing of the Class A Shares under the trading symbol "RGSI". Listing is subject to the Company fulfilling all of the requirements of the TSX on or before December 30, 2025, including distribution of the Class A Shares to a minimum number of public securityholders.

Price: C$22.00 per Class A Share

	Price to the Public[(1)]	Underwriters' Commission	Net Proceeds to the Company[(2)]	Net Proceeds to the Selling Shareholders[(2)(3)]
Per Class A Share	C$22.00	C$1.10	C$20.90	—
Total Offering[(3)]	C$704,000,000	C$35,200,000	C$668,800,000	—

Notes:

(1) The Offering Price was determined by negotiation among the Company, Brookfield (including on behalf of the Selling Shareholders) and the Lead Underwriters (as defined below), on behalf of the Underwriters (as defined below).

(2) Before deducting the expenses of the Offering, estimated to be C$9,600,000, which together with the Underwriters' commission in respect of the Class A Shares sold in connection with the Offering, will be paid from the proceeds of the Offering. The Company will pay the Underwriters' commission and expenses associated with the Offering and the Selling Shareholders will pay the Underwriters' commission and expenses associated with the Secondary Offering. The Company will not receive any of the proceeds from the Secondary Offering. Pursuant to the Underwriting Agreement (as defined below), the Selling Shareholders will reimburse the Company for the expenses of the Offering, including the Underwriters' commission.

(3) The Selling Shareholders have granted to the Underwriters an option (the "**Over-Allotment Option**"), exercisable at the Underwriters' discretion at any time, in whole or in part, until 30 days after the Closing Date (as defined below), to purchase, at the Offering Price, up to 4,800,000 Class A Shares from the Selling Shareholders (representing 15% of the number of Class A Shares offered under this prospectus prior to the exercise of the Over-Allotment Option) to cover over-allotments, if any, and for market stabilization purposes. If the Over-Allotment Option is exercised in full, the total "Price to the Public", "Underwriters' Commission", "Net Proceeds to the Company" and "Net Proceeds to the Selling Shareholders" will be C$809,600,000, C$40,480,000, C$668,800,000 and C$100,320,000, respectively. This prospectus also qualifies the grant of the Over-Allotment Option and the distribution of the Class A Shares pursuant to the exercise of the Over-Allotment Option. A purchaser who acquires Class A Shares forming part of the Underwriters' over-allocation position acquires such Class A Shares under this prospectus, regardless of whether the over-allocation position is ultimately filled through the exercise of the Over-Allotment Option or secondary market purchases. See "Brookfield" and "Plan of Distribution".

RBC Dominion Securities Inc. ("**RBC**") and J.P. Morgan Securities Canada Inc. ("**J.P. Morgan**" and, together with RBC, the "**Lead Underwriters**"), Wells Fargo Securities Canada, Ltd., BMO Nesbitt Burns Inc., CIBC World Markets Inc., National Bank Financial Inc., Scotia Capital Inc., TD Securities Inc., ATB Securities Inc., Desjardins Securities Inc. and Peters & Co. Limited (collectively with the Lead Underwriters, the "**Underwriters**"), as principals, conditionally offer the Class A Shares qualified under this prospectus, subject to prior sale, if, as and when issued by the Company and accepted by the Underwriters in accordance with the conditions contained in the underwriting agreement dated October 8, 2025 (the "**Underwriting Agreement**") among the Company, Brookfield Infrastructure, the Selling Shareholders and the Underwriters referred to under "Plan of Distribution" and subject to the approval of certain legal matters on behalf of the Company by Torys LLP, with respect to matters of Canadian law, and Latham & Watkins LLP, with respect to matters of U.S. law, and on behalf of the Underwriters by Blake, Cassels & Graydon LLP, with respect to matters of Canadian law, and Skadden, Arps, Slate, Meagher & Flom LLP, with respect to matters of U.S. law.

In connection with the Offering, the Underwriters have been granted the Over-Allotment Option and may, subject to applicable law, over-allocate or effect transactions which stabilize or maintain the market price of the Class A Shares at levels other than those which otherwise might prevail on the open market. Such transactions, if commenced, may be discontinued at any time.

The Underwriters may offer the Class A Shares at a price lower than that stated above. Any such reduction will not affect the net proceeds of the Offering and the Secondary Offering to be received by the Company and the Selling Shareholders, respectively. See "Plan of Distribution".

The following table sets out the number of Class A Shares that may be sold by the Selling Shareholders to the Underwriters pursuant to the Over-Allotment Option:

Underwriters' Position	Maximum Size or Number of Securities Available	Exercise Period	Exercise Price
Over-Allotment Option	4,800,000 Class A Shares from the Selling Shareholders	For a period of 30 days after the Closing Date	C$22.00 per Class A Share

Subscriptions for the Class A Shares will be received subject to rejection or allocation in whole or in part and the Underwriters reserve the right to close the subscription books at any time without notice. The closing of the Offering (the "**Closing**") is expected to occur on or about October 15, 2025 or such other date as the Company, the Selling Shareholders and the Underwriters may agree, but in any event no later than November 18, 2025 (the "**Closing Date**"). The Class A Shares offered under this prospectus are to be taken up by the Underwriters, if at all, on or before a date that is 42 days after the date of the receipt for the final base PREP prospectus. The Class A Shares will be deposited with CDS Clearing and Depository Services Inc. ("**CDS**") in electronic form on the Closing Date through the non-certificated inventory system administered by CDS. A purchaser of Class A Shares will receive only a customer confirmation from the registered dealer from or through which the Class A Shares are purchased. See "Plan of Distribution — Non-Certificated Inventory System".

Upon Closing, the Company will have two classes of outstanding shares: (i) Class A Shares; and (ii) class "B" voting shares (the "**Class B Shares**", and together with the Class A Shares, the "**Shares**"). Each Class A Share and each Class B Share is entitled to one vote on all matters upon which each such class of Shares are entitled to vote and, except as provided by the Articles (as defined below) or required by law, the holders of Class A Shares will vote together with the holders of Class B Shares as a single class. Upon completion of the Transactions, the Company will have 53,200,000 Class A Shares and 79,800,000 Class B Shares outstanding. See "Description of Share Capital and OpCo Interests".

Upon completion of the Transactions, assuming the Over-Allotment Option is not exercised, Brookfield will own approximately 39.8% of the outstanding Class A Shares and 100% of the outstanding Class B Shares, representing approximately 75.9% of the aggregate outstanding Shares and voting interest in the Company (or approximately 30.8% of the Class A Shares, representing, together with Brookfield's Class B Shares, approximately 72.3% of the aggregate outstanding Shares and voting interest in the Company, if the Over-Allotment Option is exercised in full). Upon completion of the Transactions, Rockpoint will own approximately 40% of the OpCo Interests and Brookfield will own approximately 60% of the OpCo Interests, excluding any indirect beneficial ownership of Brookfield in OpCo Interests by virtue of its ownership in the Company. As a result, Brookfield will have control over the Company, the OpCos and the Business.

In addition, at Closing, the Company, Brookfield and the Selling Shareholders will enter into the Registration Rights Agreement (as defined below) and the Shareholder Agreement (as defined below) that, together, among other things, will provide Brookfield with the Registration Right (as defined below) and the Demand Registration Right (as defined below) and certain governance rights, including with respect to the nomination of directors to the Board (as defined below). The Company, Brookfield and the OpCos have entered into the Relationship Agreement (as defined below) that provides, among other things, for the composition of the OpCo Boards (as defined below) and Brookfield with access to information in respect of the Company. The Relationship Agreement also provides that there are no restrictions on Brookfield's ability to compete with the Company and the OpCos following Closing. In addition, the Company, Brookfield and the OpCos have entered into the Exchange Agreement (as defined below) that provides for the Exchange Right (as defined below) and provides that Brookfield will not be permitted to exercise the Exchange Right: (i) for a period of 12 months from the Closing Date; and (ii) at any time, to the extent that the change of proportional ownership or operational control of the OpCos between Brookfield, on the one hand, and Rockpoint, on the other, would result in a change of control of the Lodi or Wild Goose operating subsidiaries for the purposes of the operating permits issued by the CPUC (as defined below), unless the CPUC Approval (as defined below) has first been obtained. See "Relationship with Brookfield", "Brookfield" and "Risk Factors". All of the Shares held upon completion of the Transactions by Brookfield, other than in connection with the Secondary Offering, and the directors and executive officers of the Company will be subject to contractual lock-up agreements with the Underwriters. See "Brookfield" and "Plan of Distribution — Lock-Up".

BIF II CalGas Carry (Delaware) LLC and BIP BIF II U.S. Holdings (Delaware) LLC, each a Selling Shareholder, and BIF OpCo are incorporated, continued or otherwise organized under the laws of a foreign jurisdiction and Suzanne Nimocks, Peter Cella, Gene Stahl, David Devine and William Burton, each a current or proposed director of the Company, reside outside of Canada. BIF II CalGas Carry (Delaware) LLC, BIP BIF II U.S. Holdings (Delaware) LLC, BIF OpCo and each of the aforementioned directors have each appointed Rockpoint at 400 – 607 8th Ave. S.W., Calgary, Alberta, Canada, T2P 0A7, as agent for service of process in Canada. Purchasers are advised that it may not be possible for investors to enforce judgments obtained in Canada against any person or company that is incorporated, continued or otherwise organized under the laws of a foreign jurisdiction or resides outside of Canada, even if the party has appointed an agent for service of process. See "Enforcement of Judgments Against Foreign Persons".

Securities legislation in certain of the provinces and territories of Canada provides purchasers with the right to withdraw from an agreement to purchase securities. See "Purchasers' Statutory Rights".

In this prospectus, references to "$" are to United States dollars and references to "C$" are to Canadian dollars, unless otherwise indicated.

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NOTICE TO INVESTORS

About this Prospectus

An investor should rely only on the information contained in this prospectus and is not entitled to rely on parts of the information contained in this prospectus to the exclusion of others. None of the Company, Brookfield or the Underwriters have authorized anyone to provide investors with additional or different information. The information contained on www.rockpointgs.com, www.brookfield.com, any of the Company's or Brookfield's other controlled or affiliated websites, or any third-party website is not intended to be included in or incorporated by reference in this prospectus and prospective investors should not rely on such information when deciding whether or not to buy Class A Shares.

The information contained in this prospectus is accurate only as of the date of this prospectus or the date otherwise indicated, regardless of the time of delivery of this prospectus or of any sale of the Class A Shares. Our Business, financial condition, results of operations and prospects may have changed since the date of this prospectus.

Any graphs, tables or other information demonstrating the historical performance of the Business, the Company or any other entity contained in this prospectus are intended only to illustrate past performance of such entities and are not necessarily indicative of future performance of the Company or such entities.

None of the Company, the Selling Shareholders or the Underwriters are offering to sell the Class A Shares in any jurisdiction where the offer or sale of such securities is not permitted. For investors outside Canada, none of the Company, the Selling Shareholders or any of the Underwriters has done anything that would permit the Offering or possession or distribution of this prospectus in any jurisdiction where action for that purpose is required, other than in Canada. Investors are required to inform themselves about, and to observe any restrictions relating to, the Offering, the Secondary Offering and the possession or distribution of this prospectus.

This prospectus includes summary descriptions of certain material agreements of the Company. See "Material Contracts". The summary descriptions disclose attributes that the Company believes are material to an investor in the Class A Shares, but are not complete. Each summary is qualified in its entirety by reference to the full terms of the material agreements described, which will be filed with the Canadian securities regulatory authorities and available on SEDAR+. Prospective investors are encouraged to read the full text of such material agreements.

In this prospectus, references to "$" are to United States dollars and references to "C$" are to Canadian dollars, unless otherwise indicated. Certain totals, subtotals and percentages throughout this prospectus may not reconcile due to rounding.

Meaning of Certain References

In this prospectus, unless otherwise indicated or the context otherwise requires, capitalized terms used in this prospectus are defined under "Glossary". Words importing the singular include the plural and vice versa and words importing any gender include all genders. A reference to an agreement means the agreement as it may be amended, supplemented or restated from time to time.

Unless otherwise noted or the context otherwise requires:

- the disclosure in this prospectus: (i) gives effect to the Transactions described under "The Company and the OpCos — The Transactions" and "Relationship with Brookfield — The Transactions"; and (ii) assumes that the Over-Allotment Option has not been exercised;
- the terms "we", "us" and "our" refer to, collectively, Swan OpCo, BIF OpCo, WGS LP, BIF II SIM Limited, SIM Energy LP, SIM Energy Limited, Swan Debt Aggregator LP and, prior to March 21, 2024, BIF II Tres Palacios Aggregator (Delaware) LLC, and their subsidiaries;
- the terms "Rockpoint" and the "Company" refer to Rockpoint Gas Storage Inc. and do not, for greater clarity, include any of its OpCo Interests following completion of the Transactions;

- the terms “the Business”, “our Business” and “Rockpoint Gas Storage” refer to the ownership and operation, directly or indirectly of a portfolio of six strategically located natural gas storage facilities in North America with a total effective working gas storage capacity of approximately 279.2 Bcf, being the business currently carried on by collectively, Swan OpCo, BIF OpCo, WGS LP, BIF II SIM Limited, SIM Energy LP, SIM Energy Limited, Swan Debt Aggregator LP and, prior to March 21, 2024, BIF II Tres Palacios Aggregator (Delaware) LLC and their subsidiaries; and
- the terms “our assets” and similar terms refer to the assets of the Business, including, the AECO Hub™, Wild Goose, Lodi and Kirby Hills, Warwick, AGS and ESAS assets described in this prospectus.

Forward-Looking Information

This prospectus contains “forward-looking information” (including financial outlook) within the meaning of applicable securities laws. Forward-looking information may relate to future plans, expectations and intentions, results, levels of activity, performance, goals or achievements, business strategy, growth strategy, budgets, operations, financial results, taxes, dividends, plans and objectives. Particularly, information regarding the Company’s and the OpCos’ future results, performance, achievements, prospects or opportunities or the markets in which the Company and the OpCos operate is forward-looking information. In some cases, forward-looking information can be identified by the use of forward-looking terminology such as “may”, “will”, “would”, “should”, “could”, “expects”, “plans”, “intends”, “trends”, “indicates”, “anticipates”, “believes”, “estimates”, “predicts”, “likely” or “potential” or the negative or other variations of these words or other comparable words or phrases. In addition, any statements that refer to expectations, intentions, projections or other characterizations of future events or circumstances contain forward-looking information. Statements containing forward-looking information are not facts but instead represent management’s expectations, estimates and projections regarding future events or circumstances.

Discussions containing forward-looking information may be found, among other places, under “Summary of the Offering”, “Risk Factors”, “The Company and the OpCos”, “Industry Overview”, “Our Business”, “Relationship with Brookfield”, “Description of Share Capital and OpCo Interests”, “Dividend Policy”, “Consolidated Capitalization”, “Use of Proceeds”, “Management’s Discussion and Analysis”, “Directors and Executive Officers”, “Corporate Governance”, “Executive Compensation”, “Plan of Distribution” and “Brookfield”.

Forward-looking information in this prospectus includes, among other things, information relating to:

- the completion, size and expenses of the Offering and the Closing Date;
- the Over-Allotment Option, the completion, size and expenses of the Secondary Offering;
- the execution of ancillary agreements made in connection with the Transactions by, among others, the Company, Brookfield and the OpCos and the terms and conditions thereof;
- the gross and net proceeds of the Offering and the anticipated use of the net proceeds of the Offering;
- expectations regarding the payment of distributions by the OpCos, including amounts and the timing thereof;
- the establishment of a dividend policy and expectations regarding the payment of dividends by the Company following completion of the Transactions, including amounts, timing and potential growth;
- the Transactions;
- the implementation of corporate governance practices;
- the composition of the executive officers, directors and committees of the Company and of the OpCos;
- expectations regarding future director and executive compensation levels and plans;
- the security ownership by directors and executive officers;
- the market price for the Class A Shares;
- the establishment of the Revolving Credit Facility, refinancing of the ABL Facility and repayment of the Warwick Credit Facility;

- the number and percentage of Class A Shares and Class B Shares outstanding following completion of the Transactions;
- the Company's relationship with Brookfield, including Brookfield's expected holdings of Class A Shares, Class B Shares and OpCo Interests;
- Rockpoint's expected holdings of OpCo Interests;
- the authorized share capital of the Company and the OpCos at Closing;
- the rights and restrictions of the authorized capital of the Company and the OpCos at Closing;
- the commission payable to the Underwriters;
- potential conflicts of interest;
- the future revenue and earnings generated from operations;
- the demand, volatility and price of energy, natural gas and gas storage;
- the completion of the battery storage facility in Alberta and the revenue and earnings generated therefrom;
- the completion and capital expenditures of the Warwick facility expansion project and the revenue and earnings generated therefrom;
- the completion of the deliverability enhancements and the revenue and earnings generated therefrom;
- the completion of the storage expansions and the revenue and earnings generated therefrom;
- the completion of future brownfield expansions identified by the Company, the resulting increase in working gas storage capacity and deliverability, and the revenue and earnings generated therefrom;
- future working gas storage capacity and increased deliverability;
- future natural gas contracts and any terms therein;
- the future allocation among ToP, STS and optimization strategies;
- the projected power mix of energy sources;
- future capital expenditures, including amounts estimated for near-term brownfield opportunities and longer-term growth opportunities;
- the duration of construction of natural gas storage facilities;
- future growth and expansion of the operations;
- future acquisitions;
- regulatory approvals related to new projects or expansions;
- future LNG export capacity and trade, potential LNG export projects in western Canada and the export capacity, cost and timing thereof;
- seasonal natural gas spreads;
- the future net load (less wind and solar renewable output);
- the future regulatory compliance capital expenditures;
- structural tightening in the North American natural gas market;
- sufficiency of cash generated to meet cash requirements; and
- future decommissioning obligations.

In addition, the Company's financial outlook with respect to growth in Adjusted EBITDA and Distributable Cash Flow is considered forward-looking information. See "Risk Factors — Forward-Looking Information and Financial and Operational Targets May Prove Inaccurate" and "Prospectus Summary — Our

Business — Our Competitive Strengths — High free cash flow conversion supports reinvestment and return of capital" for additional information concerning the Company's outlook and related assumptions and risks.

Forward-looking information is not a guarantee of future performance and is based on the Company's opinions, estimates and assumptions in light of the Company's and the OpCos' experience and perception of historical trends, current conditions and expected future developments, as well as other factors that the Company and the OpCos currently believe are appropriate and reasonable in the circumstances. Despite a careful process to prepare and review the forward-looking information, there can be no assurance that the underlying opinions, estimates and assumptions will prove to be correct. Certain assumptions in respect of the Offering; the Company's and the OpCos' ability to build our market share and growth outlook; the ability to retain key personnel; the ability to obtain or maintain existing financing on acceptable terms; currency exchange and interest rates; the impact of competition; the changes and trends in our industry or the global economy; operations and maintenance cost estimates; and capital costs remaining steady are material factors underlying forward-looking information and management's expectations. Additionally, material assumptions underlying the Company's financial outlook with respect to Adjusted EBITDA and Distributable Cash Flow growth include our Business objectives, our assessment of the position of our Business, including our expectation for continued working gas capacity utilization, that recurring contract renewals will continue to provide us with stable and predictable cash flow and that we will see growth in storage value, our assessment of market conditions and our ability to successfully execute our growth strategies.

The forward-looking information in this prospectus is necessarily based on a number of opinions, assumptions and estimates that the Company considered appropriate and reasonable as of the date such statements were made. It is also subject to known and unknown risks, uncertainties, assumptions and other factors that may cause the Company's and the OpCos' actual results, level of activity, performance or achievements to be materially different from those expressed or implied by such forward-looking information, including but not limited to the following factors described in greater detail under the heading "Risk Factors":

- business dependency on the supply of and demand for the products;
- operating results adversely affected by unfavourable economic and market conditions;
- operational risks and hazards of natural gas storage operations;
- impact of stabilization of natural gas prices on demand for natural gas storage and on seasonal spread;
- exposure level to the market value of natural gas storage services;
- unavailability or increase in cost of third-party pipelines interconnected to our facilities to transport natural gas;
- land or reservoirs used as storage facilities are not owned;
- majority of the lands on which we operate is leased;
- proprietary optimization activities may cause volatility in financial results and cash flow;
- risk management policies cannot eliminate all commodity price risk;
- impact of derivatives regulation on our ability to hedge risks and on the cost of our hedging activities;
- significant competition;
- inability to recruit, retain and motivate members of our senior management team and other key personnel;
- experience cushion migration at our storage facilities;
- financial results are seasonal and generally lower in the second and third quarters of the calendar year;
- supply chain disruptions and inflation;
- dependence on a limited number of customers for a significant portion of our revenues;
- exposed to the credit risk of our customers and counterparties, and any material nonpayment or nonperformance by our key customers or counterparties;

- exposure to currency exchange rate fluctuations;
- dependence on information technology systems, which are subject to interruption, failure and potential cybersecurity attack;
- terrorist activities and catastrophic events that could result from terrorism;
- snow, rain or ice storms, earthquakes, flooding and other natural disasters, as well as climate-related physical risks;
- insurance policies do not cover all losses, costs or liabilities and insurance companies that currently insure companies in the energy industry may cease to do so or substantially increase premiums;
- reputational risks and risks relating to public opinion;
- effects of U.S. and Canadian government policies on tariffs and trade relations between Canada and the U.S.;
- change in the jurisdictional characterization of our assets by regulatory agencies or a change in policy by those agencies;
- extensive and complex government regulations;
- our operations and our customers' operations are subject to regulatory and permitting obligations;
- environmental, health and safety laws and regulations impose and will continue to impose significant costs and liabilities;
- increased regulatory requirements relating to the safety and integrity of our storage facilities;
- the CPUC may inquire into whether, or take position that, the Transactions constitute a change of control of the Lodi or Wild Goose operating subsidiaries for the purposes of the operating permits issued by the CPUC;
- climate-related risks and related regulation;
- the Business is involved in various legal proceedings, the outcomes of which are uncertain;
- changing expectations of stakeholders and government policies regarding sustainability, ESG, climate change, and environmental protection practices;
- the costs related to abandonment of storage assets at the end of their economic lives could be significant;
- if certain U.S. federal income tax rules under Section 7874 of the U.S. Internal Revenue Code apply to the Company, such rules could result in adverse U.S. federal income tax consequences;
- our material indebtedness and cash flow requirements to meet our debt service requirements, continue our operations and pursue our growth strategy;
- restrictions and limitations in the agreements and instruments governing our debt;
- interest rate risk from variable rate debt;
- the potential incurrence of substantially more debt;
- changes to applicable tax laws and regulations, exposure to additional income tax liabilities, changes in our effective tax rates or an assessment of taxes resulting from an examination of our income or other tax returns;
- failure to comply with the restrictions and covenants in the Credit Agreements or our future debt agreements;
- forward-looking information and financial and operational targets may prove inaccurate;
- Rockpoint is a holding company whose sole material assets following completion of the Transactions will be its OpCo Interests;
- the requirements of being a public company, including compliance with the reporting requirements of applicable Canadian securities laws;

- failure of Rockpoint's internal or disclosure controls to satisfy its public company reporting obligations;
- investors in the Offering will experience immediate and substantial dilution;
- future sales of Class A Shares, or the perception that such sales may occur, may depress the Class A Share price, and any additional capital raised through the sale of equity or convertible securities may dilute ownership;
- Rockpoint's reliance on an exclusion from the definition of "investment company" under the Investment Company Act of 1940;
- if no regular cash dividends on the Class A Shares following the Offering are paid, investors may not receive a return on investment;
- Brookfield has the ability to direct the voting of a majority of Shares and control certain decisions with respect to Rockpoint's and the OpCos' management and business and Brookfield's interests may conflict with those of the other shareholders;
- the historical and pro forma financial information may not be a reliable indicator of the Company's and the OpCos' future financial performance;
- Brookfield is not limited in its ability to compete with Rockpoint and the Business and may benefit from opportunities that might otherwise be available to Rockpoint, the OpCos or their subsidiaries;
- a significant reduction by Brookfield of its ownership interests in Rockpoint could adversely affect Rockpoint and the Business;
- certain of the Company's and Swan GP's directors and members of BIF OpCo's board of managers may have significant duties with, and spend significant time serving, other entities, and, accordingly, may have conflicts of interest in allocating time or pursuing business opportunities;
- Underwriters may waive or release parties to the lock-up agreements entered into in connection with the Offering;
- net proceeds of the Offering will be paid to Brookfield in exchange for newly issued OpCo Interests and will not be available to fund Rockpoint's or the Business' operations;
- if securities or industry analysts publish or do not publish research or reports about the Company or the Business, the price of the Class A Shares could decline;
- the Offering Price may not be indicative of the market price of the Class A Shares after the Offering;
- the market price of the Class A Shares could be adversely affected by sales of substantial amounts of the Class A Shares in the public or private markets or the perception in the public markets that these sales may occur;
- the Articles contain provisions that could discourage acquisition bids or merger proposals;
- Canadian investors may find it difficult or impossible to effect service of process and enforce judgments against certain non-resident directors of the Company and the OpCos and certain of the Selling Shareholders;
- Rockpoint may lose its foreign private issuer status in the United States; and
- the Business Transfer Agreement provides the Company with limited rights and remedies.

The business, financial condition and results of operations of the Company, including its ability to pay cash dividends, are effectively entirely dependent on the business, financial condition and results of operations of the OpCos and the Business. As a result, factors or events that impact the OpCos and the Business are likely to have a commensurate impact on the Company, the market price and value of the Class A Shares and the ability of the Company to pay dividends. Similarly, given the nature of the relationship between the Company and the Business on the one hand and Brookfield on the other hand, factors or events that impact Brookfield may have consequences for the Company and/or the Business.

If any of these risks or uncertainties materialize, or if the opinions, estimates or assumptions underlying the forward-looking information prove incorrect, actual results or future events might vary materially from those anticipated in the forward-looking information. The factors and assumptions are not intended to represent a complete list of the factors and assumptions that could affect the Company and the Business. However, the opinions, estimates or assumptions referred to above and described in greater detail in “Risk Factors” should be considered carefully by prospective investors.

Although the Company has attempted to identify important risk factors that could cause actual results or future events to differ materially from those contained in forward-looking information, there may be other risk factors not presently known to the Company or that the Company presently believe are not material that could also cause results to differ from those anticipated, estimated or intended. There can be no assurance that such information will prove to be accurate, as actual results and future events could differ materially from those anticipated in such information. Accordingly, prospective investors should not place undue reliance on forward-looking information, which speaks only to opinions, estimates and assumptions as of the date made. The forward-looking information contained in this prospectus represents the Company’s expectations as of the date of this prospectus (or as of the date it is otherwise stated to be made), and is subject to change after such date. The Company disclaims any intention or obligation or undertaking to update or revise any forward-looking information whether as a result of new information, future events or otherwise, except as required under applicable securities laws in Canada.

All of the forward-looking information contained in this prospectus is expressly qualified by the cautionary statements set out in this prospectus. Investors should read this entire prospectus and consult their own professional advisors to ascertain and assess the income tax, legal, risk factors and other aspects of their investment in the Class A Shares.

Non-IFRS Measures

This prospectus makes reference to certain non-IFRS measures. These measures are not recognized measures under IFRS and do not have standardized meaning prescribed by IFRS and are therefore unlikely to be comparable to similar measures presented by other companies. Rather, these measures are provided as additional information to complement IFRS measures by providing further understanding of our results of operations from management’s perspective. Accordingly, these measures should not be considered in isolation or as a substitute for analysis of our financial information reported under IFRS. The Company uses non-IFRS measures and industry metrics, including “Adjusted EBITDA”, “Adjusted EBITDA Margin”, “Net Debt”, “Adjusted Gross Margin”, “Fee for Service as a percentage of Adjusted Gross Margin”, “Distributable Cash Flow” and “Distributable Cash Flow Conversion”, to provide investors with supplemental measures. Management also uses non-IFRS measures internally in order to facilitate operating performance comparisons from period to period, prepare annual operating budgets and assess our ability to meet our future debt service, capital expenditure and working capital requirements. Management believes that securities analysts, investors and other interested parties frequently use non-IFRS measures in the evaluation of issuers.

Prospective investors should review this information in conjunction with the Financial Statements of the Business, as well as “Management’s Discussion and Analysis” and “Consolidated Capitalization”, included elsewhere in this prospectus.

See “Management’s Discussion and Analysis — Non-IFRS Measures Utilized by the Business” for a reconciliation of the non-IFRS measures referred to above to their most directly comparable measures calculated in accordance with IFRS.

Marketing Materials

A “template version” of the following “marketing materials” (as such terms are defined under applicable Canadian securities laws) for this Offering filed on SEDAR+ is specifically incorporated by reference into this prospectus:

- the pre-deal investor presentation filed on September 18, 2025;
- the investor presentation filed on September 29, 2025;
- the term sheet filed on September 29, 2025;
- the investor presentation filed on October 6, 2025;

- the term sheet filed on October 6, 2025; and
- the final term sheet filed on October 8, 2025.

In addition, any template version of any marketing materials utilized by the Underwriters in connection with the Offering to be incorporated by reference herein will not be part of this prospectus to the extent that the contents of the template version of the marketing materials have been modified or superseded by a statement contained in this prospectus. The template version of any marketing materials filed on SEDAR+ after the date hereof and before the termination of the distribution pursuant to the Offering (including any amendments to, or an amended version of, the template version of the marketing materials) will be deemed to be incorporated by reference into this prospectus.

Market Data and Industry Data

Market and industry data presented throughout this prospectus was obtained from third-party sources, industry reports and publications, websites and other publicly available information, including from the EIA, the AER, S&P Global Commodity Insights, the CER and the IEA as well as industry and other data prepared by us or on our behalf on the basis of management's knowledge of, and experience in, the markets in which we operate. We believe that the market and economic data presented throughout this prospectus is accurate and, with respect to data prepared by us or on our behalf, that management's opinions, estimates and assumptions are currently appropriate and reasonable. Actual outcomes may vary materially from those forecast in such reports or publications, and the prospect for material variation can be expected to increase as the length of the forecast period increases. Although we believe it to be reliable, none of the Company, Brookfield or any of the Underwriters have independently verified any of the data from third-party sources referred to in this prospectus, analyzed or verified the underlying studies or surveys relied upon or referred to by such sources, or ascertained the underlying market, economic and other assumptions relied upon by such sources. Market and economic data is subject to variations and cannot be verified due to limits on the availability and reliability of data inputs, the voluntary nature of the data gathering process and other limitations and uncertainties inherent in any statistical survey.

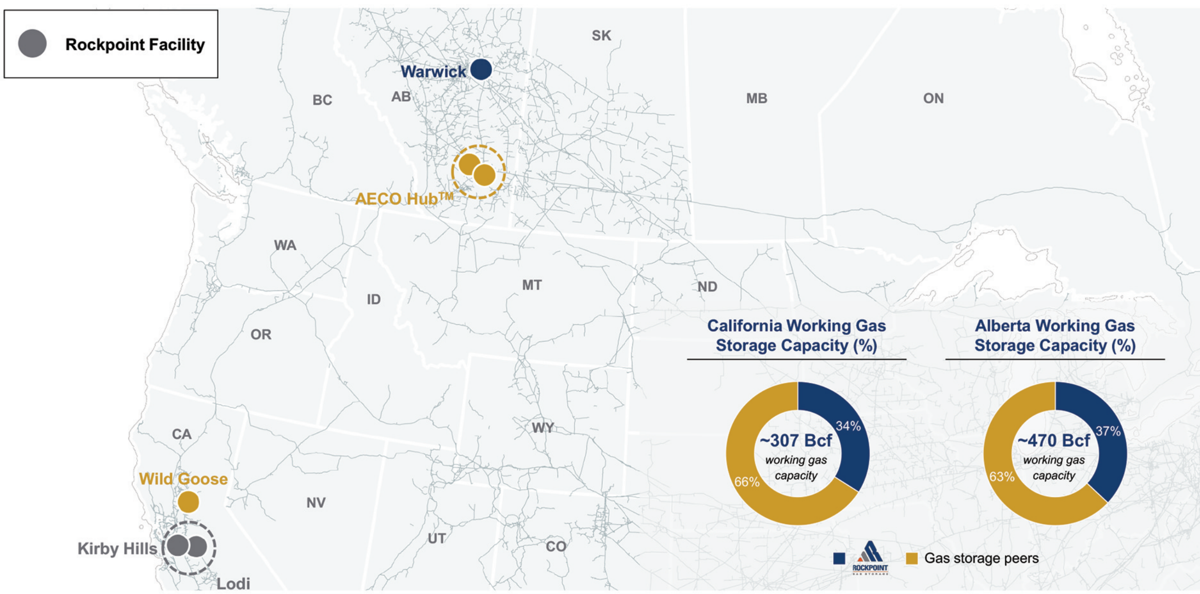
PROSPECTUS SUMMARY

The following is a summary of the principal features of the Company, the Business and certain information contained elsewhere in this prospectus. This summary does not contain all of the information a prospective investor should consider before investing in Class A Shares. A prospective investor should read this entire prospectus carefully, especially the "Our Business", "Industry Overview" and "Risk Factors" sections of this prospectus and the Financial Statements of the Business appearing elsewhere in this prospectus, before making an investment decision.

In this prospectus, references to "$" are to United States dollars and references to "C$" are to Canadian dollars, unless otherwise indicated.

Our Business

We are the largest independent pure play operator of natural gas storage facilities in North America. We own and operate strategically located natural gas storage infrastructure that is critical for ensuring the reliable and stable supply of natural gas in our service areas. We believe that our assets are uniquely positioned to capture the benefits associated with growing natural gas demand, particularly from LNG, gas-fired power generation to support data centre growth, oil sands and electrification broadly. Our business strategy is to optimize our storage platform to capitalize on these demand trends and offer our customers unique and highly customizable natural gas storage solutions which are critical to their operations.



Sources: Management estimate (as of September 12, 2025); AER; GeoSCOUT; and EIA.

Overview

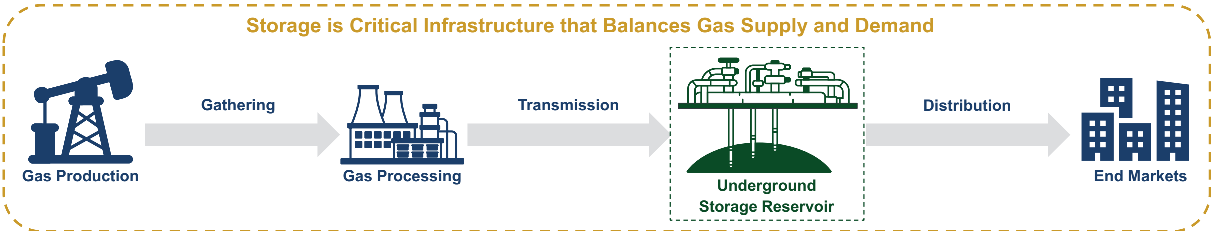
We are a natural gas storage operator with a portfolio consisting of six facilities located across California and Alberta with total effective working gas storage capacity of approximately 279.2 Bcf (as of September 12, 2025). According to the EIA and the AER, our total effective working gas storage capacity represents approximately one third of the combined storage market in Alberta and California (as of September 12, 2025). Our facilities are strategically located and are interconnected with several key natural gas pipelines to ensure long-term availability of supply and connectivity to quality customers and demand hubs.

Our history

Our Business was established in 2016, however, our asset portfolio has a 37-year operational history with the AECO Hub™ commencing operations in 1988. Our strategic development has been shaped by three key storage facility acquisitions which have defined our extensive operational footprint in North America. The acquisition of Warwick in 2012 marked our initial entry into the Alberta market providing a foundation for potential subsequent expansion. In 2014, the acquisition of Lodi established our presence in California, offering essential storage facilities integral to the region's energy infrastructure and acquisition of the AECO Hub™ and Wild Goose in 2016 firmly established our position as a leading independent owner and operator of natural gas storage infrastructure in North America.

Importance of natural gas storage

The diagram below illustrates the North American natural gas logistics value chain:



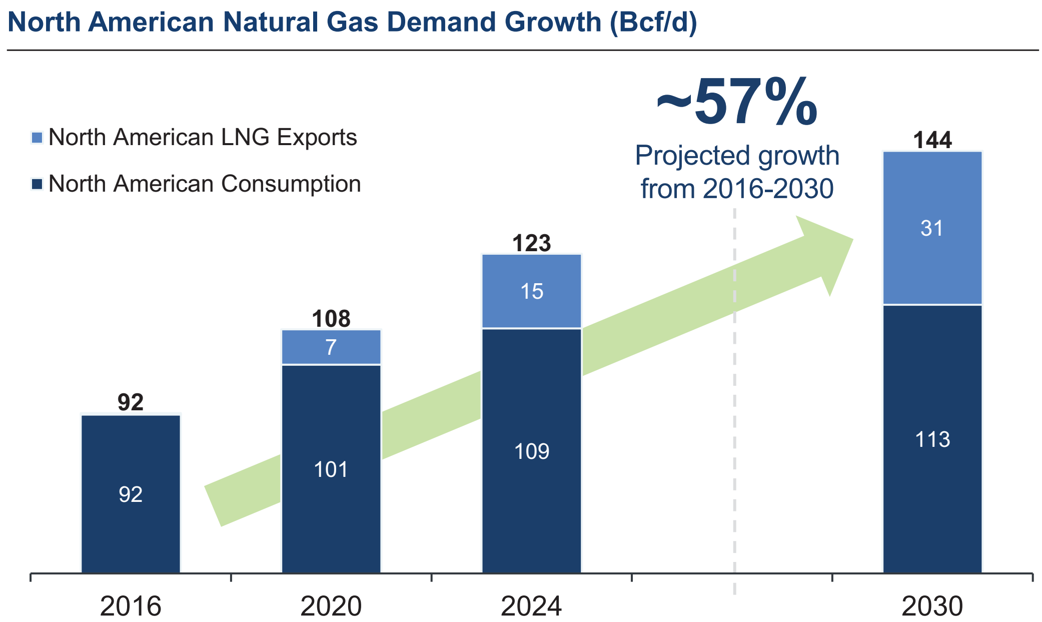
Natural gas storage infrastructure plays a crucial role in the natural gas value chain to ensure supply meets demand throughout the year. It bolsters production and delivery systems, providing a reliable supply during periods of high demand and enabling the injection of supplemental production during low demand or off-peak times. This process balances steady production with fluctuating daily, monthly, and seasonal consumption. When production exceeds demand, typically in summer, excess gas is stored; conversely, during winter, stored gas is withdrawn to meet increased demand. Natural gas storage acts as the critical balancing mechanism to manage supply disruption and maintain orderly markets. We define a gas market as being "tight" if demand exceeds available supply. According to industry sources such as the EIA, in the coming years, natural gas demand is expected to grow, driven primarily by: (i) the expansion of LNG exports; (ii) continued build out of gas-to-power infrastructure to support data centre growth and electrification broadly; and (iii) the need for flexible gas-fired power generation to support intermittent renewable energy sources. We believe that increased demand for natural gas will create a significant structural tightening in the North American market. North American natural gas demand in 2024 was approximately 123 Bcf/d, up from approximately 92 Bcf/d in 2016.[2] We expect this upward demand trend to continue, reaching an anticipated 144 Bcf/d by 2030 based on our assessment of LNG export and domestic consumption forecasts prepared by industry sources such as CER, EIA, and SENER. A tighter gas market typically translates into increased natural gas price volatility and the potential for significant short term supply disruptions.

The North American natural gas storage market is comprised of more than 400 storage facilities with effective working gas capacity of approximately 5.6 Tcf.[3] We believe existing gas storage infrastructure will be critical to meet future structural changes in natural gas demand. There have been minimal additions to gas storage over the past decade with significant geographic, regulatory and interconnection barriers hindering new development. Assuming completion of all U.S. storage projects and expansions currently in development (and no other projects or expansions in North America being completed), we expect North American effective working gas storage capacity to be approximately 6.0 Tcf by 2030, which is virtually unchanged relative to capacity today. We believe this scarcity of capacity competitively positions current storage owners and operators, including us, to benefit from strong market fundamentals and upward pressure on storage rates. The value of natural gas storage services and associated storage rates are principally based on four components: (i) operational and location characteristics of the storage facility; (ii) seasonal value in natural gas prices; (iii) insurance value of storage, representing a premium the market allocates to mitigate gas pricing volatility; and (iv) demand factor. The relationship between these components in determining the value of storage is seasonal value plus the insurance value of storage plus the demand factor, where the operational characteristics of the facility (i.e., the ability to efficiently and reliably respond and the demand elasticity) can act as a multiplier on the seasonal value and insurance value components.

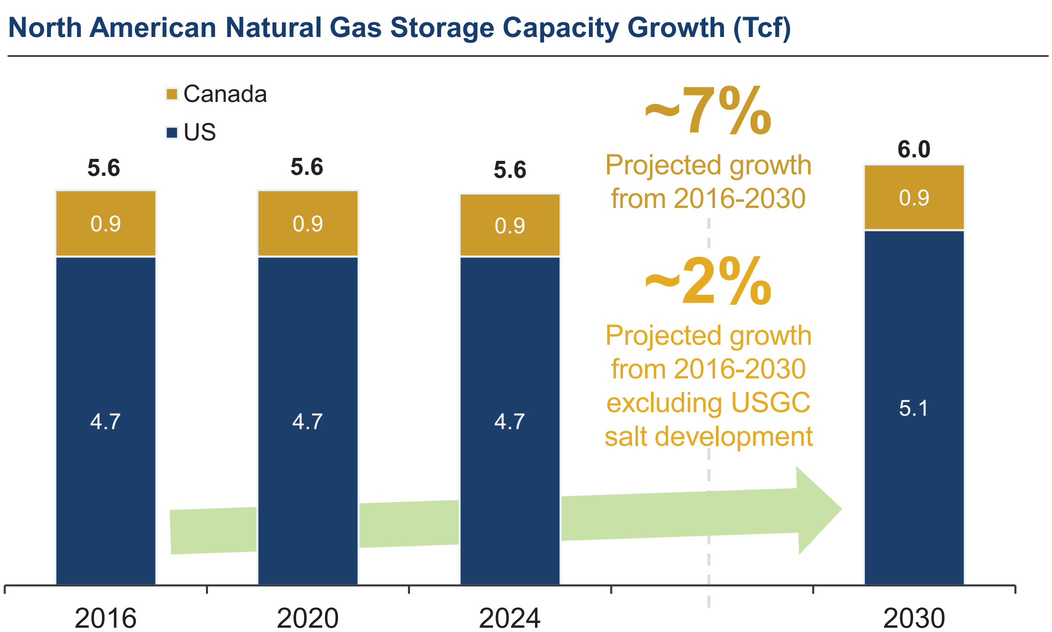
2 *Sources: Statistics Canada; EIA; and SENER.*

3 *Sources: EIA; and Statistics Canada.*

The charts below illustrate anticipated North American natural gas demand growth and anticipated North American natural gas storage capacity growth:



Sources: EIA; and CER.



Sources: EIA; and CER.

Outlook for our business

As global natural gas demand continues to grow, the role of gas storage in balancing supply and demand variations has become even more important. The lack of new gas storage development has created scarcity value for existing storage assets which has translated into higher storage rates for existing facilities. Our assets are strategically located within the North American natural gas logistics network, and we believe are well positioned to benefit from strong market fundamentals and structural drivers of demand including reindustrialization and energization of the North American grid, increasing reliance on intermittent renewables generation, and global gas pricing exposure through rising LNG exports. As a result, we expect to see significant growth from contract renewals in a rising rate environment further supported by new customer demand. Our appraisal of the foregoing factors has allowed us to implement a long-term annual Adjusted EBITDA growth target of 4% to 5%, which we expect to translate to a Distributable Cash Flow growth target of 5% to 6%. In addition, we believe that our growth outlook can be further enhanced by accretive capital projects as well as strategic optionality from various opportunities including but not limited to future acquisitions and portfolio and balance sheet optimization. Based on the foregoing, we are also targeting incremental annual Distributable Cash Flow growth of 4% to 5% over the long-term in the event that such growth projects and opportunities are consummated.

In addition to our Adjusted EBITDA growth targets, in reliance on our assessment of the current position of our Business and market conditions as noted above, we plan to include a sustainable target dividend payout of 50% to 60% of the OpCos' Distributable Cash Flow in our financial policy.

See "Our Business", "Industry Overview", "Management's Discussion and Analysis — Our Business" and "Risk Factors".

Our Assets

We operate six natural gas storage facilities in Alberta and California with a total effective working gas storage capacity of approximately 279.2 Bcf (as of September 12, 2025). In Canada, we own and operate: (i) the AECO Hub™ which is comprised of two facilities in Alberta (Suffield and Countess) totaling 154.0 Bcf of effective working gas capacity; and (ii) the Warwick storage facility in central Alberta with 21.5 Bcf of effective working gas capacity. In the United States, we own and operate: (i) the Wild Goose storage facility in northern California with 75.0 Bcf of effective working gas capacity; and (ii) the Lodi and Kirby Hills storage facilities in northern California with 28.7 Bcf of combined effective working gas capacity.

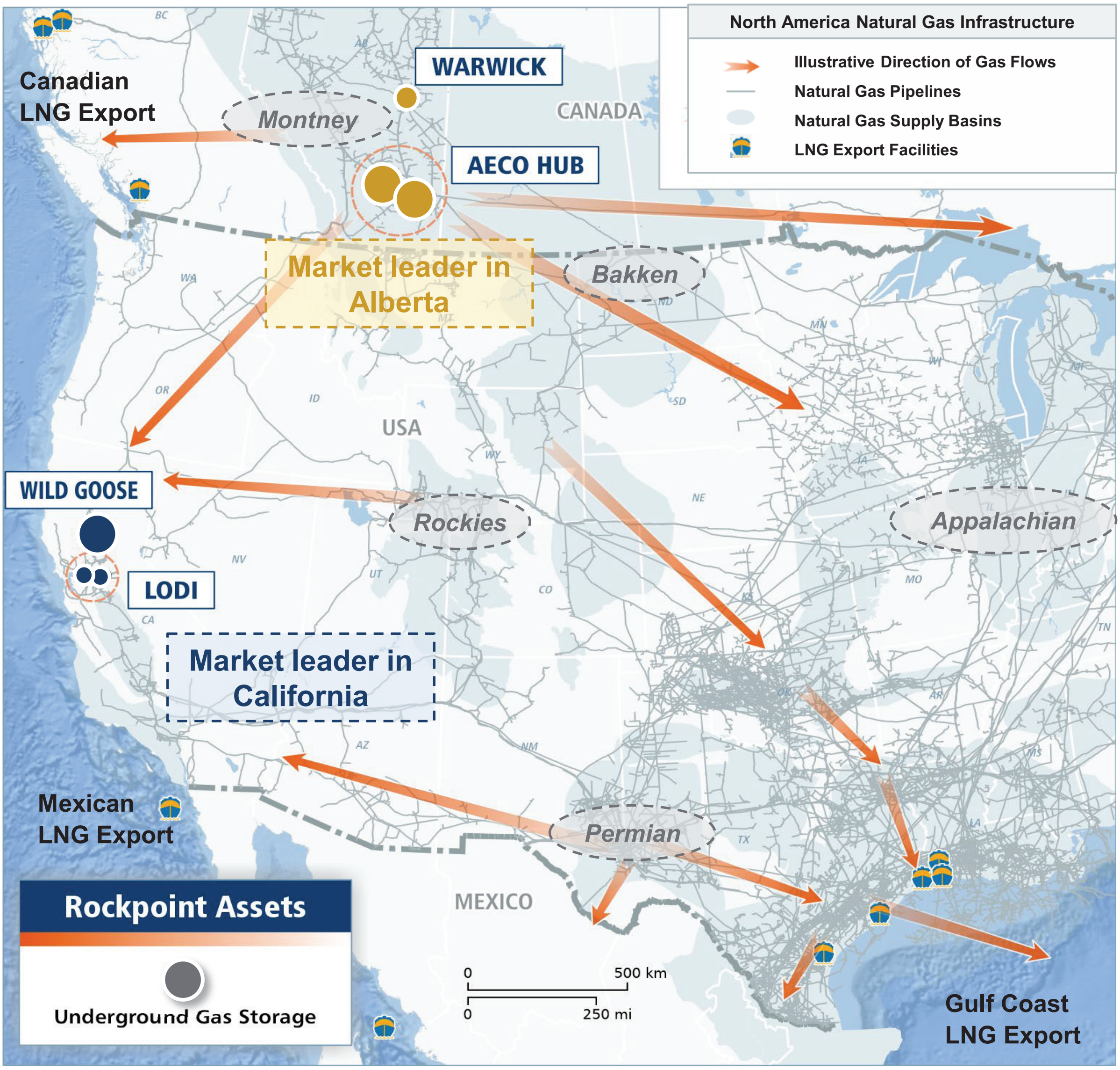
Wild Goose

Lodi & Kirby Hills

AECO Hub™

Warwick

The following depicts the location of our assets relative to natural gas supply basins and pipeline infrastructure:



Sources: geoSCOUT; and EIA.

Our storage facilities consist of high-quality underground depleted reservoirs which utilize a total of 156 wells alongside large-scale and integrated surface infrastructure to inject, store, and withdraw natural gas.

Depleted reservoirs are underground geological formations that have previously produced oil or natural gas. These reservoirs are ideal for storage due to their proven natural containment properties including porosity and permeability. Our reservoirs are equipped with advanced compression technology, including both gas drive and electric drive compressors, providing the necessary horsepower to quickly inject or withdraw large volumes of natural gas. All six of our storage assets can be characterized as having high peak deliverability. Deliverability, often expressed in MMcf/d or MMDth/d, is a measure of the amount of gas that can be withdrawn from a storage facility daily. High deliverability refers to the ability to extract and inject gas quickly during periods of peak demand or price spikes, allowing us to quickly meet customer needs. At full capacity, our storage reservoirs and equipment can deliver combined injection rates of 4,125 MMcf/d and withdrawal rates of 5,000 MMcf/d, allowing us to rapidly respond to market conditions and fulfill customer obligations. Since the establishment of the Business platform in 2016, our storage facilities have consistently fulfilled our ToP and STS contractual obligations.

Our assets are supported by 311 owned pipeline kilometers and 8 interconnects which connect us to major natural gas pipeline networks, such as PG&E's Redwood Path in California and TC Energy's NGTL System in Alberta. We believe these interconnections give our facilities access to highly liquid natural gas supply and demand markets. Our large, diversified and well-connected platform allows us to offer unique and highly customizable natural gas storage solutions to our wide range of customers.

We believe our reservoirs are high quality, meeting high standards from both an integrity and safety perspective. We maintain a five-year plan to forecast and allocate maintenance capital needs within major spending categories of regulatory compliance, reliability, and integrity. We also recognize that a robust safety culture not only improves safety outcomes but also drives operational efficiency. Over the past three years, our assets have maintained exemplary safety records with a Total Recordable Incident Rate of zero.

The following table highlights certain important design information about our assets:

Storage Facility	Wild Goose	Lodi & Kirby Hills	AECO Hub™	Warwick	Total
Ownership Interest	100%	100%	100%	100%	100%
Location	California, U.S.	California, U.S.	Alberta, CA	Alberta, CA	California and Alberta
Facility Type	Depleted Reservoir	Depleted Reservoir	Depleted Reservoir	Depleted Reservoir	Depleted Reservoir
Start of Operations	1999	2002	1988	2010	1988 – 2010
# of Injection/Withdrawal Wells	21	34	85	16	156
Effective Working Gas Capacity (Bcf)	75.0	28.7	154.0	21.5	279.2
Max Injection (MMcf/d)	525	550	2,750	300	4,125
Max Withdrawal (MMcf/d)	950	750	3,050	250	5,000
Heat Rate (dth / Mcf)	1.0536	1.0535	1.0733	1.0593	—
# of Interconnects	2	3	2	1	8
Owned Pipeline Kilometers	55	72	156	27	311

Our Commercial Model

Our commercial model is designed to be flexible and create mutually beneficial outcomes for us and our customers. Our revenue is categorized as either Fee for Service or optimization. Fee for Service includes both long-term Firm Storage Service ("**Take-or-Pay**" or "**ToP**") contracts and recurring Short-term Storage Service ("**STS**") contracts. We also maintain a portion of our effective working gas capacity to capture value through optimization activities undertaken with internally owned gas. Our storage capacity is initially reserved to service ToP customer contracts. This ToP reserve reflects the expected seasonal build of our ToP customers' summer injection and winter withdrawal as a portion of total working gas capacity. STS contracts are then leveraged to primarily fill gaps left by the ToP reserve cycle. The remaining small portion of storage capacity is then utilized by Rockpoint for optimization activities. The storage capacity for optimization varies depending on actual ToP customer injection and withdrawal observed throughout the year.

We have prudent risk management policies in place and do not carry open commodity price risk in any of our revenue segments. Our allocation between ToP, STS, and optimization strategies is designed to maximize the economic value of our storage capacity while maintaining operational flexibility. Our long-term target is to achieve 60% of Adjusted Gross Margin from ToP contracts, 25% of Adjusted Gross Margin from STS contracts, and 15% Adjusted Gross Margin from optimization strategies. In California, our facilities are operating at or near our long-term contracting targets. In Alberta, we continue to experience growth in contracted ToP volumes and storage rates as new customers enter the market.

Fee for Service Revenue

Fee for Service revenue consists of longer-term ToP contracts (typically ranging from one to ten years) and STS contracts (typically spanning up to one storage season with a strong history of contract renewals). Our Fee for Service revenue is underpinned by a diverse and high-quality customer base that stores customer-owned gas volumes in our storage facilities. Our strong performance not only reflects the resilience and attractiveness of our commercial model but also reinforces our strategic positioning in the market, enabling predictable cash flows and long-term value creation.

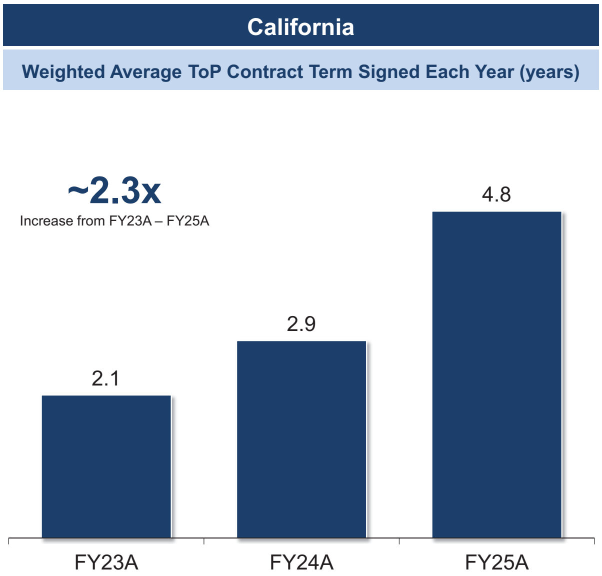
Under ToP contracts, our customers are obligated to pay a fixed monthly demand charge for storage capacity regardless of utilization. Customers have the right, but not the obligation, to inject, store or withdraw a predetermined amount of gas as specified in each contract. We receive the monthly demand charge regardless of the actual capacity utilized by our customers. When customers utilize reserved capacity under these contracts, we receive additional variable fees based on the actual volumes of natural gas injected or withdrawn. These variable fee payments help us recover operating costs. ToP contracts accounted for approximately 45% of total fiscal 2025 Adjusted Gross Margin and have a 3.5-year weighted average contract life. The ToP contracts accounted for approximately 70% of fiscal 2025 Adjusted Gross Margin in California and approximately 12% of fiscal 2025 Adjusted Gross Margin in Alberta. The ToP contracts currently have a weighted average tenor of approximately 3.6 years in California and approximately 2.9 years in Alberta. In fiscal 2025, we executed 25 new ToP contracts contributing a cumulative $499 million of future contracted revenue with weighted average contract terms of approximately five years in California and three years in Alberta.

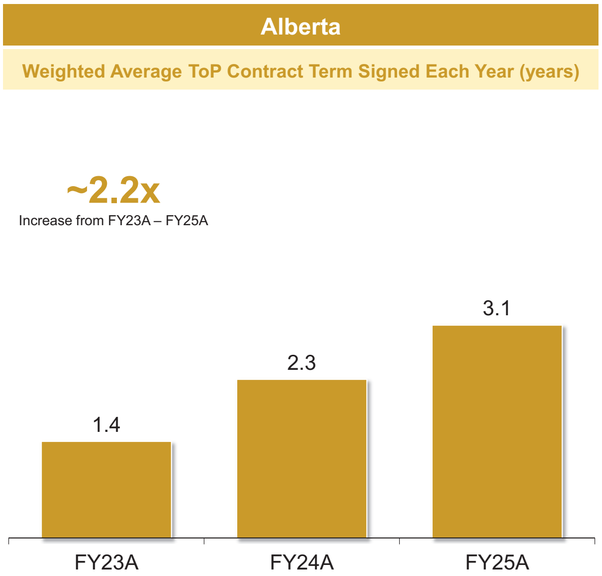
In California, our ToP contracting has increased from 49% of our California facilities' total effective working gas storage capacity in fiscal 2023 to 69% in fiscal 2025. Over the same period, our ToP contracted demand charges in California have increased from $1.02/Dth earned in fiscal 2023 to $2.30/Dth in fiscal 2025. This has resulted in an increase in California ToP Adjusted Gross Margin from $59.9 million in fiscal 2023 to $163.3 million in fiscal 2025. This upward trend reflects the transition of our contract portfolio as lower priced legacy contracts have rolled off in favour of multi-year higher-priced market rate contracts. For example, our ToP contracts in California have an average ToP demand charge of $2.87/Dth in fiscal 2026, representing an approximately 25% increase over the realized average ToP demand charge in fiscal 2025. We expect California ToP demand charge to increase due to a tighter storage market and strong customer demand for long-term security of gas supply.

In Alberta, our ToP contracting capacity has doubled from 7% of our Alberta facilities' total effective working gas storage capacity in fiscal 2023 to 15% in fiscal 2025. Over the same period, our ToP contracted demand charges in Alberta have increased from $0.42/Dth earned in fiscal 2023 to $0.75/Dth earned in fiscal 2025. This has resulted in an increase in Alberta ToP Adjusted Gross Margin from $6.2 million in fiscal 2023 to $21.7 million in fiscal 2025. We expect our Alberta ToP contracted gas storage volumes and contracted demand charges to increase as additional west coast LNG projects enter into service. Our ToP contracts in Alberta have an average ToP demand charge of $0.94/Dth in fiscal 2026, representing an approximately 26% increase over the realized ToP average demand charges in fiscal 2025.

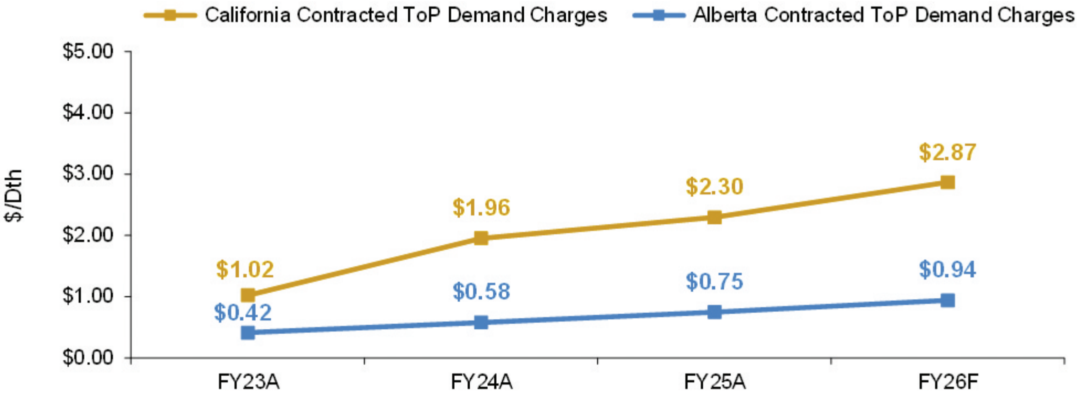
We believe these developments in the gas storage market and customer demand position us to capitalize on emerging market dynamics and reinforce the strategic importance of our Alberta storage assets in supporting Canada's evolving energy structure.

The following charts show the growth in weighted average ToP contract terms signed each year in California and Alberta:





The following chart shows the current weighted average ToP contracted storage demand charges for California and Alberta operations:



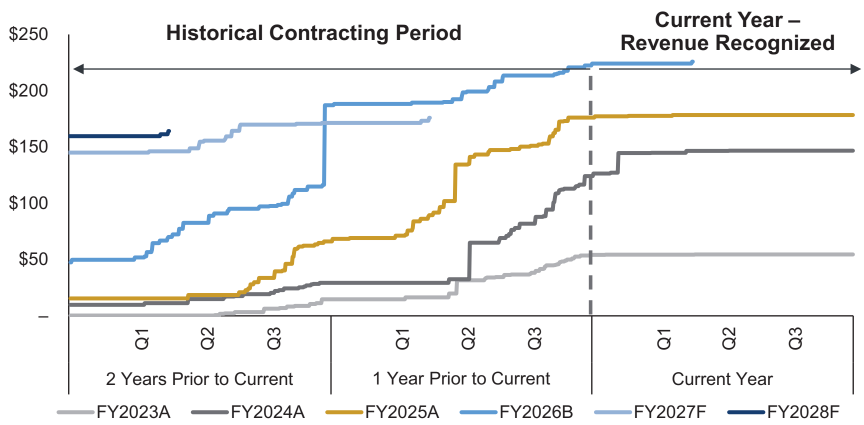
The table below represents ToP contracted demand capacity as a % of total effective working gas storage capacity:

	FY23A	FY24A	FY25A	FY26F
California	49%	70%	69%	68%
Alberta	7%	14%	15%	15%

ToP contracts are typically negotiated and executed with counterparties in the fall and winter for storage service commencing the following fiscal year and beyond. This contracting timeline is required to allow customers to be able to prepare for and utilize the full summer season (April 1st to October 31st) to inject their gas into our facilities prior to the start of the winter withdrawal season (November 1st to March 31st). Since fiscal 2023, we've enhanced our ToP contract profile through increased ToP contract volumes, improved rates and longer contract tenors.

The following chart represents the ToP gross margin build over time for each financial year (fiscal 2026, fiscal 2027, and fiscal 2028 represent contracted ToP gross margin not yet recognized in the Financial Statements of the Business):

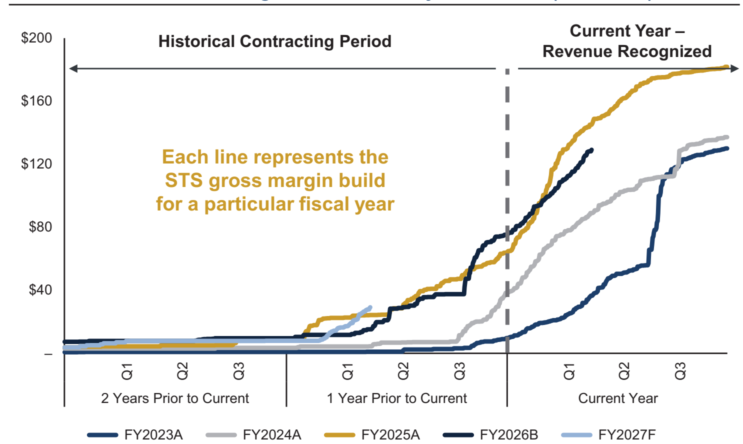
Transacted ToP Gross Margin Over Time – By Fiscal Year ($ millions)



Under STS contracts, our customers pay a fixed fee to inject and withdraw specified quantities of natural gas which are typically recognized as revenue (50% paid on injection and 50% paid on withdrawal). Unlike ToP contracts, STS contracts require customers to inject and withdraw specified quantities on specified, predetermined dates. STS contracts enable us to secure value by capturing the seasonal value of the price difference between summer and winter months net of the customer's required return on the transaction. Because STS contracts specify predetermined injection and withdrawal volumes at predetermined times, it also allows us to opportunistically enter into offsetting transactions to capture incremental storage value as spot and future natural gas spreads fluctuate prior to the original transaction's specified withdrawal date. A typical example of an STS contract is when a customer enters a contract with us to inject gas at a consistent daily rate in the summer months, when gas prices are lower, and to withdraw the same amount at a consistent daily rate in the winter months, when prices are higher. In fiscal 2025, our STS contracts made up approximately 41% of total Adjusted Gross Margin across the portfolio.

STS is an important component of our Fee for Service strategy, providing a base fee and also allowing us to retain upside from additional contract layering throughout the year. While STS gross margin is primarily transacted within each fiscal year, our STS gross margin has continually increased each year as demonstrated in the following chart. Since fiscal 2023, our STS contracted rates have increased by 59% in California and 134% in Alberta, reflecting strong storage fundamentals in each respective market.

Transacted STS Gross Margin Over Time – By Fiscal Year ($ millions)[1]



Note:

(1) Transacted STS gross margin chart excludes STS payables pertaining to cushion gas support.

As of March 31, 2025, we had approximately $893 million in contracted Fee for Service revenue backlog which includes both ToP and STS contracts. In fiscal 2025, 86% of our total Adjusted Gross Margin was contracted on a Fee for Service basis, surpassing our target of 85%. ToP contracts accounted for approximately 45% of fiscal 2025 Adjusted Gross Margin while STS contracts made up approximately 41% of fiscal 2025 Adjusted Gross Margin.

Optimization Revenue

We manage a small portion of our storage capacity through a storage optimization strategy which is intended to provide us the flexibility to first manage our firm fee for service customer obligations if needed and then capture market opportunities as they arise. Storage optimization involves purchasing, storing and selling natural gas for our own account using our own corporate liquidity for profit. In line with our internal risk policy, we do not take open positions that expose us to price or physical delivery risk. Instead, we aim to eliminate market price risks by matching inventory purchases with physical and financial contracts effectively locking in margins at the time of injection. As a result, our activities remain non-speculative, operating strictly within defined operational risk tolerances. Our storage optimization strategy has proven to be valuable in allowing us to capture seasonal spread value and subsequently generate incremental gross margin.

Storage optimization activities include capturing the spread from short term weakness in cash markets versus forward markets, selling gas inventory in cash markets during high price events while simultaneously repurchasing gas forwards in backward dated markets, and intra-season injections and withdrawals. Typically, as long as Rockpoint has owned inventory in the ground and available injection and withdrawal capacity, we can participate in positive value capture either in the cash market or on the natural gas forward curve. This provides operational flexibility by leveraging unused capacity, providing stable base cash flows while maximizing upside value capture.

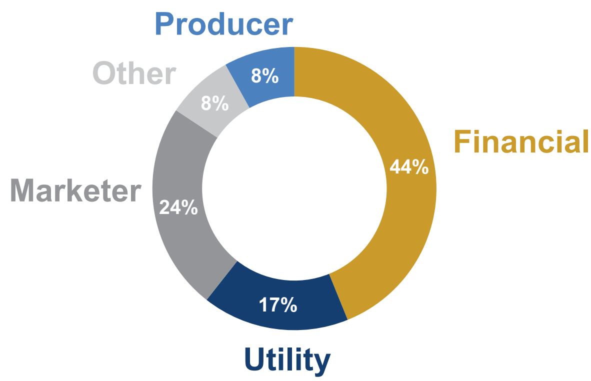
See “Industry Overview”, “Our Business” and “Risk Factors”.

Our Customers

We have cultivated a high-quality, diverse, and long-standing customer base across North America. Our customers include utilities, producers, pipelines, power generators, LNG operators, financial institutions, and marketers each of whom have their own unique storage needs. For utilities, our storage provides supply security during demand spikes and peak day needs, effectively helping manage ratepayer and end-user costs. Producers benefit from our storage through an ability to manage their operational risks and ensure energy availability during high volatility events. Pipeline companies rely heavily on storage to facilitate load balancing and system supply management on their transmission lines. Power generators leverage gas storage to balance the intermittent nature of renewable power and for accelerated deployment to meet urgent needs, especially during peak demand. Financial institutions can leverage our storage to utilize their cost of capital advantage and earn returns on “parked inventory” of natural gas that lock in seasonal spreads. Marketers and commodity traders use our storage services for managing positions, utilizing storage contracts to secure value, and optimize transport positions. Going forward, we expect that LNG exporters will rely significantly on gas storage platforms to balance year-round LNG demand and to mitigate operational disruptions from planned and unplanned outages similar to what we have seen occur in the U.S. Gulf Coast region.

The following chart demonstrates our diversified customer base:

Diversified Customer Base[1]



Note:

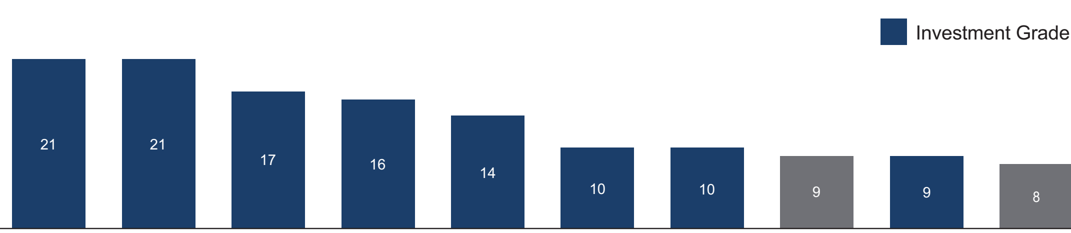
(1) Based on fiscal 2025 Fee for Service Adjusted Gross Margin.

Relationship length and creditworthiness

We maintain strong, long-standing relationships across our customer base, with a weighted average customer relationship tenure of approximately 8 years among our 57 customers. Customer relationship tenure is defined as the number of years that a customer has consecutively had active ToP or STS contracts with Rockpoint. Several relationships extend beyond 15 years, underscoring the durability of our commercial partnerships. Our top 10 ToP customers have an approximate 7-year weighted average customer relationship tenure and represented 26% of fiscal 2025 Adjusted Gross Margin. Our top 10 STS customers have an approximate 9-year weighted average customer relationship tenure and represented 42% of fiscal 2025 Adjusted Gross Margin. We believe that our strong customer retention is supported by our operating track record, high deliverability, reliability, customizable service offering, and the scarcity of alternative gas storage solutions. Furthermore, our customers are incentivized to renew their contracts to: (i) maintain continuity and avoid financial penalties when volumes are not fully withdrawn at the end of their existing contract; (ii) opportunistically take advantage of rolling existing inventory into future premium periods; and (iii) reduce the risk of an inability to find storage capacity in the future.

The following charts demonstrate our top 10 ToP and STS customers by relationship tenure:

Current Top 10 ToP Customers by Tenure (years)



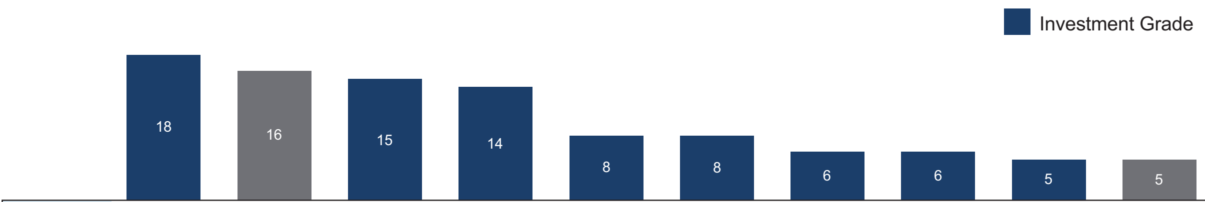
S&P Credit Rating	GOVT[1]	GOVT[1]	A	A-	A-	BBB+	BBB+	NR[2]	A	NR[2]
Type	Utility	Utility	Producer	Financial	Utility	Producer	Producer	Marketer	Financial	Marketer

Notes:

(1) "GOVT" is not an S&P credit rating and is defined as any government institutions, which may include U.S. states, counties, municipalities, school districts, and special government districts.

(2) "NR" is defined as not rated by S&P.

Current Top 10 STS Customers by Tenure (years)



S&P Credit Rating	A	NR[1]	A+	A-	A	BBB+	A-	BBB-	A-	NR[1]
Type	Financial	Marketer	Financial	Financial	Financial	Financial	Financial	Utility	Financial	Marketer

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Note:

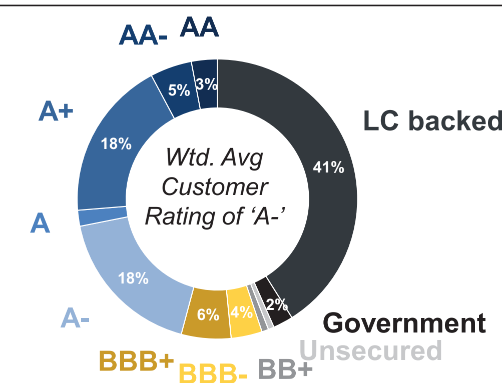
(1) "NR" is defined as not rated by S&P.

All credit ratings referenced in the above charts reflect credit ratings issued by S&P, unless stated otherwise. S&P considers credit ratings from 'AAA' to 'BBB-' as "investment grade". S&P defines: (i) a credit rating of 'AAA' as extremely strong capacity to meet financial commitments; (ii) a credit rating of 'AA' as very strong capacity to meet financial commitments; (iii) a credit rating of 'A' as strong capacity to meet financial commitments, but somewhat susceptible to economic conditions and changes in circumstances; and (iv) a credit rating of BBB as adequate capacity to meet financial commitments, but more subject to adverse economic conditions. Ratings may be modified by the addition of a plus (+) or minus (-) sign to show relative standing within the major rating categories. Any companies which are not rated by S&P are categorized as "NR" in the table above. Any government institutions, which may include U.S. states, counties, municipalities, school districts, and special government districts, are labeled as "GOVT" in the above charts.

The weighted average credit rating of our rated customer base is 'A-'. More than 95% of our customers are either investment-grade rated or are required to post a letter of credit equal to one year's demand charge. We also have a contractual right to take possession and liquidate a customer's injected gas in the event of their default. This allows us to settle any uncollected contractual amounts and provides us with additional credit certainty. We have had no material collection issues from storage customers in more than ten years.

The following chart demonstrates our highly creditworthy customers:

Customers Credit Quality[1]



Note:

(1) Based on fiscal 2025 Fee for Service Adjusted Gross Margin.

See "Our Business — Our Customers" and "Risk Factors".

Our Competitive Strengths

We believe that the following strengths of our business differentiate us from our competitors, reinforce our leadership position, and enable us to capitalize on expected growth in natural gas storage demand.

Our assets are strategically positioned in diversified markets with increasing natural gas demand

In California, storage assets are essential for balancing energy needs, especially as renewable energy sources are projected to comprise 48% of the power mix by the end of 2025 according to the EIA. This shift necessitates natural gas-fired power generation to manage intermittency and ensures reliable energy supply during periods when renewable output is low. Furthermore, the ongoing buildout of data centres will require northern California to compete more aggressively for gas supply. While demand is growing, the supply of natural gas into northern California is constrained with only two pipeline sources, Baja in the south and Redwood Path in the north. As a result, there is a heightened reliance on independent storage operators in northern California to provide essential storage solutions, ensure grid reliability, and effectively assist in managing price volatility in the energy markets.

In Alberta, we expect western Canadian LNG projects to increase regional demand by approximately 5.0 Bcf/d by 2031 (after adjusting expected demand, based on project status, from all currently proposed western Canadian LNG projects) and demand to be further amplified by oil sands expansion, growing electricity needs and potential data centre development. According to S&P Global Commodity Insights, total natural gas demand in western Canada is expected to increase by approximately 26% from 2024 to 2031. S&P Global Commodity Insights also expects domestic industrial gas demand in Alberta to increase by approximately 19% by 2030, primarily driven by the growth in oil sands production. As of September 12, 2025, there were 29 data centres in the AESO queue, representing approximately 15 GW of potential aggregate power demand according to AESO. Renewable energy will be able to respond to a portion of the incremental energy demands; however, a reliable source of natural gas-fired power generation is also expected to be required to counterbalance renewable intermittency. As a result, we expect Alberta's storage facilities to become increasingly essential for managing natural gas supply and ensuring its stable delivery to domestic and international export markets, particularly as demand grows and during peak demand periods.

We believe our facilities in California and Alberta are strategically positioned to capitalize on increasing storage demand and play a critical role in balancing regional supply shortfalls. Our facilities are competitively positioned with interconnections to several key natural gas pipelines to ensure long-term availability of supply and connectivity to quality customers and demand hubs. See "Risk Factors — Risks Related to Our Business and Industry".

Our assets are difficult to replicate with significant barriers to entry

We believe that replicating our portfolio of operating assets would be very challenging due to: (i) complex and lengthy regulatory permitting processes; (ii) the need for ideal reservoir physical characteristics such as porosity, permeability and retention capacity; (iii) limited land availability with proximity to demand centres or LNG facilities; (iv) lengthy development lead times; (v) the requirement for reliable and available pipeline capacity; and (vi) high development costs. New entrants must navigate a landscape where optimal conditions are essential. In the current environment we would expect it to take approximately five to ten years to build a greenfield natural gas storage facility including establishing a connection to a major pipeline, with greenfield economics likely requiring storage rates typically higher than the current weighted average rate we earn on our working gas capacity. Moreover, in California, there are incremental challenges including stringent regulatory requirements and limited supply of gas due to constrained pipeline capacity that significantly inhibit any development of greenfield projects.

Our large and diverse platform enables us to offer highly customizable natural gas storage solutions to a diverse customer base

In California and Alberta, we own and operate multiple strategically positioned gas storage facilities. Our large and diversified platform allows us to offer tailored storage solutions that are able to address multiple customer requirements. These customer requirements may include: (i) managing supply security during peak demand periods; (ii) optimizing energy distribution to accommodate renewable energy integration; and (iii) providing flexible storage options for LNG developments. We believe that our ability to serve a broad range of customer profiles and offer operational and commercial flexibility provides us with a significant competitive advantage. Furthermore, our diversified asset base provides additional operational flexibility within our portfolio. For example, our AECO Hub™ facilities function as a single commercial hub which allows for efficient deliverability by utilizing preferred storage pools across the two facilities to service contract obligations.

Exemplary operational track record with history of high deliverability and reliability

We believe deliverability rate and reliability are crucial aspects for natural gas storage customers as they directly impact customers' ability to meet fluctuating demand and ensure a reliable supply of energy. Our facilities allow our customers to withdraw gas at a rate that matches their consumption patterns, particularly during peak demand periods or unexpected spikes. This capability is essential for utilities and power generation companies who must balance ratable pipeline takes with non-ratable power burn to ensure they can provide consistent energy output without interruption. We believe our assets have some of the highest deliverability rates in their respective markets. For example, the Wild Goose facility in northern California has a maximum withdrawal capacity of 950 MMcf/d, while the AECO Hub™ in Alberta offers a maximum withdrawal capacity of 3,050 MMcf/d. We believe that these rates are critical for balancing supply and demand in the regions that we serve and ensuring customers can meet their requirements. In our 9 year operating history under the Rockpoint platform, our storage facilities have consistently fulfilled all of our ToP and STS contractual obligations.

We invested $53 million of maintenance capital between fiscal 2023 and fiscal 2025 to ensure plant reliability and performance, which has allowed us to achieve high availability of 95%. Our operations are supported by built-in redundancies such as back-up power generation in California and a functioning operational hub concept in Alberta, which allows us to achieve a high reliability standard. We believe that our operational reputation and high reliability are competitive advantages with customers.

Stable and predictable cash flow provides financial flexibility

Our contract structure, customer retention, and recurring contract renewals have historically provided us with stable and predictable cash flow. As of March 31, 2025, we had secured approximately $893 million in contracted Fee for Service revenue backlog. The use of ToP contracts allows us to secure predictable cash flows by charging fixed monthly demand charges, regardless of utilization. This cash flow predictability also provides us with the flexibility needed to strategically plan operations and financial policy. We target to have ToP contracts comprise 60% of Adjusted Gross Margin. STS and optimization activities provide significant cash flow in addition to our ToP cash flows.

High EBITDA margins and Distributable Cash Flow Conversion supports reinvestment and returns of capital

Our high Distributable Cash Flow Conversion allows us to strategically re-invest in the Business to drive growth and evaluate various forms of returning capital to our shareholders, such as through dividends and share buybacks. Our operations have consistently demonstrated high Adjusted EBITDA margins and strong Distributable Cash Flow Conversion underpinned by minimal maintenance capital expenditure requirements. In fiscal 2025, we generated Distributable Cash Flow of $234.5 million, that represented 69% of our fiscal 2025 Adjusted EBITDA. We have achieved Distributable Cash Flow Conversion above 60% over the last three fiscal years and our current strategic goals and targets have been designed with the goal of continuing this trend. We have adopted a sustainable target dividend payout of 50% to 60% of the OpCos' Distributable Cash Flow in our financial policy which is predicated on our stable cash flow base and financial outlook. Our target dividend payout plans for $110 million to $120 million of total annual dividends from the Business (of which approximately 40% of any payout would be paid to the Company), and growing annually at a rate of 3% to 5%. We have identified various strategies for maintaining, and potentially growing, Distributable Cash Flow, including future fee for service contract executions, accretive capital projects and strategic optionality opportunities, see "Our Business and Growth Strategies".

Industry leading management team with significant experience and proven track record

Our senior management team is composed of seasoned professionals with approximately 150 years of combined experience in the natural gas industry. They have a strong track record of building and operating natural gas storage assets, and executing mergers and acquisitions in the natural gas storage space. We also have a comprehensive in-house team of specialists including geologists, reservoir engineers, risk managers, marketers, schedulers, accountants, lawyers and regulatory experts with extensive experience in natural gas storage operations and development. Their deep understanding of risk management, natural gas market dynamics, and the regulatory landscape enables us to navigate complex challenges and seize emerging opportunities.

See “Our Business — Our Competitive Strengths”, “Risk Factors”, “Notice to Investors — Forward-Looking Information”, “Dividend Policy”, “Risk Factors — Risks Related to Our Business and Industry”, “Risk Factors — Risks Related to Our Financial Condition”, and “Selected Historical Financial Information”.

Our Business and Growth Strategies

Since our formation in 2016, we have actively optimized and divested assets. Notwithstanding this progress, we continue to identify market opportunities to enhance our business. Our strategic initiatives are focused on further optimizing existing assets while exploring new avenues for expansion.

Utilize our large portfolio of strategically located assets in key markets to grow cash flows under long-term, ToP contracts at attractive rates

As natural gas demand continues to grow, our facilities are becoming increasingly important in balancing the constrained regional supply shortfalls in the California and Alberta markets. As a result, we expect the demand for our gas storage services to continue to increase. We expect to continue to grow our business by entering into additional ToP contracts on favourable terms. We have a demonstrated contracting track record that validates this trend with customers actively signing contracts to secure more storage capacity at higher rates and for longer tenors. In California, our ToP contracted storage demand charges have increased from $1.02/Dth earned in fiscal 2023 to $2.30/Dth earned in fiscal 2025. This upward trend reflects the transition of our contract portfolio as lower priced legacy contracts have rolled off in favour of multi-year higher-priced market rate contracts. Similarly, in Alberta, our ToP contracted storage demand charges have increased from $0.42/Dth earned in fiscal 2023 to $0.75/Dth earned in fiscal 2025. We expect Alberta ToP contracted gas storage rates to increase as additional west coast LNG projects enter into service. In fiscal 2025, we executed 25 new ToP contracts at rates higher than historical averages, with weighted average contract terms of approximately five years in California and approximately three years in Alberta, which has increased from approximately two years and approximately one year in fiscal 2023, respectively.

Pursue high return and capital efficient organic growth opportunities

We have identified a robust pipeline of capital efficient organic growth projects focused on: (i) increasing margins; (ii) enhancing deliverability; (iii) increasing working gas capacity; and (iv) improving connectivity and infrastructure to support buildouts and complementary storage service offerings. We currently have several such brownfield growth opportunities in progress with other longer-term initiatives under consideration. Our near-term brownfield opportunities growth capital expenditures are anticipated at approximately $50 million to $150 million over an estimated three to five year period, with Adjusted EBITDA build multiples averaging 5x.

We recently completed an expansion project at the Wild Goose storage facility in California which included the drilling and tie-in of three new storage wells. The expansion at Wild Goose added approximately 20 MMcf/d of incremental deliverability with growth capital expenditures of approximately $14 million with an Adjusted EBITDA build multiple of approximately 3x, where Adjusted EBITDA build multiple is calculated as the total growth capital expenditures divided by our expected average five-year run-rate Adjusted EBITDA.

We anticipate an Alberta expansion project at the Warwick facility that will add up to 5 Bcf of incremental working gas capacity and increase overall operational efficiency. Infrastructure has already been acquired and efforts to acquire mineral rights for the expansion project are underway. The regulatory applications have been prepared and the capital plan is progressing. We expect the expansion to be completed in 2026 and growth capital expenditures of approximately $11 million, with an Adjusted EBITDA build multiple of approximately 3x.

Additional brownfield projects have been identified to increase capacity and to increase deliverability. In California, we are pursuing an opportunity to increase storage capacity and deliverability through the addition of wells and compression. In Alberta, we have identified a reservoir that we may be able to tie into an existing facility that could add additional working gas capacity. The brownfield opportunities allow us to stage capital and de-risk the opportunity as we pursue the full development.

We believe that there will be additional opportunities to deploy capital to optimize the existing assets. We have identified unutilized and underutilized assets that may be redeployed to further increase working gas capacity and the deliverability of the existing assets.

Diversify service offerings beyond natural gas storage by pursuing capital efficient innovative energy solutions

Our Alberta battery storage initiative represents a significant step towards integrating renewable energy sources into our operations. The implementation of Battery Energy Storage Solutions ("**BESS**") provides the ability to store low-priced power and deliver during times of peak demand. This project involves the installation of 31 MW of standalone battery storage across two facilities (11 MW at Warwick and 20 MW at the AECO Hub™) with an estimated completion in 2027 for Warwick and in 2029 for the AECO Hub™. The required permits from the Alberta Utilities Commission were received in fiscal 2025. The project has been further de-risked through the advancement in the AESO interconnection capital plan and commercial strategy. We expect the initiative to incur a growth capital expenditure of approximately $30 million, with an Adjusted EBITDA build multiple of approximately 6x. We believe that BESS is a logical extension to our core business as it leverages our significant standby power requirement with our low intermittent power load industrial sites and in-house market expertise. Battery storage infrastructure is also becoming a more important tool in stabilizing an evolving Alberta power grid and we expect it will represent a meaningful and diversified revenue stream for our Business going forward.

RNG is experiencing significant industry growth driven by increasing regulatory support, technological advancements, and rising demand for renewable energy sources. As RNG production scales up, we anticipate that there will be a growing need for reliable storage solutions to manage supply fluctuations, ensure consistent delivery to end-users and to provide valuable custody transfer services for carbon offset credits. We intend to continue to monitor and pursue strategic and accretive opportunities when they arise to grow our storage services catering to the RNG industry over the long-term.

Additionally, we are evaluating salt cavern development in multiple markets which we believe will be important to capitalize on certain long-term industry fundamentals. None of these projects have received final approval at this time, and we will implement our longer-term plans opportunistically at times that we determine to be most strategically advantageous for the Business.

Pursue opportunistic acquisitions to build further scale and strengthen our market position

As we continue to evaluate market dynamics and growth opportunities, we intend to evaluate and selectively pursue accretive acquisitions of complementary assets to further bolster our position and enhance our competitive advantage in the industry. We will employ a rigorous framework to evaluate such opportunities, and potential acquisitions will compete with alternative uses of capital including: (i) organic growth projects; (ii) shareholder dividends; (iii) share repurchases; and (iv) debt reduction. We have a demonstrated track record of completing mergers and acquisitions. Our strategic development has been shaped by three key storage facility acquisitions which have defined our extensive operational footprint in North America. These acquisitions established the Business as the largest independent pure play operator of natural gas storage facilities in North America, strengthened our market position, expanded our operational capabilities and enabled cost efficiencies.

See "Our Business — Our Business and Growth Strategies" and "Risk Factors".

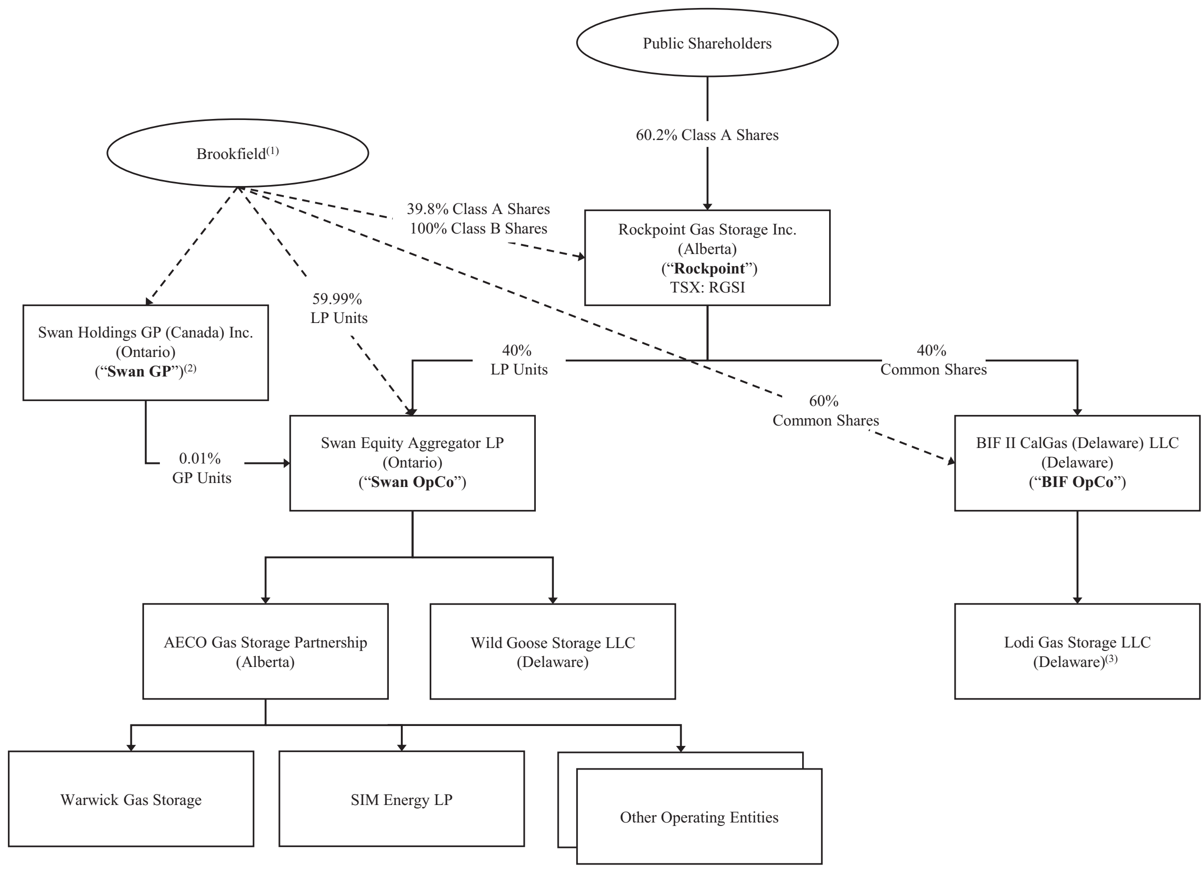
Formation of Rockpoint and the OpCos

Rockpoint was incorporated by Brookfield Infrastructure Holdings (Canada) Inc. under the ABCA on July 28, 2025. Rockpoint's registered and head office is located at 400 — 607 8th Ave. S.W., Calgary, Alberta, Canada, T2P 0A7. Rockpoint has not carried on any business as of the date hereof and was formed to complete the Transactions.

Swan OpCo is a limited partnership formed under the laws of the Province of Ontario on March 2, 2016. Swan OpCo's registered and head office is located at Brookfield Place, Suite 100, 181 Bay Street, Toronto, Ontario, Canada, M5J 2T3.

BIF OpCo is a limited liability company formed under the laws of the State of Delaware on July 23, 2014. BIF OpCo's head office is located at Brookfield Place, 250 Vesey Street, New York, New York, USA, 10281-1023 and its registered office is located at 2711 Centerville Road, Suite 400, Wilmington, Delaware, USA, 19808.

The Business is currently carried on by Brookfield through its ownership of the OpCos and WGS LP and their direct and indirect subsidiaries. Following completion of the Transactions, in which Rockpoint will acquire an approximate 40% interest in the Business, the simplified structure of the Company, including the interests in the OpCos (and therefore the Business), will be as follows:



Notes:

(1) Includes various affiliates of Brookfield. Consolidated for ease of reference.

(2) Swan GP, the general partner of Swan OpCo, is an affiliate of Brookfield.

(3) Lodi Gas Storage LLC owns the Lodi and Kirby Hills facilities.

(4) Unless otherwise disclosed, the percentage of votes attaching to all voting securities of the subsidiary beneficially owned, or controlled or directed, directly or indirectly, by the parent is 100%.

See "The Company and the OpCos".

The Transactions

The Transactions are being conducted through what is commonly referred to as an "Up-C" structure whereby all of the assets of the Business will be held by the OpCos and their respective subsidiaries and the sole material assets of the Company will consist of its equity interests in the OpCos. This structure is often used by partnerships and limited liability companies undertaking an initial public offering.

See "The Company and the OpCos — The Transactions" and "Relationship with Brookfield — The Transactions".

Relationship with Brookfield

Upon completion of the Transactions, Rockpoint will own approximately 40% of the OpCo Interests and Brookfield will own approximately 60% of the OpCo Interests, excluding any indirect beneficial ownership of Brookfield in OpCo Interests by virtue of its ownership in the Company. In addition, upon completion of the Transactions, assuming the Over-Allotment Option is not exercised, Brookfield will own approximately 39.8% of the outstanding Class A Shares and 100% of the outstanding Class B Shares, representing approximately 75.9% of the aggregate outstanding Shares and voting interest in the Company (or approximately 30.8% of the outstanding Class A Shares, representing, together with Brookfield's Class B Shares, approximately 72.3% of the aggregate outstanding Shares and voting interest in the Company, if the Over-Allotment Option is exercised in full). As a result, Brookfield will have control over the Company, the OpCos and the Business.

At Closing, the Company, Brookfield and the Selling Shareholders will enter into the Registration Rights Agreement and the Shareholder Agreement that, together, among other things, will provide Brookfield with the Registration Right, the Demand Registration Right and certain governance rights, including with respect to the nomination of directors to the Board. In addition, the Company, Brookfield and the OpCos have entered into the Relationship Agreement that provides, among other things, for the composition of the OpCo Boards and Brookfield with access to information in respect of the Company. The Relationship Agreement also provides that there are no restrictions on Brookfield's ability to compete with the Company and the OpCos following Closing. The Company and Brookfield have also entered into the Exchange Agreement that provides for the Exchange Right. See "Relationship with Brookfield", "Brookfield" and "Risk Factors". All of the Shares held upon completion of the Transactions by Brookfield, other than in connection with the Secondary Offering, and the directors and executive officers of the Company will be subject to contractual lock-up agreements with the Underwriters.

See "Relationship with Brookfield", "Plan of Distribution — Lock-Up" and "Brookfield".

Selected Historical Financial Information

The following tables present selected historical financial information for the Business. We have prepared the Financial Statements of the Business in accordance with IFRS. Prospective investors should read this information together with the Financial Statements of the Business appearing elsewhere in this prospectus and the information under "Management's Discussion and Analysis". The following selected historical financial information of the Business is only a summary and is not necessarily indicative of the results of future operations of the Business following completion of the Transactions.

The information set forth below represents selected historical financial information for 100% of the Business. Upon completion of the Transactions, the Company will hold an approximate 40% interest in the Business.

The interim historical financial information for the Business has been derived from selected unaudited interim condensed combined consolidated statements of net earnings and comprehensive earnings data for the three months ended June 30, 2025 and 2024, and selected unaudited interim condensed combined consolidated statements of financial position data as at June 30, 2025 and March 31, 2025, from the Interim Financial Statements appended to this prospectus.

(in millions, $)	Three Months Ended June 30, 2025	2024
Statement of Earnings and Comprehensive Earnings Information		
Revenues	**$104.1**	$91.7
Earnings before income taxes	**51.6**	47.9
Net earnings	**48.3**	45.6
Non-IFRS measures[(1)]		
Adjusted EBITDA	**$ 77.1**	$64.0
Adjusted Gross Margin	**95.9**	82.4
Distributable Cash Flow	**46.6**	49.7

	As at June 30, 2025	As at March 31, 2025
Statement of Financial Position Information (at end of period):		
Property, plant, and equipment, net	**$ 886.5**	$ 884.6
Total assets	**1,294.2**	1,430.2
Long-term debt	**1,219.1**	1,208.1
Non-current financial liabilities	**1,241.2**	1,231.2

Note:

(1) Adjusted EBITDA, Adjusted Gross Margin and Distributable Cash Flow are non-IFRS financial measures. See "Notice to Investors — Non-IFRS Measures" and "Management's Discussion and Analysis — Non-IFRS Measures Utilized by Our Business" for more information on each non-IFRS financial measure.

In reviewing the above information, reference should be made to: (i) the Interim Financial Statements; and (ii) the sections entitled "Management's Discussion and Analysis" and "Risk Factors" of this prospectus.

The annual historical financial information for the Business has been derived from selected combined consolidated statements of net earnings and comprehensive earnings data for the fiscal years ended March 31, 2025, 2024 and 2023, and selected combined consolidated statements of financial position data as at March 31, 2025 and 2024, from the Annual Financial Statements appended to this prospectus.

(in millions, $)	Fiscal Years Ended March 31, 2025	2024	2023
Statement of Earnings and Comprehensive Earnings Information			
Revenues	**$ 415.3**	$ 348.6	$278.0
Earnings before income taxes	**198.8**	249.3	47.1
Net earnings	**209.4**	253.9	44.5
Non-IFRS measures[(1)]			
Adjusted EBITDA	**$ 338.8**	$ 244.2	$152.6
Adjusted Gross Margin	**412.4**	318.7	229.1
Distributable Cash Flow	**234.5**	177.0	95.0
Statement of Financial Position Information (at end of period):			
Property, plant, and equipment, net	**$ 884.6**	$ 881.5	
Total assets	**1,430.2**	1,331.0	
Long-term debt	**1,208.1**	464.7	
Non-current financial liabilities	**1,231.2**	711.2	

Note:

(1) Adjusted EBITDA, Adjusted Gross Margin and Distributable Cash Flow are non-IFRS financial measures. See "Notice to Investors — Non-IFRS Measures" and "Management's Discussion and Analysis — Non-IFRS Measures Utilized by Our Business" for more information on each non-IFRS financial measure.

In reviewing the above information, reference should be made to: (i) the Annual Financial Statements; and (ii) the sections entitled "Management's Discussion and Analysis" and "Risk Factors" of this prospectus.

See the unaudited pro forma financial statements of the Company as at and for the three months ended June 30, 2025 and for the fiscal year ended March 31, 2025 included elsewhere in this prospectus for expected adjustments to the foregoing historical financial information for our Business resulting from the Transactions.

Risk Factors

An investment in Class A Shares involves significant risks. Prospective investors should carefully consider the risks described below and the other information elsewhere in this prospectus before making a decision to buy Class A Shares.

Other risks and uncertainties that the Company does not presently consider to be material, or of which the Company is not presently aware, may become important factors that affect the Company's and the OpCos' future financial condition and results of operations. If any of the following or other risks occur, our Business, prospects, financial condition, results of operations and cash flows could be materially adversely impacted. In that case, the trading price of the Class A Shares could decline and investors could lose all or part of their investment in the Class A Shares. There can be no assurance that risk management steps taken will avoid future loss due to the occurrence of the below described or other unforeseen risks. Below is a summary of the principal risks the Company and the Business face. These risks are discussed more fully under "Risk Factors".

- Risks related to our Business and industry, including risks related to:
  - the effects on our operating results of unfavourable economic and market conditions;
  - dependency on the supply of and demand for the products we handle;
  - operational risks and hazards of natural gas storage operations;
  - the impact of significant stabilization or reduction in the seasonal spread of natural gas prices on the demand for our natural gas storage services; and
  - our level of exposure to the market value of natural gas storage services.
- Risks related to environmental, public utility regulation and other regulations, including risks related to:
  - changes in the jurisdictional characterization of our assets by regulatory agencies or a change in policy by those agencies;
  - extensive and complex government regulations;
  - regulatory and permitting obligations;
  - environmental and health and safety laws and regulations; and
  - regulatory requirements relating to the safety and integrity of our storage facilities.
- Risks related to our financial condition, including risks related to:
  - our indebtedness and sufficiency of cash flows from operations;
  - the restrictions and limitations contained in the agreements and instruments governing our debt;
  - the interest rate risk associated with our variable rate debt;
  - the possibility that we incur substantially more debt, including secured debt; and
  - changes to applicable tax laws and regulations, exposure to additional income tax liabilities, changes in our effective tax rates or an assessment of taxes resulting from an examination of our income or other tax returns.
- Risks related to the Offering, Rockpoint's corporate structure and the Class A Shares, including risks related to:
  - Rockpoint being a holding company and its sole material assets to consist of its OpCo Interests;

- Rockpoint being solely dependent on the directors and management of Swan GP, as the general partner of Swan OpCo, and the board of managers and management of BIF OpCo, each of which is comprised of a majority of Brookfield-affiliated directors and managers for the operation of the Business and the amount and timing of cash distributions paid to the Company from the Business;
- there are no restrictions on the ability of Brookfield and its affiliates to compete with Rockpoint following completion of the Transactions;
- the requirements of being a public company, including compliance with the reporting requirements of applicable Canadian securities laws; and
- the failure of Rockpoint's internal or disclosure controls to satisfy its public company reporting obligations.

An investment in the Class A Shares is speculative and involves a high degree of risk. Prospective investors should carefully consider the information set out under "Risk Factors" and the other information in this prospectus before purchasing Class A Shares.

SUMMARY OF THE OFFERING

The following is a summary of the principal features of the Offering and should be read together with the more detailed information contained elsewhere in this prospectus.

Issuer:	Rockpoint Gas Storage Inc.
Proposed Trading Symbol:	"RGSI".
Offering:	32,000,000 Class A Shares from the treasury of the Company. If the Over-Allotment Option is exercised in full, the Selling Shareholders will sell 4,800,000 Class A Shares. See "Plan of Distribution".
Offering Size:	C$704,000,000.
Offering Price:	C$22.00 per Class A Share.
Over-Allotment Option:	The Selling Shareholders have granted to the Underwriters the Over-Allotment Option, exercisable at the Underwriters' discretion at any time, in whole or in part, until 30 days after the Closing Date, to purchase, at the Offering Price, up to 4,800,000 Class A Shares from the Selling Shareholders (representing 15% of the number of Class A Shares offered under this prospectus prior to the exercise of the Over-Allotment Option) to cover over-allotments, if any, and for market stabilization purposes. See "Plan of Distribution".
Shares Outstanding:	Upon completion of the Transactions, whether or not the Over-Allotment Option is exercised, 53,200,000 Class A Shares and 79,800,000 Class B Shares will be outstanding and no preferred shares will be outstanding. It is anticipated that Brookfield, through Brookfield Infrastructure Holdings (Canada) Inc. and the Selling Shareholders, will beneficially own approximately 75.9% of the total outstanding Shares following completion of the Offering (72.3%, if the Over-Allotment Option is exercised in full). See "Description of Share Capital and OpCo Interests".
Use of Proceeds:	The net proceeds to the Company from the Offering are estimated to be approximately C$659,200,000 after deduction of the Underwriters' commission and the estimated expenses of the Offering. Pursuant to the Underwriting Agreement, the Selling Shareholders will reimburse the Company for the expenses of the Offering, including the Underwriters' commission. The Company intends to use the proceeds received by it from the Offering to fund a portion of the OpCo Interest Purchase Price payable to the Selling Shareholders for approximately 40% of the OpCo Interests to be acquired, and to acquire 40% of the Warwick Receivable (which will subsequently be cancelled), pursuant to the Reorganization. If the Over-Allotment Option is exercised in full, the net proceeds to the Selling Shareholders from the Secondary Offering are estimated to be approximately C$100,320,000 after deduction of the Underwriters' commission. The Selling Shareholders will pay the Underwriters' commission in respect of the Secondary Offering. The Company will not receive any of the proceeds from the Secondary Offering. See "Use of Proceeds" and "Plan of Distribution".
Class A Shares:	Each Class A Share entitles the holder to one vote per Class A Share at all meetings of shareholders, except meetings at which or in respect of matters for

	which only the holders of another class of shares are entitled to vote separately as a class pursuant to the Articles or by law. Subject to the rights of holders of another class of shares of the Company, each Class A Share entitles the holder to receive any dividends or distributions declared by the Board from time to time on the Class A Shares and to receive the remaining property of the Company in the event of liquidation, dissolution or winding-up of the Company. Unless otherwise required by the Articles or by law, the holders of Class A Shares and Class B Shares vote together as a single class. See "Risk Factors — Brookfield has the ability to direct the voting of a majority of Shares and control certain decisions with respect to Rockpoint's management and business. Brookfield's interests may conflict with those of the other shareholders". 53,200,000 Class A Shares will be outstanding upon completion of the Transactions, representing approximately 40.0% of the total outstanding Shares. It is anticipated that Brookfield, through the Selling Shareholders, will beneficially own approximately 39.8% of the total outstanding Class A Shares following completion of the Offering (30.8%, if the Over-Allotment Option is exercised in full). See "Description of Share Capital and OpCo Interests".
Class B Shares:	Each Class B Share entitles the holder thereof to one vote per Class B Share held at all meetings of the shareholders, except meetings at which or in respect of matters for which only the holders of another class of shares are entitled to vote separately as a class pursuant to the Articles or by law. The holders of Class B Shares are generally not entitled to receive dividends or other distributions. Subject to the rights of the holders of preferred shares of the Company then outstanding, if any, and in priority to the holders of Class A Shares, each Class B Share entitles the holder to an amount of C$0.000001 per Class B Share in the event of liquidation, dissolution or winding-up of the Company. The Articles contain "coattail" provisions restricting the transfer of the Class B Shares in certain circumstances. Unless otherwise required by the Articles or by law, the holders of Class A Shares and Class B Shares vote together as a single class. See "Risk Factors — Brookfield has the ability to direct the voting of a majority of Shares and control certain decisions with respect to Rockpoint's management and business. Brookfield's interests may conflict with those of the other shareholders". Brookfield, through Brookfield Infrastructure Holdings (Canada) Inc., will beneficially own all of the outstanding Class B Shares following completion of the Offering. See "Description of Share Capital and OpCo Interests".
Dividend Policy:	The Company currently intends to establish a dividend policy pursuant to which the Company will pay a quarterly dividend in an amount based on its share of the OpCos' Distributable Cash Flow. The Company is currently targeting an initial dividend in the amount of approximately $0.22 per Class A Share (C$0.31 per Class A Share based on the Bloomberg mid-market exchange rate of C$1.00 = $0.7168 on October 7, 2025) or $0.88 per Class A Share on an annualized basis (C$1.23 per Class A Share based on the Bloomberg mid-market exchange rate of C$1.00 = $0.7168 on October 7, 2025), representing a payout ratio of 50% to 60% of its share of the OpCos' Distributable Cash Flow. The Company intends to pay its first such dividend on December 31, 2025 and thereafter, on a quarterly basis. The Company targets its dividend to grow annually at a rate of 3% to 5%. The Board's declaration of cash dividends on the Class A Shares will be subject to

applicable law and depend on, among other things, the timing and amount of distributions declared and paid by the OpCos to the Company, economic conditions, the Company's expenses, financial condition, results of operations, liquidity, earnings, projections, legal requirements, and restrictions in the agreements governing the Company's indebtedness, including the Credit Facilities. The OpCos intend to pay dividends to their partners and members, as applicable, including the Company, on a quarterly basis sufficient to ensure that the Company can fund its expenses and the payment of dividends. The OpCos have adopted a sustainable target dividend payout of 50% to 60% of their respective Distributable Cash Flow (of which approximately 40% of any payout would be paid to the Company). The OpCos' target dividend payout plans for $110 million to $120 million of total annual dividends from the Business (of which approximately 40% of any payout would be paid to the Company). Following its first dividend payment to shareholders, if, as and when an OpCo pays a cash distribution, the Company anticipates that the Board will declare and pay a corresponding cash dividend on the Class A Shares.

The OpCos' sustainable target dividend payout of 50% to 60% of their respective Distributable Cash Flow is based on our assessment of the current position of the Business and market conditions. We expect distributions from the OpCos to grow in line with the expected growth of our Distributable Cash Flow.

The Company will be fully dependent on distributions declared and paid by the OpCo Boards for cash to fund its expenses and the payment of dividends to holders of Class A Shares. However, each OpCo has agreed to use commercially reasonable efforts to make pro rata distributions in an amount sufficient to allow the Company to satisfy its income tax liabilities with respect to its allocable share of the income of such OpCo. Additionally, amendments to the financial policy setting forth the OpCos' sustainable target dividend payout will require the approval of the OpCo Boards. The OpCo Boards are comprised entirely of directors of the Company, with a majority of Brookfield-affiliated directors. See "Relationship with Brookfield — The Transactions" and "Risk Factors — Rockpoint is a holding company. The sole material assets of the Company following completion of the Transactions will be its OpCo Interests. Accordingly, the Company will be fully dependent upon distributions from the OpCos to fund its expenses and the payment of dividends".

The payment of any future dividends will be at the discretion of the Board, and there can be no assurances that any dividend will be declared and paid.

See "Dividend Policy".

Standstill/Lock-Up: Other than in connection with the Transactions, pursuant to the Underwriting Agreement, the Company has agreed that, subject to certain limited exceptions, it will not, and the Company shall use its reasonable commercial efforts to have each of its directors and executive officers who hold Class A Shares immediately following Closing to agree to not, directly or indirectly, without the prior written consent of the Lead Underwriters, on behalf of the Underwriters, which consent shall not be unreasonably withheld, issue, in the case of the Company, and sell (or direct the sale of), in the case of the directors and executive officers of the Company, or offer, grant or sell any option, warrant or other right for the purchase of, lend, transfer, assign or otherwise dispose of, in a public offering or by way of private placement or otherwise, any Class A Shares or other equity securities of the Company or other securities convertible into, exchangeable for, or exercisable into Class A Shares or other equity securities of the Company, or agree to do any of the foregoing or publicly announce any intention to do any of the foregoing, for a period of 180 days from the Closing Date.

In addition, the Selling Shareholders have agreed that, other than in connection with the Secondary Offering, they will not directly or indirectly, without the prior written consent of the Lead Underwriters, on behalf of the Underwriters, which consent shall not be unreasonably withheld, sell (or direct the sale of), or offer, grant or sell any option, warrant or other right for the purchase of, lend, transfer, assign, pledge or otherwise dispose of any of their Shares for a period of 180 days from the Closing Date, subject to certain limited exceptions.

See “Plan of Distribution — Lock-Up”.

Exchange Right:

Under the Exchange Agreement, subject to certain limitations, Brookfield (and its permitted transferees (other than the Company)), upon its determination, has the right (the “**Exchange Right**”) to cause the Company to acquire all or a portion of its OpCo Interests (along with the cancellation of a number of Class B Shares held by Brookfield corresponding to the number of OpCo Interests tendered) for, at the Company’s election (upon approval of a majority of the Non-Conflicted Directors): (i) Class A Shares at an exchange ratio of one Class A Share for each OpCo Interest and corresponding Class B Share exchanged (the “**Exchange Ratio**”), subject to adjustments for share splits, share consolidations, share reclassifications and other similar transactions; (ii) cash in an amount equal to the Cash Election Amount of such Class A Shares otherwise issuable to Brookfield pursuant to the Exchange Right; or (iii) a combination of (i) and (ii). In connection with any exchange of OpCo Interests pursuant to the Exchange Right, a number of Class B Shares held by Brookfield corresponding to the number of OpCo Interests exchanged will be cancelled.

The Exchange Agreement provides that Brookfield will not be permitted to exercise the Exchange Right: (i) for a period of 12 months from the Closing Date; and (ii) at any time, to the extent that the change of proportional ownership or operational control of the OpCos between Brookfield, on the one hand, and Rockpoint, on the other, would result in a change of control of the Lodi or Wild Goose operating subsidiaries for the purposes of the operating permits issued by the CPUC, unless the CPUC Approval has first been obtained.

The Exchange Agreement contains provisions effectively linking: (i) each BIF OpCo Share to a corresponding Swan OpCo Unit and vice versa; (ii) each OpCo Interest held by the Company with one Class A Share; and (iii) each OpCo Interest held by Brookfield with one Class B Share. No Class B Shares can be transferred without transferring an equal number of OpCo Interests and vice versa.

For additional information, please see “Relationship with Brookfield — Agreements Between the Company and Brookfield — Exchange Agreement”.

RISK FACTORS

An investment in Class A Shares involves significant risks. Prospective investors should carefully consider the risks described below and the other information elsewhere in this prospectus before making a decision to buy Class A Shares.

Other risks and uncertainties that the Company does not presently consider to be material, or of which the Company is not presently aware, may become important factors that affect the Company's and the OpCos' future financial condition and results of operations. If any of the following or other risks occur, our Business, prospects, financial condition, results of operations and cash flows could be materially adversely effected. In that case, the trading price of the Class A Shares could decline and investors could lose all or part of their investment in the Class A Shares. There can be no assurance that risk management steps taken will avoid future loss due to the occurrence of the below described or other unforeseen risks. Please also see "Notice to Investors — Forward-Looking Information".

Risks Related to Our Business and Industry

Our operating results may be adversely affected by unfavourable economic and market conditions.

Unfavourable conditions such as a general slowdown of the global, U.S. and/or Canadian economy, uncertainty and volatility in the financial markets, or inflation and rising interest rates, could materially adversely affect our operating results. For example, the global economic downturn caused by the coronavirus pandemic in 2020 affected numerous industries, including the natural gas industry and specific segments and markets in which we operate, resulting in reduced demand for natural gas. Also, inflationary pressure in recent years has resulted in higher operating expenses and project costs for us, as well as higher interest rates. More recently, there has been and may continue to be market uncertainty and volatility due to shifts in U.S. and foreign trade, economic and other policies following the most recent change in U.S. presidential administration.

In addition, uncertain or changing economic conditions within one or more geographic regions where we, our shippers or customers operate may affect our operating results within the affected regions. Sustained unfavourable commodity prices, volatility in commodity prices or adverse changes in markets for a given commodity might also have a negative impact on many of our customers, which could impair their ability to meet their obligations to us. See "— We are exposed to the credit risk of our customers and counterparties, and any material nonpayment or nonperformance by our key customers or counterparties could adversely affect our financial results".

If economic and market conditions (including volatility in commodity markets) globally, in the U.S., Canadian or other key markets become more volatile or deteriorate, we may experience material adverse effects on the Business and our results of operations and financial condition.

The Business is dependent on the supply of and demand for the products we handle.

Our natural gas storage activities depend in part on continued production of natural gas in the geographic areas that they serve. Without additions to gas reserves, production will decline over time as reserves are depleted and production costs may rise. Producers in areas served by us may not be successful in exploring for and developing additional reserves or their costs of doing so may become uneconomic. Commodity prices and tax incentives may not remain at levels that encourage producers to explore for and develop additional reserves, produce existing marginal reserves or renew transportation contracts as they expire. Decreases in the supply of or demand for natural gas could materially adversely affect the utilization of our storage facilities and storage services.

Conditions in the natural gas business environment generally, such as declining or sustained low commodity prices, supply disruptions, or higher development or production costs, could result in a slowing of supply to our storage facilities. Also, sustained lower demand for hydrocarbons, or changes in the regulatory environment or applicable governmental policies, including in relation to climate change or other environmental concerns, may have a negative impact on the supply of natural gas and other products generally.

Each of the foregoing supply and demand issues could negatively impact our Business directly, as well as our customers, which in turn could negatively impact our prospects for new contracts for natural gas storage, renewals of existing contracts or the ability of our customers to honour their contractual commitments. See "— We are exposed to the credit risk of our customers and counterparties, and any material nonpayment or nonperformance by our key customers or counterparties could adversely affect our financial results". Furthermore, such unfavourable conditions may compound the adverse effects of larger economic disruptions. See "— Our operating results may be adversely affected by unfavourable economic and market conditions".

We cannot predict the impact of future economic conditions, fuel conservation measures, alternative fuel requirements, governmental regulation, including in relation to climate change, and/or tax incentives or technological advances in fuel economy and energy generation devices, all of which could reduce the production of and/or demand for the products we handle.

Our Business involves inherent operational risks and hazards which could result in a prolonged interruption of our operations and negatively affect the Business and our results of operations and financial condition.

Our operations are subject to the many hazards inherent in the storage of natural gas, including, but not limited to:

- negative unpredicted performance by our storage reservoirs, including gas migration, that could cause us to fail to meet expected or forecasted operational levels or contractual commitments to our customers;
- unanticipated equipment failures at our facilities and on pipelines that interconnect with our facilities;
- unanticipated underperformance, failure or compromise of information and control systems or processes;
- damage to storage facilities and related equipment caused by snow, rain or ice storms, floods, earthquakes, fires, extreme weather conditions, other natural disasters and/or acts of terrorism (see "— Snow, rain or ice storms, earthquakes, flooding and other natural disasters, as well as climate-related physical risks, could have a material adverse effect on the Business and our results of operations and financial condition");
- leaks of or other losses of natural gas as a result of the malfunction of equipment or facilities;
- blowouts (uncontrolled escapes of natural gas from a well), fires and explosions;
- operator error;
- labour disputes/work stoppages;
- disputes with interconnected facilities and carriers; and
- environmental pollution or release of toxic or hazardous substances.

These risks could result in substantial losses due to breaches of our contractual commitments, personal injury or loss of life, damage to and destruction of property, natural resources and equipment and pollution or other environmental damage and may result in curtailment or suspension of our operations, any of which also could result in substantial financial losses, including lost revenue and cash flow to the extent that an incident causes an interruption of service. In addition, operational interruptions or disturbances, mechanical malfunctions, faulty measurements or other acts, omissions, or errors may result in significant costs or lost revenues, reputational damage, regulatory fines or penalties and civil or criminal liability. For storage facilities located near populated areas, including residential areas, commercial business centres, industrial sites and other public gathering areas, the level of damage resulting from these risks may be greater.

Any significant stabilization of natural gas prices could have a negative impact on the demand for our natural gas storage services or reduction in the seasonal spread.

Storage businesses may benefit from price volatility as well as the seasonality of natural gas prices, which impacts the level of demand for services and the rates that can be charged for storage services. If seasonal price differences or volatility remain low for an extended period of time, then the demand for storage services, and the prices that we will be able to charge for those services, may decline or be depressed below the costs to operate storage facilities, resulting in a decision to shut-in all or a portion of a facility. A sustained decline in the prices we are able to charge or a shutting-in of all or a portion of a facility could have a materially adverse effect on the Business and our results of operations and financial condition.

Over time, there has been an increase in the capacity and interconnectivity of natural gas pipeline networks, which has resulted in a dampening of price differentials between geographic markets. Any material reduction between seasonal prices or historical geographic price differentials in the natural gas futures market could reduce our operating margins and further affect the Business and our results of operations and financial condition.

Our level of exposure to the market value of natural gas storage services could adversely affect our Business.

As portions of our third-party natural gas storage contract portfolio come up for replacement or renewal, and capacity becomes available, adverse market conditions may prevent us from replacing or renewing the contracts on terms favourable to us or at all. The market value of our storage capacity, realized through the value customers are willing to pay for ToP contracts or via the opportunities to be captured by our STS contracts or optimization activities, could be adversely affected by a number of factors beyond our control, including:

- a material change in the relationship between prices of differing time periods on the natural gas futures market, including the difference between winter and summer prices, sometimes referred to as the seasonal spread, due to real or perceived changes in supply and demand fundamentals;
- prolonged reduced natural gas prices and price volatility (see "— Any significant stabilization of natural gas prices or long-term low gas prices could have a negative impact on the demand for our natural gas storage services or reduction in the seasonal spread");
- a decrease in demand for natural gas storage in the markets we serve;
- increased competition for natural gas storage in the markets we serve; and
- increased interest rates which increase the cost of carrying proprietary inventory and decrease the rates at which we contract with our customers.

A prolonged downturn in the natural gas storage market, including any downturn due to the occurrence of any of the above factors, could result in our inability to renegotiate or replace a number of our ToP contracts upon their expiration on terms that are acceptable to us, leaving more capacity available to generate value through STS contracts or optimization which are shorter term in nature. STS and optimization values could be impacted by the same factors, and market conditions could deteriorate further before the opportunity to extract value with those strategies could be realized by us.

Further, our lines of business and assets are concentrated in the natural gas storage industry. Accordingly, adverse developments, including any of the industry-specific factors listed above, could have a more severe effect on the Business and our results of operations and financial condition than if we carried on a more diverse business.

If third-party pipelines interconnected to our facilities become unavailable or more costly to transport natural gas, our Business could be adversely affected.

We depend upon third-party pipelines that provide delivery options to and from our storage facilities for our benefit and the benefit of our customers. Because we do not own these pipelines, their continuing operation is not within our control. These pipelines may become unavailable for a number of reasons, including but not limited to testing, maintenance, line repair, reduced operating pressure, lack of operating capacity or curtailments of receipt or deliveries due to insufficient capacity. In addition, these third-party pipelines may become unavailable to us and our customers because of the failure of the interconnections that transport natural gas between our facilities and the third-party pipelines. Wild Goose is connected to third-party pipelines by two interconnecting pipelines, Lodi by three interconnecting pipelines, Warwick by one interconnecting pipeline and the AECO Hub™ by two interconnecting pipelines. Due to the limited number of interconnections at our facilities, the disruption of any interconnection could materially impact our ability or the ability of our customers to deliver or receive natural gas into our storage facilities or into the third-party pipelines. If the costs to us or our customers to access and transport on these third-party pipelines significantly increase, the Business and our results of operations and financial condition may be materially adversely affected.

Further, the pipelines on which we rely can be constrained in their capacity. For instance, in areas like western and northwestern Alberta, natural gas production often exceeds the capacity of the pipelines on the NGTL System, leading to constraints. Although maintenance and expansion projects have been undertaken on the NGTL System to address this issue, such activities have necessitated temporary restrictions on the amount of gas flowing through certain parts of the NGTL System to maintain safety. If third-party pipelines become partially or completely unavailable, our ability to operate could be restricted, thereby adversely affecting our results of operations and financial condition. A prolonged or permanent interruption at any key pipeline interconnection to our storage facilities could also have a material adverse effect on the Business and our results of operations and financial condition.

Throughput on any of the pipelines on which we rely also may decline as a result of changes in business conditions. Over the long-term, the Business will depend, in part, on the level of demand for crude oil, natural gas and refined petroleum products in the geographic areas in which deliveries are made by pipelines and the ability and willingness of shippers having access or rights to utilize the pipelines to supply such demand. If any of these pipelines or other midstream facilities become unable to receive, transport or process natural gas, or if the volumes we withdraw do not meet the natural gas quality requirements (such as hydrocarbon dew point, temperature and foreign content, including water, sulfur, carbon dioxide and hydrogen sulfide) of such pipelines or facilities, the Business and our results of operations and financial condition could be materially adversely affected.

We do not own certain of the land or the reservoirs we use as storage facilities. We operate such storage reservoirs under various types of leases, easements and other access agreements, and our rights thereunder generally continue only for so long as we pay rent or, in some cases, minimum royalties, and there may be deficiencies in our title to such rights.

Our rights under storage easements, leases and other access agreements continue for so long as we conduct storage operations and pay our grantors for our use, or otherwise pay rent owing to the applicable lessor. If we are unable to pay the rent or the minimum royalty, as applicable, required to maintain such storage easements and leases in good standing, or breach certain of the terms of the access agreements that provide us with access to such facilities, we might lose title or other access to our natural gas storage rights underlying our storage facilities.

In addition, title to some of our real property assets may have title defects which, although they have not historically materially affected the ownership or operation of our assets, could result in third party claims against our assets. In either case, to recover our lost rights or to rectify the title defects, we may be required to expend significant time and resources. We have not conducted a full title review, nor are full title reviews customary in the industry, in respect of many of our assets at the time of their acquisition and, as such, cannot confirm there may not be adverse claims against our title to certain of our assets. In addition, we might be required to exercise our power of condemnation to the extent available or applicable. Condemnation proceedings are adversarial proceedings, the outcomes of which are inherently difficult to predict, and the compensation we might be required to pay to the parties whose rights we condemn could be significant and could materially adversely affect the Business and our results of operations and financial condition.

Further, when we buy or lease land for our operations, we may not always acquire the mineral rights to adjacent lands. Others may have the right to extract minerals from or operate in proximity to the land we own or lease, which could disrupt our operations, including causing gas migration, or otherwise damage our facilities. Additionally, we may be exposed to disputes or legal proceedings with royalty owners or other operators. Any of these factors could have a material adverse effect on the Business and our results of operations and financial condition.

We lease the majority of the land on which we operate, which could lead to disruptions, increased costs, reduced revenue, and potential legal disputes with landowners if these leases are terminated, not renewed, or subject to unfavourable terms.

We do not own all of the land on which our facilities are located, and are, therefore, subject to the possibility that the leases for the land on which we operate could be terminated, not renewed or subject to unfavourable terms. This could disrupt our operations, increase our costs, or reduce our revenue. Additionally, we may also be exposed to disputes or legal proceedings related to the leases. Any of these factors could have a material adverse effect on the Business and our results of operations and financial condition.

Our proprietary optimization activities may cause volatility in our financial results and cash flow.

When market conditions warrant, we purchase natural gas in economically hedged transactions and utilize available capacity in our storage facilities. These proprietary optimization activities allow us to achieve higher margins than could otherwise be obtained through third-party contracts at the relevant time. Nonetheless, such activities may not effectively manage or fully eliminate risks as expected or intended due to differing conditions than those assumed or forecasted at the time such activities are commenced, including those related to demand, pricing, volatility, market correlations, generation facility availability, unforeseen market disruptions, and weather events. Further, a significant change in the price of natural gas could require us to post more margin to cover potential losses than liquidity we have available at the time, which could require us to liquidate inventory under potentially unfavourable market conditions. Given the inherent uncertainty in developing future market expectations, actual market conditions could be materially different than our expectations, which could materially adversely impact the results of our proprietary optimization activities.

When winter gas prices fall below forward prices for the following summer, we may defer the withdrawal of proprietary optimization inventory until the next fiscal year in order to reduce operating costs and add incremental margin and economic value, independent of the period in which that revenue is earned. This may result in the deferral of realized earnings and cash flow from one fiscal year to the next and cause volatility in our results of operations and cash flow.

In addition to the foregoing, if natural gas prices fall, the value of our economic hedges increases and the value of the proprietary optimization inventory underlying those hedges decreases to the extent that inventory is carried into future fiscal years. With the realization of hedging gains positioned in one fiscal year and the positioning of new hedges at lower values in future periods, the estimated market value of our remaining inventories may be less than the carrying cost and require us to adjust the carrying value of our proprietary inventories.

Our risk management policies cannot eliminate all commodity price risk. In addition, any non-compliance with our risk management policies could result in significant financial losses.

While our policies are designed to minimize commodity price risk, some degree of exposure to unforeseen fluctuations in market conditions remains. We have in place risk management systems that are intended to quantify and manage risks, including commodity price risk and basis risk. We monitor processes and procedures to prevent unauthorized trading and to maintain substantial balance between purchases and future sales and delivery obligations. However, these steps may not detect and prevent all violations of our risk management policies and procedures, particularly if deception or other intentional misconduct is involved. There is no assurance that our risk management procedures or activities will prevent losses that could adversely affect the Business and our results of operations and financial condition.

Derivatives regulation could have an adverse impact on our ability to hedge risks associated with our Business and on the cost of our hedging activities.

We use over-the-counter ("**OTC**") derivative products to hedge commodity risks and, to a lesser extent, our currency risk, interest rate risk and electricity prices. The OTC derivatives market and entities, including us, that participate in that market are regulated by the United States Commodity Futures Trading Commission, the United States Securities and Exchange Commission and other regulators in the U.S. and Canada and applicable legislation, including the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "**Dodd-Frank Act**").

Although these rules and regulations have not materially impacted our Business or hedging activities to date, new laws and regulations could be enacted that could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, and reduce our ability to monetize or restructure our existing derivative contracts.

If we reduce our use of derivatives as a result of any such regulation, our results of operations may become more volatile and our cash flows may be less predictable. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of natural gas prices, which some U.S. legislators attributed to speculative trading in derivatives and commodity instruments related to natural gas. Our revenues could be adversely affected to the extent that regulations result in lower commodity prices. Any of these consequences could have a material adverse effect on the Business and our results of operations and financial condition.

We face significant competition that may cause us to lose market share, adversely affecting the Business.

The natural gas storage business is competitive. Our ability to renew or replace existing contracts with our customers at rates sufficient to maintain or increase current revenue and cash flows could be adversely affected by the activities of our competitors. The principal elements of competition among storage facilities are rates, terms of service, types of service, deliverability, supply and market access, flexibility and reliability of service. Our operations compete primarily with other storage facilities in the same markets in the storage of natural gas.

We also compete with certain pipelines and marketers that provide services that can substitute for certain of the storage services we offer. In addition, natural gas as a fuel competes with other forms of energy available to end-users, including electricity, coal and liquid fuels. Increased demand for such forms of energy at the expense of natural gas could lead to a reduction in demand for natural gas storage services. Some of our competitors have greater financial resources and may now, or in the future, have greater access to development opportunities than we do. If our competitors substantially increase the resources they devote to the development and marketing of competitive services or substantially decrease the prices at which they offer their services, we may be unable to compete effectively. Some of these competitors may construct new storage facilities that could create additional competition for us. Such construction activities, if undertaken in the future, could result in storage capacity in excess of actual demand, which could reduce the demand for our services, and potentially reduce the rates that we receive for our services.

We also face competition from alternatives to natural gas storage, including ways to increase supply of or reduce demand for natural gas at peak times such that storage is less necessary. For example, excess production or supply capability with sufficient delivery capacity on standby until required for peak demand periods or ability for significant demand to quickly switch to alternative fuels at peak times could represent alternatives to natural gas storage.

Competition could intensify the negative impact of factors that significantly decrease demand for natural gas at peak times in the markets served by our storage facilities, such as competing or alternative forms of energy, a recession or other adverse economic conditions, weather, higher fuel costs and taxes or governmental or regulatory actions that directly or indirectly increase the cost or limit the use of natural gas. Increased competition could reduce the volumes of natural gas stored in our facilities or could force us to lower our storage rates.

Any of foregoing factors could have a material adverse effect on the Business and our results of operations and financial condition.

We may be unable to recruit, retain and motivate members of our senior management team and other key personnel.

Our Business depends on the collective performance, contribution and expertise of the senior management teams and other key personnel throughout the Business, including qualified management, professional, operational, scientific, technical and business development personnel. There is significant competition for qualified personnel in the natural gas storage industry, particularly in the locations in which we operate and with skills, training and education in the scientific and technical fields and experience in natural gas storage operations and development. As competition for experienced talent grows, we may be forced to increase spending on employee salaries or provide additional incentives, including potentially dilutive equity-based compensation. Significant increases in staffing costs could adversely affect the Business and our results of operations and financial condition. The loss of any key executive, or our inability to continue to recruit, retain and motivate key personnel and replace departed personnel in a timely fashion, may adversely impact our ability to compete effectively and may adversely affect our or Rockpoint's ability to meet our short and long-term financial and operational objectives.

We may experience cushion migration at our storage facilities.

Cushion gas migration refers to the movement of natural gas through faults in the rock or to an area of the storage reservoir where it no longer provides effective pressure support for purposes of storing and cycling a storage facility's working gas. During each of the fiscal years ended March 31, 2025 and 2024, we estimate that our facilities experienced approximately 1.696 MMDth and 0.878 MMDth, respectively, of proprietary cushion gas migration. Cushion gas migration depends on a variety of factors regarding storage levels and cycling requirements, which can vary significantly depending on operating conditions. Such gas could be permanently lost and must be replaced in order to maintain design storage performance. We may be required to purchase additional gas in the market at prices higher than anticipated to replace such migrated or lost gas, and we may not be able to control the timing of these purchases, which could adversely affect the Business and our results of operations and financial condition.

Our financial results are seasonal and generally lower in the second and third quarters of the calendar year.

The Business is highly seasonal. In general, revenue and operating expenses are typically highest during our third and fourth fiscal quarters (November through March), during the peak of the natural gas storage winter withdrawal season, when we typically sell most of our optimization inventory to serve the seasonal demand created by the North American residential market, which uses natural gas to heat their homes. Revenue is typically lower during our first and second fiscal quarters (April through October) in the natural gas storage summer months, when natural gas prices are generally lower, and we shift to the storage injection season and replenish our natural gas inventory.

As a part of our proprietary optimization activities, we typically purchase natural gas and build inventories during the summer months while simultaneously hedging financial sales in future periods, including the upcoming winter, in accordance with our risk management policy. This can result in borrowing under our Credit Facilities being higher as the amount of proprietary inventory increases. Borrowings can also increase when there are variations in future gas prices that result in increases to our margin posting requirements associated with future purchase and sale commitments despite having a locked-in margin and possession of physical inventory. Because a substantial amount of the physical sales of our proprietary inventory occurs in the winter, our greatest accounts receivable collections typically occur in our fourth fiscal quarter to the extent we elect to sell our physical inventory. With lower cash flow during the summer months (April through October), we may be required to borrow money during such periods, including to fund any dividends that may be declared and payable to the Company's shareholders during such period.

Supply chain disruptions and inflation could adversely affect our Business.

Relying on third-party suppliers for sourcing and delivery of equipment, parts and supplies used at our facilities creates risk with respect to supply shortages and delivery delays that could have a material adverse effect on the Business and our results of operations and financial condition. We source certain key components, raw materials, equipment and component parts from a variety of suppliers in Canada, the U.S. and internationally. We also outsource some or all construction services as part of our capital expenditure programs. We maintain relationships with several key suppliers and contractors and maintain an inventory of key components, materials, equipment and parts. We also place advance orders for components that have long lead times. We may, however, experience cost increases (including due to tariffs imposed on certain products), delays in delivery due to strong activity increasing demand for equipment, parts and supplies or financial hardship of suppliers or contractors or other circumstances relating to third-parties that are outside of our control. Increased inflation may also result in cost increases for the key components, materials, equipment and parts we use in our Business. Further, our operations depend in part on rig availability to enable our customers to produce natural gas. Rig availability in California has declined, and may continue to decline, in parallel with the ongoing de-escalation of California's oil and gas industry, which could have a material adverse effect on the Business and our results of operations and financial condition.

We depend on a limited number of customers for a significant portion of our revenues. The loss of any of these customers could result in a decline in our revenues.

We rely on a limited number of customers for a significant portion of our revenues. Additionally, while our ToP contracts may be multi-year agreements, our STS contracts typically have terms of less than one year. There can be no assurance that our expiring contracts will be renewed in whole or in part at the end of their terms. The loss of all or a portion of the revenues attributable to our key customers as a result of competition, creditworthiness, or inability to negotiate extensions or replacements of contracts on terms satisfactory to us or otherwise, could have a material adverse effect on the Business and our results of operations and financial condition.

We are exposed to the credit risk of our customers and counterparties, and any material nonpayment or nonperformance by our key customers or counterparties could adversely affect our financial results.

We are subject to the risk of loss resulting from nonpayment or nonperformance by our customers. Our customers are subject to their own operating, market, financial and regulatory risks, and some have experienced, are experiencing, or may experience in the future, financial difficulties that have had or may have a significant impact on their creditworthiness. Our credit procedures and policies may not be adequate to fully reduce customer credit risk. If we fail to adequately assess the creditworthiness of existing or future customers or unanticipated deterioration in their creditworthiness, any resulting increase in nonpayment or nonperformance frequency by them and our inability to re-market or otherwise use the capacity could have a material adverse effect on the Business and our results of operations and financial condition.

There can be no assurance that our customers or counterparties will not become financially distressed or that such financially distressed customers or counterparties will not default on their obligations to us or file for creditor or bankruptcy protection. If one or more of our customers or counterparties file for creditor or bankruptcy protection, it is possible we would be unable to collect all, or even a significant portion of, amounts they owe to us despite having the contractual right to liquidate any gas they may have stored in our facilities in settlements of amounts due. Similarly, our contracts with such customers may be renegotiated at lower rates or terminated altogether. Significant customer or counterparty defaults and insolvency or bankruptcy filings could have a material adverse effect on the Business and our results of operations and financial condition.

Exposure to currency exchange rate fluctuations will result in fluctuations in our cash flows and operating results.

Currency exchange rate fluctuations could have a material adverse effect on our results of operations. Historically, a portion of our revenue has been generated in Canadian dollars, but we incur operating and administrative expenses in both U.S. dollars and Canadian dollars and financing expenses in U.S. dollars. If the Canadian dollar weakens significantly relative to the U.S. dollar, we would recognize less revenue when converted to and reported in U.S. dollars and be required to convert more Canadian dollars to U.S. dollars to satisfy our obligations, which could have a material adverse effect on the Business and our results of operations and financial condition.

In addition, because we report our operating results in U.S. dollars, changes in the value of the U.S. dollar relative to the Canadian dollar also results in fluctuations in our reported revenues and earnings. In addition, all foreign currency-denominated monetary assets and liabilities such as cash and cash equivalents, accounts receivable, accounts payable, long-term debt and decommissioning obligations are revalued and reported based on the prevailing exchange rate at the end of the reporting period. This revaluation may cause us to report non-monetary foreign currency exchange gains and losses in certain periods.

We depend upon information technology systems, which are subject to interruption, failure and potential cybersecurity attack.

The Business could be disrupted if information technology systems fail to perform adequately. We are reliant on technology to improve efficiency in our Business, and information technology systems are critical to our operations. The failure of information technology systems to perform as we anticipate could disrupt the Business and could result in transaction errors, processing inefficiencies and the loss of sales and customers, causing the Business and our results of operations and financial condition to suffer. In addition, information technology systems may be vulnerable to damage or interruption from circumstances beyond our control, including fire, natural disasters, power outages, and systems failures. These systems could also be a potential target for a cybersecurity attack or other attempted security breach, as they are used to store and process sensitive information regarding our operations, financial position, and information pertaining to our customers and vendors. Additionally, employee errors, including with respect to ineffective password management, may result in a breach of the Business' or its third party service providers' security measures, which could result in a breach of confidential information. While we employ certain cybersecurity measures, we cannot guarantee safety from all threats and attacks. Any successful breach of security could result in the spread of inaccurate or confidential information, disruption of operations, environmental harm, endangerment of employees, damage to our assets, and increased costs to respond. Any of these instances could have a negative impact on cash flows, customer relationships and/or our reputation and/or result in claims and proceedings against us, which could have a material adverse effect on the Business and our results of operations and financial condition. Furthermore, there is no guarantee that adequate insurance to cover the effects of any such interruption, failure or cybersecurity attack will be available at rates we believe are reasonable or that the cost of responding to an incident will be recoverable.

The Business could be affected by terrorist activities and catastrophic events that could result from terrorism.

In the event that our storage facilities are subject to terrorist activities, such activities could significantly impair our operations and result in a decrease in revenues and additional costs to repair and insure our assets. The effects of, or threat of, terrorist activities could result in a significant decline or volatility in the North American economy and the decreased availability and increased cost of insurance coverage. Any of these factors could have a material adverse effect on the Business and our results of operations and financial condition.

Snow, rain or ice storms, earthquakes, flooding and other natural disasters, as well as climate-related physical risks, could have a material adverse effect on the Business and our results of operations and financial condition.

Some of our natural gas storage facilities operate in areas that are susceptible to snow, rain or ice storms, earthquakes, flooding, forest fires and other natural disasters. These natural disasters could potentially damage or destroy our assets and disrupt the supply of the natural gas we store, which could in turn have a material adverse effect on the Business and our results of operations and financial condition. Many climate models indicate that global warming is likely to result in rising sea levels, increased frequency and severity of weather events such as snow, rain, or ice storms, extreme precipitation, flooding and forest fires. Climate-related changes such as these could result in damage to our physical assets, especially operations located in low-lying areas near coasts and riverbanks, and facilities situated in snow-prone, fire-prone and rain-susceptible regions. Natural disasters can similarly affect the facilities of our customers. The timing, severity and location of these climate change impacts are not known with certainty, and these impacts are expected to manifest themselves over varying time horizons.

Our insurance policies do not cover all losses, costs or liabilities that we may experience, and insurance companies that currently insure companies in the energy industry may cease to do so or substantially increase premiums.

Our insurance program may not cover all operational risks and costs and may not provide sufficient coverage in the event of a claim. We may not be able to obtain the levels or types of insurance we desire and the insurance coverage we do obtain may contain large deductibles. We do not maintain insurance coverage against all potential losses and could suffer losses for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. Losses in excess of our insurance coverage could have a material adverse effect on the Business and our results of operations and financial condition.

Changes in the insurance markets subsequent to certain weather events and other natural disasters have made it more difficult and more expensive to obtain certain types of coverage. The occurrence of an event that is not fully covered by insurance, or failure by one or more of our insurers to honour its coverage commitments for an insured event, could cause us to incur significant losses. Insurance companies may reduce or eliminate the insurance capacity they are willing to offer or may demand significantly higher premiums or deductibles to cover our assets. If significant changes in the number or financial solvency of insurance underwriters for the energy industry occur, we may be unable to obtain and maintain adequate insurance at a reasonable cost. The unavailability of adequate insurance coverage to cover events in which we suffer significant losses could have a material adverse effect on the Business and our results of operations and financial condition.

We are subject to reputational risks and risks relating to public opinion.

The Business and our results of operations or financial condition may be negatively impacted as a result of negative public opinion towards our industry sector, the products we handle, or us specifically. Public opinion may be influenced by negative portrayals of the energy industry as well as opposition to development projects. In addition, events specific to us could result in the deterioration of our reputation with key stakeholders.

We believe that reputational risk cannot be managed in isolation from other forms of risk and that operational, market, credit, insurance, regulatory and legal risks, among others, must all be managed effectively to safeguard our reputation. Our reputation and public opinion could also be impacted by the actions and activities of other companies operating in the energy industry, particularly other energy infrastructure providers, over which we have no control. In particular, our reputation and that of our industry could be impacted by negative publicity related to pipeline or other energy infrastructure incidents or unpopular expansion projects and due to opposition to development of hydrocarbons and energy infrastructure, particularly projects involving resources that are alleged to increase GHG emissions and contribute to climate change. Negative impacts from a compromised reputation or changes in public opinion (including with respect to the production, transportation and use of hydrocarbons generally) could include increased regulatory oversight and costs, difficulty obtaining rights-of-way and delays in obtaining, or challenges to, regulatory approvals with respect to growth projects, blockades, project cancellations, difficulty securing financing, revenue loss, reduction in customer base, and decreased value of the Company's securities and the Business. In certain circumstances, governmental agencies have responded to negative publicity from certain public interest groups by imposing greater scrutiny in the permit approval process and enforcement actions that could exacerbate the negative reputational impacts, and they may do so in the future.

The effects of U.S. and Canadian government policies on tariffs and trade relations between Canada and the U.S. are uncertain and could adversely impact us.

The imposition of trade tariffs by the U.S. on imports from Canada, together with potential retaliatory tariffs by Canada on imports from the U.S., and other potential measures, including tariffs, duties, fees, economic sanctions or other trade measures, present risks to our Business operations. Such measures, the nature, extent and timing of which are uncertain, could lead to increased costs for us and our customers and reduced demand for Canadian natural gas.

The potential for such measures introduces uncertainty in North American energy markets, possibly disrupting supply chains and access to capital markets and jeopardizing our competitiveness and could have a material adverse effect on the Business and our results of operations and financial condition.

The U.S. Government has also stated its interest in renegotiating and altering the United States-Mexico-Canada Agreement, a free trade agreement between the U.S., Mexico and Canada, which could further impact the energy market and our Business.

Risks Related to Environmental, Public Utility Regulation and Other Regulations

A change in the jurisdictional characterization of our assets by regulatory agencies or a change in policy by those agencies may result in increased regulation of our assets, which may cause our revenues to decline and/or operating expenses to increase.

Alberta, Canada

In Alberta, the AER has jurisdiction to regulate the technical aspects of construction, development, and operation of natural gas storage facilities, including the AECO Hub™ and Warwick. The AECO Hub™ and Warwick are subject to private commercial arrangements and not subject to rate regulation. While legislation in Alberta may permit storage services to be deemed a utility service and for the rates for underground gas storage to be regulated by the Alberta Utilities Commission ("**AUC**") on that basis, we do not currently expect the AUC to exercise such jurisdiction. If, however, the AUC was authorized to regulate the rates we charge for gas storage services in Alberta, it could have a material adverse effect on the Business and our results of operations and financial condition.

California, United States

Wild Goose and Lodi operations are regulated California public utilities subject to the jurisdiction of CPUC. The CPUC has broad jurisdictional authority over regulated California public utilities, including, without limitation, investigating and enforcing matters of public health and safety, environmental protection, and safe and reliable service. Public utilities must cooperate with CPUC investigations and enforcement actions or risk being subject to additional violations. The CPUC has general authority, after completing necessary procedural steps, unless under emergency situations, to determine that a class of public utilities (such as gas storage facilities) must make certain improvements on health, safety, reliability, or other jurisdictional grounds, or to determine that a particular facility must correct or address such a concern or permit violation, any of which could result in significant costs and operational obligations to the utility.

Under the California Public Utilities Code, regulated public utilities, such as Wild Goose and Lodi, must obtain pre-approval from the CPUC before taking certain actions, including, without limitation, changes in ownership or control (including indirect changes of parent-level ownership or control), issuance of stock or indebtedness by the utility, providing a guarantee by the utility, selling or encumbering utility assets, the utility (or an affiliate or holding company of the utility) buying stock in another California public utility, and other regulated actions. The CPUC generally considers such decisions on a case-by-case basis and has not established brightline tests. If the CPUC determines that a public utility took any such action without necessary pre-approval, the CPUC may, in some cases, declare the action void, impose fines or conditions, or take other enforcement actions. The requirement to obtain such pre-approvals or the taking of any of these actions by the CPUC may restrict or place limitations on the ability of the Business to take certain actions, which may adversely affect the Business and our results of operations and financial condition.

The CPUC has authorized Wild Goose and Lodi to charge customers market-based rates because, as independent storage providers, Wild Goose and Lodi, rather than ratepayers, bear the risk of any underutilized or discounted storage capacity. If the CPUC changes this determination, for instance as a result of a complaint, Wild Goose and Lodi could be limited to charging rates based on our cost of providing service plus a reasonable rate of return. This could have a material adverse effect on Wild Goose's and Lodi's revenues associated with providing storage services, which could in turn have a material adverse effect on the Business and our results of operations and financial condition. Notably, the CPUC issued an Order Initiating Investigation (I.) 23-03-008 following high natural gas prices in the winter of 2022 – 2023. In A Staff White Paper Supporting CPUC Investigation (I.) 23-03-008 Part I, dated July 2, 2024 (the "**White Paper**"), CPUC staff determined that the independent gas storage providers acted appropriately during the period in question and did not contribute to the winter price spikes. However, in Part II of the White Paper, dated June 5, 2025, CPUC staff did pose questions regarding whether the independent gas storage market in northern California is competitive and explored whether further inquiry into a cost of service model for gas storage is merited. This line of inquiry was not supported during the comment period, though we expect the CPUC to continue Investigation (I.) 23-03-008 in due course, which has the potential to result in regulatory changes or further proceedings that could impact tariff structures, rates, reporting obligations, or other conditions relevant to the independent gas storage industry, including Wild Goose and Lodi, which could have a material adverse effect on the Business and our results of operations and financial condition.

We are subject to extensive and complex government regulations that may adversely affect our future operations.

Our assets and operations are subject to extensive and complex regulation and oversight by a variety of U.S. and Canadian federal, provincial, state and local regulatory authorities, including laws and regulations relating to the protection or preservation of the environment, natural resources and human health and safety. Regulation affects almost every aspect of our Business. In addition to environmental and safety matters, we are subject to regulatory oversight and regulations regarding: (i) federal, provincial, state, local and foreign taxation; (ii) rates, operating terms and conditions of service; (iii) the types of services we may offer to our customers; (iv) the contracts for service entered into with our customers; (v) the certification and construction of new facilities; (vi) the costs of raw materials, such as steel, which may be affected by tariffs (such as those proposed by the current U.S. presidential administration) or otherwise; (vii) the integrity, safety and security (including against cyber-attacks) of facilities and operations; (viii) the acquisition of other businesses; (ix) the acquisition, extension, disposition or abandonment of services or facilities; (x) reporting and information posting requirements; (xi) the maintenance of accounts and records; and (xii) relationships with affiliated companies involved in various aspects of the natural gas and energy businesses.

It is possible that costs associated with complying with the aforementioned laws will change depending on the emphasis regulatory authorities are placing on protection of the environment and other public interest considerations. Liability under such laws and regulations may be incurred jointly and severally without regard to fault under CERCLA, the Resource Conservation and Recovery Act, the U.S. federal Clean Water Act, the U.S. Oil Pollution Act, or analogous U.S. state laws or under Canadian federal or provincial laws, as a result of the presence or release of hydrocarbons or hazardous substances into or through the environment, and these laws may require response actions and remediation and may impose liability for natural resource and other damages. Private parties, including the owners of properties through which pipelines we access pass, also may have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with such laws and regulations or for personal injury or property damage. Our insurance may not cover all environmental risks and costs and/or may not provide sufficient coverage in the event an environmental claim is made against us.

If we fail to comply with any applicable statutes, rules, regulations, and orders of the applicable regulatory authorities, we could be subject to substantial administrative, civil, and criminal penalties and fines, the imposition of remedial obligations, the issuance of orders enjoining our operations or the filing of other claims and complaints. New laws or regulations, or different interpretations of existing laws or regulations, including unexpected policy changes, applicable to our income, operations, assets or another aspect of the Business could have a material adverse effect on the Business and our results of operations and financial condition.

Many of our operations and our customers' operations are subject to regulatory and permitting obligations, and failure to secure timely regulatory approval for our proposed projects, or loss of required approvals for our existing operations, could have a material adverse effect on the Business and our results of operations and financial condition.

Our Business and our customers' businesses are required to obtain, maintain, and comply with, numerous U.S. and Canadian federal, provincial, state and local government permits, licenses and approvals. Any of these permits, licenses or approvals may be subject to denial, revocation or modification under various circumstances. The nature and degree of regulation and legislation affecting permitting and environmental review for energy infrastructure companies in Canada and the U.S. continues to evolve. In addition, in Canada and the U.S., energy companies continue to face opposition from anti-energy/anti-pipeline activists, environmental groups, Indigenous groups, politicians and other stakeholders concerned with the safety of energy infrastructure and its potential environmental effects, which could impact our ability or the ability of our customers to obtain or maintain permits, licenses and approvals required for our projects and operations.

In the U.S., the EPA has released rules to reduce methane emissions from the oil and gas sector, standards for reducing emissions from fossil fuel fired power plants, and rules to streamline the process for states and Indigenous groups to assume authority over the U.S. federal Clean Water Act's section 404 permitting program for discharges of dredge and fill material. Additionally, the development of our assets or expansion of our operations may be subject to review under the United States federal National Environmental Policy Act ("**NEPA**") or state equivalent statutes (such as the CEQA), which requires federal and state agencies, as applicable, to assess the environmental impacts of their proposed actions. The scope of required review for energy and infrastructure projects under NEPA is subject to change after the U.S. Supreme Court narrowed the scope of review in May 2025 and the current U.S. presidential administration rescinded the long-standing NEPA guidelines and directed agencies to update their guidelines implementing the law. The PHMSA promulgates rules and requirements for sustainable and safe operation of underground natural gas storage facilities in the U.S. Many regulations are being challenged in the courts, and some have been overturned by reviewing courts. The current U.S. presidential administration has taken and may continue to take action to modify or reverse regulations that were promulgated by the previous U.S. presidential administrations. While the impact of these changes on our operations is currently uncertain, initial executive orders and actions by the current U.S. presidential administration, and related regulatory proposals, suggest such changes could influence future regulatory developments in our industry.

Changes to permitting regimes or their enforcement could adversely impact permitting of a wide range of energy projects, including our projects and the projects of our customers. We may not be able to obtain or maintain all required regulatory approvals for our operating assets or development projects or we may be required to obtain additional operating permits, licenses or approvals. If there is a significant delay in obtaining any required regulatory approvals, if we fail to obtain or comply with them, or if laws or regulations change or are administered in a more stringent manner, the operations of existing facilities or the development of new facilities could be prevented, delayed or become subject to additional costs. Failure to obtain or maintain such approvals or comply with the conditions of permits, licenses or approvals may result in temporary suspension of our activities or curtailment of our operations and may subject us to fines, penalties, injunctive relief and other sanctions, which could have a material adverse effect on the Business and our results of operations and financial condition. Additionally, failure by our customers to obtain or maintain their own regulatory approvals could result in reduced demand for our services.

Environmental and health and safety laws and regulations impose and will continue to impose significant costs and liabilities, including civil liabilities, for contamination of the environment or related personal injuries.

Failure to comply with environmental and health and safety laws and regulations, including required permits and other approvals, may expose us to civil, criminal and administrative fines, penalties and/or interruptions in our operations that could have a material adverse effect on the Business and our results of operations and financial condition. For example, if a leak, release or spill of liquid petroleum products, chemicals or hazardous substances occurs at or from our storage facilities, we may experience significant operational disruptions, and we may be required to pay a significant amount to clean up or otherwise respond to the leak, release or spill, pay government penalties, address natural resource damage, compensate for human exposure or property damage, incur costs to install additional pollution control equipment or undertake a combination of these and other measures. The significant costs and liabilities that could be imposed due to a failure to comply with these laws and regulations may result in increases in our or our customers' operating expenses and capital expenditures and decreases in our earnings and cash flows, which could have a material adverse effect on the Business and our results of operations and financial condition. In addition, new environmental, health and safety and other laws, policies, regulations, rulemaking and oversight, as well as changes to those or more stringent enforcement of those currently in effect, could adversely impact the Business and our results of operations and financial position, as well as the results of operations and financial position of our customers.

We operate numerous properties and equipment that have been used for many years in connection with our Business activities and contain hydrocarbons or hazardous substances. While we strive to utilize operating, handling and disposal practices that are consistent with industry practices, hydrocarbons or hazardous substances may be released at or from properties and equipment owned, operated or used by us, or at or from properties where our wastes have been taken for disposal. In addition, many of these properties are owned and/or operated by third-parties whose management, handling and disposal of hydrocarbons or hazardous substances are not under our control. These properties and any hazardous substances released and wastes disposed at or from them may be subject to numerous laws and regulations (including U.S. laws such as CERCLA), which impose joint and several liability without regard to fault or the legality of the original conduct. Under such laws, we could be required to remove previously disposed wastes, remediate property contamination or both, including contamination caused by prior owners or operators. Furthermore, it is possible that some wastes that are currently classified as non-hazardous, which could include wastes currently generated during our operations or wastes from oil and gas facilities that are currently exempt as being exploration and production waste, may in the future be designated as hazardous wastes. Hazardous wastes are subject to more rigorous and costly handling and disposal requirements than non-hazardous wastes. Such changes in the regulations may result in additional capital expenditures or operating expenses for us.

Laws and regulations, including those relating to the environment and health and safety, are subject to change, which could place more stringent restrictions and limitations on activities that may be perceived to affect the environment, wildlife, natural resources and human health, including without limitation, the exploration, development, storage and transportation of oil and gas. For example, several U.S. federal and state agencies have increased their daily and maximum penalty amounts in recent years.

Such changes, as well as regulatory actions or changes in enforcement priorities taken by regulatory authorities, have the potential to adversely affect our profitability. Additional regulatory burdens and uncertainties will be created if and to the extent that more stringent energy and environmental and storage safety policies are enacted. In recent years, there has been an increase in the efforts of regulatory authorities to issue new regulations and guidance and to interpret existing laws and regulations in ways that promoted the use of renewable energy sources and further protection of the environment, and called upon companies to increase monitoring and emissions reduction efforts, and increased investigations and enforcement actions for potential violations of environmental laws. For example, in December 2023, the EPA finalized a rule containing standards of performance for methane and volatile organic compound emissions from crude oil and natural gas sources, including the production, processing, and transmission and storage segments and, in February 2020, the PHMSA amended its rules for the minimum safety standards for underground natural gas storage facilities. These rules and others that are currently proposed, or similar new legislation or regulations, if finalized and implemented, would affect our assets and operations indirectly, such as by increasing the costs associated with the production of natural gas and liquids that we store or affecting our customers' operations and demand for our services, or directly, such as by significantly increasing our capital and operating costs associated with impacted equipment or subjecting us to the potential for regulatory penalties associated with the inability to comply with the rules in the timeframe allotted, which could have a material adverse effect on the Business and our results of operations and financial condition.

New or revised regulations that require us to make significant capital expenditures at our facilities, result in other increased compliance costs or result in additional operating restrictions, particularly if the costs associated with such requirements and restrictions are not fully recoverable from our customers, and/or increased penalty amounts, even for inadvertent non-compliance, could have a material adverse effect on the Business and our results of operations and financial condition. There can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation, and actual future expenditures may be different from the amounts we currently anticipate.

Increased regulatory requirements relating to the safety and integrity of our storage facilities may require us to incur significant capital and operating expenses.

We are subject to extensive laws and regulations related to storage safety and integrity at the federal, provincial and state levels. For example, the PHMSA regulates underground natural gas storage facilities in the U.S., while individual states, such as California, may adopt more stringent standards for intrastate storage facilities. We expect the costs of compliance with these regulations, including integrity management rules, will continue to be substantial. Repairs or upgrades deemed necessary to address results of integrity assessments and other testing and/or to ensure the continued safe and reliable operation of our storage facilities could cause us to incur significant and unanticipated capital and operating expenditures. Such expenditures will vary depending on the number of repairs determined to be necessary as a result of integrity assessments and other testing.

The CPUC may inquire into whether, or take the position that, the Offering constitutes a change of control.

The CPUC has authority over public utilities in California. Gas storage is classified as a public utility in California and therefore Wild Goose and Lodi are under the CPUC's jurisdiction. The CPUC must pre-approve certain actions taken by public utilities, including changes of control. Based on CPUC precedent, changes of control can potentially include indirect changes at the parent company level even without changes at the utility company level. The CPUC has not adopted a brightline test for whether a transaction constitutes a change of control but instead assesses each transaction on a case-by-case basis. The CPUC considers indicia of control to determine if a new entity controls the public utility, including whether a new entity has acquired a 50% or greater ownership interest or otherwise obtained the ability to direct or control management or operation of the public utility. In this case, Brookfield is currently the ultimate owner of Wild Goose and Lodi, which the CPUC has previously approved. Upon completion of the Transactions, Brookfield will: (i) continue to retain majority ownership and control over Wild Goose and Lodi; and (ii) oversee, through the OpCo Boards, the management of the business and affairs of Wild Goose and Lodi. Upon completion of the Transactions, the public will not be able to obtain a majority interest in Rockpoint without prior CPUC Approval. Given that Brookfield will continue to own and control Wild Goose and Lodi, Brookfield and the Company do not expect that the Offering will result in a change of control for purposes of the CPUC's assessment. However, due to the limited CPUC precedent for initial public offerings and the lack of a brightline test, it is possible that the CPUC will inquire into whether, or take the position that, the Offering constitutes a change of control for Wild Goose or Lodi.

Further, the CPUC may deny or condition a future change of control. The CPUC must pre-approve changes of control. In the future, if Brookfield desires to sell a majority interest in Rockpoint or otherwise give up control of Wild Goose or Lodi, Brookfield will be required to first obtain CPUC Approval. Under that scenario, the CPUC will consider whether the change of control is adverse to the public interest. Based on precedent, the CPUC typically has approved changes of control, but in some cases has imposed conditions of approval on the new entity. It is possible that the CPUC would deny or condition a requested change of control if Brookfield seeks approval to sell a majority interest or otherwise give up control of Wild Goose or Lodi.

Climate-related risks and related regulation could result in significantly increased operating and capital costs for us and could reduce demand for our products and services.

Various laws and regulations exist or are under development at all levels of government in Canada and the U.S. that seek to regulate the emission of GHGs such as methane and carbon dioxide. Approaches to further address GHG emissions include establishing GHG "cap-and-trade" programs, increased efficiency standards, participation in international climate agreements and incentives or mandates for pollution reduction, use of renewable energy sources or use of alternative fuels with lower carbon content.

Many federal, provincial, state and local jurisdictions across Canada and the U.S. have, either recently or in the past, introduced legislative initiatives and policies to reduce fossil fuel demand and GHG emissions. These multiple jurisdictions may diverge on their approaches to climate and GHG emissions. Adoption of any such laws or regulations could increase our costs to operate and maintain our facilities, expand existing facilities or construct new facilities. We could be required to install new emission controls on our facilities, acquire allowances for our GHG emissions, pay taxes related to our GHG emissions and administer and manage a GHG emissions reduction program, the costs of which could be significant. Recovery of such increased costs from our customers is uncertain and may depend on events beyond our control, including the outcome of future rate proceedings with regards to our California facilities. Further, these policies and regulations when combined could lead to a significant reduction in the use of, and demand for, natural gas. The decrease in market demand could have the parallel effect of reduced demand for natural gas storage services. In addition, decarbonization efforts may also cause an increase in demand and use of alternative sources of energy which could further decrease demand for natural gas storage. All of these factors could directly or indirectly have a material adverse effect on the Business and our results of operations and financial condition. At this time, it is not possible to accurately estimate how potential future laws or regulations addressing GHG emissions would impact the Business.

In March 2024, the SEC finalized rules requiring significant new climate-related disclosure in SEC filings, including certain climate-related metrics and GHG emissions data, and third-party attestation requirements. However, these rules have been challenged and stayed pending litigation, and the SEC has since resiled from its defence of these rules. The implementation and ultimate impact of these rules remains uncertain. The State of California has also enacted legislation requiring climate-related disclosures, though such laws are also subject to ongoing litigation. Other U.S. states have announced similar proposed regulations. In Canada, the Canadian securities regulators recently paused their implementation of additional climate-related disclosure for public companies, and the status of such disclosure requirements in the future is unclear. These types of regulations may expose us to significant additional monitoring and compliance costs. Some customers and other third-parties also have begun requesting disclosures from us related to their own reporting obligations. At this time, we cannot predict the costs of compliance with, or other potential adverse impacts resulting from, these or similar future rules or regulations that may be adopted; however, any additional requirements would likely require us to incur additional costs or otherwise adversely affect the Business. Further, a lack of harmonization globally and within jurisdictions in relation to climate-related legal and regulatory reform could lead to a risk of fragmentation in our priorities as a result of the different pace of sustainability transition.

Any of the foregoing could have adverse effects on the Business and our results of operations and financial condition.

The Business is involved in various legal proceedings, the outcomes of which are uncertain, and resolutions adverse to us could adversely affect our financial results and reputation.

We are subject to various legal proceedings related to the Business. In recent years, there has been an increase in climate-related regulatory action and litigation, including against companies involved in the energy industry. There is no assurance that we will not be impacted by such regulatory action, litigation or other legal proceedings. By its nature, litigation is subject to many uncertainties, and we cannot predict the outcome of individual matters with assurance. It is reasonably possible that the final resolution of some of the matters in which we are involved or new matters could require additional expenditures, in excess of established reserves, over an extended period of time and in a range of amounts that could adversely affect our financial results, condition or reputation.

Changing expectations of stakeholders and government policies regarding sustainability, environmental, social, and governance ("ESG") matters and climate change continue to evolve and diverge, and an inability to meet these requirements and expectations could erode stakeholder trust and confidence, damage our reputation, influence actions or decisions about us or our industry and have negative impacts on the Business and our results of operations and financial condition.

Companies across all sectors and industries are facing changing expectations and increasing scrutiny from a wide range of stakeholders related to their approach to climate change, human capital, and other sustainability and ESG matters. Our and other energy infrastructure companies' customers, shareholders, regulators, employees and other stakeholders have diverse expectations, demands and perspectives on these topics, which are continuing to evolve. Changing expectations of our practices and performance across these areas may result in or create exposure to new or heightened risks, which may include higher costs, project delays or cancellations, loss of ability to secure new growth opportunities or permits, changes in the availability or cost of capital and related products, restrictions on or the cessation of operations due to increasing pressure on governments and regulators and public opposition, including protests, activism and legal action. We may not be able to meet the diverse expectations and demands of all of our stakeholders, which could result in adverse publicity and harm our reputation, lead to claims against us and affect our relationships with our customers and employees, and subject us to legal and operational risks, any of which could have a material adverse effect on the Business and our results of operations and financial condition. Any efforts to manage such matters and address stakeholder expectations (such as goals, policies, disclosures, or otherwise) may entail additional capital and resources.

With the increasing regulatory attention to various sustainability and ESG matters, certain proponents and opponents of various sustainability matters are increasingly resorting to activism, including litigation, to advance their perspectives. However, as with other stakeholder expectations, such regulations are divergent, which increases the complexity and cost of compliance and associated risks. Addressing stakeholder expectations, including new regulatory requirements or novel interpretations or applications of existing regulatory requirements, entails costs, and any failure to successfully navigate such expectations may result in reputational harm, loss of customers or contracts, changes to the cost or availability of financing, litigation, regulatory or investor engagement, or other adverse impacts on our Business and our results of operations and financial condition. Our customers and other stakeholders may be subject to similar expectations, which may augment or create additional risks.

Costs related to abandonment of our storage assets at the end of their economic lives could be significant, decreasing our cash available for distributions or to service our debt obligations.

The Business is responsible for compliance with all applicable laws and regulations regarding the abandonment of its storage and other assets at the end of their economic life, and these abandonment costs may be substantial. Presently, abandonments are estimated to occur far into the future; however, changing environmental laws and regulations may expedite abandonments much sooner than expected. Furthermore, materials used in the wells may not last as long as expected and may not be reparable on an economic basis. While the Business estimates future abandonment costs and charges customers fees to establish such reserves, actual abandonment costs may be higher than the amounts received. Additionally, applicable laws or regulations may require the Business to either establish and fund new reclamation trusts or increase the size of existing reclamation trusts. Any additional or unexpected expenditures incurred in respect of abandonment costs could decrease Distributable Cash Flow available for dividends to shareholders and to service obligations under any applicable debt obligations of the Business.

If certain U.S. federal income tax rules under Section 7874 of the U.S. Internal Revenue Code apply to the Company, such rules could result in adverse U.S. federal income tax consequences.

A corporation is generally considered for U.S. federal income tax purposes to be a tax resident in the jurisdiction of its organization or incorporation. Accordingly, under the generally applicable U.S. federal income tax rules, the Company, which is incorporated under the laws of Canada, would be classified as a non-U.S. corporation (and, therefore, not a U.S. tax resident) for U.S. federal income tax purposes. Section 7874 of the U.S. Internal Revenue Code of 1986, as amended (the "**Code**") provides an exception to this general rule under which a non-U.S. incorporated entity may, in certain circumstances, be treated as a U.S. corporation for U.S. federal income tax purposes. If the Company were to be treated as a U.S. corporation for U.S. federal income tax purposes, we could be subject to substantial liability for additional U.S. income taxes on our worldwide income, and the gross amount of any dividend payments to non-U.S. holders could be subject to U.S. withholding tax.

Generally, this exception under Section 7874 of the Code, will apply if: (i) a non-U.S. corporation (pursuant to a plan or a series of related transactions) directly or indirectly acquires substantially all of the properties of a U.S. corporation or substantially all the properties constituting a trade or business of a U.S. partnership; (ii) the former stockholders of the acquired U.S. corporation or the acquired U.S. partnership hold, by vote or value, at least 80% of the shares of the non-U.S. acquiring corporation after the acquisition by reason of holding shares in the acquired U.S. corporation or interests in the acquired U.S. partnership; and (iii) the non-U.S. corporation's "expanded affiliated group" does not have substantial business activities in the non-U.S. corporation's country of tax residency relative to such expanded affiliated group's worldwide activities. An expanded affiliated group will generally have substantial business activities in a country if at least 25% of its employees (by headcount and compensation), real and tangible assets and gross income is based, located and derived, respectively, in such country.

In addition, even if the Company were not treated as a U.S. corporation pursuant to Section 7874 of the Code because the ownership attributable to stockholders of the acquired U.S. corporation or the acquired U.S. partnership was less than 80%, the Company could be subject to unfavorable treatment as a "surrogate foreign corporation" in the event that such ownership was at least 60%. If it were determined that the Company was treated as a surrogate foreign corporation under Section 7874 of the Code, the Company and certain of its affiliates and shareholders might be subject to adverse tax consequences including, but not limited to, restrictions on the use of tax attributes with respect to "inversion gain" recognized over a 10-year period following the transaction and disqualification of dividends paid from preferential "qualified dividend income" rates.

The Company will acquire an ownership interest in certain U.S. entities in the Reorganization, but we do not expect Section 7874 of the Code to apply as of the Closing Date because we do not expect such debt and securities acquisitions to constitute the acquisition of substantially all of the relevant properties of a U.S. corporation or substantially all of the properties constituting a trade or business of a U.S. partnership as of the Closing Date. The Company, however, may continue to acquire further ownership interests in such U.S. entities pursuant to the Exchange Right, and such acquisitions may eventually result in the Company being considered to have acquired substantially all of the relevant properties of a U.S. corporation or partnership, in which case we still do not expect Section 7874 of the Code to apply because we expect the Company's expanded affiliated group to have substantial business activities in Canada. Whether the Company's expanded affiliated group has substantial business activities in Canada, however, must be determined at the completion of the Company's acquisition of substantially all of the relevant properties of such U.S. entities, the timing of which is uncertain, and by which time there could be changes to the relevant facts and circumstances or the applicable law. Further, the rules for determining ownership and whether the expanded affiliated group that includes the Company has substantial business activities in Canada under Section 7874 of the Code are complex and the subject of ongoing legislative and regulatory review and change. Accordingly, there can be no assurance that the IRS would not assert that Section 7874 of the Code applies to the Company or that such an assertion would not be sustained by a court in the event of litigation.

Risks Related to Our Financial Condition

We have incurred material indebtedness, and we may not generate sufficient cash flow from operations to meet our debt service requirements, continue our operations and pursue our growth strategy, and we may be unable to raise capital when needed or on acceptable terms.

As of June 30, 2025, we had approximately $1,243.8 million aggregate principal of debt outstanding under the Term Loan due 2031, C$17.7 million aggregate principal amount of debt outstanding under the Warwick Credit Facility and $13.0 million debt outstanding under the ABL Facility. Our material level of indebtedness increases the risk that we may be unable to generate cash sufficient to pay amounts due in respect of our indebtedness, pay dividends and to fund our general corporate and capital requirements. The material indebtedness incurred by us and our subsidiaries could have important consequences to our shareholders, including the Company, including:

- a portion of our cash flow from operations must be dedicated to the payment of principal and interest on our debt, thereby reducing the funds available to us for other purposes;
- our ability to satisfy our obligations under the applicable Credit Agreements may be adversely affected;
- our ability to make loans and investments or engage in acquisitions without issuing additional equity or obtaining additional debt financing may be impaired in the future;
- our ability to obtain additional financing for working capital, capital expenditures, acquisitions, debt service requirements or general corporate purposes may be impaired in the future;
- our ability to pay dividends or distributions or engage in share repurchases may continue to be restricted;
- our flexibility may be limited in planning for, or reacting to, changes or challenges relating to the Business;
- our cost of borrowing may be increased;
- we may be more vulnerable to general adverse economic and industry conditions;
- we may be at a competitive disadvantage compared to our competitors who have less debt or comparable debt at more favorable interest rates or terms and who, as a result, may be better positioned to withstand economic downturns or to finance capital expenditures or acquisitions; and
- we may be unable to refinance our debt on terms as favorable as our existing debt or at all.

The occurrence of any one of these events could have an adverse effect on our Business, financial condition, results of operations, ability to satisfy our obligations under the applicable Credit Agreements and the OpCos' ability to pay distributions, including to the Company. See "— Rockpoint is a holding company. The sole material assets of the Company following completion of the Transactions will be its OpCo Interests. Accordingly, the Company will be fully dependent upon distributions from the OpCos to fund its expenses and the payment of dividends".

We may not be able to access capital on acceptable terms, raise additional capital in the future, or make effective capital allocation decisions, which could result in our inability to achieve operational objectives. Any disruption in access to capital could require us to take measures to conserve cash until alternative credit arrangements or other funding for business needs can be arranged. Such measures could include deferring capital expenditures, acquisitions or other discretionary uses of cash, including paying dividends or distributions to the Company, or revising capital allocation decisions. Any of these risks could adversely affect our Business, financial condition, and results of operations.

The agreements and instruments governing our debt contain restrictions and limitations that could significantly impact our management's flexibility and our financial and operational flexibility to operate our Business.

Restrictive covenants in the applicable Credit Agreements place limits on our ability to conduct our Business. Covenants in the Term Loan Credit Agreement, the Revolving Credit Agreement and the Warwick Credit Facility include those that, subject to certain exceptions, collectively restrict the ability of the applicable subsidiaries that operate a portion of the Business to:

- materially alter the Business;
- make changes to our name, location, executive office, or fiscal year without prior notice;
- engage in certain transactions with our affiliates;
- consolidate, merge, sell or otherwise dispose of all or substantially all of our assets;
- incur or permit to exist additional indebtedness and guarantee indebtedness;
- create, incur or assume liens or permit liens to exist;
- make certain investments or acquisitions;
- provide certain financial assistance;
- make dividends, distributions and certain other payments to security holders, including the Company;
- sell, transfer, lease or otherwise dispose of assets, including capital stock of our subsidiaries;
- operate accounts with or conduct banking business, other than with certain financial institutions;
- use the proceeds of such facilities to finance a hostile takeover bid; and
- enter into any restrictive agreements prohibiting the creation of liens to secure our obligations under the Term Loan Credit Agreement and the Revolving Credit Agreement.

Covenants in the ABL Credit Agreement include those that, subject to certain exceptions, restrict the ability of the applicable subsidiaries that operate a portion of the Business to:

- consolidate, merge, sell or otherwise dispose of all or substantially all of our assets;
- materially alter the Business;
- make changes to our name, location, executive office, or fiscal year without prior notice;
- create, incur, assume or suffer to exist certain additional indebtedness and guarantee indebtedness;
- create, assume or incur liens;
- make certain investments;
- enter into certain swap contracts or other transactions in violation of our risk management policy;
- declare or make any dividends, distributions, and certain other payments to security holders, including the Company;
- sell, transfer, lease or otherwise dispose of assets, including capital stock of our subsidiaries;
- engage in certain transactions with our affiliates;
- declare or make debt payments on certain subordinated debt;
- establish or maintain certain pension plans; and
- enter into any restrictive agreements limiting the ability of our subsidiaries to: (i) make certain dividends or distributions; (ii) transfer property to the borrowers and guarantors under the ABL Credit Agreement; (iii) guarantee the obligations under the ABL Credit Agreement; or (iv) create, incur, assume or suffer to exist liens to secure our obligations under the ABL Credit Agreement.

In addition, our ability to borrow under the ABL Facility is limited by a borrowing base and may be restricted by the agreements governing our indebtedness. Under certain circumstances, the ABL Credit Agreement requires us to comply with a minimum fixed charge coverage ratio and may require us to reduce debt or take other actions in order to comply with this ratio. See "Management's Discussion and Analysis — Liquidity and Capital Resources" and the Annual Financial Statements appended to this prospectus. The Term Loan Credit Agreement also requires the maintenance of a certain debt service coverage ratio. The Revolving Credit Agreement is expected to require the maintenance of a certain total net leverage ratio. These restrictions may prevent us from taking actions that we believe would be in the best interest of our Business and may make it difficult for us to execute our business strategy successfully or compete effectively with companies that are not similarly restricted. We may also incur future debt obligations that might subject us to additional restrictive covenants that could affect our financial and operational flexibility. Our ability to comply with the covenants and restrictions contained in the Term Loan Credit Agreement, the Revolving Credit Agreement and the ABL Credit Agreement may be affected by economic, financial and industry conditions beyond our control. The breach of any of these covenants or restrictions could result in a default under the applicable Credit Agreements, as applicable, which, if not cured or waived, would permit the applicable lenders, as the case may be, to declare all amounts outstanding thereunder to be due and payable, together with accrued and unpaid interest. In addition, the occurrence and continuation of such an event of default or acceleration may result in the acceleration of any other debt to which a cross-acceleration or cross-default provision applies. Our obligations under the Credit Agreements are secured by substantially all our current and fixed assets. If we are unable to repay debt, lenders having secured obligations under the Term Loan Credit Agreement, the Revolving Credit Agreement or the ABL Credit Agreement, as applicable, could proceed against the collateral securing such debt. This could materially adversely affect our Business, financial condition, and results of operations and could cause us to become bankrupt or insolvent.

We rely on cash generated from our financing and operating activities as our primary source of liquidity. To support our operations, execute our growth strategy as planned and make distributions, including to the Company, we will need to continue generating significant amounts of cash from operations, including funds required to pay our employees, related benefits and other operating expenses, finance future acquisitions, invest in the growth of our Business and pay for the increased direct and indirect costs associated with the Company operating as a public company. If our Business does not generate sufficient cash flow from operations to fund these activities, we may need to reduce or delay capital expenditures, sell assets, seek additional capital, including by incurring additional debt or equity capital or refinance or restructure our indebtedness. Our ability to restructure or refinance indebtedness will depend on the condition of the capital markets and our financial condition at such time. Any refinancing of indebtedness could be on unfavourable terms, including at higher interest rates, and may require us to comply with more restrictive covenants. The terms of our existing or future debt instruments may restrict us from adopting some of these alternatives. There can be no assurance that any refinancing or restructuring would be possible, that any assets could be sold or that, if sold, the timing of the sales and the amount of proceeds realized from those sales would be favourable to us or that additional financing could be obtained on favourable terms, if at all. In addition, any failure to service our debt, including paying interest or principal on a timely basis, would likely result in a reduction of our credit rating, if any, which could harm our ability to incur additional indebtedness and/or adversely impact our borrowing costs. In addition, incurring indebtedness requires that a portion of cash flow from operating activities be dedicated to interest and principal payments. Debt service requirements could reduce our ability to use our cash flow to fund operations and capital expenditures, to capitalize on future business opportunities, including additional acquisitions, or to make distributions, including to the Company. Any of these risks could adversely affect our Business, financial condition, and results of operations.

Our ability to make scheduled payments on or refinance our debt obligations depends on our financial condition and operating performance, which are subject to prevailing economic and competitive conditions and to financial, business, legislative, regulatory and other factors beyond our control. We may be unable to maintain a level of cash flows from operations sufficient to permit us to pay the principal, premium, if any, and interest on our indebtedness. Any insufficiency may adversely impact our Business and our results of operations and financial condition.

In connection with, and conditional upon, completion of the Offering, we intend to repay in full and terminate each of the ABL Credit Agreement and the Warwick Credit Agreement, and therefore we will no longer be subject to the restrictions and limitations under the ABL Credit Agreement and the Warwick Credit Agreement, in each case, described above and contained therein.

Our variable rate debt subjects us to interest rate risk, which could cause our debt service obligations to increase significantly and affect our operating results.

The indebtedness under the Credit Agreements accrue interest at variable rates of interest, which exposes us to interest rate risk. In addition, the Term Loan due 2031, the Revolving Credit Facility and the ABL Facility reference or will reference, as applicable, SOFR as one of the primary benchmark rates for our variable rate indebtedness in U.S. dollars and, in the case of the Revolving Credit Facility, ABL Facility and the

Warwick Credit Facility, reference or will reference, as applicable, CORRA as the primary benchmark rate for our variable rate indebtedness in Canadian dollars. If benchmark interest rates, including SOFR or CORRA, were to increase, our debt service obligations on our variable rate indebtedness would increase even if the amount borrowed remains the same, and our net income and cash flows, including cash available for servicing our indebtedness and paying distributions, including to the Company, will correspondingly decrease. In addition, while our obligations under the applicable Credit Agreements will continue to be subject to SOFR and/or CORRA (as applicable), other factors may impact SOFR and CORRA, including factors causing SOFR or CORRA to cease to exist, new methods of calculating SOFR or CORRA to be established, or the use of an alternative reference rate. Such circumstances are not entirely predictable, but could have an adverse impact on our financing costs and results of operations. As of June 30, 2025, we had $1,243.8 million outstanding principal amount of variable rate debt subject to interest rate exposure under the Term Loan due 2031. 100.0% of our principal borrowings were hedged through September 2025, which decreased to 72.8%, or $900.0 million, in October 2025 to September 2026. Thereafter, the full principal balance is unhedged which will expose us to interest rate fluctuations unless the debt is re-hedged.

In March 2022, the U.S. Federal Reserve began, and continued through 2023, to raise interest rates in an effort to curb inflation. Although the U.S. Federal Reserve reduced benchmark interest rates in 2024, we may continue to experience further financing cost increases if interest rates on borrowings, credit facilities and debt offerings increase compared to previous levels. Changes in interest rates, either positive or negative, may also affect the yield requirements of investors who invest in the Class A Shares, and the elevated interest rate environment could have an adverse impact on the price of the Class A Shares, or our ability to issue equity or incur debt for acquisitions or other purposes.

Forward-Looking Information and Financial and Operational Targets May Prove Inaccurate.

Investors are cautioned not to place undue reliance on forward-looking information included in this prospectus, including targets relating to Adjusted EBITDA growth, Distributable Cash Flow growth and dividends and distributions. By their nature, forward-looking information, including financial and operational targets, involve numerous assumptions, known and unknown risks and uncertainties that could cause actual results to differ materially from those suggested by the forward-looking information. The financial and operational targets presented in this prospectus are based on our assessment of the Business, our competitive strengths and current market trends and conditions, as described throughout this prospectus. If such assessments do not prove accurate, the forward-looking information, including the financial and operational targets, may change materially. See "Notice to Investors — Forward-Looking Information", "Management's Discussion and Analysis — Our Business — Outlook for our business", "Our Business — Our Competitive Strengths — High free cash flow conversion supports reinvestment and return of capital" and "Dividend Policy".

Despite our indebtedness level, we may incur substantially more debt, including secured debt. This could further exacerbate the risks associated with our material indebtedness.

We and our subsidiaries may incur substantial additional indebtedness in the future. Although the terms of the Credit Agreements contain restrictions on the incurrence of additional indebtedness, such restrictions are subject to a number of significant exceptions and qualifications and any additional indebtedness incurred in compliance with such restrictions could be substantial. These restrictions also will not prevent us from incurring obligations that do not constitute indebtedness. If we and our subsidiaries incur significant additional indebtedness or other obligations, the related risks that we face could increase, and we may not be able to meet all our debt obligations.

Changes to applicable tax laws and regulations, exposure to additional income tax liabilities, changes in our effective tax rates or an assessment of taxes resulting from an examination of our income or other tax returns could adversely affect our results of operations, cash flows and financial position, including our ability to repay our debt.

We are subject to various complex and evolving U.S. and Canadian federal, provincial, state and local taxes. Applicable tax laws, policies, statutes, rules, regulations or ordinances could be interpreted, changed, modified or applied adversely to us, in each case, possibly with retroactive effect, and may have an adverse effect on our results of operations, cash flows and financial position, including our ability to repay our debt.

Changes in our effective tax rates or tax liabilities could also adversely affect our results of operations, cash flows and financial position. Our future effective tax rates could be subject to volatility or adversely affected by a number of factors, including:

- changes in the valuation of our deferred tax assets and liabilities;
- expected timing and amount of the release of any tax valuation allowances;
- expansion into future activities in new jurisdictions;
- changes in the mix of earnings in countries with differing statutory tax rates;
- the availability of tax deductions, credits, exemptions, refunds and other benefits to reduce tax liabilities; and
- tax effects of share-based compensation.

We are subject to the examination of our tax returns and other tax matters by the U.S. Internal Revenue Service, the CRA and other tax authorities and governmental bodies. An adverse outcome arising from an examination of our income or other tax returns could result in higher tax exposure, penalties, interest or other liabilities that could have an adverse effect on our results of operations, cash flows and financial position.

If we fail to comply with the restrictions and covenants in the applicable Credit Agreements or our future debt agreements, there could be an event of default under the terms of such agreements, which could result in an acceleration of such debt.

A breach of compliance with any restriction or covenant in the Credit Agreements or any of our future debt agreements could result in an event of default under the terms of the applicable agreement, and our ability to comply with such restrictions and covenants may be affected by events beyond our control. As a result, there can be no assurance that we will be able to comply with these restrictions and covenants. A default, if not cured or waived, could result in acceleration of the applicable indebtedness and a declaration of all amounts borrowed due and payable, which could have a material adverse effect on us, our cash flows and our financial position and negatively impact our ability to borrow. If an acceleration occurs, we may be unable to make all of the required payments and may be unable to find alternative financing. Even if alternative financing is available at that time, it may not be on terms that are favourable or acceptable to us. Additionally, we may not be able to amend the Credit Agreements or such future agreements governing our indebtedness or obtain necessary waivers on satisfactory terms.

Our obligations under the ABL Credit Agreement are secured by first priority security interests in substantially all of our current assets and by second priority security interests in substantially all of our fixed assets, in each case now owned and hereafter acquired. Our obligations under the Term Loan Credit Agreement are secured by first priority security interests in substantially all of our fixed assets and by second priority security interests in substantially all of our current assets and fixed assets, now owned or hereafter acquired. Our obligations under the Warwick Credit Agreement are secured by, among other security, first priority security interests in substantially all of the assets of WGS LP. Following the termination and repayment of the ABL Credit Agreement, our obligations under the Revolving Credit Agreement and the Term Loan Credit Agreement are expected to be secured on a *pari passu* basis by first priority security interests in substantially all of our assets, now owned or hereafter acquired. The amounts borrowed pursuant to the terms of the Revolving Credit Agreement, the ABL Credit Agreement and the Term Loan Credit Agreement are or will be, as applicable, secured by substantially all of our and our material subsidiaries' present and after-acquired assets. Additionally, our obligations under the Revolving Credit Agreement, the ABL Credit Agreement and the Term Loan Credit Agreement are, or will be, as applicable, each jointly and severally guaranteed by us and our material subsidiaries. As a result of the above, following the occurrence of an event of default under the Revolving Credit Agreement, the ABL Credit Agreement or the Term Loan Credit Agreement, as applicable, the applicable lenders may enforce their security interests over our and/or our subsidiaries' assets that secure or will secure, as applicable, the obligations under the Revolving Credit Agreement, the ABL Credit Agreement or the Term Loan Credit Agreement, as applicable, take control of our assets and business, force us to seek creditor or bankruptcy protection or force us to curtail or abandon our current business plans. If that were to happen, a holder of the Class A Shares may lose all, or a part of, its investment in the Class A Shares.

In connection with, and conditional upon, completion of the Offering, we intend to repay in full and terminate each of the ABL Credit Agreement and the Warwick Credit Agreement, and therefore we will no longer be subject to the obligations under the ABL Credit Agreement and the Warwick Credit Agreement, in each case, described above and contained therein.

Risks Related to the Offering, Rockpoint's Corporate Structure and the Class A Shares

Rockpoint is a holding company. The sole material assets of the Company following completion of the Transactions will be its OpCo Interests. Accordingly, the Company will be fully dependent upon distributions from the OpCos to fund its expenses and the payment of dividends.

Following completion of the Transactions, Rockpoint will be a holding corporation whose sole material assets consist of approximately 40% of the OpCo Interests. The Company will not have any independent means of generating revenue. As such, the Company's ability to pay its taxes and expenses or declare and pay dividends in the future is fully dependent upon the financial results and cash flows of the OpCos and their subsidiaries, and distributions it receives from the OpCos. The OpCos and their respective subsidiaries may not generate sufficient cash flow to distribute funds to securityholders, including the Company and applicable laws and contractual restrictions, including negative covenants in our debt instruments, may not permit such distributions.

Following completion of the Transactions:

- Brookfield will hold the controlling voting interests in the Company, including with respect to the right to vote for the election of directors to the Board;
- Brookfield will be: (i) the sole shareholder of Swan GP, the general partner of Swan OpCo; (ii) the majority shareholder of BIF OpCo; and (iii) the sole shareholder of BIF II CalGas Carry (Delaware) LLC and BIP BIF II US Holdings (Delaware) LLC, two of the three members of BIF OpCo (other than the Company);
- each of the OpCo Boards will be comprised of three directors or managers, respectively, selected from the existing members of the Board by the members of the Board subject to, at all times, compliance with existing CPUC approvals, with one manager or director, as applicable, being an independent director of Rockpoint and the remaining two being non-independent directors of Rockpoint who are affiliated with Brookfield; and
- the OpCos will hold the Business.

As a result of the foregoing, Brookfield will have the ability to influence the overall management of the Business, including the amount of cash distributions to be made by the OpCos, which distributions will be relied on as the sole source of funds for the Company. Accordingly, Rockpoint will be reliant on the cooperation of Brookfield and the managers, directors and officers of the OpCos and Swan GP and their subsidiaries that it has appointed to make decisions regarding the operations, management and administration of the OpCos and the cash to be paid to the Company. If the Company's interests and those of Brookfield or the OpCos differ, the Company will not, without the cooperation of Brookfield, be able to implement policies in respect of the management and operations of the OpCos that it determines are desirable.

In addition, BIF OpCo is a distinct legal entity and may be subject to legal or contractual restrictions, including those under its debt agreements, that, under certain circumstances, may limit the Company's ability to obtain cash from BIF OpCo. If BIF OpCo is unable to make distributions, the Company may not receive adequate distributions to pay its tax or other liabilities or to fund its operations or any dividends.

Rockpoint anticipates that BIF OpCo and Swan OpCo will continue to be classified as partnerships for U.S. federal income tax purposes and, as such, will not be subject to any entity-level U.S. federal income tax. Instead, the OpCos' U.S. taxable income will be allocated to Brookfield and Rockpoint. Accordingly, Rockpoint will incur income taxes on Rockpoint's allocable share of any net U.S. taxable income of the OpCos.

In addition to tax expenses, Rockpoint will also incur expenses related to its operations. From a Canadian tax perspective, the Business is effectively carried on through entities that would be considered corporations for Canadian tax purposes. However, for Canadian tax purposes, Swan OpCo is classified as a partnership. Notwithstanding that Swan OpCo should not be subject to Canadian federal income tax, distributions received from the Business through Swan OpCo may be subject to Canadian withholding taxes and thereby reducing the cash flow to the Company. In addition, as the Canadian Business operations will be conducted through Canadian corporations, there may be tax expenses incurred by those entities thereby reducing the cash flow to the Company.

The LLC Agreement of BIF OpCo provides that BIF OpCo or its board of managers, in their sole discretion, may authorize distributions by BIF OpCo to its members at such times and in such amounts as they shall determine. Such distributions may be made as either: (i) a return of capital in respect of such members' BIF OpCo Shares; or (ii) as distributions other than a return of capital, in which case such distribution will reduce the amount of Retained Earnings (as defined in the LLC Agreement) as to such BIF OpCo Shares.

The A&R LPA states that distributions shall be made to the Swan OpCo Partners at such times and in such amounts as may be determined in the sole discretion of Swan GP. Distributions to Swan OpCo Limited Partners shall be shared among the Swan OpCo Limited Partners on a *pro rata* basis in proportion to the number of Swan OpCo Units held by each of them.

Rockpoint will be dependent upon the OpCo Boards, which are comprised of a majority of Brookfield-affiliated directors or managers, as applicable, for supervision of the management and operation of the Business and the OpCos, which could affect the value of Rockpoint's investment in the Business.

Following Closing, the OpCo Boards will be comprised of three directors or managers, as applicable, one of which will be an independent director of Rockpoint and the remaining two of which will be non-independent directors who are affiliated with Brookfield. In addition to determining the amount and timing of distributions to holders of OpCo Interests (including Rockpoint), the OpCo Boards will have broad discretion to make key decisions and approvals with respect to the Business and other matters that could have a material impact on the interests of the holders of the OpCo Interests (including the Company), in each case without the approval of the Company (as a holder of OpCo Interests) or the shareholders of the Company.

The requirements of being a public company, including compliance with the reporting requirements of applicable Canadian securities laws, will increase Rockpoint's costs and divert management's attention from other business concerns.

As a public company, Rockpoint will be required to comply with new laws, regulations and requirements of applicable Canadian securities laws and TSX rules, with which it is not currently required to comply as a private company. Complying with these statutes, regulations and requirements will occupy a significant amount of time of the Board and management and will significantly increase the Company's costs and expenses. As a public company, Rockpoint will be required to:

- institute a more comprehensive compliance function;
- comply with continuous disclosure requirements under Canadian securities laws, including to prepare and distribute periodic public reports;
- comply with rules promulgated by the TSX;
- establish new internal policies, such as those relating to disclosure and personal trading; and
- involve and retain to a greater degree outside counsel and accountants in the above activities.

In addition, Rockpoint expects that being a public company subject to these rules and regulations may make it more difficult and more expensive for it to obtain director and officer liability insurance and the Company may be required to accept reduced policy limits and coverage or incur substantially higher costs to obtain the same or similar coverage. As a result, it may be more difficult for Rockpoint to attract and retain qualified individuals to serve on the Board or as executive officers. The Company cannot predict or estimate the amount of additional costs it may incur or the timing of such costs.

Failure of Rockpoint's internal or disclosure controls to satisfy its public company reporting obligations could have a material adverse impact on the Company.

Rockpoint is not currently required to comply with National Instrument 52-109 — *Certification of Disclosure in Issuers' Annual and Interim Filings* ("**NI 52-109**") with respect to the establishment, maintenance and report of internal controls over financial reporting and disclosure controls and procedures. As a publicly traded company, the Company will become subject to reporting and other obligations under applicable Canadian securities laws, including NI 52-109, and the rules of the TSX. These reporting and other obligations will place significant demands on the Company's management, administrative, operational and accounting resources. In order to meet such requirements, it will, among other things, establish systems, implement financial and management controls, reporting systems and procedures and, if necessary, hire qualified accounting and finance staff and/or retain external advisors to assist with such matters. However, if Rockpoint is unable to accomplish any such necessary objectives in a timely and effective manner, its ability to comply with its financial reporting obligations and other rules applicable to reporting issuers could be impaired. The process for establishing and maintaining adequate internal controls over financial reporting has inherent limitations, including the possibility of human error and any failure to maintain effective internal controls could cause Rockpoint to fail to satisfy its reporting obligations or result in material misstatements in its financial statements. If the Company cannot provide reliable financial reports or prevent fraud, its reputation and operating results could be materially adversely affected which could also cause investors to lose confidence in the Company's reported financial information, which could result in a reduction in the market price of the Class A Shares.

Rockpoint does not expect that its disclosure controls and procedures and internal controls over financial reporting will prevent all error or fraud. A control system, no matter how well-designed and implemented, can provide only reasonable, not absolute, assurance that the control system's objectives will be met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Due to the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues within an organization are detected. The inherent limitations include the realities that judgments in decision making can be faulty, and that breakdowns can occur because of simple errors or mistakes. Controls can also be circumvented by individual acts of certain persons, by collusion of two or more people or by management override of the controls. Due to the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and may not be detected in a timely manner or at all.

Future sales of Class A Shares, or the perception that such sales may occur, may depress the Class A Share price, and any additional capital raised through the sale of equity or convertible securities may dilute your ownership in the Company.

Rockpoint may in the future issue additional securities. The potential issuance of such additional securities may result in the dilution of the ownership interests of the holders of the Class A Shares and may create downward pressure on the trading price of the Class A Shares.

In addition, at Closing, the Company will grant the Registration Right and the Demand Registration Right to Brookfield to facilitate the sale of Brookfield's interests in the Company and the Business. See "Relationship with Brookfield — Agreements Between the Company and Brookfield — Registration Rights Agreement". In addition, the Company, Brookfield and the OpCos have entered into the Exchange Agreement that provides for the Exchange Right and provides that Brookfield will not be permitted to exercise the Exchange Right: (i) for a period of 12 months from the Closing Date; and (ii) at any time, to the extent that the change of proportional ownership or operational control of the OpCos between Brookfield, on the one hand, and Rockpoint, on the other, would result in a change of control of the Lodi or Wild Goose operating subsidiaries for the purposes of the operating permits issued by the CPUC, unless the CPUC Approval has first been obtained. Other than with respect to the limitations set out in the Exchange Agreement, following the expiration of the 180-day lock-up period, Brookfield is under no obligation to maintain its ownership interest in the Company or the Business (provided that Brookfield will have first obtained CPUC Approval prior to selling a majority interest in Rockpoint or the OpCos or otherwise giving up control of Wild Goose or Lodi (see "— The CPUC may inquire into whether, or take the position that, the Offering constitutes a change of control")), and Brookfield will be able to exercise its rights under the Registration Rights Agreement in its sole discretion, and sales of Class A Shares pursuant to such rights may be material in amount and occur at any time, subject to the terms of the Registration Rights Agreement. The sales of substantial amounts of the Class A Shares or the perception that such sales may occur could cause the market price of the Class A Shares to decline and impair the Company's ability to raise capital. Rockpoint also may grant additional registration rights in connection with any future issuance of Class A Shares.

The Company cannot predict the size of future issuances or sales of the Class A Shares or securities convertible into Class A Shares or the effect, if any, that future issuances and sales of the Class A Shares or other securities will have on the market price of the Class A Shares or that such issuances or sales will take place. Sales of substantial amounts of the Class A Shares or the perception that such sales could occur, may adversely affect the prevailing market price of the Class A Shares.

Exclusion from the definition of "investment company" under the Investment Company Act.

Rockpoint intends to fall outside the definition of an "investment company" under the U.S. Investment Company Act of 1940 (the "**Investment Company Act**"), and to avoid regulation under the Investment Company Act. Consequently, the Company does not intend to register as an investment company under the Investment Company Act and investors will not receive the regulatory protections offered by investment companies registered under the Investment Company Act.

If the Company were deemed to be an investment company under the Investment Company Act, it would be impractical for the Company to operate as contemplated and it could be subject to material U.S. federal taxes, which could materially adversely affect the Business and our results of operations and financial condition. Accordingly, the Company would be required to take extraordinary steps to address regulatory risks under the Investment Company Act. Further, any such actions would require additional expense and attention from management for which the Company has not accounted.

If the Company does not pay regular cash dividends on the Class A Shares following the Offering, a holder of Class A Shares may not receive a return on investment unless it sells its Class A Shares for a price greater than that which its paid for them.

Dividend payments are not guaranteed and are within the absolute discretion of the Board. Although the Company anticipates that the Board will declare and pay a corresponding cash dividend on the Class A Shares if, as and when an OpCo pays a cash distribution to the Company, the Company is not obligated to do so, and will only be able to do so to the extent it receives distributions from the OpCos. Moreover, the payment of any future dividends will be at the discretion of the Board, and there can be no assurances that any dividend will be declared and paid. While it intends to do so, the Company has not yet adopted a written dividend policy.

The Board's declaration of cash dividends on the Class A Shares will be subject to applicable law and depend on, among other things, the timing and amount of distributions declared and paid by the OpCos to the Company economic conditions, the Company's expenses, financial condition, results of operations, liquidity, earnings, projections, legal requirements, and restrictions in the agreements governing the Company's indebtedness, including the Credit Facilities. Accordingly, Rockpoint may not be able to pay dividends even if the Board would otherwise deem it appropriate. See "Management's Discussion and Analysis — Liquidity and Capital Resources", "Management's Discussion and Analysis — Contractual Obligations and Commitments" and "Dividend Policy".

Any return on investment in the Class A Shares may be solely dependent upon the appreciation of the price of the Class A Shares on the open market, which may not occur. There can be no assurance that Rockpoint will pay dividends in the future or continue to pay any dividends if the Company does commence paying dividends. Prospective investors should make any investment in the Class A Shares without relying on any expectation or belief that dividends will be paid on the Class A Shares.

Brookfield has the ability to direct the voting of a majority of Shares and control certain decisions with respect to Rockpoint's management and business. Brookfield's interests may conflict with those of the other shareholders.

Upon completion of the Transactions, Brookfield will own approximately 39.8% of the outstanding Class A Shares and 100% of the outstanding Class B Shares, representing approximately 75.9% of the outstanding Shares and voting interest in the Company (approximately 30.8% of the outstanding Class A Shares, representing, together with Brookfield's Class B Shares, approximately 72.3% of the outstanding Shares and voting interest in the Company, if the Over-Allotment Option is exercised in full). Brookfield's initial ownership, control or direction of greater than 50% of the voting power attached to all of the outstanding Shares means Brookfield will be able to, subject to applicable laws, control (or exercise significant influence over) certain matters requiring shareholder approval, including the election of directors, certain changes to the Articles, approval of acquisition offers and other significant corporate transactions. This concentration of ownership makes it unlikely that any other holder or group of holders of the Class A Shares will be able to affect the way the Company is managed or the direction of the Business.

Furthermore, concurrent with the completion of the Reorganization, Rockpoint will enter into the Shareholder Agreement. The Shareholder Agreement will provide that Brookfield will have director nomination rights as long as it owns, controls or directs at least 5% of the voting power attached to all of the outstanding Shares (on a non-diluted basis). The members of the Board are required to act honestly and in good faith with a view to the best interests of the Company. The interests of Brookfield with respect to matters potentially or actually involving or affecting the Company, such as future acquisitions, financings and other corporate opportunities and attempts to acquire the Company, may conflict with the interests of the other shareholders. See "Relationship with Brookfield — Agreements Between the Company and Brookfield — Shareholders Agreement".

The existence of Brookfield as a significant shareholder may have the effect of deterring hostile takeovers, delaying or preventing changes in control or changes in management or limiting the ability of the other shareholders to approve transactions that they may deem to be in the best interests of Rockpoint. Moreover, the concentration of share ownership with Brookfield may adversely affect the trading price of the Class A Shares to the extent investors perceive a disadvantage in owning shares of a company with significant shareholders or anticipate that a significant number of shares may be sold on the market or pursuant to a secondary offering of those shares.

In addition, Brookfield may have different tax positions from Rockpoint that could influence its decisions regarding whether and when to support the disposition of assets, the payment or characterization of distributions and the incurrence or refinancing of new or existing indebtedness. In addition, the determination of future tax reporting positions, the structuring of future transactions and the handling of any challenge by any taxing authority to the Company's tax reporting positions may take into consideration tax or other considerations of Brookfield, which may differ from the considerations of the other shareholders.

Rockpoint is a newly formed company with no separate operating history and the historical and pro forma financial information included herein does not reflect the financial condition or operating results Rockpoint would have achieved during the periods presented, and therefore may not be a reliable indicator of its future financial performance.

Rockpoint was incorporated under the ABCA on July 28, 2025 by Brookfield Infrastructure Holdings (Canada) Inc. Rockpoint has not conducted and will not conduct any material business operations prior to the completion of the Transactions other than certain activities related to the Transactions, and, although Rockpoint's sole asset will be its investment in the Business through the OpCos, the historical and pro forma financial information included herein may not reflect the financial condition or operating results Rockpoint would have achieved during the periods presented, and therefore may not be a reliable indicator of the Company's future financial performance. The Company's lack of operating history will make it difficult to assess its ability to operate profitably and make distributions to shareholders. Although the Business has been under Brookfield's control prior to the formation of Rockpoint, its results have not previously been reported on a stand-alone basis and, therefore, may not be indicative of the Company's future financial condition or operating results. Rockpoint urges prospective investors to carefully consider the basis on which the historical and pro forma financial information included herein was prepared and presented.

Brookfield is not limited in its ability to compete with Rockpoint and may benefit from opportunities that might otherwise be available to Rockpoint.

The Company's relationship with Brookfield, as a significant shareholder of the Company, does not impose any duty on Brookfield to act in the best interest of the Company or the Business and Brookfield is not prohibited from engaging in other business activities that may compete with the Company or the Business. Pursuant to the Relationship Agreement, the Company and the OpCos have acknowledged and agreed that Brookfield carries on a diverse range of businesses worldwide, and that except as explicitly provided in the Relationship Agreement, the Relationship Agreement will not in any way limit or restrict Brookfield from carrying on its business. Among other things, the Company and each of the OpCos have also acknowledged and agreed that Brookfield may pursue other business activities and provide services to third parties that compete directly or indirectly with the Business. In addition, the Relationship Agreement provides that Brookfield has established or advised, and may continue to establish or advise, other entities that rely on the diligence, skill and business contacts of Brookfield's professionals and the information and acquisition opportunities they generate during the normal course of their activities. The Company and the OpCos have acknowledged and agreed that some of these entities may have objectives that overlap with the objectives of the Company or the OpCos or such entities may acquire business services and industrial operations that could be considered appropriate acquisitions for the OpCos, and that Brookfield could have financial incentives to assist those other entities over us.

Brookfield may become aware, from time to time, of certain business opportunities (such as acquisition opportunities) and may direct such opportunities to other businesses in which it has invested, in which case the Company may not become aware of or otherwise have the ability to pursue such opportunity. Furthermore, such businesses may choose to compete with the Company for these opportunities, possibly causing these opportunities to not be available to it or causing them to be more expensive for the Company to pursue. This may create actual and potential conflicts of interest between the Company and Brookfield, and result in less than favourable treatment of the Company and its shareholders if attractive business opportunities are pursued by Brookfield for its own benefit rather than for the Company's.

A significant reduction by Brookfield of its ownership interest in Rockpoint could adversely affect Rockpoint.

The Company believes that Brookfield's ownership interest in it provides it with an economic incentive to assist the Company to be successful. The Company, Brookfield and the OpCos have entered into the Exchange Agreement that provides for the Exchange Right and provides that Brookfield will not be permitted to exercise the Exchange Right: (i) for a period of 12 months from the Closing Date; and (ii) at any time, to the extent that the change of proportional ownership or operational control of the OpCos between Brookfield, on the one hand, and Rockpoint, on the other, would result in a change of control of the Lodi or Wild Goose operating subsidiaries for the purposes of the operating permits issued by the CPUC, unless the CPUC Approval has first been obtained. Upon the expiration of the 180-day lock-up restrictions on transfers or sales of the Company's securities following the completion of the Transactions, Brookfield will not be subject to any obligation to maintain its ownership interest in Rockpoint (provided that Brookfield will have first obtained CPUC Approval prior to selling a majority interest in Rockpoint or the OpCos or otherwise giving up control of Wild Goose or Lodi) and may elect at any time thereafter (including in accordance with but subject to the provisions of the Registration Rights Agreement) to sell all or a substantial portion of or otherwise reduce its ownership interest in the Company. See "Plan of Distribution — Lock-Up". If Brookfield sells all or a substantial portion of its ownership interest in the Company, it may have less incentive to assist in Rockpoint's success and its director nominees may resign. Such actions could adversely affect the Company's ability to successfully implement its business strategies, which could adversely affect its results of operations, cash flows and financial position.

If Brookfield has not first obtained CPUC Approval and sells all or a substantial portion of its ownership interest in the Company, the CPUC may, depending upon the proportion of the interest sold, take the position that such disposition by Brookfield constitutes a change of control for Wild Goose and/or Lodi. If the CPUC determines that such disposition constitutes a change of control, it is possible that the CPUC would deny or condition that change of control, which could adversely affect the Business and our results of operations and financial condition. See "— The CPUC may inquire into whether, or take position that, the Offering constitutes a change of control".

Certain of the Company's directors may have significant duties with, and spend significant time serving, other entities, including entities that may compete with Rockpoint and the OpCos in seeking acquisitions and business opportunities, and, accordingly, may have conflicts of interest in allocating time or pursuing business opportunities.

Certain of the Company's directors who are responsible for managing the Business may hold positions of responsibility with other entities, including those that are in the energy industry. The existing and potential positions held by these directors and executive officers may give rise to fiduciary or other duties that are in conflict with the duties they owe to Rockpoint and may also otherwise require attention and time that could otherwise be devoted to the Business. These directors may become aware of business opportunities that may be appropriate for presentation to the Company as well as to the other entities with which they are or may become affiliated. Due to these existing and potential future affiliations, subject to applicable laws, such directors may present potential business opportunities to other entities prior to presenting them to the Company, which could cause additional conflicts of interest. They may also decide that certain opportunities are more appropriate for other entities with which they are affiliated, and, as a result, they may elect not to present those opportunities to the Company.

The Underwriters may waive or release parties to the lock-up agreements entered into in connection with the Offering, which could adversely affect the price of the Class A Shares.

All of the Company's directors and executive officers and Brookfield will enter into lock-up agreements pursuant to which they will be subject to certain restrictions with respect to the sale or other disposition of the Class A Shares or securities convertible into or exercisable or exchangeable for Class A Shares, including OpCo Interests and Class B Shares for a period of 180 days following the date of this prospectus. See "Plan of Distribution — Lock-Up". If the restrictions under the lock-up agreements are waived by the Lead Underwriters on behalf of the Underwriters, then the Class A Shares, subject to compliance with applicable securities laws, will be available for sale into the public markets, which could cause the market price of the Class A Shares to decline and impair the Company's ability to raise capital.

All of the net proceeds of the Offering will be used to acquire 40% of the OpCo Interests and 40% of the Warwick Receivable.

As described in "Relationship with Brookfield — The Transactions" and "Use of Proceeds", Rockpoint intends to use the net proceeds from the Offering to acquire 40% of the OpCo Interests and 40% of the Warwick Receivable (which will subsequently be cancelled). If the Over-Allotment Option is exercised, the Company will not receive any proceeds therefrom. Consequently, none of the proceeds of the Offering will be available to fund Rockpoint's future operations, capital expenditures, dividends or acquisition opportunities. See "Use of Proceeds".

If securities or industry analysts do not publish research or reports about the Company or the Business, if they adversely change their recommendations regarding the Class A Shares or if the Company's operating results do not meet their expectations, the price of the Class A Shares could decline.

The trading market for the Class A Shares will be influenced by the research and reports that industry or securities analysts publish about the Company or the Business. If one or more of these analysts cease coverage of Rockpoint or fail to publish reports on the Company regularly, Rockpoint could lose visibility in the financial markets, which in turn could cause the price or trading volume of the Class A Shares to decline. Moreover, if one or more of the analysts who cover Rockpoint downgrades the Class A Shares or if its operating results do not meet their expectations, the price per Class A Share could decline.

The Offering Price may not be indicative of the market price of the Class A Shares after the Offering. In addition, an active, liquid and orderly trading market for the Class A Shares may not develop or be maintained, and the Class A Shares price per share may be volatile.

The Class A Shares are not traded on any market. After the Offering, only the Class A Shares will be publicly traded. The Company does not know the extent to which investor interest will lead to the development of a trading market or how liquid that market might be. Active, liquid and orderly trading markets usually result in less price volatility and more efficiency in carrying out investors' purchase and sale orders. The market price of the Class A Shares could vary significantly as a result of a number of factors, some of which are beyond Rockpoint's control. In the event of a decrease in the market price of the Class A Shares, a holder of Class A Shares could lose a substantial part or all of its investment in the Class A Shares. The Offering Price was negotiated among the Company, Brookfield and the Lead Underwriters and may not be indicative of the market price of the Class A Shares after the Offering. The market price of the Class A Shares may decline below the Offering Price. Consequently, a holder of Class A Shares may not be able to sell the Class A Shares at prices equal to or greater than the price paid by it in the Offering.

The following factors could affect the price per Class A Share:

- quarterly or annual variations in Rockpoint's financial and operating results or the financial or operating results of the Business, or those of other companies in its industry;
- the public reaction to Rockpoint's press releases, its other public announcements and its filings;
- strategic actions by Rockpoint or its competitors, including announcements of significant contracts or acquisitions;
- changes in revenue or earnings estimates, or changes in recommendations or withdrawal of research coverage, by equity research analysts;
- speculation in the press or investment community;
- the failure of research analysts to cover the Class A Shares;
- sales of the Class A Shares by Rockpoint, Brookfield or other shareholders, or the perception that such sales may occur;
- changes in accounting principles, policies, guidance, interpretations or standards;
- additions or departures of key management personnel;
- actions by shareholders;
- general market conditions, including fluctuations in natural gas prices;
- domestic and international economic, legal and regulatory factors unrelated to our performance; and
- the realization of any risks described under this "Risk Factors" section.

The stock markets in general have experienced extreme volatility that has often been unrelated to the operating performance of particular companies. These broad market fluctuations may adversely affect the trading price of the Class A Shares. Securities class action litigation has often been instituted against companies following periods of volatility in the overall market and in the market price of a company's securities. Such litigation, if instituted against the Company, could result in very substantial costs, divert management's attention and resources and adversely affect the Business and our results of operations and financial condition.

The Articles contain provisions that could discourage acquisition bids or merger proposals, which may adversely affect the market price of the Class A Shares and could deprive investors of the opportunity to receive a premium for their shares.

The Articles authorize the Board to issue preferred shares without shareholder approval in one or more series, designate the number of shares constituting any series and fix the rights, preferences, privileges and restrictions thereof, including dividend rights, voting rights, rights and terms of redemption, including redemption prices and liquidation preferences of such series. If the Board elects to issue preferred shares, it could be more difficult for a third-party to acquire Rockpoint.

Canadian investors may find it difficult or impossible to effect service of process and enforce judgments against certain of our directors.

Certain of the Company's directors reside outside of Canada. Consequently, it may not be possible for Canadian investors to enforce judgments obtained in Canada against any person who resides outside of Canada, even if the person has appointed an agent for service of process. Furthermore, it may be difficult to realize upon or enforce in Canada any judgment of a court of Canada against the aforementioned directors who reside outside of Canada since the assets of such persons may be located outside of Canada. See "Enforcement of Judgments Against Foreign Persons".

Rockpoint may lose its foreign private issuer status in the United States.

We expect the Company to be a foreign private issuer (as defined in Rule 405 under the U.S. Securities Act). If, as of the last business day of the Company's second fiscal quarter for any year, the Company determines that more than 50% of its outstanding voting securities (as determined pursuant to Rule 405) are directly or indirectly held of record by residents of the United States, effective on the first day of its fiscal year immediately succeeding such determination the Company will no longer meet the definition of a foreign private issuer, which may have adverse consequences on the Company's ability to raise capital in private placements or Canadian prospectus offerings. In addition, the loss of the Company's foreign private issuer status would mean that, if the Company became a reporting issuer in the United States, it would have to comply with U.S. domestic reporting requirements and, as such, the Company would be subject to the increased reporting and disclosure requirements imposed on U.S. domestic reporting companies, including the requirement to report in U.S. generally accepted accounting principles (GAAP), likely resulting in increased audit, legal and administration costs and a significant diversion of the Company's time and resources. These increased costs may adversely affect the Business and our results of operations and financial condition.

The Business Transfer Agreement provides the Company with limited rights and remedies and may contain other terms that are less favourable to the Company than those which might have otherwise been obtained from unrelated parties.

The Business Transfer Agreement was negotiated between parties that may be considered non-arm's length. As a result, the Business Transfer Agreement may contain terms that are less favourable to the Company than those which might have otherwise been obtained from unrelated parties. In particular, other than representations and warranties relating to the organization and good standing of the vendors, the authorization and enforceability of the Business Transfer Agreement, the validity of title to the securities and Warwick Receivable being transferred, and the valid issuance of the OpCo Interests being acquired and the good standing and enforceability of the Warwick Receivable being acquired, the Company has not received any representations or warranties from the vendors under the Business Transfer Agreement, including as would relate to the Business. Given the terms of the Business Transfer Agreement, the Company is ultimately acquiring its interest in the OpCos from the Selling Shareholders on an "as-is where-is" basis and has very few rights and remedies available to it in respect of the interests being acquired and the nature and value thereof.

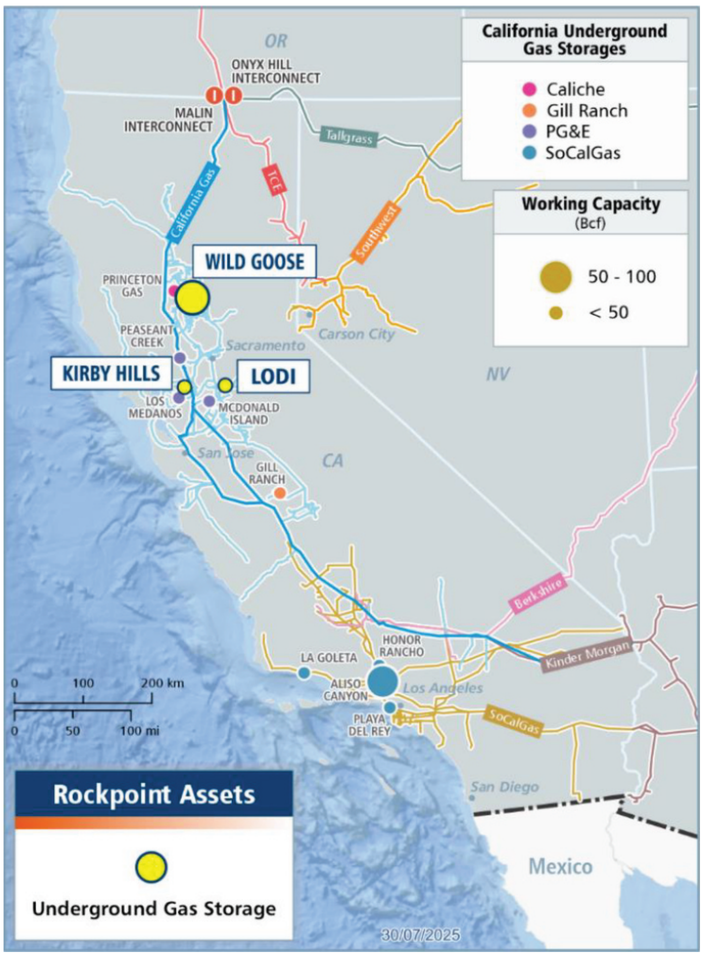
OUR BUSINESS

Overview

We are a natural gas storage operator with a portfolio consisting of six facilities located across California and Alberta with total effective working gas storage capacity of approximately 279.2 Bcf (as of September 12, 2025). According to the EIA and AER, our total effective working gas storage capacity represents approximately one third of the combined storage market in Alberta and California (as of September 12, 2025). Our facilities are strategically located and are interconnected with several key natural gas pipelines to ensure long-term availability of supply and connectivity to quality customers and demand hubs.

California operations

The following illustration depicts the location of our California assets relative to gas pipeline infrastructure and other storage assets:



Source: EIA.

While California has been a leader in renewables and the energy transition, the State's natural gas consumption has remained steady. The State's power sector relies heavily on gas-fired power to buffer against the unpredictable nature of wind and solar power generation, as well as the seasonal fluctuations of hydro power generation. As is currently the case, we expect that natural gas and gas-fired generation will continue to act as a critical resource to support renewable generation during times of intermittency and high baseload demand. California's constrained pipeline infrastructure and limited opportunity to expand its import capacity places increasingly higher reliance on existing gas storage infrastructure to meet demand. Additionally, we expect this pressure to intensify with emerging demand sources in the State, particularly from AI growth and associated data centre expansion. We anticipate that LNG facilities such as the under-development Costa

Azul facility in Baja California, Mexico, and the LNG Canada Development Inc. facility in British Columbia, Canada, will compete for natural gas available to supply the California region. We expect the competition for natural gas supply to increase and further enhance the strategic value of existing gas storage.

In California, we operate the Wild Goose storage facility, located 89 kilometers north of Sacramento. Wild Goose is the largest gas storage facility in northern California with an effective working gas capacity of 75.0 Bcf (as of September 12, 2025). It is well known for its reliability which is made possible by the geology of its reservoirs, use of horizontal well technology and its exceptional above ground infrastructure and redundancies. We believe Wild Goose is strategically positioned in a highly liquid market through integration with PG&E. Natural gas receipt and delivery services are provided at PG&E Citygate which is a crucial trading point where natural gas supply from multiple upstream basins is bought and sold to various wholesale, end-use and retail market participants. The Wild Goose storage facility is regulated by the CPUC and is approved for market-based rates, enabling us and our customers the opportunity to leverage PG&E Citygate pricing and liquidity. Direct connection to the PG&E system provides a high level of demand certainty with strategic proximity to the San Francisco delivery zone.

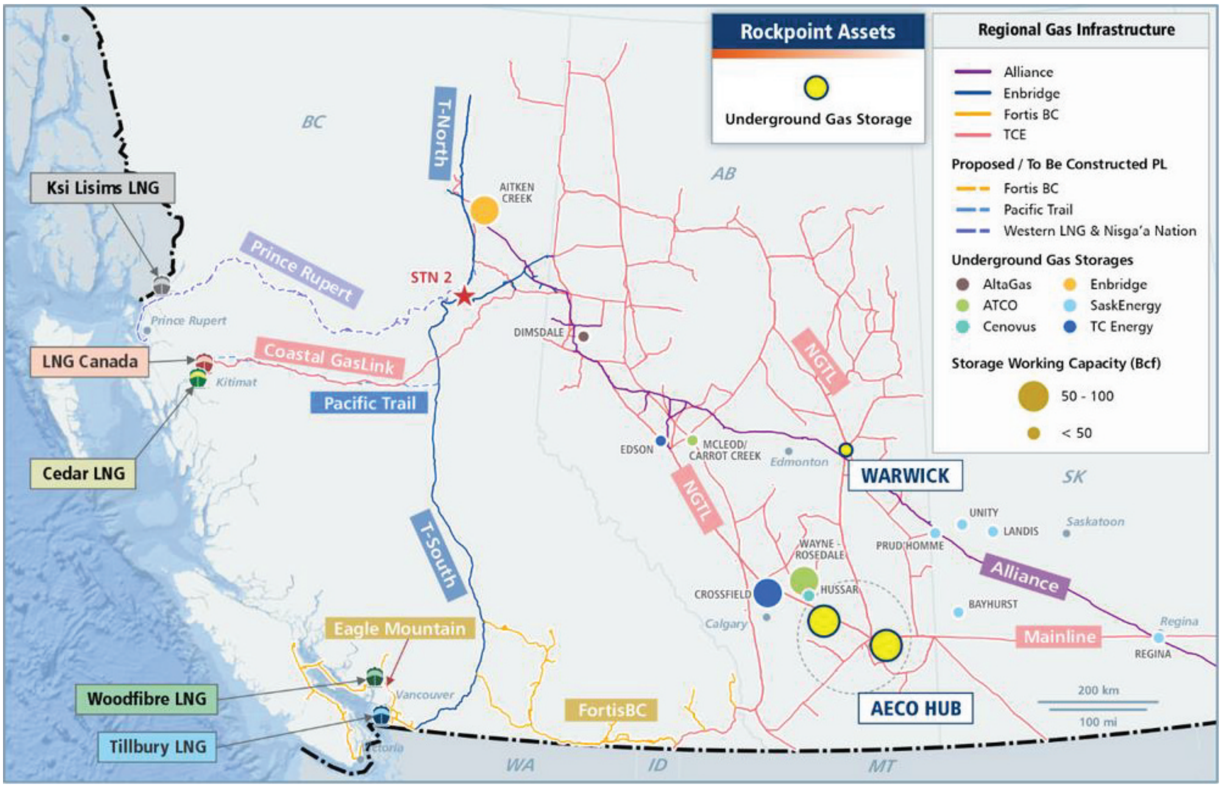
We also own and operate the Lodi storage complex comprised of two fully integrated facilities: Lodi and Kirby Hills. The Lodi facility is a high turn "peaking" facility critical to meeting California's utility demand. Combined, the Lodi and Kirby Hills facilities have an effective working gas capacity of 28.7 Bcf (as of September 12, 2025) which was expanded from its original 12 Bcf capacity when it was placed into service in 2002. Lodi and Kirby Hills are connected to the PG&E Citygate intrastate pipeline via three interconnections. The PG&E Citygate intrastate pipeline serves demand in the San Francisco and Sacramento markets. Lodi and Kirby Hills facilities are regulated by the CPUC and can also charge market-based rates, providing customers with the opportunity to take advantage of PG&E Citygate pricing and liquidity.

Our California facilities have high deliverability with a combined peak withdrawal capacity of 1.7 Bcf/d. We believe we are a market leader in California natural gas storage industry with a market share of approximately 34% on a working gas storage capacity basis.

See "Risk Factors — Risks Related to Our Business and Industry" and "Risk Factors — Risks Related to Environmental, Public Utility Regulation and Other Regulations".

Alberta operations

The following illustration depicts the location of our Alberta assets relative to gas pipeline infrastructure and other storage assets:



Source: geoSCOUT.

Alberta's natural gas market is poised for significant growth driven by the anticipated increase in LNG exports. The Province's strategic position as a key supplier to both domestic and international markets underscore its importance in the North American energy landscape. Alberta's storage facilities, such as the AECO Hub™, are set to play a crucial role in balancing regional supply shortfalls that are expected to emerge from intermittent west coast Canada LNG demand. Our Alberta facilities have indirect connectivity to major west coast LNG export facilities as well as direct connectivity to the oil sands, natural gas fired power plants, utilities, and industrial consumers across western Canada. We also support gas balancing via connectivity to export pipelines which service Chicago, Southern Ontario, the Pacific Northwest and California markets.

The AECO Hub™ is comprised of two facilities: Suffield and Countess. Both facilities are located 121 kilometers apart but function as a single commercial hub. With a total effective working gas storage capacity of 154 Bcf (as of September 12, 2025), the AECO Hub™ is the largest natural gas storage provider in western Canada and the largest independent storage hub in North America. The strategic location of AECO Hub™ on TC Energy's NGTL System offers direct access to abundant western Canadian natural gas supply as well as pipeline connections to most major U.S. and Canadian natural gas markets.

The Warwick facility is situated in central Alberta, approximately 113 kilometers east of Edmonton. Originally developed in 2009, the facility features a 21.5 Bcf depleted reservoir. Full ownership and operatorship of the facility, which is directly connected to the NGTL System, occurred in 2012. The Warwick facility's low relative reservoir pressure enables injection without compression at a maximum rate of 300 MMcf/d coupled with a maximum withdrawal rate of 250 MMcf/d for robust deliverability. Plans to expand Warwick's effective working gas capacity by acquiring and integrating adjacent pools to the existing reservoir and plant are progressing. Mineral rights for these pools are currently being secured with plans to apply to expand the existing storage scheme. Land acquisition and well development at Warwick are expected to increase the maximum allowable injection volume by up to 25% which will increase working gas capacity by up to 5 Bcf.

Additionally, we own and operate AGS, which provides natural gas marketing and transportation services in Canada. We also own and operate ESAS, which provides consulting and procurement services for natural gas, responsibly sourced gas, and renewable natural gas.

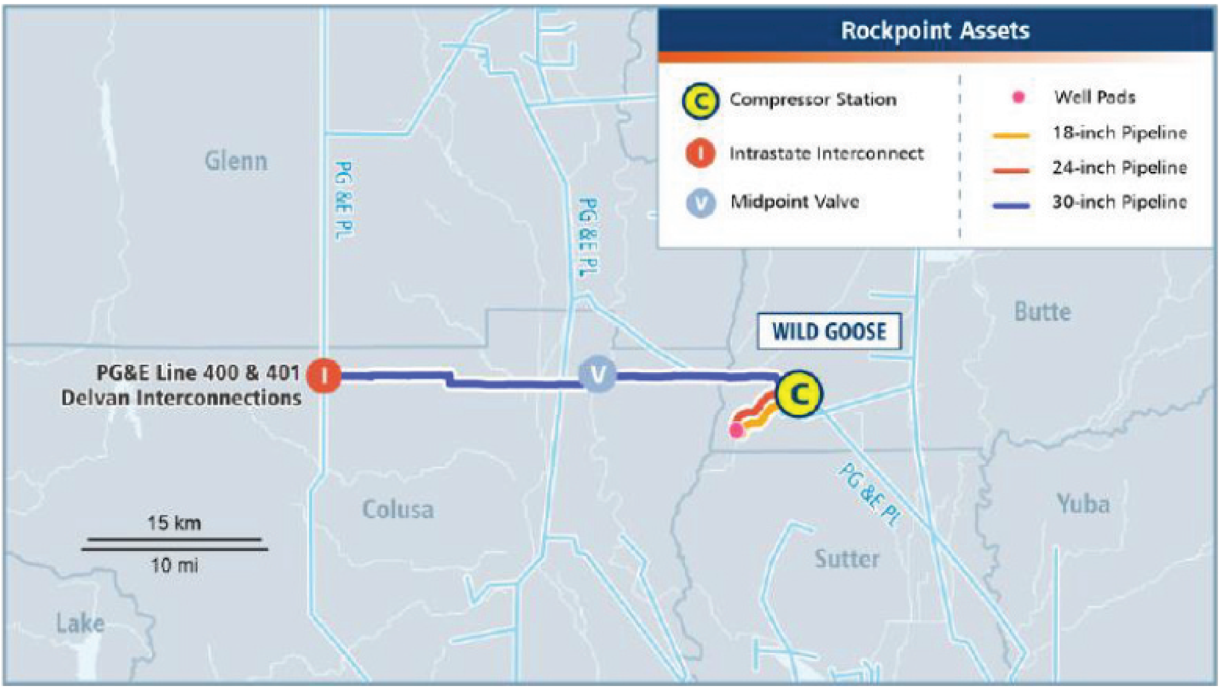
We believe we are a market leader in Alberta natural gas storage industry with a combined peak withdrawal capacity of approximately 3.3 Bcf/d and a market share of approximately 37% on a working gas storage capacity basis.

See "Risk Factors — Risks Related to Our Business and Industry" and "Risk Factors — Risks Related to Environmental, Public Utility Regulation and Other Regulations".

Facility Overview

Wild Goose (California)

An asset map and key operational statistics of Wild Goose have been provided below:



Source: EIA.

Facility Stats

Ownership Interest	100%
Location	California, U.S.
Facility Type	Depleted Reservoir
Start of Operations	1999
# of Injection/Withdrawal Wells	21
Effective Working Gas Capacity (Bcf)	75.0
Max Injection (MMcf/d)	525
Max Withdrawal (MMcf/d)	950
Heat Rate (dth / Mcf)	1.0536
# of Interconnects	2
Owned Pipeline Kilometers	55

Wild Goose

Facility

Wild Goose operates 21 natural gas storage wells in three active depleted natural gas reservoirs with an effective working gas capacity of 75 Bcf and gas generated compression of 27,970 horsepower. The Wild

Goose reservoirs are in high quality Cretaceous sandstone reservoirs which have produced over 100 Bcf historically. In addition, the reservoirs have a strong water drive mechanism, which helps maintain reservoir pressure and well deliverability. Wild Goose has two interconnections to the PG&E interstate gas pipeline system, providing access to PG&E Citygate pricing. Direct connection to the PG&E system provides a high level of demand certainty with connectivity to the San Francisco delivery zone. See "Risk Factors — Risks Related to Our Business and Industry".

Customers

Wild Goose's customers include a mix of gas market participants, including utilities, gas producers, power generators, pipelines, municipalities, financial institutions and marketers. This results in a portfolio of customers with diverse usage patterns, allowing us to optimize underutilized capacity across the facility and California's supply scarcity creates an environment that attracts a broad customer base across the natural gas value chain. See "Risk Factors — Risks Related to Our Business and Industry".

Historic and future expansion

In November 2024, we successfully drilled, completed, and tied-in three new storage wells, increasing the withdrawal capability of the facility by approximately 20 MMcf/d. Given supportive market conditions, we continue to pursue several strategic brownfield expansion initiatives to enhance our operational storage capacity and deliverability at Wild Goose. We have completed preliminary engineering design and received regulatory approval and civil works permits for a future plant expansion within the existing footprint. Additionally, we are assessing the potential development of an undeveloped storage pool within our existing storage scheme and have converted an existing observation well to a storage well. These early-stage initiatives have the potential to add increased working gas capacity and deliverability. See "Risk Factors — Risks Related to Our Business and Industry", "Risk Factors — Risks Related to Environmental, Public Utility Regulation and Other Regulations" and "Risk Factors — Risks Related to Our Financial Condition".

Maintenance capital

We have a strong history of successfully working collaboratively with the CPUC to achieve compliance in a cost-efficient manner. We maintain a five-year plan to forecast and allocate maintenance capital needs within major spending categories of regulatory compliance, reliability, and integrity. From fiscal 2023 to fiscal 2025, Wild Goose incurred an aggregate maintenance capital expenditure of $13.5 million, with a sizable portion attributable to regulatory compliance. Maintenance capital expenditures include total adjustments of $1.5 million made between fiscal 2023 and fiscal 2025 associated with heat imbalances and cushion gas migration. As part of California regulations that came into effect in 2018, certain maintenance measures are required to remain compliant, which includes installing tubing and packers in wells and completing annual inspection programs. Regulatory compliance capital expenditures at Wild Goose are expected to reduce after fiscal 2027 once all wells have been retrofitted with tubing and packer. Reliability spending consists primarily of compressor and engine overhauls and other periodic equipment maintenance. Finally, integrity spending is largely made up of: (i) annual voluntary inspections of facility piping; (ii) vessels and pipelines; and (iii) replacement of water handling piping. See "Risk Factors — Risks Related to Our Business and Industry", "Risk Factors — Risks Related to Environmental, Public Utility Regulation and Other Regulations" and "Risk Factors — Risks Related to Our Financial Condition".

Regulatory

Wild Goose is regulated as a state utility by the CPUC and is certified to serve the California intra-state market. Wild Goose has regulatory authority to negotiate market-based rates for third-party storage contracts and can buy and sell gas for its own account to optimize operations. As a regulated public utility, Wild Goose operates pursuant to approvals from the CPUC, including operating permits called CPCNs. The CPCNs impose specified terms, responsibilities, conditions and reporting obligations on Wild Goose. The CPCNs and authorizing approvals for Wild Goose include various conditions, including, without limitation, conditions prohibiting Wild Goose from sharing certain sensitive market information or obtaining a commonality of interest as between Wild Goose and Lodi and Kirby Hills. The CPUC has the right to investigate, request information and enforce compliance with the CPCNs.

We expect Wild Goose would be required to obtain approval from the CPUC before initiating a new development project or expansion at the facility. The CPUC review process would involve staff review, possible hearings, and a CPUC decision. Interested third-parties, such as competitors, rate advocates and environmental groups, may have the right to intervene in the review proceeding. Depending on the nature of the project, the approval may require compliance with the CEQA, which would involve the preparation of an environmental analysis and opportunities for public review and comment, and other federal or state environmental laws and regulations. The CPUC and CEQA review processes can be lengthy and can result in new environmental or operational conditions being imposed, as well as litigation from various stakeholders that could seek injunctive relief to prevent any project from moving forward.

In addition, the CPUC has broad jurisdictional authority to protect the environment, public health, safety and reliability. Wild Goose is regulated by other California regulatory agencies, such as the CalGEM, which regulates the injection and withdrawal of substances into and out of storage reservoirs and supervises underground gas storage facilities to prevent damage to public health and the environment.

On October 23, 2015, a natural gas leak was discovered from a well in the Aliso Canyon Natural Gas Storage Facility in Los Angeles County. In response, the California Legislature passed Senate Bill 887 (Pavley, Chapter 673 statutes of 2016) to establish new statutory requirements for underground gas storage facilities. The CPUC and CalGEM have also imposed more stringent regulatory requirements on gas storage facilities following the Aliso Canyon leak. For example, CalGEM issued new regulations, effective October 1, 2018, imposing updated safety requirements for California underground natural gas storage facilities. These regulations, among other things, require gas storage operators to design, construct and maintain gas storage wells to ensure that a single point of failure does not pose an immediate threat of loss of control of fluids and to address well integrity concerns before they can become a threat to life, health property, or natural resources. Compliance with Senate Bill 887 and other environmental and safety regulations, now or in the future, may result in significant capital and operating expenses. See “Risk Factors — Risks Related to Environmental, Public Utility Regulation and Other Regulations”.

Lodi and Kirby Hills (California)

An asset map and key operational statistics of Lodi and Kirby Hills facilities have been provided below:

Source: EIA.

Facility Stats

Ownership Interest	100%
Location	California, U.S.
Facility Type	Depleted Reservoir
Start of Operations	2002
# of Injection/Withdrawal Wells	34
Effective Working Gas Capacity (Bcf)	28.7
Max Injection (MMcf/d)	550
Max Withdrawal (MMcf/d)	750
Heat Rate (dth / Mcf)	1.0535
# of Interconnects	3
Owned Pipeline Kilometers	72

Lodi & Kirby Hills

Facilities

The Lodi storage facilities have a combined daily maximum injection and withdrawal capability of 550 MMcf/d and 750 MMcf/d, respectively. The Lodi storage facilities have 34 wells in four depleted natural gas reservoirs in Eocene, Cretaceous and Paleocene sandstones. Multiple reservoirs provide operational flexibility with Lodi reservoirs serving peaking needs and Kirby Hills reservoirs serving seasonal baseload needs.

The Lodi facility is linked to an interconnect with the PG&E pipeline system north of Antioch, California by 50 kilometers of pipeline and a 10 kilometer pipeline links the Kirby Hills facility to two interconnections with the PG&E pipeline system west of Rio Vista. These three interconnections to the PG&E intrastate pipeline system provide us and our customers with access to the PG&E Citygate pricing market. See “Risk Factors — Risks Related to Our Business and Industry”.

Customers

Lodi and Kirby Hills’ customers include a mix of gas market participants, consisting primarily of utilities and marketers, but customers also include financial institutions, producers, pipelines, and municipalities, resulting in a portfolio of customers with diverse usage patterns. The diversity of customer needs allows us to optimize underutilized capacity across the facilities. In particular, utilities serving Sacramento and the San Francisco Bay Area utilize Lodi as a result of its connectivity to the PG&E pipeline system. See “Risk Factors — Risks Related to Our Business and Industry”.

Historic and future expansion

We are evaluating several strategic expansion initiatives at Lodi and Kirby Hills to further enhance operational working gas capacity and deliverability. Currently, we are exploring an option to secure a site for future natural gas storage development. See “Risk Factors — Risks Related to Our Business and Industry”, “Risk Factors — Risks Related to Environmental, Public Utility Regulation and Other Regulations” and “Risk Factors — Risks Related to Our Financial Condition”.

Maintenance capital

At Lodi and Kirby Hills, we maintain a five-year plan to forecast and allocate maintenance capital needs within major spending categories of regulatory compliance, reliability and integrity. From fiscal 2023 to fiscal 2025, Lodi and Kirby Hills facilities incurred cumulative maintenance capital expenditures of $23.6 million, with a significant portion attributable to regulatory compliance. As part of certain California regulations that came into effect in 2018, incremental measures are required to remain compliant which include completing tubing and packer installations in wells and annual inspection programs. Regulatory compliance capital expenditures are expected to reduce after fiscal 2027 once all wells have been retrofit with tubing and packer. Lodi and Kirby Hills reliability spending is generally made up of compressor / engine overhauls and other reliability maintenance (storage wells, screen replacements, gas processing ancillary). Integrity spending is largely comprised of voluntary inspections of facility piping, vessels and pipelines, along with various other piping and valve replacements. See “Risk Factors — Risks Related to Our Business and Industry”, “Risk Factors — Risks Related to Environmental, Public Utility Regulation and Other Regulations” and “Risk Factors — Risks Related to Our Financial Condition”.

Regulatory

Lodi and Kirby Hills operate as a single operating and commercial entity from the perspective of the regulators and customers. Lodi and Kirby Hills are regulated as a state utility by the CPUC and are certified to serve the California intra-state market. Lodi and Kirby Hills have regulatory authority to negotiate market-based rates for third-party storage contracts and can buy and sell gas for their own account to optimize operations. As a regulated public utility, Lodi and Kirby Hills operates pursuant to approvals from the CPUC, including operating permits called CPCNs. The CPCNs impose specified terms, responsibilities, conditions and reporting obligations on Lodi and Kirby Hills. The CPCNs and authorizing approvals for Lodi and Kirby Hills include various conditions, including, without limitation, conditions prohibiting Lodi and Kirby Hills from sharing certain sensitive market information or obtaining a commonality of interest as between Wild Goose and Lodi and Kirby Hills. The CPUC has the right to investigate, request information and enforce compliance with the CPCNs.

We expect Lodi and Kirby Hills would be required to obtain approval from the CPUC before initiating a new development project or expansion at the facility. The CPUC review process would involve staff review, possible hearings and a CPUC decision. Interested third-parties, such as competitors, rate advocates, and environmental groups, may have the right to intervene in the review proceeding. Depending on the nature of the project, the approval may require compliance with the CEQA, which would involve the preparation of an environmental analysis and opportunities for public review and comment, and other federal or state environmental laws and regulations. The CPUC and CEQA review processes can be lengthy and can result in new environmental or operational conditions being imposed, as well as litigation from various stakeholders that could seek injunctive relief to prevent any project from moving forward.

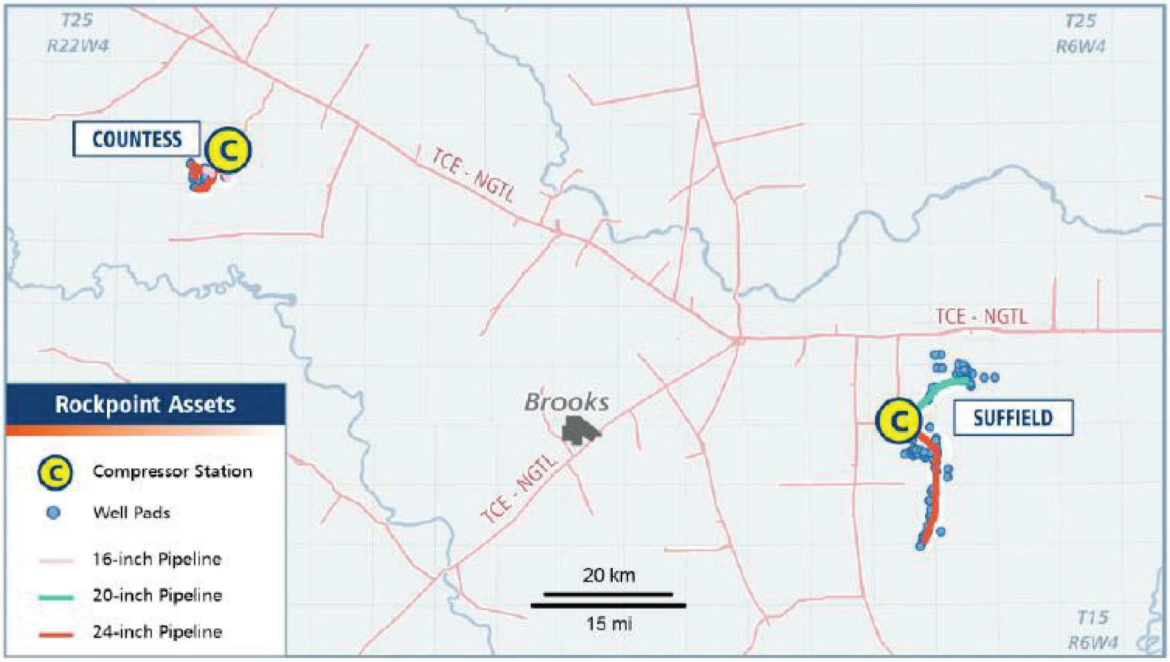
In addition, the CPUC has broad jurisdictional authority to protect the environment, public health, safety and reliability. Lodi and Kirby Hills is regulated by other California regulatory agencies, such as the CalGEM, which regulates the injection and withdrawal of substances into and out of storage reservoirs and supervises underground gas storage facilities to prevent damage to public health and the environment.

In response to the Aliso Canyon leak, the California Legislature passed Senate Bill 887 (Pavley, Chapter 673 statutes of 2016) to establish new statutory requirements for underground gas storage facilities. The CPUC and CalGEM have also imposed more stringent regulatory requirements on gas storage facilities. CalGEM issued new regulations, effective October 1, 2018, imposing updated safety requirements for California underground natural gas storage facilities. These regulations, among other things, require gas storage operators to design, construct and maintain gas storage wells to ensure that a single point of failure does not pose an immediate threat of loss of control of fluids and to address well integrity concerns before they can become a threat to life, health, property or natural resources. Compliance with Senate Bill 887 and other environmental and safety regulations, now or in the future, may result in significant capital and operating expenses.

See “Risk Factors — Risks Related to Environmental, Public Utility Regulation and Other Regulations”.

AECO Hub™ (Alberta)

An asset map and key operational statistics of the AECO Hub™ have been provided below:



Source: geoSCOUT.

Facility Stats

Ownership Interest	100%
Location	Alberta, CA
Facility Type	Depleted Reservoir
Start of Operations	1988
# of Injection/Withdrawal Wells	85
Effective Working Gas Capacity (Bcf)	154.0
Max Injection (MMcf/d)	2,750
Max Withdrawal (MMcf/d)	3,050
Heat Rate (dth / Mcf)	1.0733
# of Interconnects	2
Owned Pipeline Kilometers	156

AECO Hub™

Suffield storage facility

Suffield is located in southeastern Alberta. It is near the NGTL System's "Eastern Gate", the largest natural gas delivery point in Canada, where gas is delivered into TC Energy's mainline pipeline system (transporting natural gas to eastern Canada and the northeastern U.S.) and the Foothills/northern Border pipeline system (transporting natural gas to Chicago and the Midwestern U.S.). Suffield consists of 58 storage wells and five storage reservoirs with aggregate effective working gas capacity of approximately 83.5 Bcf. The storage reservoirs are connected to a central processing and compression facility by a system of five pipelines. Compression is provided by natural gas-powered engines that have a total of 36,150 horsepower. See "Risk Factors — Risks Related to Our Business and Industry".

Countess storage facility

Countess is located in south central Alberta, approximately 97 kilometers east of Calgary, Alberta. Countess is connected to a large diameter pipe of the NGTL System. This modern natural gas storage facility consists of 27 storage wells and two high performance gas storage reservoirs that are connected to a central processing and compression facility. The two storage reservoirs each have their own gathering pipeline system. Compression is electrically powered and totals approximately 34,500 horsepower. The two reservoirs have total effective working gas storage capacity of approximately 70.5 Bcf. See “Risk Factors — Risks Related to Our Business and Industry”.

Customers

The AECO Hub™ is a regional trading benchmark and as a result the customer base is strongly weighted towards creditworthy financial institutions, who transact frequently and provide liquidity to AECO market participants. Other AECO Hub™ customers include marketers, producers and utilities which provide customer diversification. See “Risk Factors — Risks Related to Our Business and Industry”.

Historic and future expansion

We continue to explore and assess various growth opportunities, including potential expansions to increase effective working gas capacity and enhance deliverability. We are currently advancing a battery storage project which involves the installation of 20 MW of standalone battery storage at the Countess facility. This initiative is designed to store low-priced power and deliver it during peak demand periods thereby providing a diversified ancillary revenue stream, enhancing operational flexibility and reducing greenhouse gas emissions. See “Risk Factors — Risks Related to Our Business and Industry”, “Risk Factors — Risks Related to Environmental, Public Utility Regulation and Other Regulations” and “Risk Factors — Risks Related to Our Financial Condition”.

Maintenance capital

The Business has a strong track record of asset maintenance activities at its AECO facilities. We maintain a five-year plan to forecast and allocate maintenance capital needs within major spending categories of regulatory compliance, reliability and integrity. From fiscal 2023 to fiscal 2025, the AECO facilities incurred cumulative maintenance capital expenditures of $13.5 million. Regulatory compliance spend at the AECO Hub™ is largely comprised of Multi-Sector Air Pollutants Regulations compliance costs and Methane Emissions Reduction compliance costs. Reliability spending is largely comprised of compressor / engine overhauls, other reliability maintenance (supervisory control and data acquisition (“**SCADA**”), gas processing, ancillary) and cushion gas purchases. Integrity spending is generally comprised of voluntary inspections of facility piping, vessels, and pipelines, along with various piping and value replacements. See “Risk Factors — Risks Related to Our Business and Industry”, “Risk Factors — Risks Related to Environmental, Public Utility Regulation and Other Regulations” and “Risk Factors — Risks Related to Our Financial Condition”.

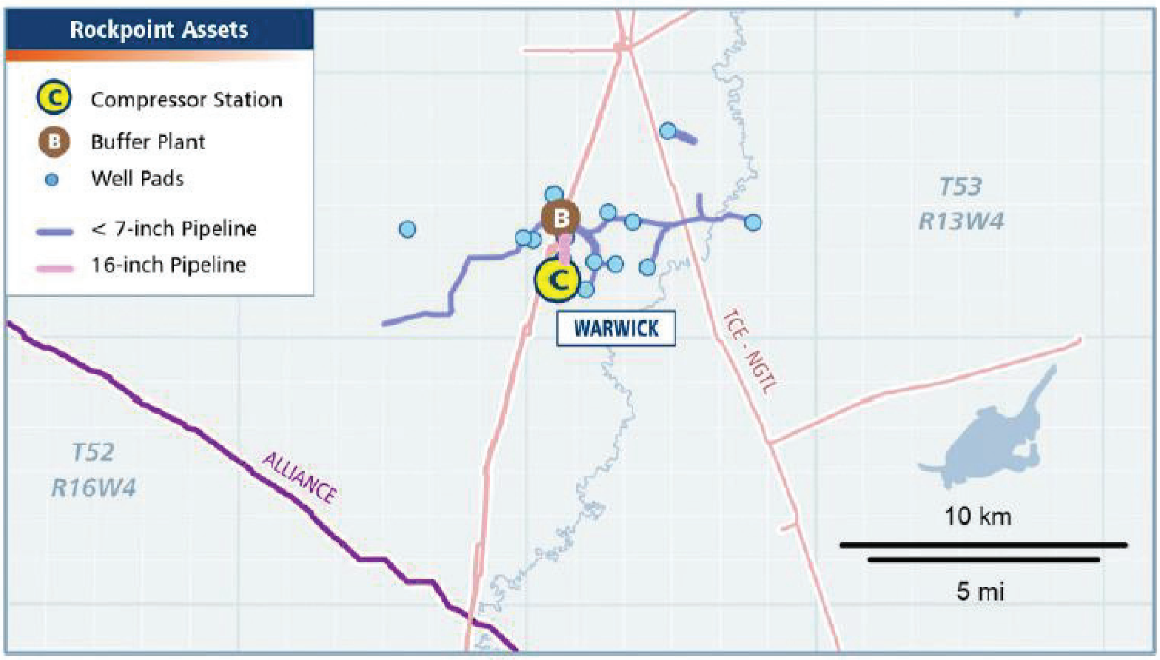
Regulatory

The AECO Hub™ is subject to provincial regulatory jurisdiction. Operations are subject to the regulation of the AER, which must also approve any proposed expansions of storage capacity. The AECO Hub™ is not subject to active market regulation and is able to charge customers negotiated market-based rates and store purchased gas for its own account. There is no cost-of-service or other utility-type regulation of storage rates or other commercial terms of storage contracts in Alberta. While the AUC does have overriding jurisdiction to set gas storage prices when authorized to do so by the Alberta Government, it is not currently in Alberta Government policy to apply such rate regulation.

In Canada, Part 1 of the federal Greenhouse Gas Pollution Pricing Act (“**GGPPA**”) imposes a regulatory charge on the distribution of certain fossil fuels like gasoline and natural gas (the “**federal fuel charge**”). Part 2 of the GGPPA establishes an output-based annual emissions limit for covered industrial facilities and currently imposes a carbon price of $95/tonne of CO2e emitted over the annual limit by covered facilities. Under current legislation, the carbon price for industrial facilities will increase by $15/tonne per year until it reaches $170/tonne in 2030 (requirements for provinces and territories to have a consumer-facing carbon price were removed effective April 1, 2025). The GGPPA acts as a backstop, meaning that Part 1 and/or Part 2 will not apply to a province or territory that has implemented a sufficiently stringent GHG pricing system. For example, Part 1 of the GGPPA historically applied in Alberta, as the Province did not have a provincial fuel charge that met the federal benchmark. However, in early 2025, the federal fuel charge was effectively nullified. The federal fuel charge was set at $0 per litre and the requirement for jurisdictions to have their own provincial fuel charge was removed. All fuel charge provisions in the GGPPA are set to be repealed effective October 1, 2025. Part 2 of the GGPPA does not currently apply in Alberta, as the Technology Innovation and Emissions Reduction Regulation ("**TIER**") currently meets the federal benchmark stringency requirements for the emission sources that TIER covers. However, the Alberta Government recently announced an indefinite freeze on the carbon price at $95 per tonne, meaning TIER would not be compliant with Part 2 of the GGPPA starting in 2026. See "Risk Factors — Risks Related to Environmental, Public Utility Regulation and Other Regulations".

Warwick (Alberta)

An asset map and key operational statistics of Warwick facility have been provided below:



Source: geoSCOUT.

Facility Stats

Ownership Interest	100%
Location	Alberta, CA
Facility Type	Depleted Reservoir
Start of Operations	2010
# of Injection/Withdrawal Wells	16
Effective Working Gas Capacity (Bcf)	21.5
Max Injection (MMcf/d)	300
Max Withdrawal (MMcf/d)	250
Heat Rate (dth / Mcf)	1.0593
# of Interconnects	1
Owned Pipeline Kilometers	27

Warwick

Customers

Warwick's customer base primarily consists of financial institutions and marketers with investment-grade profiles and long-standing customer relationships with some relationship tenures as high as 10 to 15 years.

Historic and future expansion

Strategic initiatives to expand working gas capacity and develop battery storage are currently underway at Warwick. We are in the process of acquiring storage, surface and mineral rights which will allow for the expansion of the storage unit and associated working gas capacity. We anticipate this project could potentially increase incremental working gas capacity by up to 5 Bcf through the implementation of additional storage wells and plant upgrades. The development of an 11 MW battery electricity storage facility is also being advanced. The necessary facility permits for this project have been obtained and grid interconnection applications are underway. The battery storage development is aimed at providing a diversified ancillary revenue stream, operational flexibility and reducing greenhouse gas emissions. We are also evaluating our mineral rights in the Lotsberg and Prairie Evaporite geological formations as potential candidates for salt cavern development is also being explored. These salt formations are located near key demand centres (approximately 100 kilometers from Edmonton and 16 kilometers to Alliance Pipeline receipt points) and represent a strong expansion opportunity in an upside storage rate environment due to their smaller relative size and high deliverability potential. See "Risk Factors — Risks Related to Our Business and Industry", "Risk Factors — Risks Related to Environmental, Public Utility Regulation and Other Regulations" and "Risk Factors — Risks Related to Our Financial Condition".

Maintenance capital

The maintenance program at the Warwick facility has a strong track record. A five-year plan to forecast and allocate maintenance capital needs within major spending categories of regulatory compliance, reliability, and integrity is maintained. From fiscal 2023 to fiscal 2025, the Warwick facility incurred cumulative maintenance capital of $2.7 million, with a large portion attributable to a one-time cushion gas replacement cost in fiscal 2025. Maintenance capital expenditures include total adjustments of $1.2 million made between fiscal 2023 and fiscal 2025 associated with heat imbalances and cushion gas migration. Regulatory compliance spending is attributable to methane emissions reduction compliance and AER closure spend compliance. Reliability spending is largely comprised of compressor overhauls along with other reliability maintenance (SCADA, gas processing, ancillary). Finally, integrity spending is generally comprised of well inspections and repairs/replacements/upgrades when necessary. See "Risk Factors — Risks Related to Our Business and Industry", "Risk Factors — Risks Related to Environmental, Public Utility Regulation and Other Regulations" and "Risk Factors — Risks Related to Our Financial Condition".

Regulatory

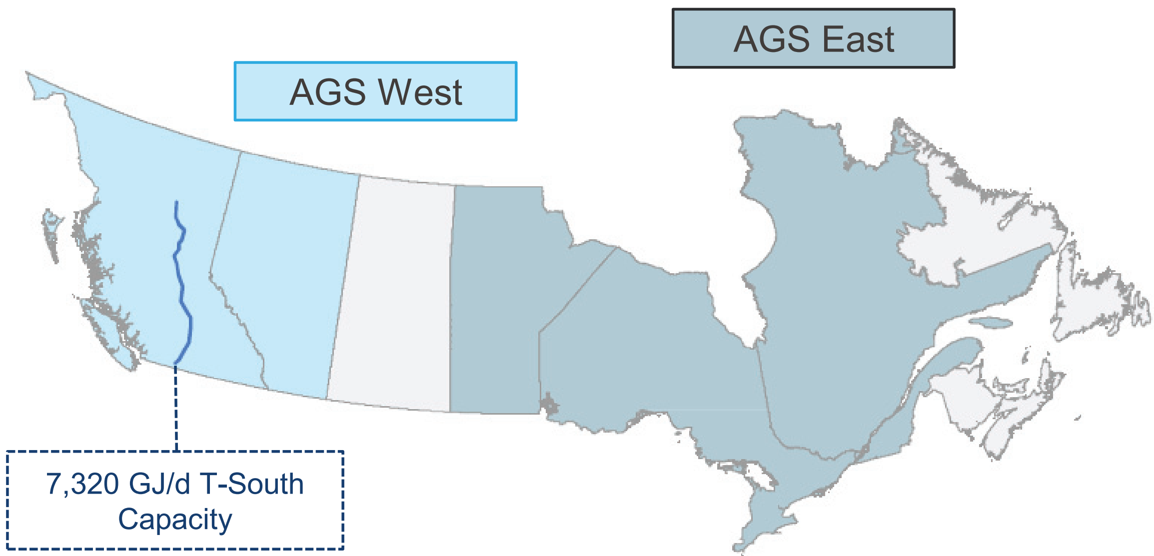
Warwick is subject to provincial regulatory jurisdiction. Operations are subject to the regulation of the AER, which must also approve proposed expansions of storage capacity. Warwick is not subject to active market regulation. Apart from the utility-owned Carbon storage facility, which is in the process of being withdrawn from financial regulation, there is no cost-of-service or other utility-type regulation of storage rates or other commercial terms of storage contracts in Alberta. While the AUC does have overriding jurisdiction to set gas storage prices when authorized to do so by the Alberta Government, it is not currently in Alberta Government policy to apply such rate regulation. As such, Warwick is able to charge customers negotiated market-based rates as well as store purchased gas for its own account. See "Our Business — Facility Overview — AECO Hub™ (Alberta)" for additional information regarding regulations that also apply Warwick. See "Risk Factors — Risks Related to Our Business and Industry" and "Risk Factors — Risks Related to Environmental, Public Utility Regulation and Other Regulations".

Access Gas Services

AGS provides natural gas marketing and transportation services in Canada and offers a strong complementary cash flow to the Business. AGS provides natural gas procurement and portfolio management services to a broad range of commercial, industrial, and institutional (e.g., municipalities, hospitals, school boards, etc.) customers in five Canadian provinces which include British Columbia, Alberta, Manitoba, Ontario, and Québec, and also serves a small residential customer base in British Columbia. AGS specializes in delivering customized portfolio-based solutions that offer customers a superior alternative to utility pricing by reducing exposure to natural gas price volatility. AGS serves over 1,700 commercial, industrial, and institutional customers, with approximately 56% being fixed-price contracts. In fiscal 2025, AGS delivered an average daily volume of approximately 155,000 GJ/d and realized significant volume growth at a 5% CAGR from 2019 to 2025, driven largely by contracting of new customers and an increasing preference for fixed-price contracts.

AGS is split into AGS West, which includes British Columbia and Alberta and AGS East, which includes Manitoba, Ontario, and Québec. AGS West benefits from contracted capacity on critical regional pipelines including the WEI T-South (Sumas) system, the WEI (Interior) pipeline, the Foothills system and the NGTL System. AGS West holds 7,320 GJ/d of T-South evergreen capacity on the WEI T-South pipeline from Station 2 to Sumas and has long-term customer relationships averaging eight years.

An asset map of AGS has been provided below:



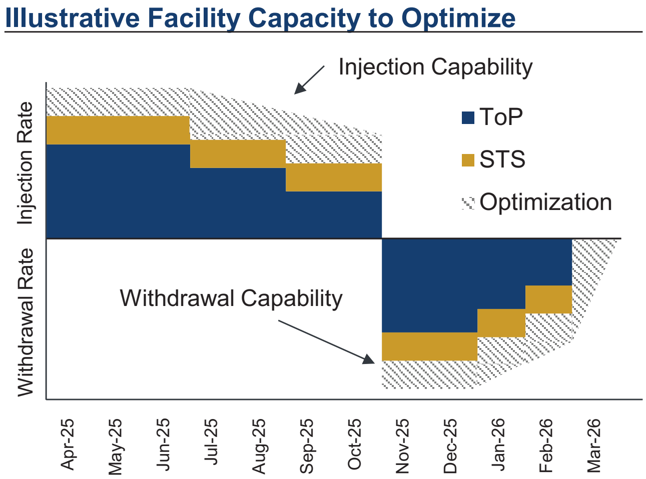
EnerStream Agency Services Inc.

ESAS provides natural gas consulting and procurement services to industrial, commercial, and institutional customers throughout Canada. ESAS offers complete account management and marketing services, as well as customized innovative products tailored to meet specific customer needs through leading procurement strategies, flexible products, transparent billing, and dedicated customer service. ESAS has over 20 years of combined operations management experience and has access to responsibly sourced gas and renewable natural gas.

Our Commercial Model

Our commercial model is designed to be flexible and create mutually beneficial outcomes for us and our customers. Our revenue is categorized as either Fee for Service or optimization. Fee for Service includes both long-term ToP contracts and recurring STS contracts. We also maintain a portion of our effective working gas capacity to capture value through optimization activities undertaken with internally owned gas. Our storage capacity is initially reserved to service ToP customer contracts. This ToP reserve reflects the expected seasonal build of our ToP customers' summer injection and winter withdrawal as a portion of total working gas capacity. STS contracts are then leveraged to primarily fill gaps left by the ToP reserve cycle. The remaining small portion of storage capacity is then utilized by Rockpoint for optimization activities. The storage capacity for optimization varies depending on actual ToP customer injection and withdrawal observed throughout the year. We have prudent risk management policies in place and do not carry open commodity price risk in any of our revenue segments. Our allocation between ToP, STS, and optimization strategies is designed to maximize the economic value of our storage capacity while maintaining operational flexibility. Our long-term target is to achieve 60% of Adjusted Gross Margin from ToP contracts, 25% of Adjusted Gross Margin from STS contracts, and 15% Adjusted Gross Margin from optimization strategies. In California, our facilities are operating at or near our long-term contracting targets. In Alberta, we continue to experience growth in contracted ToP volumes and storage rates as new customers enter the market. See “Risk Factors — Risks Related to Our Business and Industry”.

The chart below demonstrates illustrative facility injection / withdrawal capability utilization by our revenue strategies.



Fee for Service Revenue

Fee for Service revenue consists of longer-term ToP contracts (typically ranging from one to ten years) and STS contracts (typically spanning up to one storage season with a strong history of contract renewals). Our Fee for Service revenue is underpinned by a diverse and high-quality customer base that stores customer-owned gas volumes in our storage facilities. Our strong performance not only reflects the resilience and attractiveness of our commercial model but also reinforces our strategic positioning in the market, enabling predictable cash flows and long-term value creation.

Under ToP contracts, our customers are obligated to pay a fixed monthly demand charge for storage capacity regardless of utilization. Customers have the right, but not the obligation, to inject, store or withdraw a predetermined amount of gas as specified in each contract. We receive the monthly demand charge regardless of the actual capacity utilized by our customers. When customers utilize reserved capacity under these contracts, we receive additional variable fees based on the actual volumes of natural gas injected or withdrawn. These variable fee payments help us recover operating costs. ToP contracts accounted for approximately 45% of total fiscal 2025 Adjusted Gross Margin and have a 3.5-year weighted average contract life. The ToP contracts accounted for approximately 70% of fiscal 2025 Adjusted Gross Margin in California and approximately 12% of fiscal 2025 Adjusted Gross Margin in Alberta. The ToP contracts currently have a weighted average tenor of approximately 3.6 years in California and approximately 2.9 years in Alberta. In fiscal 2025, we executed 25 new ToP contracts contributing a cumulative $499 million of future contracted revenue with weighted average contract terms of approximately five years in California and three years in Alberta.

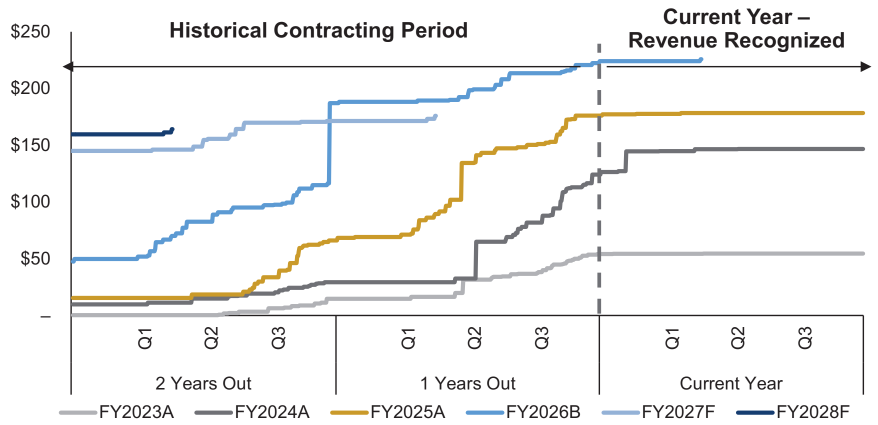
ToP contracts not only define the total capacity available for a customer’s utilization but also outline the customer’s daily withdrawal and injection rights, which increase or decrease based on changes in their utilization. Typically, a customer’s maximum injection rate is highest when the customer has zero utilized capacity and reduces as the customer utilizes its capacity by injecting gas. Once a customer’s contracted capacity is fully utilized, they have no further injection rights. Conversely, a customer’s maximum withdrawal rate is generally the highest when their contracted capacity is fully utilized, and reduces as the customer withdraws gas, declining incrementally to zero when the customer’s capacity utilization is zero. ToP contracts offer customers the flexibility to utilize their capacity partially or fully, allowing them to inject or withdraw gas within their daily limits.

ToP contracts are typically negotiated and executed with counterparties in the fall and winter for storage service commencing the following fiscal year and beyond. This contracting timeline is required to allow customers to be able to prepare for and utilize the full summer season (April 1st to October 31st) to inject their gas into our facilities prior to the start of the winter withdrawal season (November 1st to March 31st).

Since fiscal 2023, we have enhanced our ToP contract profile through increased ToP contract volumes, improved rates and longer contract tenors.

The following chart represents the ToP gross margin build over time for each financial year (fiscal 2026, fiscal 2027, and fiscal 2028 represent contracted ToP gross margin not yet recognized in the Financial Statements of the Business):

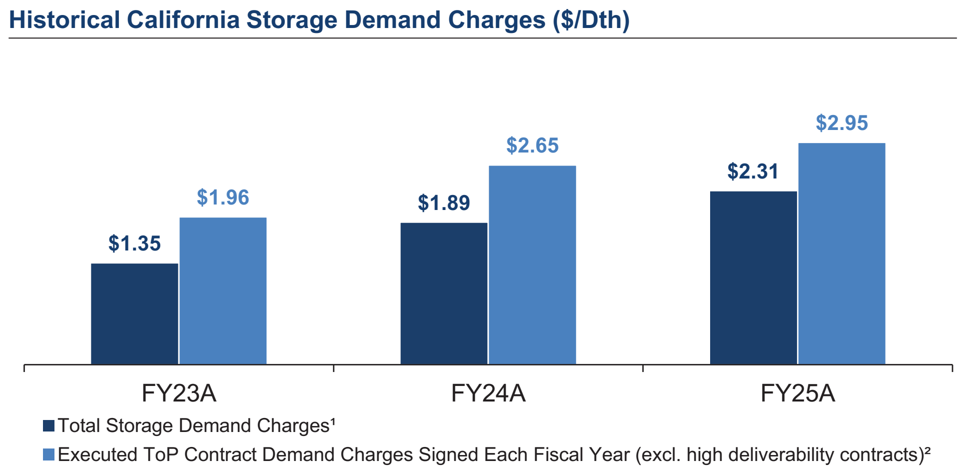
Transacted ToP Gross Margin Over Time – By Fiscal Year ($mm)

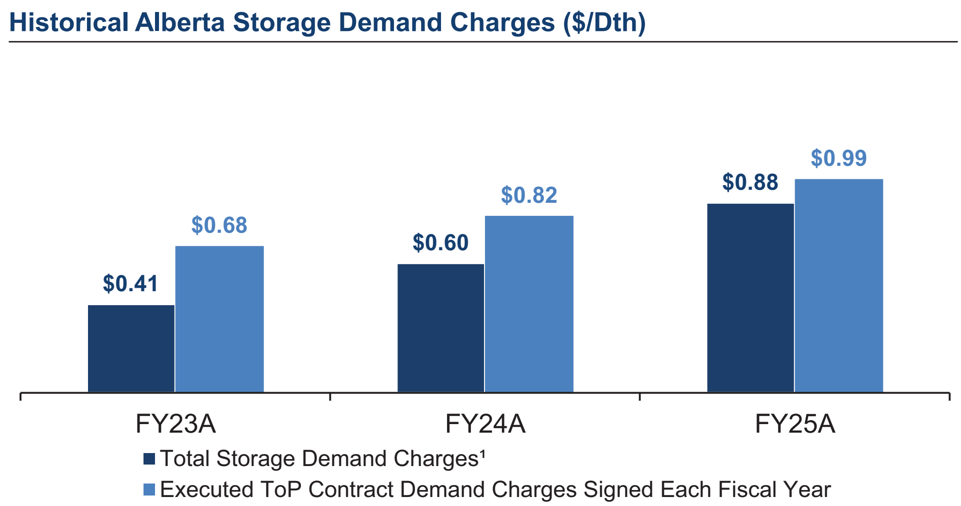


In California, our ToP contracting has increased from 49% of our California facilities' total effective working gas storage capacity in fiscal 2023 to 69% in fiscal 2025. Over the same period our ToP contracted demand charges in California have increased from $1.02/Dth earned in fiscal 2023 to $2.30/Dth in fiscal 2025. This has resulted in an increase in California ToP Adjusted Gross Margin from $59.9 million in fiscal 2023 to $163.3 million in fiscal 2025. This upward trend reflects the transition of our contract portfolio as lower priced legacy contracts have rolled off in favour of multi-year higher-priced market rate contracts. For example, our ToP contracts in California have an average ToP demand charge of $2.87/Dth in fiscal 2026, representing an approximately 25% increase over the realized average ToP demand charge in fiscal 2025. We expect California ToP demand charge to increase due to a tighter storage market and strong customer demand for long-term security of gas supply.

In Alberta, our ToP contracting capacity has doubled from 7% of our Alberta facilities' total effective working gas storage capacity in fiscal 2023 to 15% in fiscal 2025. Over the same period, our ToP contracted demand charges in Alberta have increased from $0.42/Dth earned in fiscal 2023 to $0.75/Dth earned in fiscal 2025. This has resulted in an increase in Alberta ToP Adjusted Gross Margin from $6.2 million in fiscal 2023 to $21.7 million in fiscal 2025. We expect our Alberta ToP contracted gas storage volumes and contracted demand charges to increase as additional west coast LNG projects enter into service. Our ToP contracts in Alberta have an average ToP demand charge of $0.94/Dth in fiscal 2026, representing an approximately 26% increase over the realized ToP average demand charges in fiscal 2025.

The following charts show the total realized storage demand charges and executed ToP contract demand charges signed each fiscal year in California and Alberta:



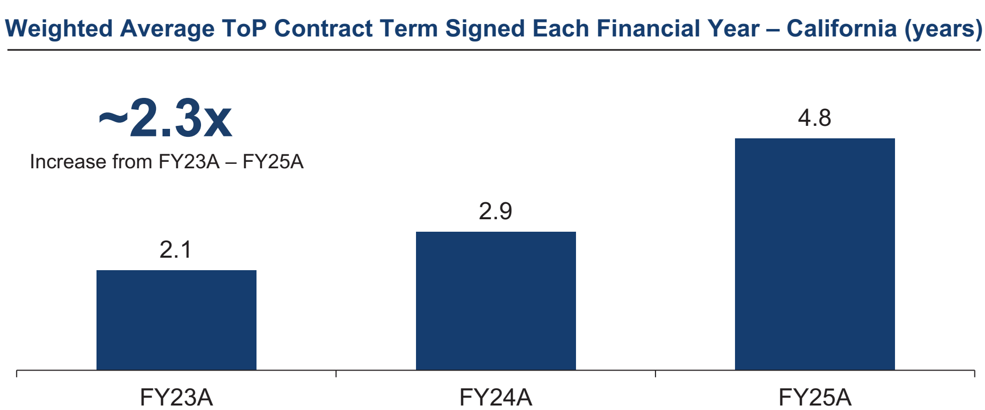


Notes:

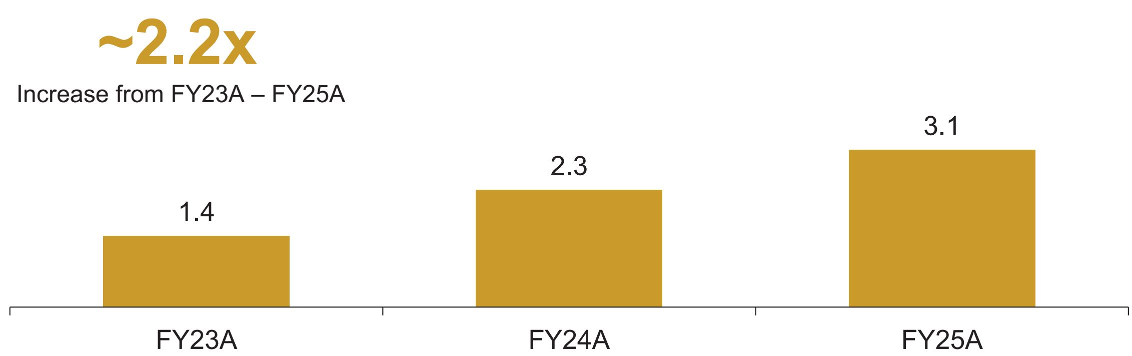
(1) Total storage demand charges are calculated as the sum of ToP, STS, and Optimization Adjusted Gross Margin divided by the sum of ToP,STS, and Optimization working gas capacity excluding incremental cushion gas and reserved capacity.

(2) Executed ToP excluding certain high deliverability contracts executed in California.

The following charts show the growth in weighted average ToP contract terms signed each fiscal year in California and Alberta:



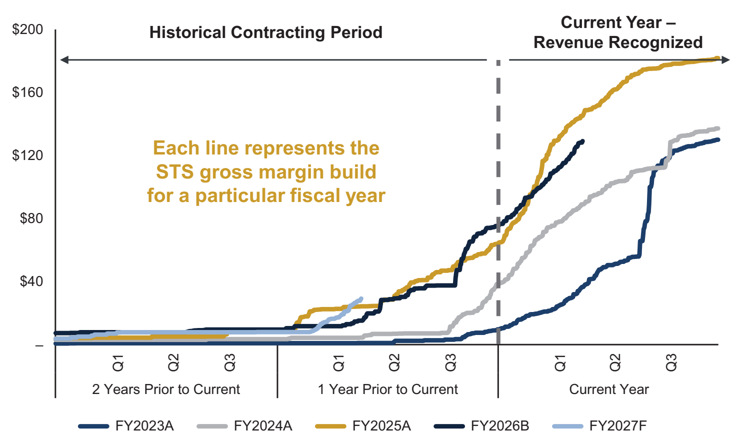
Weighted Average ToP Contract Term Signed Each Financial Year – Alberta (years)



Under STS contracts, our customers pay a fixed fee to inject and withdraw specified quantities of natural gas which are typically recognized as revenue (50% paid on injection and 50% paid on withdrawal). Unlike ToP contracts, STS contracts require customers to inject and withdraw specified quantities on specified, predetermined dates. STS contracts enable us to secure value by capturing the seasonal value of the price difference between summer and winter months net of the customer's required return on the transaction. Because STS contracts specify predetermined injection and withdrawal volumes at predetermined times, it also allows us to opportunistically enter into offsetting transactions to capture incremental storage value as spot and future natural gas spreads fluctuate prior to the original transaction's specified withdrawal date. A typical example of an STS contract is when a customer enters a contract with us to inject gas at a consistent daily rate in the summer months, when gas prices are lower, and to withdraw the same amount at a consistent daily rate in the winter months, when prices are higher. In fiscal 2025, our STS contracts made up approximately 41% of total Adjusted Gross Margin across the portfolio. See "Risk Factors — Risks Related to Our Business and Industry".

STS is an important component of our Fee for Service strategy, providing a base fee and also allowing us to retain upside from additional contract layering throughout the year. While STS gross margin is primarily transacted within each fiscal year, our STS gross margin has continually increased each year as demonstrated in the following chart. Since fiscal 2023, our STS contracted rates have increased by 59% in California and 134% in Alberta, reflecting strong storage fundamentals in each respective market.

Transacted STS Gross Margin Over Time – By Fiscal Year ($ millions)[1]



Note:

(1) Transacted STS gross margin chart excludes STS payables pertaining to cushion gas support.

As of March 31, 2025, we had approximately $893 million in contracted Fee for Service revenue backlog which includes both ToP and STS contracts. In fiscal 2025, 86% of our total Adjusted Gross Margin was contracted on a Fee for Service basis, surpassing our target of 85%. ToP contracts accounted for approximately

45% of fiscal 2025 Adjusted Gross Margin while STS contracts made up approximately 41% of fiscal 2025 Adjusted Gross Margin.

Optimization Revenue

We manage a small portion of our storage capacity through a storage optimization strategy which is intended to provide us the flexibility to first manage our firm fee for service customer obligations if needed and then capture market opportunities as they arise. Storage optimization involves purchasing, storing and selling natural gas for our own account using our own corporate liquidity for profit. In line with our internal risk policy, we do not take open positions that expose us to price or physical delivery risk. Instead, we aim to eliminate market price risks by matching inventory purchases with physical and financial contracts effectively locking in margins at the time of injection. As a result, our activities remain non-speculative, operating strictly within defined operational risk tolerances. Our storage optimization strategy has proven to be valuable in allowing us to capture seasonal spread value and subsequently generate incremental gross margin.

Storage optimization activities include capturing the spread from short term weakness in cash markets versus forward markets, selling gas inventory in cash markets during high price events while simultaneously repurchasing gas forwards in backward dated markets, and intra-season injections and withdrawals. Typically, as long as Rockpoint has owned inventory in the ground and available injection and withdrawal capacity, we can participate in positive value capture either in the cash market or on the natural gas forward curve. This provides operational flexibility by leveraging unused capacity, providing stable base cash flows while maximizing upside value capture.

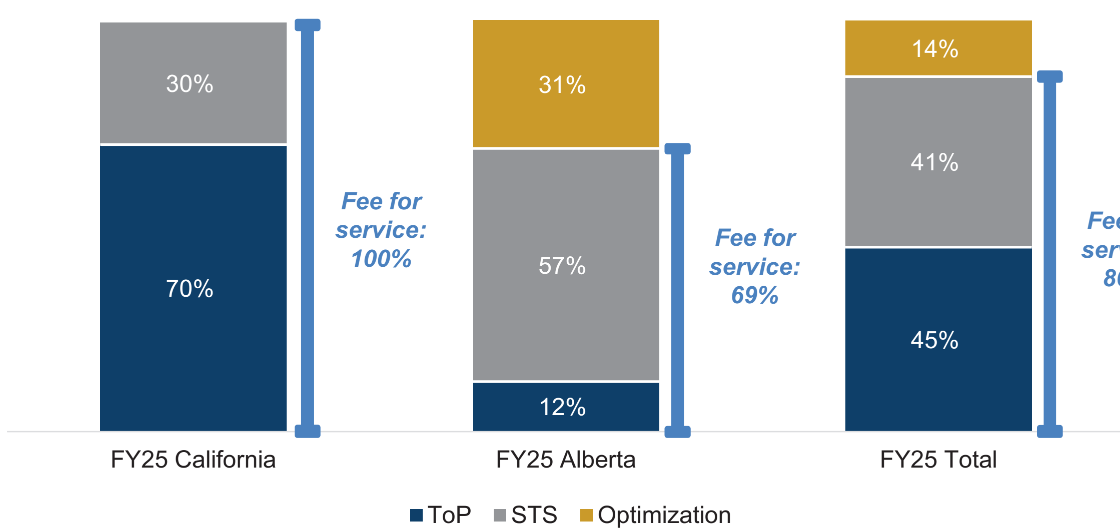
The effective working gas capacity utilized for optimization activities has decreased from 31% in fiscal 2023 to 13% in fiscal 2025 resulting in a drop in optimization Adjusted Gross Margin from $64.3 million in fiscal 2023 to $56.6 million in fiscal 2025. In fiscal 2025, our total optimization activities made up approximately 14% of total Adjusted Gross Margin. We also provide natural gas marketing and transportation services in Canada through AGS which is included in our optimization activities. See "— Access Gas Services" above.

See "Risk Factors — Risks Related to Our Business and Industry".

Contracting targets

Our allocation between ToP, STS, and optimization strategies is designed to maximize the economic value of our storage capacity while maintaining operational flexibility. Our long-term target is to achieve 60% of Adjusted Gross Margin from ToP contracts, 25% of Adjusted Gross Margin from STS contracts, and 15% of Adjusted Gross Margin from optimization strategies. In California, our facilities are operating at or near these long-term contracting targets. In Alberta, we continue to see an increase in contracted ToP volumes and contracted storage rates with new customers entering the market. See "Risk Factors".

The following chart demonstrates our fiscal 2025 contracting status based on effective Adjusted Gross Margin:



The following table shows the segmented historical results by contract type for California and Alberta operations.

Fee for Service Gross Margin ($ millions)	Years ended March 31, 2025	2024	2023
ToP Contracts			
California			
Working gas capacity contribution (MMDth)	68.9	67.4	49.3
Contract rate ($/Dth)[1]	$ 2.37	$ 2.06	$ 1.22
California ToP gross margin	**$163.3**	**$138.6**	**$ 59.9**
Alberta			
Working gas capacity contribution (MMDth)	27.2	26.0	12.6
Contract rate ($/Dth)[1]	$ 0.80	$ 0.64	$ 0.49
Alberta ToP gross margin	**$ 21.7**	**$ 16.7**	**$ 6.2**
Total ToP gross margin	**$185.0**	**$155.3**	**$ 66.1**
STS Contracts[2][3]			
California STS gross margin	$ 69.5	$ 67.0	$ 68.9
Alberta STS gross margin	101.3	49.0	29.8
Total STS gross margin	**$170.8**	**$116.0**	**$ 98.7**
Total Fee for Service gross margin	**$355.8**	**$271.3**	**$164.8**
Realized optimization gross margin[3]	56.6	47.4	64.3
Adjusted Gross Margin	**$412.4**	**$318.7**	**$229.1**

Notes:

(1) Fiscal 2025 ToP demand charges, excluding fuel and commodity recovery, were $2.30/Dth and $0.75/Dth for California and Alberta facilities, respectively (fiscal 2024 — $1.96/Dth and $0.58/Dth, respectively; fiscal 2023 — $1.02/Dth and $0.42/Dth, respectively).

(2) Net of cost of gas storage services from the Statements of Net Earnings and Comprehensive Earnings.

(3) Fiscal 2023 presented on a same-store basis, excluding Fee for Service gross margin from the Salt Plains facility. "Same-store basis" refers to the consistent comparison of financial or operational metrics over time, using a stable set of assets. This excludes any assets that have been divested during the comparable period, ensuring that the comparison reflects only those assets that are consistently part of the Business.

Our Customers

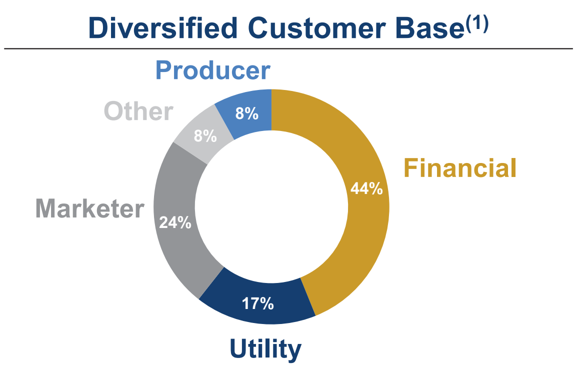
We have cultivated a high-quality, diverse, and long-standing customer base across North America. Our customers include utilities, producers, pipelines, power generators, LNG operators, financial institutions, and marketers each of whom have their own unique storage needs. For utilities, our storage provides supply security during demand spikes and peak day needs, effectively helping manage ratepayer and end-user costs. Producers benefit from our storage through an ability to manage their operational risks and ensure energy availability during high volatility events. Pipeline companies rely heavily on storage to facilitate load balancing and system supply management on their transmission lines. Power generators leverage gas storage to balance the intermittent nature of renewable power and for accelerated deployment to meet urgent needs, especially during peak demand. Financial institutions can leverage our storage to utilize their cost of capital advantage and earn returns on "parked inventory" of natural gas that lock in seasonal spreads. Marketers and commodity traders use our storage services for managing positions, utilizing storage contracts to secure value, and optimize transport positions. Going forward, we expect that LNG exporters will rely significantly on gas storage platforms to balance year-round LNG demand and to mitigate operational disruptions from planned and unplanned outages similar to what we have seen occur in the U.S. Gulf Coast region. Over the past decade, the expansion of LNG exports in the U.S. Gulf Coast has resulted in a significant increase in natural gas storage rates, driven by higher seasonal value from exposure to international gas price spreads and enhanced insurance value to mitigate operational disruptions. We expect western Canada to follow a similar trend to that seen in the U.S. Gulf Coast, with more than 5.0 Bcf/d of LNG export capacity expected to come online by 2031 according to S&P Global Commodity Insights (after adjusting expected demand, based on project status, from all currently proposed western Canadian LNG projects).

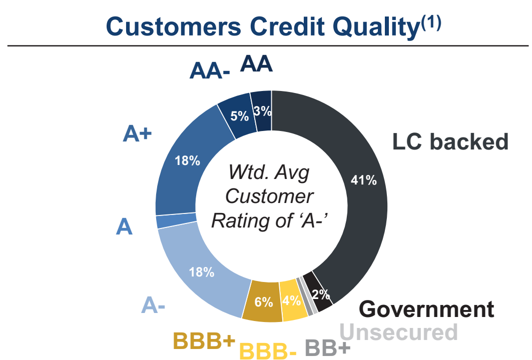
See "Risk Factors — Risks Related to Our Business and Industry".

Relationship length and creditworthiness

We maintain strong, long-standing relationships across our customer base, with a weighted average customer relationship tenure of approximately 8 years among our 57 customers. Customer relationship tenure is defined as the number of years that a customer has consecutively had active ToP or STS contracts with Rockpoint. Several relationships extend beyond 15 years, underscoring the durability of our commercial partnerships. Our top 10 ToP customers have an approximate 7 year weighted average customer relationship tenure and represented 26% of fiscal 2025 Adjusted Gross Margin. Our top 10 STS customers have an approximate 9 year weighted average customer relationship tenure and represented 42% of fiscal 2025 Adjusted Gross Margin. We believe that our strong customer retention is supported by our operating track record, high deliverability, reliability, customizable service offering, and the scarcity of alternative gas storage solutions. Furthermore, our customers are incentivized to renew their contracts to: (i) maintain continuity and avoid financial penalties when volumes are not fully withdrawn at the end of their existing contract; (ii) opportunistically take advantage of rolling existing inventory into future premium periods; and (iii) reduce the risk of an inability to find storage capacity in the future.

The following charts illustrate our customer mix:





Note:

(1) Based on fiscal 2025 Fee for Service Adjusted Gross Margin.

California customer base

In California, our facilities serve a varied customer base, with utilities, financial institutions and marketers playing a prominent role. Utilities accounted for 25% of the Fee for Service gross margin in California in fiscal 2025, reflecting the strategic location of these facilities near major demand centres like the San Francisco Bay Area and Sacramento. The overall weighted average customer tenure in California is approximately 7 years, with several customers with a tenure of 15+ years.

Alberta customer base

In Alberta, our facilities serve a diverse customer base, with financial institutions accounting for a sizable portion of our customer base. In recent years, our customer base has evolved to include more producers, pipeline operators and utilities resulting in additional diversification. In the future, LNG related demand in western Canada is increasingly expected to drive ToP storage contracting in order to secure long-term supply for LNG exports. The overall weighted average customer tenure in Alberta is approximately 7 years, with several customers with a tenure of 10+ years.

Our Competitive Strengths

We believe that the following strengths of our business differentiate us from our competitors, reinforce our leadership position, and enable us to capitalize on expected growth in natural gas storage demand. See "Risk Factors".

Our assets are strategically positioned in diversified markets with increasing natural gas demand

In California, storage assets are essential for balancing energy needs, especially as renewable energy sources are projected to comprise 48% of the power mix by the end of 2025 according to the EIA. This shift necessitates natural gas-fired power generation to manage intermittency and ensures reliable energy supply during periods when renewable output is low. Furthermore, the ongoing buildout of data centres will require northern California to compete more aggressively for gas supply. While demand is growing, the supply of natural gas into northern California is constrained with only two pipeline sources, Baja in the south and Redwood Path in the north. As a result, there is a heightened reliance on independent storage operators in northern California to provide essential storage solutions, ensure grid reliability, and effectively assist in managing price volatility in the energy markets.

In Alberta, we expect western Canadian LNG projects to increase regional demand by approximately 5.0 Bcf/d by 2031 (after adjusting expected demand, based on project status, from all currently proposed western Canadian LNG projects) and demand to be further amplified by oil sands expansion, growing electricity needs and potential data centre development. According to S&P Global Commodity Insights, total natural gas demand in western Canada is expected to increase by approximately 26% from 2024 to 2031. S&P Global Commodity Insights also expects domestic industrial gas demand in Alberta to increase by approximately 19% by 2030, primarily driven by the growth in oil sands production. As of September 12, 2025, there were 29 data centres in the AESO queue, representing approximately 15 GW of potential aggregate power demand according to AESO. Renewable energy will be able to respond to a portion of the incremental energy demands; however, a reliable source of natural gas-fired power generation is also expected to be required to counterbalance renewable intermittency. As a result, we expect Alberta's storage facilities to become increasingly essential for managing natural gas supply and ensuring its stable delivery to domestic and international export markets, particularly as demand grows and during peak demand periods.

We believe our facilities in California and Alberta are strategically positioned to capitalize on increasing storage demand and play a critical role in balancing regional supply shortfalls. Our facilities are competitively positioned with interconnections to several key natural gas pipelines to ensure long-term availability of supply and connectivity to quality customers and demand hubs. See "Risk Factors — Risks Related to Our Business and Industry".

Our assets are difficult to replicate with significant barriers to entry

We believe that replicating our portfolio of operating assets would be very challenging due to: (i) complex and lengthy regulatory permitting processes; (ii) the need for ideal reservoir physical characteristics such as porosity, permeability and retention capacity; (iii) limited land availability with proximity to demand centres or LNG facilities; (iv) lengthy development lead times; (v) the requirement for reliable and available pipeline capacity; and (vi) high development costs. New entrants must navigate a landscape where optimal conditions are essential. In the current environment we would expect it to take approximately five to ten years to build a greenfield natural gas storage facility including establishing a connection to a major pipeline, with greenfield economics likely requiring storage rates typically higher than the current weighted average rate we earn on our working gas capacity. Moreover, in California, there are incremental challenges including stringent regulatory requirements and limited supply of gas due to constrained pipeline capacity that significantly inhibit any development of greenfield projects. See "Risk Factors — Risks Related to Our Business and Industry" and "Risk Factors — Risks Related to Environmental, Public Utility Regulation and Other Regulations".

Our large and diverse platform enables us to offer highly customizable natural gas storage solutions to a diverse customer base

In California and Alberta, we own and operate multiple strategically positioned gas storage facilities. Our large and diversified platform allows us to offer tailored storage solutions that are able to address multiple customer requirements. These customer requirements may include: (i) managing supply security during peak demand periods; (ii) optimizing energy distribution to accommodate renewable energy integration; and (iii) providing flexible storage options for LNG developments. We believe that our ability to serve a broad range of customer profiles and offer operational and commercial flexibility provides us with a significant competitive advantage. Furthermore, our diversified asset base provides additional operational flexibility within our portfolio. For example, our AECO Hub™ facilities function as a single commercial hub which allows for efficient deliverability by utilizing preferred storage pools across the two facilities to service contract obligations. See “Risk Factors — Risks Related to Our Business and Industry”.

Exemplary operational track record with history of high deliverability and reliability

We believe deliverability rate and reliability are crucial aspects for natural gas storage customers as they directly impact customers’ ability to meet fluctuating demand and ensure a reliable supply of energy. Our facilities allow our customers to withdraw gas at a rate that matches their consumption patterns, particularly during peak demand periods or unexpected spikes. This capability is essential for utilities and power generation companies who must balance ratable pipeline takes with non-ratable power burn to ensure they can provide consistent energy output without interruption. We believe our assets have some of the highest deliverability rates in their respective markets. For example, the Wild Goose facility in northern California has a maximum withdrawal capacity of 950 MMcf/d, while the AECO Hub™ in Alberta offers a maximum withdrawal capacity of 3,050 MMcf/d. We believe that these rates are critical for balancing supply and demand in the regions that we serve and ensuring customers can meet their requirements. In our 9 year operating history under the Rockpoint platform, our storage facilities have consistently fulfilled all of our ToP and STS contractual obligations.

We invested $53 million of maintenance capital between fiscal 2023 and fiscal 2025 to ensure plant reliability and performance, which has allowed us to achieve high availability of 95%. Our operations are supported by built-in redundancies such as back-up power generation in California and a functioning operational hub concept in Alberta, which allows us to achieve a high reliability standard. We believe that our operational reputation and high reliability are competitive advantages with customers.

See “Risk Factors — Risks Related to Our Business and Industry”.

Stable and predictable cash flow provides financial flexibility

Our contract structure, customer retention, and recurring contract renewals have historically provided us with stable and predictable cash flow. As of March 31, 2025, we had secured approximately $893 million in contracted Fee for Service revenue backlog. The use of ToP contracts allows us to secure predictable cash flows by charging fixed monthly demand charges, regardless of utilization. This cash flow predictability also provides us with the flexibility needed to strategically plan operations and financial policy. We target to have ToP contracts comprise 60% of Adjusted Gross Margin. STS and optimization activities provide significant cash flow in addition to our ToP cash flows. See “Risk Factors — Risks Related to Our Business and Industry” and “Risk Factors — Risks Related to Our Financial Condition”.

High EBITDA margins and Distributable Cash Flow Conversion supports reinvestment and returns of capital

Our high Distributable Cash Flow Conversion allows us to strategically re-invest in the Business to drive growth and evaluate various forms of returning capital to our shareholders, such as through dividends and share buybacks. Our operations have consistently demonstrated high Adjusted EBITDA margins and strong Distributable Cash Flow Conversion underpinned by minimal maintenance capital expenditure requirements. See “— Stable and predictable cash flow provides financial flexibility”. In fiscal 2025, we generated Distributable Cash Flow of $234.5 million, that represented 69% of our fiscal 2025 Adjusted EBITDA. See “Selected Historical Financial Information”. We have achieved Distributable Cash Flow Conversion above 60% over the last three fiscal years and our current strategic goals and targets have been designed with the goal of continuing this trend. We have adopted a sustainable target dividend payout of 50% to 60% of the OpCos’ Distributable Cash Flow in our financial policy which is predicated on our stable cash flow base and financial outlook. Our target dividend payout plans for $110 million to $120 million of total annual dividends from the Business (of which approximately 40% of any payout would be paid to the Company), and growing annually at a rate of 3% to 5%. We have identified various strategies for maintaining, and potentially growing, Distributable Cash Flow, including future fee for service contract executions, accretive capital projects and strategic optionality opportunities, see “Our Business and Growth Strategies”.

See “Notice to Investors — Forward-Looking Information”, “Dividend Policy”, “Risk Factors — Risks Related to Our Business and Industry” and “Risk Factors — Risks Related to Our Financial Condition”.

Industry leading management team with significant experience and proven track record

Our senior management team is composed of seasoned professionals with approximately 150 years of combined experience in the natural gas industry. They have a strong track record of building and operating natural gas storage assets and executing mergers and acquisitions in the natural gas storage space. We also have a comprehensive in-house team of specialists including geologists, reservoir engineers, risk managers, marketers, schedulers, accountants, lawyers and regulatory experts with extensive experience in natural gas storage operations and development. Their deep understanding of risk management, natural gas market dynamics, and the regulatory landscape enables us to navigate complex challenges and seize emerging opportunities. See “Risk Factors — Risks Related to Our Business and Industry”.

Our Business and Growth Strategies

Since our formation in 2016, we have actively optimized and divested assets. Notwithstanding this progress, we continue to identify market opportunities to enhance our business. Our strategic initiatives are focused on further optimizing existing assets while exploring new avenues for expansion.

Utilize our large portfolio of strategically located assets in key markets to grow cash flows under long-term, ToP contracts at attractive rates

As natural gas demand continues to grow, our facilities are becoming increasingly important in balancing the constrained regional supply shortfalls in the California and Alberta markets. As a result, we expect the demand for our gas storage services to continue to increase. We expect to continue to grow our business by entering into additional ToP contracts on favourable terms. We have a demonstrated contracting track record that validates this trend with customers actively signing contracts to secure more storage capacity at higher rates and for longer tenors. In California, our ToP contracted storage demand charges have increased from $1.02/Dth earned in fiscal 2023 to $2.30/Dth earned in fiscal 2025. This upward trend reflects the transition of our contract portfolio as lower priced legacy contracts have rolled off in favour of multi-year higher-priced market rate contracts. Similarly, in Alberta, our ToP contracted storage demand charges have increased from $0.42/Dth earned in fiscal 2023 to $0.75/Dth earned in fiscal 2025. We expect Alberta ToP contracted gas storage rates to increase as additional west coast LNG projects enter into service. In fiscal 2025, we executed 25 new ToP contracts at rates higher than historical averages, with weighted average contract terms of approximately five years in California and approximately three years in Alberta, which has increased from approximately two years and approximately one year in fiscal 2023, respectively. See “Risk Factors — Risks Related to Our Business and Industry” and “Risk Factors — Risks Related to Environmental, Public Utility Regulation and Other Regulations”.

Pursue high return and capital efficient organic growth opportunities

We have identified a robust pipeline of capital efficient organic growth projects focused on: (i) increasing margins; (ii) enhancing deliverability; (iii) increasing working gas capacity; and (iv) improving connectivity and infrastructure to support buildouts and complementary storage service offerings. We currently have several such brownfield growth opportunities in progress with other longer-term initiatives under consideration. Our near-term brownfield opportunities growth capital expenditures are anticipated at approximately $50 million to $150 million over an estimated three to five year period, with Adjusted EBITDA build multiples averaging 5x.

We recently completed an expansion project at the Wild Goose storage facility in California which included the drilling and tie-in of three new storage wells. The expansion at Wild Goose added approximately 20 MMcf/d of incremental deliverability with growth capital expenditures of approximately $14 million with an Adjusted EBITDA build multiple of approximately 3x, where Adjusted EBITDA build multiple is calculated as the total growth capital expenditures divided by our expected average five-year run-rate Adjusted EBITDA.

We anticipate an Alberta expansion project at the Warwick facility that will add up to 5 Bcf of incremental working gas capacity and increase overall operational efficiency. Infrastructure has already been acquired and efforts to acquire mineral rights for the expansion project are underway. The regulatory applications have been prepared and the capital plan is progressing. We expect the expansion to be completed in 2026 and growth capital expenditures of approximately $11 million, with an Adjusted EBITDA build multiple of approximately 3x.

Additional brownfield projects have been identified to increase capacity and to increase deliverability. In California, we are pursuing an opportunity to increase storage capacity and deliverability through the addition of wells and compression. In Alberta, we have identified a reservoir that we may be able to tie into an existing facility that could add additional working gas capacity. The brownfield opportunities allow us to stage capital and de-risk the opportunity as we pursue the full development.

We believe that there will be additional opportunities to deploy capital to optimize the existing assets. We have identified unutilized and underutilized assets that may be redeployed to further increase working gas capacity and the deliverability of the existing assets.

See “Risk Factors — Risks Related to Our Business and Industry”, “Risk Factors — Risks Related to Environmental, Public Utility Regulation and Other Regulations” and “Risk Factors — Risks Related to Our Financial Condition”.

Additionally, we are evaluating salt cavern development in multiple markets which we believe will be important to capitalize on certain long-term industry fundamentals. None of these projects have received final approval at this time, and we will implement our longer-term plans opportunistically at times that we determine to be most strategically advantageous for the Business.

See “Risk Factors — Risks Related to Our Business and Industry”, “Risk Factors — Risks Related to Environmental, Public Utility Regulation and Other Regulations” and “Risk Factors — Risks Related to Our Financial Condition”.

Pursue opportunistic acquisitions to build further scale and strengthen our market position

As we continue to evaluate market dynamics and growth opportunities, we intend to evaluate and selectively pursue accretive acquisitions of complementary assets to further bolster our position and enhance our competitive advantage in the industry. We will employ a rigorous framework to evaluate such opportunities, and potential acquisitions will compete with alternative uses of capital including: (i) organic growth projects; (ii) shareholder dividends; (iii) share repurchases; and (iv) debt reduction. We have a demonstrated track record of completing mergers and acquisitions Our strategic development has been shaped by three key storage facility acquisitions which have defined our extensive operational footprint in North America. These acquisitions established the Business as the largest independent pure play operator of natural gas storage facilities in North America, strengthened our market position, expanded our operational capabilities and enabled cost efficiencies. See “Risk Factors — Risks Related to Our Business and Industry”.

Human Capital

We understand that our employees and management team are our greatest asset and are committed to attracting, fostering and retaining talented and high-performing individuals. Our senior management team is composed of seasoned professionals with approximately 150 years of combined experience in the natural gas industry. As of June 30, 2025, our workforce included approximately 137 full-time and 15 contractors working in areas such as engineering, corporate finance, legal, and natural gas marketing based out of our three Canadian offices in British Columbia, Alberta and Ontario, and field locations in Alberta, Canada and California, United States. As we continue to grow and advance our projects, we expect to generate additional skilled roles, both for full-time staff and contractors in all of our operating regions and offices.

We provide a wide array of company-sponsored benefits and performance-based incentives, which we believe are competitive within the industry. Our employees are not currently part of any labor unions or collective bargaining agreements, and we enjoy a strong and positive relationship with our team. We are dedicated to creating a safe and harmonious work environment that supports professional growth and encourages excellence.

See “Risk Factors — Risks Related to Our Business and Industry”.

Competition

Competition in the natural gas storage industry is influenced by several factors which include: (i) pricing; (ii) service terms; (iii) types of services offered; (iv) access to supply sources; (v) connectivity to demand markets; (vi) pipeline connectivity; and (vii) the overall flexibility and reliability of service. Our primary competitors are midstream energy consolidators, integrated energy firms, pipeline operators, and natural gas marketers. We are currently the largest independent natural gas storage facility operator in North America. See “Risk Factors”.

The following charts show the gas storage facilities in western Canada and California:

Largest Gas Storage Portfolio in Western Canada

Owner	Facility	Storage Capacity (Bcf)	Withdrawal Capacity (Bcf/d)
ROCKPOINT	AECO Hub™	154	3.0
Enbridge	Aitken Creek	77	1.3
TC Energy	Crossfield East	68	0.5
ATCO	Wayne-Rosedale	62	0.5
TC Energy	Edson	50	1.5
Tidewater Midstream	Brazeau River	39	0.1
ATCO	Carrot Creek	35	0.6
SaskEnergy	Saskatchewan	34	NA
ROCKPOINT	Warwick	22	0.3
AltaGas	Dimsdale	15	0.1
Husky Energy	Hussar	15	0.3
ATCO	McLeod	10	0.1
ROCKPOINT	Rockpoint Total	154 + 22 = 176	3.0 + 0.3 = 3.3

Critical Infrastructure to California Market

Owner	Facility	Storage Capacity (Bcf)	Withdrawal Capacity (Bcf/d)
ROCKPOINT	Wild Goose	75	1.0
SoCalGas	Aliso Canyon	69	1.9
PG&E	McDonald Island	53	1.2
ROCKPOINT	Lodi & Kirby Hills	29	0.8
SoCalGas	Honor Ranco	27	1.0
SoCalGas	La Goleta	22	0.4
PG&E + Sensa	Gill Ranch	20	0.7
Sixth Street + Caliche	Central Valley	11	0.3
SoCalGas	Playa Del Rey	2	0.4
ROCKPOINT	Rockpoint Total	75 + 29 = 104	1.0 + 0.8 = 1.7

Sources: Management estimate (as of September 12, 2025); AER; and EIA.

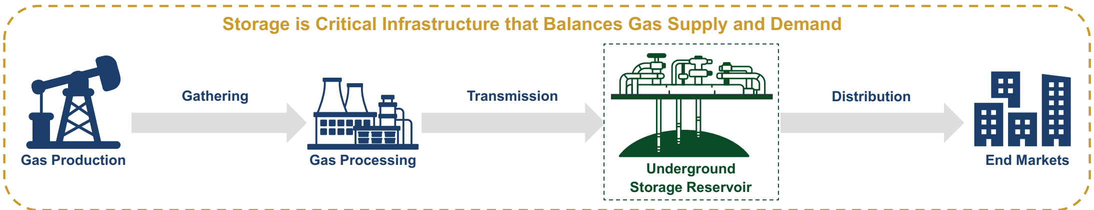
Health and Safety

Ensuring the health and safety of our operations is a fundamental priority. We are deeply committed to fostering a safe and reliable environment across all our facilities through our five core values: safety, environment, teamwork, integrity, and transparency. To achieve this, we have established a dedicated Health, Safety, Security and Environment team that plays a crucial role in overseeing the safe execution of our projects. This team reports directly to our leadership, underscoring the importance of safety at every organizational level. Our safety strategy involves implementing comprehensive programs that address the unique hazards present at each stage of our operations. These programs include regular safety meetings, lagging and leading indicator tracking, critical controls, training and awareness, incident investigations, and performance management, all aimed at cultivating a proactive safety culture. We continuously review and update our safety standards to ensure they remain effective and aligned with the highest industry benchmarks. We recognize that a robust safety culture not only enhances safety performance but also boosts operational efficiency and staff morale. Our commitment to these principles is reflected in our exemplary safety record, which includes zero serious safety incidents. Our dedication to health and safety underscores our commitment to providing a secure and supportive work environment for all employees, positioning us as industry leaders in safety and environmental stewardship. Over the past three fiscal years, our assets have maintained exemplary safety records with an average Total Recordable Injury Rate of zero, zero lost time incidents and zero reportable pipeline incidents.

See “Risk Factors — Risks Related to Our Business and Industry”.

The Natural Gas Value Chain

The natural gas "value chain" encompasses the entire process from extracting natural gas from the earth's subsurface through distribution to the end-user. As depicted in the illustration below, this chain includes several key stages: (i) production at the wellhead; (ii) gathering; (iii) processing; (iv) storage; and (v) distribution.



Source: EIA.

Production

The initial phase of the natural gas value chain involves the exploration and extraction of natural gas from underground reservoirs. Key production regions in North America include the Appalachian region, the Permian Basin, the U.S. Gulf Coast and the Western Canadian Sedimentary Basin.

Gathering

Gathering systems, consisting of small-diameter, low-pressure pipelines, transport raw natural gas from the wellhead to processing plants or connect it to larger mainline pipelines.

Processing

Natural gas processing is the industrial procedure that refines raw natural gas into a form suitable for transportation and use, aiming to produce "pipeline quality" gas primarily composed of methane separated from NGLs and heavier hydrocarbons not suitable for transmission or commercial use.

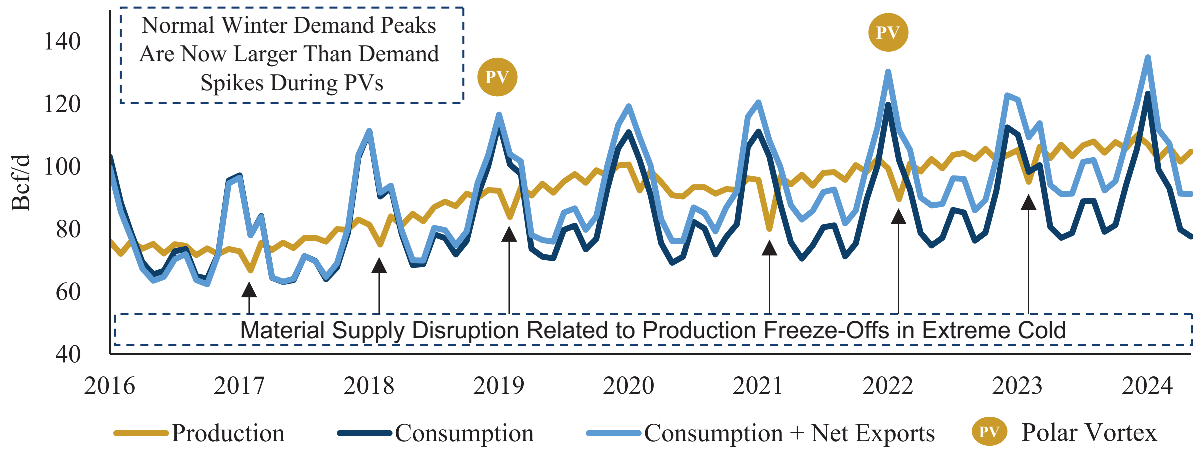
Natural gas storage

Natural gas storage infrastructure plays a crucial role in the natural gas value chain, serving multiple essential functions to ensure supply meets demand throughout the year. It bolsters production and delivery systems, providing a reliable supply during periods of high demand and enabling the injection of supplemental production during low demand or off-peak times. This process balances the steady production with fluctuating daily, monthly, and seasonal consumption. When production exceeds demand, typically in summer, excess gas is stored; conversely, during winter, stored gas is withdrawn to meet increased demand. Storage also plays a vital role in maintaining supply during temporary disruptions and assists pipeline companies in balancing system supply on long-haul transmission lines.

By injecting lower-priced gas during off-peak periods and withdrawing it during peak demand, storage helps reduce costs associated with peak-demand times. The flexibility and reliability provided by storage are critical to maintaining stable natural gas markets for end-users, ensuring that supply consistently matches demand throughout the year. This adaptability is essential for keeping natural gas flowing to customers and maintaining stable market conditions globally. Additionally, stored gas is increasingly utilized to capitalize on price fluctuations over time, managing seasonal price differences and enabling strategic arbitrage in gas markets. Through LNG, North America has integrated its supply of natural gas to international markets, driving significant increases in supply and demand as well as exposing all stakeholders to premium global pricing dynamics, according to the IEA.

The chart below illustrates the imbalance between fluctuating demand and stable supply, as well as an upward trend in both supply and demand:

High Reliance on Storage Facilities to Manage Daily Balance of U.S. Natural Gas Supply / Demand



Source: EIA.

See "Risk Factors — Risks Related to Our Business and Industry".

Distribution

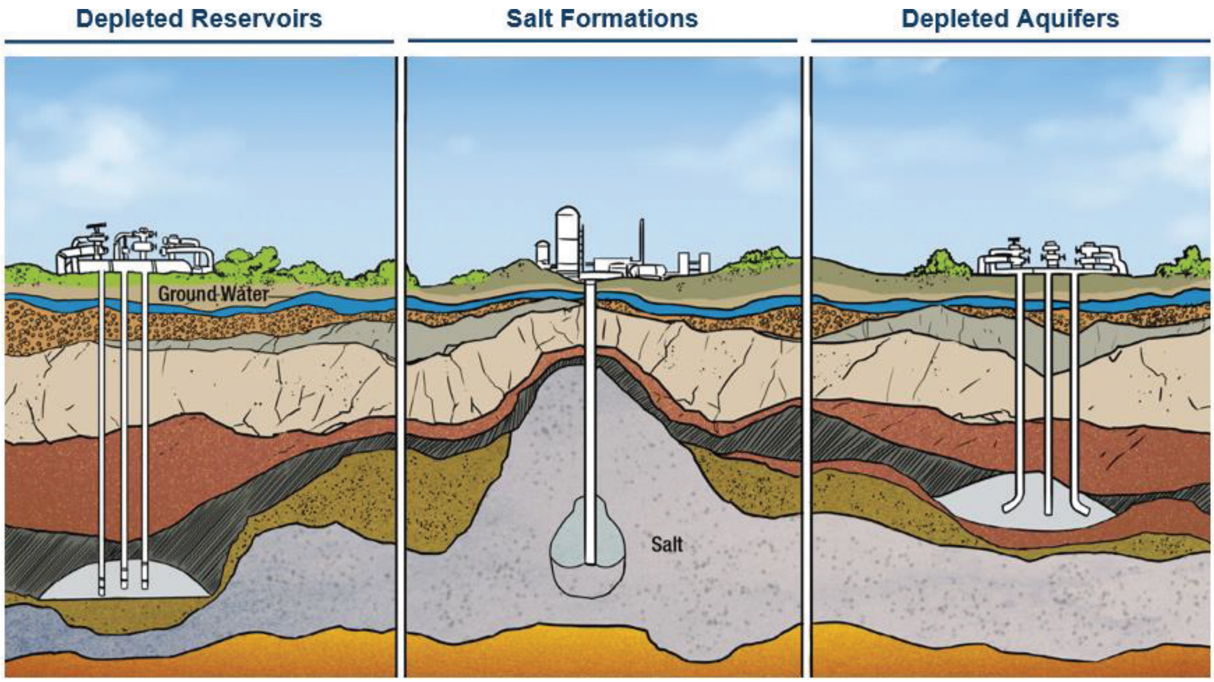
Produced and stored natural gas is transported from gathering facilities and processing plants to consumption areas by transmission pipelines. According to the U.S. Department of Transportation, in the United States, there are approximately 483,000 kilometers of large-diameter, high-pressure interstate and intrastate transmission pipelines operated by more than 210 companies in 2025. In Canada, there are approximately 117,000 kilometers of large-diameter transmission pipelines, with most provinces having significant pipeline infrastructure according to Natural Resources Canada in 2025.

Once natural gas reaches the market through transmission pipelines, it is either: (i) directly delivered from transmission pipelines to large industrial, commercial and power generation customers; or (ii) delivered to residential and commercial consumers at reduced pressures through local distribution companies.

Natural Gas Storage Reservoir Types

Natural gas can be stored in several different ways. Most commonly, natural gas is stored underground and under pressure in one of three major types of reservoirs: (i) depleted reservoirs; (ii) salt cavern formations; and (iii) depleted aquifers. Each storage type has its own physical characteristics (including porosity, permeability, retention capability) and economics (including deliverability rates, cycling capability, maintenance costs) which govern its suitability for applications. Two important characteristics of an underground storage reservoir are its capacity to hold natural gas for future use and the rate at which gas inventory can be injected and withdrawn. Additionally, infrastructure such as underground wells, transmission lines, gathering systems and compression are required for natural gas storage injection and withdrawal; however, levels of significance vary between the reservoir types. See "Risk Factors — Risks Related to Our Business and Industry".

The illustration below provides an overview of the main types of reservoir storage in North America:



Source: American Petroleum Institute.

Depleted reservoirs

Depleted reservoirs are underground formations that have been previously used for oil and natural gas extraction and have natural containment qualities. After production has ceased and the reservoir has been drained of most of its recoverable hydrocarbons, they are considered depleted. Of the three primary types of underground storage facilities, depleted reservoirs are the most common across North America and are typically the most economical to develop, operate, and maintain due to their existing infrastructure and proven containment capabilities. Compressor stations are utilized to control the flow of natural gas between reservoirs and transmission pipelines. Depleted reservoirs account for approximately 78%[5] of the working gas capacity of subsurface storage systems globally. To maintain sufficient pressure for design withdrawal rates, a portion of the formation's volume is required for "cushion gas" which is a permanent volume of gas required to maintain adequate pressure and deliverability. Depending on the quality of the reservoir, depleted reservoirs can be developed with cycling capabilities between one and five cycles per year, but most commonly cycle their working gas one or two times annually. Reservoirs with higher porosities and permeabilities, when combined with modern techniques such as horizontal well technology, can achieve higher cyclabilities, making them a versatile and efficient option for gas storage.

Salt cavern formations

Salt caverns, formed by leaching or mining underground salt deposits, offer high withdrawal and injection rates relative to their working gas capacity, with less cushion gas required as a percentage of total capacity when compared to depleted reservoirs and aquifers. Salt caverns account for approximately 7% of the working gas capacity of subsurface storage systems globally. While salt caverns typically have smaller working gas capacities compared to depleted reservoirs and aquifers, they excel in deliverability, allowing for rapid and frequent gas withdrawal and injection. Without the benefit of utilizing pre-existing wellheads and repurposed facilities, infrastructure costs for salt cavern development can be significant. Additionally, salt caverns require more capital-intensive natural gas compression stations to provide the necessary pressure to sustain higher deliverability requirements. Although construction costs for salt caverns are higher than depleted reservoir conversions, their ability to cycle working gas up to twelve times a year can provide greater injection and withdrawal flexibility to manage seasonal demand requirements.

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5 *Source: U.S. Department of Transportation.*

Depleted Aquifers

Aquifers are underground, porous, permeable rock formations that naturally store water. They account for approximately 12%[6] of the working gas capacity of subsurface storage systems globally. In certain situations, these formations can be reconditioned and repurposed as natural gas storage facilities. However, the cushion gas requirement for aquifers is higher than for depleted reservoirs and salt caverns. This high cushion gas requirement is due to the need to maintain pressure and ensure the integrity of the storage system. Infrastructure requirements for aquifers are similar to that of depleted reservoirs, such that existing wells and related facilities, pipelines and other infrastructure can be utilized and repurposed to reduce construction costs. Additionally, lower cyclability results in lower capital requirements for compressor stations. Typical aquifer storage can only be cycled one time per year, making it less flexible compared to other storage options.

Natural Gas Storage Stakeholders

Owners and operators of storage facilities

According to the EIA, the United States had approximately 4.7 Tcf of natural gas storage capacity (as of November 2024). At that same time, in Canada, natural gas storage capacity was 0.9 Tcf, with the majority located in Alberta, according to the CER. The primary owners and operators of these facilities include pipeline companies, local distribution companies and independent storage service providers.

Ownership of storage facilities does not equate to ownership of the natural gas stored within; most working gas is owned by shippers, local distribution companies and end-users. The entity managing a facility influences its capacity utilization. Interstate or interprovincial pipeline companies utilize underground storage for load balancing and system management on long-haul transmission lines, reserving some capacity under regulation, while leasing the majority to other industry participants. Non-regulated pipeline companies similarly employ storage for system management, optimization, and customer service, without a reserve capacity requirement.

Historically, local distribution companies have used storage primarily to meet direct customer needs. However, deregulation, which began to occur in the 1970s and 1980s across the U.S. and Canada, respectively, has enabled some local distribution companies, particularly those with extensive distribution systems, to lease portions of their capacity to third parties, such as marketers, while maintaining service obligations to core customers. Deregulation, alongside robust market fundamentals and shifting demand, has facilitated the entry of unregulated independent storage operators. These entities serve third-party customers seeking high-capacity, high-deliverability facilities in strategic markets, underscoring the critical role of underground storage in ensuring reliable natural gas supply across North America.

Gas storage key customer groups

Gas storage facilities serve diverse customer groups with distinct operational needs. The two main groups are: (i) strategic end-users; and (ii) marketers and financial institutions. Strategic end-users, including utilities, power generators, pipeline companies, and energy producers, depend on storage for reliability, energy security, peak demand management, and price volatility mitigation. Meanwhile, marketers and financial institutions use storage for firm capacity and STS agreements, supporting daily trading operations and services they offer to strategic users looking to manage their natural gas exposures.

Within the strategic end-user's group, utilities and power generators contract for ToP capacity to balance intermittent supply and manage rate payer costs effectively. They require storage to ensure a steady energy supply during peak demand periods and to mitigate the impact of price fluctuations. Pipeline companies utilize gas storage for load balancing as well as for regulatory supply needs. Producers benefit from storage by managing operational risk and ensuring energy availability, particularly during high volatility events, thus securing their operations against market uncertainties. Additionally, for our Alberta operations, west coast LNG stakeholders are expected to become additional strategic end-users requiring natural gas storage to manage daily fluctuations in gas supply due to supply disruptions and LNG facility maintenance and downtime, in the same manner as LNG stakeholders became strategic end-users in the U.S. Gulf Coast.

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6 *Source: U.S. Department of Transportation.*

Marketers and financial institutions play a crucial role in the natural gas market by contracting for ToP and STS capacity. They provide a reliable source of demand to assist their customers in managing natural gas portfolios, securing supply, and managing transportation and exposures. Natural gas marketers and financial institutions facilitate market transactions between buyers and sellers and lend their balance sheets to reduce the storage operator's working capital investment. Additionally, they provide end-users with hedging opportunities that support long-term price stability and supply reliability.

Value of Natural Gas Storage for Market Based Storage Services

The value of a natural gas storage facility or storage services contract, whether ToP or STS, is principally based on four components: (i) operational and location characteristics of the storage facility; (ii) seasonal value in natural gas prices; (iii) insurance value of storage, representing a premium the market allocates to mitigate gas pricing volatility; and (iv) demand factor. The relationship between these components in determining the value of storage is seasonal value plus the insurance value of storage plus the demand factor, where the operational characteristics of the facility (i.e., the ability to efficiently and reliably respond to variable supply and demand) can act as a multiplier on the seasonal value and insurance value components. See "Risk Factors — Risks Related to Our Business and Industry".

Operational characteristics and location of the storage facility

The operational characteristics of a storage facility play a crucial role in determining the value of its storage services. Key facility characteristics include the total gas storage capacity, its cyclability (the number of times the working gas volume can be completely injected and withdrawn within a year) and geographic location. The duration for which a facility can maintain its peak withdrawal rate before experiencing a decline, along with the steepness of the decline in withdrawal rate as additional inventory is removed, are fundamental aspects of a facility's profile that define its cyclability. Facilities offering greater flexibility (cyclability) in their profiles can generate more value, whether through contracted services or optimization opportunities. Additionally, the value of a storage facility is influenced by its strategic location within the natural gas infrastructure network, such as proximity to market regions or connections to multiple pipelines, which enhances its market accessibility and operational efficiency.

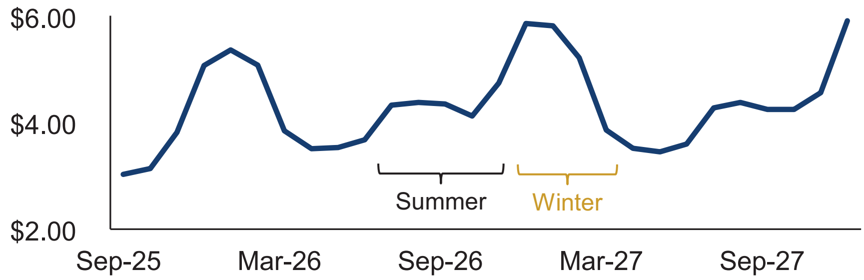
Seasonal value in natural gas prices

Natural gas seasonality is a key feature of the energy market, driven by temperature-induced demand fluctuations. As natural gas is used to meet heating needs, demand typically peaks in winter and declines in summer. This cyclical pattern necessitates the strategic use of storage facilities to balance supply and demand throughout the year. Storage facilities manage these seasonal imbalances by injecting excess gas during low-demand periods, like summer, and withdrawing it during high-demand winter months, thereby providing greater energy security and price stability.

Over the past five years, when comparing winter to summer total natural gas consumption, winter months have exceeded summer months consumption by approximately 30% and 60%, in the U.S. and Canada, respectively. This is primarily due to heating needs in the residential and commercial sectors. Consequently, natural gas prices are lower in the summer and higher in the winter, creating a price differential known as the seasonal value. Gas storage capacity allows capacity holders to capitalize on this spread by injecting and storing gas when prices are low and withdrawing the gas during periods of high demand when prices are also higher. Storage customers can lock in a minimum value, securing a gross margin from buying and injecting gas in summer months and subsequently entering forward sales of the gas for winter withdrawal net of the fee they pay to the storage owner.

Below is an example of an illustrative gas price futures curve as at August 2025 to illustrate the seasonal value:

PG&E Citygate Forward Curve (US$ / Dth)



PG&E Citygate Prices (US$ / Dth)

		Seasonal Value	
Summer 2026 avg.	**Winter 2027 avg.**	**Raw**	**Facility Adjusted**
$3.98	$5.09	$1.11	$1.64

Source: Bloomberg.

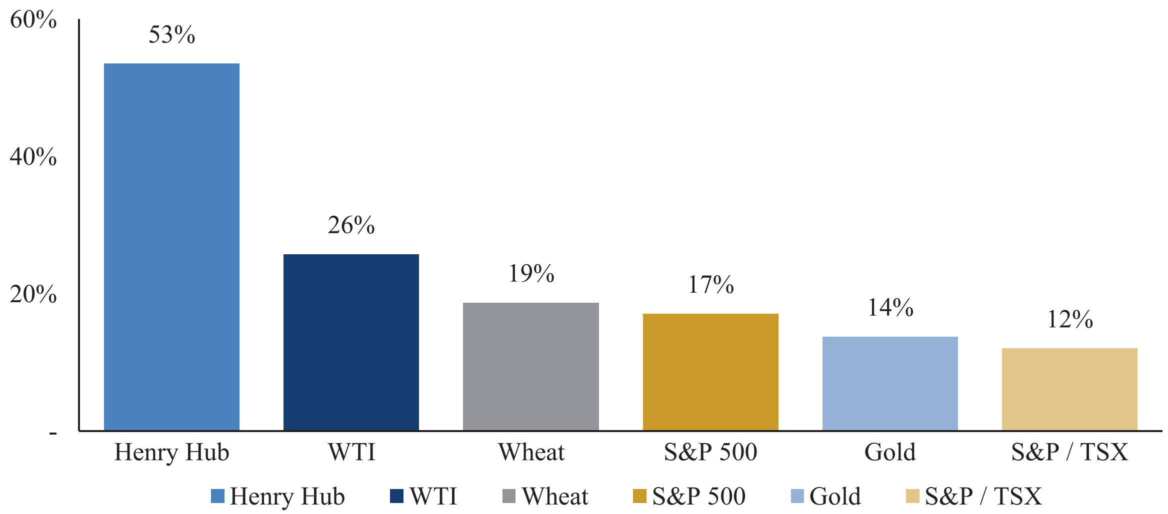
Insurance value of storage

During periods of heightened natural gas price volatility, the insurance or option value of storage capacity increases significantly. Contract holders with rights to inject or withdraw gas are well-positioned to capitalize on these market fluctuations, capturing incremental value beyond traditional seasonal value. The value of this flexibility is amplified during periods of supply or demand disruption, when the ability to respond quickly becomes critical to market reliability. Facilities with superior cyclability and strategic geographic positioning are best equipped to leverage this volatility, reinforcing the importance of high-performance infrastructure in a dynamic energy landscape.

Higher natural gas prices lead to greater absolute price movements, offering higher margins that can be captured through storage. In such environments, users are motivated to mitigate exposure to significant price changes, as the benefits from larger price movements outweigh higher variable costs. Additionally, certain regulatory agencies may mandate utility companies to secure incremental storage to protect their customers against large price spikes, demonstrating the importance of storage services. The chart below highlights the relatively high volatility of natural gas when compared to other commodities and indices in North America, as evidenced by the Henry Hub (a key pricing point for natural gas) 2025 year-to-date cash volatility. This trend underscores the growing importance of storage facilities in managing price volatility and capturing value in the natural gas market.

The chart below shows the price volatility across commodities and common equity market indices:

2025YTD Annualized Cash Volatility

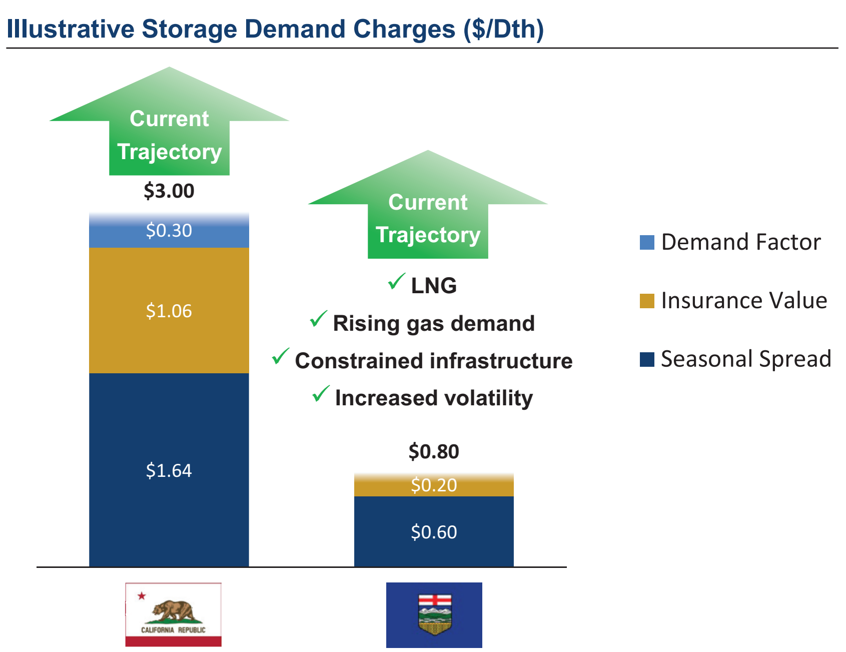


Source: Bloomberg.

Demand Factor

Demand factor represents a range of elements including storage scarcity, term premiums and facility specific characteristics that further impact the value of storage to customers. Strategic customers with strong requirements for downside protection, such as load balancing, are willing to pay a premium to secure storage capacity. Operational flexibility such as strategic location, connectivity, and deliverability of the facilities is another contributor to demand factor, and the premium customers are willing to pay for securing storage capacity. Additionally, long term storage contracts also drive the demand factor in a rising rate environment, providing the customer greater future option value.

The chart below describes illustrative storage demand charges in Alberta and California as of August 2025:



Fundamental Industry Trends

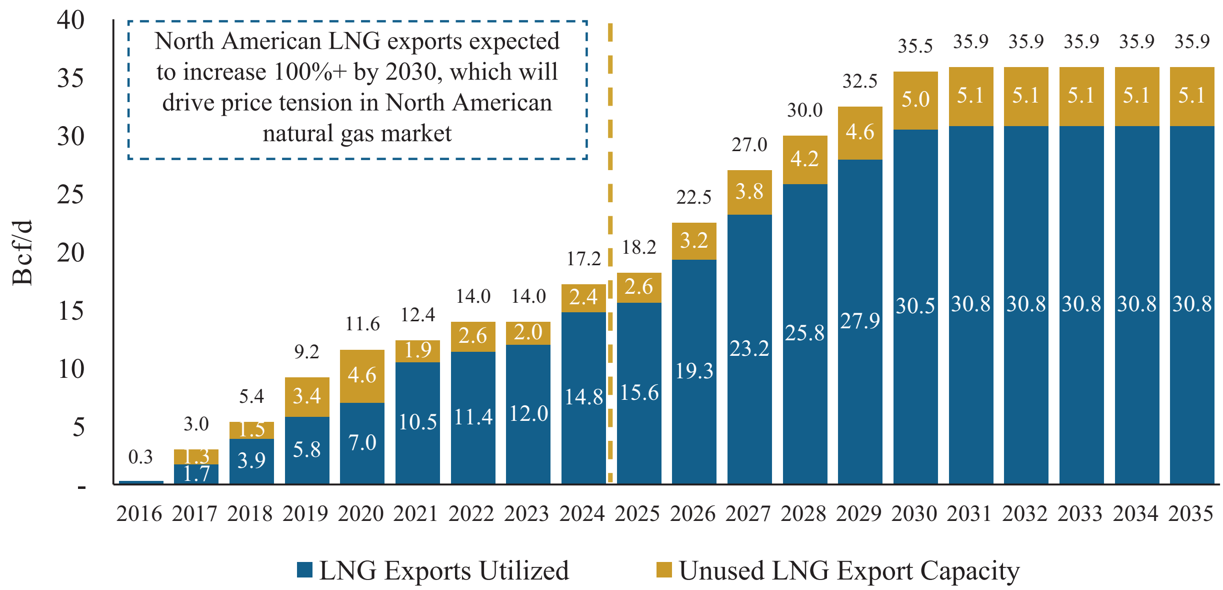
The North American natural gas storage industry has undergone structural changes in recent years that have contributed to increasing rates and tenures of storage contracts. The factors driving this include: (i) increased demand from LNG exports; (ii) globalization of North American natural gas markets; (iii) growing power demand from electrification and expansion of data centres; (iv) storage market barriers to entry; and (v) increasing volatility in natural gas prices. See "Risk Factors — Risks Related to Our Business and Industry" and "Risk Factors — Risks Related to Environmental, Public Utility Regulation and Other Regulations".

Increased demand from LNG exports

Since the first major LNG export in 2015, North American LNG export capacity increased to approximately 15 Bcf/d in 2024. The expansion of LNG export capacity from key regions such as the U.S. Gulf Coast, British Columbia and Mexico is projected to create significant competition for North American natural gas supply during peak demand periods, particularly in the winter. By 2030, these exports are projected to reach approximately 30.5 Bcf/d, doubling North American LNG exports from current levels and constituting nearly 23% of North America's expected natural gas production. We believe that overseas prices have the potential to create LNG arbitrage upside incremental to traditional North American spreads as LNG exports become approximately 25% of North American production.[9]

The chart below illustrates the projected near-term growth of North American LNG exports:

<u>Substantial Increase in North American LNG Exports</u>



Sources: Management estimate (as of September 12, 2025); CER, EIA, and SENER.

Globalization of North American natural gas markets

Prior to LNG export capacity, North America had an oversupplied, 'landlocked' natural gas market. The expansion of North American LNG export capacity caused the integration of North American supply with international markets, particularly European and Asian gas consumption markets, which has driven significant increases in North American natural gas supply and demand. Integrating North American natural gas supply with European and Asian natural gas consumption markets has had a material, sustaining impact on seasonal natural gas storage value according to the EIA.

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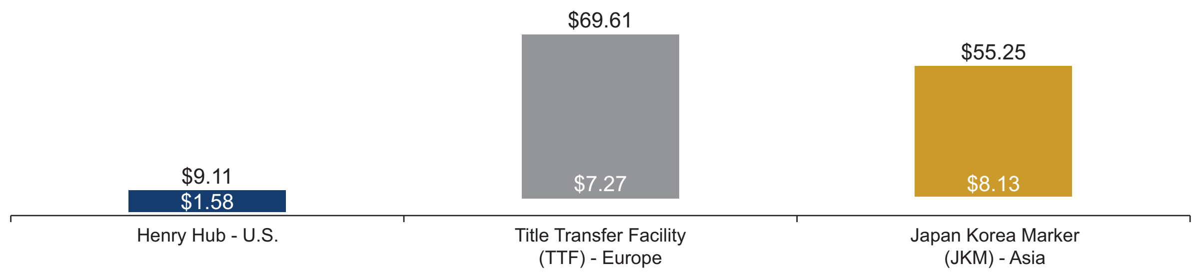
9 *Sources: EIA; CER; and NGI.*

The chart below illustrates the three-year month to prompt high and low across the U.S., Europe, and Asia:

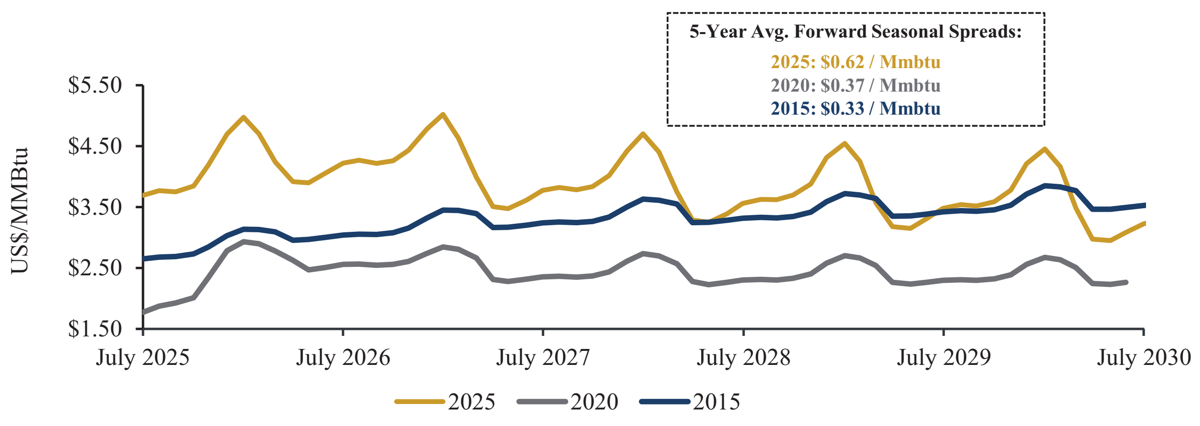
3-Year Prompt Month High/Low ($ / MMBtu)



Source: Intercontinental Exchange.

The expansion of North American markets through LNG exports has introduced global gas price dynamics, such as wider seasonal values, in the domestic North American market. This shift has significantly increased the value of North American gas storage and has elevated service fees since 2015, particularly in the U.S. Gulf Coast region. Henry Hub Seasonal values today are $0.15/MMbtu higher than they were in 2020, as shown in the chart below. Should North American LNG continue to expand and exposure to global natural gas markets increase, we expect the North American storage value will continue to increase. See "Risk Factors — Risks Related to Our Business and Industry".

Henry Hub Forward Curve Has Seen a ~68% Increase in Seasonal Spreads Over the Last Five Years



Source: Bloomberg.

Note:

(1) Forward seasonal value is calculated as the average pricing of futures contracts in the winter months (November – March) less the average pricing of futures contracts in the previous summer months (April – October).

Growing power demand from electrification and expansion of data centres

Electrification trends such as the rise of electric vehicles, manufacturing reshoring, heat pumps and data centres are driving increased electricity demand and therefore demand for natural gas via power generation. According to the IEA, global electricity generation to supply data centres is projected to grow from 460 TWh in 2024 to over 1,000 TWh in 2030 and 1,300 TWh in 2035 (approximately 10% CAGR). A combination of renewables and natural gas are expected to be the most significant suppliers of the forecasted power generation requirements. Natural gas demand to power data centres is expected to grow by nearly 1.2 Tcf globally between 2024 and 2035.[11] In North America, we expect natural gas fired power to play a significant role for the next several decades in meeting the increased power load growth, balancing the intermittency of renewables as well as supporting decarbonization of the power supply, by replacing higher emission baseload power sources such as coal. According to the IEA and S&P Global Commodity Insights, North American gas consumption is

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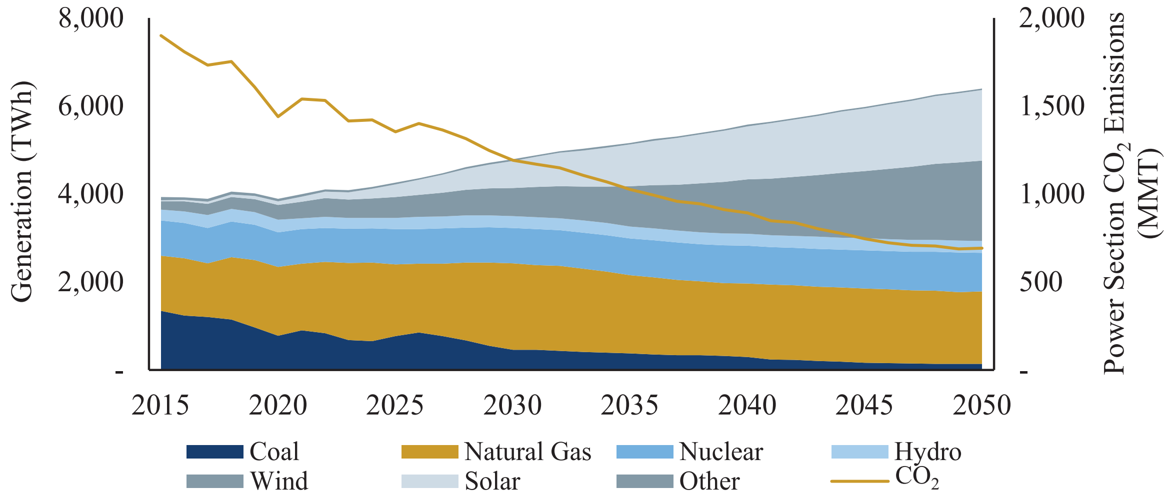
[11] *Source: World Energy Outlook.*

expected to grow by approximately 5 Bcf/d by 2030 primarily driven by data centre growth and increasing need to support renewables intermittency. See "Risk Factors — Risks Related to Our Business and Industry" and "Risk Factors — Risks Related to Environmental, Public Utility Regulation and Other Regulations".

U.S. L48 Generation by Fuel and Power Sector CO_2 Emissions



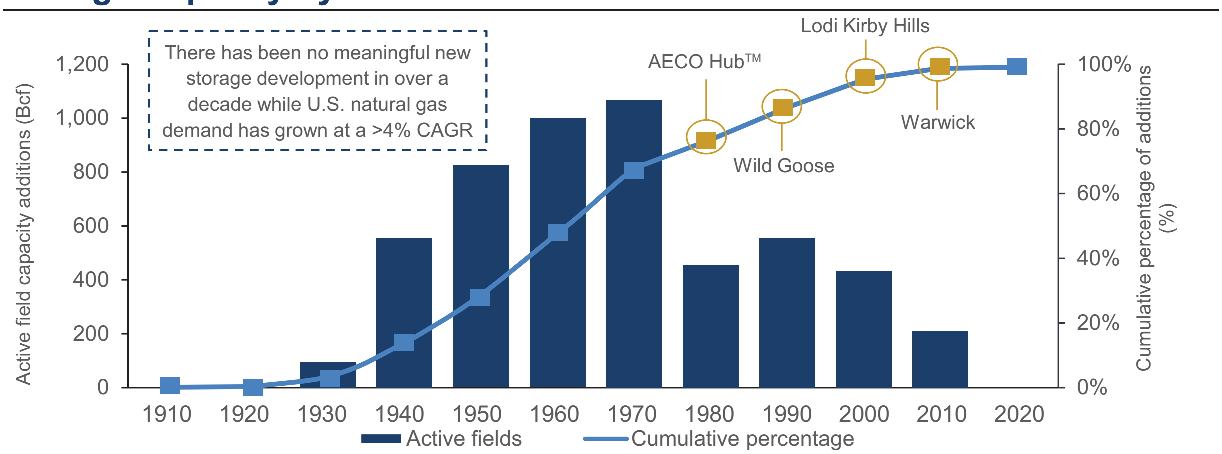
Source: S&P Global Commodity Insights.

Storage market barriers to entry

Over the past decade, working gas capacity has remained constant at 5.6 Tcf in North America. Despite natural gas supply and demand having grown by over 4% annually since 1975 and an increasing reliance on natural gas storage to stabilize markets, North American storage capacity remains scarce, with no significant development identified, due to significant geographic, regulatory and interconnection barriers to new development. These barriers allow existing storage owners and operators additional opportunities to leverage robust market fundamentals and structural shifts in demand to capitalize on rising rate environments. See "Risk Factors — Risks Related to Our Business and Industry" and "Risk Factors — Risks Related to Environmental, Public Utility Regulation and Other Regulations".

The chart below illustrates storage capacity additions by decade since 1975:

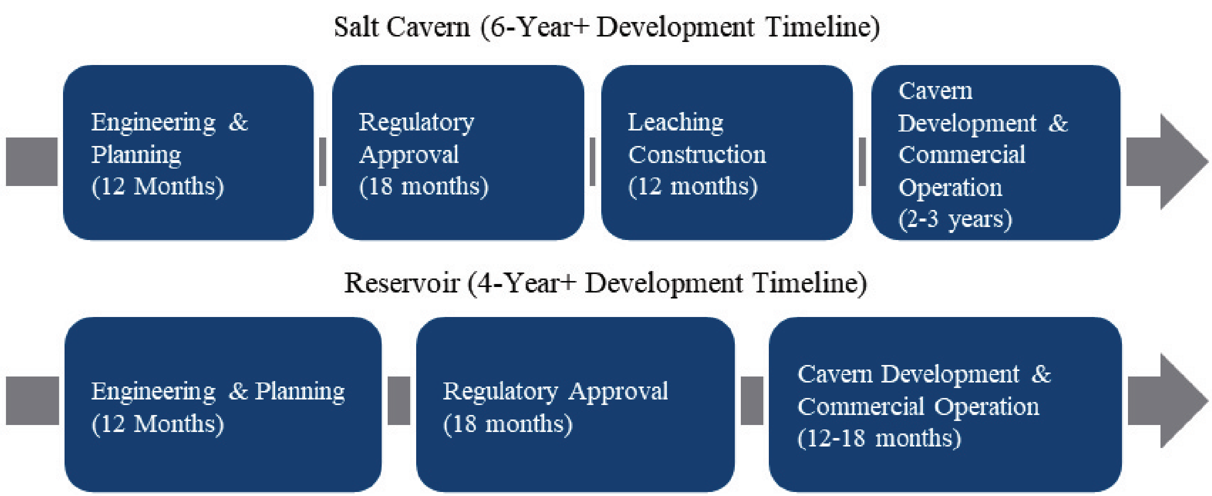
Storage Capacity by Activation Decade



Source: EIA.

The development timeline for gas storage facilities, particularly salt caverns and reservoirs, is a lengthy, costly and complex process. The process begins with a detailed engineering and planning phase, where feasibility and design are assessed, considering geological and geographical factors. Following this, operators must navigate a regulatory approval process (which may take up to 18 months depending on the jurisdiction) to secure necessary distribution and storage rights. The regulatory approval processes often focus on environmental and safety standards and may include public consultations. For salt caverns, a 12-month leaching construction phase is then required to create the storage space by dissolving salt with water. The final phase, cavern development and achieving a commercial operation date, takes two to three years for salt caverns and 12 to 18 months for reservoirs, involving the installation of necessary infrastructure to ensure safe and efficient gas storage and delivery. Depleted reservoir sites often consist of necessary pipeline infrastructure and connections for gas distribution which reduces the overall construction time when compared to salt cavern gas storage development. Overall, the current development timeline for salt caverns can exceed six years, while reservoirs typically take four years or more. Furthermore, additional time can be required to secure connection to major pipelines. These long development timelines, coupled with geographic, geological, technical, regulatory, operational and commercial challenges, significantly enhance the value of in-place storage capacity.

Significant Gas Storage Development Timeline

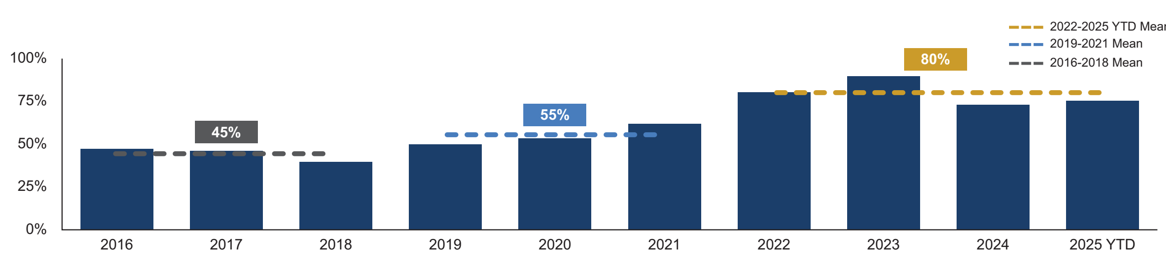


Source: Oil & Gas Journal.

Increasing volatility in natural gas prices

Natural gas price volatility has increased over the past five years due to a combination of factors including growing exposure to global natural gas markets, increasing penetration of intermittent renewables, additional extreme weather events and growing natural gas demand putting additional strain on constrained infrastructure. As these trends continue to evolve and natural gas volatility heightens, we expect the "insurance" value of natural gas storage (and associated demand) to continue to increase. See "Risk Factors — Risks Related to Our Business and Industry".

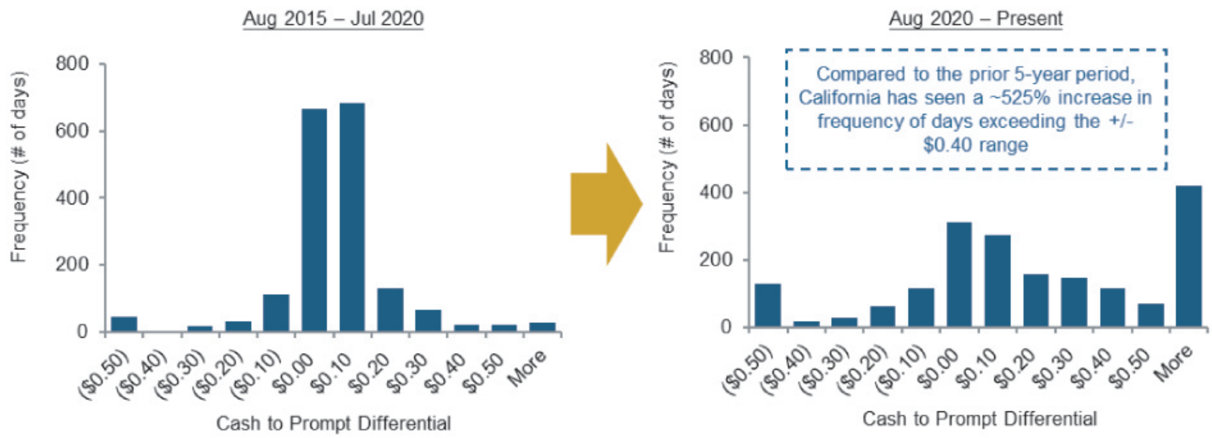
The chart below illustrates historical Henry Hub natural gas one-year average implied volatility since 2016:



Source: Bloomberg.

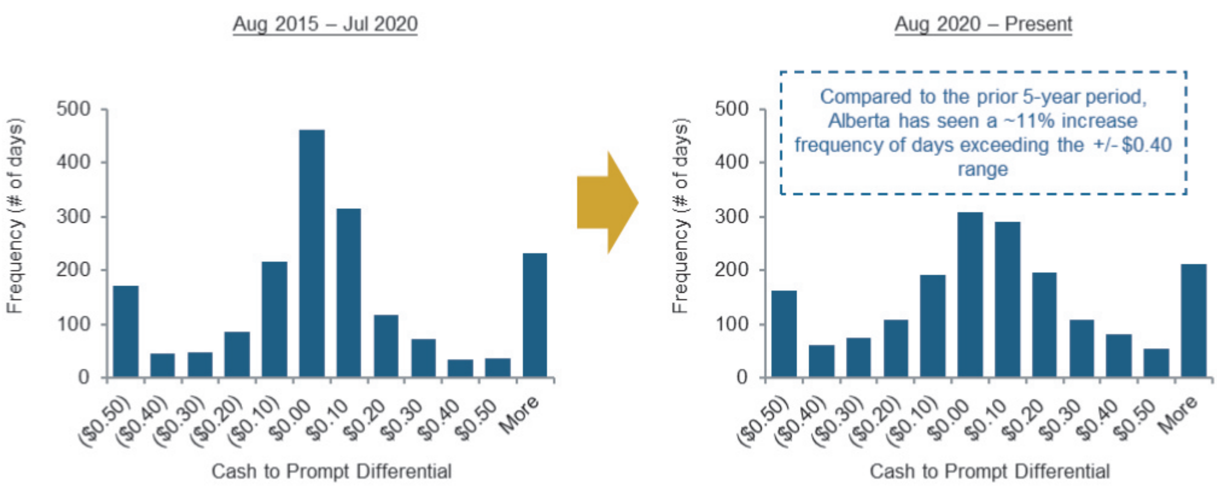
Over the last decade, California and Alberta have realized significantly higher frequency of price differentials. In the California market, the last five years have seen a 32% and approximately 525% increase in frequency of price differentials exceeding the +/-$0.10 and +/-$0.40 range, respectively. In the Alberta market, the last five years have seen a 13% and 11% increase in frequency of price differentials exceeding the +/-$0.10 and +/-$0.40 range, respectively. Wider and more frequent price fluctuations are expected to continue resulting in increased insurance value, driving recontracting demand.

The charts below illustrate historical cash to prompt differentials since 2015 in California:



Source: Intercontinental Exchange.

The charts below illustrate historical cash to prompt differentials since 2015 in Alberta:



Source: Intercontinental Exchange.

North American Gas Storage Market

The North American natural gas storage market is comprised of more than 400 storage facilities with working gas capacity of approximately 5.6 Tcf.[12] Our key markets include California and Alberta.

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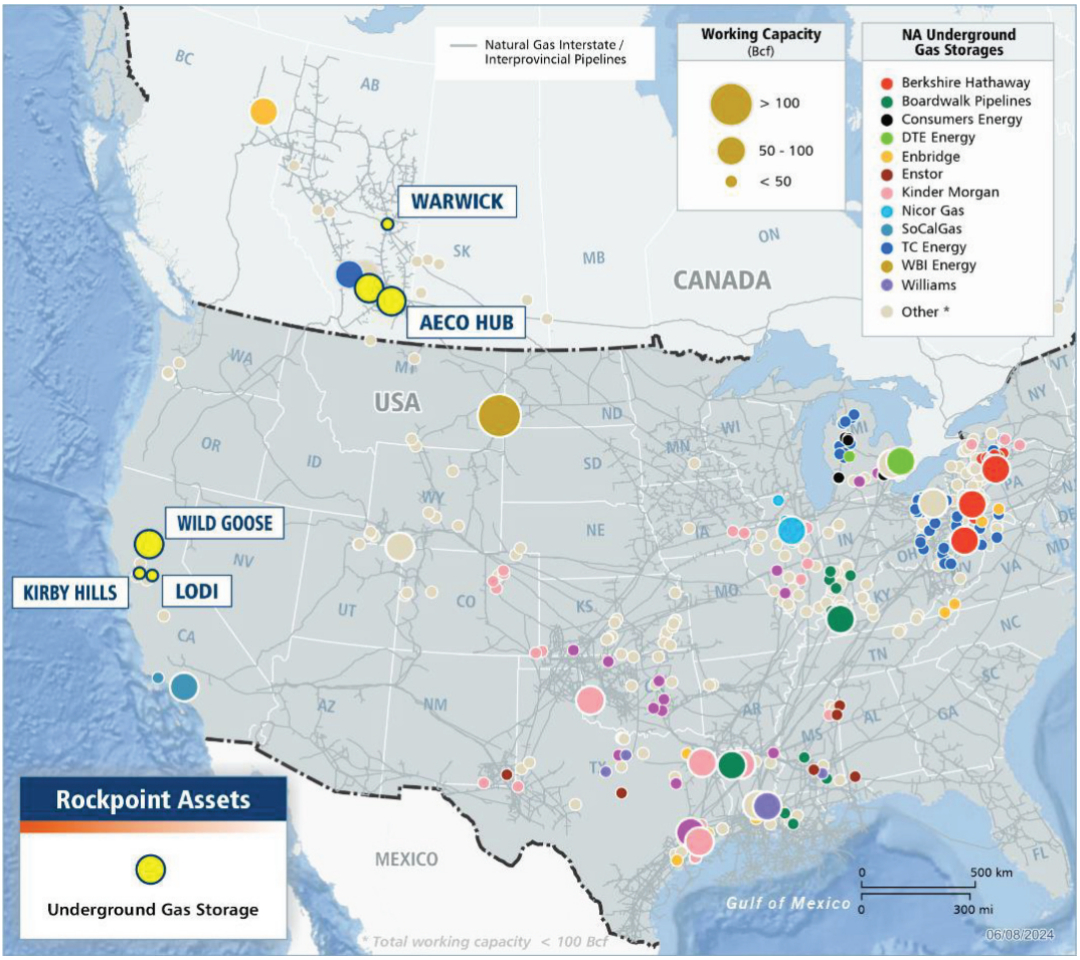
[12] *Sources: Statistics Canada; EIA; and SENER.*

The image below displays underground storage by company across North America:



Sources: geoSCOUT; and EIA.

California gas storage market dynamics

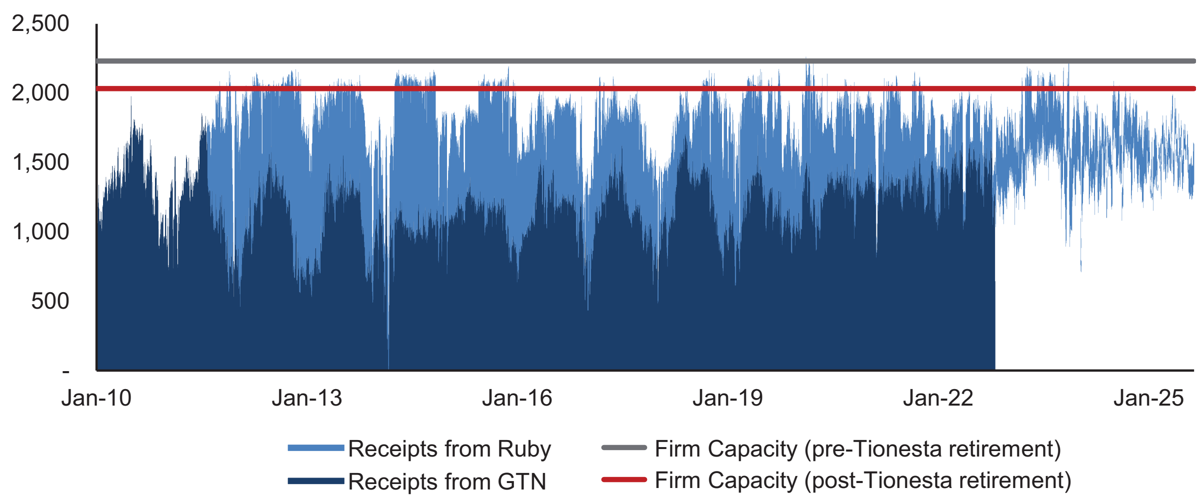
Natural gas storage remains vital to ensuring energy affordability and reliability in California, where the State's gas supply consistently falls short due to limited regional production, constrained pipeline access and regulatory hurdles for greenfield development. California's natural gas consumption deficit is approximately 5 Bcf/d and the natural gas storage market consists of 12 storage facilities with an effective working gas storage capacity of approximately 307 Bcf according to the EIA and management estimate (as of September 12, 2025). In addition to requiring natural gas as an energy source, natural gas storage assets are also needed to balance California's overall energy needs, especially given the State's significant existing and projected use of renewable energy sources. As energy output from renewable energy sources fluctuates, natural gas-fired energy generation is needed to manage that intermittency, ensuring reliable energy supply during periods when renewable output is low.

There is a heightened reliance on independent storage operators in northern California to provide essential storage solutions, ensure grid reliability and effectively manage price spikes and volatility in the market. PG&E sources natural gas supply through two pipelines, Redwood and Baja. California's constrained pipeline infrastructure and limited opportunity to expand its import capacity places increasingly higher reliance on existing gas storage infrastructure to meet demand. In May 2025, PG&E retired the Tionesta compressor station, reducing the monthly maximum Redwood path capacity by an average of approximately 207.5 MMcf/d. The Baja path puts PG&E in competition with the Southern California Gas Company's regional supply needs, which will be further constrained by growing demand from LNG exporters on the U.S. Gulf Coast and Mexico and Southwest markets. In addition, PG&E's working gas storage capacity reduction from 103 Bcf to 52 Bcf has impacted the regional supply dynamics in northern California. We expect the

State's gas balance to continue to remain in deficit, with minimal regional production and a heavy reliance on imports. With significant economic and regulatory barriers to greenfield development, existing natural gas storage facilities in northern California are positioned to serve utility and power demand and have participated in rising storage rates from constrained regional natural gas infrastructure and wide seasonal values. See "Risk Factors — Risks Related to Our Business and Industry" and "Risk Factors — Risks Related to Environmental, Public Utility Regulation and Other Regulations".

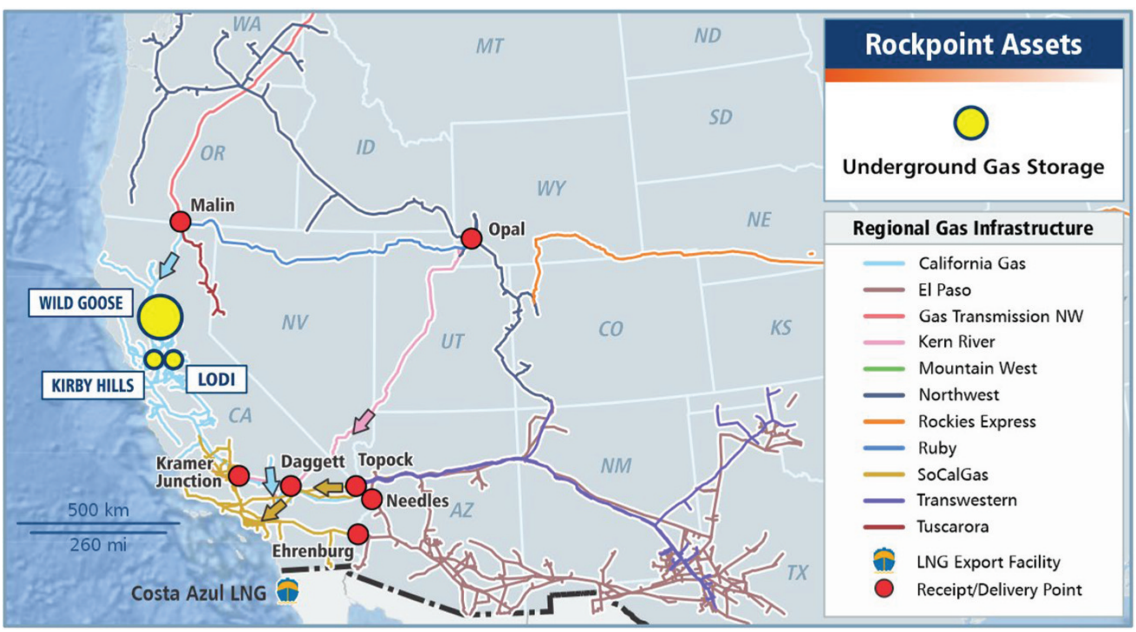
The image below displays California natural gas pipeline ingress:

Northern California Historical Receipts (MMcf/d)



Source: PG&E.

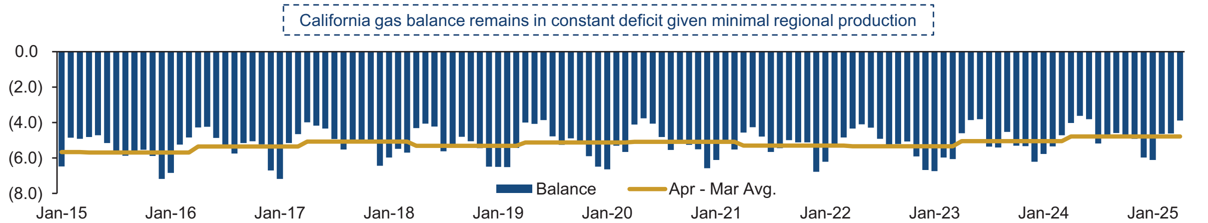
Critical Infrastructure in Constrained Region



Source: EIA.

The following chart illustrates the average daily balance by month between California's dry gas production and consumption:

California Gas Balance Remains in Significant Deficit (Bcf/d)[(1)]



Source: EIA.

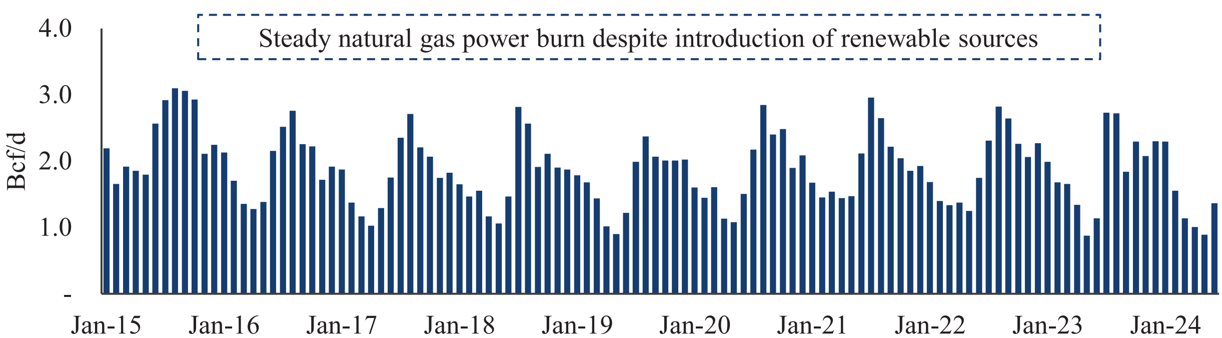
Note:

(1) Represents the average daily balance by month between California's dry production and consumption, a negative value implies a deficit position.

We expect the ongoing buildout of data centres alongside the reshoring of manufacturing to compel northern California to compete more aggressively for gas supply. According to S&P Platts, California currently ranks as the fourth largest data centre utility demand region in the U.S. with further buildout of data centres expected in the near-term. Natural gas has emerged as a critical resource in California, essential for maintaining energy affordability and reliability amid surging power costs. As the State increasingly turns to natural gas to support its grid, the competition for electricity is growing, making power less affordable for consumers. The dynamics of the California market highlight the growing reliance on natural gas to stabilize the energy grid, even as power costs continue to rise, underscoring the challenges of balancing energy demand with affordability.

The image below highlights natural gas consumption in the California power sector:

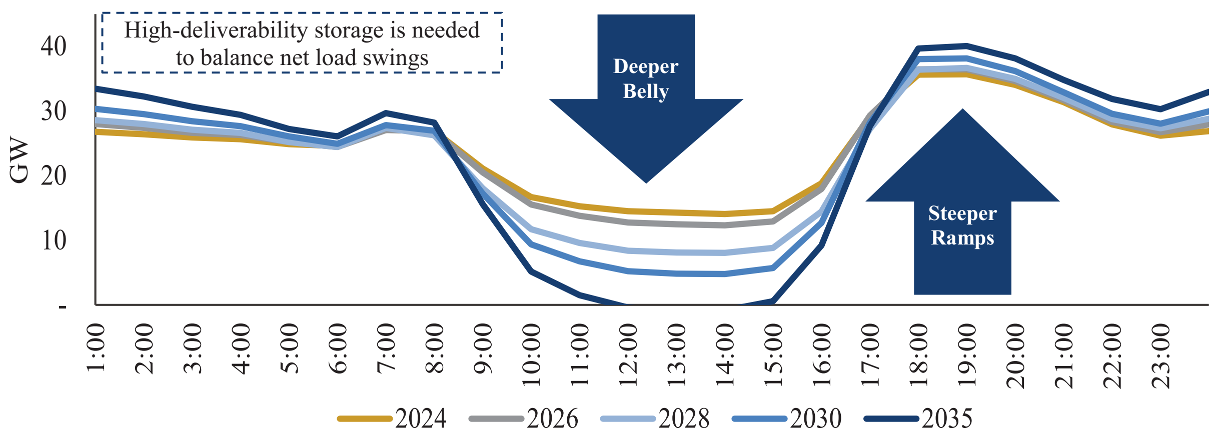
Steady Gas Burn in California Power Sector



Source: EIA.

In California, natural gas has proven to be a critical resource in supporting energy affordability and reliability, especially as the California Independent System Operator ("**CAISO**") increasingly integrates inherently intermittent renewable energy sources. For example, while solar power is California's flagship renewable energy source, the State is facing a growing issue of overproduction during midday hours when solar energy generation peaks, but demand is relatively low. In 2024 alone, California wasted over 2.6 million megawatt-hours of renewable energy (source: Rextag). This overproduction forces grid operators to curtail excess solar energy because of storage capacity limitations. Additionally, much of California's solar generation occurs in rural, sunny regions far from densely populated urban centres where demand is highest. Lack of sufficient transmission infrastructure makes it difficult to move this energy efficiently across the state. Natural gas-fired power generation provides the flexibility needed to manage load variability, helping to ensure stable and cost-effective energy for consumers. In northern California, the substantial presence of natural gas power generation, with approximately 6.7 GW of capacity across around 90 facilities, including 1.6 GW of peaking capacity, further amplifies the need for storage solutions. Given pipeline capacity into California is near full utilization, there is limited ability for the State to respond to increasing swings in power usage and, by extension, natural gas demand, due to increasing penetration of intermittent renewables. The chart below illustrates intra-day net load (load less wind and solar renewable output) forecast to 2035, whereby peak energy consumption during the day becomes increasingly more significant as it relates to renewable power supply. This highlights a need for high-deliverability storage to provide balance to net load swings. With scarce natural gas storage capacity and significant geographic, regulatory and interconnection barriers to entry, existing storage owners and operators may benefit from this structural demand shift. See "Risk Factors — Risks Related to Our Business and Industry" and "Risk Factors — Risks Related to Environmental, Public Utility Regulation and Other Regulations".

CAISO Net Load Forecast



Source: CAISO.

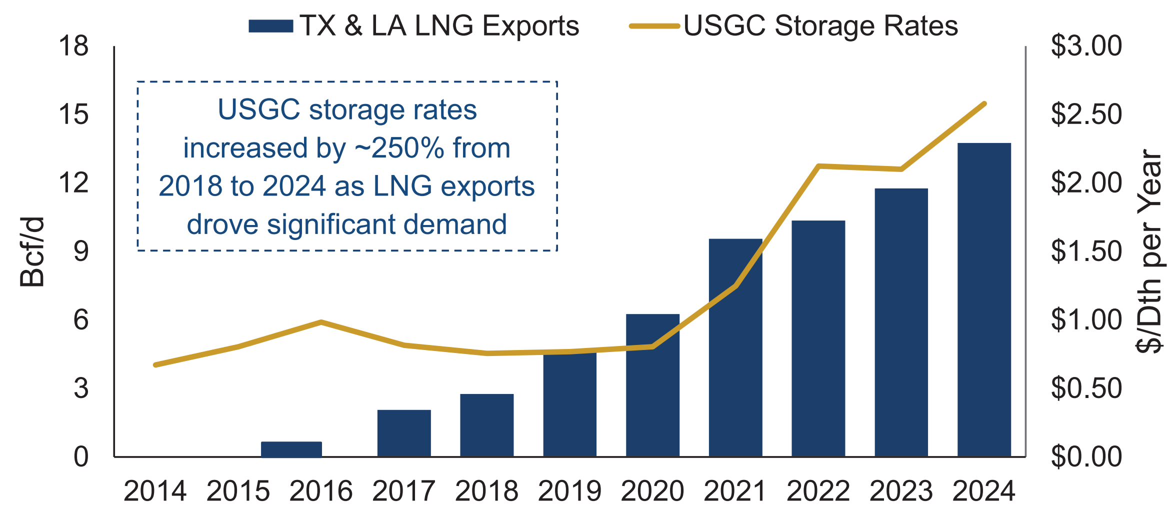
Alberta gas storage market dynamics

Alberta serves as a key hub for natural gas production and storage in Canada, benefitting from its vast natural gas reserves. The province has a total of ten storage facilities with an effective working gas storage capacity of approximately 470 Bcf according to the AER. Alberta's storage facilities are essential for managing supply and ensuring stable delivery to domestic and international export markets, particularly during peak demand periods. Storage infrastructure within the province includes large-scale facilities like the AECO Hub™, which is one of the most significant natural gas trading points in North America. Alberta's extensive pipeline network, including connections to TC Energy's NGTL System, enables seamless regional storage and transportation for producers. With the most liquid physical gas-trading market in North America, Alberta offers significant opportunities to capture value during market disruptions. Alberta's storage industry is a cornerstone of its energy strategy, providing essential flexibility and reliability amid evolving market conditions.

According to S&P Global Commodity Insights as of April 2025, western Canadian natural gas demand is approximately 19 Bcf/d, including pipeline exports. We expect the commissioning of western Canada LNG facilities to have a significant positive impact on regional natural gas markets which is anticipated to drive higher demand for large scale storage capacity with high injection and withdrawal capabilities. Western Canada's gas demand is projected to rise by approximately 26% by 2031, primarily driven by LNG development, oil sands expansion and electrification needs for data centre development. With British Columbia's limited natural gas storage infrastructure, Alberta's natural gas storage facilities are increasingly vital for managing demand fluctuations and ensuring stable supply. Connectivity from Alberta's storage facilities to pipeline systems such as the NGTL System provide producers with access to LNG terminals along the Canadian west coast, thus providing exposure to international export markets. In western Canada, more than 5.0 Bcf/d of LNG export capacity is expected to come online by 2031 according to S&P Global Commodity Insights (after adjusting expected demand, based on project status, from all currently proposed western Canadian LNG projects). We expect gas storage in western Canada to follow a similar trend to that seen in the U.S. Gulf Coast, where significant expansion of LNG exports over the past decade has resulted in a significant increase in natural gas storage rates, driven by higher seasonal value from exposure to international gas price spreads and enhanced insurance value to mitigate operational disruptions. As western Canadian LNG exports ramp up, the value of storage is expected to increase due to the tightening of gas storage markets and increased volatility in western Canada.

The following chart illustrates the impact of LNG exports on natural gas storage rates in the U.S. Gulf Coast over the past decade:

U.S. Gulf Coast Storage Rates[(1)] vs. LNG Exports



Source: Management estimate (as of September 12, 2025); EIA; and SENER.

Note:

(1) Based on moving average of recurring March storage option valuations.

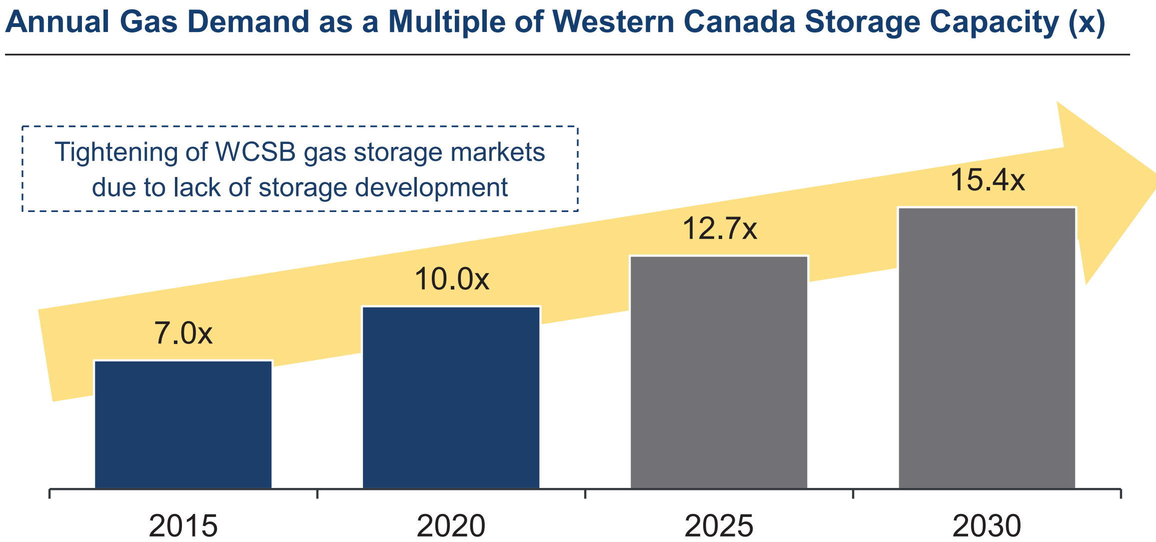
The following table lists the potential LNG export projects in western Canada:

Select Western Canada LNG Export Projects

Company	Export Capacity	FID Date	Capex	In-Service Date
1 LNG Canada Phase I	~1.8 Bcf/d	2018	C$48.3bn	2025
2 Woodfibre LNG	~0.3 Bcf/d	2022	$8.8bn	2026+
3 Cedar LNG	~0.4 Bcf/d	2024	$4.0bn	2027+
4 Fortis Inc. (Tilbury)	~0.3 Bcf/d	n/a	C$3.3bn	2028+
5 Ksi Lisims LNG	~1.6 Bcf/d	n/a	C$9.9bn	2030+
6 LNG Canada Phase II	~1.8 Bcf/d	n/a	TBD	2030+

Source: Respective third-party company public disclosure.

The following chart shows annual gas demand as a multiple of gas storage capacity in western Canada:



Source: Management estimate (as of September 12, 2025); and AER.

We expect Alberta's power demand to experience notable growth, driven by the expected build-out of data centres. Alberta's abundant supply of natural gas and its capacity to produce renewable energy provides scalable and reliable power supply for energy-intensive data centres. Alberta is a cost-effective location for data centre development as it has abundant and low-cost rural land capacity as well as the lowest corporate income tax rate in Canada. Furthermore, operating cost reductions are captured in Alberta through cooler climates offsetting the heat generated by facilities and abundant water resources allowing operators to utilize water-cooling technologies. Finally, Alberta boasts a deregulated, open, and competitive electricity market allowing developers to negotiate power purchase agreements with independent producers rather than relying on government-owned utilities and grid connectivity.

The current AESO electricity forecast does not yet fully account for the power upside from data centres. As of September 12, 2025, there were 29 data centres in the AESO queue, representing approximately 15 GW of potential aggregate power demand according to AESO. The increased deployment of wind and solar energy further complicates this growth, as these sources contribute to intra-day load swings due to their intermittent nature. To address unexpected demand periods and ensure grid reliability, backup from natural gas supply will be essential. As Alberta navigates these scenarios, the integration of data centres and the strategic use of natural gas will be crucial in managing the province's evolving energy needs and maintaining a stable power supply.

SELECTED HISTORICAL FINANCIAL INFORMATION

The following tables present selected historical financial information for the Business. We have prepared the Financial Statements of the Business in accordance with IFRS. Prospective investors should read this information together with the Financial Statements of the Business appearing elsewhere in this prospectus and the information under "Management's Discussion and Analysis". The following selected historical financial information of the Business is only a summary and is not necessarily indicative of the results of future operations of the Business following completion of the Transactions.

The information set forth below represents selected historical financial information for 100% of the Business. Upon completion of the Transactions, the Company will hold an approximate 40% interest in the Business.

The interim historical financial information for the Business has been derived from selected unaudited interim condensed combined consolidated statements of net earnings and comprehensive earnings data for the three months ended June 30, 2025 and 2024, and selected interim condensed combined consolidated statements of financial position data as at June 30, 2025 and March 31, 2025, from the Financial Statements of the Business appended to this prospectus.

	Three Months Ended June 30,	
(in millions, $)	**2025**	**2024**
Statement of Earnings and Comprehensive Earnings Information		
Revenues	**$104.1**	$91.7
Earnings before income taxes	**51.6**	47.9
Net earnings	**48.3**	45.6
Non-IFRS measures[1]		
Adjusted EBITDA	**$ 77.1**	$64.0
Adjusted Gross Margin	**95.9**	82.4
Distributable Cash Flow	**46.6**	49.7

	As at June 30,	As at March 31,
	2025	**2025**
Statement of Financial Position Information (at end of period):		
Property, plant, and equipment, net	**$ 886.5**	$ 884.6
Total assets	**1,294.2**	1,430.2
Long-term debt	**1,219.1**	1,208.1
Non-current financial liabilities	**1,241.2**	1,231.2

Note:

(1) Adjusted EBITDA, Adjusted Gross Margin and Distributable Cash Flow are non-IFRS financial measures. See "Notice to Investors — Non-IFRS Measures" and "Management's Discussion and Analysis — Non-IFRS Measures Utilized by Our Business" for more information on each non-IFRS financial measure.

In reviewing the above information, reference should be made to: (i) the Interim Financial Statements; and (ii) the sections entitled "Management's Discussion and Analysis" and "Risk Factors" of this prospectus.

The annual historical financial information for the Business has been derived from selected Combined Consolidated Statements of Net Earnings and Comprehensive Earnings data for the fiscal years ended March 31, 2025, March 31, 2024 and March 31, 2023, and selected Combined Consolidated Statements of Financial Position data as at March 31, 2025, and March 31, 2024, from the Financial Statements of the Business appended to this prospectus.

	Fiscal Years Ended March 31,		
(in millions, $)	**2025**	**2024**	**2023**
Statement of Earnings and Comprehensive Earnings Information			
Revenues	**$ 415.3**	$ 348.6	$278.0
Earnings before income taxes	**198.8**	249.3	47.1
Net earnings	**209.4**	253.9	44.5
Non-IFRS measures(1)			
Adjusted EBITDA	**$ 338.8**	$ 244.2	$152.6
Adjusted Gross Margin	**412.4**	318.7	229.1
Distributable Cash Flow	**234.5**	177.0	95.0
Statement of Financial Position Information (at end of period):			
Property, plant, and equipment, net	**$ 884.6**	$ 881.5	
Total assets	**1,430.2**	1,331.0	
Long-term debt	**1,208.1**	464.7	
Non-current financial liabilities	**1,231.2**	711.2	

Note:

(1) Adjusted EBITDA, Adjusted Gross Margin and Distributable Cash Flow are non-IFRS financial measures. See “Notice to Investors — Non-IFRS Measures” and “Management’s Discussion and Analysis — Non-IFRS Measures Utilized by Our Business” for more information on each non-IFRS financial measure.

In reviewing the above information, reference should be made to: (i) the Annual Financial Statements; and (ii) the sections entitled “Management’s Discussion and Analysis” and “Risk Factors” of this prospectus.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Introduction and Basis of Presentation

This Management's Discussion and Analysis ("**MD&A**") discusses the financial position of our Business as at June 30, 2025 and March 31, 2025 and 2024 and results of operations for the three months ended June 30, 2025 and 2024 as well as fiscal 2025, fiscal 2024 and fiscal 2023. The MD&A also presents pro forma financial information related to the Company as at June 30, 2025 and for the three months ended June 30, 2025 and the fiscal year ended March 31, 2025. Following completion of the Transactions, the Company will own an approximate 40% interest in our Business.

The information in this MD&A should be read in conjunction with the following Combined Consolidated Financial Statements included elsewhere in this prospectus: (i) the Annual Financial Statements; (ii) the Pro Forma Financial Statements; and (iii) the Interim Financial Statements.

All financial information contained herein, unless stated otherwise, has been prepared in accordance with IFRS, representing generally accepted accounting principles for publicly accountable enterprises in Canada, using the accounting policies described in Note 3 of the Annual Financial Statements. This MD&A is presented in millions of United States dollars unless otherwise noted.

The information set forth below represents selected historical financial information for 100% of the Business. Upon completion of the Transactions, the Company will hold an approximate 40% interest in the Business.

General

The Company was incorporated under the ABCA on July 28, 2025 and on that date issued one common share in the capital of the Company to Brookfield Infrastructure Holdings (Canada) Inc. for nominal consideration, which share was redesignated as a Class A Share concurrently with the amendment to the Articles on September 17, 2025.

Our Business

We are a natural gas storage operator with a portfolio consisting of six facilities located across California and Alberta with total effective working gas storage capacity of approximately 279.2 Bcf (as of September 12, 2025). We estimate that our total effective working gas storage capacity represents approximately one third of the combined storage market in Alberta and California (as of September 12, 2025). Our facilities are strategically located and are interconnected with several key natural gas pipelines to ensure long-term availability of supply and connectivity to quality customers and demand hubs. See "Our Business — Overview" and "Risk Factors".

Our history

Our Business was established in 2016, however, our asset portfolio has a 37-year operational history with the AECO Hub™ commencing operations in 1988. Our strategic development has been shaped by three key storage facility acquisitions which have defined our extensive operational footprint in North America. The acquisition of Warwick in 2012 marked our initial entry into the Alberta market providing a foundation for potential subsequent expansion. In 2014, the acquisition of Lodi established our presence in California, offering essential storage facilities integral to the region's energy infrastructure and acquisition of the AECO Hub™ and Wild Goose in 2016 firmly established our position as a leading independent owner and operator of natural gas storage infrastructure in North America. See "Our Business — Facility Overview".

Importance of natural gas storage

Natural gas storage infrastructure plays a crucial role in the natural gas value chain to ensure supply meets demand throughout the year. It bolsters production and delivery systems, providing a reliable supply during periods of high demand and enabling the injection of supplemental production during low demand or off-peak times. This process balances steady production with fluctuating daily, monthly, and seasonal consumption. When production exceeds demand, typically in summer, excess gas is stored; conversely, during winter, stored gas is withdrawn to meet increased demand. Natural gas storage acts as the critical balancing mechanism to manage supply disruption and maintain orderly markets. We define a gas market as being "tight" if demand exceeds available supply. According to industry sources such as the EIA, in the coming years, natural gas demand is expected to grow, driven primarily by: (i) the expansion of LNG exports; (ii) continued build out of gas-to-power infrastructure to support data centre growth and electrification broadly; and (iii) the need for flexible gas-fired power generation to support intermittent renewable energy sources. We believe that increased demand for natural gas will create a significant structural tightening in the North American market. North American natural gas demand in 2024 was approximately 123 Bcf/d, up from approximately 92 Bcf/d in 2016.[15] We expect this upward demand trend to continue, reaching an anticipated 144 Bcf/d by 2030 based on our assessment of LNG export and domestic consumption forecasts prepared by industry sources such as CER, EIA and SENER. A tighter gas market typically translates into increased natural gas price volatility and the potential for significant short term supply disruptions.

The North American natural gas storage market is comprised of more than 400 storage facilities with effective working gas capacity of approximately 5.6 Tcf.[16] We believe existing gas storage infrastructure will be critical to meet future structural changes in natural gas demand. There have been minimal additions to gas storage over the past decade with significant geographic, regulatory and interconnection barriers hindering new development. Assuming completion of all U.S. storage projects and expansions currently in development (and no other projects or expansions in North America being completed), we expect North American effective working gas storage capacity to be approximately 6.0 Tcf by 2030, which is virtually unchanged relative to capacity today. We believe this scarcity of capacity competitively positions current storage owners and operators, including us, to benefit from strong market fundamentals and upward pressure on storage rates. The value of natural gas storage services and associated storage rates are principally based on four components: (i) operational and location characteristics of the storage facility; (ii) seasonal value in natural gas prices; (iii) insurance value of storage, representing a premium the market allocates to mitigate gas pricing volatility; and (iv) demand factor. The relationship between these components in determining the value of storage is seasonal value plus the insurance value of storage plus the demand factor, where the operational characteristics of the facility (i.e., the ability to efficiently and reliably respond and the demand elasticity) can act as a multiplier on the seasonal value and insurance value components.

See "Industry Overview — The Natural Gas Value Chain — Natural Gas Storage", "Industry Overview — Value of Natural Gas Storage for Market Based Storage Services", "Industry Overview — Fundamental Industry Trends" and "Industry Overview — North American Gas Storage Market".

Outlook for our business

As global natural gas demand continues to grow, the role of gas storage in balancing supply and demand variations has become even more important. The lack of new gas storage development has created scarcity value for existing storage assets which has translated into higher storage rates for existing facilities. Our assets are strategically located within the North American natural gas logistics network, and we believe are well positioned to benefit from strong market fundamentals and structural drivers of demand including reindustrialization and energization of the North American grid, increasing reliance on intermittent renewables generation, and global gas pricing exposure through rising LNG exports. As a result, we expect to see significant growth from contract renewals in a rising rate environment further supported by new customer demand. Our appraisal of the foregoing factors has allowed us to implement a long-term annual Adjusted EBITDA growth target of 4% to 5%, which we expect to translate to a Distributable Cash Flow growth target of 5% to 6%. In addition, we believe that our growth outlook can be further enhanced by accretive capital projects as well as strategic optionality from various opportunities including but not limited to future acquisitions and portfolio and balance sheet optimization. Based on the foregoing, we are also targeting incremental annual Distributable Cash Flow growth of 4% to 5% over the long-term in the event that such growth projects and opportunities are consummated. See "Notice to Investors — Forward-Looking Information" for information regarding the material assumptions and risks relating to such growth targets.

[15] *Sources: Statistics Canada; EIA; and SENER.*

[16] *Sources: EIA; and Statistics Canada.*

In addition to our Adjusted EBITDA growth targets, in reliance on our assessment of the current position of our Business and market conditions as noted above, we plan to include a sustainable target dividend payout of 50% to 60% of the OpCos' Distributable Cash Flow in our financial policy.

See "Industry Overview — Fundamental Industry Trends", "Industry Overview — North American Gas Storage Market", "Our Business — Our Competitive Strengths — High free cash flow conversion supports reinvestment and return of capital", "Risk Factors — Risks Related to Our Business and Industry" and "Risk Factors — Risks Related to Our Financial Condition".

Financial Policy and Principles

We strive to adhere to a conservative financial policy, which we believe is essential in generating a stable and growing Distributable Cash Flow profile, maintaining a high rate of cash conversion, managing corporate liquidity and ensuring downside protection for our investors and stakeholders.

The key pillars of our financial principles are as follows:

- *Generate the vast majority of our cash flows from Fee for Service contracts*

  We target 85% Fee for Service cash flows with investment grade and highly credit worthy counterparties. We believe this is critical in providing cash flow stability as well as reducing the capital intensity of our operations. See "Dividend Policy".

- *Provide a balanced payout ratio to our shareholders*

  We are committed to delivering a 50-60% payout of our Distributable Cash Flow to our shareholders primarily generated from ToP cash flows. We expect Distributable Cash Flow to grow over time, both organically through recontracting and through the execution of our growth initiatives.

- *Maintain high levels of liquidity*

  As at June 30, 2025 our Business had $125.6 million of available liquidity, which was comprised of $20.3 million of available cash and cash equivalents, $105.3 million undrawn and available capacity on the ABL Facility and Warwick Credit Facility after $219.8 million in distributions to owners and advances extended to related parties were made in May of 2025. As at March 31, 2025, we had $316.8 million of available liquidity, which was primarily comprised of cash and cash equivalents along with available capacity on our credit facilities. Our Business has few non-discretionary capital requirements and thus our available liquidity is reserved to reinvest into growth initiatives intended to enhance our storage service offerings, fund working capital, provide our shareholders a stable and growing dividend and to opportunistically repurchase shares when we believe there is a disconnect between our intrinsic value and market valuation.

- *Conservative capitalization of our balance sheet*

  We maintain a prudent level of long-term capitalization through our Term Loan due 2031, which can be prepaid at par without penalty. This provides us with the flexibility to adjust our capitalization in response to changing financial conditions, if required.

  In addition, we target leverage at, or below, 3.5x of Net Debt to Adjusted EBITDA over the near-term, which we believe is appropriate for our existing business model. The Business is currently rated as 'BB' with a 'Stable' outlook by S&P and 'B1' with a 'Stable' outlook by Moody's.

Notable Transactions

Refinancing & Capitalization Changes

On August 29, 2024 and September 18, 2024, we undertook changes to our capitalization structure as outlined below to optimize our available liquidity and to fund a distribution to our shareholders, Brookfield.

On August 29, 2024, we amended the ABL Facility, which is comprised of a U.S. revolving credit facility and a Canadian revolving facility, to extend the maturity date from August 17, 2026, to August 29, 2029 (or, if earlier, a springing maturity date 91 days prior to the maturity of the Term Loan due 2031). In addition, the amendment improved the availability of the ABL Facility by expanding the borrowing base calculation to include a portion of amounts that will contractually become receivable up to four months forward.

On September 18, 2024, we completed the issuance of the $1,250.0 million Term Loan due 2031, to fully repay the then existing $450.0 million Term Loan due 2026 and all remaining outstanding Brookfield-affiliated debt, including accrued interest, in the amount of $233.5 million. The remaining proceeds were used to fund a $455.2 million distribution to Brookfield, an advance of $83.0 million to Brookfield as well as transaction fees related to the refinancing. The Term Loan due 2031 initially bore a floating interest rate equal to SOFR plus 3.5%, which we subsequently repriced to SOFR plus 3.0% on March 19, 2025. We fully hedged our interest rate exposure under the Term Loan due 2031 to a fixed rate of 6.7% until September 2025. The swaps stepped down to $900.0 million of hedged exposure in October 2025 until September 2026. Thereafter, the full principal balance is unhedged, which will expose us to interest rate fluctuations unless the debt is re-hedged.

The Sale of Salt Plains and Tres Holdings

On April 1, 2023, we completed the sale of the Salt Plains storage facility in Oklahoma, which had 13 Bcf of working gas capacity for net proceeds of $35.2 million, after adjustments for working capital, and other like items, and deducting transaction costs.

On April 3, 2023, we completed the sale of our 49.99% equity investment in Tres Holdings, which is a Texas-based company operating a gas storage facility with 34 Bcf of working gas capacity, for net proceeds of $175.4 million, after adjustments for working capital, and other like items, and deducting transaction costs.

Financial Operations Overview

Our Commercial Model

Our commercial model is designed to be flexible and create mutually beneficial outcomes for us and our customers. Our revenue is categorized as either Fee for Service or optimization. Fee for Service includes both long-term ToP contracts and recurring STS contracts. We also maintain a portion of our effective working gas capacity to capture value through optimization activities undertaken with internally owned gas. Our storage capacity is initially reserved to service ToP customer contracts. This ToP reserve reflects the expected seasonal build of our ToP customers' summer injection and winter withdrawal as a portion of total working gas capacity. STS contracts are then leveraged to primarily fill gaps left by the ToP reserve cycle. The remaining small portion of storage capacity is then utilized by Rockpoint for optimization activities. The storage capacity for optimization varies depending on actual ToP customer injection and withdrawal observed throughout the year.

We have prudent risk management policies in place and do not carry open commodity price risk in any of our revenue segments. Our allocation between ToP, STS, and optimization strategies is designed to maximize the economic value of our storage capacity while maintaining operational flexibility. Our long-term target is to achieve 60% of Adjusted Gross Margin from ToP contracts, 25% of Adjusted Gross Margin from STS contracts, and 15% Adjusted Gross Margin from optimization strategies. In California, our facilities are operating at or near our long-term contracting targets. In Alberta, we continue to experience growth in contracted ToP volumes and storage rates as new customers enter the market. See "Risk Factors — Risks Related to Our Business and Industry".

Fee for Service Revenue

Fee for Service revenue consists of longer-term ToP contracts (typically ranging from one to ten years) and STS contracts (typically spanning up to one storage season with a strong history of contract renewals). Our Fee for Service revenue is underpinned by a diverse and high-quality customer base that stores customer-owned gas volumes in our storage facilities. Our strong performance not only reflects the resilience and attractiveness of our commercial model but also reinforces our strategic positioning in the market, enabling predictable cash flows and long-term value creation. Our strong performance not only reflects the resilience and attractiveness of our commercial model but also reinforces our strategic positioning in the market, enabling predictable cash flows and long-term value creation.

Under ToP contracts our customers are obligated to pay a fixed monthly demand charge for storage capacity regardless of utilization. Customers have the right, but not the obligation, to inject, store or withdraw a predetermined amount of gas as specified in each contract. We receive the monthly demand charge regardless of the actual capacity utilized by our customers. When customers utilize reserved capacity under these contracts, we receive additional variable fees based on the actual volumes of natural gas injected or withdrawn. These variable fee payments help us recover operating costs. ToP contracts accounted for approximately 45% of total fiscal 2025 Adjusted Gross Margin and have a 3.5-year weighted average contract life. The ToP contracts accounted for approximately 70% of fiscal 2025 Adjusted Gross Margin in California and approximately 12% of fiscal 2025 Adjusted Gross Margin in Alberta. The ToP contracts currently have a weighted average tenor of approximately 3.6 years in California and approximately 2.9 years in Alberta. In fiscal 2025, we executed 25 new ToP contracts contributing a cumulative $499 million of future contracted revenue with weighted average contract terms of approximately five years in California and three years in Alberta.

In California, our ToP contracting has increased from 49% of our California facilities' total effective working gas storage capacity in fiscal 2023 to 69% in fiscal 2025. Over the same period, our ToP contracted demand charges in California have increased from $1.02/Dth earned in fiscal 2023 to $2.30/Dth in fiscal 2025. This has resulted in an increase in California ToP Adjusted Gross Margin from $59.9 million in fiscal 2023 to $163.3 million in fiscal 2025. This upward trend reflects the transition of our contract portfolio as lower priced legacy contracts have rolled off in favour of multi-year higher-priced market rate contracts. For example, our ToP contracts in California have an average ToP demand charge of $2.87/Dth in fiscal 2026, representing an approximately 25% increase over the realized average ToP demand charge in fiscal 2025. We expect California ToP demand charge to increase due to a tighter storage market and strong customer demand for long-term security of gas supply.

In Alberta, our ToP contracting capacity has doubled from 7% of our Alberta facilities' total effective working gas storage capacity in fiscal 2023 to 15% in fiscal 2025. Over the same period, our ToP contracted demand charges in Alberta have increased from $0.42/Dth earned in fiscal 2023 to $0.75/Dth earned in fiscal 2025. This has resulted in an increase in Alberta ToP Adjusted Gross Margin from $6.2 million in fiscal 2023 to $21.7 million in fiscal 2025. We expect our Alberta ToP contracted gas storage volumes and contracted demand charges to increase as additional west coast LNG projects enter into service. Our ToP contracts in Alberta have an average ToP demand charge of $0.94/Dth in fiscal 2026, representing an approximately 26% increase over the realized ToP average demand charges in fiscal 2025.

We believe these developments in the gas storage market and customer demand position us to capitalize on emerging market dynamics and reinforce the strategic importance of our Alberta storage assets in supporting Canada's evolving energy structure.

ToP contracts are typically negotiated and executed with counterparties in the fall and winter for storage service commencing the following fiscal year and beyond. This contracting timeline is required to allow customers to be able to prepare for and utilize the full summer season (April 1st to October 31st) to inject their gas into our facilities prior to the start of the winter withdrawal season (November 1st to March 31st).

Under STS contracts, our customers pay a fixed fee to inject and withdraw specified quantities of natural gas which are typically recognized as revenue (50% paid on injection and 50% paid on withdrawal). Unlike ToP contracts, STS contracts require customers to inject and withdraw specified quantities on specified, predetermined dates. STS contracts enable us to secure value by capturing the seasonal value of the price difference between summer and winter months net of the customer's required return on the transaction. Because STS contracts specify predetermined injection and withdrawal volumes at predetermined times, it also allows us to opportunistically enter into offsetting transactions to capture incremental storage value as spot and future natural gas spreads fluctuate prior to the original transaction's specified withdrawal date. A typical example of an STS contract is when a customer enters a contract with us to inject gas at a consistent daily rate in the summer months, when gas prices are lower, and to withdraw the same amount at a consistent daily rate in the winter months, when prices are higher. In fiscal 2025, our STS contracts made up approximately 41% of total Adjusted Gross Margin across the portfolio.

STS is an important component of our Fee for Service strategy, providing a base fee and also allowing us to retain upside from additional contract layering throughout the year. While STS gross margin is primarily transacted within each fiscal year, our STS gross margin has continually increased each year. Since fiscal 2023, our STS contracted rates have increased by 59% in California and 134% in Alberta, reflecting strong storage fundamentals in each respective market.

As of March 31, 2025, we had approximately $893 million in contracted Fee for Service revenue backlog which includes both ToP and STS contracts. In fiscal 2025, 86% of our Adjusted Gross Margin was contracted on a Fee for Service basis, surpassing our target of 85%. ToP contracts accounted for approximately 45% of fiscal 2025 Adjusted Gross Margin while STS contracts made up approximately 41% of fiscal 2025 Adjusted Gross Margin.

See "Risk Factors — Risks Related to Our Business and Industry".

Optimization Revenue

We manage a small portion of our storage capacity through a storage optimization strategy which is intended to provide us the flexibility to first manage our firm fee for service customer obligations if needed and then capture market opportunities as they arise. Storage optimization involves purchasing, storing and selling natural gas for our own account using our own corporate liquidity for profit. In line with our internal risk policy, we do not take open positions that expose us to price or physical delivery risk. Instead, we aim to eliminate market price risks by matching inventory purchases with physical and financial contracts effectively locking in margins at the time of injection. As a result, our activities remain non-speculative, operating strictly within defined operational risk tolerances. Our storage optimization strategy has proven to be valuable in allowing us to capture seasonal spread value and subsequently generate incremental gross margin.

We also provide natural gas marketing and transportation services in Canada through AGS which is included in our optimization activities. In fiscal 2025, our total optimization activities made up approximately 14% of total Adjusted Gross Margin.

Principal Components of Our Cost Structure

Operating Expenses

Our operating expenses include components that are largely fixed in nature and those that are variable. The largely fixed components of our operating expenses include salaries and labor, parts and supplies, and other general operating costs. These operating expenses are relatively stable from year to year but can vary within a narrow range due to factors such as inflation and heavy facility usage.

The largest components of our variable operating costs are the costs of natural gas and electricity used to power our compressors. These items are affected by the amount and price of energy used to inject and withdraw natural gas from our facilities and by the frequency and timing of gas injections and withdrawals. For example, if we experience large injections of natural gas in the early summer (instead of a steady rate of injections throughout the summer), we will have higher costs in our first quarter and lower costs in the second quarter. A mild winter could lead to fewer withdrawals in total, and therefore lower overall fuel and power costs due to fewer injections required to fill our storage facilities the following summer. Fuel and utilities cost savings can be realized when simultaneous injections and withdrawals occur. This dynamic requires no physical gas flow in or out of the facility which allows us to reduce the usage of our compressors. Variable operating expenses are partially offset by the variable fees we collect from our ToP customers.

We also have variable costs that are driven by our revenues. Land lease agreements with certain landowners in California increase or decrease as a direct result of changes in revenues generated. Certain property tax related facility valuations include income-based components. As our revenues drive the largest component of our income, our property taxes are likewise influenced. There can be time lags in changes in property taxes as property value assessments may not line up with the same period in which revenues were generated.

General and Administrative

Our general and administrative expenses primarily consist of employee and contractor compensation, professional fees, and other general costs.

Results of Operations and Financial Results

The Pro Forma Financial Information of Rockpoint Gas Storage Inc.

The following section contains a discussion of the pro forma results of operations and financial position of the Company for the periods indicated and should be read in conjunction with the Pro Forma Financial Statements appended to this prospectus. The Company was incorporated by Brookfield as part of its plan to conduct the Offering and distribute a portion of our Business to public shareholders. Following completion of the Transactions, the Company's assets and operations will consist of its approximate 40% interest in our Business. The pro forma financial information of the Company described below may not be indicative of future results. See "Risk Factors".

	As at June 30, 2025	
(in millions, $)	**Historical**	**Adjusted**
Asset		
Cash and cash equivalents	$ —	$ —
Investments in our Business	—	838.8
Total assets	$ —	$838.8
Total liabilities and equity	$ —	$838.8

The Company's pro forma financial position as at June 30, 2025 gives effect to the Transactions as if they had been consummated on June 30, 2025 and is comprised of a $838.8 million investment in our Business, which represents an approximate 40% ownership interest.

	Three Months Ended June 30, 2025	
(in millions, $)	**Historical**	**Adjusted**
Share of income of our Business	$ —	$11.3
Income tax (expense) benefit	—	—
Net earnings	$ —	$11.3

The Company's pro forma statement of income for the three months ended June 30, 2025 gives effect to the Transactions as if they had been consummated on April 1, 2024 and presents net earnings of $11.3 million. Net earnings consists of the Company's equity interest in the earnings of our Business.

Interim Condensed Combined Consolidated Financial Results of our Business

The following table sets forth our results of operations for the periods presented:

	Three Months Ended June 30,	
(in millions, $)	**2025**	**2024**
Revenues		
Fee for Service revenue	**$ 92.2**	$89.6
Optimization, net	**11.9**	2.1
Total revenues	**104.1**	91.7
Expenses (income)		
Cost of gas storage services	**1.2**	1.5
Operating	**12.7**	11.9
General and administrative	**5.5**	6.5
Depreciation and amortization	**8.1**	7.9
Financing costs	**25.6**	15.8
Gains on gas storage obligation, net	**(1.6)**	(0.9)
Other expenses	**1.0**	1.1
Earnings before income taxes	**51.6**	47.9
Income tax expense, net	**3.3**	2.3
Net earnings	**$ 48.3**	$45.6

Comparison for the Three Months Ended June 30, 2025 and 2024

Fee for Service revenue

(in millions, $)	Three Months Ended June 30, 2025	2024
Fee for Service revenue	**$92.2**	$89.6
ToP revenue	**58.5**	46.2
STS revenue	**33.7**	43.4

Total revenue includes Fee for Service and optimization, net. For the three months ended June 30, 2025, Fee for Service revenue was approximately 89% of total revenue, while the remaining 11% of revenue was derived from our optimization strategies. Total revenue for the three months ended June 30, 2025 was $104.1 million, compared to $91.7 million for the three months ended June 30, 2024.

Fee for Service revenue consists of revenues from ToP contracts where our customers pay a fixed monthly demand charge and STS service contracts where our customers pay a fixed fee to inject and withdraw a specified quantity of gas at a set date or over a period of time. Fee for Service revenue increased by $2.6 million, or 3%, for the three months ended June 30, 2025 compared to the three months ended June 30, 2024 due to the changes in ToP and STS revenues as described below.

ToP revenues increased compared to the prior year quarter due to higher fees per unit of storage capacity contracted and higher contracted capacity. Weighted average ToP contract fees were approximately $2.32 per Dth for the three months ended June 30, 2025, a 25% increase compared to $1.86 per Dth for the three months ended June 30, 2024. Effective working gas capacity allocated to ToP contracts increased by 1% to 97.4 MMDth.

The decrease in STS revenue was primarily driven by realizing wider seasonal spreads in the three months ended June 30, 2024, mainly across our Alberta-based facilities. A relatively warm winter preceding the start of the June 30, 2024 ended quarter caused a decrease in summer prices, while winter prices remained elevated. Storage conditions for STS in California remained relatively consistent between the three months ended June 30, 2025 and 2024.

Optimization, net

(in millions, $)	Three Months Ended June 30, 2025	2024
Optimization, net	**$11.9**	$ 2.1
Realized optimization, net	**4.8**	(5.7)
Unrealized optimization gains, net	**7.1**	7.8

Realized optimization, net is generated from the purchase of natural gas inventory and its forward sale to future periods through financial energy trading contracts. Our facilities are used to store the inventory between the purchase and physical sale of the natural gas. When evaluating the performance of our optimization business, we focus on our realized optimization margins, including the impact of inventory adjustments, if any, but excluding the impact of unrealized economic hedging gains and losses. For financial reporting purposes, our revenue includes the impact of unrealized economic hedging gains and losses which cause our reported optimization, net to fluctuate from period to period.

Realized optimization, net increased by $10.5 million for the three months ended June 30, 2025, due to greater contributions from both our Wild Goose and AECO facilities. During the three months ended June 30, 2024 we recognized an accounting loss on our realized optimization, net revenue stream. This loss was the result of timing differences in the recognition of financial hedging gains, which were recognized before the start of the prior comparative period, while offsetting physical gas costs were recognized during that period.

Expenses

(in millions, $)	Three Months Ended June 30, 2025	2024
Cost of gas storage services	**$ 1.2**	$ 1.5
Operating	**12.7**	11.9
General and administrative	**5.5**	6.5
Depreciation and amortization	**8.1**	7.9
Financing costs	**25.6**	15.8
Gains on gas storage obligation, net	**(1.6)**	(0.9)
Other expenses	**1.0**	1.1

Cost of gas storage services was $1.2 million for the three months ended June 30, 2025, materially consistent with the prior comparative period.

Operating expenses increased by $0.8 million, or 7%, for the three months ended June 30, 2025 compared to the three months ended June 30, 2024. The increase was mainly attributed to increases in land rental costs and property taxes driven primarily by higher revenues.

General and administrative expenses decreased by $1.0 million or 15% primarily due to reductions in incentive compensation costs.

Depreciation and amortization expense increased by $0.2 million or 3% due to the depreciation of the previous capital expenditure related to expanding the capacity of the Wild Goose facility.

Financing costs increased by $9.8 million, or 62%, for the three months ended June 30, 2025 compared to the three months ended June 30, 2024 primarily as a result of higher total debt outstanding following the $1,250.0 million Term Loan due 2031 issued in September 2024, which was partially used to repay the $450.0 million Term Loan due 2026.

Other expenses were materially consistent between the three months ended June 30, 2025 and the three months ended June 30, 2024.

Income tax expense, net

(in millions, $)	Three Months Ended June 30, 2025	2024
Income tax expense	**$3.3**	$2.3

Income tax expense increased by $1.0 million, or 43%, for the three months ended June 30, 2025 compared to the three months ended June 30, 2024. The change was primarily due to higher earnings in Canadian entities in the current period.

Annual Combined Consolidated Financial Results of our Business

Comparison of Fiscal Years Ended March 31, 2025, 2024 and 2023

The following table sets forth our results of operations for the periods presented:

	Fiscal Years Ended March 31,		
(in millions, $)	**2025**	**2024**	**2023**
Revenues			
Fee for Service revenue	**$366.8**	$ 292.5	$195.8
Optimization, net	**48.5**	56.1	82.2
Total revenues	**415.3**	348.6	278.0
Expenses (income)			
Cost of gas storage services	**11.0**	21.2	38.3
Operating	**49.5**	53.2	56.5
General and administrative	**24.2**	23.5	22.2
Depreciation and amortization	**33.1**	34.0	34.5
Financing costs	**93.1**	76.0	68.7
Equity in net earnings of equity accounted investee	**—**	—	(3.9)
Gain on disposals of subsidiary and equity accounted investee	**—**	(114.7)	—
Asset impairment	**—**	—	11.3
(Gains) losses on gas storage obligation, net	**(1.3)**	(1.8)	0.6
Other expenses	**6.9**	7.9	2.7
Earnings before income taxes	**198.8**	249.3	47.1
Income tax (benefit) expense, net	**(10.6)**	(4.6)	2.6
Net earnings	**$209.4**	$ 253.9	$ 44.5

Fee for Service revenue

	Fiscal Years Ended March 31,		
(in millions, $)	**2025**	**2024**	**2023**
Fee for Service revenue	**$366.8**	$292.5	$195.8
ToP revenue	**185.0**	155.3	66.1
STS revenue	**181.8**	137.2	129.7

Comparison of Fiscal Years Ended March 31, 2025 and 2024

Total revenue includes Fee for Service and optimization, net. In fiscal 2025, Fee for Service revenue was approximately 88% of total revenue, while the remaining 12% of revenue was derived from our optimization strategies. Total revenue in fiscal 2025 was $415.3 million, compared to $348.6 million in fiscal 2024.

Fee for Service revenue increased by $74.3 million, or 25%, in fiscal 2025 compared to fiscal 2024 due to the changes in ToP and STS that are discussed below.

ToP revenues increased year-over-year due to higher fees per unit of storage capacity contracted and higher contracted capacity. Weighted average ToP contract fees were approximately $1.93 per Dth in fiscal 2025, a 17% increase compared to $1.66 per Dth in fiscal 2024. Effective working gas capacity allocated to ToP contracts increased by 1% to 96.1 MMDth. The increase in revenue from higher contracted capacity and fees were partially offset by a decline in pass through fuel and commodity costs received from our ToP customers.

The increase in STS revenue was primarily driven by realizing wider seasonal spreads primarily across our Alberta-based facilities. In particular, fiscal 2025 summer prices were lower due to higher levels of gas in storage while winter prices remained elevated. This increase in Alberta STS revenue was partially offset by a decline in STS revenue at our California-based facilities due to a moderate reduction in natural gas price volatility.

Comparison of Fiscal Years Ended March 31, 2024 and 2023

Total revenue for fiscal 2024 was $348.6 million, compared to $278.0 million in fiscal 2023. The increase was driven by a 49% increase in Fee for Service revenue as a result of higher demand charges and a shift in effective working gas capacity allocation to higher rate ToP contracts, which was partially offset by a decline in optimization revenue.

Fee for Service revenue increased by $96.7 million, or 49%, in fiscal 2024 compared to fiscal 2023. ToP revenues increased year-over-year due to higher fees per storage volume contracted of approximately $1.66 per Dth in fiscal 2024, compared to $1.07 per Dth in fiscal 2023, and higher volumes contracted.

The increase in STS revenue was primarily driven by our Alberta-based facilities as a result of a decrease in natural gas production, which enabled us and our customers to take advantage of summer price volatility. Increased Alberta STS revenue was partially offset by a decline in revenue at our California-based facilities due to an increase in capacity of ToP contracts, leading to fewer STS contract opportunities.

Optimization, net

	Fiscal Years Ended March 31,		
(in millions, $)	**2025**	**2024**	**2023**
Optimization, net	**$48.5**	$56.1	$82.2
Realized optimization, net	**56.6**	49.8	67.7
Unrealized optimization (losses) gains, net	**(8.1)**	6.3	14.5

Realized optimization, net is generated from the purchase of natural gas inventory and its forward sale to future periods through financial energy trading contracts. Our facilities are used to store the inventory between the purchase and physical sale of the natural gas. When evaluating the performance of our optimization business, we focus on our realized optimization margins, including the impact of inventory adjustments, if any, but excluding the impact of unrealized economic hedging gains and losses. For financial reporting purposes, our revenue includes the impact of unrealized economic hedging gains and losses which cause our reported optimization, net to fluctuate from period to period.

Comparison of Fiscal Years Ended March 31, 2025 and 2024

Realized optimization, net increased by $6.8 million, or 14%, primarily due to greater contributions from our Wild Goose facility.

Comparison of Fiscal Years Ended March 31, 2024 and 2023

Realized optimization, net decreased by $17.9 million, or 26%, primarily due to operations at our California-based facilities, partially offset by strong contributions from our Alberta-based facilities.

Expenses

(in millions, $)	Fiscal Years Ended March 31, 2025	2024	2023
Cost of gas storage services	**$11.0**	$ 21.2	$38.3
Operating	**49.5**	53.2	56.5
General and administrative	**24.2**	23.5	22.2
Depreciation and amortization	**33.1**	34.0	34.5
Financing costs	**93.1**	76.0	68.7
Equity in net earnings of equity accounted investee	**—**	—	(3.9)
Gain on disposals of subsidiary and equity accounted investee	**—**	(114.7)	—
Asset impairment	**—**	—	11.3
(Gains) losses on gas storage obligation, net	**(1.3)**	(1.8)	0.6
Other expenses	**6.9**	7.9	2.7

Comparison of Fiscal Years Ended March 31, 2025 and 2024

Cost of gas storage services decreased by $10.2 million, or 48%, in fiscal 2025 compared to fiscal 2024 due to changes in natural gas market prices resulting in lower costs of procuring pressure support gas for injection and withdrawal processes.

Operating expenses decreased by $3.7 million, or 7%, in fiscal 2025 compared to fiscal 2024. The decrease was mainly attributed to lower fuel and electricity costs as a result of lower natural gas prices and less compression and injection activity required to refill storage levels in fiscal 2025. A higher drawdown of natural gas in storage at the beginning of fiscal 2024 resulted in our Business consuming larger amounts of natural gas and electricity in order to inject and refill storage levels. The aforementioned benefit was partially offset by higher property taxes and higher variable lease costs.

General and administrative expense was relatively consistent between fiscal 2025 and fiscal 2024.

Depreciation and amortization expense was $33.1 million in fiscal 2025, materially consistent with fiscal 2024.

Financing costs increased by $17.1 million, or 23%, in fiscal 2025 compared to fiscal 2024 primarily as a result of higher total debt outstanding following the $1,250.0 million Term Loan due in 2031 issued in September 2024 to replace the $450.0 million Term Loan due 2026.

The results in fiscal 2024 included a $114.7 million net gain from the sale of our investments in Tres Holdings and the Salt Plains facility.

Other expenses decreased by $1.0 million, or 13%, in fiscal 2025 compared to fiscal 2024, primarily due to a one-time severance expense paid to a former executive in fiscal 2024.

Comparison of Fiscal Years Ended March 31, 2024 and 2023

Cost of gas storage services decreased by $17.1 million, or 45%, in fiscal 2024 compared to fiscal 2023 due to changes in natural gas market prices resulting in lower costs of procuring pressure support for injection and withdrawal processes. Fiscal 2023 was impacted by the inclusion of cost of gas storage services at the Salt Plains facility.

Operating expense decreased by $3.3 million, or 6%, in fiscal 2024 compared to fiscal 2023. The decrease was mainly attributed to lower fuel and electricity costs as a result of lower natural gas prices and the sale of the Salt Plains facility.

General and administrative expense was $23.5 million in fiscal 2024, materially in line with fiscal 2023.

Depreciation and amortization expense was $34.0 million in fiscal 2024, materially consistent with fiscal 2023.

Financing costs increased by $7.3 million, or 11%, in fiscal 2024 compared to fiscal 2023 due to higher interest on term loans as a result of a higher average outstanding principal, partially offset by lower interest on our revolving credit facilities.

Equity in net earnings of equity accounted investee decreased in fiscal 2024 compared to fiscal 2023 due to the disposition of interest in Tres Holdings on April 3, 2023, which was accounted for as an equity-method investment.

Asset impairment decreased by $11.3 million in fiscal 2024 compared to fiscal 2023. In fiscal 2023, an assessment of the recoverable value of the property, plant and equipment at the Salt Plains facility prior to the sale resulted in a one-time impairment charge.

Gain on disposals of subsidiary and equity accounted investee increased by $114.7 million driven by the net gain recognized from the sale of our investments in Tres Holdings and the Salt Plains facility in fiscal 2024.

Other expenses increased by $5.2 million, in fiscal 2024 compared to fiscal 2023 primarily due to the payment of a one-time severance expense to a former executive.

Income tax expense (benefit), net

	Fiscal Years Ended March 31,		
(in millions, $)	**2025**	**2024**	**2023**
Income tax (benefit) expense	**$(10.6)**	$(4.6)	$2.6

Comparison of Fiscal Years Ended March 31, 2025 and 2024

Income tax benefit increased by $6.0 million, or 130%, in fiscal 2025 compared to fiscal 2024, predominately due to the tax benefit recognized from the settlement of loans subject to a deferred gain on debt during the current period.

Comparison of Fiscal Years Ended March 31, 2024 and 2023

Income tax expense decreased by $7.2 million, or 277%, in fiscal 2024 compared to fiscal 2023 resulting in an income tax benefit. The increase in tax benefit was mainly due to changes in the value of our risk management assets and liabilities.

Balance Sheet

Comparison of June 30, 2025 and March 31, 2025

The following table summarizes the statement of financial position as at June 30, 2025 and March 31, 2025:

	As at June 30,	As at March 31,
(in millions, $)	**2025**	**2025**
Total assets	**$1,294.2**	$1,430.2
Property, plant and equipment, net	**886.5**	884.6
Long-term debt	**1,219.1**	1,208.1
Equity	**(218.5)**	(85.8)

Total assets were $1,294.2 million at June 30, 2025, compared to $1,430.2 million at March 31, 2025. The decrease is primarily attributed to a decrease in cash as a result of distributions paid to Brookfield in May 2025, partially offset by increased amounts due from affiliates and an increase in natural gas inventories.

As of the date hereof, the Business had receivable $37.0 million ($120.0 million as at June 30, 2025) due from Brookfield, representing advances of cash flows from operations earned prior to June 30, 2025. The $37.0 million receivable balance is expected to be settled in calendar 2026 when a distribution in the form of a note payable in the same amount is issued to Brookfield, at which point the receivable and payable balances will be set-off. Prior to Closing, we are targeting to pay up to an approximately $40 million distribution to Brookfield, which is representative of the targeted payout of Brookfield's share of annualized Distributable Cash Flow up to September 30, 2025.

Property, plant and equipment, net increased from $884.6 million at March 31, 2025 to $886.5 million at June 30, 2025 primarily due to capital additions related to maintenance capital requirements in California, partially offset by depreciation expense.

Long-term debt increased to $1,219.1 million at June 30, 2025, compared to $1,208.1 million at March 31, 2025. The increase is primarily attributed to drawings on our ABL Facility as required to fund a portion of the distribution paid in May 2025, and the subsequent refilling of inventories. The increase was partially offset by quarterly required repayments on the Term Loan due 2031.

Comparison of March 31, 2025 and 2024

The following table summarizes the statement of financial position for the fiscal years ended March 31, 2025 and March 31, 2024:

	As at March 31,	
(in millions, $)	**2025**	**2024**
Total assets	**$1,430.2**	$1,331.0
Property, plant and equipment, net	**884.6**	881.5
Long-term debt	**1,208.1**	464.7
Equity	**(85.8)**	335.5

Total assets were $1,430.2 million at March 31, 2025, compared to $1,331.0 million at March 31, 2024. The increase is attributed to an increase in cash, amount due from affiliates, capital additions during the period and timing of contractual receivables, partially offset by lower natural gas inventory and risk management assets.

During fiscal 2025, property, plant and equipment, net increased from $881.5 million to $884.6 million primarily due to capital additions related to the drilling and tie-in of three new performance-enhancing storage wells at Wild Goose, partially offset by depreciation expense.

Long-term debt increased to $1,208.1 million at March 31, 2025, compared to $464.7 million at March 31, 2024. The increase is primarily attributed to successfully recapitalizing our Business with the Term Loan due 2031, partially offset by the repayment of the Term Loan due 2026 and all remaining outstanding Brookfield debt, including accrued interest, in the amount of $233.5 million. The remaining proceeds were used to fund a $455.2 million distribution to Brookfield, an advance of $83.0 million to Brookfield as well as transaction fees related to the refinancing.

Cash Flows

Comparison for the Three Months Ended June 30, 2025 and 2024

The following table summarizes our cash flows for the periods presented:

(in millions, $)	Three Months Ended June 30, 2025	Three Months Ended June 30, 2024
Statement of Cash Flows Summary		
Operating activities:		
Net earnings	**$ 48.3**	$ 45.6
Adjustments to reconcile net earnings to net cash provided by operating activities:		
Deferred income tax expense	**3.3**	2.3
Unrealized risk management gains	**(6.3)**	(8.6)
Depreciation and amortization	**8.1**	7.9
Other	**(0.8)**	(0.8)
Changes in non-cash working capital	**(14.9)**	63.7
Net cash provided by operating activities	**37.7**	110.1
Net cash used in investing activities	**(10.9)**	(4.7)
Net cash used in financing activities	**(211.6)**	(171.3)

Net cash provided by operating activities

Net cash provided by operating activities was $37.7 million for the three months ended June 30, 2025, compared to $110.1 million for the three months ended June 30, 2024. Net cash provided by operating activities decreased primarily due to the refilling of our proprietary natural gas inventories, which was partially offset by increased revenues. A relatively warm winter prior to the start of the three months ended June 30, 2024 allowed us to carry over higher volumes of proprietary inventories into that period, consequently requiring less cash outflows to refill.

Net cash used in investing activities

Net cash used in investing activities was $10.9 million for the three months ended June 30, 2025, compared to net cash used in investing activities of $4.7 million for the three months ended June 30, 2024. The increase in net cash used in investing activities was driven primarily by spending on maintenance capital projects occurring in the last quarter of fiscal 2025 paid in the three months ended June 30, 2025.

Net cash used in financing activities

During the three months ended June 30, 2025, net cash used in financing activities was $211.6 million compared to $171.3 million for the three months ended June 30, 2024. The increase in cash outflows was primarily attributable to larger distributions to Brookfield, mainly as a result of increased earnings. The overall increase in cash outflows was offset to some extent by increased drawings on the ABL Facility.

Comparison of Fiscal Years Ended March 31, 2025, 2024 and 2023

The following table summarizes our cash flows for the periods presented:

(in millions, $)	Fiscal Years Ended March 31, 2025	2024	2023
Statement of Cash Flows Summary			
Operating activities:			
Net earnings	**$ 209.4**	$ 253.9	$ 44.5
Adjustments to reconcile net earnings to net cash provided by (used in) operating activities:			
Deferred income tax (benefit) expense	**(11.2)**	(4.2)	2.4
Unrealized risk management losses (gains)	**4.0**	(6.0)	(15.7)
Inventory adjustments	**—**	—	67.7
Depreciation and amortization	**33.1**	34.0	34.5
Equity in net earnings of equity accounted investee	**—**	—	(3.9)
Asset impairment	**—**	—	11.3
Gain on disposals of subsidiary and equity accounted investee	**—**	(114.7)	—
Other	**6.9**	6.7	6.1
Changes in non-cash working capital	**71.5**	75.8	(148.0)
Net cash provided by (used in) operating activities	**313.7**	245.5	(1.1)
Net cash (used in) provided by investing activities	**(34.9)**	196.5	(12.5)
Net cash (used in) provided by financing activities	**(174.2)**	(364.8)	16.6

Comparison of Fiscal Years Ended March 31, 2025 and 2024

Net cash provided by operating activities

Net cash provided by operating activities was $313.7 million for fiscal 2025, compared to $245.5 million for fiscal 2024. Net cash provided by operating activities increased due to increased earnings from operations, primarily from higher Fee for Service revenues. Lower costs of inventories also contributed to the increase in cash. The overall increase in net cash provided by operating activities was partially offset by a timing difference in collecting receivables across fiscal years.

Net cash (used in) provided by investing activities

Net cash used in investing activities was $34.9 million for fiscal 2025, compared to net cash provided by investing activities of $196.5 million for fiscal 2024. The increase in net cash used in investing activities was driven by capital projects undertaken to expand injection and withdrawal capacity at the Wild Goose facility. Fiscal 2024 benefited from the net proceeds of approximately $175.4 million received from the sale of our equity accounted investment in Tres Holdings and approximately $35.2 million from the sale of the Salt Plains facility.

Net cash used in financing activities

During fiscal 2025, net cash used in financing activities was $174.2 million compared to $364.8 million for fiscal 2024. In fiscal 2025, net cash used in financing activities was primarily attributed to $453.1 million repayment of long-term debt, distributions of $628.9 million, and other financing costs related to term loan refinancings. This was partially offset by proceeds from the issuance of the Term Loan due 2031. Fiscal 2024 net cash used in financing activities was primarily comprised of distributions made to Brookfield of approximately $316.5 million, offset by net proceeds from long-term debt of approximately $450.0 million.

Comparison of Fiscal Years Ended March 31, 2024 and 2023

Net cash provided by (used in) operating activities

Net cash provided by operating activities for fiscal 2024 was $245.5 million, compared to net cash used in operating activities of $1.1 million for fiscal 2023. Net cash provided by operating activities increased primarily as a result of stronger contributions from earnings and timing of working capital movements, partially offset by the gain on disposal of subsidiary and equity accounted investee.

Net cash provided by (used in) investing activities

Net cash provided by investing activities for fiscal 2024 was $196.5 million compared to net cash used in investing activities of $12.5 million for fiscal 2023. The increase in net cash provided by investing activities was driven by proceeds from the sales of Tres Holdings and the Salt Plains facility of approximately $175.4 million and $35.2 million, respectively.

Net cash (used in) provided by financing activities

Net cash used in financing activities for fiscal 2024 was $364.8 million compared to net cash provided by financing activities of $16.6 million for fiscal 2023. The decrease was mainly driven by distributions paid to Brookfield in fiscal 2024. The fiscal 2023 inflow was as a result of net proceeds from debt of approximately $220.0 million, an advance of $175.0 million from Brookfield, partially offset by a $397.3 million repayment of 7.00% senior secured notes (the "**Senior Notes**").

Non-IFRS Measures Utilized by Our Business

We report our financial results in accordance with IFRS. However, management believes that certain non-IFRS financial measures provide investors with useful information in evaluating our performance. Management believes that excluding certain items that may vary substantially in frequency and magnitude period-to-period from net earnings provides useful supplemental measures that assist in evaluating our ability to generate earnings and cash flow, and more readily compare these metrics between past and future periods. These non-IFRS financial measures are not standardized measures under IFRS and may not be comparable to similarly titled measures used by other companies.

Our non-IFRS financial measures should not be considered in isolation from, or as substitutes for, financial information prepared in accordance with IFRS. There are several limitations related to the use of our non-IFRS financial measures as compared to the closest comparable IFRS measures. Some of these limitations include:

- the exclusion of some, but not all, items that affect net earnings and comprehensive earnings;
- not allowing us to analyze the effect of certain recurring and non-recurring items that materially affect our net earnings and comprehensive earnings;
- not reflecting all cash expenditures, or future requirements, for capital expenditures or contractual commitments; and
- other companies within the industry may calculate the non-IFRS measures differently than we do, limiting its usefulness as a comparative measure.

Non-IFRS Financial Measures and Ratios

Adjusted EBITDA, Adjusted Gross Margin, Distributable Cash Flow and Net Debt are non-IFRS financial measures and ratios and are used by our management and by external users of our financial statements, such as investors, research analysts and others, to assess the financial performance of our assets over the long-term to generate sufficient cash to service indebtedness, fund maintenance and growth capital projects and to make a distributions to our shareholders. In addition, Adjusted EBITDA, Adjusted Gross Margin, Distributable Cash Flow and Net Debt are frequently used by securities analysts, investors and other interested parties in the evaluation of companies in our industry with similar capital structures. We use Adjusted EBITDA, Adjusted Gross Margin, Distributable Cash Flow and Net Debt to supplement IFRS financial measures of performance to evaluate the effectiveness of our business strategies, to make budgeting decisions and to compare our performance against that of other peer companies using similar measures.

Adjusted EBITDA

We define Adjusted EBITDA, which we use as the primary non-IFRS financial measure of profitability to evaluate the performance of our Business, as net earnings adjusted by financing costs, income tax (benefit) expense, depreciation and amortization, unrealized risk management losses (gains), gain on disposals of subsidiary and equity accounted investee, net loss (earnings) from assets disposed of, asset impairment, and other expenses.

We believe that Adjusted EBITDA is meaningful because it presents the financial performance of our Business on a basis which excludes the impact of certain non-cash items as well as how the operations have been financed.

Adjusted EBITDA when expressed as a percentage of Adjusted Gross Margin ("**Adjusted EBITDA Margin**") is a non-IFRS ratio calculated as Adjusted EBITDA divided by Adjusted Gross Margin. Adjusted EBITDA Margin is used by our management and by external investors to assess efficiency in managing operating expenses relative to our Adjusted Gross Margin.

Adjusted Gross Margin

We define Adjusted Gross Margin, which we use as a non-IFRS financial measure of profitability, as net earnings adjusted by financing costs, income tax (benefit) expense, depreciation and amortization, unrealized risk management losses (gains), gain on disposals of subsidiary and equity accounted investee, net loss (earnings) from assets disposed of, asset impairment, other expenses, operating, general and administrative expenses and other items.

We believe that Adjusted Gross Margin is a useful measure of profitability because it presents our residual earnings after deducting the direct costs of gas storage services from our Fee for Service and realized optimization revenue.

Fee for Service as a percentage of Adjusted Gross Margin is a non-IFRS ratio and is calculated as Fee for Service gross margin divided by Adjusted Gross Margin. Fee for Service as a percentage of Adjusted Gross Margin is used by our management and by external investors to determine the proportion of Adjusted Gross Margin that is driven by Fee for Service.

Distributable Cash Flow

In addition to Adjusted EBITDA and Adjusted Gross Margin, we utilize Distributable Cash Flow as a non-IFRS financial measure of profitability to provide insights into the cash earnings that are available for distribution, to buyback shares, fund working capital requirements, and/or reinvest in our Business to further enhance growth. We define Distributable Cash Flow as net earnings adjusted by financing costs, income tax (benefit) expense, depreciation and amortization, unrealized risk management losses (gains), gain on disposals of subsidiary and equity accounted investee, net loss (earnings) from assets disposed of, asset impairment, other expenses, interest expense, mandatory debt repayments, current taxes, cash lease payments, maintenance capital expenditures and other items.

We believe that Distributable Cash Flow is a meaningful financial metric because it presents our cash earnings that are available for distribution, to buyback shares, and/or reinvest in our Business.

Distributable Cash Flow when expressed as a percentage of Adjusted EBITDA ("**Distributable Cash Flow Conversion**") is a non-IFRS ratio calculated as Distributable Cash Flow divided by Adjusted EBITDA. Distributable Cash Flow Conversion is used by our management and by external investors to assess how effectively the Business converts its earnings into Distributable Cash Flow.

Net Debt

Net debt is a non-IFRS financial measure used by management to assess the credit profile of our Business. Net debt is defined as total debt outstanding adjusted by unamortized discount and deferred financing costs and cash and cash equivalents.

The following table sets forth a reconciliation of Adjusted EBITDA, Adjusted Gross Margin and Distributable Cash Flow to net earnings, the most directly comparable IFRS financial measure for the periods indicated.

(in millions, $)	Three Months Ended June 30, 2025	Three Months Ended June 30, 2024
Net earnings	**$ 48.3**	$ 45.6
Add (deduct):		
Financing costs	**25.6**	15.8
Income tax expense	**3.3**	2.3
Depreciation and amortization	**8.1**	7.9
Unrealized risk management gains	**(9.2)**	(8.7)
Other expenses	**1.0**	1.1
Adjusted EBITDA	**77.1**	64.0
Operating	**12.7**	11.9
General and administrative	**5.5**	6.5
Other items(1)	**0.6**	—
Adjusted Gross Margin	**95.9**	82.4
Operating	**(12.7)**	(11.9)
General and administrative	**(5.5)**	(6.5)
Interest expense(2)	**(20.4)**	(9.1)
Mandatory debt repayments	**(3.1)**	—
Current taxes	**—**	—
Cash lease payments	**(0.4)**	(0.3)
Maintenance capital expenditures	**(6.6)**	(4.9)
Other items(1)	**(0.6)**	—
Distributable Cash Flow	**$ 46.6**	$ 49.7

Notes:

(1) Other items consists of unrealized electricity contract gains.

(2) Interest expense includes interest on debt obligations, including the Term Loan due 2026, Term Loan due 2031, the ABL Facility, the Warwick Credit Facility and other interest income (expense), net of realized gains on interest rate swaps.

The following table presents a reconciliation of net debt to total debt outstanding, the most directly comparable IFRS financial measure for the periods indicated:

(in millions, $)	As at June 30, 2025	As at March 31, 2025
Short-term debt	**$ 25.1**	$ 25.8
Long-term debt	**1,219.1**	1,208.1
Total debt outstanding	**1,244.2**	1,233.9
Add: Unamortized discount and deferred financing costs	**25.6**	26.5
Less: cash and cash equivalents	**(20.3)**	(204.1)
Net debt	**$1,249.5**	$1,056.3

The following table sets forth a reconciliation of Adjusted EBITDA, Adjusted Gross Margin and Distributable Cash Flow to net earnings, the most directly comparable IFRS financial measure for the periods indicated.

(in millions, $)	Fiscal Years Ended March 31, 2025	2024	2023
Net earnings	**$209.4**	$ 253.9	$ 44.5
Add (deduct):			
Financing costs	**93.1**	76.0	68.7
Income tax (benefit) expense	**(10.6)**	(4.6)	2.6
Depreciation and amortization	**33.1**	34.0	34.5
Unrealized risk management losses (gains)	**6.9**	(6.0)	(15.7)
Gain on disposals of subsidiary and equity accounted investee	**—**	(114.7)	—
Net loss (earnings) from assets disposed of[1]	**—**	(2.3)	4.0
Asset impairment	**—**	—	11.3
Other expenses	**6.9**	7.9	2.7
Adjusted EBITDA	**338.8**	244.2	152.6
Operating	**49.5**	53.2	56.5
General and administrative	**24.2**	23.5	22.2
Other items[2]	**(0.1)**	(2.2)	(2.2)
Adjusted Gross Margin	**412.4**	318.7	229.1
Operating	**(49.5)**	(53.2)	(56.5)
General and administrative	**(24.2)**	(23.5)	(22.2)
Interest expense[3]	**(70.0)**	(43.6)	(31.3)
Mandatory debt repayments	**(3.1)**	—	—
Current taxes	**(0.6)**	0.4	(0.2)
Cash lease payments	**(9.3)**	(8.9)	(9.1)
Maintenance capital expenditures[4]	**(21.3)**	(15.1)	(17.0)
Other items[2]	**0.1**	2.2	2.2
Distributable Cash Flow	**$234.5**	$ 177.0	$ 95.0

Notes:

(1) Fiscal 2023 and fiscal 2024 presented on a same store basis, excluding net earnings from the Salt Plains facility and equity in net earnings of equity accounted investee.

(2) Other items consists of unrealized electricity contract gains and operating, and general and administrative expenses associated with assets disposed of in fiscal 2023.

(3) Interest expense includes interest on debt obligations, including the Term Loan due 2026, Term Loan due 2031, the ABL Facility, Senior Notes, the Warwick Credit Facility and other interest income (expense), net of realized gains on interest rate swaps.

(4) Maintenance capital expenditures adjusted to reflect a one-time cost associated with historical heat imbalances and cushion gas migration.

The following table presents a reconciliation of net debt to total debt outstanding, the most directly comparable IFRS financial measure for the periods indicated:

(in millions, $)	As at March 31, 2025	As at March 31, 2024
Short-term debt	**$ 25.8**	$ —
Long-term debt	**1,208.1**	464.7
Total debt outstanding	**1,233.9**	464.7
Add: Unamortized discount and deferred financing costs	**26.5**	3.6
Less: cash and cash equivalents	**(204.1)**	(100.1)
Net debt	**$1,056.3**	$ 368.2
Net debt to Adjusted EBITDA	**3.1x**	1.5x

Supplementary Financial Measures Utilized by Our Business

Contracted Fee for Service Revenue Backlog

Contracted Fee for Service revenue backlog is a supplementary financial measure that represents the cumulative contracted revenues for our ToP and STS services, not yet recognized in the Financial Statements of the Business. Contracted Fee for Service revenue backlog is an operating measure that we use to evaluate the effectiveness of our contracting strategies and the stability of cash flow generation in the coming years.

The following table outlines the changes in our California contracted Fee for Service revenue backlog for fiscal 2025 and fiscal 2024:

(in millions, $)	Fiscal Year Ended March 31, 2025	Fiscal Year Ended March 31, 2024
Opening balance	**$ 452.0**	$ 248.9
Fee for Service contracts signed during the period	**521.5**	418.8
Fee for Service contracted backlog recognized in revenue	**(235.8)**	(215.7)
Foreign currency adjustments and other	**—**	—
Ending balance[(1)]	**$ 737.7**	$ 452.0

Note:

(1) Contracted Fee for Service revenue backlog excludes fuel and commodity recovery associated with ToP contracts.

As of March 31, 2025, contracted Fee for Service revenue backlog at our California facilities was $737.7 million compared to $452.0 million as of the end of fiscal 2024. Fee for Service contracts signed in fiscal 2025 contributed $521.5 million to the backlog due to signing longer term ToP contracts at improved demand charges. This increase was partially offset by $235.8 million of contracted fee for service revenue recognized in the period. New ToP contracts executed in fiscal 2025 at our California facilities had a weighted average contract term of 4.8 years compared to 2.9 years in fiscal 2024.

The following table outlines the changes in our Alberta contracted Fee for Service revenue backlog for fiscal 2025 and fiscal 2024:

(in millions, $)	Fiscal Year Ended March 31, 2025	Fiscal Year Ended March 31, 2024
Opening balance	**$ 115.6**	$ 52.4
Fee for Service contracts signed during the fiscal period	**166.5**	131.8
Fee for Service contracted backlog recognized in revenue	**(124.6)**	(68.6)
Foreign currency adjustments and other	**(2.0)**	—
Ending balance[(1)]	**$ 155.5**	$115.6

Note:

(1) Contracted Fee for Service revenue backlog excludes fuel and commodity recovery associated with ToP contracts.

As of March 31, 2025, contracted Fee for Service revenue backlog at our Alberta facilities was $155.5 million compared to $115.6 million as of the end of fiscal 2024. Fee for Service contracts added $166.5 million to the backlog in fiscal 2025 as storage rates and weighted average contract terms were higher than the prior year. This increase was partially offset by $124.6 million of contracted fee for service revenue recognized in the period. New ToP contracts executed in fiscal 2025 at our Alberta facilities had a weighted average contract term of 3.1 years, compared to 2.3 years in fiscal 2024.

Analysis of Key Financial and Operating Measures

The following section contains a discussion of key financial and operating measures utilized in managing the Business, including for performance measurement, capital allocation and valuation purposes.

Take-or-Pay Contracted Storage Rates

ToP contracted storage rates refers to the weighted average demand charge paid by our long-term firm storage service contract customers. Under these arrangements, our customers are obligated to pay us a fixed monthly demand charge for storage capacity regardless of utilization, resulting in steady, stable cash flow generation. ToP contracted storage rates are primarily driven by the expected summer to winter seasonal differences in gas prices over the term of the contract combined with the value a customer places on our ability to deliver the stored gas reliably and quickly for their own use.

Short-term Storage Contract Rates

Under STS contract arrangements, which typically span up to one storage season, our customers pay a fixed fee to inject and withdraw specified quantities of natural gas. Similar to ToP contracted storage rates, STS contract rates are primarily driven by the difference in future gas prices between when it is stored and when it will be withdrawn, and our ability to deliver the stored gas reliably and on time.

ToP and STS contracts are referred to on a combined basis as "Fee for Service" contracts.

Working Gas Capacity

Working gas capacity is an operating measure that we use to evaluate the effective working gas capacity at our Business to store natural gas on behalf of our customers or, in a small portion, for ourselves through our optimization strategy. In addition, we use working gas capacity to evaluate the adherence to our long-term goal of allocating 60% of working gas capacity to ToP contracts, 25% to STS contracts, and 15% to optimization. This strategy allows for a contracting approach aimed at securing revenue stability, while maintaining optionality to capitalize on favourable market dynamics.

Adjusted EBITDA, Adjusted Gross Margin and Distributable Cash Flow

The following table outlines our Adjusted EBITDA, Adjusted Gross Margin and Distributable Cash Flow for the three months ended June 30, 2025 and 2024.

	Three Months Ended June 30,	
(in millions of $)	**2025**	**2024**
Fee for Service gross margin		
ToP	**$ 58.5**	$ 46.2
STS, net of cost of gas storage services	**32.6**	41.9
Total Fee for Service gross margin[(1)]	**91.1**	88.1
Realized optimization gross margin	**4.8**	(5.7)
Adjusted Gross Margin	**95.9**	82.4
Operating, general and administrative expense and other	**(18.8)**	(18.4)
Adjusted EBITDA	**$ 77.1**	$ 64.0
Distributable Cash Flow	**46.6**	49.7
Fee for Service as a % of Adjusted Gross Margin	**95%**	107%
Adjusted EBITDA Margin	**80%**	78%

Adjusted EBITDA was $77.1 million for the three months ended June 30, 2025, an increase of $13.1 million, or 20% from the three months ended June 30, 2024. The increase was primarily the result of an increase in ToP contract revenue at our California facilities.

Demand for storage services remained strong in California as our customers utilized natural gas storage services to provide price stability and energy reliability in a state that is a net importer of natural gas and increasingly powered by intermittent renewable power generation.

Distributable Cash Flow decreased by $3.1 million primarily due to increased interest costs resulting from higher outstanding principal balances of our term loan debt. The decrease was partially offset by increased revenues.

The following table outlines our Adjusted EBITDA, Adjusted Gross Margin and Distributable Cash Flow for fiscal 2025, fiscal 2024 and fiscal 2023.

	Fiscal Years Ended March 31,		
(in millions of $)	**2025**	**2024**	**2023**
Fee for Service gross margin			
ToP	**$185.0**	$155.3	$ 66.1
STS, net of cost of gas storage services	**170.8**	116.0	98.7
Total Fee for Service gross margin[1]	**355.8**	271.3	164.8
Realized optimization gross margin	**56.6**	47.4	64.3
Adjusted Gross Margin	**412.4**	318.7	229.1
Operating, general and administrative expense and other	**(73.6)**	(74.5)	(76.5)
Adjusted EBITDA	**$338.8**	$244.2	$152.6
Distributable Cash Flow	**234.5**	177.0	95.0
Fee for Service as a % of Adjusted Gross Margin	**86%**	85%	72%
Adjusted EBITDA Margin	**82%**	77%	67%

Note:

(1) Fiscal 2023 presented on a same-store basis, excluding Fee for Service gross margin from the Salt Plains facility.

The following table summarizes the changes in ToP contracted rates and the allocation of working gas capacity that contributed to Fee for Service gross margin in fiscal 2025 and fiscal 2024.

	Fiscal 2025			Fiscal 2024		
	Contract Rate ($/Dth[1])	**Working Gas Capacity Contribution (MMDth)**	**Fee for Service Gross Margin (in millions of $)**	**Contract Rate ($/Dth[1])**	**Working Gas Capacity Contribution (MMDth)**	**Fee for Service Gross Margin (in millions of $)**
ToP Contracts						
California	**2.37**	**68.9**	**163.3**	2.06	67.4	138.6
Alberta	**0.80**	**27.2**	**21.7**	0.64	26.0	16.7
			185.0			155.3
STS Contracts[2]						
California			**69.5**			67.0
Alberta			**101.3**			49.0
			170.8			116.0

Notes:

(1) Fiscal 2025 ToP contracted demand charge, excluding fuel and commodity recovery, were $2.30/Dth and $0.75/Dth for California and Alberta facilities, respectively (fiscal 2024 — $1.96/Dth and $0.58/Dth, respectively).

(2) Net of cost of gas storage services from the Combined Consolidated Statements of Net Earnings and Comprehensive Earnings in the Annual Financial Statements.

The following table summarizes the changes in ToP contracted rates and the allocation of working gas capacity that contributed to Fee for Service gross margin in fiscal 2024 and fiscal 2023.

	Fiscal 2024			Fiscal 2023		
	Contract Rate ($/Dth[1])	Working Gas Capacity Contribution (MMDth)	Fee for Service Gross Margin (in millions of $)	Contract Rate ($/Dth[1])	Working Gas Capacity Contribution (MMDth)	Fee for Service Gross Margin (in millions of $)
ToP Contracts						
California	**2.06**	**67.4**	**138.6**	1.22	49.3	59.9
Alberta	**0.64**	**26.0**	**16.7**	0.49	12.6	6.2
			155.3			66.1
STS Contracts[2][3]						
California			**67.0**			68.9
Alberta			**49.0**			29.8
			116.0			98.7

Notes:

(1) Fiscal 2024 ToP contracted demand charge, excluding fuel and commodity recovery, were $1.96/Dth and $0.58/Dth for California and Alberta, respectively (fiscal 2023 — $1.02/Dth and $0.42/Dth, respectively).

(2) Fiscal 2023 presented on a same-store basis, excluding Fee for Service gross margin from the Salt Plains facility.

(3) Net of cost of gas storage services from the Combined Consolidated Statements of Net Earnings and Comprehensive Earnings in the Annual Financial Statements.

Comparison of Fiscal Years Ended March 31, 2025 and 2024

Adjusted EBITDA was $338.8 million for fiscal 2025, an increase of $94.6 million, or 39% from fiscal 2024. The increase was primarily the result of:

- an increase in Fee for Service Gross Margin from our California facilities of $27.2 million, driven primarily by higher ToP contracting rates realized in fiscal 2025. Demand for storage services remained strong in the region as our customers utilized natural gas storage services to provide price stability and energy reliability in a state that is a net importer of natural gas and increasingly powered by intermittent renewable power generation; and
- a $57.3 million increase in Fee for Service Gross Margin from our Alberta operations, which was driven largely by a favourable spread environment as fiscal 2025 summer gas prices declined due to an abundance of stored gas, without a corresponding decrease in the fiscal 2025 winter prices.

Distributable Cash Flow increased by $57.5 million primarily due to the aforementioned factors, partially offset by a higher maintenance capital expenditure which fluctuates from time to time based on our integrity programs.

Comparison of Fiscal Years Ended March 31, 2024 and 2023

Adjusted EBITDA was $244.2 million for fiscal 2024, an increase of $91.6 million, or 60% from fiscal 2023. The increase was primarily the result of:

- an increase in Fee for Service Gross Margin from our California facilities of $76.8 million, driven primarily by increased ToP revenue as our customers looked for stability in natural gas pricing and protection against supply-demand imbalances; and
- a $29.7 million increase in Fee for Service Gross Margin from our Alberta facilities, which was driven primarily by increased demand for ToP services and by a cold weather event in January 2024, which drove price volatility and allowed us to capture strong STS and optimization value;

Distributable Cash Flow increased by $82.0 million due to the aforementioned factors, with maintenance capital expenditures remaining relatively consistent when compared to fiscal 2023.

Liquidity and Capital Resources

The following table presents available liquidity of our Business:

(in millions, $)	As at June 30, 2025	As at March 31, 2025
Cash and cash equivalents	**$ 20.3**	$204.1
Undrawn and available committed credit facilities[1]	**105.3**	112.7
Total available liquidity	**$125.6**	$316.8

Note:

(1) Excludes ABL Facility borrowing base attributable to cash on hand.

As of June 30, 2025, we had $125.6 million of available liquidity, which was comprised of $20.3 million of available cash and cash equivalents, $105.3 million undrawn and available capacity on the ABL Facility and Warwick Credit Facility after $219.8 million in distributions to owners and advances extended to related parties were made in May of 2025. Our primary source of liquidity and capital resources are cash flows generated by operating activities and available undrawn amounts on the ABL Facility.

Our Business has few non-discretionary capital requirements and generates strong free-cash flows from operations. Our largest normal course capital requirements are interest payments on our debt facilities and capital expenditures to maintain the operating performance of our storage assets.

We expect our cash generated from operations and available capacity under our available Credit Facilities (and other anticipated sources of credit) to be sufficient to meet our material cash requirements over the next 12 months. These requirements include changes in working capital, debt service obligations, anticipated capital expenditures, and cash lease payments.

We intend to establish a new secured Revolving Credit Facility to enhance liquidity and replace the existing ABL Facility. The borrowers under the new Revolving Credit Facility will be Rockpoint and certain subsidiaries of the OpCos. We anticipate that most of the borrowings under the new Revolving Credit Facility will be made by the subsidiaries of the OpCos to fund the requirements of the Business, and as such the costs relating to the new Revolving Credit Facility will be borne by Rockpoint and Brookfield in proportion to their respective ownership interests in the OpCos and the Business. Rockpoint expects that its separate borrowings under the new Revolving Credit Facility to service stand-alone administrative expenditures and requirements will be relatively minimal. The Revolving Credit Facility is expected to have an aggregate commitment of $350.0 million, including a letter of credit sub-limit of $175.0 million. The Revolving Credit Facility will mature on the fifth anniversary of the closing date of the facility. The Revolving Credit Facility will be available in U.S. dollars and Canadian dollars, and subject to lender consent, we can request additional currencies. The Revolving Credit Facility bears interest at a floating rate, which for U.S. dollars, can be either base rate or Term SOFR, and for Canadian dollars, can be any of Term CORRA, the Canadian prime rate and Daily Compound CORRA, with interest accruing at the applicable benchmark plus an applicable margin determined by a pricing grid based on Rockpoint Gas Storage Partners LP's (or, if available, Rockpoint Gas Storage Inc.'s) corporate rating. Customary commitment and letter of credit fees will be payable under the Revolving Credit Facility. Proceeds from the Revolving Credit Facility will be used to refinance the ABL Facility, issue of letters of credit, pay certain transaction costs, and to support working capital, capital expenditures, and other general corporate purposes as well as to repay the Warwick Credit Facility, to the extent required. Execution of the Revolving Credit Facility remains subject to final documentation and customary closing conditions, and definitive terms may differ from those summarized above.

Dividends

See "Dividend Policy".

Contractual Obligations and Commitments

The following table summarizes our contractual obligations as of June 30, 2025:

	Payment due by period				
(in millions, $)	Total	Less than 1 year	1 – 3 years	3 – 5 years	More than 5 years
Debt obligations	$1,269.6	$ 25.3	$ 25.0	$ 38.0	$1,181.3
Interest on debt obligations	486.6	84.0	152.1	154.5	96.0
Lease obligations	411.4	9.7	19.5	19.9	362.3
Gas storage obligations	20.0	—	12.6	7.4	—
Decommissioning obligations	263.8	0.1	1.2	0.1	262.4
Purchase obligations(1)	130.3	82.8	45.5	2.0	—
Other(2)	66.6	54.3	10.5	1.8	—
Total	**$2,648.3**	**$256.2**	**$266.4**	**$223.7**	**$1,902.0**

Notes:

(1) Our Business economically hedges substantially all of its natural gas purchases.

(2) Other includes trade payables and accrued liabilities not included in separate categories above, committed costs of gas storage services, compensation obligations and firm storage transportation costs.

The debt obligations of the Business are comprised of the ABL Facility, the Warwick Credit Facility and the Term Loan due 2031. The ABL Facility is a secured asset backed revolving credit facility consisting of a U.S. revolving credit facility and a Canadian revolving credit facility of $125.0 million each, maturing on August 29, 2029 (or, if earlier, a springing maturity date 91 days prior to the maturity of the Term Loan due 2031). Borrowings under the ABL Facility bear interest at a floating rate. For U.S. dollar denominated borrowings, the floating rate is equal to a base rate plus an applicable margin equal to 2.00% or, at our option, SOFR plus an applicable margin equal to 3.00%, in each case, subject to two 25 basis points step-downs in the applicable margin based on an average excess liquidity-based pricing grid. For Canadian dollar denominated borrowings, the floating rate is equal to 2.00% or, at our option, CORRA plus an applicable margin equal to 3.00% plus a spread adjustment, in each case, subject to two 25 basis points step-downs in the applicable margin based on an average excess liquidity-based pricing grid. The Term Loan due 2031 bears interest at a floating rate, which can be either a base rate plus an applicable margin equal to 2.00% or, at our option, SOFR plus an applicable margin equal to 3.00%.

As of June 30, 2025, we have fully hedged the floating interest rate exposure on the Term Loan due 2031 by entering into interest rate swaps to September 2025, $900.0 million of which is hedged thereafter to September 2026. The weighted average fixed rate, inclusive of interest rate swaps, was 6.66% as of March 31, 2025.

As of June 30, 2025, our Business maintained the Warwick Credit Facility with a Canadian bank with a maximum limit of $27.5 million (March 31, 2025 — $26.1 million) or C$37.5 million (March 31, 2025 — C$37.5 million) in combined cash borrowings and letter of credit issuances. The Warwick Credit Facility matures on May 31, 2026.

Our Business maintains long-term lease arrangements primarily related to surface and subsurface land use across our natural gas storage facilities in North America. These lease obligations represent the contractual cash payments required to satisfy the terms of the lease. As of June 30, 2025, the total lease obligation was $111.4 million (March 31, 2025 — $108.8 million) of which $102.2 million (March 31, 2025 — $99.7 million) is classified as long-term in accordance with the lease terms.

The decommissioning obligations of the Business relate to the plugging and abandonment of its wells and decommissioning of our storage facilities at the end of their estimated useful economic lives. As of March 31, 2025, the estimated undiscounted cash flows required to settle the decommissioning obligations were approximately $258.2 million (March 31, 2024 — $267.0 million). At March 31, 2025, the expected timing of payment for settlement of the obligations was 55 years, aside from certain short-term well and other abandonment obligations.

Purchase obligations consist of forward physical commitments related to future purchases of natural gas inventory and cushion gas. As we economically hedge substantially all of our natural gas purchases for our Business, there are forward sales that offset these commitments, which include future sales of certain existing inventory.

The following table summarizes our contractual obligations as of March 31, 2025:

	Payment due by period				
(in millions, $)	Total	Less than 1 year	1 – 3 years	3 – 5 years	More than 5 years
Debt obligations	$1,260.4	$ 26.1	$ 25.0	$ 25.0	$1,184.3
Interest on debt obligations	516.1	83.1	158.5	158.0	116.5
Lease obligations	410.9	9.6	19.5	19.9	361.9
Gas storage obligations	19.7	—	19.7	—	—
Decommissioning obligations	258.2	0.2	1.2	0.1	256.7
Purchase obligations(1)	144.8	98.1	46.7	—	—
Other(2)	78.5	68.2	9.0	1.0	0.3
Total	**$2,688.6**	**$285.3**	**$279.6**	**$204.0**	**$1,919.7**

Notes:

(1) Our Business economically hedges substantially all of its natural gas purchases.

(2) Other includes trade payables and accrued liabilities not included in separate categories above, committed costs of gas storage services, compensation obligations and firm storage transportation costs.

Off-Balance Sheet Arrangements

Currently we do not, and during fiscal 2025, fiscal 2024 or fiscal 2023 we did not, have any off-balance sheet arrangements or any relationships with unconsolidated entities or financial partnerships, including entities (sometimes referred to as structured finance or special purpose entities) that were established for the purpose of facilitating off-balance sheet arrangements or other contractually narrow or limited purposes.

Transactions Between Related Parties

Brookfield has and will enter into a number of related party transactions with the Company. See Note 19 of the Annual Financial Statements, Note 10 of the Interim Financial Statements and “Relationship with Brookfield — The Transactions”.

Qualitative and Quantitative Disclosures about Market Risk

We are exposed to market risks in the ordinary course of business. Market risk represents the risk of loss that may impact our financial position due to adverse changes in financial market prices and rates. Our market risk exposure is primarily the result of fluctuations in interest rates, commodity prices, inflation and credit. See “Risk Factors”.

Interest Rate Risk

To the extent that it is economic to do so, our Business enters into interest rate swaps to hedge the exposure from its variable interest rates. We use derivatives to manage or maintain exposure to changes in interest rates given the ABL Facility and Term Loan due 2031 are indexed against SOFR, and solely with respect to Canadian dollar borrowings under the ABL Facility, CORRA, and are exposed to variable interest rate risk. Our Business entered into interest rate swaps to hedge the exposure from the Term Loan due 2031. These contracts fully hedged the principal borrowings from November 2024 to September 2025, which decreased to

72.8%, or $900 million, in October 2025 to September 2026. Thereafter, the full principal balance is unhedged, which will expose us to interest rate fluctuations unless the debt is re-hedged.

Interest rate risk on the ABL Facility varies depending on draws outstanding at a point in time. Given there were no draws outstanding on the ABL Facility as of March 31, 2025 and 2024, we were not exposed to interest rate risk related to the ABL Facility.

Commodity Price Risk

As a result of our natural gas inventory and any future requirements to purchase cushion gas, we are exposed to risks associated with changes in price when buying and selling natural gas across future time periods. To manage these risks and reduce the variability of cash flows, our Business utilizes a combination of financial and physical derivative contracts, including forwards, futures and swap contracts.

Our Business uses electricity to run compressors used to inject and withdraw natural gas and is also exposed to risks associated with changes in the price of electricity. To manage these risks and reduce the variability of cash flows, we utilize swap contracts to hedge the price of electricity.

As of June 30, 2025, March 31, 2025 and 2024, the volumes of inventories which were economically hedged were:

	As of June 30,	As of March 31,	
(in million Dth, unless otherwise noted)	2025	2025	2024
Forwards	(0.9)	0.2	(13.6)
Futures	30.5	12.2	51.0
Total inventory hedged	29.6	12.4	37.4
Total inventory	30.2	12.4	38.5
Percent of inventory hedged	98%	100%	97%

To limit exposure to natural gas prices, we purchase and sell natural gas inventory and concurrently enter into derivative contracts hedging the volumes. At June 30, 2025 natural gas inventory of 30.2 million Dth was 98% hedged with financial contracts. As of March 31, 2025, natural gas inventory of 12.4 million Dth was fully hedged with financial contracts. As of March 31, 2024, natural gas inventory of 38.5 million Dth was 97% hedged with financial contracts.

Outstanding Share Data

As at the date of this prospectus, one Class A Share of the Company is issued and outstanding, which is held by Brookfield Infrastructure Holdings (Canada) Inc. and which will be cancelled upon Closing. See *"Brookfield"* and *"Prior Sales"*.

Proposed Transactions

For a description of proposed transactions of the Company, see "Relationship with Brookfield — The Transactions".

Critical Accounting Policies and Estimates and Changes in Accounting Policies including Initial Adoption

See Note 3, "Material Accounting Policy Information" to the Annual Financial Statements appended to this prospectus for a discussion and analysis of our critical accounting estimates and our recently adopted accounting pronouncements and future accounting policy changes.

Principles of combination and consolidation

The Financial Statements of the Business were prepared for the purpose of presenting the financial position, results of operations and cash flows of Swan OpCo, BIF OpCo, WGS LP, SIM, Swan Debt and, prior to March 21, 2024, Tres and its subsidiaries, which are commonly controlled and managed as a single economic entity.

All significant intercompany balances, transactions, revenues and expenses are eliminated.

Revenue recognition

Our Business recognizes revenue when it transfers control of a product or service to a customer.

Revenue is measured based on the consideration specified in a contract with a customer and excludes amounts collected on behalf of third parties. Cash received in advance from customers is recorded as deferred revenue until revenue recognition criteria are met.

Our fee for service revenues are earned by providing storage services on a ToP contract basis, for which we receive a fixed monthly demand charge for specified amounts of injection, storage, and withdrawal capabilities regardless of utilization, and by providing storage services on an STS contract basis, where customers pay a fixed fee to both inject a specified quantity of natural gas on a specified date or dates and to withdraw on a specified future date or dates.

ToP contract revenue contains both fixed monthly demand charges and variable operating fees based on volumes of natural gas injected or withdrawn. Our Business identified one performance obligation relating to ToP contract revenue, which encompasses the injection, storage, and withdrawal of natural gas within our facilities. Monthly demand charges are recognized over the period covered by each contract, to the extent that we have the right to invoice. A relatively small portion of our ToP revenues are derived from variable fees related to fuel and injection and withdrawal fees, which are recognized over time as injection and withdrawal of natural gas occurs.

STS contracts are fixed in nature and do not provide the customer any option to adjust the volumes or timing specified in a contract, which generally have durations of one year or less. Our Business identified one performance obligation relating to STS contract revenue, which is the combination of injection and withdrawal of gas over a specified date or dates. STS contract revenue is recognized over time, to the extent that we have the right to invoice, using the output measures of volume of gas injected and withdrawn, which is when the services are provided.

Optimization, net is comprised of realized and unrealized gains and losses on our natural gas trading activities. Realized gains and losses include realized gains and losses from physical energy trading contracts, for which revenues and costs are recognized at the time of physical delivery, net of realized gains and losses on financial trading contracts, which are recognized when the contract settles and period to which the contract relates is completed. Unrealized gains and losses represent the change in the value of derivative contracts, which are risk management positions that have been entered into to lock-in future prices of natural gas and currency exchange rates. Because our natural gas inventories relate directly to our proprietary optimization activities, any adjustment in those inventories is reflected as part of optimization, net.

Cash and cash equivalents

Cash and cash equivalents include cash on hand, and as applicable, short-term investments with original maturities of three months or less.

Margin deposits

Cash held in margin represents the right to receive or the obligation to pay cash collateral under a master netting arrangement that has not been offset against derivative positions. These derivatives are marked-to-market daily and the profit or loss on the daily position is then received from, or paid to, the account as appropriate under the terms of our Business' contract with its broker.

Natural gas inventory

Our Business' inventory is natural gas injected into storage and held for resale. Inventory is valued at the lower of weighted average cost or net realizable value. Net realizable value is the estimated selling price in the ordinary course of business, less estimated costs to complete the sale.

Reversals of adjustments to inventory are required when circumstances that previously caused inventories to be written down no longer exist in subsequent periods, or when there is clear evidence of an increase in net realizable value because of changed economic circumstances.

Costs to store inventory are recognized as operating expenses in the period the costs are incurred in the combined consolidated statements of net earnings and comprehensive earnings.

Property, plant and equipment

Property, plant and equipment is recorded at cost, net of accumulated depreciation and accumulated impairment losses, if any. The initial cost of an asset includes its purchase price or construction cost, any costs directly attributable to bringing the asset into operation and estimated decommissioning obligations.

The cost of right-of-use ("**ROU**") assets, is comprised of the amount of the initial measurement of the corresponding lease liability, lease payments made at or before the commencement day, less incentives received, and any initial direct costs.

When significant parts of property, plant and equipment are required to be replaced at intervals, our Business recognizes such parts as individual assets with specific useful lives and depreciates them accordingly. Likewise, when a major inspection is performed, its cost is recognized in the carrying amount of the property, plant and equipment as a replacement if the recognition criteria are satisfied. Repairs, maintenance and renewals that do not provide future economic benefits to the assets are recognized in the combined consolidated statements of net earnings and comprehensive earnings as incurred.

Assets are derecognized upon disposal, replacement or when no future economic benefits are expected to arise from the continued use of the asset. Any gains or losses arising on the disposal or retirement of an asset are determined by comparing the proceeds from disposal with the carrying amount of the asset and are recognized in the combined consolidated statements of net earnings and comprehensive earnings.

Depreciation of an asset commences when it is available for use. Property, plant and equipment are depreciated using the straight-line method over the estimated useful lives of each component of the assets as follows:

	In years
Pipelines and interconnects	25 – 60
Wells	1 – 60
Land and storage formations	3 – 83
Facilities and other	3 – 60

Depreciation on property, plant and equipment is calculated to depreciate the net cost of each asset over its expected useful life to its estimated residual value. Land and pipeline rights of way are not depreciated. The estimated useful lives, residual values and depreciation methods are reviewed on an annual basis and, if necessary, any changes are accounted for prospectively.

ROU assets as related to defined-term leases are depreciated on a straight-line basis over the expected useful life of the asset, which is the shorter of the lease term or the expected useful life of the underlying asset. Land-based leases that are renewable into perpetuity at our Business' option are treated as an acquisition of land and are not depreciated.

Costs of major overhauls of engines and compressors included within the gas storage facilities are depreciated using the actual number of hours used over the estimated number of hours until the next scheduled major overhaul. The estimated useful lives of major overhauls, based on expected utilization, ranges from 10 to 20 years.

Certain volumes of hydrocarbons defined as cushion gas are required for maintaining a minimum reservoir pressure. Cushion gas is considered a component of the facility and as such is not amortized because of its indefinite useful life. Cushion gas is monitored to ensure that it provides effective pressure support for the facility. If cushion gas moves to another area of the reservoir where it does not provide effective pressure support or is withdrawn due to heat imbalances of native cushion volumes, a loss is recorded within depreciation expense, equal to the cost of estimated volumes that have migrated.

Goodwill

Goodwill represents the excess of the price paid for the acquisition of an entity over the fair value of the net tangible and intangible assets and liabilities acquired. Goodwill is allocated to the cash generating unit ("**CGU**") or units to which it relates. We identify a CGU or group of CGUs as identifiable groups of assets that are largely independent of the cash inflows from other assets or groups of assets.

Goodwill is not subject to amortization. Goodwill is evaluated for impairment annually or more often if events or circumstances indicate there may be impairment. Impairment is determined for goodwill by assessing if the carrying value of a CGU, including the allocated goodwill, exceeds its recoverable amount determined as the greater of the estimated fair value less costs of disposal or the value in use. Impairment losses recognized in respect of a CGU are first allocated to the carrying value of goodwill and any excess is allocated to the carrying amount of assets in the CGU. Any goodwill impairment is charged to net earnings (loss) in the period in which the impairment is identified. Impairment losses on goodwill are not subsequently reversed.

Impairment of long-lived assets

At each reporting date, our Business assesses, for its long-lived assets, if there is any indication that such assets are impaired. This assessment includes a review of internal and external factors that include, but are not limited to, changes in the technological, economic or legal environment in which the entity operates in, structural changes in the industry, changes in the level of demand, physical damage and obsolescence due to technological changes. An impairment is recognized if the recoverable amount, determined as the higher of the estimated fair value less costs of disposal or the value in use and eventual disposal from an asset or CGU is less than their carrying value. The projections used to calculate value in use consider the relevant operating plans and management's best estimate of the most probable set of conditions anticipated to prevail.

Impairments may be reversed for all CGUs and individual assets, other than goodwill, if there has been a change in the estimates and judgments used to determine the asset's recoverable amount. If such indication exists, the carrying amount of the asset or CGU unit is increased to the lesser of the revised estimate of recoverable amount and the carrying amount that would have been recorded had no impairment loss been recognized previously.

Risk management activities

Our Business uses natural gas derivatives and other financial instruments to manage its exposure to changes in natural gas prices, electricity prices, interest rates and foreign exchange rates. These financial assets and liabilities, which are recorded at fair value on a recurring basis, are included in one of three categories based on a fair value hierarchy, with realized and unrealized gains (losses) recognized in net earnings (losses) for the period (see Note 18 to our Annual Financial Statements) since these contracts are not treated as hedges for financial reporting purposes.

The fair value of our Business' derivative risk management contracts is recorded as a component of risk management assets and liabilities, which are classified as current or non-current assets or liabilities based upon the anticipated settlement date of the contracts.

Netting of certain statements of financial position accounts

Certain risk management assets and liabilities and certain accrued gas sales and purchases are presented on a net basis in the statements of financial position when all of the following exist: (i) our Business and the other party owe each other a determinable amount; (ii) our Business has the right to offset amounts owed with the other party; (iii) we intend to offset; and (iv) the right of offset is enforceable by law.

Provisions

Provisions are recognized by our Business when it has a legal or constructive obligation as a result of past events, it is probable that an outflow of economic resources will be required to settle the obligation and a reliable estimate can be made of the amount of the obligation. The amount recognized as a provision is the best estimate of the consideration required to settle the present obligation at the end of the reporting period, taking into account the risks and uncertainties surrounding the obligation. Where a provision is measured using the cash flows estimated to settle the obligation, its carrying amount is the present value of those cash flows.

Provisions are recognized for decommissioning obligations associated with our Business' property, plant and equipment at the end of their economic life. Provisions for decommissioning obligations are measured at the present value of management's best estimate of the future cash flows required to settle the present obligation, using a credit-adjusted interest rate. The value of the obligation is added to the carrying amount of the associated asset and amortized over the useful life of the asset. Any change in the present value, as a result of a change in discount rate or expected future costs, of the estimated obligation are recognized as a change in the decommissioning obligations and related assets. The provision is accreted over time through financing costs with actual expenditures charged to the accumulated obligation.

Gas storage obligations

Our gas storage obligations represent agreements to deliver set amounts of natural gas during specific timeframes from our Warwick gas storage facility that cannot be physically delivered in the timeframes specified. WGS LP has a practice of moving the delivery dates into the future through use of storage agreements with counterparties that offset delivery dates specified in previous agreements. This obligation is accounted for as a hybrid financial liability with an embedded natural gas derivative and is therefore recorded at fair value through profit and loss.

Leases

Our Business determines if a contract contains a lease at inception of a contract by using judgment in assessing the following aspects: i) the contract specifies an identified asset that is physically distinct or, if not physically distinct, represents substantially all of the capacity of the asset; ii) the contract provides the customer with the right to obtain substantially all of the economic benefits from the use of the asset; and iii) the customer has the right to direct how and for what purpose the identified asset is used throughout the period of the contract. If the contract is determined to contain a lease, further judgment is required to identify separate lease components of the arrangement by assessing whether the lessee can benefit from the right of use either on its own or together with other resources that are readily available to the lessee, as well as if the right of use is neither highly dependent on, nor highly interrelated, with the other rights to use the underlying assets in the contract. We consider non-lease components as distinct elements of a contract that are not related to the use of the leased asset. A good or service that is provided to a customer is distinct if: i) the customer can benefit from the good or service either on its own or together with other resources that are readily available to the customer; and ii) the entity's promise to transfer the good or service to the customer is separately identifiable from other promises in the contract.

Remeasurement of lease liabilities and a corresponding adjustment to the related ROU assets occurs when i) the lease term has changed or there is a change in the assessment of whether a purchase option will be exercised, in which case the lease liability is remeasured by discounting the revised lease payments using a revised discount rate; ii) the lease payments have changed due to changes in an index or rate or a change in expected payment under a guaranteed residual value, in which case the lease liability is remeasured by discounting the revised lease payments using the initial discount rate (unless the lease payments change is due to a change in a floating interest rate, in which case a revised discount rate is used); or iii) a lease contract is modified and the lease modification is not accounted for as a separate lease, in which case the lease liability is remeasured by discounting the revised lease payments using a revised discount rate.

Our Business applies the practical expedient to not recognize ROU assets or lease liabilities for leases that qualify for the short-term lease recognition exemption.

Cost of gas storage services

When market conditions warrant, our Business may pay a counterparty to flow gas into or out of our facilities. Such deals are transacted for the purpose of generating an overall positive net margin when combined with offsetting revenue generating activities. These costs are not recorded as a reduction of revenue, but rather are presented as a cost of providing gas storage services.

Deferred financing costs

Deferred financing costs relate to costs incurred on the issuance of debt and are amortized over the term of the related debt to financing costs using the effective interest method.

Foreign currency translation

The reporting currency of the Financial Statements of the Business is the U.S. dollar. Each entity within the combined group determines its own functional currency based on the primary economic environment in which it operates. For WGS LP, SIM Energy LP and SIM Energy Limited, the functional currency is the Canadian dollar. Assets and liabilities of these entities are translated into U.S. dollars at the period-end exchange rate. Revenues and expenses are translated at the average exchange rate for the reporting period. Non-monetary items measured at historical cost are translated at the exchange rate in effect on the date of the transaction. Foreign exchange gains and losses arising from the translation of the financial statements are recognized in other comprehensive income. Foreign exchange gains and losses arising from monetary transactions denominated in currencies other than the functional currency are recognized in net earnings (loss) for the period.

All other entities within the Combined Consolidated Financial Statements have a functional currency of U.S. dollars.

Current income tax

Current income tax assets and liabilities for the current period are measured at the amount expected to be recovered from or paid to the taxation authorities. The tax rates and tax laws used to compute the amount are those that are enacted, or substantively enacted at the reporting date in the countries where our Business operates and generates taxable income.

Deferred tax

Deferred tax is provided using the liability method on temporary differences between the tax basis of assets and liabilities and their carrying amounts for financial reporting purposes at the reporting date. Deferred tax liabilities are recognized for all taxable temporary differences, except:

- when the deferred tax liability arises from the initial recognition of goodwill or an asset or liability in a transaction that is not a business combination and, at the time of the transaction, affects neither the accounting profit nor taxable net earnings (loss); and
- in respect of taxable temporary differences associated with investments in subsidiaries, associates and interests in joint arrangements, when the timing of the reversal of the temporary differences can be controlled and it is probable that the temporary differences will not reverse in the foreseeable future.

Deferred tax assets are recognized for all deductible temporary differences and the carry forward of unused tax credits and unused tax losses, to the extent that it is probable that taxable profit will be available to use against the deductible temporary differences. The carry forward of unused tax credits and unused tax losses can be utilized, except:

- when the deferred tax asset relating to the deductible temporary difference arises from the initial recognition of an asset or liability in a transaction that is not a business combination and, at the time of the transaction, affects neither the accounting profit nor taxable net earnings (loss); and
- in respect of deductible temporary differences associated with investments in subsidiaries, associates and interests in joint arrangements, deferred tax assets are recognized only to the extent that it is probable that the temporary differences will reverse in the foreseeable future and taxable profit will be available against which the temporary differences can be utilized.

The carrying amount of deferred tax assets is reviewed at each reporting date and reduced to the extent that it is no longer probable that sufficient taxable profit will be available to allow all or part of the deferred tax asset to be utilized. Unrecognized deferred tax assets are reassessed at each reporting date and are recognized to the extent that it has become probable that future taxable profits will allow the deferred tax asset to be recovered.

Deferred tax assets and liabilities are measured at the tax rates that are expected to apply in the year when the asset is realized, or the liability is settled, based on tax rates (and tax laws) that have been enacted or substantively enacted at the reporting date.

Deferred tax relating to items recognized outside net earnings (loss) are recognized in correlation to the underlying transaction either in other comprehensive income or directly in equity.

Deferred tax assets and deferred tax liabilities are offset if a legally enforceable right exists to offset current tax assets against current income tax liabilities and the deferred taxes relate to the same taxable entity and the same taxation authority. Tax benefits acquired as part of a business combination, but not satisfying the criteria for separate recognition at that date, are recognized subsequently if new information about facts and circumstances change. The adjustment is either treated as a reduction to goodwill (as long as it does not exceed goodwill) if it is incurred during the measurement period or recognized in net earnings (loss).

Critical accounting judgments and key sources of estimation uncertainty

In preparing the Financial Statements of the Business, we are required to make estimates and assumptions that affect both the amount and timing of recording assets, liabilities, revenues and expenses since the determination of these items may be dependent on future events. Significant estimates made by management include: fair value of derivatives and other financial instruments, assessment of inventory adjustments, goodwill and other long-lived assets, income taxes, cushion gas migration, provisions for decommissioning obligations, gas storage obligations and recognizing lease liabilities and ROU assets. Management uses the most current information available and exercises careful judgment in making these estimates. Although management believes that these Financial Statements of the Business have been prepared within the limits of materiality and within the framework of its material accounting policy information summarized, actual results could differ from these estimates.

The estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimate is revised if the revision affects only that period, or in the period of the revision and future periods if the revision affects both current and future periods.

The preparation of financial statements requires management to make critical judgments that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses that are not readily apparent from other sources, during the reporting period. These estimates and associated assumptions are based on historical experience and other factors that are considered to be relevant. Critical judgments made by management and utilized in the normal course of preparing the Financial Statements of the Business are outlined below.

a. Fair value of risk management assets and liabilities

The determination of the fair value of natural gas derivatives and other financial instrument contracts reflects the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date.

There are uncertainties in our methodology in the determination of fair value since it requires our Business to consider various factors, including over-the-counter quotations, customer attrition, costs of fulfillment, location differentials and closing interest and foreign exchange rates underlying the contracts. Although the fair value of risk management assets and liabilities may fluctuate for commodity risk contracts, such fluctuations are offset by equivalent changes in the value of our physical inventory. Our policy is for our inventory and purchases to be economically hedged, within small tolerances permitted under our risk management policy; therefore, we reduce our economic exposure to the risk of fluctuating commodity prices.

b. Inventory

Our Business' inventory is natural gas injected into storage and held for resale. Inventory is valued at the lower of weighted average cost or net realizable value. Adjustments to the carrying value of inventory to net realizable value are recorded as an offset to optimization, net while costs to store the gas are recognized as operating expenses in the period the costs are incurred.

At the end of each reporting period, management determines whether an adjustment is required to reduce the carrying value of inventory to the lower of weighted average cost or net realizable value. This determination has built-in uncertainties since it requires judgment in both estimating fair market values in the periods in which our inventory can be sold and the volumes that can be sold in those periods.

c. Impairment of long-lived assets

Our Business evaluates whether events or circumstances have occurred that indicate that long-lived assets may not be recoverable or that the remaining useful life may warrant revision. When such events or circumstances are present, management assesses the recoverability of long-lived assets by comparing the higher of (1) fair value less costs of disposal or (2) the value in use and eventual disposal from an asset or CGU to their carrying value. The projections used to calculate value in use consider the relevant operating plans and management's best estimate of the most probable set of conditions anticipated to prevail.

Our Business' estimate for the impairment of long-lived assets contains uncertainties since it requires management to make a judgment on fair value, cost of disposals and expected value from the continued use of long-lived assets.

d. Income taxes

Our Business is predominantly not a taxable entity in the United States. Income taxes are the responsibility of the equity holders and have accordingly not been recorded in the Financial Statements of the Business.

Our Business has corporate subsidiaries, which are taxable corporations subject to Canadian federal and provincial income taxes, which are included in the Financial Statements of the Business.

Our Business' accounting of its income taxes has inherent uncertainties since it requires an estimate of the timing of the realization of its tax assets and liabilities, including the allocation of income among different entities and tax jurisdiction, and also requires us to make assumptions on the estimated probabilities of utilization of deferred tax assets and on the determination of tax exposures associated with our tax filing positions.

e. Cushion gas effectiveness

Certain volumes of cushion gas are required for maintaining a minimum reservoir pressure. Owned cushion gas is considered a component of the facility and as such is not depreciated because of its indefinite useful life. Cushion gas is monitored to ensure that it provides effective pressure support. In the event that natural gas moves to another area of the reservoir where it does not provide effective pressure support or is withdrawn due to heat imbalances of native cushion volumes, charges against cushion gas are included in depreciation in an amount equal to the cost of estimated volumes that have migrated.

Cushion gas requirements and its effectiveness are estimated using pressure and volumetric data accumulated over many years of storage operation.

f. Provisions for decommissioning obligations

Decommissioning, abandonment, and site reclamation expenditures for storage facilities, wells and pipelines are expected to be incurred by our Business over many years into the future. Amounts recorded for decommissioning obligations and the associated accretion are calculated based on estimates of the extent and timing of decommissioning activities, future site remediation regulations and technologies, inflation, liability specific discount rates and related cash flows. The provision represents management's best estimate of the present value of the future abandonment and reclamation costs required. Actual abandonment and reclamation costs could be materially different from estimated amounts.

g. Recognition of lease liabilities and right of use assets

Our Business has applied critical judgments in the application of lease accounting standards, including: i) identifying whether a contract, or part of a contract, includes a lease; ii) determining whether it is reasonably certain that lease extension or termination options will be exercised in determining the lease term; and iii) determining whether variable payments are in-substance fixed. We also use critical estimates in the application of lease accounting standards, including the estimation of lease term and determination of the appropriate rate to discount the lease payments. For leases that can be renewed into perpetuity at our option, a 60-year timeframe has been used as an estimate to measure the liability, ROU asset offset and undiscounted future cash outflows. Under the discount rates applicable to our leases, substantially all of the present value is contained within the first 60 years.

h. Gas storage obligations

Gas storage obligations are measured at fair value based on contracted volumes, estimated external forward price curves available at period end and an estimated discount rate applicable to the liabilities. Changes in forward pricing between period end and maturity of the derivative contracts could have a material impact on their carrying value.

Recently Adopted Accounting Pronouncements

We applied, for the first time, certain new standards applicable to our Business that became effective April 1, 2024. The impact of these amendments on our Business' accounting policies are as follows:

1. *Amendments to IAS 1 — Classification of Liabilities as Current or Non-current ("IAS 1")*

The amendments to IAS 1 affect only the presentation of liabilities as current or non-current in the combined consolidated statements of financial position and not the amount or timing of recognition of any asset, liability, income or expenses, or the information disclosed about those items. The amendments clarify that the classification of liabilities as current or non-current is based on rights that are in existence at the end of the reporting period, specify that classification is unaffected by expectations about whether our Business will exercise its right to defer settlement of a liability, explain that rights are in existence if covenants with which an entity is required to comply on or before the end of the reporting period are satisfied, and introduce a definition of 'settlement' to make clear that settlement refers to the transfer to the counterparty of cash, equity instruments, other assets or services. The amendments were applied retrospectively on April 1, 2024, and did not have a material impact on the financial position of our Business.

2. *Amendments to IAS 12 — International Tax Reform — Pillar Two Model Rules*

Our Business operates in the United States as well as Canada, which has enacted new legislation to implement the global minimum top-up tax, effective from January 1, 2024. We have applied a temporary mandatory relief from recognizing and disclosing deferred taxes in connection with the global minimum top-up tax and will account for it as a current tax when it is incurred. There is no material current tax impact for the fiscal year ended March 31, 2025. The global minimum top-up tax is not anticipated to have a significant impact on the financial position of our Business.

Future Accounting Policies

IFRS 18 — Presentation and Disclosure in Financial Statements ("IFRS 18")

In April 2024, the IASB issued IFRS 18, Presentation and Disclosure of Financial Statements. IFRS 18 is effective for periods beginning on or after January 1, 2027, with early adoption permitted. IFRS 18 is expected to improve the quality of financial reporting by requiring defined subtotals in the statement of profit or loss, requiring disclosure about management defined performance measures, and adding new principles for aggregation and disaggregation of information. Our Business is in the process of determining the impact of the amendments on its Combined Consolidated Financial Statements.

Amendments to IFRS 9 Financial Instruments and IFRS 7 Financial Instruments: Disclosures

On May 30, 2024, the IASB issued targeted amendments to IFRS 9, “Financial Instruments”, and IFRS 7, “Financial Instruments: Disclosures”. The amendments include new requirements not only for financial institutions but also for corporate entities which include clarifying the date of recognition and derecognition of some financial assets and liabilities, with a new exception for some financial liabilities settled through an electronic cash transfer system. These new requirements will apply from January 1, 2026, with early application permitted. Our Business is in the process of determining the impact of the amendments on its Combined Consolidated Financial Statements.

USE OF PROCEEDS

The net proceeds to the Company from the Offering are estimated to be approximately C$659,200,000 after deduction of the Underwriters' commission and the estimated expenses of the Offering. No Underwriters' commission will be payable by the Company to the Underwriters in connection with the Secondary Offering. Pursuant to the Underwriting Agreement, the Selling Shareholders will reimburse the Company for the expenses of the Offering, including the Underwriters' commission.

The Company intends to use the proceeds received by it from the Offering to fund a portion of the OpCo Interest Purchase Price payable to the Selling Shareholders for approximately 40% of the OpCo Interests to be acquired, and to acquire 40% of the Warwick Receivable (which will subsequently be cancelled), pursuant to the Reorganization. The purchase price for each OpCo Interest acquired under the Reorganization will be equal to the Offering Price. The Company will issue 21,200,000 Class A Shares to the Selling Shareholders at the Offering Price to satisfy the remaining OpCo Interest Purchase Price.

If the Over-Allotment Option is exercised in full, the net proceeds to the Selling Shareholders from the Secondary Offering are estimated to be approximately C$100,320,000 after deduction of the Underwriters' commission. The Selling Shareholders will pay the Underwriters' commission in respect of the Secondary Offering. The Company will not receive any of the proceeds from the Secondary Offering. See "Brookfield" and "Plan of Distribution".

DESCRIPTION OF SHARE CAPITAL AND OPCO INTERESTS

A description of the share capital of the Company and the OpCos is set forth below. This description discloses all attributes material to an investor in Class A Shares and is qualified in its entirety by reference to the Articles, to the A&R LPA and the LLC Agreement, as applicable, which will be available under the Company's SEDAR+ profile at www.sedarplus.ca. Investors are encouraged to read the full text of such Articles, the A&R LPA and LLC Agreement. See "Material Contracts".

The Company

The authorized share capital of the Company consists of: (i) an unlimited number of Class A Shares; (ii) an unlimited number of Class B Shares; and (iii) an unlimited number of preferred shares, issuable in series.

Upon completion of the Transactions, 53,200,000 Class A Shares, 79,800,000 Class B Shares and no preferred shares will be issued and outstanding. 21,200,000 Class A Shares (16,400,000 Class A Shares if the Over-Allotment Option is exercised in full) and all of the Class B Shares will be held by Brookfield. The Company does not intend to list the Class B Shares on any stock exchange.

Class A Shares

Class A Shares will be issued to Brookfield and to the public pursuant to the Transactions. Holders of Class A Shares are entitled to one vote for each Class A Share held at all meetings of shareholders of the Company, except meetings at which or in respect of matters for which only holders of another class of shares are entitled to vote separately as a class pursuant to the Articles or by law. Except as otherwise provided by the Articles or required by law, the holders of Class A Shares vote together with the holders of Class B Shares as a single class.

The holders of Class A Shares are entitled to receive, subject to the rights of the holders of another class of shares, any dividends or distributions declared by the Board from time to time and the remaining property of the Company on the liquidation, dissolution or winding-up of the Company, whether voluntary or involuntary. The Company may not issue or distribute to all or to substantially all of the holders of the Class A Shares either: (i) Class A Shares; or (ii) rights or securities of the Company exchangeable for or convertible into or exercisable to acquire Class A Shares, unless contemporaneously therewith, the Company issues or distributes Class B Shares or rights or securities of the Company exchangeable for or convertible into or exercisable to acquire Class B Shares on substantially similar terms (having regard to the specific attributes of the Class B Shares) and in the same proportion.

None of the Class A Shares will be subdivided, consolidated, reclassified or otherwise changed unless contemporaneously therewith the Class B Shares are subdivided, consolidated, reclassified or otherwise changed in the same proportion or same manner (having regard to the specific attributes of the classes of securities comprising the Shares).

The Company may not modify or remove any of the rights, privileges, conditions or restrictions of the Class A Shares without the approval by special resolution of the holders of Class A Shares.

Class B Shares

Class B Shares will be issued to Brookfield pursuant to the Transactions. Under the Articles, the Company is prohibited from issuing any Class B Shares unless a proportionate number of associated OpCo Interests are simultaneously issued by each of the OpCos. Holders of Class B Shares are entitled to one vote for each Class B Share held at all meetings of shareholders of the Company, except meetings at which or in respect of matters for which only holders of another class of shares are entitled to vote separately as a class pursuant to the Articles or by law. Except as otherwise provided by the Articles or required by law, the holders of Class B Shares vote together with the holders of Class A Shares as a single class.

The holders of Class B Shares are entitled to receive, subject to the rights of the holders of preferred shares and in priority to the holders of Class A Shares, an amount per Class B Share equal to C$0.000001 on the liquidation, dissolution or winding-up of the Company, whether voluntary or involuntary.

The holders of Class B Shares, as such, are not entitled to receive any dividends or other distributions (except for such dividends payable in Class B Shares, as described below, as may be declared by the Board from time to time). The Company may not issue or distribute to all or to substantially all of the holders of the Class B Shares either: (i) Class B Shares; or (ii) rights or securities of the Company exchangeable for or convertible into or exercisable to acquire Class B Shares, unless contemporaneously therewith, the Company issues or distributes Class A Shares, or rights or securities of the Company exchangeable for or convertible into or exercisable to acquire Class A Shares on substantially similar terms (having regard to the specific attributes of the Class A Shares) and in the same proportion.

The Class B Shares are subject to anti-dilution provisions, which provide that adjustments will be made to the Class B Shares in the event of a change to the Class A Shares in order to preserve the voting equivalency of such Class B Shares. See "— Class A Shares".

The Articles contain "coattail" provisions restricting the transfer of the Class B Shares in certain circumstances. Under applicable securities laws in Canada, an offer to purchase Class B Shares (and the accompanying OpCo Interests) would not necessarily require that an offer be made to purchase Class A Shares. In accordance with the rules of the TSX designed to ensure that, in the event of a take-over, the holders of Class A Shares are entitled to participate on an equal footing with holders of Class B Shares, the Articles contain customary coattail provisions which provide that no holder of Class B Shares is permitted to transfer such Class B Shares unless either: (i) such transfer would not require that the transferee make an offer to holders of Class A Shares to acquire Class A Shares on the same terms and conditions under applicable securities laws, if such Class B Shares were outstanding as Class A Shares; or (ii) if such transfer would require that the transferee make such an offer to holders of Class A Shares to acquire Class A Shares on the same terms and conditions under applicable securities laws, the transferee acquiring such Class B Shares makes a contemporaneous identical offer for Class A Shares (in terms of price, timing, proportion of securities sought to be acquired and conditions) and does not acquire such Class B Shares unless the transferee also acquires a proportionate number of Class A Shares actually tendered to such identical offer.

The Company may not modify or remove any of the rights, privileges, conditions or restrictions of the Class B Shares without the approval by special resolution of the holders of Class B Shares.

Preferred Shares

The preferred shares may at any time be issued in one or more series. Subject to the ABCA, the Board may fix, before the issue thereof, the number of preferred shares of each series, the designation, rights, privileges, restrictions and conditions attaching to the preferred shares of each series, including, without limitation, any voting rights, any right to receive dividends, any terms and conditions of redemption or purchase, any conversion rights, any rights on the liquidation, dissolution or winding up of the Company, and any sinking fund or other provisions, the whole to be subject to the issue of a certificate of amendment or articles of the Company setting forth the designation, rights, privileges, restrictions and conditions attaching to the preferred shares of the series. The preferred shares of each series shall, with respect to the payment of dividends and the distribution of assets in the event of the liquidation, dissolution or winding up of the Company, whether voluntary or involuntary, rank on a parity with the preference shares of every other series and be entitled to preference over the Class A Shares and the Class B Shares with respect to priority in payment of dividends and the distribution of assets in the event of the liquidation, dissolution or winding-up of the Company. There are currently no outstanding preferred shares and there will be no outstanding preferred shares following completion of the Transactions.

The OpCos

Swan OpCo

General

Swan OpCo is a limited partnership established under the laws of the Province of Ontario for the purpose of engaging in all lawful activities for which a limited partnership may be formed under the *Limited Partnerships Act* (Ontario) (the "**Limited Partnerships Act**"). Swan OpCo has a perpetual existence and will continue as an Ontario limited liability partnership unless it is terminated or dissolved in accordance with the A&R LPA.

Swan OpCo Partnership Interests

Swan OpCo is authorized to issue an unlimited number of Swan OpCo Units (being limited partner units) and Swan OpCo GP Units. All Swan OpCo GP Units outstanding at any time collectively represent a 0.01% interest in Swan OpCo, with the remaining 99.99% interest in Swan OpCo being divided into and represented by Swan OpCo Units. No holder of Swan OpCo Units has a priority over any other holder of Swan OpCo Units, either as to the return of capital contributions or as to profits, losses or distributions.

Issuance of Additional Partnership Interests

Subject to applicable law and the provisions of the Relationship Agreement, Swan GP has broad rights to cause Swan OpCo to issue additional partnership interests (including additional Swan OpCo Units, new classes of partnership units and options, rights, warrants and appreciation rights relating to such Swan OpCo Units, and other units) for any partnership purpose, and to admit additional limited and general partners, at any time and on such terms and conditions as it may determine without the approval of any Swan OpCo Limited Partner. Any additional partnership units may be issued in one or more classes, or one or more series of classes, with such designations, preferences, rights, powers and duties (which may be senior to existing classes and series of partnership units) as may be determined by Swan GP in its sole discretion, all without approval of the Swan OpCo Limited Partners.

Swan OpCo Limited Partner Limited Liability

The A&R LPA provides that, notwithstanding any provision of the A&R LPA, the Swan OpCo Limited Partners shall not be liable for any of the losses, debts or liabilities of Swan OpCo in excess of their respective capital contributions and their *pro rata* share of the undistributed profits of Swan OpCo, except as required by the Limited Partnerships Act.

Transfers of Swan OpCo Units

In accordance with the A&R LPA, a Swan OpCo Limited Partner may not transfer, assign, pledge or hypothecate, in whole or in part, their Swan OpCo Units without the prior written consent of Swan GP, which consent will be evidenced by a unanimous written resolution of the board of directors of Swan GP. In addition, pursuant to the Exchange Agreement, Brookfield has agreed that it will not transfer any OpCo Interests if such transfer would result in Brookfield no longer holding a majority of the outstanding OpCo interests unless and until CPUC Approval has been obtained.

Allocation of Profits and Losses

Pursuant to the A&R LPA, the profits and losses (each as defined in the A&R LPA) of Swan OpCo for each fiscal year, including for income tax purposes, will be determined by Swan GP and allocated at the end of each fiscal year among the Swan OpCo Partners as follows: (i) 0.01% of the profits and losses of Swan OpCo will be allocated to Swan GP; and (ii) 99.99% of the profits and losses of Swan OpCo will be allocated among the Swan OpCo Limited Partners of record at the end of the fiscal year on a *pro rata* basis in proportion to the number of Swan OpCo Units held by each of them. Whenever a proportionate part of Swan GP's profit and loss is allocated to a Swan OpCo Partner, every item of income, gain, loss, deduction and credit entering into the computation of or otherwise relating to such profit or loss applicable to the period during which such profit or loss was realized, shall be allocated to such Swan OpCo Partner in the same proportion.

Distributions

Distributions from Swan OpCo to the Swan OpCo Limited Partners are not guaranteed. The A&R LPA states that distributions shall be made to the Swan OpCo Partners at such times and in such amounts as may be determined in the sole discretion of Swan GP. See "Risk Factors — Rockpoint is a holding company. The sole material assets of the Company following completion of the Transactions will be its OpCo Interests. Accordingly, the Company will be fully dependent upon distributions from the OpCos to fund its expenses and the payment of dividends" and "Risk Factors — Rockpoint will be dependent upon the OpCo Boards, which are comprised of a majority of Brookfield-affiliated directors or managers, for supervision of the management and operation of the Business and the OpCos, which could affect the value of Rockpoint's investment in the Business".

Distributions to Swan OpCo Limited Partners shall be shared among the Swan OpCo Limited Partners on a *pro rata* basis in proportion to the number of Swan OpCo Units held by each of them. Notwithstanding any provision to the contrary contained in the A&R LPA, Swan OpCo shall not make a distribution to the Swan OpCo Partners on account of their interests in Swan OpCo if such distribution would violate the Limited Partnerships Act or other applicable law. Swan GP will not be entitled to any fees or distributions in connection with its role as general partner of Swan OpCo.

The A&R LPA states that if the payment of a distribution at any time would cause the amount determined immediately after that time under the Tax Act in respect of any Swan OpCo Limited Partner's interest in Swan OpCo to be an amount greater than nil, no distribution shall be declared or paid to the Swan OpCo Limited Partners. In lieu of making such distribution, Swan GP shall cause Swan OpCo to make a non-interest bearing loan to each Swan OpCo Limited Partner in an amount equal to the amount of the distribution that would otherwise have been made to such Swan OpCo Limited Partner (each a "**Loan**", and collectively, the "**Loans**"), which Loans will be due and payable in full 30 days after the end of the fiscal year of Swan OpCo in which the Loans are made. Any amounts paid to a Swan OpCo Limited Partner in connection with such distribution shall be deemed to be advanced as a Loan. Any share of a distribution not paid to a Swan OpCo Limited Partner (including a former Swan OpCo Limited Partner) pursuant to these requirements shall be paid to such Swan OpCo Limited Partner (or former Swan OpCo Limited Partner) on the 30th day after the end of the fiscal year of Swan OpCo in which the distribution was to be paid (the "**Follow-up Payment**") or, in the event of a dissolution of Swan OpCo, on the date of dissolution. The payment of a Follow-up Payment by Swan OpCo shall be automatically set-off against the amounts owing under the Loans and such amounts shall be considered to be repaid and settled in full. The amount of any Loan made to a Swan OpCo Limited Partner pursuant to these requirements shall not be considered to be a distribution received by such Swan OpCo Limited Partner for purposes of the A&R LPA, and a Follow-up Payment shall be considered to be a distribution in respect of the fiscal year of Swan OpCo in which the distribution to which such Follow-up Payment relates was to be paid.

Termination and Dissolution

In accordance with the terms of the A&R LPA, Swan OpCo shall dissolve, and its affairs shall be wound up upon the first to occur of the following: (i) subject to the provisions of the Relationship Agreement, the decision of Swan GP; (ii) the termination, dissolution, liquidation, bankruptcy, insolvency, winding-up or other event of withdrawal of Swan GP unless the Swan OpCo Limited Partners unanimously consent to the appointment of a new general partner within 30 days of such event occurring; and (iii) at any time there are no Swan OpCo Limited Partners.

In the event of dissolution, Swan OpCo shall conduct only such activities as are necessary to wind up its affairs (including the sale of the assets of Swan OpCo in an orderly manner) and the assets of Swan OpCo shall be applied and distributed, to the extent permitted by law, in the following order: (i) to the discharge of debts and obligations of Swan OpCo, and (ii) the Swan OpCo Partners holding Swan OpCo Units pro rata in proportion to the number of Swan OpCo Units then held by each of them. Notwithstanding any provision to the contrary contained in the A&R LPA, Swan OpCo shall not make a distribution to the Swan OpCo Partners on account of their interests in Swan OpCo if such distribution would violate the Limited Partnerships Act or other applicable law.

Management

The conduct of the business and affairs of Swan OpCo is managed by Swan GP. According to the A&R LPA, subject to the express limitations contained in any provision of the A&R LPA or the Limited Partnerships Act, Swan GP has complete and absolute control of the affairs and business of Swan OpCo, and possesses all powers necessary, convenient or appropriate to carrying out the purposes and business of Swan OpCo. Further, the A&R LPA provides that, subject to the provisions of the A&R LPA, Swan GP is authorized to execute and deliver any document on behalf of Swan OpCo without any vote or consent of any other Swan OpCo Partner.

Swan GP may delegate to any person any or all of its powers, rights and obligations under the A&R LPA and may appoint, contract or otherwise deal with any person to perform any acts or services for Swan OpCo as Swan GP may reasonably determine.

No Swan OpCo Partner (other than Swan GP) is entitled to participate in the management or control or conduct of the business of, nor does any Swan OpCo Partner (other than Swan GP) have any rights or powers with respect to, Swan OpCo except those expressly granted to such Swan OpCo Partner by the terms of the A&R LPA or applicable law.

The A&R LPA provides that other than the entitlements to which Swan GP may be entitled as a result of the terms of the Swan OpCo GP Unit, Swan GP will receive no amounts and will not be compensated for any services it provides to Swan OpCo in its capacity as general partner of Swan OpCo without the unanimous consent of the Swan OpCo Partners.

Outside Business Interests

Each Swan OpCo Partner may engage in, or possess an interest in, other business ventures (unconnected with Swan OpCo) of every kind and description, independently or with others. Swan OpCo shall not have any rights in or to such independent ventures or the income or profits therefrom by virtue of the A&R LPA or the relationships created thereby.

Indemnification; Limitations on Liability

None of Swan GP, any officer of Swan GP or any authorized person of Swan OpCo shall be liable, responsible or accountable in damages to the Swan OpCo Limited Partners or Swan OpCo for: (i) any act or omission on behalf of Swan OpCo performed or omitted to be taken by them in good faith and in a manner reasonably believed by them to be within the scope of the authority granted to them by the A&R LPA and in, or not opposed to, the best interests of Swan OpCo, provided that such person is not guilty of gross negligence or willful misconduct; (ii) any action or omission taken or suffered by any other Swan OpCo Partner; or (iii) any mistake, negligence, dishonesty or bad faith of any delegatee or other agent of Swan OpCo selected by such person with reasonable care. To the extent that, at law or in equity, any such person has duties (including fiduciary duties) and liabilities relating thereto to Swan OpCo or to another Swan OpCo Partner, any such person acting under the A&R LPA shall not be liable to Swan OpCo or such other Swan OpCo Partner for their good faith reliance on the provisions of the A&R LPA. In accordance with the A&R LPA, to the extent that such provisions expand, restrict or eliminate the duties and liabilities of Swan GP otherwise existing at law or in equity, the Swan OpCo Partners agree to modify to that extent such other duties and liabilities of Swan GP. Under the A&R LPA, to the fullest extent permitted by law, Swan OpCo has agreed to indemnify Swan GP, each officer of Swan GP and each authorized person of Swan OpCo against any loss, damage or expense (including amounts paid in satisfaction of judgments, in settlements, as fines and penalties and legal and other costs and expenses of investigation or defense) incurred by such person by reason of any act or omission so performed or omitted by them (and not involving gross negligence or willful misconduct) and any such amount shall be paid by Swan OpCo to the extent assets are available; however, notwithstanding the forgoing, the A&R LPA also provides that the Swan OpCo Limited Partners shall not have any personal liability to any such person or Swan OpCo on account of such loss, damage or expense.

In addition to the terms set out above, the A&R LPA provides that Swan GP, each officer of Swan GP and each authorized person of Swan OpCo may consult with legal counsel, accountants and other professional experts selected by them and any act or omission suffered or taken by them on behalf of Swan OpCo or in furtherance of the interests of Swan OpCo in good faith in reliance upon and in accordance with the advice of such counsel, accountants or other professional experts shall be full justification for any such act or omission, and each such person shall be fully protected in so acting or omitting to act, provided such counsel, accountants or other professional experts were selected with reasonable care.

Under the A&R LPA, the Swan OpCo Partners have agreed that to the fullest extent permitted by law, expenses incurred by Swan GP, any officer of Swan GP or any authorized person of Swan OpCo in defense or settlement of any claim that may, at the determination of Swan GP, be subject to a right of indemnification hereunder may be paid by Swan OpCo in advance of the final disposition thereof upon receipt of an undertaking by or on behalf of each such person to repay such amount to Swan OpCo if it shall be determined, by a court of competent jurisdiction pursuant to a final non-appealable judgment, order or decree, that such person is not entitled to be indemnified hereunder.

Amendments to the A&R LPA

Subject to the provisions of the Relationship Agreement, the A&R LPA may not be modified, altered, supplemented or amended except pursuant to a written agreement executed and delivered by the Swan OpCo Partners. In connection with the completion of the Reorganization, the Company will receive Swan OpCo Units and become a Swan OpCo Limited Partner.

BIF OpCo

General

BIF OpCo is a Delaware limited liability company formed for the purpose of engaging in any lawful acts or activities permitted by limited liability companies under the *Delaware Limited Liability Company Act* (the "**LLC Act**"). BIF OpCo has a perpetual existence and will continue as a Delaware limited liability company unless it is terminated or dissolved in accordance with the LLC Agreement.

BIF OpCo Shares

Pursuant to the LLC Agreement, BIF OpCo is authorized to issue a single class of shareholder interests (BIF OpCo Shares) designated as "Common Shares". Each BIF OpCo Share represents one unit of limited liability company interest issued by BIF OpCo. The BIF OpCo Shares entitle the holders thereof to one vote per BIF OpCo Share held on all matters submitted to a vote of the stockholders and the right to receive distributions of BIF OpCo's assets in accordance with the LLC Agreement and the LLC Act. BIF OpCo is entitled at its discretion to purchase for cancellation any BIF OpCo Shares held by a holder thereof subject to the LLC Act, other applicable law and the provisions of the Relationship Agreement.

Limited Liability of the Shareholders and Managers of BIF OpCo

The LLC Agreement provides that, except as otherwise provided by the LLC Act, the debts, obligations and liabilities of BIF OpCo, whether arising in contract, tort or otherwise, shall be solely the debts, obligations and liabilities of BIF OpCo, and no BIF OpCo Shareholder, manager of BIF OpCo, or officer, employee or agent of BIF OpCo (including a person having more than one such capacity) will be obligated personally for any such debt, obligation or liability of BIF OpCo solely by reason of acting in such capacity.

Transfers of BIF OpCo Shares

In accordance with the LLC Agreement, holders of BIF OpCo Shares may transfer their BIF OpCo Shares, provided that the transferee executes and agrees to all the provisions of the LLC Agreement and otherwise assumes all of the obligations of a BIF OpCo Shareholder. However, pursuant to the Exchange Agreement, Brookfield has agreed that it will not transfer any OpCo Interests if such transfer would result in Brookfield no longer holding a majority of the outstanding OpCo Interests, unless and until CPUC Approval has been obtained.

Retained Earnings

The profits and losses of BIF OpCo for each taxable year are determined on an annual basis and are available for distribution to BIF OpCo Shareholders in proportion to their ownership of BIF OpCo Shares. The cumulative net amount at any time is referred to as "Retained Earnings".

Distributions

Pursuant to the LLC Agreement, BIF OpCo is entitled to make distributions in respect of a BIF OpCo Share held by BIF OpCo Shareholders as follows: (i) subject to the provisions of the Relationship Agreement, as a return of capital in respect of a BIF OpCo Share; and (ii) as a distribution other than a return of capital, which distribution shall reduce the amount of Retained Earnings.

Distributions from BIF OpCo to the BIF OpCo Shareholders are not guaranteed. Distributions may be made to a BIF OpCo Shareholder at such times and in such amounts as may be determined in the sole discretion of BIF OpCo or the managers of BIF OpCo, so long as such distribution would not violate Section 18-607 of the LLC Act or other applicable law.

Dissolution

In accordance with the terms of the LLC Agreement, BIF OpCo must dissolve, and its affairs must be wound up, upon the first to occur of the following: (i) subject to the provisions of the Relationship Agreement, the written consent of the BIF OpCo Shareholders; (ii) the dissolution, termination, winding up, bankruptcy, or other inability to act in such capacity, of the last remaining BIF OpCo Shareholders; and (iii) any entry of a decree of judicial dissolution under Section 18-802 of the LLC Act. In the event of dissolution, BIF OpCo must conduct only such activities as are necessary to wind up its affairs (including the sale of the assets of BIF OpCo in an orderly manner).

Management

The business and affairs of BIF OpCo is managed by a board of managers and its officers. According to the LLC Agreement, subject to the express limitations contained in the LLC Agreement or the LLC Act, the board of managers of BIF OpCo has complete and absolute control over the affairs and business of BIF OpCo, and possesses all powers necessary, convenient or appropriate to carrying out the purpose and business of BIF OpCo, including, without limitation, doing all things and taking all actions necessary to carrying out the terms and provisions of the LLC Agreement.

The LLC Agreement provides that the number of managers constituting the whole board of managers of BIF OpCo must be at least one, and that such number may be fixed from time to time by action of the BIF OpCo Shareholders. Each manager of BIF OpCo will serve as a manager until the earlier to occur of the bankruptcy, adjudicated incompetency, termination of the legal existence, death, or retirement of the manager, or the resignation or removal, with or without cause, of the manager by the BIF OpCo Shareholders. Upon the occurrence of such event, the BIF OpCo Shareholders may designate the replacement manager, if any. The initial board of managers of BIF OpCo was appointed by the initial BIF OpCo Shareholders, BIF II CalGas Carry (Delaware) LLC and BIP BIF II US Holdings (Delaware) LLC. Following the Reorganization, Rockpoint will be admitted as the third BIF OpCo Shareholder and will participate in the election of replacement managers, including in compliance with the terms of the Relationship Agreement.

The LLC Agreement also provides that the board of managers of BIF OpCo may appoint one or more officers of BIF OpCo (which may include BIF OpCo Shareholders or managers of BIF OpCo) with such powers, titles and duties as may be approved by the board of managers of BIF OpCo. Pursuant to the Relationship Agreement, the officers of BIF OpCo will be comprised of executive officers of the Company. Each officer will hold office until the first to occur of his or her death, retirement, resignation or removal with or without cause by the board of managers of BIF OpCo.

Finally, the LLC Agreement provides that BIF OpCo is entitled to reimburse its managers for their reasonable expenses incurred in attending meetings of the board of managers of BIF OpCo or committee meetings or otherwise serving as managers of BIF OpCo.

Indemnification

The LLC Agreement provides that BIF OpCo must indemnify and hold harmless each BIF OpCo Shareholder, manager of BIF OpCo, and officer, employee or agent of BIF OpCo to the fullest extent permitted under the LLC Act, against all expenses, liabilities and losses (including reasonable attorneys' fees and expenses, judgments, fines, excise taxes or penalties) reasonably incurred or suffered by such person by reason of the fact that such person is or was a BIF OpCo Shareholder, manager of BIF OpCo, or officer, employee or agent of BIF OpCo or is or was serving as a shareholder, manager, officer, employee or agent of a subsidiary of BIF OpCo; provided, however, that no such person will be indemnified by BIF OpCo for any expenses, liabilities or losses suffered that are attributable to such person's bad faith, intentional misconduct or knowing violation of law. The LLC Agreement further provides that expenses, including reasonable attorney's fees and expenses, incurred by any indemnified person in defending a proceeding must be paid by

BIF OpCo in advance of the final disposition of such proceeding, including any appeal therefrom, upon receipt of an undertaking by or on behalf of such person to repay promptly such amount if it will ultimately be determined that such person is not entitled to be indemnified by BIF OpCo.

Amendments to the LLC Agreement

Subject to the provisions of the Relationship Agreement, the LLC Agreement may be amended by the BIF OpCo Shareholders in writing from time to time.

DIVIDEND POLICY

The Company currently intends to establish a dividend policy pursuant to which the Company will pay a quarterly dividend in an amount based on its share of the OpCos' Distributable Cash Flow. The Company is currently targeting an initial dividend in the amount of approximately $0.22 per Class A Share (C$0.31 per Class A Share based on the Bloomberg mid-market exchange rate of C$1.00 = $0.7168 on October 7, 2025) or $0.88 per Class A Share on an annualized basis (C$1.23 per Class A Share based on the Bloomberg mid-market exchange rate of C$1.00 = $0.7168 on October 7, 2025), representing a payout ratio of 50% to 60% of its share of the Opcos' Distributable Cash Flow. The Company intends to pay its first such dividend on December 31, 2025 and thereafter, on a quarterly basis. The Company targets its dividend to grow annually at a rate of 3% to 5%. The Board's declaration of cash dividends on the Class A Shares will be subject to applicable law and depend on, among other things, the timing and amount of distributions declared and paid by the OpCos to the Company, economic conditions, the Company's expenses, financial condition, results of operations, liquidity, earnings, projections, legal requirements, and restrictions in the agreements governing the Company's indebtedness, including the Credit Facilities. The OpCos intend to pay dividends to their partners and members, as applicable, including the Company, on a quarterly basis sufficient to ensure that the Company can fund its expenses and the payment of dividends. The OpCos have adopted a sustainable target dividend payout of 50% to 60% of their respective Distributable Cash Flow (of which approximately 40% of any payout would be paid to the Company). The OpCos' target dividend payout plans for $110 million to $120 million of total annual dividends from the Business (of which approximately 40% of any payout would be paid to the Company). Following its first dividend payment to shareholders, if, as and when an OpCo pays a cash distribution, the Company anticipates that the Board will declare and pay a corresponding cash dividend on the Class A Shares. See "Notice to Investors — Forward-Looking Information", "Risk Factors — Risks Related to Our Business and Industry" and "Risk Factors — Risks Related to Our Financial Condition".

The OpCos' sustainable target dividend payout of 50% to 60% of their respective Distributable Cash Flow is based on our assessment of the current position of the Business and market conditions. See "Prospectus Summary — Our Business — Our Competitive Strengths — High free cash flow conversion supports reinvestment and return of capital". We expect distributions from the OpCos to grow in line with the expected growth of our Distributable Cash Flow.

The Company will be fully dependent on distributions declared and paid by the OpCo Boards, for cash to fund its expenses and the payment of dividends to holders of Class A Shares. However, each OpCo has agreed to use commercially reasonable efforts to make *pro rata* distributions in an amount sufficient to allow the Company to satisfy its income tax liabilities with respect to its allocable share of the income of such OpCo. Additionally, amendments to the financial policy setting forth the OpCos' sustainable target dividend payout will require the approval of the OpCo Boards. The OpCo Boards are comprised entirely of directors of the Company, with a majority of Brookfield-affiliated directors. See "Relationship with Brookfield — The Transactions" and "Risk Factors — Rockpoint is a holding company. The sole material assets of the Company following completion of the Transactions will be its OpCo Interests. Accordingly, the Company will be fully dependent upon distributions from the OpCos to fund its expenses and the payment of dividends".

The payment of any future dividends will be at the discretion of the Board, and there can be no assurances that any dividend will be declared and paid.

The Term Loan Credit Agreement and the ABL Credit Agreement contain restrictions on the payment of dividends by Rockpoint Gas Storage Partners LP, BIF OpCo and their subsidiaries and the Revolving Credit Agreement is expected to contain restrictions on the payment of dividends by the Company, the OpCos and their subsidiaries. Such restrictions allow the Company, Rockpoint Gas Storage Partners LP, the OpCos and their subsidiaries, as applicable, to pay dividends after the completion of the Transactions to the extent a basket or carve-out under the Term Loan Credit Agreement, the Revolving Credit Agreement and the ABL Credit Agreement, as applicable, permits the making of such dividend. Under both the Term Loan Credit Agreement and the Revolving Credit Agreement, the baskets include or will include, as applicable, but are not limited to: (i) a leverage-based restricted payment basket subject to satisfaction of a 5.00x first lien net leverage ratio (or, if greater, the first lien net leverage ratio as of the last day of the most recent test period); (ii) a post-Offering restricted payment basket equal to the sum of 8.0% of the market capitalization of the Company plus 7.0% per annum of Offering proceeds contributed to Rockpoint Gas Storage Partners LP, BIF OpCo and their subsidiaries, in the case of the Term Loan Credit Agreement and the ABL Credit Agreement, and the

Company, the OpCos and their subsidiaries, in the case of the Revolving Credit Agreement, in each such case, which may be carried forward or back; (iii) a builder basket based on our Consolidated EBITDA, Consolidated Net Income or Retained Excess Cash Flow (each foregoing capitalized term as defined in the Revolving Credit Agreement and the Term Loan Credit Agreement, as applicable); and (iv) a general restricted payments basket based on the greater of $126.25 million and 50% of our Consolidated EBITDA (as defined in the Revolving Credit Agreement and the Term Loan Credit Agreement, as applicable) plus certain other inclusions. Under the ABL Credit Agreement, unlimited dividends are permitted subject to satisfaction of payment conditions, which include a fixed charge coverage ratio of at least 1.25 to 1.00 on a pro forma basis, pro forma excess liquidity in excess of the greater of 25% of the maximum amount available to be drawn under the ABL Facility and $24 million and no event of default having occurred and be continuing immediately before and after such dividend.

The Warwick Credit Agreement contains restrictions on the payment of salaries, bonuses, dividends, management fees, loan outstandings, or otherwise to shareholders, unitholders or persons associated therewith if such payment would cause a default under its debt service coverage ratio covenant, which requires WGS LP's debt service coverage ratio to be at least 1.2:1.0.

The Company does not view the restrictive covenants contained in the Credit Agreements as currently having a restrictive impact on the OpCos' ability to meet their minimum target distribution of 50% as the thresholds under such restrictive covenants are minimal.

The Company has not declared any dividends on the Shares since its incorporation.

CONSOLIDATED CAPITALIZATION

The following table sets forth the consolidated capitalization of the Company and the pro forma consolidated capitalization of the Company as at July 28, 2025 after giving effect to the Transactions. Other than as described below, there has not been any material change in the share and loan capital of the Company since its incorporation. The consolidated capitalization presented below has been prepared on a basis consistent in all material respects with the accounting policies of the Business in accordance with IFRS and should be read together with the information under "Selected Historical Financial Information", "Management's Discussion and Analysis" contained elsewhere in this prospectus and the Financial Statements of the Business contained elsewhere in this prospectus.

	As at July 28, 2025 after giving effect to the Transactions	
(in millions, $)	**Actual(1)**	**Adjusted(2)**
Cash and cash equivalents	—	—
Equity		
Class A Shares	—	$838.8
Class B Shares	—	—
Total Equity	—	$838.8

Notes:

(1) The Company was incorporated by Brookfield Infrastructure Holdings (Canada) Inc. under the ABCA on July 28, 2025 and actual results reflect the seed balance sheet as at July 28, 2025. The Company will have no operating history until completion of the Transactions.

(2) Pursuant to the Transactions, the Company will issue 79,800,000 Class B Shares to Brookfield Infrastructure Holdings (Canada) Inc. for nominal consideration to align Brookfield's voting interest in the Company with its economic interest in the OpCos. The Company will acquire an approximate 40% equity accounted interest in each of the OpCos measured at an aggregate carrying value of approximately $838.8 million in exchange for the net proceeds from the Offering and 21,200,000 newly issued Class A Shares.

CORPORATE GOVERNANCE

The structure, practices and committees of the Board, including matters relating to the size, independence and composition of the Board, the election and removal of directors, requirements relating to board action and the powers delegated to board committees are governed by the Articles and By-laws, policies adopted by the Board, certain contracts entered into with Brookfield, as described under "Relationship with Brookfield", and applicable law. The Board is responsible for exercising the management, control, power and authority of the Company except as contemplated by applicable law.

Size, Composition and Independence of the Board

The Board is currently comprised of three directors, being Brian Baker, William Burton and Tobias McKenna. Following Closing, we expect the Board to be comprised of the nine directors identified under "Directors and Executive Officers", with a majority of those members being independent.

The Board's charter includes a policy in relation to the number of independent directors on the Board in order to ensure that the Board operates independent of management and effectively oversees the conduct of management. The Company will obtain information from its directors annually to determine their independence. The Board will decide which directors are considered to be independent based on the recommendation of the GNC Committee, which will evaluate director independence based on the guidelines set forth under applicable securities laws.

Upon Closing, we expect the Chair of the Board to be Rick Eng, who will not be an independent director. However, all directors on the Audit Committee will be independent and the Board will have a Lead Independent Director, Sippy Chhina. In addition, special committees of independent directors may be formed from time to time to review particular matters or transactions. The Board encourages regular and open dialogue between the independent directors and the Chair to discuss matters raised by independent directors.

Meetings of Independent Directors

Private sessions of the independent directors without management and non-independent directors present will be held at the end of each regularly scheduled and special Board meeting. Each private session of the independent members of the Board will be chaired by the Lead Independent Director, who will then report back to the Chief Executive Officer on any matters requiring action by management.

Private sessions of the Committees without members of management and non-independent directors present will also be held after each Committee meeting. The Chair of the applicable committee, will then report back to an appropriate executive on any matters requiring action by management. Certain committees may have a non-independent director serve as a Chair of the committee.

Lead Independent Director

Where the Board has not appointed an independent Chair, a Lead Independent Director will be appointed. Any Lead Independent Director will generally be responsible for facilitating the functioning of the Board independent of management and the non-independent Chair. The responsibilities of the Lead Independent Director will include, among other things: maintaining and enhancing the quality of corporate governance; coordinating the activities of the other independent directors; consulting and communicating directly with shareholders of the Company and other stakeholders, when appropriate; presiding over all private sessions of the Company's independent and unaffiliated directors and ensuring that matters raised during these meetings are reviewed with the Chief Executive Officer and Chair and acted upon in a timely fashion; providing leadership to the Board if circumstances arise in which the Chair may be, or may be perceived to be, in conflict, in responding to any reported conflicts of interest, or potential conflicts of interest, arising for any director; and calling meetings of the independent directors, if necessary.

Transactions in which a Director has an Interest

A director who directly or indirectly has an interest in a contract, transaction or arrangement involving the Company, one or more of the Company's affiliates or the Business is required to disclose the nature of his or her interest to the full Board as soon as the director becomes aware of it. Such disclosure may take the form of a general notice given to the Board to the effect that the director has the interest and is to be regarded as interested in the particular contract, transaction or arrangement which may occur after the date of the notice be given effect. In situations where a director has an interest in a matter to be considered by the Board or any Committee on which he or she serves, such director may be required to recuse himself or herself from the meeting while discussions and voting with respect to the matter are taking place. Directors are also required to comply with the relevant provisions of the ABCA regarding conflicts of interest.

Election and Removal of Directors

The GNC Committee will be responsible for identifying and placing before the shareholders of the Company, the directors to be nominated for election to the Board, including the candidates proposed to be nominated for election to the Board at the annual meeting of shareholders.

In addition to its Advance Notice Provisions, the Company will enter into the Shareholder Agreement pursuant to which Brookfield will be entitled to certain director nomination rights. See "Relationship with Brookfield — Agreements Between the Company and Brookfield — Shareholder Agreement". Following its assessment of the directors nominated by Brookfield, if any, and any other shareholder, at each meeting of shareholders at which director elections are to be considered, the GNC Committee will determine the final list of directors that will be recommended to the Board for presentation to shareholders for their consideration.

Each holder of Class A Shares and Class B Shares is entitled to one vote per Share in connection with the election of the directors of the Company.

Following Closing, each of the Company's directors will serve until the next annual meeting of shareholders of the Company or his or her death, resignation or removal from office, whichever occurs first. Vacancies on the Board may be filled by the directors and the directors may, between annual general meetings, appoint one or more additional directors of the Company to serve until the next annual general meeting, but the number of additional directors shall not at any time exceed 1/3 of the number of directors who held office at the expiration of the last annual meeting of the Company. Additional directors may also be added to the Board between annual general meetings by a resolution of the Company's shareholders.

A director may be removed from office by a resolution of the Company's shareholders and a director will be removed from the Board if they cease to be qualified to act as a director of the Company and do not promptly resign.

The Board does not expect to adopt a majority voting policy for the election of directors immediately following Closing. The Company will be exempt from the TSX's requirement to adopt such a policy because upon completion of the Transactions, assuming no exercise of the Over-Allotment Option, Brookfield will own approximately 39.8% of the aggregate outstanding Class A Shares and 100% of the aggregate outstanding Class B Shares, representing approximately 75.9% of the aggregate outstanding Shares and voting interest in the Company (approximately 30.8% of the aggregate outstanding Class A Shares, representing, together with Brookfield's Class B Shares, approximately 72.3% of the aggregate outstanding Shares and voting interest in the Company if the Over-Allotment Option is exercised in full). As a result of Brookfield's voting interest, a majority voting policy would not serve a useful purpose for a majority-controlled corporation like the Company.

Mandate of the Board

The Board oversees the management of the Company's business and affairs directly and through two standing committees: (i) the Audit Committee; and (ii) the GNC Committee (collectively, the "**Committees**", and each a "**Committee**"). The responsibilities of the Board and each Committee, respectively, will be set out in written charters, which will be reviewed and approved annually by the Board.

The Board will be responsible for, among other things:

- overseeing the Company's long-term strategic planning process and reviewing and approving its annual strategic plan;
- reviewing major strategic initiatives to determine whether management's proposed actions accord with the Company's long-term corporate goals and shareholder objectives;

- assessing management's performance against approved business plans;
- approving and monitoring material contracts, business transactions, litigation, financing matters and corporate restructurings;
- assessing the major risks facing the Company and overseeing management's approach to managing the impact of such key risks;
- promoting effective corporate governance and a culture of compliance and integrity;
- overseeing the Company's overall approach to sustainability as reported to the Board by the GNC Committee;
- appointing the Chief Executive Officer, approving the compensation of the Chief Executive Officer, overseeing the selection of other executive officers, the compensation of such executive officers and reviewing senior management succession planning;
- reviewing and approving the reports issued to shareholders, including annual and interim financial statements; and
- reviewing and monitoring the Company's controls and procedures (including for the purposes of assessing whistleblower policies and practices, financial reporting and compliance).

The Board of Directors Charter is attached as Appendix "A" to this prospectus.

Term Limits and Board Renewal

The GNC Committee will be responsible for identifying and recruiting candidates to join the Board. In this context, the Company's view is that the Board should reflect a balance between the experience that comes with longevity of service on the Board and the need for renewal and fresh perspectives.

The Company does not support a mandatory retirement age, director term limits or other mandatory board of directors turnover mechanisms because its view is that such policies are overly prescriptive; therefore, the Company does not have term limits or other mechanisms that compel Board turnover. The Company does believe that periodically adding new members to the Board can help the Company adapt to a changing business environment and Board renewal is a priority.

The GNC Committee will review the composition of the Board on a regular basis and recommend changes as appropriate to renew the Board.

Advance Notice

Advance notice provisions with respect to the election of directors have been included in the By-laws (the "**Advance Notice Provisions**"). The Advance Notice Provisions are intended to: (i) facilitate orderly and efficient annual meetings or, where the need arises, special meetings; (ii) ensure that all shareholders receive adequate notice of any Board nominations and sufficient information with respect to all nominees; and (iii) allow shareholders to register an informed vote. Other than those individuals who are nominated by Brookfield, if any, pursuant to the Shareholder Agreement, or the Board, only persons who are nominated by shareholders in accordance with the Advance Notice Provisions will be eligible for election as directors at any annual meeting of shareholders, or at any special meeting of shareholders if one of the purposes for which the special meeting was called was the election of directors.

Under the Advance Notice Provisions, other than Brookfield pursuant to the exercise of its rights under the Shareholder Agreement, a holder of Class A Shares wishing to nominate a director will be required to provide the Company with notice, in the prescribed form, within the prescribed time periods. These time periods include: (i) in the case of an annual meeting of shareholders (including annual and special meetings), not less than 30 days prior to the date of the annual meeting of shareholders; provided, that if the first public announcement of the date of the annual meeting of shareholders (the "**Notice Date**") is less than 50 days before the meeting date, not later than the close of business on the 10th day following the Notice Date; and (ii) in the case of a special meeting (which is not also an annual meeting) of shareholders called for any purpose which includes electing directors, not later than the close of business on the 15th day following the Notice Date.

Notwithstanding the foregoing, the Board is, in its sole discretion, entitled to waive any requirement set out in the Advance Notice Provisions.

Diversity

The Company is committed to workplace diversity, diversity of gender, culture, geography and skills are important to the Company's long-term success and the Company intends to actively support the development and advancement of a diverse group of employees capable of achieving leadership positions. Leadership appointments will be solely based on merit, and not on other factors because the Company believes that merit should be the guiding factor in determining whether a particular candidate is capable of bringing value to the Company. As such, the Company does not intend to adopt formal targets for female representation in executive positions. However, a cornerstone of the Company's succession planning process will be a tailored approach to the development and advancement of employees capable of achieving executive officer positions. This tailored approach to developing executives starts with identifying individuals who demonstrate the skills and attributes required to achieve executive officer positions within the Company. The progress of these individuals will be reviewed annually in order to ensure that each individual is being provided opportunities to achieve their potential. Development opportunities are expected to include exposure to a new competency or skill, a transfer between business units, a relocation, a role expansion and other stretch opportunities. Tailoring the development plan for each individual will permit the Company to consider the needs of the individual, including considerations that are gender-based.

The Company is committed to enhancing the diversity of the Board. The Company's view is that the Board should reflect a diversity of backgrounds relevant to the Company's strategic priorities. This includes such factors as diversity of business expertise, in addition to geographic and gender diversity. All Board appointments will be based solely on merit, having due regard for the benefits of diversity, so that each nominee possesses the necessary skills, knowledge and experience to serve effectively as a director. Therefore, in the director identification and selection process, gender diversity influences succession planning and is one criterion in adding new members to the Board.

The GNC Committee will be responsible for monitoring progress towards achieving the Company's diversity objectives.

On Closing, of the five independent directors and nine total number of directors on the Board, two directors are women and both are independent. Therefore 40% of the independent directors on the Board and 22% of the entire Board will be women.

Director Orientation and Education

New directors of the Company will be provided with comprehensive information about the Company and the Business. Arrangements will be made for specific briefing sessions from appropriate senior personnel to help new directors better understand the Company's strategies and operations. They will also be provided with the opportunity to participate in all of the Board's continuing education measures.

It is also anticipated that the Board will receive annual operating plans for the Business and more detailed presentations on particular strategies. The directors will have the opportunity to meet and participate in work sessions with management to obtain insight into the operations of the Company and the Business. Directors will be regularly briefed to help them better understand industry-related issues such as accounting rule changes, transaction activity, capital markets initiatives, significant regulatory developments, as well as trends in corporate governance.

Committees of the Board

The following two standing Committees will assist in the effective functioning of the Board and help to ensure that the views of the independent directors are effectively represented:

- Audit Committee; and
- GNC Committee.

The responsibilities of the Committees will be set out in written charters, which will be reviewed and approved annually by the Board. It is the Board's policy that the Audit Committee must consist entirely of independent directors and each member of the Audit Committee must be financially literate. Special committees may be formed from time to time to review particular matters or transactions. While the Board retains overall responsibility for corporate governance matters, each standing Committee has specific responsibilities for certain aspects of corporate governance in addition to its other responsibilities, as described below.

Audit Committee

The Audit Committee will be responsible for monitoring the Company's systems and procedures for financial reporting and associated internal controls, as well as the performance of the Company's external and internal auditors. It will be responsible for reviewing certain public disclosure documents before their approval by the full Board and release to the public, such as the Company's quarterly and annual financial statements and management's discussion and analysis and ensuring adequate procedures are in place for the review of the Company's financial information. The Audit Committee will also be responsible for, among other things: overseeing the adequacy of the Company's internal controls over financial reporting and disclosure controls and procedures; overseeing the Company's cybersecurity program and practices; reviewing the status of taxation matters; overseeing the Company's risk management and assessment policies; recommending the independent registered public accounting firm to be nominated for appointment by shareholders as the Company's external auditors; recommending a change in, or termination of, the external auditors of the Company; pre-approving the assignment of any non-audit work to be performed by the external auditor (including the adoption of a pre-approval policy specifying the number, type and cost of non-audit services that will be permitted); reviewing and recommending to the Board the compensation of the Company's auditors; and reviewing and approving the Company's hiring policies regarding partners, employees and former partners and employees of the present and former external auditor of the Company. Further, the Audit Committee will establish procedures for the receipt, retention and treatment of complaints received by the Company regarding accounting, internal accounting controls, or auditing matters and the confidential, anonymous submission by employees of the Company of concerns regarding questionable accounting or auditing matters.

The Audit Committee will meet regularly in private sessions with the Company's external and internal auditors, without management present, to discuss and review specific issues as appropriate.

In addition to the foregoing, in accordance with the terms of the Relationship Agreement, for so long as the Company owns, controls or directs less than a majority of the OpCo Interests, the Audit Committee will have the right to engage directly with the external and internal auditors of the OpCos and to participate in the review and preparation of the quarterly and annual financial statements, as applicable, of each OpCo. See "Relationship with Brookfield — Agreements Between the Company and Brookfield — Relationship Agreement".

The Audit Committee charter is attached as Appendix "B" to this prospectus.

External Auditor Service Fee

The Business incurred the following fees by its external auditor, Deloitte LLP, during the periods set forth below:

	Fiscal year ended March 31, 2025	Fiscal year ended March 31, 2024
Audit Fees[(1)]	C$692,614	C$673,668
Audit Related Fees[(2)]	C$279,715	C$268,957
Tax Fees[(3)]	—	—
All Other Fees[(4)]	—	—
Total Fees Paid	**C$972,330**	**C$942,625**

Notes:

(1) Fees for audit service, including audits of financial statements during the 12 months ended March 31, 2025 and 2024.

(2) Fees for assurance and related services not included in audit service above, including services associated with other financial statement related disclosures and procedures.

(3) Fees for tax compliance, tax advice and tax planning.

(4) All other fees not included above.

GNC Committee

It will be the responsibility of the GNC Committee to, among other things: assess from time to time the size and composition of the Board and its Committees; review the effectiveness of Board operations and its relations with management; assess the performance of the Board, its Committees and individual directors; develop and review Board and Committee charters and certain position descriptions; review and recommend the implementation of structures and procedures to facilitate the Board's independence from management and avoid conflicts of interest; monitor relationships between the Board and senior management; review the Company's statement of corporate governance practices; and review and recommend the compensation of the Company's directors. The Board will implement a formal procedure for evaluating the performance of the Board, its Committees and individual directors and the GNC Committee will review the performance of the Board, its Committees and the contribution of individual directors on a periodic basis.

The GNC Committee will be responsible for reviewing the credentials of proposed nominees for election or appointment to the Board and for recommending candidates (including those nominated by Brookfield, if any, under the Shareholder Agreement as described under "Relationship with Brookfield — Agreements Between the Company and Brookfield — Shareholder Agreement") to be nominated for election to the Board, including the candidates proposed to be nominated for election to the Board at the annual meeting of shareholders. To do this, the GNC Committee will maintain an "evergreen" list of potential candidates to ensure outstanding candidates with needed skills can be quickly identified to fill planned or unplanned vacancies. Candidates will be assessed based on the principle of ensuring that the Board has the appropriate mix of talent, quality, skills, diversity, perspectives and other requirements necessary to promote sound governance and the effectiveness of the Board.

The GNC Committee also will be responsible for overseeing the Company's approach to sustainability including with respect to, among other things, environmental regulatory and/or compliance matters; health and safety; human rights; labour practices; diversity and inclusion; talent attraction and retention; human capital development; community/stakeholder engagement; Board composition and engagement; business ethics; anti-bribery and corruption; audit practices; regulatory functions; and data protection and privacy. The GNC Committee's oversight activities in this regard will include reviewing and assessing the performance of the Company in respect of the approach to sustainability matters determined appropriate by the Board in consultation with the GNC Committee and senior management. The GNC Committee will also review and make recommendations to the Board in respect of any shareholder proposal that relates to corporate governance.

The GNC Committee will take responsibility for reviewing and reporting on management resource matters for the Company, including ensuring a diverse pool for succession planning, the job descriptions and annual objectives of senior executives, the form of executive compensation in general including assessment of the risks associated with the compensation plans and the levels of compensation of the executive officers of the Company. The GNC Committee will also review and report to the Board on the performance of senior management against written objectives and reports thereon. Further, the GNC Committee will be responsible for the ongoing review and assessment of the Company's Code of Business Conduct and Ethics (the "**Code of Conduct**") and any waivers in respect of the Code of Conduct as well as the review of other Company policies, including its Disclosure Policy, Anti-Bribery and Corruption Policy, Positive Work Environment Policy, Delegation of Authority Policy and Personal Trading Policy.

In reviewing the compensation policies and practices of the Company each year, the GNC Committee will seek to ensure the executive compensation program provides an appropriate balance of risk and reward consistent with the risk profile of the Company. The GNC Committee will also seek to ensure that the Company's compensation practices do not encourage excessive risk-taking behavior by the senior management team.

In addition to the foregoing, in accordance with the terms of the Relationship Agreement, for so long as the Company owns, controls or directs less than a majority of the OpCo Interests, the GNC Committee has been granted the right to be consulted in the review and setting of the compensation policy and practices of each OpCo. See "Relationship with Brookfield — Agreements Between the Company and Brookfield — Relationship Agreement".

Board, Committee and Director Evaluation

The Board believes that a regular and formal process of evaluation improves the performance of the Board as a whole, the Committees and individual directors. The Company expects that a survey will be sent annually to directors inviting comments and suggestions on areas for improving the effectiveness of the Board and its Committees. The results of this survey will be reviewed by the GNC Committee, which will make recommendations to the Board as required. The Board Chair is also expected to hold private interviews with each director annually to discuss the operations of the Board and its Committees, and to provide any feedback on the contributions made by individual directors.

Board Chair and Chief Executive Officer Position Descriptions

In addition to its written position description respecting the Lead Independent Director, the Board has adopted a written position description for the Chair, which sets out the Chair's key responsibilities, including, as applicable, duties relating to, among other things: ensuring that the functions identified in the Board Mandate are being carried out effectively by the Board and its Committees; setting Board meeting agendas; chairing Board and shareholder meetings; ensuring directors receive the information required to perform their duties; ensuring an appropriate committee structure is in place; consulting and communicating directly with shareholders of the Company and other stakeholders, when appropriate; and working with the Chief Executive Officer and other members of senior management to monitor progress on strategic planning, policy implementation and succession planning. The Board has also adopted a written position description for each of the Committee chairs which sets out each of the Committee chair's key responsibilities, including duties relating to setting Committee meeting agendas, chairing Committee meetings and working with the Committee and management to ensure, to the greatest extent possible, the effective functioning of the Committee.

The Board has also adopted a written position description for the Chief Executive Officer which sets out the key responsibilities of the Chief Executive Officer. The primary functions of the Chief Executive Officer are to, among other things: lead the management of the business and affairs of the Company and oversee its strategic plans; lead the implementation of the resolutions and the policies of the Board; supervise day to day management of the Company; together with the Company's Chief Financial Officer, establish and maintain controls and procedures appropriate to ensure the accuracy and integrity of the Company's financial reporting and public disclosures; and act as the primary spokesperson for the Company to its shareholders and stakeholders.

Trading Restrictions

The directors, officers and employees of the Company are subject to the Company's Personal Trading Policy, which, among other things, prohibits trading in the securities of the Company while in possession of material undisclosed information about the Company. Individuals are also prohibited from entering into certain types of hedging transactions involving the securities of the Company, such as short sales, prepaid variable forward contracts, equity swaps and put options and from entering into derivative-based transactions involving, directly or indirectly, securities of the Company. In addition, subject to limited exceptions, the Company's Personal Trading Policy prohibits trading in the Company's securities and precludes the grant or exercise of stock options or similar forms of stock-based compensation (such as stock appreciation rights, deferred share units or restricted stock awards) for cash, during prescribed blackout periods. The Company also requires all executives and directors to pre-clear trades in the Company's securities.

Disclosure Policy

The Company has a Disclosure Policy that summarizes its policies and practices regarding public disclosure of information to investors, analysts and the media. The Disclosure Policy is intended to ensure that the Company's communications with the investment community are timely, consistent and in compliance with all applicable securities laws. Each director, officer and employee of the Company and its subsidiaries are subject to the Disclosure Policy. The Board will review the Disclosure Policy annually.

Code of Business Conduct and Ethics

The Company's policy is that all of its activities must be conducted with the utmost honesty, integrity, fairness and respect and in compliance with all legal and regulatory requirements. To that end, the Company has implemented and will maintain a Code of Conduct, a copy of which will be filed following Closing under the Company's SEDAR+ profile at www.sedarplus.ca. The Code of Conduct sets out the guidelines and principles for how directors, officers, employees and other stakeholders should conduct themselves as members of the Company's team. Preserving the Company's corporate culture is vital to the organization and the Code of Conduct is designed to help the Company do that.

All directors, officers, employees and temporary workers of the Company and its controlled subsidiaries will be required to provide a written acknowledgment upon joining the Company that they are familiar with and will comply with the Code of Conduct. All directors, officers, employees and temporary workers of the Company and its subsidiaries will be required to provide this same acknowledgment annually. The Board will review the Code of Conduct annually.

Management will provide regular instructions and updates to the Code of Conduct to the Company's employees, as appropriate, and will provide training and e-learning tools to support the understanding of the Code of Conduct throughout the organization. Employees will have the ability to report activities which they feel are not consistent with the spirit and intent of the Code of Conduct through a hotline or through a designated ethics reporting website (in each case on an anonymous basis), or alternatively, to designated members of management. Monitoring of the Company's reporting hotline will be managed by an independent third party. The Audit Committee is to be notified of any significant reports of activities that are not consistent with the Code of Conduct.

DIRECTORS AND EXECUTIVE OFFICERS

Directors and Executive Officers

The Board is currently comprised of three directors: Brian Baker, William Burton and Tobias McKenna. At Closing, the Board will consist of nine directors. The directors, five of whom are independent directors, will be elected by shareholders at each annual meeting of shareholders, and all directors will hold office for a term expiring at the close of the next annual meeting or until their respective successors are elected or appointed. Pursuant to the terms of the Shareholder Agreement, Brookfield will retain certain director nomination rights. See "Relationship with Brookfield — Agreements Between the Company and Brookfield — Shareholder Agreement". Any nominees not put forward by Brookfield will be determined by the GNC Committee in accordance with its mandate and put forward by the Company in accordance with all applicable law.

The following table sets forth the names, places of residence and positions for each of the directors and executive officers of the Company at Closing. Additional biographical information for each individual is provided below.

Following completion of the Transactions, the OpCo Boards will be comprised of three managers and directors, as applicable, selected from the existing members of the Board by the members of the Board subject to, at all times, compliance with existing CPUC approvals, with one manager and director being an independent director of Rockpoint and the other two being non-independent directors of Rockpoint who are affiliated with Brookfield. We expect that Brian Baker, William Burton and Peter Cella will serve as the managers of BIF OpCo and the directors of Swan GP.

See "Relationship with Brookfield — Agreements Between the Company and Brookfield — Relationship Agreement". The Chief Executive Officer of the Company will be the Chief Executive Officer of each of BIF OpCo and Swan GP, the Chief Financial Officer of the Company will be the Chief Financial Officer of each of BIF OpCo and Swan GP and the remaining members of the BIF OpCo and Swan GP management teams will be selected from the other executive officers of the Company.

Name, Province or State and Country of Residence	Position/Title	Independent	Principal Occupation
Tobias J. McKenna *Alberta, Canada*	Chief Executive Officer and Director	No	Chief Executive Officer of the Company
Jon Syrnyk *Alberta, Canada*	Chief Financial Officer	N/A	Chief Financial Officer of the Company
Kevin Donegan *Alberta, Canada*	Senior Vice President, Accounting and Administration	N/A	Senior Vice President, Accounting and Administration of the Company
Hardip Kalar *Alberta, Canada*	Senior Vice President, Strategy and Analytics	N/A	Senior Vice President, Strategy and Analytics of the Company
Sheri Doell *Alberta, Canada*	Senior Vice President, Commercial Operations	N/A	Senior Vice President, Commercial Operations of the Company
Scott Aycock *Alberta, Canada*	Senior Vice President, Storage Operations	N/A	Senior Vice President, Storage Operations of the Company
James Bartlett *Alberta, Canada*	General Counsel and Corporate Secretary	N/A	General Counsel and Corporate Secretary of the Company
Suzanne Nimocks(2) *Texas, United States*	Director	Yes	Corporate Director
Peter Cella(1) *Florida, United States*	Director	Yes	Corporate Director

Name, Province or State and Country of Residence	Position/Title	Independent	Principal Occupation
David Devine[1] *Texas, United States*	Director	Yes	Corporate Director
Sippy Chhina[1] *Alberta, Canada*	Director	Yes	Corporate Director
Rick Eng[2] *British Columbia, Canada*	Director	No	Corporate Director
Gene Stahl *Texas, United States*	Director	Yes	Corporate Director
Brian Baker[2] *Alberta, Canada*	Director	No	Operating Partner for Brookfield Asset Management's Infrastructure Group
William Burton *Texas, United States*	Director	No	Operating Partner for Brookfield Asset Management's Infrastructure Group

Notes:

(1) Member of the Audit Committee.

(2) Member of the GNC Committee.

Biographical Information Regarding the Directors and Executive Officers at Closing

Tobias J. McKenna **—** Mr. McKenna serves as a director and Chief Executive Officer of the Company and will be responsible for, among other things, the management and performance of the Company's storage and retail distribution assets. See "Corporate Governance — Board Chair and Chief Executive Officer Position Descriptions". Mr. McKenna has served as the Chief Executive Officer of the Company since July 28, 2025 and prior thereto as the Chief Executive Officer of Rockpoint Gas Storage Partners LP since November 30, 2020. Mr. McKenna brings to Rockpoint over 30 years of experience in the energy industry with leadership roles across a wide spectrum of disciplines including gas storage and marketing, midstream operations, energy trading, business development and acquisitions and divestitures. From 2014 to 2020 Mr. McKenna was cofounder of Tidewater Midstream and Infrastructure Ltd. where Mr. McKenna served in multiple roles including Director, President and CEO, Vice President of Business Development and Commercial and most recently as President, Midstream. From 2010 to 2014, Mr. McKenna was Vice President, Natural Gas Trading for Castleton Commodities Canada and prior thereto was cofounder of its predecessor, Louis Dreyfus Energy Canada in 2003. Mr. McKenna holds a Bachelor of Business Administration from Saint Francis Xavier University.

Jon Syrnyk — Mr. Syrnyk serves as Chief Financial Officer of the Company and will be responsible for, among other things, leading various strategic corporate and business development initiatives to drive value and appropriately allocate capital. Mr. Syrnyk collaborates with Rockpoint's commercial, finance, risk and engineering and operations functions to identify, assess and execute investment opportunities across the Business. Mr. Syrnyk has served as the Chief Financial Officer of the Company since September 10, 2025 and prior thereto as the Senior Vice President, Corporate Development of Rockpoint Gas Storage Partners LP since September 2023. Prior to joining Rockpoint Gas Storage Partners LP, Mr. Syrnyk spent seven years with Brookfield's Infrastructure Group on their buy-side investment and portfolio management teams. Mr. Syrnyk is a legacy Chartered Accountant member of the Chartered Professional Accountants of Canada and obtained a Chartered Business Valuator (CBV) designation, which were earned during his time working in the Deal Advisory and Audit Service groups of an international accounting firm. Mr. Syrnyk holds a Bachelor of Health Science and Kinesiology from the University of British Columbia.

Kevin Donegan **—** Mr. Donegan serves as Senior Vice President, Accounting and Administration of the Company and will be responsible for, among other things supervision of the accounting, tax and information technology departments of the Company. Mr. Donegan has served as the Senior Vice President, Accounting and Administration of the Company since September 10, 2025 and prior thereto as the Chief Financial Officer of Rockpoint Gas Storage Partners LP since May of 2024 and VP Finance since May, 2015. Mr. Donegan has almost 30 years of finance, tax and accounting experience with various public and private entities in, and servicing the upstream and midstream energy industry. Mr. Donegan's most recent role prior to joining Rockpoint Gas Storage Partners LP was as the Chief Financial Officer and Vice President Finance of Montana Exploration Corp., a TSXV-listed company in the exploration and production industry, from December 2013 to May 2015. Prior thereto, Mr. Donegan spent 8 years as the Chief Financial Officer of Blaze Energy Ltd., a privately-held upstream company with substantial midstream operations including gas gathering, transportation, processing and natural gas storage services. Earlier in his career, Mr. Donegan gained experience from Quicksilver Resources Inc., AltaGas Ltd. and Deloitte LLP. Mr. Donegan holds a Bachelor of Commerce from the University of Saskatchewan and is a legacy Chartered Accountant member of the Chartered Professional Accountants of Alberta.

Hardip Kalar — Mr. Kalar serves as Senior Vice President, Strategy and Analytics of the Company and will be responsible for, among other things, the commercial activities at the Lodi and Warwick natural gas storage facilities. Mr. Kalar has served as the Senior Vice President, Strategy and Analytics of the Company since September 10, 2025 and prior thereto served as the Vice President, Marketing and Optimization of Rockpoint Gas Storage Partners LP since the entity's formation in June 2015. Mr. Kalar has over 20 years of varied experience in the natural gas business. Mr. Kalar spent 12 years at Iberdrola Canada Energy Services Ltd. (formerly PPM Energy), the third largest independent owner and operator of natural gas storage in North America, working in a variety of roles related to the Canadian gas storage business. Mr. Kalar's most recent role prior to joining Rockpoint Gas Storage Partners LP was as the Manager of Marketing at Iberdrola Canada Energy Services Ltd. Mr. Kalar holds a Bachelor of Commerce in Finance from the University of Calgary.

Sheri Doell — Ms. Doell serves as Senior Vice President, Commercial Operations of the Company and will be responsible for, among other things, the long-term strategy for designing and negotiating storage service arrangements across a wide variety of customers for assets in both Canada and the United States. Ms. Doell's lead commercial role involves developing strategy and executing initiatives across a spectrum of business operations such as storage, optimization, transportation, power and carbon. Ms. Doell has served as the Senior Vice President, Commercial Operations of the Company since September 10, 2025 and prior thereto as Vice President, Origination and Renewable Energy of Rockpoint Gas Storage Partners LP since 2021. Ms. Doell joined Rockpoint's predecessor company, Encana, in 2003 as the AECO Hub™ cash trader and, over the years, has held various positions within the trading and marketing group, spanning her 22+ year career with the business. Ms. Doell holds a Master of Business Administration from the University of Calgary Haskayne School of Business and Bachelor of Commerce degree from the University of Saskatchewan.

Scott Aycock — Mr. Aycock serves as Senior Vice President, Storage Operations of the Company and will be responsible for, among other things, the operations, integrity and safety of the storage assets. Mr. Aycock has served as the Senior Vice President, Storage Operations of the Company since September 10, 2025. Mr. Aycock brings over 25 years of energy related experience across a wide spectrum of disciplines including upstream development and operations, gas storage development and operations, marketing and business development. Prior to joining Rockpoint, Mr. Aycock was Senior Director, Strategy at AltaGas Ltd. and Vice President of Business Development at Tidewater Midstream and Infrastructure Ltd. Mr. Aycock holds a Master of Business Administration from the University of Calgary with a specialization in Finance and a Bachelor of Engineering in Chemical Engineering from McGill University.

James Bartlett — Mr. Bartlett serves as General Counsel and Corporate Secretary of the Company and will be responsible for, among other things, human resources, insurance, land, regulatory and all legal affairs of Rockpoint. Mr. Bartlett has served as the General Counsel and Corporate Secretary of the Company since September 10, 2025 and prior thereto as the General Counsel and Corporate Secretary of Rockpoint Gas Storage Partners LP. Prior to joining Rockpoint Gas Storage Partners LP in 2017, Mr. Bartlett was an associate at Bennett Jones LLP where he focused on mergers and acquisitions and other commercial arrangements. Mr. Bartlett holds a Master of Business Administration degree and a Juris Doctor degree, both from the University of Calgary.

Suzanne Nimocks — At Closing, Ms. Nimocks will serve as a director of the Company. Ms. Nimocks is an independent director of Brookfield Infrastructure Corporation, Brookfield Infrastructure Partners Limited (general partner of Brookfield Infrastructure Partners L.P.) and Owens Corning. Ms. Nimocks is a former director of Ovintiv Inc., Arcelor Mittal, Rowan Companies plc and Valaris plc. and was formerly a Senior Partner of McKinsey & Company where she was a leader in the firm's global organization, risk management and electric power, natural gas and renewables practices. Ms. Nimocks obtained a Master of Business Administration from Harvard University and a Bachelor of Arts from Tufts University.

Peter Cella — At Closing, Mr. Cella will serve as a director of the Company. Mr. Cella has more than 36 years of general management and financial experience in the energy and related sectors, including nearly 30 years in the petrochemicals and polymers industry. From 2011 until his retirement in 2017, Mr. Cella was the President and Chief Executive Officer of Chevron Phillips Chemical Company LP, where he led it through the development and construction of an ethane cracker and two polyethylene units. Previously, Mr. Cella served in a variety of executive posts at BASF Corporation, INEOS Nitriles (part of the INEOS Group), BP, and Innovene, LLC. He began his career at Amoco Corporation in 1981. Mr. Cella is a director on the board of directors of Frontdoor, Inc. and serves on the board of directors for the Brookfield-owned private company, Inter Pipeline Ltd. Mr. Cella also previously served as the Chairman of the board of directors of the American Chemistry Council and served on the boards of the Saudi Arabian Oil Co (Aramco), ServiceMaster, and privately-held Critica Infrastructure, and served on the board of directors and executive committee for Junior Achievement of Southeast Texas, a not-for-profit organization dedicated to improving the financial literacy and work-readiness of young people. Mr. Cella holds a Master of Business Administration degree from Northwestern University and a Bachelor of Science degree in finance from the University of Illinois.

David Devine — At Closing, Mr. Devine will serve as a director of the Company. From 2016 to 2021, Mr. Devine was the Chief Executive Officer and President of Natural Gas Pipeline Company of America LLC, an interstate natural gas pipeline. Mr. Devine was also previously the President of the Natural Gas Pipelines Central Region of Kinder Morgan Inc. ("**Kinder Morgan**") since May 2005 and served in that position until February 2015. Mr. Devine represented Kinder Morgan on the board of directors of the Interstate Natural Gas Association of America (INGAA) for several years, serving as Chairman in 2014.

Sippy Chhina — At Closing, Ms. Chhina will serve as a director of the Company. Until her retirement on December 31, 2023, Ms. Chhina was a Partner at Deloitte LLP and a Vice Chair for the Canadian firm. Ms. Chhina has served Canadian and global businesses both in an assurance and advisory capacity. In her professional career, Ms. Chhina was either the lead audit partner, a quality assurance partner, or the lead advisory partner serving some of Deloitte LLP's largest clients in the energy and resource sectors. Ms. Chhina has significant experience with respect to audits, securities offerings, initial public offerings, management buyouts, merger and acquisition transaction advisory, strategy, corporate structuring and advisory including areas such as business model design, master data management, supply chain, and sustainability. Ms. Chhina's professional services experience included advising companies operating in subsectors such as oil and gas, power, renewables, mining and related infrastructure across North America, South America, and Africa. She also acted as the lead audit partner for investees of large Canadian and U.S. private equity and pension funds operating either directly or through infrastructure investments in the Canadian energy and resource sectors. Ms. Chhina is a director of Ovintiv Inc. and Trans Mountain Corporation. Ms. Chhina is a member of the Chartered Professional Accountants of Alberta and Canada, a member of ICD Rotman's Director Education Program and holds an I Comm degree from Sambalpur University.

Rick Eng — At Closing, Mr. Eng will serve as a director of the Company and be appointed Chair of the Board. Mr. Eng has nearly 30 years of experience in investment banking, private equity, and advisory roles, primarily focused on mergers and acquisitions, capital markets, and strategic business planning. Mr. Eng spent over 17 years at Brookfield, where he served as a Managing Partner in the Infrastructure Group from 2015 to 2024. Mr. Eng's responsibilities included leading new investments as well as overseeing and supporting portfolio companies in strategic growth and operational initiatives. Mr. Eng was also previously Chief Investment Officer responsible for the underwriting of Brookfield's Transport investments globally. Prior to moving into the Infrastructure Group in 2015, Mr. Eng was a senior member of Brookfield's private equity group, where he also served for several years as the Chief Financial Officer of publicly-listed Ainsworth Lumber Co. Before joining Brookfield in 2006, he was a vice president in investment banking at National Bank Financial where he focused on North American paper and forest products companies as well as regional coverage of western Canada. He is a director of Stantec Inc. Mr. Eng is a member of the Chartered Professional Accountants of Canada and holds a Bachelor of Arts degree in Economics and History from Queen's University.

***Gene Stahl* —** At Closing, Mr. Stahl will serve as a director of the Company. Gene Stahl was appointed as President, North American Drilling of Precision Drilling Corporation ("**Precision**") in 2023 where he previously held the position of Chief Marketing Officer since 2019. Since joining Precision in 1993, Mr. Stahl has progressed his way through Precision holding several positions with increasing responsibility, including Contracts, Investor Relations, Engineering, Manufacturing, Rig Construction, Procurement, Field Training and Development, and Health, Safety and Environment (HSE). He also serves as a member of the executive committee of the International Association of Drilling Contractors and is the Chairman of the North American Onshore Advisory Panel. Mr. Stahl holds a Bachelor of Arts degree in Economics from the University of Calgary and is a graduate of the Harvard Business School, Advanced Management Program.

***Brian Baker* —** Mr. Baker serves as a director of the Company. He is an Operating Partner in Brookfield Asset Management's Infrastructure Group, working primarily with Brookfield's Midstream operating companies to set strategic direction, manage risk and support growth initiatives. Since joining Brookfield in 2007, he has held several senior roles across Brookfield's Infrastructure Group, including heading investment activities in Europe and North America for over a decade where he oversaw acquisitions in the Data Infrastructure, Transportation, Utilities and Midstream sectors. Mr. Baker currently serves as Chair of the Board of Inter Pipeline Ltd. and serves as a director for TransAlta Corporation and NorthRiver Midstream Inc. Mr. Baker is a member of the Chartered Professional Accountants of Canada and holds a Bachelor of Commerce degree from the University of Calgary.

***William Burton* —** Mr. Burton serves as a director of the Company. Mr. Burton is an Operating Partner in Brookfield's Infrastructure Group. In this role, Mr. Burton works primarily with Brookfield's midstream operating companies to set strategic direction, manage risk and support growth initiatives to create long-term value. Since joining Brookfield in 2013, Mr. Burton has held several senior roles, most recently as President of Natural Gas Pipeline Company of America. Prior to joining Brookfield, Mr. Burton worked in natural resource development and in the assurance and advisory group at one of the Big Four accounting firms. Mr. Burton is a member of the Chartered Professional Accountants of Ontario and holds a Bachelor of Business Administration from Wilfrid Laurier University.

Security Ownership by Directors and Executive Officers

As at the date hereof, the directors and executive officers of the Company do not beneficially own or exercise control or direction over, directly or indirectly, any Class A Shares or Class B Shares. See "Relationship with Brookfield".

External Directorships

Certain directors of the Company are also directors of other reporting issuers (or the equivalent):

Director	Other Directorships	Stock Exchange Listing
Suzanne Nimocks	Brookfield Infrastructure Corporation	TSX; NYSE
	Brookfield Infrastructure Partners L.P.	TSX; NYSE
	Owens Corning	NYSE
Peter Cella	Frontdoor, Inc.	NASDAQ
	Inter Pipeline Ltd.	N/A
Sippy Chhina	Ovintiv Inc.	TSX; NYSE
Rick Eng	Stantec Inc.	TSX; NSYE
Brian Baker	TransAlta Corporation	TSX
	Inter Pipeline Ltd.	N/A
Gene Stahl	Precision Drilling Corporation	TSX; NSYE

Cease Trade Orders

None of the Company's directors or executive officers (nor any personal holding company of any of such persons) are as at the date of this prospectus, or have been within the ten years before the date of this prospectus, a director, chief executive officer or chief financial officer of any company that: (i) was subject to an order that was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer; or (ii) was subject to an order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer. For the purposes of this paragraph, "order" means (a) a cease trade order, (b) an order similar to a cease trade order, or (c) an order that denied the relevant company access to any exemption under securities legislation, in each case, that was in effect for a period of more than 30 consecutive days.

Bankruptcies

Except as described below, none of the Company's directors or executive officers (nor any personal holding company of any of such persons), and to the best of the Company's knowledge, no shareholder holding a sufficient number of securities to affect materially the control of the Company: (i) is, as of the date of this prospectus, or has been within the ten years before the date of this prospectus, a director or executive officer of any company that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or (ii) has, within the ten years before the date of this prospectus, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, executive officer or shareholder.

Suzanne Nimocks served as a director of Valaris plc (formerly Ensco-Rowan) from 2010 until April 2021. Valaris plc filed for bankruptcy in August 2020 and emerged on May 1, 2021. Ms. Nimocks resigned from the board of directors of Valaris plc on April 30, 2021.

Penalties or Sanctions

None of the Company's directors or executive officers (nor any personal holding company of any of such persons), and to the best of the Company's knowledge, no shareholder holding a sufficient number of securities to affect materially the control of the Company, has been subject to: (i) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or (ii) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

Conflicts of Interest

Certain conflicts of interest could arise as a result of the relationships among the Company, Brookfield and the OpCos. For example, it is contemplated that, following completion of the Transactions, the OpCo Boards will be comprised of Brian Baker, a non-independent director of Rockpoint, William Burton, a non-independent director of Rockpoint, and Peter Cella, an independent director of Rockpoint. See "Relationship with Brookfield — Agreements Between the Company and Brookfield — Relationship Agreement" and "Risk Factors — Risks Related to the Offering, Rockpoint's Corporate Structure and the Class A Shares". The Chief Executive Officer of the Company will be the Chief Executive Officer of each of BIF OpCo and Swan GP, the Chief Financial Officer of the Company will be the Chief Financial Officer of each of BIF OpCo and Swan GP and the remaining members of the BIF OpCo and Swan GP management teams will be selected from the other executive officers of the Company.

Following completion of the Transactions, Brookfield will hold the controlling voting interest in the Company, including with respect to the right to vote for the election of directors to the Board, will be the sole shareholder of Swan GP (being the general partner of Swan OpCo) and the majority shareholder of BIF OpCo. See "Risk Factors — Brookfield has the ability to direct the voting of a majority of Shares and control certain decisions with respect to Rockpoint's management and business. Brookfield's interests may conflict with those of the other shareholders". In addition, Swan GP, which is a subsidiary of Brookfield, will remain the general partner of Swan OpCo, and the board of directors of Swan GP will be comprised of three directors selected from the existing members of the Board by the members of the Board subject to, at all times, compliance with the requirement for prior CPUC Approval, with at least one director being an independent director of Rockpoint. The board of managers of BIF OpCo will be comprised of three managers selected from the existing members of the Board by the members of the Board subject to, at all times, compliance with existing CPUC approvals, with at least one manager being an independent director of Rockpoint, Swan GP, as the general partner of Swan OpCo, and BIF OpCo, will control and be responsible for all operational, management and administrative decisions relating to the businesses of Swan OpCo and BIF OpCo, respectively. The board of directors of Swan GP and the board of managers of BIF OpCo will oversee the management of, and provide stewardship over, the businesses of Swan OpCo and BIF OpCo, respectively. As a result of the foregoing, Brookfield will have the ability to control the overall management of the Business. See "Risk Factors — Rockpoint will be dependent upon the OpCo Boards, which are comprised of a majority of Brookfield-affiliated directors or managers, for supervision of the management and operation of the Business and the OpCos, which could affect the value of Rockpoint's investment in the Business".

Subject to applicable law, Brookfield will not be prohibited from competing with the Company and the OpCos. See "Risk Factors — Brookfield is not limited in its ability to compete with Rockpoint and may benefit from opportunities that might otherwise be available to Rockpoint".

The ABCA provides that in the event that an officer or director of a corporation is a party to, or is a director or an officer of, or has a material interest in any person who is a party to, a material contract or material transaction or proposed material contract or proposed material transaction with the corporation, such officer or director shall disclose the nature and extent of his or her interest and shall refrain from voting to approve such contract or transaction, unless otherwise provided under the ABCA. To the extent that conflicts of interest arise, such conflicts will be resolved in accordance with the provisions of the ABCA.

Indebtedness

The Company is not aware of any individuals who are either current or former executive officers, directors or employees of the Company and who have indebtedness outstanding as at the date hereof (whether entered into in connection with the purchase of securities of the Company or otherwise) that is owing to: (i) the Company or any of its subsidiaries; or (ii) another entity where such indebtedness is the subject of a guarantee, support agreement, letter of credit or other similar arrangement or understanding provided by the Company or any of its subsidiaries.

EXECUTIVE COMPENSATION

Introduction

The following discussion describes the significant elements of the compensation program for the named executive officers ("**NEOs**") of the Company. The discussion below also reflects certain contemplated changes to such compensation program that would be implemented in connection with, and contingent upon, the completion of the Offering. The anticipated NEOs for fiscal 2026 are:

- Mr. Tobias McKenna, Chief Executive Officer;
- Mr. Jon Syrnyk, Chief Financial Officer;
- Mr. Kevin Donegan, Senior Vice President, Accounting and Administration;
- Ms. Sheri Doell, Senior Vice President, Commercial Operations; and
- Mr. Hardip Kalar, Senior Vice President, Strategy and Analytics.

Each of the NEOs are employed by SIM Energy LP, an affiliate of the OpCos upon closing of the Reorganization, which will administer and pay all salaries, bonuses and other cash compensation and benefits arrangements for the NEOs. The Chief Executive Officer of the Company will be the Chief Executive Officer of each of BIF OpCo and Swan GP, the Chief Financial Officer of the Company will be the Chief Financial Officer of each of BIF OpCo and Swan GP and the remaining members of the BIF OpCo and Swan GP management teams will be selected from the other executive officers of the Company, with each of the NEOs holding the same titles with each of BIF OpCo and Swan GP as they hold with the Company.

Compensation Discussion and Analysis

Overview

To achieve strategic business and financial objectives, the Company and the OpCos need to attract, retain and motivate a highly talented executive team. Their compensation program seeks to achieve the following objectives:

- provide competitive compensation opportunities in order to attract and retain talented, high-performing and experienced executive officers, whose knowledge, skills and performance are critical to organizational success;
- motivate the executive team to achieve strategic business and financial objectives;
- align the interests of executive officers with those of its shareholders by tying a meaningful portion of compensation directly to the long-term value and growth of the Business;
- maintain a strong pay for performance relationship; and
- provide incentives that encourage appropriate levels of risk-taking by the executive team.

Executive officers receive cash compensation in the form of base salary and discretionary bonuses, which have historically been awarded under the STIP and MTIP (as described further below). Objectives and performance measures may vary from year to year as determined to be appropriate by the OpCo Boards in consultation with the GNC Committee. In the future, executive officers may be granted long-term incentives consisting of stock options, performance share units ("**PSUs**") and/or restricted share units ("**RSUs**") under the Company's new equity incentive plan (the "**Equity Incentive Plan**"). The Company believes that equity-based compensation awards motivate executive officers to achieve strategic business and financial objectives, and also align their interests with the long-term interests of the Company's shareholders. While the Company has determined that the current executive officer compensation program is effective at attracting and retaining executive officer talent, compensation practices will be evaluated on an ongoing basis to ensure competitive compensation opportunities for the executive team. The compensation of the executive team is expected to be reviewed on an annual basis and guided by the philosophy and objectives outlined above, as well as other factors which may become relevant.

Compensation-Setting Process

The OpCo Boards, in consultation with the GNC Committee, will be responsible for assisting the Board in fulfilling its governance and supervisory responsibilities, and overseeing human resources, succession planning, and compensation policies, processes and practices. The OpCo Boards, in consultation with the GNC Committee, will also be responsible for ensuring that the compensation policies and practices provide an appropriate balance of risk and reward consistent with each of the Company's and the OpCo's respective risk profile.

The Board has a written charter for the GNC Committee setting out its responsibilities in respect of the compensation programs and reviewing and making recommendations to the Board and the OpCo Boards concerning the level and nature of the compensation payable to the directors and officers. The OpCo Boards, in consultation with the GNC Committee, will be responsible for reviewing objectives, evaluating performance and ensuring that total compensation paid to the executive officers, personnel who report directly to the Chief Executive Officer ("**CEO**") and various other key officers and managers is fair, reasonable and consistent with the objectives and philosophy of the compensation program. See also "Corporate Governance — Committees of the Board — GNC Committee".

It is anticipated that the CEO will make recommendations to the OpCo Boards and GNC Committee each year with respect to the compensation for each of the other NEOs, following which the OpCo Boards, in consultation with the GNC Committee, will review the compensation for the CEO and the other NEOs and make recommendations to the Board for any changes, as appropriate. As part of this annual review, the OpCo Boards and GNC Committee may consider compensation programs in relevant sectors of the gas storage industry as well as the compensation programs of its competitors and may engage in benchmarking with a specific peer group for purposes of setting levels of compensation.

Risk and Executive Compensation

In reviewing compensation policies and practices each year, the OpCo Boards and GNC Committee will seek to ensure the executive compensation program provides an appropriate balance of risk and reward consistent with the risk profile of the Company and the OpCos. The OpCo Boards, in consultation with the GNC Committee, will also seek to ensure the compensation practices do not encourage excessive risk-taking behaviour by the executive team. The key risk-mitigating practices that are intended to be incorporated into the compensation program are discussed below.

Share Ownership Guidelines

All of the NEOs will be expected to maintain a significant equity investment in the Company to align their interests with those of the Company's shareholders, and mitigate against the likelihood of undue risk taking. The executive share ownership guidelines, described below under "— Executive Share Ownership Guidelines", will establish minimum equity ownership levels for executives based on a multiple of their base salary and their level of seniority.

Personal Trading Policy

All of the Company's executives, including the NEOs, directors and employees will be subject to the personal trading policy, as described under "Corporate Governance — Trading Restrictions".

Components of Compensation

Upon completion of the Offering, the compensation of the Company's executive officers is expected to include three major elements: (i) base salary, (ii) short-term incentives, consisting of an annual bonus in accordance with the STIP, and (iii) long-term equity incentives, consisting of stock options, PSUs and/or RSUs granted from time to time under the Equity Incentive Plan. Perquisites and benefits are not expected to be a significant element of compensation for the executive officers.

Base salaries

Base salary is provided as a fixed source of compensation for the executive officers. Base salaries are determined on an individual basis taking into account the scope of the executive officer's responsibilities and their prior experience and performance. Base salaries are expected to be reviewed annually by the OpCo Boards, in consultation with the GNC Committee, and may be increased based on the executive officer's success in meeting or exceeding individual objectives, as well as to maintain market competitiveness. In addition, base salaries can be adjusted as warranted throughout the year to reflect promotions or other changes in the scope or breadth of an executive officer's role or responsibilities.

Annual bonuses

The NEOs are currently eligible to receive discretionary annual bonuses. The structure and formulation of these bonuses vary by individual and may take into account a range of performance-based and discretionary factors in accordance with the short-term incentive plan (the "**STIP**"). Following completion of the Offering, annual bonus targets are expected to be set as a percentage of the relevant NEO's base salary (between 60% and 100% of base salary), which varies based on his or her position. Individual annual bonus payouts will be higher or lower than the target amount depending on the performance of the Company and the achievement of any corporate or individual performance objectives. Annual bonuses are currently paid in cash and it is anticipated that this will also be the case upon completion of the Offering. Bonus payments are expected to be determined by the OpCo Boards in consultation with the GNC Committee.

Medium-Term Incentive Plan

The NEOs have historically been eligible to receive discretionary cash bonuses under a medium-term incentive plan (the "**MTIP**"). The structure and formulation of these bonuses vary by individual and may take into account a range of annual performance-based and discretionary factors. Awards under the MTIP have generally been granted annually in June, with equal installments paid at grant, the following March, and the subsequent March, subject to continued employment. While payments will continue to be made in respect of outstanding MTIP awards previously granted, no new awards will be made under the MTIP following the completion of the Offering. Following completion of the Offering, the Company and OpCo Boards intend to grant bonuses and other incentive awards solely pursuant to the STIP and Equity Incentive Plan (which is further discussed below).

Long-Term Incentive Plans

Equity Incentive Plan

The Company will adopt the Equity Incentive Plan to become effective as of completion of the Offering. The material features of the Equity Incentive Plan are summarized below.

<u>Administration and Eligibility</u>

The Equity Incentive Plan will be administered by the Board, provided that the Board may, in its discretion, delegate its administrative powers under the Equity Incentive Plan to the OpCo Boards, in consultation with the GNC Committee. Employees and officers of the Company, OpCos and their designated affiliates (including SIM Energy LP, as described above) will be eligible to participate in the Equity Incentive Plan. Non-employee directors will not be eligible to participate in the Equity Incentive Plan. The OpCo Boards, in consultation with the GNC Committee, will approve the terms of any proposed equity incentive awards to their employees or officers and will recommend that the Board approve and grant such awards pursuant to the terms of the Equity Incentive Plan. Brookfield will be responsible for a portion of the costs associated with such equity incentive awards based on its proportionate ownership of the OpCos as of the applicable time.

<u>Class A Shares Subject to the Equity Incentive Plan and Participation Limits</u>

The maximum number of Class A Shares that will be available for issuance under the Equity Incentive Plan is 5,320,000, representing approximately 10% of the number of Class A Shares anticipated to be issued and outstanding on completion of the Offering, assuming no exercise of the Over-Allotment Option. Class A Shares underlying stock options that have expired or terminated for any reason will become available for subsequent issuance under the Equity Incentive Plan. Class A Shares underlying RSUs and PSUs that have been settled for cash or that have expired or terminated for any reason will become available for subsequent issuance under the Equity Incentive Plan.

No more than 5% of the outstanding Class A Shares may be issued under the Equity Incentive Plan or pursuant to any other security-based compensation arrangements of the Company to any one person. The number of Class A Shares that may be: (i) issued to insiders of the Company within any one-year period, or (ii) issuable to insiders of the Company at any time, in each case, under the Equity Incentive Plan alone, or when combined with all of the Company's other security-based compensation arrangements, cannot exceed 10% of the outstanding Class A Shares.

Stock Options

The exercise price for stock options will be determined by the Board, which may not be less than the fair market value of a Class A Share (being the volume-weighted average trading price of a Class A Share on the TSX for the five trading days preceding the applicable date (the "**Market Value**") on which the stock option is granted). Unless the Board or an agreement between the Company and a participant provides otherwise, stock options will vest in accordance with the vesting schedule established on the grant date, which will be 20% on each of the first five anniversaries of the grant date.

Stock options must be exercised within a period fixed by the Board that may not exceed 10 years from the date of grant, provided that if the expiry date falls during a blackout period, the expiry date will be automatically extended until 10 business days after the end of the blackout period. The Equity Incentive Plan will also provide for earlier expiration of stock options upon the occurrence of certain events, including the termination of a participant's employment.

In order to facilitate the payment of the exercise price of the stock options, the Equity Incentive Plan will have a cashless exercise feature and a net settlement feature (in each case, with a full deduction from the number of Class A Shares available for issuance under the Equity Incentive Plan). The cashless exercise feature will permit a participant (or his or her personal legal representative in the event of a participant's death) to receive an amount in cash equal to the cash proceeds realized upon the sale of the Class A Shares underlying the stock options by a securities dealer in the capital markets, less the aggregate exercise price, any applicable withholding taxes and any transfer costs charged by the securities dealer. The Equity Incentive Plan will also permit participants to exercise vested stock options on a "net settlement" basis in exchange for a number of Class A Shares equivalent in value to: (i) the aggregate fair market value of the Class A Shares underlying the stock options on the exercise date minus the aggregate exercise price of the stock options, less (ii) applicable withholding taxes (only to the extent such taxes have not otherwise been satisfied by the participant). This provides for a reduction in shareholder dilution upon the exercise of stock options using this feature.

RSUs and PSUs

The terms and conditions of grants of RSUs or PSUs, including the quantity, type of award, grant date, vesting conditions, vesting periods, settlement date and other terms and conditions with respect to the awards, will be set out in the participant's grant agreement.

In the case of PSUs, the performance-related vesting conditions may include financial or operational performance of the Company or the OpCos, total shareholder return (either absolute or relative or both), individual performance criteria or other criteria as determined by the Board and the OpCo Boards (in consultation with the GNC Committee), which will be measured over a specified period, generally until the end of the third fiscal year from the date of the grant.

Subject to the achievement of the applicable vesting and performance-related (if applicable) conditions, on the settlement date of an RSU or PSU, the Company will either, in its sole discretion: (i) issue from treasury the number of Class A Shares covered by the RSUs or PSUs and related Dividend Share Units (as defined below), (ii) deliver, or cause to be delivered, to the participant an amount in cash (net of applicable withholding taxes) equal to the number of Class A Shares covered by the RSUs or PSUs and related Dividend Share Units multiplied by the Market Value as at the settlement date, or (iii) a combination of (i) and (ii).

Dividend Share Units

When dividends (other than stock dividends) are paid on Class A Shares, additional share units ("**Dividend Share Units**") will be automatically credited to each participant who holds RSUs or PSUs on the dividend payment date. The number of Dividend Share Units to be credited to a participant is equal to the aggregate number of RSUs and PSUs held by the participant on the relevant record date multiplied by the amount of the dividend paid by the Company on each Class A Share, and then divided by the Market Value of the Class A Shares on the dividend payment date. Dividend Share Units shall be in the form of RSUs or PSUs, as applicable. Dividend Share Units credited to a participant will be subject to the same vesting conditions applicable to the related RSUs or PSUs.

Termination of Employment

Unless otherwise determined by the OpCo Boards, in consultation with the GNC Committee, upon a participant's termination of employment, all rights, title and interest in awards granted to the participant under the Equity Incentive Plan that are vested or unvested on the termination date will be handled according to the following table:

	RSUs	**PSUs**	**Stock Options**
Resignation	Forfeit unvested	Forfeit unvested	Forfeit unvested 60 days to exercise vested
Termination Without Cause	A pro rata number of unvested RSUs vest on termination; remainder of unvested RSUs are forfeited	A pro rata number of unvested PSUs vest on termination (no performance multiplier will be applied); remainder of unvested PSUs are forfeited	Forfeit unvested 60 days to exercise vested
Death	A *pro rata* number of unvested RSUs vest on death; remainder of unvested RSUs are forfeited	A *pro rata* number of unvested PSUs vest on death (based on performance to such date); remainder of unvested PSUs are forfeited	Stock options continue to vest for 6 months following the date of death 1 year to exercise vested
Retirement	A *pro rata* number of unvested RSUs vest on the date of retirement; remainder of unvested RSUs are forfeited Such vested RSUs will be settled on the original vesting date(s)	A *pro rata* number of unvested PSUs remain outstanding and are eligible to vest on the original vesting date based on original performance metrics; remainder of PSUs are forfeited	Forfeit unvested 1 year to exercise vested
Termination for Cause	Forfeit unvested	Forfeit unvested	Forfeit vested and unvested
Change of Control & Termination/Resignation for Good Reason (Double Trigger)[1]	Accelerated vesting	If 12 or more months through performance period, vest based on performance to date; if less than 12 months through performance period, vest based on target performance	Accelerated vesting 1 year to exercise vested

Note:

(1) Eligible if termination without cause or resignation for good reason occurs within 12 months following the change of control event.

Changes of Control

In the event of a change of control of the Company, the surviving, successor or acquiring entity may assume any outstanding awards or substitute similar awards for the outstanding awards, as applicable (provided, however, that a sale by Brookfield of voting securities of the Company will generally not constitute a change of control unless such sale results in an acquiror (together with its Affiliates, other than Brookfield being entitled to exercise more than 50% of the voting rights attached to the outstanding voting securities of the Company). If the surviving, successor or acquiring entity does not assume the outstanding awards or substitute similar awards for the outstanding awards, as applicable, or if the Board otherwise determines, the Company will give written notice to all participants advising that the Equity Incentive Plan will be terminated effective immediately prior to the change of control and all stock options and RSUs (and related Dividend Share Units) and a specified number of PSUs (and related Dividend Share Units) will be deemed to be vested and, unless otherwise exercised, settled, forfeited or cancelled prior to the termination of the Equity Incentive Plan, will expire or, with respect to RSUs and PSUs, be settled, immediately prior to the termination of the Equity Incentive Plan. The number of PSUs which will be deemed to be vested will be determined by the Board, in its sole discretion, having regard to the level of achievement of the applicable performance vesting conditions prior to the change of control.

In the event of a change of control of the Company, the Board has the power to: (i) make such changes to the terms of the awards as it considers fair and appropriate in the circumstances, provided such changes are not adverse to the participants; (ii) otherwise modify the terms of the awards to assist the participants to tender to takeover bid or participate in the arrangement or transaction leading to a change of control, and thereafter; and (iii) terminate, conditionally or otherwise, the awards not exercised or settled, as applicable, following successful completion of such change of control. If the change of control is not completed within the specified time (as the same may be extended), the awards which vest will be returned by the Company to the participant and the original terms applicable to such awards will be reinstated.

Adjustments

In the event of any stock dividend, stock split, combination or exchange of shares, merger, amalgamation, arrangement, consolidation, spin-off or other distribution (other than normal cash dividends) of the Company's assets to shareholders, or any other change in the capital of the Company affecting the Class A Shares (collectively, "**Adjustment Events**"), the Board will make such proportionate adjustments, if any, as it deems appropriate to reflect such change with respect to the number or kind of securities subject to outstanding awards, the exercise price and number of outstanding stock options and the number of RSUs or PSUs credited to a participant, in order to preserve proportionately the rights and obligations of the participants under the Equity Incentive Plan.

Amendment and Termination

The Board will be permitted to amend, suspend or terminate the Equity Incentive Plan or any award without shareholder approval, subject to applicable law and stock exchange rules that requires the approval of shareholders, in certain circumstances, provided that no such action may be taken that materially adversely alters or impairs any rights of a participant under any award previously granted without the consent of such affected participant.

The Board will be able to make amendments to the Equity Incentive Plan or to any award outstanding thereunder without seeking shareholder approval, including housekeeping amendments, amendments to comply with applicable law or stock exchange rules, amendments necessary to receive favorable treatment under applicable tax laws, amendments to the vesting, termination or early termination provisions of the Equity Incentive Plan, amendments to modify the cashless exercise feature that provides for a full deduction of the number of Class A Shares available for issuance under the Equity Incentive Plan or amendments to suspend or terminate the Equity Incentive Plan. However, the following types of amendments may not be made without obtaining shareholder approval:

- increasing the number of Class A Shares available for issuance under the Equity Incentive Plan;
- increasing the length of the period after a blackout period during which stock options may be exercised;

- permitting the introduction or reintroduction of non-employee directors as eligible participants on a discretionary basis or any amendment that increases the limits previously imposed on non-employee director participation;
- removing or exceeding the insider participation limit specified under "Class A Shares Subject to the Equity Incentive Plan and Participation Limits";
- reducing the exercise price of a stock option or allowing for the cancellation and reissuance of a stock option, which would be considered a repricing under the rules of the TSX, except, in each case, pursuant to an Adjustment Event;
- extending the expiry date of a stock option, except for an automatic extension of a stock option that expires during or shortly following a blackout period;
- permitting awards to be transferred or assigned other than for normal estate settlement purposes; and
- deleting or reducing the range of amendments which require approval by shareholders under the amendment provision of the Equity Incentive Plan.

Assignment

Except as required by law, the rights of a participant under the Equity Incentive Plan are not transferable or assignable.

No awards are expected to be granted to the NEOs under the Equity Incentive Plan upon Closing.

Legacy Long-term Incentive Plan and Cash Bonus Arrangements

Certain executive officers are participants in a legacy long-term incentive plan (the "**Legacy Incentive Plan**") established in 2018. No new awards will be made under the Legacy Incentive Plan following Closing and any outstanding entitlements will be paid out in accordance with the terms of the plan. All payments to be made in connection with the Legacy Incentive Plan will be funded entirely by Brookfield.

Overview of Legacy Incentive Plan

Under the terms of the Legacy Incentive Plan, participants are entitled to receive cash payments based on the net capital appreciation of the investment in certain entities that operate the Company's natural gas storage businesses from the date of award to the date that a liquidity event is completed. No payments are due and payable prior to a liquidity event in respect of all of the specified entities under the Legacy Incentive Plan. Brookfield may elect to pay a special bonus in lieu of, and upon surrender of, entitlements under the Legacy Incentive Plan and related agreements.

If the liquidity event does not result in the sale of 100% of the specified entities that operate the Company's natural gas storage businesses, participants are entitled to a cash payment in respect of both the initial liquidity event and the subsequent disposition of the remaining interest in such entities by Brookfield. Payments in respect of such disposition are based on the net capital appreciation of the investment in certain entities that operate the Company's natural gas storage businesses from the initial liquidity event to the date of the disposition.

Since the value that may be realized by certain executive officers under the Legacy Incentive Plan is tied to the appreciation in value of the OpCos, any such value creation after Closing will, in turn, benefit the Company. As a result, the Legacy Incentive Plan provides considerable alignment between the interests of such executive officers with those of the Company's shareholders. These entitlements also assist with ensuring that such executive officers make decisions and take risks in a manner that aligns with the interests of the Company's shareholders. A participant may not sell, assign or otherwise transfer, pledge or encumber its interest in respect of the Legacy Incentive Plan and all right and entitlement pursuant to the Legacy Incentive Plan terminates upon the participant's cessation of active employment.

Cash Bonus Arrangements

Cash bonus arrangements ("**Cash Bonuses**") were established for certain executive officers who were hired after 2018. These Cash Bonuses are based on substantially the same terms as the Legacy Incentive Plan and also specify the amounts payable to such executives upon a cessation of active employment, in a manner similar to the early exit entitlement agreements discussed under "— Termination and Change of Control Provisions" below.

Termination and Change of Control Provisions

Each participant under the Legacy Incentive Plan and those subject to Cash Bonuses have entered into an early exit entitlement agreement which specifies the cash payment to be made to the participant upon a cessation of active employment.

In the event of a termination of employment without cause, death or permanent disability of a participant under the Legacy Incentive Plan or executive with a Cash Bonus, such executive shall be entitled to receive a cash termination payment based upon the net capital appreciation of the investment in certain entities that operate the Company's natural gas storage business to the date of termination. In the event of a termination of employment for cause, no amounts are payable under the Legacy Incentive Plan or Cash Bonuses and all rights under the Legacy Incentive Plan and Cash Bonuses terminate as of the date of termination. In the event of a resignation of an executive on terms and conditions acceptable to Brookfield, such executive will be entitled to a cash termination payment, the manner of calculation of such payment and the timing of payment thereof will be determined in Brookfield's discretion (subject to the terms of the applicable early exit entitlement agreement).

Brookfield intends to pay participants, including certain NEOs, a portion of their entitlements under the Legacy Incentive Plan and Cash Bonuses in connection with completion of the Offering. However, the amounts of such payments will not be determinable until following completion of the Offering. Based on Brookfield's internal valuations and current estimates, the aggregate payout range anticipated to be paid to the NEOs following completion of the Offering is between approximately $15.0 million and $15.7 million.

Benefit Plans

The OpCos provide their officers, including the NEOs, with life, disability, health, dental and emergency medical travel insurance coverage on the same basis as other employees of the OpCos. The OpCos offer these benefits consistent with local market practice.

Retirement Arrangements

The OpCos maintain a group registered retirement savings plan (the "**Group RRSP**") for certain employees, including the NEOs, to assist employees in preparing for their retirement. The OpCos make contributions to the plan on behalf of each participant equal to 8% of base salary. The NEOs do not participate in a registered defined benefit plan or any other post-retirement supplementary compensation plans and do not have any entitlement to future pension benefits or other post-employment benefits from the Company or the OpCos.

Perquisites

The Company and the OpCos do not offer significant perquisites as part of the compensation program.

Executive Share Ownership Guidelines

The Company will establish executive share ownership guidelines to further align the interests of its executives with those of the Company's shareholders. The ownership guidelines will establish minimum equity ownership levels for executives based on a multiple of their base salary and their level of seniority. Executives will be expected to meet the prescribed ownership levels within five years of the later of Closing and the date of their appointment to an executive position. Class A Shares and the value of RSUs and other long-term incentive awards as determined by the Board from time to time (including awards under the Legacy Incentive Plan) may be included in determining an individual's ownership value.

The following table shows the expected ownership guidelines for the executives:

Level	Base Salary Multiple
Chief Executive Officer	3x
Chief Financial Officer	2x
Senior Vice Presidents/Other titles	1x

Summary Compensation Table

The following table sets out information concerning the expected compensation to be earned by, paid to, or awarded to the NEOs in respect of fiscal 2026. Amounts paid or payable in Canadian dollars have been converted to U.S. dollars at an exchange rate of C$1.00 = $0.7176, which is the Bloomberg mid-market exchange rate on October 1, 2025.

					Non-Equity Incentive Plan Compensation				
Name and Principal Position	**Fiscal Year**	**Salary ($)[1]**	**Share-Based Awards ($)[2]**	**Option-Based Awards ($)**	**Annual Incentive Plans ($)[3]**	**Long-Term Incentive Plans ($)**	**Pension Value ($)**	**All Other Compensation ($)[4]**	**Total Compensation ($)**
Tobias McKenna *Chief Executive Officer*	2026	$343,123	—	—	$343,123	$467,394	Nil	$31,038	$1,184,678
Jon Syrnyk *Chief Financial Officer*	2026	$214,174	—	—	$214,174	$185,858	Nil	$17,852	$ 632,058
Kevin Donegan *Senior Vice President, Accounting and Administration*	2026	$196,562	—	—	$117,938	$155,025	Nil	$16,442	$ 485,967
Sheri Doell *Senior Vice President, Commercial Operations*	2026	$196,562	—	—	$127,766	$501,961	Nil	$17,303	$ 843,592
Hardip Kalar *Senior Vice President, Strategy and Analytics*	2026	$196,562	—	—	$117,938	$229,214	Nil	$16,442	$ 560,156

Notes:

(1) Represents the base salary expected to be paid in fiscal 2026.

(2) The Company anticipates granting awards under the Equity Incentive Plan to the NEOs prior to the commencement of fiscal 2027. However, the timing and value of such grants have not yet been determined and remain subject to approval by the Board and the OpCo Boards. It is currently anticipated that the value of such grants will be set in the range of 100% to 300% of base salary for the NEOs.

(3) Amount reflects the estimated annual bonuses for the NEOs for fiscal year 2026, paid at target and based on the expected base salary amounts for fiscal 2026. Actual amounts for fiscal 2026 will depend on performance for 2026 and may be higher or lower than these amounts.

(4) None of the NEOs are entitled to perquisites or other personal benefits which, in aggregate, are worth over $50,000 or over 10% of their base salary.

Employment Agreements

The NEOs do not have contractual termination, post-termination or change of control arrangements or employment contracts, except for (i) Mr. McKenna, who is party to an employment agreement (which is described below) and (ii) the NEOs with contractual entitlements in connection with the Legacy Incentive Plan, as set forth in "— Components of Compensation — Long-Term Incentive Plans — Legacy Long-term Incentive Plan and Cash Bonus Arrangements". It is anticipated that the other NEOs will enter into employment agreements following the completion of the Offering which are substantially similar to Mr. McKenna's employment agreement with respect to contractual termination, post-termination and change of control arrangements (including restrictive covenants).

Mr. Tobias McKenna, Chief Executive Officer

Mr. McKenna's employment agreement provides for base salary, an annual bonus, benefits and participation in the Legacy Incentive Plan. The payment of severance to Mr. McKenna is conditioned on his execution of a release of claims.

If Mr. McKenna (i) is terminated without just cause, (ii) resigns with good reason, or (iii) is terminated for any reason other than just cause within 12 months of a change of control, he will be entitled to severance equal to 12 months of his annual base salary and 12 months' annual bonus (based on the average amount of Mr. McKenna's annual bonuses for the two fiscal years preceding the termination of his employment) on a lump sum basis, plus his annual bonus entitlement (if any) calculated pro rata for the period up to the termination date based on the achievement of the bonus incentive target to such date (as well as his accrued but unpaid base salary and vacation pay up to the termination date and benefits continuation).

If Mr. McKenna's employment is terminated with just cause, due to his resignation or by reason of retirement, death or incapacity of work, he will not be entitled to any further notice of termination, payment in lieu of notice of termination or severance. However, in the event that Mr. McKenna's employment is terminated by reason of retirement, death or incapacity of work, he will be entitled to receive his annual bonus entitlement (if any) calculated pro rata for the period up to the termination date based on the achievement of the bonus incentive target to such date.

Mr. McKenna's employment agreement also contains customary confidentiality covenants and certain restrictive covenants that will continue to apply following the termination of his employment, including non-competition and non-solicitation provisions which are in effect during Mr. McKenna's employment and for the six months and 12 months, respectively, following the termination of his employment.

Termination and Change of Control Benefits

The table below provides a summary of the termination and change of control benefits provided under Mr. McKenna's employment agreement and the employment agreements anticipated to be entered into with the other NEOs following completion of the Offering, the termination entitlements in connection with the Legacy Incentive Plan as well as the anticipated incremental costs associated with various termination events (assuming the termination events occurred on the completion of the Offering). Amounts payable in Canadian dollars have been converted to U.S. dollars at an exchange rate of C$1.00 = $0.7176, which is the Bloomberg mid-market exchange rate on October 1, 2025.

Name and Principal Position[(1)]	Event	Severance	Other Payments	Total
Tobias McKenna *Chief Executive Officer*	Termination without cause, termination within 12 months of a change of control or resignation for Good Reason	$1,076,869	$9,514	$1,086,383
	Retirement, Death or Incapacity of Work	$ 200,155	—	$ 200,155
Jon Syrnyk *Chief Financial Officer*	Termination without cause, termination within 12 months of a change of control or resignation for Good Reason	$ 500,253	$5,210	$ 505,463
	Retirement, Death or Incapacity of Work	$ 124,935	—	$ 124,935

Name and Principal Position[1]	Event	Severance	Other Payments	Total
Kevin Donegan . . . . *Senior Vice President, Accounting and Administration*	Termination without cause, termination within 12 months of a change of control or resignation for Good Reason	$ 400,318	$5,246	$ 405,564
	Retirement, Death or Incapacity of Work	$ 68,797	—	$ 68,797
Sheri Doell . . . . *Senior Vice President, Commercial Operations*	Termination without cause, termination within 12 months of a change of control or resignation for Good Reason	$ 455,372	$5,246	$ 460,618
	Retirement, Death or Incapacity of Work	$ 74,530	—	$ 74,530
Hardip Kalar . . . . *Senior Vice President, Strategy and Analytics*	Termination without cause, termination within 12 months of a change of control or resignation for Good Reason	$ 449,510	$5,246	$ 454,756
	Retirement, Death or Incapacity of Work	$ 68,797	—	$ 68,797

Note:

(1) Severance amounts payable to the NEOs are based on the amount of base salary expected to be paid in fiscal 2026 to the applicable NEO and the average amount of the annual bonus paid to the applicable NEO for fiscal years 2024 and 2025 (in the case of Mr. Syrnyk, such average amount included the amount of his annual bonus for fiscal year 2024, which was pro-rated based on his start date in September 2023), plus a pro-rated amount in respect of their annual bonus entitlement for fiscal year 2026 paid at target based on such individual working seven (7) of twelve (12) months in the fiscal year 2026.

For a summary of the termination and change of control benefits provided under the Equity Incentive Plan, please refer to the "— Components of Compensation — Long-term Incentive Plan" section above.

Outstanding Share-Based Awards and Option-Based Awards

None of the NEOs currently hold any share-based or option-based awards.

	Option-based Awards				Share-based Awards		
Name	Number of securities underlying unexercised options (#)	Option exercise price ($)	Option expiration date	Value of unexercised in-the-money options ($)	Number of shares or units of shares that have not vested (#)	Market or payout value of share-based awards that have not vested ($)	Market or payout value of vested share-based awards not paid out or distributed ($)
Tobias McKenna . . . . . . *Chief Executive Officer*	—	—	—	—	—	—	—
Jon Syrnyk . . . . *Chief Financial Officer*	—	—	—	—	—	—	—
Kevin Donegan . . . . *Senior Vice President, Accounting and Administration*	—	—	—	—	—	—	—
Sheri Doell . . . . *Senior Vice President, Commercial Operations*	—	—	—	—	—	—	—
Hardip Kalar. . . . . *Senior Vice President, Strategy and Analytics*	—	—	—	—	—	—	—

Incentive Plan Awards — Value Vested or Earned During the Year

The following table sets out, for each of the NEOs, the value of non-equity incentive plan compensation expected to be earned during fiscal 2026. None of the NEOs currently hold any share-based awards or option-based awards. Amounts paid or payable in Canadian dollars have been converted to U.S. dollars at an exchange rate of C$1.00 = $0.7176, which is the Bloomberg mid-market exchange rate on October 1, 2025.

Name and Principal Position	Option-Based Awards – Value Expected to Vest During the Year ($)	Share-based awards – Value Expected to Vest During the Year ($)	Non-equity Incentive Plan Compensation – Value Expected to be Earned During the Year ($)
Tobias McKenna *Chief Executive Officer*	—	—	$810,518
Jon Syrnyk *Chief Financial Officer*	—	—	$400,033
Kevin Donegan *Senior Vice President, Accounting and Administration*	—	—	$272,963
Sheri Doell *Senior Vice President, Commercial Operations*	—	—	$629,727
Hardip Kalar *Senior Vice President, Strategy and Analytics*	—	—	$347,151

Note:

(1) Amounts reflect the estimated annual bonuses for the NEOs for fiscal year 2026, paid at target and based on the expected base salary amounts for fiscal 2026 as well as estimated MTIP payments to be earned in fiscal year 2026. Actual amounts for fiscal 2026 annual bonuses will depend on performance for 2026 and may be higher or lower than these amounts.

DIRECTOR COMPENSATION

Introduction

The following discussion describes the significant elements of the expected compensation program for the independent members of the Board and its committees, which excludes directors who are employees of the Company, the OpCos or Brookfield. Directors who are employees of the Company, the OpCos or Brookfield receive no compensation for their service on the Board. The compensation of the Company's independent directors is designed to attract and retain committed and qualified directors and to align their compensation with the long-term interests of the Company's shareholders.

Director Compensation

The Board, on the recommendation of the GNC Committee, will be responsible for reviewing and approving any changes to the independent directors' compensation arrangements. In consideration for serving on the Board, each independent director will be paid an annual retainer which will be paid in a combination of cash and DSUs. Such independent directors will be expected to take at least 50% of their annual retainer in DSUs, with the option to elect to receive up to 100% of their fees in DSUs.

The chart below outlines the proposed compensation program for such independent directors.

Type of Fee		Amount
Annual Retainer	Board Chair	$155,000
	Board Member	$130,000
Committee Retainer	Committee Chair	$ 20,000
	Committee Member	$ 10,000

All directors will be reimbursed for their reasonable out-of-pocket expenses incurred while serving as directors. Any independent director who serves on the OpCo Boards as the Company's representative will also receive an annual retainer of $10,000 which will be paid by the Company.

Upon completion of the Offering, the Company will establish a Director Deferred Share Unit Plan (the "**DSU Plan**"). The DSU Plan will allow directors to elect to take all or a portion of their annual cash retainer in the form of DSUs. Each director wishing to make an election will generally be required to elect to receive all or a portion of his or her annual cash retainer in DSUs no later than the end of the calendar year preceding the year in which such election is to apply.

A DSU is a notional unit, equivalent in value to a Class A Share, credited by means of a bookkeeping entry in the books of the Company, to an account in the name of the director. When dividends (other than share dividends) are paid on Class A Shares, additional DSUs will automatically be granted to each director who holds DSUs on the record date for such dividends. Following an eligible director ceasing to hold all positions with the Company and its related entities, the director will receive a payment in cash at the fair market value of the Class A Shares represented by his or her DSUs on the director's elected redemption date. Each director's elected redemption date will not be earlier than the date the director ceases to hold all positions with the Company and its related entities and will not be later than December 15th of the year following the year in which the director ceases to hold all positions with the Company and its related entities.

Director Share Ownership Guidelines

The Company will establish director share ownership guidelines for independent directors to further align the interests of such directors with those of the Company's shareholders. The ownership guidelines will establish minimum equity ownership levels for each independent director based on a multiple of their annual retainer. Such directors will be expected to meet the prescribed ownership levels within six years of the later of: (i) Closing; and (ii) the date of their appointment to the Board. Class A Shares and the value of DSUs and other equity-based awards (if any) will be included in determining an individual's equity ownership value. The expected ownership guideline for these directors is 3x their annual retainer.

Outstanding Share-Based Awards and Option-Based Awards

None of the non-employee directors currently hold any share-based or option-based awards.

	Option-based Awards				Share-based Awards		
Name	Number of securities underlying unexercised options (#)	Option exercise price ($)	Option expiration date	Value of unexercised in-the-money options ($)	Number of shares or units of shares that have not vested (#)	Market or payout value of share-based awards that have not vested ($)	Market or payout value of vested share-based awards not paid out or distributed ($)
Brian Baker	—	—	—	—	—	—	—
William Burton	—	—	—	—	—	—	—
Peter Cella	—	—	—	—	—	—	—
Sippy Chhina	—	—	—	—	—	—	—
David Devine	—	—	—	—	—	—	—
Rick Eng	—	—	—	—	—	—	—
Suzanne Nimocks	—	—	—	—	—	—	—
Gene Stahl	—	—	—	—	—	—	—

Incentive Plan Awards — Value Vested or Earned During the Year

The following table sets out, for each of the non-employee directors, the value of the share-based awards expected to vest in accordance with their terms during fiscal 2026 (assuming the continued service of the non-employee director).

Name and Principal Position	Option-Based Awards – Value Expected to Vest During the Year ($)	Share-based awards – Value Expected to Vest During the Year ($)	Non-equity Incentive Plan Compensation – Value Expected to be Earned During the Year ($)
Brian Baker	—	—	—
William Burton	—	—	—
Peter Cella	—	$37,500	—
Sippy Chhina	—	$37,500	—
David Devine	—	$35,000	—
Rick Eng	—	$41,250	—
Suzanne Nimocks	—	$35,000	—
Gene Stahl	—	$32,500	—

THE COMPANY AND THE OPCOS

Formation of Rockpoint and the OpCos

Rockpoint was incorporated by Brookfield Infrastructure Holdings (Canada) Inc. under the ABCA on July 28, 2025. The Articles were amended on September 17, 2025 to authorize the Class A Shares and Class B Shares.

Rockpoint's registered and head office is located at 400 – 607 8th Ave. S.W., Calgary, Alberta, Canada, T2P 0A7.

Swan OpCo is a limited partnership formed under the laws of the Province of Ontario on March 2, 2016. Swan OpCo's registered and head office is located at Brookfield Place, Suite 100, 181 Bay Street, Toronto, Ontario, Canada, M5J 2T3. The general partner of Swan OpCo is Swan GP, a subsidiary of Brookfield. Following completion of the Transactions, the limited partners of Swan OpCo will be Rockpoint, Swan Equity Carry LP and BIP BIF II Swan AIV LP. Swan OpCo, through its subsidiaries, Rockpoint GS Holdings I, LP and Rockpoint Gas Storage Canada Ltd., is the owner of: (i) the Wild Goose California public utility; and (ii) the AECO Hub™ and the AGS and ESAS assets, respectively. Following completion of the Transactions, Swan OpCo will also own the Warwick facility.

BIF OpCo is a limited liability company formed under the laws of the State of Delaware on July 23, 2014. BIF OpCo's head office is located at Brookfield Place, 250 Vesey Street, New York, New York, USA, 10281-1023 and its registered office is located at 2711 Centerville Road, Suite 400, Wilmington, Delaware, USA, 19808. BIF OpCo, through its subsidiary, Lodi Gas Storage, LLC, is the owner of the Lodi California public utility. Following completion of the Transactions, the members of BIF OpCo will be Rockpoint and two subsidiaries of Brookfield, being BIF II CalGas Carry (Delaware) LLC and BIP BIF II US Holdings (Delaware) LLC. BIF OpCo, through its subsidiary, Lodi Gas Storage, LLC, is the owner of the Lodi California public utility.

If CPUC Approval is obtained and once Brookfield holds less than 50% of the OpCo Interests, Brookfield will transfer ownership of the Swan OpCo GP Units held by Swan GP to a new entity controlled by Rockpoint for nominal consideration pursuant to the Relationship Agreement and Brookfield will cooperate with Rockpoint to reconstitute the OpCo Boards to reflect the constitution of the Board at such time.

The Transactions

As of the date hereof, Rockpoint has no active operations and nominal assets. Following completion of the Transactions, Rockpoint will be a holding corporation whose sole material assets consist of approximately 40% of the OpCo Interests, and as a result, will hold an approximate 40% interest in the Business.

Following the completion of the Transactions, purchasers under the Offering will hold approximately 60.2% of the Class A Shares, comprising approximately 24.1% of the votes attached to all outstanding Shares, and Brookfield will own approximately 39.8% of the Class A Shares and 100% of the Class B Shares, comprising approximately 75.9% of the votes attached to all outstanding Shares, in each case prior to any exercise of the Over-Allotment Option. If the Over-Allotment Option is exercised in full, purchasers under the Offering and the Secondary Offering will hold approximately 69.2% of the Class A Shares, comprising approximately 27.7% of the votes attached to all outstanding Shares, and Brookfield will own approximately 30.8% of the Class A Shares and 100% of the Class B Shares, comprising approximately 72.3% of the votes attached to all outstanding Shares.

For a description of the Business, see "Our Business" and for a description of the material terms of the Transactions, see "Relationship with Brookfield — The Transactions".

Intercorporate Relationships

The Business is currently carried on by Brookfield through its direct and indirect ownership of the OpCos and WGS LP and their direct and indirect subsidiaries. Following completion of the Transactions, Rockpoint will indirectly own approximately 40% of the Business through its OpCo Interests and the Business will be conducted through the OpCos and their respective subsidiaries. Rockpoint currently has no subsidiaries.

RELATIONSHIP WITH BROOKFIELD

The Transactions

Rockpoint was incorporated under the ABCA for the purpose of facilitating the Offering and acquiring approximately 40% of the Business. The Business will be conducted through the OpCos and their subsidiaries, who will own the Wild Goose, Lodi, Kirby Hills, AECO Hub™, Warwick, AGS, and ESAS assets upon completion of the Transactions.

The Transactions are being conducted through what is commonly referred to as an "Up-C" structure whereby all of the assets of the Business will be held by the OpCos and their respective subsidiaries and the sole material assets of the Company will consist of its equity interests in the OpCos. This structure is often used by partnerships and limited liability companies undertaking an initial public offering.

Rockpoint will use all of the net proceeds received by it from the Offering to fund the cash portion of the Transactions, completed through a number of steps, including:

(a) AECO Gas Storage Partnership, a wholly-owned subsidiary of Swan OpCo, will borrow $135,600,000 from Brookfield (such amount, the "**Warwick Receivable**") and will use the proceeds to acquire WGS LP;

(b) Rockpoint will sell 79,800,000 newly issued Class B Shares to Brookfield Infrastructure Holdings (Canada) Inc. for nominal consideration to align Brookfield's voting interest in Rockpoint with its economic interest in the OpCos;

(c) Rockpoint will sell 32,000,000 newly issued Class A Shares to the public pursuant to the Offering at a price of C$22.00 per Class A Share for aggregate gross proceeds of C$704,000,000;

(d) Rockpoint will purchase: (i) approximately 40% of the Swan OpCo Units and approximately 40% of the BIF OpCo Shares from the Selling Shareholders for $450,400,000 of cash and 21,200,000 newly issued Class A Shares; and (ii) approximately 40% of the Warwick Receivable from Brookfield for $54,200,000 of cash;

(e) Rockpoint and Brookfield will transfer their interests in the Warwick Receivable to Swan OpCo in exchange for additional Swan OpCo Units following which the Warwick Receivable will be contributed to AECO Gas Storage Partnership and cancelled by operation of law; and

(f) a wholly-owned subsidiary of Swan OpCo will acquire the entity in which the executive officers of the Company and the OpCos are employed by purchasing 100% of the shares of SIM Energy Limited, 99% of the class B units of SIM Energy LP and 100% of the shares of BIF II SIM Limited from Brookfield for $3,000,000 of cash, funded by cash on hand.

See "Use of Proceeds".

Swan GP, which is an affiliate of Brookfield, will remain the general partner of Swan OpCo, and the board of directors of Swan GP will be comprised of three directors. Pursuant to the Relationship Agreement, the directors of Swan GP will be selected from the existing members of the Board by the members of the Board subject to, at all times, compliance with the requirement for prior CPUC Approval, as applicable, with at least one director being an independent director of Rockpoint. Swan GP will not be entitled to any fees or distributions in connection with its role as general partner of Swan OpCo.

The board of managers of BIF OpCo will be comprised of three managers. Pursuant to the Relationship Agreement, the managers of BIF OpCo will be selected from the existing members of the Board by the members of the Board subject to, at all times, compliance with the requirement for prior CPUC Approval, as applicable, with at least one manager being an independent director of Rockpoint.

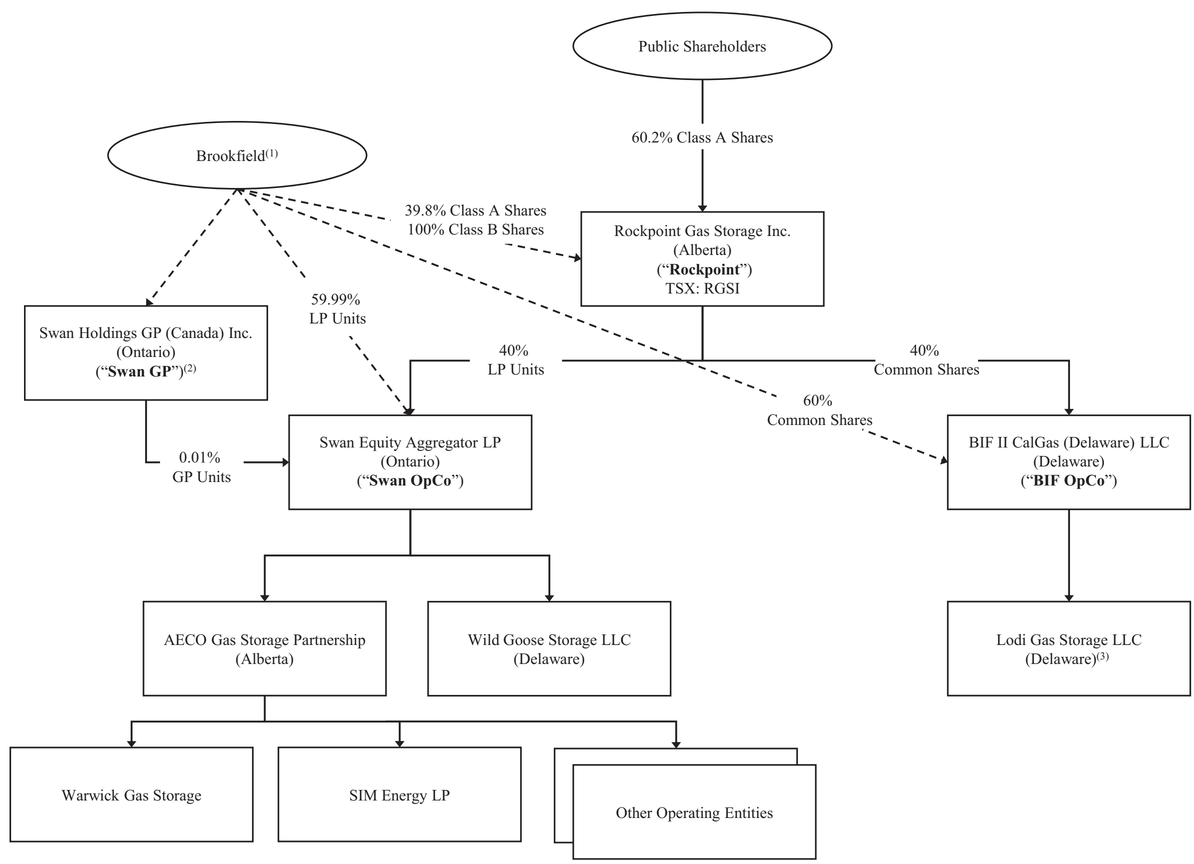
The board of directors of Swan GP, as the general partner of Swan OpCo, and the board of managers of BIF OpCo will control and be responsible for all operational, management and administrative decisions relating to the businesses of Swan OpCo and BIF OpCo, respectively. The OpCo Boards will oversee the management of, and provide stewardship over, the businesses of Swan OpCo and BIF OpCo, respectively.

Pursuant to the Relationship Agreement, no manager of BIF OpCo will be removed from the board of managers of BIF OpCo without the prior approval of the Board and no director of Swan GP will be removed from the board of directors of Swan GP without the prior approval of the Board. Moreover, no manager shall be appointed to the BIF OpCo board of managers without the prior approval of the Board and no director shall be appointed to the Swan GP board of directors without the prior approval of the Board. Any vacancy on either of the OpCo Boards will be promptly filled by an individual elected in accordance with the foregoing requirements.

Upon completion of the Transactions, it is anticipated that the board of managers of BIF OpCo and the board of directors of Swan GP will each be comprised of Brian Baker, a non-independent director of Rockpoint, William Burton, a non-independent director of Rockpoint, and Peter Cella, an independent director of Rockpoint.

See "Relationship with Brookfield — Agreements Between the Company and Brookfield — Relationship Agreement".

The OpCos will own the Business. Following completion of the Transactions, the simplified structure of the Company, including the interests in the OpCos (and therefore the Business), held by the Company and Brookfield, will be as follows:



Notes:

(1) Includes various affiliates of Brookfield. Consolidated for ease of reference.

(2) Swan GP, the general partner of Swan OpCo, is an affiliate of Brookfield.

(3) Lodi Gas Storage LLC owns the Lodi and Kirby Hills facilities.

(4) Unless otherwise disclosed, the percentage of votes attaching to all voting securities of the subsidiary beneficially owned, or controlled or directed, directly or indirectly, by the parent is 100%.

See "— Agreements Between the Company and Brookfield" below.

Brookfield's Ownership in the Company and the OpCos

Upon completion of the Transactions, Rockpoint will own approximately 40% of the OpCo Interests and Brookfield will own approximately 60% of the OpCo Interests, excluding any indirect beneficial ownership of Brookfield in OpCo Interests by virtue of its ownership in the Company. In addition, upon completion of the Transactions, assuming the Over-Allotment Option is not exercised, Brookfield will own approximately 39.8% of the outstanding Class A Shares and 100% of the outstanding Class B Shares, representing approximately 75.9% of the aggregate outstanding Shares and voting interest in the Company (or approximately 30.8% of the outstanding Class A Shares, representing, together with Brookfield's Class B Shares, approximately 72.3% of the aggregate outstanding Shares and voting interest in the Company, if the Over-Allotment Option is exercised in full). As a result, Brookfield will have control over the Company, the OpCos and the Business.

Upon completion of the Transactions, the OpCo Boards will each be comprised of three managers and directors, as applicable, who will be selected from the existing members of the Board by the members of the Board subject to, at all times, compliance with existing CPUC approvals, with one manager and director being an independent director of Rockpoint and the other two managers and directors being non-independent directors of Rockpoint, as applicable. See "Relationship with Brookfield — Agreements Between the Company and Brookfield — Relationship Agreement". Upon completion of the Transactions, it is anticipated that each of the OpCo Boards will be comprised of Brian Baker, a non-independent director of Rockpoint, William Burton, a non-independent director of Rockpoint, and Peter Cella, an independent director of Rockpoint. The Chief Executive Officer of the Company will be the Chief Executive Officer of each of BIF OpCo and Swan GP, the Chief Financial Officer of the Company will be the Chief Financial Officer of each of BIF OpCo and Swan GP and the remaining members of the BIF OpCo and Swan GP management teams will be selected from the other executive officers of the Company.

The OpCo Boards will oversee the management of the business and affairs of each applicable OpCo. Each OpCo Board, as applicable, will be responsible for overseeing management of the applicable OpCo, reviewing and approving budgets, financings and distributions, approving acquisitions, dispositions and other major transactions, assessing and overseeing the management of business risks, among other matters for which directors are customarily responsible. See "Risk Factors — Rockpoint will be dependent upon the OpCo Boards, which are comprised of a majority of Brookfield-affiliated directors or managers, for supervision of the management and operation of the Business and the OpCos, which could affect the value of Rockpoint's investment in the Business".

Upon completion of the Offering, Swan OpCo will indirectly own 100% of the shares of SIM Energy Limited and 99% of the class B units of SIM Energy LP. SIM Energy LP is the entity that employs all of the executive officers of the Company and the OpCos. Following completion of the Offering, Swan OpCo will also acquire 100% of the shares of BIF II SIM Limited. Pursuant to a services agreement, BIF II SIM Limited provides certain management, administrative and reporting services to certain subsidiaries of the OpCos.

The A&R LPA provides that Swan GP will not be compensated for its services as the general partner of Swan OpCo without the unanimous consent of the Swan OpCo Partners.

The CPUC has authority over public utilities in California. Gas storage is classified as a public utility in California and therefore Wild Goose and Lodi are under the CPUC's jurisdiction. The CPUC must pre-approve certain actions taken by public utilities, including changes of control. Based on CPUC precedent, changes of control can potentially include indirect changes at the parent company level even without changes at the utility company level. The CPUC has not adopted a brightline test for whether a transaction constitutes a change of control but instead assesses each transaction on a case-by-case basis. The CPUC considers indicia of control to determine if a new entity controls the public utility, including whether a new entity has acquired a 50% or greater ownership interest or otherwise obtained the ability to direct or control management or operation of the public utility. In this case, Brookfield is currently the ultimate owner of Wild Goose and Lodi, which the CPUC has previously approved. Upon completion of the Transactions, Brookfield will: (i) continue to retain majority ownership and control over Wild Goose and Lodi; and (ii) oversee, through the OpCo Boards, the management of the business and affairs of Wild Goose and Lodi. Upon completion of the Transactions, the public will not be able to obtain a majority interest in Rockpoint without prior CPUC Approval. Given that Brookfield will continue to own and control Wild Goose and Lodi, Brookfield and the

Company do not expect that the Offering will result in a change of control for purposes of the CPUC's assessment. However, due to the limited CPUC precedent for initial public offerings and the lack of a brightline test, it is possible that the CPUC will inquire into whether, or take the position that, the Offering constitutes a change of control for Wild Goose or Lodi. See "Risk Factors — The CPUC may inquire into whether, or take the position that, the Offering constitutes a change of control".

If CPUC Approval is obtained and once Brookfield holds less than 50% of the OpCo Interests, Brookfield will transfer ownership of the Swan OpCo GP Units held by Swan GP to a new entity controlled by Rockpoint for nominal consideration pursuant to the Relationship Agreement and Brookfield will cooperate with Rockpoint to reconstitute the OpCo Boards to reflect the constitution of the Board at such time.

Agreements Between the Company and Brookfield

This section provides summary descriptions of the principal agreements among Brookfield, the Company and the OpCos in connection with the Transactions and the ongoing governance of the Company and the OpCos and rights of Brookfield and the Company in relation thereto. The descriptions set out below disclose the attributes material to a prospective investor in Class A Shares and, with respect to each such agreement that constitutes a material contract, each summary, is qualified in its entirety by reference to the full terms of the agreement, which will be filed with the Canadian securities regulatory authorities and will be available under the Company's SEDAR+ profile at www.sedarplus.ca. See "Material Contracts" and "Risk Factors — Brookfield has the ability to direct the voting of a majority of Shares and control certain decisions with respect to Rockpoint's management and business. Brookfield's interests may conflict with those of the other shareholders".

Business Transfer Agreement

To give effect to the Reorganization, the Selling Shareholders, Brookfield and the Company have entered into a business transfer agreement (the "**Business Transfer Agreement**"). Under the Business Transfer Agreement, the Selling Shareholders have agreed to transfer approximately 40% of the Swan OpCo Units and approximately 40% of the BIF OpCo Shares to the Company in exchange for aggregate consideration of $784,600,000 (the "**OpCo Interest Purchase Price**"). The OpCo Interest Purchase Price will be satisfied by the Company through a cash payment of $450,400,000, funded from the proceeds received by the Company under the Offering, plus 21,200,000 newly issued Class A Shares, at a deemed price equal to the Offering Price, in an amount equal to the remaining value of the OpCo Interest Purchase Price owing after the cash payment is made. In addition, under the Business Transfer Agreement, Brookfield has agreed to transfer, for $54,200,000 of cash, approximately 40% of the Warwick Receivable to Rockpoint, which will subsequently be cancelled as part of the Transactions. As the Warwick Receivable is interest bearing, the amount of cash consideration payable by the Company for the Warwick Receivable will increase by a nominal amount should Closing not occur on the assumed date set out in the Business Transfer Agreement.

The Business Transfer Agreement contains limited representations and warranties from the Selling Shareholders and Brookfield concerning, among other things: (i) organization and good standing; (ii) authorization, execution, delivery and enforceability of the agreement and all agreements executed in connection therewith; (iii) title to the OpCo Interests and Warwick Receivable, as applicable, being transferred to the Company; (iv) with respect to the OpCo Interest, the valid issuance of such OpCo Interest; and (v) with respect to the Warwick Receivable, that the Warwick Receivable is valid and enforceable against AECO Gas Storage Partnership and that Brookfield is not aware of any risk of impairment, non-payment or non-collection of the Warwick Receivable. The Business Transfer Agreement does not contain any further representations and warranties or indemnities relating to the Business, the OpCos or any underlying assets or operations.

The Business Transfer Agreement contains customary provisions with respect to Canadian withholding taxes that may be applicable.

See "Risk Factors — The Business Transfer Agreement provides the Company with limited rights and remedies and may contain other terms that are less favourable to the Company than those which might have otherwise been obtained from unrelated parties".

Shareholder Agreement

A shareholder agreement will be entered into concurrent with the completion of the Reorganization between the Company and Brookfield (the "**Shareholder Agreement**") pursuant to which Brookfield (including its permitted transferees) will be entitled, if CPUC Approval is obtained and Brookfield holds less than 50% of the OpCo Interests, to nominate Company directors as follows:

(a) the greater of 45% of the Company's directors (rounded up to the next whole member) and four nominees (provided that at least two nominees must be independent directors) once Brookfield (including its permitted transferees) owns, controls or directs less than 50% but at least 35% of the voting power attached to all of the outstanding Shares (on a non-diluted basis);

(b) the greater of 35% of the Company's directors (rounded up to the next whole member) and three nominees (provided that at least one nominee must be an independent director) once Brookfield (including its permitted transferees) owns, controls or directs less than 35% but at least 25% of the voting power attached to all of the outstanding Shares (on a non-diluted basis);

(c) the greater of 25% of the Company's directors (rounded up to the next whole member) and two nominees once Brookfield (including its permitted transferees) owns, controls or directs less than 25% but at least 10% of the voting power attached to all of the outstanding Shares (on a non-diluted basis);

(d) the greater of 10% of the Company's directors (rounded up to the next whole member) and one nominee once Brookfield (including its permitted transferees) owns, controls or directs less than 10% but at least 5% of the voting power attached to all of the outstanding Shares (on a non-diluted basis); and

(e) none of the Company's directors once Brookfield (including its permitted transferees) owns, controls or directs less than 5% of the voting power attached to the outstanding Shares (on a non-diluted basis).

Pursuant to the Shareholder Agreement, the number of directors on the Board shall be fixed at nine.

Brookfield will provide the names and biographical and other prescribed information concerning its Board nominees to the Company within 15 days after receiving notice from the Company of its intention to hold a meeting of shareholders at which directors are to be elected. All Brookfield nominees must be acceptable to the Governance, Nomination and Compensation Committee (the "**GNC Committee**") and to the Non-Conflicted Directors, acting reasonably. If either the GNC Committee or the Non-Conflicted Directors do not approve a nominee, that decision will be communicated to Brookfield at least 50 days prior to the meeting, and Brookfield will then have the right to, within ten days after receiving the foregoing notice, designate an alternative nominee in accordance with the foregoing procedures.

Pursuant to the Shareholder Agreement, for so long as Brookfield (including its permitted transferees) is entitled to nominate two Company directors, a quorum at a meeting of the Board will consist of a majority of the directors then holding office, including at least one director nominated by Brookfield. If a duly called meeting of the Board is adjourned for lack of quorum solely because a nominee of Brookfield is not present, such meeting will be reconvened seven days following the date of the originally called meeting. If a quorum is not present at the commencement of such adjourned Board meeting solely because the Brookfield nominee(s) who caused the adjournment is not present (in person or by telephone or electronic means), then the directors who are so present, provided a majority of the directors are present, will be deemed to be a quorum. Similarly, for so long as Brookfield (including its permitted transferees) is entitled to nominate two Company directors and where a Brookfield nominee has been appointed to the Committee a quorum at a Committee meeting will consist of a majority of the Committee's members, including at least one director nominated by Brookfield. If a meeting of the Committee is adjourned for lack of quorum solely because a nominee of Brookfield is not present, such meeting will be reconvened seven days following the date of the originally called meeting. If a quorum is not present at the commencement of such adjourned Committee meeting solely because the Brookfield nominee(s) who caused the adjournment is not present (in person or by telephone or electronic means), then the directors who are so present, provided a majority of the directors on such Committee are present, will be deemed to be a quorum.

The Shareholder Agreement will automatically terminate when Brookfield (including its permitted transferees of Shares, being other affiliates of Brookfield, and other permitted assignees approved by a majority of the Non-Conflicted Directors) owns, controls or directs less than 5% of the voting power attached to the outstanding Shares (on a non-diluted basis), the Shareholder Agreement is terminated by the written agreement of the parties or the winding-up, dissolution or liquidation of the Company, whichever is earliest. The Shareholder Agreement may not be amended without, among other things, the approval of a majority of the Non-Conflicted Directors.

Relationship Agreement

A relationship agreement has been entered into among the Company, the OpCos and Brookfield (the "**Relationship Agreement**") pursuant to which the parties have acknowledged and agreed that:

a. from and after the Closing date and for so long as the Company owns, controls, or directs less than a majority of the OpCo Interests:

    i. the board of managers of BIF OpCo will be comprised of three managers and the board of directors of Swan GP will be comprised of three directors,

    ii. the managers of BIF OpCo and the directors of Swan GP will be selected from the existing members of the Board by the members of the Board,

    iii. at least one of the managers of BIF OpCo will be an independent director of the Board (who, for certainty, is not an officer or employee of Brookfield) and at least one of the directors of Swan GP will be an independent director of the Board (who, for certainty, is not an officer or employee of Brookfield),

    iv. no manager of BIF OpCo will be removed from the board of managers of BIF OpCo without the prior approval of the Board and no director of Swan GP will be removed from the board of directors of Swan GP without the prior approval of the Board,

    v. no manager shall be appointed to the BIF OpCo board of managers without the prior approval of the Board and no director shall be appointed to the Swan GP board of directors without the prior approval of the Board,

    vi. any vacancy on the board of managers of BIF OpCo or the board of directors of Swan GP will be promptly filled by an individual chosen in accordance with the foregoing,

    vii. the officers of Swan GP and BIF OpCo will be comprised of executive officers of Rockpoint,

    viii. the Company will have the right to have the Audit Committee engage directly with the external and internal auditors of each OpCo and be consulted in the review and preparation of the quarterly and annual financial statements, as applicable, of each OpCo,

    ix. in addition to its access and information rights under applicable law, the Company will have the right to access all of the information of each OpCo (which will include full access to the premises, assets, books, accounts, tax returns, contracts, commitments and records of the OpCo), and the information obtained by Company may be presented to the Board, the Committees or to Brookfield and be used and relied upon by the Company for the preparation of the disclosure documents (including financial statements) of the Company and otherwise for such other purposes as determined necessary by the Company, acting reasonably, including for the purposes of compliance with its legal, regulatory and/or tax obligations, and

    x. the Company will have the right to have the GNC Committee be consulted in the review and setting of the compensation policies and practices of each OpCo;

b. if CPUC Approval is obtained and Brookfield holds less than 50% of the OpCo Interests, for so long as Brookfield owns, controls or directs at least 5% of the voting power attached to all of the outstanding Shares (on a non-diluted basis), in addition to its access and information rights under applicable law, Brookfield will have a general right to access all of the Company's information (which will include full access to the Company's premises, assets, books, accounts, tax returns, contracts, commitments and records), and the information obtained by Brookfield may be presented to any Governing Body of Brookfield and be used and relied upon for the preparation of the disclosure documents (including financial statements) of Brookfield and otherwise for such other purposes as determined necessary by Brookfield, acting reasonably, including for the purposes of compliance with its other legal, regulatory and/or tax obligations;

c. if the CPUC Approval is obtained, once Brookfield holds less than 50% of the OpCo Interests, Brookfield will transfer ownership of the Swan OpCo GP Units held by Swan GP to a new entity controlled by the Company for nominal consideration and Brookfield will cooperate with the Company to reconstitute the OpCo Boards to reflect the constitution of the Board at such time;

d. notwithstanding any provisions of the applicable constating documents of an OpCo, the prior approval of the holders of not less than 66⅔% of the then outstanding Swan OpCo Units or BIF OpCo Shares, as applicable, and a majority of the Non-Conflicted Directors will be required to: (i) amend the A&R LPA or the LLC Agreement, (ii) other than admissions that occur in accordance with the terms of the Exchange Agreement or as a result of the transfer or assignment of OpCo Interests among Affiliates of then-existing partners or members, as applicable, admit new partners of Swan OpCo or new members of BIF OpCo, (iii) other than such issuances undertaken or occurring in accordance with the terms of the Exchange Agreement, issue new partnership interests in the capital of Swan OpCo or membership interests in the capital of BIF OpCo, (iv) other than purchases for cancellation that occur in accordance with the terms of the Exchange Agreement, purchase for cancellation any equity interests in the capital of an OpCo by such OpCo, (v) declare or pay a return of capital to the partners of Swan OpCo or the members of BIF OpCo, (vi) remove or replace the general partner of Swan OpCo or add a new general partner of Swan OpCo, or (vii) pursue a voluntary dissolution, winding-up or liquidation of an OpCo or a sale of all or substantially all of the assets and undertakings of an OpCo; and

e. so long as the Company owns, controls or directs less than a majority of the OpCo Interests, subject to available cash, the terms of any current or future debt or other arrangements, any applicable regulatory requirements and the governing documents of each OpCo, each OpCo will use commercially reasonable efforts to make pro rata distributions to its securityholders in an amount sufficient to allow the Company to satisfy its income tax liabilities with respect to its allocable share of the income of such OpCo.

Pursuant to the Relationship Agreement, the Company and the OpCos have also acknowledged and agreed that Brookfield carries on a diverse range of businesses worldwide, and that the Relationship Agreement will not in any way limit or restrict Brookfield from carrying on its business. Among other things, the Company and each of the OpCos have acknowledged and agreed that Brookfield may pursue other business activities and acquire investments in third parties that compete directly or indirectly with the Business. In addition, the Relationship Agreement provides that Brookfield has established or advised, and may continue to establish or advise, other entities that rely on the diligence, skill and business contacts of Brookfield's professionals and the information and acquisition opportunities they generate during the normal course of their activities. The Company and the OpCos have acknowledged and agreed that some of these entities may have objectives that overlap with the objectives of the Company or the OpCos, and that such entities may acquire business services and industrial operations that could be considered appropriate acquisitions for the OpCos, and that Brookfield could have financial incentives to assist those other entities over us.

Other than the provisions respecting permitted activities of Brookfield which survive termination, the Relationship Agreement will automatically terminate once Brookfield (including its permitted transferees, being other affiliates of Brookfield) owns, controls or directs less than 5% of the voting power attached to the outstanding Shares (on a non-diluted basis). The Relationship Agreement may not be amended without, among other things, the approval of a majority of the Non-Conflicted Directors.

Exchange Agreement

The Company, the OpCos, Swan GP, Brookfield Infrastructure Holdings (Canada) Inc. and the Selling Shareholders have entered into the Exchange Agreement pursuant to which Brookfield (and its permitted transferees (other than the Company)) will, upon its determination, subject to certain limitations, have the right to cause the Company to acquire all or a portion of their OpCo Interests (along with the cancellation of a number of Class B Shares held by Brookfield corresponding to the number of OpCo Interests tendered) for, at the Company's election (upon the approval of a majority of the Non-Conflicted Directors): (i) Class A Shares at the Exchange Ratio, subject to conversion rate adjustments for share splits, share consolidations, share reclassifications and other similar transactions; (ii) cash in an amount equal to the Cash Election Amount of such Class A Shares otherwise issuable to Brookfield pursuant to the Exchange Right; or (iii) a combination of (i) and (ii). In connection with any exchange of OpCo Interests pursuant to the Exchange Right, a number of Class B Shares held by Brookfield corresponding to the number of OpCo Interests exchanged by Brookfield will be cancelled.

The Exchange Agreement provides that Brookfield will not be permitted to exercise the Exchange Right: (i) for a period of 12 months from the Closing Date; and (ii) at any time, to the extent that the change of proportional ownership or operational control of the OpCos between Brookfield, on the one hand, and Rockpoint, on the other, would result in a change of control of the Lodi or Wild Goose operating subsidiaries for the purposes of the operating permits issued by the CPUC, unless the CPUC Approval has first been obtained.

In addition, pursuant to the Exchange Agreement: (i) in the event that the Class A Shares remain listed on the TSX or another national securities exchange, once Brookfield beneficially owns, in the aggregate, less than 5% of the OpCo Interests, the Company has the right (upon the approval of a majority of the Non-Conflicted Directors) to require Brookfield to exchange all, but not less than all, of its remaining OpCo Interests in substantially the same manner as set out above (including with respect to the surrender and cancellation of Class B Shares); and (ii) in the event of a bankruptcy, insolvency or other involuntary liquidation, dissolution or winding up of any of the Company, Swan OpCo or BIF OpCo, the Company has the right to require Brookfield to exchange all, but not less than all, of its remaining OpCo Interests in substantially the same manner as set out above (including with respect to the surrender and cancellation of Class B Shares); provided that in the case of a bankruptcy, insolvency or other involuntary liquidation, dissolution or winding up of any of the Company, Swan OpCo or BIF OpCo, the only consideration payable on an exchange will be Class A Shares.

The Exchange Agreement contains provisions effectively linking: (i) each BIF OpCo Share to a corresponding Swan OpCo Unit and vice versa; (ii) each OpCo Interest held by the Company with one Class A Share; and (iii) each OpCo Interest held by Brookfield with one Class B Share. No Class B Shares can be transferred without transferring an equal number of OpCo Interests and vice versa.

Subject to limited exceptions, the OpCos and the Company have also agreed to at all times maintain: (i) a one-to-one ratio between the OpCo Interests owned by the Company, directly or indirectly, and the number of outstanding Class A Shares; and (ii) a one-to-one ratio between the OpCo Interests owned by Brookfield, directly or indirectly, and the aggregate number of outstanding Class B Shares owned by Brookfield (and its permitted transferees (other than the Company)).

If a tender offer, share exchange offer, issuer bid, take-over bid, arrangement, amalgamation, recapitalization, or similar transaction with respect to the Class A Shares (a "**Company Offer**") is proposed by the Company or is proposed to the Company or its shareholders and approved or recommended by the Board or is otherwise effected or to be effected with the consent or approval of the Board or the Company's shareholders, as applicable, the Company shall provide written notice of the Company Offer to all holders of OpCo Interests and Brookfield by the earlier of (i) five business days following the execution of a definitive agreement (if applicable) with respect to, or the commencement of (if applicable), such Company Offer, and (ii) ten business days before the proposed date upon which the Company Offer is to be effected (unless earlier notice is required by law), which notice will include a reasonable description of the Company Offer (including the date of execution of such definitive agreement (if applicable) or of such commencement (if applicable), the material terms of such Company Offer, including the amount and types of consideration to be received by holders of Class A Shares in the Company Offer, any election with respect to the types of consideration that a holder of Class A Shares shall be entitled to make in connection with such Company Offer, and the number or proportion of OpCo Interests held by each holder of OpCo Interests (and the corresponding Class B Shares held by Brookfield) that is applicable to, or the subject of, such Company Offer), and contain all other information required by law. Provided that their participation does not result in Brookfield no longer holding a majority of the outstanding OpCo Interests prior to the receipt of any necessary CPUC Approval, holders of OpCo Interests (other than the Company) shall be permitted to participate in such Company Offer by delivering a written notice of participation that is effective immediately prior to the consummation of such Company Offer (and that is contingent upon consummation of such Company Offer) and shall include such information necessary for consummation of such offer as requested by the Company. In the case of any Company Offer that was initially proposed by the Company, the Company shall use reasonable best efforts to enable and permit holders of OpCo Interests (other than the Company) to participate in such transaction to the same extent or on an economically equivalent basis as the holders of Class A Shares, and to enable such holders to participate in such transaction without being required to exchange their OpCo Interests (and without Brookfield having to exchange Class B Shares), prior to the consummation of such transaction.

The Exchange Agreement automatically terminates once Brookfield does not own, control or direct any Class B Shares. The Exchange Agreement may not be amended without, among other things, the approval of a majority of the Non-Conflicted Directors on behalf of the Company.

Registration Rights Agreement

A registration rights agreement will be entered into at Closing among the Company and Brookfield (the "**Registration Rights Agreement**") pursuant to which Brookfield (including its permitted transferees) will have the right (the "**Registration Right**") to require the Company to include Class A Shares held by Brookfield (including its permitted transferees) (or Class A Shares issuable upon the exchange of the OpCo Interests and associated Class B Shares held by Brookfield (including its permitted transferees)) in any future public offering undertaken by the Company by way of prospectus that it may file with applicable Canadian securities regulatory authorities (a "**Piggy-Back Distribution**"). The Company will be required to use reasonable commercial efforts to cause to be included in the distribution all of the Class A Shares that Brookfield requests to be sold, provided that if the distribution involves an underwriting and the lead underwriter determines that the total number of Class A Shares to be included in such distribution should be limited for certain prescribed reasons, the Class A Shares to be included in the distribution will be first allocated to the Company.

Brookfield (including its permitted transferees) will have the right (the "**Demand Registration Right**") to require the Company to use reasonable commercial efforts to file one or more prospectuses with applicable Canadian securities regulatory authorities qualifying Class A Shares held by Brookfield (or Class A Shares issuable upon exercise of the Exchange Right) for public distribution (a "**Demand Distribution**"). Brookfield will be entitled to request not more than one Demand Distribution in any three-month period and each Demand Distribution must be comprised of such number of Class A Shares that would: (i) reasonably be expected to result in aggregate gross proceeds of at least C$50 million; or (ii) result in the sale of its remaining Shares. The Company may also distribute its Class A Shares in connection with a Demand Distribution; provided that, if the Demand Distribution involves an underwriting and the lead underwriter determines that the total number of Class A Shares to be included in such Demand Distribution should be limited for certain prescribed reasons, the Class A Shares to be included in the Demand Distribution will be first allocated to Brookfield in full. Any distribution contemplated by a Demand Distribution will be through underwriters selected by Brookfield in consultation with the Company.

Each of the Registration Right and the Demand Registration Right will be exercisable at any time following the 180-day lock-up period, provided that Brookfield (including its permitted transferees), owns, controls or directs, in the aggregate, at least 5% of the outstanding Shares (on a non-diluted basis) at the time of exercise. The Registration Right and the Demand Registration Right will be subject to customary conditions and limitations, and the Company (upon the approval of a majority of the Non-Conflicted Directors) will be entitled to defer any Demand Distribution in certain circumstances for a period not exceeding 90 days. All expenses in respect of a Piggy-Back Distribution or a Demand Distribution will be borne by the Company, except that any underwriting commission on the sale of Class A Shares by Brookfield (including its permitted transferees), the fees and disbursements of counsel for Brookfield (including its permitted transferees) and any other incidental out of pocket expenses of Brookfield (including its permitted transferees) will be borne by Brookfield. The Registration Rights Agreement will provide that the Company will indemnify Brookfield (including its permitted transferees) for any misrepresentation in a prospectus under which Class A Shares held by Brookfield are distributed (other than in respect of any information provided by Brookfield, in respect of Brookfield, for inclusion in the prospectus) and Brookfield will indemnify the

Company for any information provided by Brookfield, in respect of Brookfield, for inclusion in the prospectus. Unless and until the Company proposes to file a registration statement for the distribution of Class A Shares to the public in the United States, the Registration Right and the Demand Registration Right will not require the Company to register the Class A Shares under the U.S. Securities Act.

The Registration Rights Agreement will automatically terminate once Brookfield (including its permitted transferees) owns, controls or directs less than 5% of the voting power attached to the outstanding Shares (on a non-diluted basis). The Registration Rights Agreement may not be amended without, among other things, the approval of a majority of the Non-Conflicted Directors.

PLAN OF DISTRIBUTION

The Offering consists of 32,000,000 Class A Shares at a price of C$22.00 per Class A Share. See "Description of Share Capital and OpCo Interests" for a description of the attributes of the Class A Shares.

Under the Underwriting Agreement, the Company has agreed to issue and sell 32,000,000 Class A Shares and the Underwriters have severally agreed to purchase on Closing such Class A Shares at the Offering Price payable in cash to the Company against delivery of such Class A Shares on the Closing Date or such later date as may be agreed pursuant to the Underwriting Agreement, but in any event no later than November 18, 2025, for aggregate gross proceeds of C$704,000,000 to the Company, subject to and in compliance with all of the necessary legal requirements and conditions contained in the Underwriting Agreement.

In consideration for their services in connection with the Offering, the Company has agreed to pay the Underwriters a commission equal to C$1.10 per Class A Share, representing 5% of the gross proceeds of the Offering. The Underwriters' commission in connection with the Offering is payable by the Company to the Underwriters on Closing and, pursuant to the Underwriting Agreement, the Selling Shareholders will reimburse the Company for, among other expenses of the Offering, the Underwriters' commission.

Prior to the Offering, there was no public market for the Class A Shares. The Offering Price was determined by negotiation between the Company, Brookfield and the Lead Underwriters, on behalf of the Underwriters. The Underwriters propose to offer the Class A Shares initially at the Offering Price. After the Underwriters have made a reasonable effort to sell all of the Class A Shares at the Offering Price, the offering price to the public may be decreased and further changed from time to time to an amount not greater than the Offering Price, and the commission realized by the Underwriters will be decreased by the amount that the aggregate price paid by the purchasers for the Class A Shares is less than the price paid by the Underwriters to the Company and the Selling Shareholders, as applicable. Any such reduction in the Offering Price will not affect the net proceeds received by the Company and the Selling Shareholders, as applicable.

The Selling Shareholders have granted to the Underwriters the Over-Allotment Option, exercisable at the Underwriters' sole discretion at any time, in whole or in part, for a period of 30 days after the Closing Date, to purchase up to 4,800,000 Class A Shares from the Selling Shareholders (representing approximately 15% of the number of Class A Shares offered under this prospectus) to cover over-allotments, if any, and for market stabilization purposes.

If the Over-Allotment Option is exercised in full, the total "Price to the Public", "Underwriters' Commission", "Net Proceeds to the Company" and "Net Proceeds to the Selling Shareholders" will be C$809,600,000, C$40,480,000, C$668,800,000 and C$100,320,000, respectively, before deducting the expenses of the Offering. This prospectus also qualifies the grant of the Over-Allotment Option and the distribution of the Class A Shares pursuant to the exercise of the Over-Allotment Option. A purchaser who acquires Class A Shares forming part of the Underwriters' over-allocation position acquires such Class A Shares under this prospectus, regardless of whether the over-allocation position is ultimately filled through the exercise of the Over-Allotment Option or secondary market purchases.

The Company will pay the Underwriters' commission and expenses associated with the Offering and the Selling Shareholders will pay the Underwriters' commission and expenses associated with the Secondary Offering. The Company will not receive any of the proceeds from the Secondary Offering. Pursuant to the Underwriting Agreement, the Selling Shareholders will reimburse the Company for the expenses of the Offering, including the Underwriters' commission.

Pursuant to the terms of the Underwriting Agreement, the Underwriters may, at their discretion, terminate the Underwriting Agreement upon the occurrence of certain events, including "material change out", "disaster out", "regulatory out" and "market out" clauses. The Underwriters are, however, obligated to take up and pay for all of the Class A Shares that they have agreed to purchase if any of the Class A Shares are purchased under the Underwriting Agreement.

If an Underwriter fails to purchase the Class A Shares which it has agreed to purchase, the remaining Underwriters may terminate their obligation to purchase their allotment of Class A Shares, or may, but are not obligated to, purchase the Class A Shares not purchased by the Underwriter or Underwriters which fail to purchase; provided, however, that if the aggregate number of Class A Shares not so purchased is not more than 9% of the aggregate number of Class A Shares agreed to be purchased by the Underwriters, then each of the other Underwriters shall be obliged to purchase severally the Class A Shares not taken up, on a *pro rata* basis or in such other proportions as they may otherwise agree among themselves.

The Underwriting Agreement also provides that the Company, Brookfield Infrastructure and the Selling Shareholders will, in certain circumstances indemnify the Underwriters, their respective affiliates and each of their respective directors, officers, employees, partners and agents against certain liabilities, including, without restriction, civil liabilities under securities legislation in Canada, and to contribute to any payments that the Underwriters may be required to make in respect thereof.

The Offering is being made in each of the provinces and territories of Canada. The Class A Shares offered under this prospectus will be offered in each of the provinces and territories of Canada through those Underwriters or their affiliates who are registered to offer such Class A Shares for sale in such provinces and territories and such other registered dealers as may be designated by the Underwriters. Subject to applicable law and the provisions of the Underwriting Agreement, the Underwriters may offer such Class A Shares outside of Canada.

The Class A Shares offered under this prospectus have not been, and will not be, registered under the U.S. Securities Act, or any state securities laws, and may not be offered or sold within the United States absent registration or pursuant to an applicable exemption from the registration requirements of the U.S. Securities Act and applicable state securities laws. Accordingly, except to the extent permitted by the Underwriting Agreement and except for offers and sales made pursuant to an available exemption from the registration requirements of the U.S. Securities Act, the Class A Shares to be sold pursuant to the Offering may not be offered or sold within the United States. Each Underwriter has agreed that it will not offer or sell Class A Shares within the United States, except in transactions exempt from the registration requirements of the U.S. Securities Act and applicable state securities laws. The Underwriting Agreement provides that the Underwriters may re-offer and re-sell the Class A Shares that they have acquired pursuant to the Underwriting Agreement in the United States to qualified institutional buyers in accordance with Rule 144A under the U.S. Securities Act. The Underwriting Agreement also provides that the Underwriters may offer and sell the Class A Shares outside the United States in accordance with Regulation S under the U.S. Securities Act. In addition, until 40 days after the Closing, an offer or sale of the Class A Shares within the United States by any dealer (whether or not participating in the Offering) may violate the registration requirements of the U.S. Securities Act, unless such offer is made pursuant to an exemption from registration under the U.S. Securities Act.

There is currently no public market for the Class A Shares. This may affect the prevailing market price of the Class A Shares, the transparency and availability of trading prices and the liquidity of the Class A Shares. See "Risk Factors — The Offering Price may not be indicative of the market price of the Class A Shares after the Offering. In addition, an active, liquid and orderly trading market for the Class A Shares may not develop or be maintained, and the Class A Shares price per share may be volatile". Further, because the Company and the Selling Shareholders have agreed not to offer, in the case of the Company or sell (or direct the sale of), in the case of the Selling Shareholders, any equity securities of the Company (or other securities convertible into, or exchangeable or exercisable for, equity securities of the Company), subject to limited exceptions, for a certain period after Closing due to the restrictions on resale described under "— Lock-Up" below, the sale of a substantial amount of Class A Shares in the public market after these restrictions lapse could adversely affect the prevailing market price of the Class A Shares.

Subscriptions for Class A Shares offered under this prospectus will be received subject to rejection or allotment in whole or in part and the Underwriters reserve the right to close the subscription books at any time without notice. It is expected that Closing will occur on or about October 15, 2025 or such other date as the Company, Brookfield Infrastructure, the Selling Shareholders and the Underwriters may agree, but in any event no later than November 18, 2025. The Class A Shares offered under this prospectus are to be taken up by the Underwriters, if at all, on or before a date that is 42 days after the date of the receipt for the final base PREP prospectus. The Class A Shares will be deposited with CDS in electronic form on the Closing Date through the non-certificated inventory system administered by CDS. A purchaser of Class A Shares will receive only a customer confirmation from the registered dealer from or through which the Class A Shares are purchased. See "— Non-Certificated Inventory System" below.

Price Stabilization, Short Positions and Passive Market Making

In connection with the Offering, the Underwriters may, subject to applicable law, over-allocate or effect transactions which stabilize or maintain the market price of the Class A Shares at levels other than those which otherwise might prevail on the open market, including: stabilizing transactions; short sales; purchases to cover positions created by short sales; imposition of penalty bids; and syndicate covering transactions.

Stabilizing transactions consist of bids or purchases made for the purpose of preventing or retarding a decline in the market price of the Class A Shares while the Offering is in progress. These transactions may also include over-allocating or making short sales of the Class A Shares, which involve the sale by the Underwriters of a greater number of Class A Shares than they are required to purchase in the Offering. Short sales may be "covered short sales", which are short positions in an amount not greater than the Over-Allotment Option, or may be "naked short sales", which are short positions in excess of that amount.

The Underwriters may close out any covered short position either by exercising the Over-Allotment Option, in whole or in part, or by purchasing Class A Shares in the open market. In making this determination, the Underwriters will consider, among other things, the price of Class A Shares available for purchase in the open market compared with the price at which they may purchase Class A Shares through the Over-Allotment Option. If, following Closing, the market price of the Class A Shares decreases, the short position created by the over-allocation position in Class A Shares may be filled through purchases in the market, creating upward pressure on the price of the Class A Shares. If, following Closing, the market price of Class A Shares increases, the over-allocation position in Class A Shares may be filled through the exercise of the Over-Allotment Option in respect of Class A Shares at the Offering Price.

The Underwriters must close out any naked short position by purchasing Class A Shares in the open market or as otherwise permitted by applicable law. A naked short position is more likely to be created if the Underwriters are concerned that there may be downward pressure on the price of the Class A Shares in the open market that could adversely affect investors who purchase in the Offering. Any naked short position at Closing that are part of the Offering will form part of the Underwriters' over-allocation position. A purchaser who acquires Class A Shares forming part of the Underwriters' over-allocation position resulting from any covered short sales or naked short sales will, in each case, acquire such Class A Shares under this prospectus, regardless of whether the Underwriters' over-allocation position is ultimately filled through the exercise of the Over-Allotment Option or secondary market purchases.

In addition, in accordance with rules and policy statements of certain Canadian securities regulators and the Universal Market Integrity Rules ("**UMIR**") of the Canadian Investment Regulatory Organization, the Underwriters may not, at any time during the period of distribution, bid for or purchase Class A Shares. The foregoing restriction is, however, subject to certain exceptions as permitted by such policy statements and UMIR. These exceptions include a bid or purchase permitted under the provisions of such policy statements and UMIR relating to market stabilization and market balancing activities and a bid or purchase on behalf of a customer where the order was not solicited.

As a result of these activities, the price of the Class A Shares may be higher than the price that otherwise might exist in the open market. If these activities are commenced, they may be discontinued by the Underwriters at any time. The Underwriters may carry out these transactions on any stock exchange on which the Class A Shares are listed in the over-the-counter market, or as otherwise permitted by applicable law.

Lock-Up

Other than in connection with the Transactions, the Company has agreed that, subject to certain limited exceptions, it will not, and the Company shall use its reasonable commercial efforts to have each of its directors and executive officers who hold Class A Shares immediately following Closing to agree to not, directly or indirectly, without the prior written consent of the Lead Underwriters, on behalf of the Underwriters, which consent shall not be unreasonably withheld, issue, in the case of the Company, and sell (or direct the sale of), in the case of the directors and executive officers of the Company, or offer, grant or sell any option, warrant or other right for the purchase of, lend, transfer, assign or otherwise dispose of, in a public offering or by way of private placement or otherwise, any Class A Shares or other equity securities of the Company or other securities convertible into, exchangeable for, or exercisable into Class A Shares or other equity securities of the

Company (including, without limitation, by making any short sale, engaging in any hedging, monetization or derivative transaction or entering into any swap or other arrangement that transfers to another person, in whole or in part, any of the economic consequences of ownership of the Class A Shares or other equity securities of the Company or securities convertible into, exchangeable for, or exercisable into Class A Shares or other equity securities of the Company), or agree to do any of the foregoing or publicly announce any intention to do any of the foregoing, for a period of 180 days from the Closing Date.

In addition, the Selling Shareholders have agreed that, other than in connection with the Secondary Offering, they will not directly or indirectly, without the prior written consent of the Lead Underwriters, on behalf of the Underwriters, which consent shall not be unreasonably withheld, sell (or direct the sale of), or offer, grant any option, warrant or other right for the purchase of, lend, transfer, assign, pledge or otherwise dispose of any of its Shares for a period of 180 days from the Closing Date, subject to certain limited exceptions including the Over-Allotment Option.

Commissions

In consideration for their services in connection with the Offering, the Company has agreed to pay the Underwriters a commission equal to C$1.10 per Class A Share (being 5% of the Offering Price) except for Class A Shares sold pursuant to the Secondary Offering. In consideration for their services in connection with the Secondary Offering, the Selling Shareholders have agreed to pay the Underwriters a commission equal to C$1.10 per Class A Share (being 5% of the Offering Price).

Expenses Related to the Offering

It is estimated that the total expenses of the Offering (whether or not the Over-Allotment Option is exercised), not including the Underwriters' commission, will be approximately C$9,600,000. All such expenses of the Offering will be paid by the Company out of the proceeds of the Offering. Pursuant to the Underwriting Agreement, the Selling Shareholders will reimburse the Company for such expenses of the Offering.

Non-Certificated Inventory System

No certificates representing the Class A Shares to be sold in the Offering will be issued to purchasers under this prospectus; registration will be made in the depository service of CDS and electronically deposited with CDS on the Closing Date. Each purchaser of Class A Shares will receive only a customer confirmation of purchase from the participants in the CDS depository service ("**CDS Participants**") from or through which such Class A Shares are purchased, in accordance with the practices and procedures of such CDS Participant. Transfers of ownership of Class A Shares will be effected through records maintained by the CDS Participants, which include securities brokers and dealers, banks and trust companies. Indirect access to the CDS book entry system is also available to other institutions that maintain custodial relationships with a CDS Participant, either directly or indirectly.

BROOKFIELD

Brookfield Infrastructure is a promoter of the Company within the meaning of Canadian securities laws. As of the date hereof, Brookfield Infrastructure Holdings (Canada) Inc. owns one Class A Share, representing 100% of the currently outstanding Shares. Upon completion of the Transactions, assuming the Over-Allotment Option is not exercised, Brookfield will own approximately 39.8% of the outstanding Class A Shares and 100% of the outstanding Class B Shares, representing approximately 75.9% of the aggregate outstanding Shares and voting interest in the Company (or approximately 30.8% of the outstanding Class A Shares, representing, together with Brookfield's Class B Shares, approximately 72.3% of the aggregate outstanding Shares and voting interest in the Company, if the Over-Allotment Option is exercised in full). See "Relationship with Brookfield", "Description of Share Capital and OpCo Interests" and "Brookfield".

Upon completion of the Transactions, Rockpoint will own approximately 40% of the OpCo Interests and Brookfield will own approximately 60% of the OpCo Interests, excluding any indirect beneficial ownership of Brookfield in OpCo Interests by virtue of its ownership in the Company. As a result, Brookfield will have control over the Company, the OpCos and the Business. See "Risk Factors — Brookfield has the ability to direct the voting of a majority of Shares and control certain decisions with respect to Rockpoint's management and business. Brookfield's interests may conflict with those of the other shareholders". In addition, Brookfield will be party to the Registration Rights Agreement and the Shareholder Agreement that, together, among other things, provide Brookfield with the Registration Rights, the Demand Registration Right and rights respecting the nomination of directors to the Board. See "Relationship with Brookfield" and "Risk Factors". Other than Brookfield, no person or company will own, directly or indirectly, any Class B Shares at Closing. All of the Shares held upon Closing by Brookfield, other than in connection with the Secondary Offering, and the directors and executive officers of the Company will be subject to contractual lock-up agreements with the Underwriters. See "Plan of Distribution — Lock-Up".

The table below sets forth the number and percentage of Shares owned by Brookfield, indirectly through Brookfield Infrastructure Holdings (Canada) Inc. as of the date hereof, the number and percentage of Shares anticipated to be owned by Brookfield, indirectly through Brookfield Infrastructure Holdings (Canada) Inc., and the Selling Shareholders after giving effect to the Transactions (both with and without giving effect to the exercise of the Over-Allotment Option) and the type of ownership of those Shares.

		Number and percentage of Shares owned, controlled or directed prior to giving effect to the Transactions(1)			Number and percentage of Shares owned, controlled or directed after giving effect to the Transactions(2)			Number and percentage of Shares owned, controlled or directed after giving effect to the Transactions and exercise in full of the Over-Allotment Option		
Name of Shareholder	**Type of Ownership**	**Class A Shares**	**Class B Shares**	**Total Shares**	**Class A Shares**	**Class B Shares**	**Total Shares**	**Class A Shares**	**Class B Shares**	**Total Shares**
Brookfield Infrastructure Holdings (Canada) Inc.	Registered	1 (100%)	—	1 (100%)	—	79,800,000 (100%)	79,800,000 (60.0%)	—	79,800,000 (100%)	79,800,000 (60.0%)
BIF II CalGas Carry (Delaware) LLC	Registered	—	—	—	5,402,044 (10.2%)	—	5,402,044 (4.1%)	4,178,940 (7.9%)	—	4,178,940 (3.1%)
BIP BIF II U.S. Holdings (Delaware) LLC	Registered	—	—	—	3,510,948 (6.6%)	—	3,510,948 (2.6%)	2,716,016 (5.1%)	—	2,716,016 (2.0%)
Swan Equity Carry LP	Registered	—	—	—	7,446,990 (14.0%)	—	7,446,990 (5.6%)	5,760,879 (10.8%)	—	5,760,879 (4.3%)
BIP BIF II Swan AIV LP	Registered	—	—	—	4,840,018 (9.1%)	—	4,840,018 (3.6%)	3,744,165 (7.0%)	—	3,744,165 (2.8%)

Notes:

(1) Brookfield Infrastructure Holdings (Canada) Inc. was issued one common share in the capital of the Company for nominal consideration in connection with the incorporation of the Company. This share was cancelled concurrent with amending of the Articles on September 17, 2025 and Brookfield Infrastructure Holdings (Canada) Inc. was issued one Class A Share which will be cancelled upon Closing. See "Prior Sales".

(2) Assumes no exercise of the Over-Allotment Option.

PRIOR SALES

On July 28, 2025, in connection with the incorporation of the Company, the Company issued one common share in the capital of the Company to Brookfield Infrastructure Holdings (Canada) Inc. for nominal consideration. This share was cancelled concurrent with amending of the Articles on September 17, 2025 and Brookfield Infrastructure Holdings (Canada) Inc. was issued one Class A Share which will be cancelled upon Closing.

SECURITIES SUBJECT TO CONTRACTUAL RESTRICTIONS ON RESALE

Other than in connection with the Transactions, pursuant to the Underwriting Agreement, the Company has agreed that, subject to certain limited exceptions, it will not, and the Company shall use its reasonable commercial efforts to have each of its directors and executive officers who hold Class A Shares immediately following Closing to agree to not, directly or indirectly, without the prior written consent of the Lead Underwriters, on behalf of the Underwriters, which consent shall not be unreasonably withheld, issue, in the case of the Company, and sell (or direct the sale of), in the case of the directors and executive officers of the Company, or offer, grant or sell any option, warrant or other right for the purchase of, lend, transfer, assign or otherwise dispose of, in a public offering or by way of private placement or otherwise, any Class A Shares or other equity securities of the Company or other securities convertible into, exchangeable for, or exercisable into Class A Shares or other equity securities of the Company (including, without limitation, by making any short sale, engaging in any hedging, monetization or derivative transaction or entering into any swap or other arrangement that transfers to another, in whole or in part, any of the economic consequences of ownership of the Class A Shares or other equity securities of the Company or securities convertible into, exchangeable for, or exercisable into Class A Shares or other equity securities of the Company), or agree to do any of the foregoing or publicly announce any intention to do any of the foregoing, for a period of 180 days from the Closing Date.

In addition, Brookfield has agreed that, other than in connection with the Secondary Offering, it will not directly or indirectly, without the prior written consent of the Lead Underwriters, on behalf of the Underwriters, which consent shall not be unreasonably withheld, sell (or direct the sale of), or offer, grant or sell any option, warrant or other right for the purchase of, lend, transfer, assign, pledge or otherwise dispose of any of their Shares for a period of 180 days from the Closing Date, subject to certain limited exceptions including the Over-Allotment Option. See "Plan of Distribution — Lock-Up".

INTERESTS OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Except as described elsewhere in this prospectus, there is no material interest, direct or indirect, of: (i) any director or executive officer of the Company; (ii) any person or company that beneficially owns, or controls or directs, directly or indirectly, more than 10% of the Shares; or (iii) any affiliate of the persons or companies referred to above in (i) or (ii), in any transaction within the three years before the date of this prospectus that has materially affected or is reasonably expected to materially affect the Company.

ELIGIBILITY FOR INVESTMENT

In the opinion of Torys LLP, counsel to the Company, and Blake, Cassels & Graydon LLP, counsel to the Underwriters, based on the current provisions of the *Income Tax Act* (Canada) and the regulations thereunder (collectively, the "**Tax Act**"), the Class A Shares would be qualified investments at a particular time for a trust governed by a registered retirement savings plan ("**RRSP**"), registered retirement income fund ("**RRIF**"), deferred profit sharing plan, registered education savings plan ("**RESP**"), registered disability savings plan ("**RDSP**"), first home savings account ("**FHSA**") or tax-free savings account ("**TFSA**") (collectively, the "**Deferred Income Plans**"), if and provided that, at the particular time the Class A Shares are listed on a "designated stock exchange" for the purposes of the Tax Act (which currently includes the TSX) or the Company qualifies as a "public corporation" (as defined in the Tax Act).

The Class A Shares are currently not listed on a "designated stock exchange" and the Company is currently not a "public corporation", as those terms are defined in the Tax Act. Accordingly, the Class A Shares are currently not a qualified investment for Deferred Income Plans. The Company must rely on the TSX to list the Class A Shares on the TSX and have them posted for trading prior to or concurrent with the issuance of the Class A Shares on Closing and to otherwise proceed in such manner as may be required to result in the Class A Shares being considered as listed on the TSX for purposes of the Tax Act at the time of their issuance on Closing, and Torys LLP and Blake, Cassels & Graydon LLP express no opinion in this regard. Listing will be subject to the Company fulfilling all of the requirements of the TSX, and there can be no guarantee that TSX approval of a listing (if at all) will be granted or will be in a form that is, or is acceptable to the CRA as, a full and unconditional listing sufficient for "qualified investment" status under the Tax Act for purposes of a Deferred Income Plan. If the Class A Shares are not effectively listed on a "designated stock exchange" (which currently includes the TSX) for purposes of the Tax Act at the time of their issuance on Closing and the Company is not otherwise a "public corporation" at that time, the Class A Shares will not be "qualified investments" for the Deferred Income Plans at that time. The adverse tax consequences where a Deferred Income Plan acquires or holds Class A Shares that are not a "qualified investment" are not discussed in this summary. **Holders who intend to acquire or hold Class A Shares within a Deferred Income Plan should consult their own tax advisors in this regard.**

Notwithstanding that the Class A Shares may be a qualified investment for a trust governed by an RRSP, RRIF, RESP, RDSP, TFSA or FHSA (a "**Registered Plan**"), the annuitant of the RRSP or RRIF, the subscriber under an RESP or the holder of a TFSA, FHSA or RDSP, as the case may be, (the "**Controller**") will be subject to a penalty tax in respect of Class A Shares acquired by a Registered Plan if such Class A Shares are a "prohibited investment" for the particular Registered Plan. The Class A Shares will generally be a "prohibited investment" of a Registered Plan if the Controller of the Registered Plan does not deal at arm's length with the Company for the purposes of the Tax Act or has a "significant interest" (as defined in the Tax Act) in the Company. Generally, a Controller will not have a "significant interest" in the Company provided that the Controller, together with persons with whom the Controller does not deal at arm's length, does not own, directly or indirectly, at any time 10% or more of the issued shares of any class of the Company or of any corporation related to the Company (for purposes of the Tax Act). In addition, the Class A Shares will not be a "prohibited investment" if the Class A Shares are "excluded property" (as defined in the Tax Act for purposes of the prohibited investment rules) for a Registered Plan.

Prospective purchasers that intend to hold Class A Shares in a Deferred Income Plan should consult their own tax advisors with respect to their individual circumstances.

CERTAIN CANADIAN FEDERAL INCOME TAX CONSIDERATIONS

The following is, as of the date of this prospectus, a summary of the principal Canadian federal income tax considerations under the Tax Act generally applicable to an investor who acquires, as beneficial owner, Class A Shares pursuant to the Offering and who, for the purposes of the Tax Act and at all relevant times: (i) deals at arm's length with the Company, the Underwriters and any of their respective affiliates; (ii) is not affiliated with the Company, the Underwriters and any of their respective affiliates; and (iii) acquires and holds the Class A Shares as capital property. A holder who meets all of the foregoing requirements is referred to as a "**Holder**" in this summary, and this summary only addresses such Holders.

Generally, the Class A Shares will be capital property to a Holder, provided the Holder does not acquire the Class A Shares in the course of carrying on a business of trading or dealing in securities and does not acquire them as part of an adventure or concern in the nature of trade.

This summary does not apply to a Holder: (i) that is a "financial institution" for the purposes of the mark-to-market rules contained in the Tax Act; (ii) that is a "specified financial institution" as defined in the Tax Act; (iii) an interest in which would be a "tax shelter investment" as defined in the Tax Act; (iv) that makes or has made a functional currency reporting election under the Tax Act to report their "Canadian tax results", as defined in the Tax Act, in a currency other than the Canadian currency; (v) that has entered into or will enter into a "derivative forward agreement", "synthetic disposition arrangement" or "dividend rental arrangement", as those terms are defined in the Tax Act, with respect to the Class A Shares; or (vi) that is otherwise of special status or in special circumstances. **All such Holders should consult their own tax advisors.**

Additional considerations, not discussed herein, may be applicable to a Holder that is a corporation resident in Canada and is, or becomes as part of a transaction or event or series of transactions or events that includes the acquisition of the Class A Shares, controlled by a non-resident for purposes of the "foreign affiliate dumping" rules in section 212.3 of the Tax Act. **Such Holders should also consult their own tax advisors.**

This summary does not address the deductibility of interest by a Holder who borrows money to acquire the Class A Shares. **Such Holders should also consult their own tax advisors.**

This summary is based on the current provisions of the Tax Act in force as of the date hereof and our understanding of the current administrative and assessing practices of the CRA published in writing by the CRA and publicly available prior to the date hereof. This summary takes into account all specific proposals to amend the Tax Act publicly announced by or on behalf of the Minister of Finance (Canada) prior to the date hereof (the "**Tax Proposals**") and assumes that the Tax Proposals will be enacted in the form proposed, although no assurance can be given that the Tax Proposals will be enacted in their current form or at all. This summary does not otherwise take into account any changes in law or in the administrative policies or assessing practices of the CRA, whether by legislative, governmental or judicial decision or action, nor does it take into account or consider any provincial, territorial or foreign income tax considerations, which considerations may differ significantly from the Canadian federal income tax considerations discussed in this summary.

This summary is of a general nature only, is not exhaustive of all possible Canadian federal income tax considerations and is not intended to be, nor should it be construed to be, legal or tax advice to any particular investor. All investors (including Holders) should consult their own tax advisors with respect to their particular circumstances.

Currency Conversion

Generally, for purposes of the Tax Act, all amounts relating to the acquisition, holding or disposition of the Class A Shares must be converted into Canadian dollars based on the exchange rates as determined in accordance with the Tax Act.

Holders Resident in Canada

The following section of this summary applies to a Holder who, for the purposes of the Tax Act, is or is deemed to be resident in Canada at all relevant times ("**Resident Holder**"). Certain Resident Holders whose Class A Shares might not constitute capital property may make, in certain circumstances, an irrevocable election permitted by subsection 39(4) of the Tax Act to deem the Class A Shares (provided that at the time of disposition the Company is a "public corporation" as defined in the Tax Act), and every other "Canadian security" (as defined in the Tax Act) held by such persons in the taxation year of the election and each subsequent taxation year, to be capital property. Resident Holders should consult their own tax advisors regarding this election.

Dividends on Class A Shares

Dividends received or deemed to be received on the Class A Shares, if any, will be included in computing a Resident Holder's income. In the case of an individual (other than certain trusts), such dividends will be subject to the gross-up and dividend tax credit rules normally applicable to "taxable dividends" received from "taxable Canadian corporations" (each as defined in the Tax Act), including the enhanced gross-up and dividend tax credit applicable to "eligible dividends", if any, so designated by the Company to the Resident Holder in accordance with the provisions of the Tax Act. As of the date hereof, the Company anticipates that any dividends paid on the Class A Shares will be designated as "eligible dividends", and, unless otherwise notified, the Company will include disclosure on its website to this effect.

Dividends received or deemed to be received by a Resident Holder that is a corporation must be included in computing its income but may be deductible in computing its taxable income, subject to all restrictions and special rules under the Tax Act. A Resident Holder that is a "private corporation" (as defined in the Tax Act) and certain other corporations controlled by or for the benefit of an individual (other than a trust) or related group of individuals (other than trusts) generally will be liable to pay a special tax under Part IV of the Tax Act (refundable in certain circumstances) on dividends received or deemed to be received on the Class A Shares to the extent such dividends are deductible in computing taxable income. In certain circumstances, subsection 55(2) of the Tax Act will treat a taxable dividend received or deemed to be received by a Resident Holder that is a corporation as proceeds of disposition or a capital gain, and Resident Holders that are corporations should consult their own tax advisors in this regard.

Disposition of Class A Shares

Upon a disposition (or a deemed disposition) of a Class A Share (other than to the Company unless purchased by the Company in the open market in the manner in which shares are normally purchased by a member of the public in an open market) a Resident Holder generally will realize a capital gain (or a capital loss) equal to the amount by which the proceeds of disposition of a Class A Share net of any reasonable costs of disposition, are greater (or are less) than the adjusted cost base of such Class A Share to the Resident Holder.

The adjusted cost base to the Resident Holder of a Class A Share will be determined at any time by averaging the cost of such share with the adjusted cost base immediately before the time of acquisition of all other Class A Shares owned by the Resident Holder as capital property immediately before that time, if any.

The tax treatment of capital gains and capital losses is discussed in greater detail below under "— Capital Gains and Capital Losses".

Capital Gains and Capital Losses

Under the provisions of the Tax Act, generally, a Resident Holder is required to include in computing income for a taxation year one-half of the amount of any capital gain (a "**taxable capital gain**") realized in the year. Subject to and in accordance with the provisions of the Tax Act, a Resident Holder is required to deduct one-half of the amount of any capital loss (an "**allowable capital loss**") realized in a taxation year from taxable capital gains realized in the year by such Resident Holder. Allowable capital losses in excess of taxable capital gains may be carried back and deducted in any of the 3 preceding taxation years or carried forward and deducted in any following taxation year against taxable capital gains realized in such year, to the extent and under the circumstances described in the Tax Act.

The amount of any capital loss realized on the disposition or deemed disposition of Class A Shares by a Resident Holder that is a corporation may, in certain circumstances, be reduced by the amount of dividends received or deemed to have been received by it on such Class A Shares. Similar rules may apply where a corporation is a member of a partnership or a beneficiary of a trust that owns Class A Shares directly or indirectly through a partnership or trust. **Resident Holders to whom these rules may be relevant should consult their own tax advisors.**

Additional Refundable Tax

A Resident Holder that is throughout its taxation year a "Canadian-controlled private corporation", or that is a "substantive CCPC" at any time in the year, as those terms are defined in the Tax Act, may be liable for an additional tax (refundable in certain circumstances) on its "aggregate investment income", which is defined in the Tax Act to include certain amounts in respect of taxable capital gains, and dividends or deemed dividends that are not deductible in computing the Resident Holder's taxable income. **Resident Holders should consult their own advisors.**

Alternative Minimum Tax

Capital gains realized and dividends received by a Resident Holder that is an individual or a trust, other than certain specified trusts, may give rise to alternative minimum tax under the Tax Act. **Resident Holders should consult their own advisors with respect to the application of the minimum tax.**

Holders Not Resident in Canada

The following section of this summary is generally applicable to a Holder who, for the purposes of the Tax Act and at all relevant times: (i) is not, and is not deemed to be, resident in Canada; and (ii) does not use or hold, and is not deemed to use or hold, the Class A Shares in carrying on a business in Canada ("**Non-Resident Holders**").

Special rules, which are not discussed in this summary, may apply to a Non-Resident Holder that is an insurer carrying on business in Canada and elsewhere or that is an "authorized foreign bank" (as defined in the Tax Act). **Such Non-Resident Holders should consult their own tax advisors.**

Dividends on Class A Shares

Dividends paid or credited or deemed to be paid or credited to a Non-Resident Holder by the Company on a Class A Share are generally subject to Canadian withholding tax at the rate of 25% on the gross amount of the dividend unless such rate is reduced by the terms of an applicable tax treaty. For example, under the *Canada-United States Income Tax Convention (1980)* (the "**Treaty**") as amended, for example, the rate of withholding tax on dividends paid or credited to a Non-Resident Holder who is resident in the U.S. for purposes of the Treaty, is the beneficial owner of the dividends, and can substantiate entitlement to the benefits under the Treaty (a "**U.S. Holder**") is generally limited to 15% of the gross amount of the dividend (or 5% in the case of a U.S. Holder that is a corporation that beneficially owns at least 10% of the Company's voting shares). **Affected Non-Resident Holders should consult their own tax advisors in this regard.**

Disposition of Class A Shares

A Non-Resident Holder generally will not be subject to tax under the Tax Act in respect of a capital gain realized on the disposition or deemed disposition of a Class A Share, nor will capital losses arising therefrom be recognized under the Tax Act, unless the Class A Share constitutes or is deemed to constitute "taxable Canadian property" to the Non-Resident Holder thereof for purposes of the Tax Act and the gain is not exempt from tax pursuant to the terms of an applicable tax treaty.

Provided the Class A Shares are listed on a "designated stock exchange" as defined in the Tax Act (which currently includes the TSX) at the time of disposition, the Class A Shares generally will not constitute taxable Canadian property of a Non-Resident Holder at that time unless, at any time during the 60 month period ending at the time of the disposition, the following two conditions are simultaneously met: (i) the Non-Resident Holder, persons with whom the Non-Resident Holder did not deal at arm's length, partnerships in which the Non-Resident Holder or such non-arm's length person holds a membership interest (either directly or indirectly through one or more partnerships), or the Non-Resident Holder together with all such persons, owned 25% or more of the issued shares of any class or series of shares of the Company; and (ii) more than

50% of the fair market value of such shares was derived directly or indirectly from one or any combination of real or immovable property situated in Canada, "Canadian resource property" (as defined in the Tax Act), "timber resource property" (as defined in the Tax Act) or an option in respect of, an interest in or for civil law a right in or to such property, whether or not such property exists. Notwithstanding the foregoing, a Class A Share may also be deemed to be taxable Canadian property to a Non-Resident Holder under certain other provisions of the Tax Act.

A Non-Resident Holder's capital gain (or capital loss) in respect of Class A Shares that constitute or are deemed to constitute taxable Canadian property (and are not "treaty-protected property" as defined in the Tax Act) will generally be computed in the manner described above under "— Holders Resident in Canada — Disposition of Class A Shares".

Non-Resident Holders who may hold Class A Shares as taxable Canadian property should consult their own tax advisors in this regard.

UNDERTAKINGS

The Company has filed an undertaking with the Canadian securities regulatory authorities in accordance with sections 6.1 and 6.4 of National Policy 41-201 — *Income Trusts and Other Indirect Offerings* ("**NP 41-201**") pursuant to which it agreed: (i) that in complying with its reporting issuer obligations, the Company will treat any operating entity (within the meaning of NP 41-201) as a subsidiary of the Company; however, if generally accepted accounting principles used by the Company prohibit the consolidation of financial information of the Company and the operating entity, then for as long as the operating entity (including any of its significant business interests) represents a significant asset of the Company, the Company will provide securityholders with audited annual financial statements and unaudited interim financial statements of the operating entity, prepared in accordance with the same generally accepted accounting principles as the Company's financial statements, and related management's discussion and analysis (which may be contained within the Company's management's discussion and analysis); (ii) that for so long as the Company is a reporting issuer, the Company will take the appropriate measures to require each person who would be an insider of the operating entity or a person or company in a special relationship with the operating entity, if such operating entity were a reporting issuer, to comply with prohibitions against insider trading under applicable securities legislation; and (iii) that for so long as the Company is a reporting issuer, the Company will take the appropriate measures to require each person who would be a reporting insider of the operating entity, if such operating entity were a reporting issuer, to file insider reports about trades in securities of the Company.

AUDITOR, TRANSFER AGENT AND REGISTRAR

Deloitte LLP is the auditor of the Company and the Business. Deloitte LLP is independent of the Company and the Business within the meaning of the Rules of Professional Conduct of the Chartered Professional Accountants of Alberta. The offices of Deloitte LLP are located at Suite 700, 850-2nd Street S.W., Calgary, Alberta, Canada, T2P 0R8.

The transfer agent and registrar for the Shares is Computershare Trust Company of Canada at its principal office in Calgary, Alberta.

EXPERTS

Certain legal matters in connection with the Offering under Canadian law will be passed upon by Torys LLP on behalf of the Company and by Blake, Cassels & Graydon LLP on behalf of the Underwriters. Certain legal matters in connection with the Offering under U.S. law will be passed upon by Latham & Watkins LLP on behalf of the Company and by Skadden, Arps, Slate, Meagher & Flom LLP on behalf of the Underwriters. As at the date of this prospectus, the partners and associates of each of Torys LLP and Blake, Cassels & Graydon LLP beneficially own, directly and indirectly, less than 1% of the outstanding securities or other property of the Company, its associates or its affiliates.

No person or company whose profession or business gives authority to a report, valuation, statement or opinion made by such person or company and who is named in this prospectus as having prepared or certified a part of this prospectus, or a report, valuation, statement or opinion described in this prospectus, has received or shall receive a direct or indirect interest in any securities or other property of the Company or any associate or affiliate of the Company.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

There are no legal proceedings that the Company or the Business is or was a party to, or that any of the Company's or the Business' property is or was the subject of, since April 1, 2024, that were or are material to the Company or the Business, and there are no such material legal proceedings that the Company knows to be contemplated. For the purposes of the foregoing, a legal proceeding is not considered to be "material" by the Company if it involves a claim for damages and the amount involved, exclusive of interest and costs, does not exceed 10% of the value of the Business' current assets, provided that if any proceeding presents in large degree the same legal and factual issues as other proceedings pending or known to be contemplated, the Company has included the amount involved in the other proceedings in computing the percentage. See "Risk Factors".

There were no: (i) penalties or sanctions imposed against the Company or the Business by a court relating to provincial and territorial securities legislation or by a securities regulatory authority within the three years immediately preceding the date of this prospectus; (ii) other penalties and sanctions imposed by a court or regulatory body against the Company or the Business that the Company believes must be disclosed for this prospectus to contain full, true and plain disclosure of all material facts relating to the Class A Shares; or (iii) settlement agreements the Company or the Business entered into before a court relating to provincial and territorial securities legislation or with a securities regulatory authority within the three years immediately preceding the date of this prospectus.

ENFORCEMENT OF JUDGMENTS AGAINST FOREIGN PERSONS

BIF II CalGas Carry (Delaware) LLC and BIP BIF II U.S. Holdings (Delaware) LLC, each a Selling Shareholder, and BIF OpCo are incorporated, continued or otherwise organized under the laws of a foreign jurisdiction and Suzanne Nimocks, Peter Cella, Gene Stahl, David Devine and William Burton, each a director of the Company, reside outside of Canada. In addition, certain of the Company's operations and assets are located outside of Canada. BIF II CalGas Carry (Delaware) LLC, BIP BIF II U.S. Holdings (Delaware) LLC, BIF OpCo and each of the aforementioned directors have each appointed Rockpoint at 400, 607 – 8th Ave. S.W., Calgary, Alberta, Canada, T2P 0A7, as agent for service of process in Canada.

Purchasers are advised that it may not be possible for investors to enforce judgments obtained in Canada against any person or company that is incorporated, continued or otherwise organized under the laws of a foreign jurisdiction or resides outside of Canada, even if the party has appointed an agent for service of process.

MATERIAL CONTRACTS

The following are the only material contracts, other than the contracts entered into in the ordinary course of business, which: (i) have been entered into by the Company since its formation; (ii) are otherwise material to the Company; or (iii) will be entered into by the Company prior to the Closing:

1. the Term Loan Credit Agreement (see "Management's Discussion and Analysis — Liquidity and Capital Resources" and the Annual Financial Statements appended to this prospectus);
2. the A&R LPA (see "Description of Share Capital and OpCo Interests — The OpCos — Swan OpCo");
3. the LLC Agreement (see "Description of Share Capital and OpCo Interests — The OpCos — BIF OpCo");
4. the Business Transfer Agreement (see "Relationship with Brookfield — Agreements Between the Company and Brookfield — Business Transfer Agreement");
5. the Shareholder Agreement (see "Relationship with Brookfield — Agreements Between the Company and Brookfield — Shareholder Agreement");
6. the Registration Rights Agreement (see "Relationship with Brookfield — Agreements Between the Company and Brookfield — Registration Rights Agreement");
7. the Exchange Agreement (see "Relationship with Brookfield — Agreements Between the Company and Brookfield — Exchange Agreement");
8. the Relationship Agreement (see "Relationship with Brookfield — Agreements Between the Company and Brookfield — Relationship Agreement"); and
9. the Underwriting Agreement (see "Plan of Distribution").

Copies of these documents are or will be once executed, as applicable, available for inspection during normal business hours at the Company's office, 400 – 607 8th Ave. S.W., Calgary, Alberta, Canada, T2P 0A7, and at the offices of Torys LLP, 525 – 8th Avenue S.W., 46th Floor, Calgary, Alberta, Canada, T2P 1G1, during the period of distribution, or at any time after Closing on SEDAR+ at www.sedarplus.ca under the Company's profile.

PURCHASERS' STATUTORY RIGHTS

Securities legislation in certain of the provinces and territories of Canada provides purchasers with the right to withdraw from an agreement to purchase securities. This right may be exercised within two business days after the later of: (a) the date that the Company: (i) filed the prospectus or any amendment on SEDAR+ and a receipt is issued and posted for the document; and (ii) issued and filed a news release on SEDAR+ announcing that the document is accessible through SEDAR+, and (b) the date that the purchaser or subscriber has entered into an agreement to purchase the securities or a contract to purchase or a subscription for the securities. In several of the provinces and territories, the securities legislation further provides a purchaser with remedies for rescission or, in some jurisdictions, revisions of the price or damages if the prospectus and any amendment contains a misrepresentation or is not delivered to the purchaser, provided that such remedies for rescission, revisions of the price or damages are exercised by the purchaser within the time limit prescribed by the securities legislation of the purchaser's province or territory. The purchaser should refer to any applicable provisions of the securities legislation of the purchaser's province or territory for the particulars of these rights or consult with a legal adviser.

GLOSSARY

In this prospectus, unless otherwise indicated or the context otherwise requires, the following terms shall have the indicated meanings. Words importing the singular include the plural and vice versa and words importing any gender include all genders. A reference to an agreement means the agreement as it may be amended, supplemented or restated from time to time.

"**A&R LPA**" means the amended and restated limited partnership agreement of Swan OpCo dated October 7, 2025 among Swan GP, as general partner, and BIP BIF II Swan AIV LP and Swan Equity Carry LP, as limited partners.

"**ABCA**" means the *Business Corporations Act* (Alberta).

"**ABL Credit Agreement**" means the ABL credit agreement dated December 22, 2016 among Rockpoint Gas Storage Partners LP, Rockpoint Gas Storage LLC, AECO Gas Storage Partnership, certain affiliates of the borrowers party thereto, Royal Bank of Canada, in its capacity as administrative agent, and the lenders party thereto, governing the ABL Facility, as amended, restated, amended and restated, supplemented, replaced or otherwise modified from time to time in accordance with the terms therewith.

"**ABL Facility**" means the senior secured asset-backed revolving credit facility, comprised of a \$125 million U.S. revolving credit facility and a \$125 million Canadian revolving facility.

"**Adjustment Events**" has the meaning ascribed thereto under "Executive Compensation — Components of Compensation — Long-Term Incentive Plans".

"**Advance Notice Provisions**" has the meaning ascribed thereto under "Corporate Governance — Advance Notice".

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

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

"**affiliate**" has the meaning ascribed thereto in the *Securities Act* (Alberta).

"**AGS**" means Access Gas Services Inc., Access Gas Services (Ontario) Inc. and ESAS.

"**Annual Financial Statements**" means the audited combined consolidated financial statements of the Business as at March 31, 2025 and March 31, 2024 and for the fiscal years ended March 31, 2025, March 31, 2024 and March 31, 2023, together with the accompanying notes thereto.

"**Articles**" means the articles of incorporation of the Company, as amended.

"**Audit Committee**" means the Audit Committee of the Board.

"**Bcf**" means billion cubic feet and "**Bcf/d**" means billion cubic feet per day.

"**BESS**" has the meaning ascribed thereto under "Prospectus Summary — Our Business — Our Business and Growth Strategies".

"**BIF OpCo**" has the meaning ascribed thereto on the cover page of this prospectus.

"**BIF OpCo Share**" has the meaning ascribed thereto on the cover page of this prospectus.

"**BIF OpCo Shareholder**" means a holder of a BIF OpCo Share.

"**Board**" means the board of directors of the Company.

"**Brookfield**" means Brookfield Infrastructure and its affiliates, including the Selling Shareholders (other than the Company, Swan OpCo, BIF OpCo, WGS LP, BIF II SIM Limited, SIM Energy LP, SIM Energy Limited, Swan Debt Aggregator LP and any of their direct and indirect subsidiaries).

"**Brookfield Infrastructure**" means Brookfield Asset Management Private Institutional Capital Adviser (Canada), L.P.

"**Business**" means the ownership and operation, directly or indirectly of a portfolio of six strategically located natural gas storage facilities in North America with a total effective working gas storage capacity of approximately 279.2 Bcf, being the business currently carried on by collectively, Swan OpCo, BIF OpCo, WGS LP, BIF II SIM Limited, SIM Energy LP, SIM Energy Limited, Swan Debt Aggregator LP and, prior to March 21, 2024, BIF II Tres Palacios Aggregator (Delaware) LLC and their subsidiaries.

"**Business Transfer Agreement**" has the meaning ascribed thereto under "Relationship with Brookfield — Agreements Between the Company and Brookfield — Business Transfer Agreement".

"**By-laws**" means the by-law no. 1 of the Company.

"**CalGEM**" means the California Department of Conservation's California Geologic Energy Management Division.

"**Cash Election Amount**" means, with respect to the Class A Shares to be delivered to Brookfield (and its permitted transferees (other than the Company)) upon the exercise of its Exchange Right: (i) the amount of cash that would be received if the number of Class A Shares to which Brookfield would otherwise be entitled were sold at a per share price equal to the volume weighted average trading price of the Class A Shares on the TSX for the five trading days immediately preceding the exchange date; or (ii) if the Class A Shares no longer trade on the TSX or any other national securities exchange, an amount equal to the fair market value of one Class A Share that would be obtained in an arm's length transaction for cash between an informed and willing buyer and an informed and willing seller, neither of whom is under any compulsion to buy or sell and without regard to the particular circumstances of the buyer or seller, all as determined by approval of a majority of the Non-Conflicted Directors, acting reasonably.

"**CDS**" has the meaning ascribed thereto on the cover page of this prospectus.

"**CDS Participants**" has the meaning ascribed thereto under "Plan of Distribution — Non-Certificated Inventory System".

"**CEQA**" means the California Environmental Quality Act.

"**CER**" means the Canada Energy Regulator.

"**CERCLA**" means the U.S. Comprehensive Environmental Response, Compensation and Liability Act.

"**Chair**" means the chair of the Board.

"**Class A Shares**" has the meaning ascribed thereto on the cover page of this prospectus.

"**Class B Shares**" has the meaning ascribed thereto on the cover page of this prospectus.

"**Closing**" has the meaning ascribed thereto on the cover page of this prospectus.

"**Closing Date**" has the meaning ascribed thereto on the cover page of this prospectus.

"**CO2e**" means carbon dioxide equivalent.

"**Code of Conduct**" has the meaning ascribed thereto under "Corporate Governance — Committees of the Board — GNC Committee".

"**Committee**" has the meaning ascribed thereto under "Corporate Governance — Mandate of the Board".

"**Company**" or "**Rockpoint**" means Rockpoint Gas Storage Inc. and does not, for greater clarity, include any of its OpCo Interests following completion of the Transactions.

"**CORRA**" means the Canadian Overnight Repo Rate Average.

"**CPCN**" means a Certificate of Public Convenience and Necessity.

"**CPUC**" means the California Public Utility Commission.

"**CPUC Approval**" means approval by the CPUC of a change of control of Lodi and Wild Goose.

"**CRA**" means the Canada Revenue Agency.

"**Credit Agreements**" means the agreements relating to the Credit Facilities.

"**Credit Facilities**" means the Term Loan due 2031, the Revolving Credit Facility, the ABL Facility and the Warwick Credit Facility.

"**Demand Registration Right**" has the meaning ascribed thereto under "Relationship with Brookfield — Agreements Between the Company and Brookfield — Registration Rights Agreement".

"**Dividend Share Units**" has the meaning ascribed thereto under "Executive Compensation — Components of Compensation — Long-Term Incentive Plans".

"**DSU Plan**" has the meaning ascribed thereto under "Director Compensation — Director Compensation".

"**DSUs**" means deferred share units of the Company.

"**Dth**" means decatherms (a unit of energy that is equal to one million British thermal units).

"**EIA**" means the U.S. Energy Information Administration.

"**EPA**" means the U.S. Environmental Protection Agency.

"**Equity Incentive Plan**" has the meaning ascribed thereto under "Executive Compensation — Compensation Discussion and Analysis — Overview".

"**ESAS**" means EnerStream Agency Services Inc.

"**Exchange Agreement**" means the exchange agreement to be entered into concurrent with the completion of the Reorganization among the Company, the OpCos, Brookfield Infrastructure Holdings (Canada) Inc. and the Selling Shareholders pursuant to which, among other things, Brookfield will be granted the Exchange Right.

"**Exchange Ratio**" has the meaning ascribed thereto under "Summary of the Offering — Exchange Right".

"**Exchange Right**" has the meaning ascribed thereto under "Summary of the Offering — Exchange Right".

"**Fee for Service**" means ToP and STS contracts on a combined basis.

"**Financial Statements of the Business**" means the Annual Financial Statements and the Interim Financial Statements.

"**fiscal 2023**" means the fiscal year ended March 31, 2023.

"**fiscal 2024**" means the fiscal year ended March 31, 2024.

"**fiscal 2025**" means the fiscal year ended March 31, 2025.

"**fiscal 2026**" means the fiscal year ended March 31, 2026.

"**GHG**" means greenhouse gas.

"**GNC Committee**" has the meaning ascribed thereto under "Relationship with Brookfield — Agreements Between the Company and Brookfield — Shareholder Agreement".

"**Governing Body**" means: (i) with respect to a corporation or limited company, the board of directors of such corporation or limited company; (ii) with respect to a limited liability company, the manager(s), director(s) or managing member(s) of such limited liability company; (iii) with respect to a partnership, the board, committee or other body of each general partner or managing partner of such partnership, that serves a similar function (or if any such general partner or managing partner is itself a partnership, the board, committee or other body of such general or managing partner's general or managing partner that serves a similar function); and (iv) with respect to any other person, the body of such person that serves a similar function, and in the case of each of (i) through (iv) includes any committee or other subdivision of such body and any person to whom such body has delegated any power or authority, including any officer or managing director.

"**Group RRSP**" has the meaning ascribed thereto under "Executive Compensation — Components of Compensation — Retirement Arrangements".

"**GW**" means gigawatt.

"**IEA**" mean the International Energy Administration.

"**IFRS**" means IFRS Accounting Standards as issued by the International Accounting Standards Board.

"**independent director**" means a director who is "independent" within the meaning of NI 52-110.

"**Interim Financial Statements**" means the unaudited interim condensed combined consolidated financial statements of the Business as at June 30, 2025 and March 31, 2025 and for the three months ended June 30, 2025 and June 30, 2024, together with the accompanying notes thereto.

"**J.P. Morgan**" has the meaning ascribed thereto on the cover page of this prospectus.

"**Lead Underwriters**" has the meaning ascribed thereto on the cover page of this prospectus.

"**Legacy Incentive Plan**" has the meaning ascribed thereto under "Executive Compensation — Components of Compensation — Long-Term Incentive Plans".

"**Limited Partnerships Act**" has the meaning ascribed thereto under "Description of Share Capital and OpCo Interests — The OpCos — Swan OpCo — General".

"**LLC Act**" has the meaning ascribed thereto under "Description of Share Capital and OpCo Interests — The OpCos — BIF OpCo".

"**LLC Agreement**" means the limited liability company agreement of BIF OpCo dated July 23, 2014 between BIF II CalGas Carry (Delaware) LLC and BIP BIF II U.S. Holdings (Delaware) LLC.

"**LNG**" means liquified natural gas.

"**Market Value**" has the meaning ascribed thereto under "Executive Compensation — Components of Compensation — Long-Term Incentive Plans".

"**Mcf**" means thousand cubic feet.

"**MD&A**" has the meaning ascribed thereto under "Management's Discussion and Analysis — Introduction and Basis of Presentation".

"**MMbtu**" means million British thermal units.

"**MMcf**" means million cubic feet and "**MMcf/d**" means million cubic feet per day.

"**MMDth**" means million dekatherms and "**MMDth/d**" means million dekatherms per day.

"**MTIP**" has the meaning ascribed thereto under "Executive Compensation — Components of Compensation — Medium-Term Incentive Plan".

"**MW**" means megawatt.

"**NEOs**" has the meaning ascribed thereto under "Executive Compensation — Introduction".

"**NGTL System**" means TC Energy's natural gas gathering and transportation system for the Western Canadian Sedimentary Basin.

“**NI 52-110**” means National Instrument 52-110 — *Audit Committees*.

“**Non-Conflicted Director**” means a director of the Company who: (i) is an independent director of the Company, and (ii) in respect of the applicable matter, would not reasonably be considered to have a disclosable interest in such matter under section 120(1) of the ABCA; and for certainty, any director who is an officer or employee of Brookfield (for certainty, not including any independent director of Brookfield) shall not be considered to be a Non-Conflicted Director.

“**Offering**” has the meaning ascribed thereto on the cover page of this prospectus.

“**Offering Price**” has the meaning ascribed thereto on the cover page of this prospectus.

“**OpCo Boards**” means, collectively, the board of directors of Swan GP and the board of managers of BIF OpCo.

“**OpCo Interest**” has the meaning ascribed thereto on the cover page of this prospectus.

“**OpCo Interest Purchase Price**” has the meaning ascribed thereto under “Relationship with Brookfield — Agreements Between the Company and Brookfield — Business Transfer Agreement”.

“**OpCos**” has the meaning ascribed thereto on the cover page of this prospectus.

“**Over-Allotment Option**” has the meaning ascribed thereto on the cover page of this prospectus.

“**PG&E**” means Pacific Gas and Electric Company.

“**PHMSA**” means the U.S. Pipeline and Hazardous Materials Safety Administration.

“**Pro Forma Financial Statements**” means the unaudited pro forma financial statements of the Company as at and for the three months ended June 30, 2025 and for the fiscal year ended March 31, 2025, together with the accompanying notes thereto.

“**PSUs**” has the meaning ascribed thereto under “Executive Compensation — Compensation Discussion and Analysis — Overview”.

“**RBC**” has the meaning ascribed thereto on the cover page of this prospectus.

“**Registration Right**” has the meaning ascribed thereto under “Relationship with Brookfield — Agreements Between the Company and Brookfield — Registration Rights Agreement”.

“**Registration Rights Agreement**” has the meaning ascribed thereto under “Relationship with Brookfield — Agreements Between the Company and Brookfield — Registration Rights Agreement”.

“**Relationship Agreement**” has the meaning ascribed thereto under “Relationship with Brookfield — Agreements Between the Company and Brookfield — Relationship Agreement”.

“**Reorganization**” has the meaning ascribed thereto on the cover page of this prospectus.

“**Revolving Credit Agreement**” means the credit agreement expected to be dated on or around the Closing Date among Rockpoint, Rockpoint Gas Storage Partners LP, Rockpoint Gas Storage LLC and AECO Gas Storage Partnership, as borrowers, the other borrowers from time to time party thereto, the lenders and issuing banks from time to time party thereto and Royal Bank of Canada, in its capacity as administrative agent and collateral agent.

“**Revolving Credit Facility**” means the expected $350 million senior secured cash-flow revolving credit facility.

“**RNG**” means renewable natural gas.

“**RSUs**” has the meaning ascribed thereto under “Executive Compensation — Compensation Discussion and Analysis — Overview”.

“**Secondary Offering**” has the meaning ascribed thereto on the cover page of this prospectus.

"**SEDAR+**" means the System for Electronic Data Analysis and Retrieval + at www.sedarplus.ca.

"**Selling Shareholders**" means, collectively, BIF II CalGas Carry (Delaware) LLC, BIP BIF II U.S. Holdings (Delaware) LLC, Swan Equity Carry LP and BIP BIF II Swan AIV LP, who have granted the Underwriters the Over-Allotment Option.

"**SENER**" means Sener Grupo de Ingenieria.

"**Shareholder Agreement**" has the meaning ascribed thereto under "Relationship with Brookfield — Agreements Between the Company and Brookfield — Shareholder Agreement".

"**Shares**" has the meaning ascribed thereto on the cover page of this prospectus.

"**SOFR**" means the Secured Overnight Financing Rate.

"**STIP**" has the meaning ascribed thereto under "Executive Compensation — Components of Compensation — Annual Bonuses".

"**STS**" has the meaning ascribed thereto under "Prospectus Summary — Our Business — Our Commercial Model".

"**subsidiary**" has the meaning ascribed thereto in the ABCA.

"**Swan GP**" means the general partner of Swan OpCo, as of the date hereof being Swan Holdings GP (Canada) Inc.

"**Swan OpCo**" has the meaning ascribed thereto on the cover page of this prospectus.

"**Swan OpCo GP Unit**" means a general partner unit issued by Swan OpCo, representing a general partner interest in Swan OpCo.

"**Swan OpCo Limited Partner**" means a holder of a Swan OpCo Unit.

"**Swan OpCo Partner**" means a holder of a Swan OpCo Unit or a Swan OpCo GP Unit.

"**Swan OpCo Unit**" has the meaning ascribed thereto on the cover page of this prospectus.

"**S&P**" means S&P Global Ratings Limited.

"**Take-or-Pay**" and "**ToP**" have the meaning ascribed thereto under "Prospectus Summary — Our Business — Our Commercial Model".

"**Tax Act**" has the meaning ascribed thereto under "Eligibility for Investment".

"**TC Energy**" means TC Energy Corporation.

"**Tcf**" means trillion cubic feet.

"**Term Loan Credit Agreement**" means the credit agreement dated September 18, 2024 among Rockpoint Gas Storage Partners LP, Rockpoint Gas Storage Canada Ltd., certain affiliates of the borrowers party thereto, Wells Fargo Bank, National Association, in its capacity as administrative agent, and the lenders party thereto, governing the Term Loan due 2031.

"**Term Loan due 2031**" means the senior secured term loan B facility in an original aggregate principal amount of $1,250.0 million.

"**Term Loan due 2026**" means the term loan A facility in an original aggregate principal amount of $450.0 million and terminated on September 18, 2024.

"**total effective working gas storage capacity**" means the maximum volume of natural gas that can be stored in an underground storage facility in accordance with its design less base gas, where base gas (or cushion gas) is the volume of natural gas intended as permanent inventory in a storage reservoir to maintain adequate pressure and deliverability rates throughout the withdrawal season. Management conducts its own estimates for total effective working gas storage capacity and routinely commissions third-party reservoir analyses of its reservoirs to validate the reservoir operating parameters.

"**Total Recordable Incident Rate**" means the number of reportable injuries per 100 full-time employees.

"**Transactions**" has the meaning ascribed thereto on the cover page of this prospectus.

"**Tres Holdings**" means Tres Palacios Holdings LLC.

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

"**TWh**" means terawatt-hour.

"**U.S. Securities Act**" has the meaning ascribed thereto on the cover page of this prospectus.

"**Underwriters**" has the meaning ascribed thereto on the cover page of this prospectus.

"**Underwriting Agreement**" has the meaning ascribed thereto on the cover page of this prospectus.

"**Warwick Credit Agreement**" means the amended and restated commitment letter dated February 20, 2024 and the first amendment letter thereto among WGS LP, certain affiliates of WGS LP, as guarantors, and ATB Financial, governing the Warwick Credit Facility.

"**Warwick Credit Facility**" means the operating loan facility (revolving) in an aggregate principal amount of C$37.5 million.

"**Warwick Receivable**" has the meaning ascribed thereto under "Relationship with Brookfield — The Transactions".

"**we**", "**us**" or "**our**" means, collectively, Swan OpCo, BIF OpCo, WGS LP, BIF II SIM Limited, SIM Energy LP, SIM Energy Limited, Swan Debt Aggregator LP and, prior to March 21, 2024, BIF II Tres Palacios Aggregator (Delaware) LLC, and their subsidiaries.

"**WGS LP**" means, collectively, Warwick Gas Storage Ltd. and Warwick Gas Storage LP.

INDEX TO FINANCIAL STATEMENTS

Deloitte.

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Independent Auditor's Report

To the Board of Directors of
Rockpoint Gas Storage Inc.

Opinion

We have audited the financial statements of Rockpoint Gas Storage Inc. (the "Company"), which comprise the balance sheet as at July 28, 2025, and notes to the financial statements, including material accounting policy information (collectively referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Company as at July 28, 2025, and in accordance with IFRS Accounting Standards as issued by the International Accounting Standards Board ("IASB").

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards ("Canadian GAAS"). Our responsibilities under those standards are further described in the Auditor's Responsibilities for the Audit of the Financial Statements section of our report. We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada, and we have fulfilled our other ethical responsibilities in accordance with these requirements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with IFRS Accounting Standards as issued by the IASB, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company's financial reporting process.

Auditor's Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian GAAS will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

As part of an audit in accordance with Canadian GAAS, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Company to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

/s/ Deloitte LLP

Chartered Professional Accountants
Calgary, Alberta
October 7, 2025

Rockpoint Gas Storage Inc.

Balance Sheet
As at July 28, 2025
(In U.S. Dollars)

	As at July 28, 2025
Assets	
Cash	$ —
Total Assets	**$ —**
Equity	
Share capital	$ —
Total Shareholder's Equity	**$ —**

See notes to financial statements

1. Organization and Principal Business

Rockpoint Gas Storage Inc. (the "Company" or "Rockpoint") was formed on July 28, 2025 and incorporated under the Business Corporations Act (Alberta) ("ABCA").

Rockpoint was incorporated with nominal assets for the purpose of completing an offering of Class "A" common shares and acquiring an approximate 40% interest in the gas storage operations carried on by Swan Equity Aggregator LP, an Ontario limited partnership ("Swan OpCo") and BIF II CalGas (Delaware) LLC, a Delaware limited liability company ("BIF OpCo", and together with Swan OpCo, the "OpCos") and related entities, from BIF II CalGas Carry (Delaware) LLC, BIP BIF II U.S. Holdings (Delaware) LLC, Swan Equity Carry LP and BIP BIF II Swan AIV LP.

Rockpoint's registered and head office is located at 400 — 607 8th Ave. S.W., Calgary, Alberta, Canada, T2P 0A7. The financial statements were approved for issue by the Board of Directors of Rockpoint on October 7, 2025.

2. Material Accounting Policy Information

The Balance Sheet has been prepared in accordance with IFRS Accounting Standards as issued by the International Accounting Standards Board ("IASB"). Separate Statements of Income, Changes in Owners' Equity and Cash Flows have not been presented as there have been no activities for the Company.

3. Critical Accounting Judgements and Key Sources of Estimation Uncertainty

The preparation of financial statements requires management to make critical judgments, estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses that are not readily apparent from other sources, during the reporting period. These estimates and associated assumptions are based on historical experience and other factors that are considered to be relevant. Actual results may differ from these estimates.

The estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimate is revised if the revision affects only that period, or in the period of the revision and future periods if the revision affects both current and future periods.

4. Capital Structure

The authorized share capital of the Company consists of: (i) an unlimited number of Class "A" common shares, (ii) an unlimited number of Class "B" voting shares, and (iii) an unlimited number of preferred shares, issuable in series.

On July 28, 2025, in connection with the incorporation of the Company, the Company issued one common share in the capital of the Company to Brookfield Infrastructure Holdings (Canada) Inc. for nominal consideration ($0.01). The common share was redesignated as a Class "A" common share upon the filing of Articles of Amendment on September 17, 2025.

Deloitte.

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Independent Auditor's Report

To the Board of Directors of Rockpoint Gas Storage Inc.

Opinion

We have audited the combined consolidated financial statements of Swan Equity Aggregator LP, BIF II CalGas (Delaware) LLC, Warwick Gas Storage LP, Warwick Gas Storage Ltd., BIF II SIM Limited, SIM Energy LP, SIM Energy Limited, Swan Debt Aggregator LP and BIF II Tres Palacios Aggregator (Delaware) LLC (collectively, "Rockpoint Gas Storage"), which comprise the combined consolidated statements of financial position as at March 31, 2025 and 2024, and the combined consolidated statements of net earnings and comprehensive earnings, changes in owners' equity and cash flows for the years ended March 31, 2025, 2024, and 2023, and notes to the combined consolidated financial statements, including material accounting policy information (collectively referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of Rockpoint Gas Storage as at March 31, 2025, and 2024, and its financial performance and its cash flows for the years ended March 31, 2025, 2024, and 2023, and in accordance with IFRS Accounting Standards as issued by the International Accounting Standards Board ("IASB").

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards ("Canadian GAAS"). Our responsibilities under those standards are further described in the Auditor's Responsibilities for the Audit of the Financial Statements section of our report. We are independent of Rockpoint Gas Storage in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada, and we have fulfilled our other ethical responsibilities in accordance with these requirements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Other Information

Management is responsible for the other information. The other information comprises Management's Discussion and Analysis.

Our opinion on the financial statements does not cover the other information and we do not express any form of assurance conclusion thereon. In connection with our audit of the financial statements, our responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the financial statements or our knowledge obtained in the audit, or otherwise appears to be materially misstated.

We obtained Management's Discussion and Analysis prior to the date of this auditor's report. If, based on the work we have performed on this other information, we conclude that there is a material misstatement of this other information, we are required to report that fact in this auditor's report. We have nothing to report in this regard.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with IFRS Accounting Standards as issued by the IASB, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing Rockpoint Gas Storage's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate Rockpoint Gas Storage or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing Rockpoint Gas Storage's financial reporting process.

Auditor's Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian GAAS will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

As part of an audit in accordance with Canadian GAAS, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of Rockpoint Gas Storage's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on Rockpoint Gas Storage's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause Rockpoint Gas Storage to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Plan and perform the group audit to obtain sufficient appropriate audit evidence regarding the financial information of the entities or business units within Rockpoint Gas Storage as a basis for forming an opinion on the financial statements. We are responsible for the direction, supervision and review of the audit work performed for purposes of the group audit. We remain solely responsible for our audit opinion.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

/s/ Deloitte LLP

Chartered Professional Accountants
Calgary, Alberta
October 7, 2025

Rockpoint Gas Storage

Combined Consolidated Statements of Net Earnings and Comprehensive Earnings
(Millions of U.S. dollars)

	Notes	Fiscal Years Ended March 31, 2025	2024	2023
REVENUES				
Fee for service revenue	13	**$366.8**	$ 292.5	$195.8
Optimization, net	13, 18	**48.5**	56.1	82.2
Total revenues		**415.3**	348.6	278.0
EXPENSES (INCOME)				
Cost of gas storage services		**11.0**	21.2	38.3
Operating	14, 17, 18, 19	**49.5**	53.2	56.5
General and administrative	14	**24.2**	23.5	22.2
Depreciation and amortization	5, 8	**33.1**	34.0	34.5
Financing costs	7, 11, 15, 17, 18, 19	**93.1**	76.0	68.7
Equity in net earnings of equity accounted investee		**—**	—	(3.9)
Gain on disposals of subsidiary and equity accounted investee	4	**—**	(114.7)	—
Asset impairment		**—**	—	11.3
(Gains) losses on gas storage obligation, net	10, 17, 18	**(1.3)**	(1.8)	0.6
Other expenses		**6.9**	7.9	2.7
		216.5	99.3	230.9
EARNINGS BEFORE INCOME TAXES		**198.8**	249.3	47.1
Income tax (benefit) expense	16			
Current		**0.6**	(0.4)	0.2
Deferred		**(11.2)**	(4.2)	2.4
		(10.6)	(4.6)	2.6
NET EARNINGS		**$209.4**	$ 253.9	$ 44.5
OTHER COMPREHENSIVE LOSSES, NET OF TAX				
Foreign currency translation adjustment		**$ (1.8)**	$ —	$ (1.7)
NET EARNINGS AND COMPREHENSIVE EARNINGS		**$207.6**	$ 253.9	$ 42.8

(The accompanying Notes to the Combined Consolidated Financial Statements are an integral part of these statements.)

Rockpoint Gas Storage

Combined Consolidated Statements of Financial Position
(Millions of U.S. dollars)

	Notes	As at March 31, 2025	As at March 31, 2024
ASSETS			
Current Assets			
Cash and cash equivalents		**$ 204.1**	$ 100.1
Trade and accrued receivables	13	**76.7**	71.9
Natural gas inventory		**28.6**	85.2
Short-term risk management assets	17, 18	**19.5**	29.5
Margin deposits		**0.9**	27.0
Prepaid expenses and other current assets		**1.8**	3.2
Due from affiliates	19, 22	**83.0**	—
		414.6	316.9
Long-term Assets			
Property, plant and equipment, net	5, 8, 22	**884.6**	881.5
Goodwill	6	**117.2**	117.2
Long-term risk management assets	17, 18	**9.3**	12.6
Other assets		**4.5**	2.8
		1,015.6	1,014.1
TOTAL		**$1,430.2**	$1,331.0
LIABILITIES AND OWNERS' EQUITY			
Current Liabilities			
Trade payables and accrued liabilities	9, 19	**$ 59.5**	$ 75.3
Short-term debt	7, 15	**25.8**	—
Short-term risk management liabilities	17, 18	**13.9**	16.7
Short-term lease liabilities	8, 15, 22	**9.1**	8.6
Margin deposits		**3.2**	—
Deferred revenue	13	**1.4**	2.2
		112.9	102.8
Long-term Liabilities			
Long-term debt	7, 15	**1,208.1**	464.7
Long-term risk management liabilities	17, 18	**5.7**	10.9
Long-term lease liabilities	8, 15, 22	**99.7**	98.2
Gas storage obligations	10	**17.4**	19.6
Decommissioning obligations	11	**5.0**	5.0
Other long-term liabilities		**2.2**	2.1
Deferred income taxes	16	**65.0**	76.2
Due to affiliates	15, 19	**—**	216.0
		1,403.1	892.7
Equity		**(85.8)**	335.5
TOTAL		**$1,430.2**	$1,331.0
Commitments and contingencies disclosures	20		

(The accompanying Notes to the Combined Consolidated Financial Statements are an integral part of these statements.)

Rockpoint Gas Storage

Combined Consolidated Statements of Changes in Owners' Equity
(Millions of U.S. dollars)

	Capital Contributions	Retained (Deficit) Earnings	Accumulated Other Comprehensive Loss	Owners' (Deficiency) Capital
Balance, April 1, 2022	$ 398.3	$ (29.5)	$(19.1)	$ 349.7
Net earnings	—	44.5	—	44.5
Other comprehensive loss	—	—	(1.7)	(1.7)
Capital contributions	5.6	—	—	5.6
Balance, March 31, 2023	$ 403.9	$ 15.0	$(20.8)	$ 398.1
Net earnings	$ —	$ 253.9	$ —	$ 253.9
Other comprehensive income	—	—	—	—
Distributions	(153.2)	(163.3)	—	(316.5)
Balance, March 31, 2024	$ 250.7	$ 105.6	$(20.8)	$ 335.5
Net earnings	$ —	$ 209.4	$ —	$ 209.4
Other comprehensive loss	—	—	(1.8)	(1.8)
Distributions	(123.7)	(505.2)	—	(628.9)
Balance, March 31, 2025	**$ 127.0**	**$(190.2)**	**$(22.6)**	**$ (85.8)**

(The accompanying Notes to the Combined Consolidated Financial Statements are an integral part of these statements.)

Rockpoint Gas Storage

Combined Consolidated Statements of Cash Flows
(Millions of U.S. dollars)

	Notes	Fiscal Years Ended March 31, 2025	2024	2023
OPERATING ACTIVITIES				
Net earnings		**$ 209.4**	$ 253.9	$ 44.5
Adjustments to reconcile net earnings to net cash provided by (used in) operating activities:				
Deferred income tax (benefit) expense	16	**(11.2)**	(4.2)	2.4
Unrealized risk management losses (gains)	17, 18	**4.0**	(6.0)	(15.7)
Inventory adjustments	13	**—**	—	67.7
Depreciation and amortization	5, 8	**33.1**	34.0	34.5
Equity in net earnings of equity accounted investee		**—**	—	(3.9)
Asset impairment		**—**	—	11.3
Gain on disposals of subsidiary and equity accounted investee	4	**—**	(114.7)	—
Other		**6.9**	6.7	6.1
Changes in non-cash working capital	21	**71.5**	75.8	(148.0)
Net cash provided by (used in) operating activities		**313.7**	245.5	(1.1)
INVESTING ACTIVITIES				
Property, plant and equipment expenditures		**(34.9)**	(14.1)	(15.0)
Capital contributions to equity accounted investee		**—**	—	(6.2)
Return of capital from equity accounted investee		**—**	—	8.7
Proceeds from disposal of equity accounted investee	4	**—**	175.4	—
Proceeds from disposal of subsidiary	4	**—**	35.2	—
Net cash (used in) provided by investing activities		**(34.9)**	196.5	(12.5)
FINANCING ACTIVITIES				
Proceeds from Existing Revolving Credit Facilities		**40.9**	109.5	433.1
Payments of Existing Revolving Credit Facilities		**(44.7)**	(133.5)	(416.8)
Proceeds from advances from a related party		**—**	100.0	275.0
Payment of advances from a related party		**—**	(295.0)	(80.0)
Proceeds from term loans	7	**1,237.5**	450.0	200.0
Payments of term loans	7	**(453.1)**	(200.0)	—
Payments of senior notes		**—**	—	(397.3)
Payments of promissory notes	19	**(224.9)**	(73.2)	—
Notes extended to related parties	19	**(83.0)**	—	—
Payments of financing costs		**(17.2)**	(5.5)	(2.0)
Payments of lease liabilities	8	**(0.8)**	(0.6)	(1.0)
Capital contributions	12	**—**	—	5.6
Distributions		**(628.9)**	(316.5)	—
Net cash (used in) provided by financing activities		**(174.2)**	(364.8)	16.6
Effect of translation on foreign currency cash and cash equivalents		**(0.6)**	(0.2)	(0.6)
Net changes in cash and cash equivalents		**104.0**	77.0	2.4
Cash and cash equivalents, beginning of the year		**100.1**	23.1	20.7
Cash and cash equivalents, end of the year		**$ 204.1**	$ 100.1	$ 23.1
Supplemental cash flow disclosures	21			

(The accompanying Notes to the Combined Consolidated Financial Statements are an integral part of these statements.)

1. Description of Business

We are the largest independent pure play operator of natural gas facilities in North America. These financial statements represent the combined consolidated financial statements of Swan Equity Aggregator LP ("Swan OpCo"), BIF II CalGas (Delaware) LLC ("BIF OpCo"), Warwick Gas Storage LP and Warwick Gas Storage Ltd. (collectively "WGS LP" or the "Partnership"), BIF II SIM Limited, SIM Energy LP and SIM Energy Limited (collectively "SIM"), Swan Debt Aggregator LP ("Swan Debt") and prior to March 21, 2024, BIF II Tres Palacios Aggregator (Delaware) LLC ("Tres") and their subsidiaries (collectively, "we", "us", "our", "Rockpoint Gas Storage", or the "Business").

Swan OpCo is an Ontario limited partnership that independently owns and operates 229.0 billion cubic feet ("Bcf") of effective natural gas storage capacity in North America. It operates the AECO Hub™ ("AECO"), which consists of the Countess and Suffield gas storage facilities in Alberta, Canada and the Wild Goose Storage, LLC ("Wild Goose") gas storage facility in California. Each of its facilities market natural gas storage services in addition to optimizing storage capacity with gas purchases. Prior to April 1, 2023, Swan OpCo owned Salt Plains Storage, LLC ("Salt Plains") and, as part of its previous ownership of that company, it operated the Salt Plains gas storage facility in Oklahoma with 13 Bcf of working gas capacity. Swan OpCo also operates a natural gas marketing business that is an extension of its propriety optimization activities in Canada.

BIF OpCo owns Lodi Gas Storage L.L.C. ("Lodi"), a Delaware limited liability company, which owns and operates a natural gas storage facility in northern California. The facility has 28.7 Bcf of effective working natural gas storage capacity in two underground natural gas storage reservoirs and is connected to Pacific Gas and Electric's ("PG&E") intrastate natural gas pipeline system that services demand in the San Francisco and Sacramento areas in California.

WGS LP owns and operates a natural gas storage facility with 21.5 Bcf of effective working gas capacity and is engaged in the storage of third-party natural gas. The facility was originally developed in 2009 and is located east of Edmonton in central Alberta.

Tres, a former Delaware limited liability company, owned a 49.99% membership interest in Tres Palacios Holdings LLC ("Tres Holdings"). This company was a joint venture between Tres and CMLP Tres Manager LLC which owned the remaining 50.01% membership interest. Tres Holdings was set up to own and operate a Texas-based salt dome facility with 34 Bcf of working gas capacity. The Business sold its interest in Tres Holdings, together with the associated facility, on April 3, 2023 (see Note 4). On March 21, 2024, Tres and its subsidiaries were dissolved.

The Business consists of entities that are ultimately subsidiaries of Brookfield Asset Management Private Institutional Capital Advisor (Canada), L.P. ("Brookfield Infrastructure", and together with its affiliates, "Brookfield") and its institutional partners. Rockpoint Gas Storage Inc. has been formed to acquire an approximate 40% interest in the Business (the "Transaction").

2. Statement of Compliance and Basis of Presentation

These combined consolidated financial statements (the "Financial Statements of the Business") have been prepared to reflect the combined consolidated financial position, financial performance and cash flows of Swan OpCo, BIF OpCo, WGS LP, SIM, Swan Debt and, prior to March 21, 2024, Tres and their subsidiaries and have been prepared in accordance with IFRS Accounting Standards as issued by the International Accounting Standards Board ("IASB"), which were in effect as at March 31, 2025.

The Financial Statements of the Business have been prepared on a historical cost basis, except for risk management assets and liabilities and the gas storage obligations, which are measured at fair value. The Financial Statements of the Business were authorized for issue by the Board of Directors of Rockpoint Gas Storage Inc. on October 7, 2025.

3. Material Accounting Policy Information

Principles of combination and consolidation

The Financial Statements of the Business were prepared for the purpose of presenting the financial position, results of operations and cash flows of Swan OpCo, BIF OpCo, WGS LP, SIM, Swan Debt and, prior to March 21, 2024, Tres and its subsidiaries, which are commonly controlled and managed as a single economic entity.

All significant intercompany balances, transactions, revenues and expenses are eliminated.

Revenue recognition

The Business recognizes revenue when it transfers control of a product or service to a customer.

Revenue is measured based on the consideration specified in a contract with a customer and excludes amounts collected on behalf of third parties. Cash received in advance from customers is recorded as deferred revenue until revenue recognition criteria are met.

Our fee for service revenues are earned by providing storage services on a take-or-pay ("ToP") contract basis, for which we receive a fixed monthly demand charge for specified amounts of injection, storage, and withdrawal capabilities regardless of utilization, and by providing storage services on a short-term storage service ("STS") contract basis, where customers pay a fixed fee to both inject a specified quantity of natural gas on a specified date or dates and to withdraw on a specified future date or dates.

ToP contract revenue contains both fixed monthly demand charges and variable operating fees based on volumes of natural gas injected or withdrawn. The Business identified one performance obligation relating to ToP contract revenue, which encompasses the injection, storage, and withdrawal of natural gas within our facilities. Monthly demand charges are recognized over the period covered by each contract, to the extent that we have the right to invoice. A relatively small portion of our ToP revenues are derived from variable fees related to fuel and injection and withdrawal fees, which are recognized over time as injection and withdrawal of natural gas occurs.

STS contracts are fixed in nature and do not provide the customer any option to adjust the volumes or timing specified in a contract, which generally have durations of one year or less. The Business identified one performance obligation relating to STS contract revenue, which is the combination of injection and withdrawal of gas over a specified date or dates. STS contract revenue is recognized over time, to the extent that we have the right to invoice, using the output measures of volume of gas injected and withdrawn, which is when the services are provided.

Optimization, net is comprised of realized and unrealized gains and losses on our natural gas trading activities. Realized gains and losses include realized gains and losses from physical energy trading contracts, for which revenues and costs are recognized at the time of physical delivery, net of realized gains and losses on financial trading contracts, which are recognized when the contract settles and period to which the contract relates is completed. Unrealized gains and losses represent the change in the value of derivative contracts, which are risk management positions that have been entered into to lock-in future prices of natural gas and currency exchange rates. Because our natural gas inventories relate directly to our proprietary optimization activities, any adjustment in those inventories is reflected as part of optimization, net.

Cash and cash equivalents

Cash and cash equivalents include cash on hand, and as applicable, short-term investments with original maturities of three months or less.

Margin deposits

Cash held in margin represents the right to receive or the obligation to pay cash collateral under a master netting arrangement that has not been offset against derivative positions. These derivatives are marked-to-market daily and the profit or loss on the daily position is then received from, or paid to, the account as appropriate under the terms of the Business' contract with its broker.

Natural gas inventory

The Business' inventory is natural gas injected into storage and held for resale. Inventory is valued at the lower of weighted average cost or net realizable value. Net realizable value is the estimated selling price in the ordinary course of business, less estimated costs to complete the sale.

Reversals of adjustments to inventory are required when circumstances that previously caused inventories to be written down no longer exist in subsequent periods, or when there is clear evidence of an increase in net realizable value because of changed economic circumstances.

Costs to store inventory are recognized as operating expenses in the period the costs are incurred in the combined consolidated statements of net earnings and comprehensive earnings.

Property, plant and equipment

Property, plant and equipment is recorded at cost, net of accumulated depreciation and accumulated impairment losses, if any. The initial cost of an asset includes its purchase price or construction cost, any costs directly attributable to bringing the asset into operation and estimated decommissioning obligations.

The cost of right-of-use ("ROU") assets, is comprised of the amount of the initial measurement of the corresponding lease liability, lease payments made at or before the commencement day, less incentives received, and any initial direct costs.

When significant parts of property, plant and equipment are required to be replaced at intervals, the Business recognizes such parts as individual assets with specific useful lives and depreciates them accordingly. Likewise, when a major inspection is performed, its cost is recognized in the carrying amount of the property, plant and equipment as a replacement if the recognition criteria are satisfied. Repairs, maintenance and renewals that do not provide future economic benefits to the assets are recognized in the combined consolidated statements of net earnings and comprehensive earnings as incurred.

Assets are derecognized upon disposal, replacement or when no future economic benefits are expected to arise from the continued use of the asset. Any gains or losses arising on the disposal or retirement of an asset are determined by comparing the proceeds from disposal with the carrying amount of the asset and are recognized in the combined consolidated statements of net earnings and comprehensive earnings.

Depreciation of an asset commences when it is available for use. Property, plant and equipment are depreciated using the straight-line method over the estimated useful lives of each component of the assets as follows:

	In years
Pipelines and interconnects	25 – 60
Wells	1 – 60
Land and storage formations	3 – 83
Facilities and other	3 – 60

Depreciation on property, plant and equipment is calculated to depreciate the net cost of each asset over its expected useful life to its estimated residual value. Land and pipeline rights of way are not depreciated. The estimated useful lives, residual values and depreciation methods are reviewed on an annual basis and, if necessary, any changes are accounted for prospectively.

ROU assets as related to defined-term leases are depreciated on a straight-line basis over the expected useful life of the asset, which is the shorter of the lease term or the expected useful life of the underlying asset. Land-based leases that are renewable into perpetuity at the Business' option are treated as an acquisition of land and are not depreciated.

Costs of major overhauls of engines and compressors included within the gas storage facilities are depreciated using the actual number of hours used over the estimated number of hours until the next scheduled major overhaul. The estimated useful lives of major overhauls, based on expected utilization, ranges from 10 to 20 years.

Certain volumes of hydrocarbons defined as cushion gas are required for maintaining a minimum reservoir pressure. Cushion gas is considered a component of the facility and as such is not amortized because of its indefinite useful life. Cushion gas is monitored to ensure that it provides effective pressure support for the facility. If cushion gas moves to another area of the reservoir where it does not provide effective pressure support or is withdrawn due to heat imbalances of native cushion volumes, a loss is recorded within depreciation expense, equal to the cost of estimated volumes that have migrated.

Goodwill

Goodwill represents the excess of the price paid for the acquisition of an entity over the fair value of the net tangible and intangible assets and liabilities acquired. Goodwill is allocated to the cash generating unit ("CGU") or units to which it relates. We identify a CGU or group of CGUs as identifiable groups of assets that are largely independent of the cash inflows from other assets or groups of assets.

Goodwill is not subject to amortization. Goodwill is evaluated for impairment annually or more often if events or circumstances indicate there may be impairment. Impairment is determined for goodwill by assessing if the carrying value of a CGU, including the allocated goodwill, exceeds its recoverable amount determined as the greater of the estimated fair value less costs of disposal or the value in use. Impairment losses recognized in respect of a CGU are first allocated to the carrying value of goodwill and any excess is allocated to the carrying amount of assets in the CGU. Any goodwill impairment is charged to net earnings (loss) in the period in which the impairment is identified. Impairment losses on goodwill are not subsequently reversed.

Impairment of long-lived assets

At each reporting date, the Business assesses, for its long-lived assets, if there is any indication that such assets are impaired. This assessment includes a review of internal and external factors that include, but are not limited to, changes in the technological, economic or legal environment in which the entity operates in, structural changes in the industry, changes in the level of demand, physical damage and obsolescence due to technological changes. An impairment is recognized if the recoverable amount, determined as the higher of the estimated fair value less costs of disposal or the value in use and eventual disposal from an asset or CGU is less than their carrying value. The projections used to calculate value in use consider the relevant operating plans and management's best estimate of the most probable set of conditions anticipated to prevail.

Impairments may be reversed for all CGUs and individual assets, other than goodwill, if there has been a change in the estimates and judgments used to determine the asset's recoverable amount. If such indication exists, the carrying amount of the asset or CGU unit is increased to the lesser of the revised estimate of recoverable amount and the carrying amount that would have been recorded had no impairment loss been recognized previously.

Risk management activities

The Business uses natural gas derivatives and other financial instruments to manage its exposure to changes in natural gas prices, electricity prices, interest rates and foreign exchange rates. These financial assets and liabilities, which are recorded at fair value on a recurring basis, are included in one of three categories based on a fair value hierarchy, with realized and unrealized gains (losses) recognized in net earnings (losses) for the period (see Note 18) since these contracts are not treated as hedges for financial reporting purposes.

The fair value of the Business' derivative risk management contracts is recorded as a component of risk management assets and liabilities, which are classified as current or non-current assets or liabilities based upon the anticipated settlement date of the contracts.

Netting of certain Statements of Financial Position accounts

Certain risk management assets and liabilities and certain accrued gas sales and purchases are presented on a net basis in the statements of financial position when all of the following exist: (i) the Business and the other party owe each other a determinable amount; (ii) the Business has the right to offset amounts owed with the other party; (iii) we intend to offset; and (iv) the right of offset is enforceable by law.

Provisions

Provisions are recognized by the Business when it has a legal or constructive obligation as a result of past events, it is probable that an outflow of economic resources will be required to settle the obligation and a reliable estimate can be made of the amount of the obligation. The amount recognized as a provision is the best estimate of the consideration required to settle the present obligation at the end of the reporting period, taking into account the risks and uncertainties surrounding the obligation. Where a provision is measured using the cash flows estimated to settle the obligation, its carrying amount is the present value of those cash flows.

Provisions are recognized for decommissioning obligations associated with the Business' property, plant and equipment at the end of their economic life. Provisions for decommissioning obligations are measured at the present value of management's best estimate of the future cash flows required to settle the present obligation, using a credit-adjusted interest rate. The value of the obligation is added to the carrying amount of the associated asset and amortized over the useful life of the asset. Any change in the present value, as a result of a change in discount rate or expected future costs, of the estimated obligation are recognized as a change in the decommissioning obligations and related assets. The provision is accreted over time through financing costs with actual expenditures charged to the accumulated obligation.

Gas storage obligations

Our gas storage obligations represent agreements to deliver set amounts of natural gas during specific timeframes from our Warwick gas storage facility that cannot be physically delivered in the timeframes specified. WGS LP has a practice of moving the delivery dates into the future through use of storage agreements with counterparties that offset delivery dates specified in previous agreements. This obligation is accounted for as a hybrid financial liability with an embedded natural gas derivative and is therefore recorded at fair value through profit and loss.

Leases

The Business determines if a contract contains a lease at inception of a contract by using judgment in assessing the following aspects: i) the contract specifies an identified asset that is physically distinct or, if not physically distinct, represents substantially all of the capacity of the asset; ii) the contract provides the customer with the right to obtain substantially all of the economic benefits from the use of the asset; and iii) the customer has the right to direct how and for what purpose the identified asset is used throughout the period of the contract. If the contract is determined to contain a lease, further judgment is required to identify separate lease components of the arrangement by assessing whether the lessee can benefit from the right of use either on its own or together with other resources that are readily available to the lessee, as well as if the right of use is neither highly dependent on, nor highly interrelated, with the other rights to use the underlying assets in the contract. We consider non-lease components as distinct elements of a contract that are not related to the use of the leased asset. A good or service that is provided to a customer is distinct if: i) the customer can benefit from the good or service either on its own or together with other resources that are readily available to the customer; and ii) the entity's promise to transfer the good or service to the customer is separately identifiable from other promises in the contract.

Remeasurement of lease liabilities and a corresponding adjustment to the related ROU assets occurs when i) the lease term has changed or there is a change in the assessment of whether a purchase option will be exercised, in which case the lease liability is remeasured by discounting the revised lease payments using a revised discount rate; ii) the lease payments have changed due to changes in an index or rate or a change in expected payment under a guaranteed residual value, in which case the lease liability is remeasured by discounting the revised lease payments using the initial discount rate (unless the lease payments change is due to a change in a floating interest rate, in which case a revised discount rate is used); or iii) a lease contract is modified and the lease modification is not accounted for as a separate lease, in which case the lease liability is remeasured by discounting the revised lease payments using a revised discount rate.

The Business applies the practical expedient to not recognize ROU assets or lease liabilities for leases that qualify for the short-term lease recognition exemption.

Cost of gas storage services

When market conditions warrant, the Business may pay a counterparty to flow gas into or out of our facilities. Such deals are transacted for the purpose of generating an overall positive net margin when combined with offsetting revenue generating activities. These costs are not recorded as a reduction of revenue, but rather are presented as a cost of providing gas storage services.

Deferred financing costs

Deferred financing costs relate to costs incurred on the issuance of debt and are amortized over the term of the related debt to financing costs using the effective interest method.

Foreign currency translation

The reporting currency of the Financial Statements of the Business is the U.S. dollar. Each entity within the combined group determines its own functional currency based on the primary economic environment in which it operates. For WGS LP, SIM Energy LP and SIM Energy Limited, the functional currency is the Canadian dollar. Assets and liabilities of these entities are translated into U.S. dollars at the period-end exchange rate. Revenues and expenses are translated at the average exchange rate for the reporting period. Non-monetary items measured at historical cost are translated at the exchange rate in effect on the date of the transaction. Foreign exchange gains and losses arising from the translation of the financial statements are recognized in other comprehensive income. Foreign exchange gains and losses arising from monetary transactions denominated in currencies other than the functional currency are recognized in net earnings (loss) for the period.

All other entities within the Financial Statements of the Business have a functional currency of U.S. dollars.

Current income tax

Current income tax assets and liabilities for the current period are measured at the amount expected to be recovered from or paid to the taxation authorities. The tax rates and tax laws used to compute the amount are those that are enacted, or substantively enacted at the reporting date in the countries where the Business operates and generates taxable income.

Deferred tax

Deferred tax is provided using the liability method on temporary differences between the tax basis of assets and liabilities and their carrying amounts for financial reporting purposes at the reporting date. Deferred tax liabilities are recognized for all taxable temporary differences, except:

- when the deferred tax liability arises from the initial recognition of goodwill or an asset or liability in a transaction that is not a business combination and, at the time of the transaction, affects neither the accounting profit nor taxable net earnings (loss); and
- in respect of taxable temporary differences associated with investments in subsidiaries, associates and interests in joint arrangements, when the timing of the reversal of the temporary differences can be controlled and it is probable that the temporary differences will not reverse in the foreseeable future.

Deferred tax assets are recognized for all deductible temporary differences and the carry forward of unused tax credits and unused tax losses, to the extent that it is probable that taxable profit will be available to use against the deductible temporary differences. The carry forward of unused tax credits and unused tax losses can be utilized, except:

- when the deferred tax asset relating to the deductible temporary difference arises from the initial recognition of an asset or liability in a transaction that is not a business combination and, at the time of the transaction, affects neither the accounting profit nor taxable net earnings (loss); and
- in respect of deductible temporary differences associated with investments in subsidiaries, associates and interests in joint arrangements, deferred tax assets are recognized only to the extent that it is probable that the temporary differences will reverse in the foreseeable future and taxable profit will be available against which the temporary differences can be utilized.

The carrying amount of deferred tax assets is reviewed at each reporting date and reduced to the extent that it is no longer probable that sufficient taxable profit will be available to allow all or part of the deferred tax asset to be utilized. Unrecognized deferred tax assets are reassessed at each reporting date and are recognized to the extent that it has become probable that future taxable profits will allow the deferred tax asset to be recovered.

Deferred tax assets and liabilities are measured at the tax rates that are expected to apply in the year when the asset is realized, or the liability is settled, based on tax rates (and tax laws) that have been enacted or substantively enacted at the reporting date.

Deferred tax relating to items recognized outside net earnings (loss) are recognized in correlation to the underlying transaction either in other comprehensive income (loss) or directly in equity.

Deferred tax assets and deferred tax liabilities are offset if a legally enforceable right exists to offset current tax assets against current income tax liabilities and the deferred taxes relate to the same taxable entity and the same taxation authority. Tax benefits acquired as part of a business combination, but not satisfying the criteria for separate recognition at that date, are recognized subsequently if new information about facts and circumstances change. The adjustment is either treated as a reduction to goodwill (as long as it does not exceed goodwill) if it is incurred during the measurement period or recognized in net earnings (loss).

Critical accounting judgments and key sources of estimation uncertainty

In preparing the Financial Statements of the Business, we are required to make estimates and assumptions that affect both the amount and timing of recording assets, liabilities, revenues and expenses since the determination of these items may be dependent on future events. Significant estimates made by management include: fair value of derivatives and other financial instruments, assessment of inventory adjustments, goodwill and other long-lived assets, income taxes, cushion gas migration, provisions for decommissioning obligations, gas storage obligations and recognizing lease liabilities and ROU assets. Management uses the most current information available and exercises careful judgment in making these estimates. Although management believes that these Financial Statements of the Business have been prepared within the limits of materiality and within the framework of its material accounting policy information summarized below, actual results could differ from these estimates.

The estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimate is revised if the revision affects only that period, or in the period of the revision and future periods if the revision affects both current and future periods.

The preparation of financial statements requires management to make critical judgments that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses that are not readily apparent from other sources, during the reporting period. These estimates and associated assumptions are based on historical experience and other factors that are considered to be relevant. Critical judgments made by management and utilized in the normal course of preparing the Financial Statements of the Business are outlined below.

a. Fair value of risk management assets and liabilities

The determination of the fair value of natural gas derivatives and other financial instrument contracts reflects the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date.

There are uncertainties in our methodology in the determination of fair value since it requires the Business to consider various factors, including over-the-counter quotations, customer attrition, costs of fulfillment, location differentials and closing interest and foreign exchange rates underlying the contracts. Although the fair value of risk management assets and liabilities may fluctuate for commodity risk contracts, such fluctuations are offset by equivalent changes in the value of our physical inventory. Our policy is for our inventory and purchases to be economically hedged, within small tolerances permitted under our risk management policy; therefore, we reduce our economic exposure to the risk of fluctuating commodity prices.

b. Inventory

The Business' inventory is natural gas injected into storage and held for resale. Inventory is valued at the lower of weighted average cost or net realizable value. Adjustments to the carrying value of inventory to net realizable value are recorded as an offset to optimization, net while costs to store the gas are recognized as operating expenses in the period the costs are incurred.

At the end of each reporting period, management determines whether an adjustment is required to reduce the carrying value of inventory to the lower of weighted average cost or net realizable value. This determination has built-in uncertainties since it requires judgment in both estimating fair market values in the periods in which our inventory can be sold and the volumes that can be sold in those periods.

c. Impairment of long-lived assets

The Business evaluates whether events or circumstances have occurred that indicate that long-lived assets may not be recoverable or that the remaining useful life may warrant revision. When such events or circumstances are present, management assesses the recoverability of long-lived assets by comparing the higher of (1) fair value less costs of disposal or (2) the value in use and eventual disposal from an asset or CGU to their carrying value. The projections used to calculate value in use consider the relevant operating plans and management's best estimate of the most probable set of conditions anticipated to prevail.

The Business' estimate for the impairment of long-lived assets contains uncertainties since it requires management to make a judgment on fair value, cost of disposals and expected value from the continued use of long-lived assets.

d. Income taxes

The Business is predominantly not a taxable entity in the United States. Income taxes are the responsibility of the equity holders and have accordingly not been recorded in the Financial Statements of the Business.

The Business has corporate subsidiaries, which are taxable corporations subject to Canadian federal and provincial income taxes, which are included in the Financial Statements of the Business.

The Business' accounting of its income taxes has inherent uncertainties since it requires an estimate of the timing of the realization of its tax assets and liabilities, including the allocation of income among different entities and tax jurisdiction, and also requires us to make assumptions on the estimated probabilities of utilization of deferred tax assets and on the determination of tax exposures associated with our tax filing positions.

e. Cushion gas effectiveness

Certain volumes of cushion gas are required for maintaining a minimum reservoir pressure. Owned cushion gas is considered a component of the facility and as such is not depreciated because of its indefinite useful life. Cushion gas is monitored to ensure that it provides effective pressure support. In the event that natural gas moves to another area of the reservoir where it does not provide effective pressure support or is withdrawn due to heat imbalances of native cushion volumes, charges against cushion gas are included in depreciation in an amount equal to the cost of estimated volumes that have migrated.

Cushion gas requirements and its effectiveness are estimated using pressure and volumetric data accumulated over many years of storage operation.

f. Provisions for decommissioning obligations

Decommissioning, abandonment, and site reclamation expenditures for storage facilities, wells and pipelines are expected to be incurred by the Business over many years into the future. Amounts recorded for decommissioning obligations and the associated accretion are calculated based on estimates of the extent and timing of decommissioning activities, future site remediation regulations and technologies, inflation, liability specific discount rates and related cash flows. The provision represents management's best estimate of the present value of the future abandonment and reclamation costs required. Actual abandonment and reclamation costs could be materially different from estimated amounts.

g. Recognition of lease liabilities and right of use assets

The Business has applied critical judgments in the application of lease accounting standards, including: i) identifying whether a contract, or part of a contract, includes a lease; ii) determining whether it is reasonably certain that lease extension or termination options will be exercised in determining the lease term; and iii) determining whether variable payments are in-substance fixed. We also use critical estimates in the application of lease accounting standards, including the estimation of lease term and determination of the appropriate rate to discount the lease payments. For leases that can be renewed into perpetuity at our option, a 60-year timeframe has been used as an estimate to measure the liability, ROU asset offset and undiscounted future cash outflows. Under the discount rates applicable to our leases, substantially all of the present value is contained within the first 60 years.

h. Gas storage obligations

Gas storage obligations are measured at fair value based on contracted volumes, estimated external forward price curves available at period end and an estimated discount rate applicable to the liabilities. Changes in forward pricing between period end and maturity of the derivative contracts could have a material impact on their carrying value.

Recently adopted accounting policies

We applied, for the first time, certain new standards applicable to the Business that became effective April 1, 2024. The impact of these amendments on the Business' accounting policies are as follows:

a. Amendments to IAS 1 — Classification of Liabilities as Current or Non-current ("IAS 1")

The amendments to IAS 1 affect only the presentation of liabilities as current or non-current in the combined consolidated statements of financial position and not the amount or timing of recognition of any asset, liability, income or expenses, or the information disclosed about those items. The amendments clarify that the classification of liabilities as current or non-current is based on rights that are in existence at the end of the reporting period, specify that classification is unaffected by expectations about whether the Business will exercise its right to defer settlement of a liability, explain that rights are in existence if covenants with which an entity is required to comply on or before the end of the reporting period are satisfied, and introduce a definition of 'settlement' to make clear that settlement refers to the transfer to the counterparty of cash, equity instruments, other assets or services. The amendments were applied retrospectively on April 1, 2024, and did not have a material impact on the financial position of the Business.

b. Amendments to IAS 12 — International Tax Reform — Pillar Two Model Rules

The Business operates in the United States as well as Canada, which has enacted new legislation to implement the global minimum top-up tax, effective from January 1, 2024. We have applied a temporary mandatory relief from recognizing and disclosing deferred taxes in connection with the global minimum top-up tax and will account for it as a current tax when it is incurred. There is no material current tax impact for the fiscal year ended March 31, 2025. The global minimum top-up tax is not anticipated to have a significant impact on the financial position of the Business.

Future accounting policies

IFRS 18 — Presentation and Disclosure in Financial Statements ("IFRS 18")

In April 2024, the IASB issued IFRS 18, Presentation and Disclosure of Financial Statements. IFRS 18 is effective for periods beginning on or after January 1, 2027, with early adoption permitted. IFRS 18 is expected to improve the quality of financial reporting by requiring defined subtotals in the statement of profit or loss, requiring disclosure about management defined performance measures, and adding new principles for aggregation and disaggregation of information. The Business is in the process of determining the impact of the amendments on the Financial Statements of the Business.

Amendments to IFRS 9 Financial Instruments and IFRS 7 Financial Instruments: Disclosures

On May 30, 2024, the IASB issued targeted amendments to IFRS 9, "Financial Instruments", and IFRS 7, "Financial Instruments: Disclosures". The amendments include new requirements not only for financial institutions but also for corporate entities which include clarifying the date of recognition and derecognition of some financial assets and liabilities, with a new exception for some financial liabilities settled through an electronic cash transfer system. These new requirements will apply from January 1, 2026, with early application permitted. The Business is in the process of determining the impact of the amendments on the Financial Statements of the Business.

4. Disposition of Businesses

On April 1 and April 3, 2023, the Business sold its interests in Salt Plains and Tres Holdings, respectively. Tres Holdings was accounted for using the equity method prior to its sale. The net proceeds from these transactions were $35.2 million and $175.4 million, respectively, after adjustments for working capital and other like items and after deducting transaction costs. Including transaction costs, we recognized a loss of $0.8 million from the sale of Salt Plains and a gain of $115.5 million from the sale of our investment in Tres Holdings. Cash received from the sales were distributed to Brookfield and its affiliates in April 2023. The Salt Plains storage facility in Oklahoma, which was wholly owned by Swan OpCo, was a facility with 13 Bcf of working gas capacity, while our investment in Tres Holdings represented a 49.99% membership interest in the Tres Palacios facility in Texas, a facility with 34 Bcf of working gas capacity.

5. Property, Plant and Equipment

Property, plant and equipment is comprised of the following:

Cost	Cushion gas	Pipelines and interconnects	Wells	Land and storage formations	Facilities and other	Total
Balance, April 1, 2023	$167.6	$150.2	$294.4	$101.3	$410.2	$1,123.7
Additions	1.5	1.4	7.1	—	5.0	15.0
Changes in decommissioning obligations – Note 11	—	—	1.5	—	—	1.5
Remeasurements of leases – Note 8	—	—	—	—	0.1	0.1
Migration/disposals	(3.5)	—	(3.1)	—	(1.6)	(8.2)
Foreign currency translation adjustment	—	—	—	0.1	(0.1)	—
Balance, March 31, 2024	165.6	151.6	299.9	101.4	413.6	1,132.1
Additions	8.0	1.3	25.3	—	6.1	40.7
Changes in decommissioning obligations – Note 11	—	—	—	—	—	—
Lease additions and remeasurements – Note 8	—	—	—	1.2	—	1.2
Migration/disposals	(3.2)	(0.3)	(0.7)	(1.2)	(1.3)	(6.7)
Foreign currency translation adjustment	(1.0)	(0.1)	(1.2)	(0.3)	(3.3)	(5.9)
Balance, March 31, 2025	**$169.4**	**$152.5**	**$323.3**	**$101.1**	**$415.1**	**$1,161.4**

Accumulated depreciation	Cushion gas	Pipelines and interconnects	Wells	Land and storage formations	Facilities and other	Total
Balance, April 1, 2023	$ —	$(30.7)	$(65.2)	$(12.7)	$(115.4)	$(224.0)
Depreciation expense	—	(4.2)	(8.4)	(3.2)	(14.7)	(30.5)
Disposals	—	—	2.5	—	1.4	3.9
Foreign currency translation adjustment	—	—	—	—	—	—
Balance, March 31, 2024	—	(34.9)	(71.1)	(15.9)	(128.7)	(250.6)
Depreciation expense	—	(4.3)	(7.7)	(3.2)	(14.7)	(29.9)
Disposals	—	0.1	0.2	1.2	0.7	2.2
Foreign currency translation adjustment	—	—	0.4	—	1.1	1.5
Balance, March 31, 2025	**$ —**	**$(39.1)**	**$(78.2)**	**$(17.9)**	**$(141.6)**	**$(276.8)**

Net book value	Cushion gas	Pipelines and interconnects	Wells	Land and storage formations	Facilities and other	Total
Balance, March 31, 2024	$165.6	$116.7	$228.8	$85.5	$284.9	$881.5
Balance, March 31, 2025	**$169.4**	**$113.4**	**$245.1**	**$83.2**	**$273.5**	**$884.6**

Depreciation expense for the year ended March 31, 2025 includes $3.2 million (March 31, 2024 — $3.5 million) related to cushion gas migration.

6. Goodwill

Goodwill is primarily attributable to the deferred income tax liability that arose from the acquisition by Brookfield and its institutional partners of Swan OpCo's outstanding units. The inclusion of this liability in the net book value of Swan OpCo gave rise to goodwill of $117.2 million.

For the purpose of impairment testing, all of the Business' recorded goodwill is allocated to AECO, one of our gas storage facilities in Alberta, Canada, as the CGU at which the goodwill is monitored for internal management purposes. We performed our annual test for goodwill impairment at March 31, 2025 and March 31, 2024, in accordance with our policy described in Note 3.

The recoverable amount for AECO as a CGU was determined based on a value in use calculation. Value in use was calculated by discounting future cash flow projections that are based on AECO's internal forecast. AECO's projected cash flows were estimated for a period of five years and then a terminal multiple was applied. In arriving at our forecasts, we considered past experience, economic trends, such as inflation, as well as industry and market trends.

The discount rate used in the calculation of value in use represents a weighted average cost of capital ("WACC"). The WACC is an estimate of the overall required rate of return on an investment for both debt and equity owners and serves as the basis for developing an appropriate discount rate. Determination of the WACC requires separate analysis of the cost of equity and debt and considers a risk premium based on an assessment of risks related to the projected cash flows. The discount rate used to calculate AECO's value in use at March 31, 2025 was 11.8% (March 31, 2024 — 12.6%).

Based on our assessment, we assessed the recoverable amount of goodwill and determined that goodwill was not impaired. A decrease of 10% in the operating cashflows and the increase of the discount rate of 5%, with all other assumptions held constant, would not cause the recoverable amount of the CGU to fall below its carrying amount.

7. Debt

The Business' debt consisted of the following:

	As at March 31,	
	2025	2024
Asset Backed Loan	**$ —**	$ —
Warwick Credit Facility	**13.6**	18.3
Term Loan due 2026	**—**	450.0
Term Loan due 2031	**1,246.8**	—
Total principal amount of debt	**1,260.4**	468.3
Less:		
Portion classified as current, net	**(25.8)**	—
Unamortized discount and deferred financing costs	**(26.5)**	(3.6)
Total long-term debt, net	**$1,208.1**	$464.7

a) Asset Backed Loan

Rockpoint Gas Storage LLC, Rockpoint Gas Storage Partners LP, and AECO Gas Storage Partnership have available a senior secured asset-backed revolving credit facility (the "Asset Backed Loan" or the "ABL Facility") consisting of a U.S. revolving credit facility and a Canadian revolving credit facility of $125.0 million each, which matures on August 29, 2029 (or, if earlier, a springing maturity date 91 days prior to the maturity of the Term Loan due 2031).

During fiscal year 2025, we made an amendment to the agreement governing the ABL Facility (the "ABL Credit Agreement") that extended the term to August 29, 2029 and included an option to increase the aggregate facilities size by $100.0 million, subject to identifying lenders to provide such incremental commitments.

Effective May 29, 2024, Canadian dollar denominated drawings of the ABL Facility transitioned from loans based on bankers' acceptances to loans based on the Canadian Overnight Repo Rate Average ("CORRA"). The ABL Facility bears interest at a floating rate, which (1) in the case of U.S. dollar loans, can be either the Secured Overnight Financing Rate ("SOFR") plus an applicable margin or, at our option, a base rate plus an applicable margin, and (2) in the case of Canadian dollar loans, can be either CORRA plus an applicable margin and a spread adjustment or, at our option, a prime rate plus an applicable margin.

Borrowings under the ABL Facility are limited to the lesser of the borrowing base and the committed capacity. The borrowing base is determined based on specified percentages of eligible assets, including, but not limited to, eligible cash equivalents, eligible accounts receivable, hedged eligible inventory and other eligible inventory and issued but unused letters of credit, minus the amount of any reserves and other priority claims (together, the "Borrowing Base Collateral"). As at March 31, 2025, the Borrowing Base Collateral was $325.2 million (March 31, 2024 — $222.9 million).

There were no borrowings outstanding under the ABL Facility at either March 31, 2025 or 2024. Letters of credit issued under the facility totaled $32.8 million (March 31, 2024 — $36.6 million). Of the total Borrowing Base Collateral available to us, $217.2 million was unutilized as of March 31, 2025 (March 31, 2024 — $186.3 million).

The ABL Credit Agreement requires the maintenance of a minimum fixed charge coverage ratio ("FCCR") of 1.1 to 1.0 tested at the end of each fiscal quarter at any time when excess liquidity under the Asset Backed Loan is less than the greater of 12.5% of the aggregate amount of availability under the Asset Backed Loan and $20.0 million for a period of at least 30 consecutive days. The ABL Credit Agreement provides that, upon the occurrence of certain events of default, our obligations thereunder may be accelerated and the lending commitments terminated. As of March 31, 2025, the Business' FCCR, as calculated pursuant to the ABL Credit Agreement, was 3.74 to 1.00 (March 31, 2024 — 5.16 to 1.00).

As of March 31, 2025, the Business was in compliance with all covenant requirements and there were no restrictions on our ability to borrow up to the total amount of liquidity available.

b) Warwick Credit Facility

As of March 31, 2025, the Business maintains a revolving operating line of credit ("Warwick Credit Facility") with a Canadian bank with a maximum limit of $26.1 million (March 31, 2024 — $27.7 million) or CAD $37.5 million (March 31, 2024 — CAD $37.5 million) in combined cash borrowings and letter of credit issuances. The Warwick Credit Facility was set to mature on May 31, 2025. On April 30, 2025, the Warwick Credit Facility was amended to extend the maturity date to May 31, 2026 (see Note 22).

On February 20, 2024, the Warwick Credit Facility was amended to replace references to bankers' acceptances with CORRA loans and rates. As a result of the amendment, the floating interest rate applied to Canadian dollar loans can now either be CORRA plus an applicable margin or, at WGS LP's option, a prime rate plus an applicable margin. Additionally, letter of credit participation fees reference CORRA loans, replacing the formerly referenced bankers' acceptances.

Draws on the Warwick Credit Facility bear an interest rate of term CORRA plus 0.30% and 0.32%, depending on whether the draws are one month or three month in duration, respectively.

As of March 31, 2025, we had drawn $13.6 million on the Warwick Credit Facility (March 31, 2024 — $18.3 million) and had an insignificant amount of letters of credit outstanding as of each year end. The Partnership's parent company, BAIF Warwick Storage L.P., and its General Partner (collectively "the Guarantors") guarantee the Warwick Credit Facility.

The Warwick Credit Facility requires the maintenance of a debt service coverage ratio of 1.2 to 1.0. The debt service coverage ratio is defined as the ratio of (i) EBITDA, defined under the terms of the agreement governing the Warwick Credit Facility to (ii) interest expense and scheduled principal payments for the immediately preceding 12-month period, measured quarterly. As of March 31, 2025, we had a debt service coverage ratio of 12.3 to 1.0 (March 31, 2024 — 6.1 to 1.0).

As of March 31, 2025, the Business was in compliance with all covenant requirements of the Warwick Credit Facility.

c) Term Loan due 2026

On August 17, 2023, Rockpoint Gas Storage Partners LP and its wholly owned subsidiary, Rockpoint Gas Storage Canada Ltd. (together, the "Rockpoint Debt Parties"), entered into a $450.0 million term loan (the "Term Loan due 2026"), due on August 17, 2026.

Rockpoint Gas Storage Partners LP had the option at any time to voluntarily prepay all or part of the Term Loan due 2026 without premium or penalty, plus accrued and unpaid interest. On September 18, 2024, proceeds from the new $1,250.0 million Term Loan due 2031 (as defined below) were used in part to settle the then outstanding $450.0 million principal amount of the Term Loan due 2026 and all remaining outstanding Brookfield-affiliated debt, including accrued interest, in the amount of $233.5 million. The remaining proceeds were used to fund a $455.2 million distribution to Brookfield and its institutional partners, an advance of $83.0 million to Brookfield as well as transaction fees related to the refinancing.

d) Term Loan due 2031

On September 18, 2024, the Rockpoint Debt Parties, entered into a senior secured term loan in the amount of \$1,250.0 million (the "Term Loan due 2031"), due on September 18, 2031. Proceeds from the Term Loan due 2031 were \$1,237.5 million, which is net of an original issue discount of \$12.5 million. Starting March 31, 2025, we were required to make principal repayments equal to 0.25% of the original principal borrowings at the end of each fiscal quarter, which may be reduced by any other mandatory or voluntary prepayments as applicable. As a result, as of March 31, 2025, \$12.2 million of the Term Loan due 2031 was classified as short-term debt, net of discount and deferred financing costs. For the year ended March 31, 2025, we repaid \$3.1 million towards the principal balance of the Term Loan due 2031.

Term Loan due 2031 borrowings are in the form of either SOFR loans and/or base rate loans. At the loan's inception, SOFR loans bore interest equal to the SOFR plus 3.50% and base rate loans bore interest at the bank's applicable base rate plus 2.50%. Effective March 19, 2025, as permitted under the Term Loan due 2031, the Business and its creditors amended the agreement governing the Term Loan due 2031 (the "Term Loan Credit Agreement") to reduce the interest rate for SOFR loans to the SOFR plus 3.00% and the interest rate for base rate loans to the bank's applicable base rate plus 2.00%. As of March 31, 2025, the Term Loan due 2031 bore a weighted average unhedged interest rate of 7.30%. In order to reduce our exposure to variable SOFR interest rates, we entered into interest rate swap contracts during the year ended March 31, 2025 (see Note 17 for more information).

The Term Loan Credit Agreement requires the maintenance of a ratio of Consolidated EBITDA, as defined in the Term Loan Credit Agreement, to the sum of certain interest charges and scheduled principal payments, (the "Debt Service Coverage Ratio") of at least 1.10 to 1.00, tested quarterly. As of March 31, 2025, the Debt Service Coverage Ratio was 6.47 to 1.00.

Commencing with the fiscal year ending March 31, 2026, the Rockpoint Debt Parties are required to calculate, on a trailing twelve-month basis, an excess cash flow prepayment amount ("ECF Prepayment Amount"). The amount is dependent on the outstanding principal borrowings of first lien debt, net of unrestricted cash, to Consolidated EBITDA as defined in the Term Loan Credit Agreement (the "First Lien Net Leverage Ratio"). If the First Lien Net Leverage Ratio is greater than 4.50 to 1.00 for such fiscal year, we are required, subject to certain other conditions as outlined below, to prepay the Term Loan due 2031 with 75.0% of the excess cash flow, with steps down to 50.0%, 25.0% and 0.0% of the excess cash flow if the First Lien Net Leverage Ratio is less than or equal to 4.50, 4.00 and 3.50 to 1.00, respectively, for such fiscal year. Such ECF Prepayment Amount is required to be paid and applied to the outstanding principal balance of the Term Loan due 2031 unless the ECF Prepayment Amount is less than the greater of \$63.1 million or 25.0% of Consolidated EBITDA, in which case no prepayment is required. The required ECF Prepayment Amount will be reduced by certain principal payments made during the applicable fiscal year. As of March 31, 2025, the calculated First Lien Net Leverage Ratio was 3.26 to 1.00.

The Business may make restricted payments, including distributions to owners and repayments of related party debt, to the extent allowable under the applicable negative covenants in the Term Loan Credit Agreement.

As of March 31, 2025, the Business was in compliance with all covenant requirements under the Term Loan Credit Agreement.

8. Right of Use Assets and Lease Liabilities

The substantial majority of the Business' leases are for land and storage formations used in our gas storage operations. We also lease office space for use as our head office and natural gas marketing activities. As of March 31, 2025, remaining defined lease terms ranged from 2 – 78 years (March 31, 2024 — 1 – 79 years), with a weighted average remaining term of approximately 28 years (March 31, 2024 — 29 years). Included in this lease portfolio are subsurface storage leases, which have remaining terms ranging from 24 – 30 years

(March 31, 2024 — 25 – 31 years) and a weighted average remaining term of 26 years (March 31, 2024 — 27 years). The weighted average incremental borrowing rate applicable to our leases is 10% (March 31, 2024 — 10%).

ROU assets within property, plant and equipment are as follows:

	As at March 31,	
	2025	**2024**
Property, plant and equipment, net, excluding ROU assets	**$800.7**	$794.8
ROU assets	**83.9**	86.7
Net carrying amount, end of period	**$884.6**	$881.5

The following table reconciles the ROU assets by class:

	Land and storage formations	Facilities and other	Total
Net carrying amount, April 1, 2024	$85.0	$ 1.7	$86.7
Lease additions	1.2	0.1	1.3
Depreciation expense	(3.2)	(0.5)	(3.7)
Lease remeasurements and modifications	—	(0.1)	(0.1)
Foreign currency translation adjustment	(0.3)	—	(0.3)
Net carrying amount, March 31, 2025	**$82.7**	**$ 1.2**	**$83.9**

	Land and storage formations	Facilities and other	Total
Net carrying amount, April 1, 2023	$88.1	$ 2.1	$90.2
Depreciation expense	(3.2)	(0.5)	(3.7)
Lease remeasurements and modifications	—	0.1	0.1
Foreign currency translation adjustment	0.1	—	0.1
Net carrying amount, March 31, 2024	$85.0	$ 1.7	$86.7

The Business' lease liabilities consist of the following:

	As at March 31,	
	2025	**2024**
Opening lease liabilities	**$106.8**	$105.2
Lease interest expense	**10.6**	10.4
Principal repayments	**(0.8)**	(0.6)
Interest payments	**(8.5)**	(8.2)
Foreign exchange and other	**(0.1)**	(0.1)
Lease additions, remeasurements and modifications	**0.8**	0.1
Total lease liabilities	**108.8**	106.8
Less:		
Portion classified as current	**(9.1)**	(8.6)
Long-term lease liabilities	**$ 99.7**	$ 98.2

Lease expenses recognized as related to variable leases, included in operating expenses on the Combined Consolidated Statements of Net Earnings and Comprehensive Earnings, totaled $6.5 million for the year ended March 31, 2025 (March 31, 2024 — $3.5 million), while expenses related to short-term and low-value leases were negligible for both years.

The undiscounted estimated future cash outflows in each fiscal year relating to lease liabilities are as follows:

For the fiscal years ending:	Lease Payments
2026	$ 9.6
2027	9.9
2028	9.6
2029	9.8
2030	10.1
2031 and thereafter	361.9
Total	$410.9

See Note 17 and Note 21 for additional information.

9. Trade Payables and Accrued Liabilities

The Business' trade payables and accrued liabilities consisted of the following:

	As at March 31,	
	2025	2024
Trade payables	**$ 2.7**	$ 0.2
Accrued gas purchases	**27.7**	20.9
Accrued interest, affiliated debt	**—**	8.9
Accrued interest, non-affiliated debt	**1.0**	5.6
Employee-related accruals	**10.3**	13.5
Other accrued liabilities, affiliated	**0.3**	12.9
Other accrued liabilities, non-affiliated	**17.5**	13.3
Total	**$59.5**	$75.3

10. Gas Storage Obligations

As of March 31, 2025 and 2024, WGS LP had obligations to deliver 8.0 Bcf of natural gas starting in fiscal year 2027 through fiscal year 2028. These gas storage obligations are hybrid financial instruments measured at fair value through profit or loss using the AECO forward pricing curve, which is the expected future price of natural gas at the Alberta Energy Company (AECO) hub, as determined by market participants, and then discounted using our estimated borrowing rate for a similar liability, which is 6.95% as of March 31, 2025 (March 31, 2024 — 6.95%). WGS LP has a practice of moving the delivery dates into the future through use of storage agreements with counterparties that offset delivery dates specified in previous agreements.

The following table reconciles WSG LP's gas storage obligations:

	As at March 31,	
	2025	**2024**
Balance, beginning of year	**$19.6**	$21.5
Unrealized gain on gas storage obligation	**(1.3)**	(1.8)
Foreign currency translation adjustment	**(0.9)**	(0.1)
Long-term gas storage obligation	**$17.4**	$19.6

11. Decommissioning Obligations

The Business' decommissioning obligations relate to the plugging and abandonment of its storage facilities and wells at the end of their estimated useful economic lives. At March 31, 2025, the estimated undiscounted cash flows required to settle our decommissioning obligations were approximately $258.2 million (March 31, 2024 — $267.0 million), calculated using an inflation rate of 2.5% per year in the short term and 2% per year thereafter (March 31, 2024 — 3.5% per year in the next two years and 2% per year thereafter). The estimated liability at March 31, 2025 was $5.2 million after discounting the estimated cash flows at a rate of 8.2% per year (March 31, 2024 — $7.0 million at 8.2% per year). At March 31, 2025, the expected timing of payment for settlement of the obligations was 55 years (March 31, 2024 — 56 years) aside from certain short-term well and other abandonments. The decrease in estimated undiscounted cash flows was caused primarily by a weaker Canadian dollar used to convert AECO's decommissioning obligations from Canadian to U.S. dollars compared to the prior year and a lower inflation rate used for short-term estimates for each entity in the current year. Offsetting this decrease was a $2.2 million increase in undiscounted decommissioning obligations related to new wells drilled at Wild Goose during the year.

	As at March 31,	
	2025	**2024**
Balance, beginning of the year	**$ 6.8**	$ 4.1
Accretion	**0.6**	0.3
Changes in estimate	**(0.1)**	1.5
Additions	**0.1**	—
Settlements	**(2.0)**	(0.2)
Other	**—**	1.1
Foreign currency translation adjustment	**(0.2)**	—
Total decommissioning obligations	**5.2**	6.8
Less:		
Portion classified as current	**(0.2)**	(1.8)
Balance, end of the year	**$ 5.0**	$ 5.0

12. Share Capital

Capital contributions

Capital contributions represent the sum of the individual share capital of the combined companies comprising the Business, which are indirectly owned by Brookfield and its institutional partners.

13. Revenues and Contract Assets and Liabilities

The following table summarizes the Business' fee for service revenue earned from contracts with customers, by geographic area:

	Fiscal Years Ended March 31,		
	2025	**2024**	**2023**
Take-or-pay contract revenue			
U.S.	**$163.3**	$138.6	$ 59.9
Canada	**21.7**	16.7	6.2
Short-term storage service revenue			
U.S.	**77.7**	83.8	93.9
Canada	**104.1**	53.4	35.8
Total fee for service revenue from contracts with customers	**$366.8**	$292.5	$195.8

Optimization, net consists of the following:

	Fiscal Years Ended March 31,		
	2025	**2024**	**2023**
Retail realized optimization	**$16.7**	$19.9	$ 13.4
Storage realized optimization	**39.9**	29.9	122.0
Realized optimization, net	**56.6**	49.8	135.4
Retail unrealized optimization (losses) gains	**(3.5)**	(3.6)	6.1
Storage unrealized optimization (losses) gains	**(4.6)**	9.9	8.4
Unrealized optimization (losses) gains, net	**(8.1)**	6.3	14.5
Inventory adjustments	**—**	—	(67.7)
	$48.5	$56.1	$ 82.2

As of March 31, 2025, the balance of trade and accrued receivables included $36.9 million (March 31, 2024 — $30.4 million) related to ToP and STS contracts with customers. In accordance with industry practice, the Business normally collects its contractual receivables on the 25th day following the month in which the revenue was earned.

As of March 31, 2025, we recorded deferred revenue of $1.2 million (March 31, 2024 — $0.6 million) related to contracts with customers.

The Business' inventory is valued at the lower of weighted average cost or net realizable value. During the year ended March 31, 2023, the forward prices of natural gas fell below the carrying cost of our inventories, and as such, inventories were adjusted by $67.7 million.

14. Expenses

Operating expenses consist of the following:

	Fiscal Years Ended March 31,		
	2025	2024	2023
Fuel and electricity	**$11.0**	$17.0	$26.7
Salaries and benefits	**9.9**	9.6	9.7
Property taxes	**7.6**	6.5	5.0
Land rental costs	**6.5**	3.4	3.3
Maintenance	**6.7**	7.0	7.0
General operating costs	**7.7**	7.6	6.6
Unrealized electricity contracts	**0.1**	2.1	(1.8)
Total operating	**$49.5**	$53.2	$56.5

For the year ended March 31, 2025, fuel and electricity contains a $0.6 million loss (March 31, 2024 — $1.6 million gain) from realized portions of electricity contracts (see Note 18).

General and administrative expenses consist of the following:

	Fiscal Years Ended March 31,		
	2025	2024	2023
Compensation costs	**$17.3**	$16.8	$15.7
General costs, including office and IT costs	**2.4**	2.3	2.3
Legal, audit, consulting and regulatory costs	**4.5**	4.4	4.2
Total general and administrative	**$24.2**	$23.5	$22.2

15. Financing Costs

Financing costs consist of the following:

	Fiscal Years Ended March 31,		
	2025	2024	2023
Term loan and senior notes interest	**$74.4**	$33.7	$21.7
Revolving credit facility interest	**4.1**	5.3	7.9
Deferred financing costs	**6.8**	3.3	4.8
Interest on affiliated loans	**8.6**	18.6	22.1
Interest on lease obligations	**10.6**	10.4	10.4
Other interest (income) expenses	**(4.7)**	5.1	1.8
Realized gains on interest rate swaps	**(3.8)**	(0.4)	—
Unrealized gains on interest rate swaps	**(2.9)**	—	—
Total finance costs	**$93.1**	$76.0	$68.7

16. Income Taxes

Total income tax (benefit) expense differed from the amounts computed by applying the tax rate to net earnings before income taxes as a result of the following:

	Fiscal Years Ended March 31,		
	2025	**2024**	**2023**
Earnings before income taxes	**$198.8**	$249.3	$47.1
Blended applicable tax rate	**21.1%**	21.0%	20.6%
Expected tax expense	**41.9**	52.4	9.7
Deferred gain on debt	**(24.5)**	(6.6)	0.8
Earnings of non-taxable entities	**(29.8)**	(49.9)	(8.4)
Canadian statutory tax rate differences	**1.2**	0.3	0.4
Change in Canadian statutory tax rates	**—**	—	(0.1)
Adjustments and assessments	**0.5**	(0.6)	0.3
Non-taxable income	**0.1**	(0.2)	(0.1)
Income tax (benefit) expense	**$ (10.6)**	$ (4.6)	$ 2.6

The other comprehensive loss for the year ended March 31, 2025 of $1.8 million (March 31, 2024 — nil) relates to foreign currency translation adjustments in respect to flow-through entities. As the flow-through entities are not subject to income tax, no income tax expense or benefit has been recorded in other comprehensive income.

As of March 31, 2025 and 2024, the Business' Canadian subsidiaries had accumulated non-capital losses of $46.6 million and $116.5 million, respectively, that can be carried forward and applied against future taxable income. These non-capital losses have resulted in deferred income tax assets of $10.6 million and $26.7 million as of March 31, 2025 and 2024, respectively. Of the total tax assets related to losses as of March 31, 2025, deferred income tax assets of $10.6 million and $6.3 million will expire at the end of 2034 with the remaining expiring thereafter.

Deferred income tax assets and liabilities reflect the tax effect of differences between the basis of assets and liabilities for book and tax purposes. The tax effect of temporary differences that give rise to significant components of the deferred income tax liabilities and assets are presented below:

	Balance, March 31, 2025	Deferred income tax recognized on the statement of net earnings	Balance, March 31, 2024
Deferred income tax assets:			
Non-capital loss carry forwards	**$10.6**	$(16.1)	$ 26.7
Risk management liabilities	**9.0**	(5.0)	14.0
Property, plant and equipment	**1.1**	—	1.1
Deferred financing costs	**—**	(0.1)	0.1
Other	**1.2**	(0.3)	1.5
	21.9	(21.5)	43.4
Valuation allowance	**(0.3)**	(0.3)	—
Total deferred income tax assets	**$21.6**	$(21.8)	$ 43.4
Deferred income tax liabilities:			
Property, plant and equipment	**$75.9**	$ (2.5)	$ 78.4
Risk management assets	**10.3**	(6.0)	16.3
Deferred gain on debt	**—**	(24.5)	24.5
Deferred financing costs	**0.1**	0.1	—
Other	**0.3**	(0.1)	0.4
Total deferred income tax liabilities	**86.6**	(33.0)	119.6
Net deferred income tax liability	**$65.0**	$(11.2)	$ 76.2

	Balance, March 31, 2024	Deferred income tax recognized on the statement of net earnings	Balance, March 31, 2023
Deferred income tax assets:			
Non-capital loss carry forwards	$ 26.7	$(6.8)	$ 33.5
Risk management liabilities	14.0	1.4	12.6
Property, plant and equipment	1.1	(0.1)	1.2
Deferred financing costs	0.1	—	0.1
Other	1.5	0.2	1.3
Total deferred income tax assets	$ 43.4	$(5.3)	$ 48.7
Deferred income tax liabilities:			
Property, plant and equipment	$ 78.4	$(2.3)	$ 80.7
Risk management assets	16.3	(0.6)	16.9
Deferred gain on debt	24.5	(6.6)	31.1
Other	0.4	—	0.4
Total deferred income tax liabilities	119.6	(9.5)	129.1
Net deferred income tax liability	$ 76.2	$(4.2)	$ 80.4

The Business engages in ongoing discussions with tax authorities regarding the resolution of tax matters in various jurisdictions. Both the outcome of these tax matters and the timing of the resolution and/or closure of the tax audits are highly uncertain. The Business is subject to income tax examinations for the fiscal years ended 2018 through 2024 in most jurisdictions in which it operates.

17. Risk Management Activities and Financial Instruments

Risk Management Overview

The Business has exposure to commodity price, environmental compliance price, counterparty credit, interest rate, liquidity and foreign currency risk. Risk management activities are tailored to the risk they are designed to mitigate.

a. Commodity Price Risk

As a result of our natural gas inventory and any future requirements to purchase cushion gas, the Business is exposed to risks associated with changes in price when buying and selling natural gas across future time periods. To manage these risks and reduce the variability of cash flows, the Business utilizes a combination of financial and physical derivative contracts, including forwards, futures and swap contracts. The use of these contracts is subject to our risk management policies. These contracts have not been treated as hedges for financial reporting purposes and therefore changes in fair value are recorded directly in the statement of net earnings (see Note 18).

Forward contracts and futures contracts are agreements to purchase or sell a specific financial instrument or quantity of natural gas at a specified price and date in the future. We enter into forward contracts and futures contracts to mitigate the impact of changes in natural gas prices. In addition to cash settlement, exchange traded futures may also be settled by the physical delivery of natural gas. Swap contracts are agreements between two parties to exchange streams of payments over time according to specified terms. Swap contracts require receipt of payment for the notional quantity of the commodity based on the difference between a fixed price and the market price on the settlement date. We enter into commodity swaps to mitigate the impact of changes in natural gas prices.

To limit our exposure to changes in natural gas prices, we enter into purchases and sales of natural gas inventory and concurrently match the volumes in these transactions with offsetting derivative contracts. To comply with internal risk management policies, the Business is required to limit exposure of unmatched volumes of proprietary current natural gas inventory to an aggregate overall limit of 8.0 million decatherms ("Dth"). At March 31, 2025 and 2024, natural gas inventory of 12.4 million Dth and 37.4 million Dth was offset with financial contracts, representing approximately 100% and 97% of total inventory, respectively. For fiscal 2025, the 100% economic hedge meant that all changes in the value of inventory were offset by corresponding changes in the fair value of our contracts. In fiscal 2024, a $1.00 price increase in the price of natural gas would result in a mismatch of $1.1 million due to the Business only economically hedging 97% of total inventory.

As of March 31, 2025 and 2024, the volumes of inventories that were economically hedged using each type of contract were (in million Dth):

	As at March 31,	
	2025	**2024**
Forwards	**0.2**	(13.6)
Futures	**12.2**	51.0
	12.4	37.4

The Business uses electricity to run compressors used to inject and withdraw natural gas and is exposed to risks associated with changes in the price of electricity. To manage these risks and reduce the variability of cash flows, we utilize swap contracts. These contracts have not been treated as hedges for financial reporting purposes and therefore changes in fair value are recorded directly in the statement of net earnings (see Note 18).

At March 31, 2025, future electricity consumption of 94,201 megawatt hours ("MWh") for the following 24 months (March 31, 2024 — 32,746 MWh for the following 12 months) was fully offset with swap contracts at a weighted average hedged price of $33.78/MWh (March 31, 2024 — $55.35/MWh).

b. Price Risk Associated with Compliance with Environmental Regulations

Two of the Business' operating facilities, the Lodi and Wild Goose storage facilities, are located in California. In 2006, California adopted AB 32, the Global Warming Solutions Act of 2006, which requires the state to reduce anthropogenic greenhouse gas ("GHG") emissions by 85% below 1990 levels and achieve carbon neutrality by 2045. It also established a mandatory emissions reporting program. AB 32 is implemented by the California Air Resources Board ("CARB"). The CARB approved a GHG cap-and-trade program in December 2010, which took effect in 2012.

Under the program, entities are subject to compliance obligations if they exceed certain CARB-defined emission thresholds. During each year of the program, the CARB issues emission allowances (i.e., the rights to emit GHGs) equal to the amount of GHG emissions allowed for that year. Emitters can obtain allowances from the CARB at quarterly auctions or from third parties or exchanges. Emitters may also satisfy a portion of their compliance obligation through the purchase of offset credits; e.g., credits for GHG reductions achieved by third parties (such as landowners, livestock owners, and farmers) that occur outside the industry sectors covered under the cap through CARB-qualified offset projects such as reforestation or biomass projects. The Business exceeded its allowable emissions threshold for its Wild Goose facility during fiscal 2016 and as such is subject to ongoing compliance obligations whereby it must purchase allowances or offset credits. As of March 31, 2025, we had $0.2 million worth of prepaid emission allowances and offset credits and thus were not exposed to risks associated with changes in the price of credits for GHG reductions for past emissions (March 31, 2024 — $0.5 million accrued emission allowances and offset credits).

c. Counterparty Credit Risk

The Business is exposed to counterparty credit risk on its trade and accrued accounts receivable and risk management assets. Counterparty credit risk is the risk of financial loss to us if a customer fails to perform its contractual obligations. We engage in transactions for the purchase and sale of products and services primarily with major companies in the energy industry and with industrial, commercial, residential and municipal energy consumers.

The Business analyzes the financial condition of storage and significant retail counterparties prior to entering into an agreement. Credit limits are established and monitored on an ongoing basis. Management believes, based on its credit policies, that our financial position, results of operations and cash flows will not be materially affected as a result of non-performance by any single counterparty. Credit risk is assessed prior to transacting with any counterparty and each storage or significant retail counterparty is required to maintain an investment grade rating, provide a parental guarantee from an investment grade parent, or provide an alternative method of financial assurance (letter of credit, cash, etc.) to support proposed transactions. In addition, our contracts contain provisions that permit us to take title to a customer's inventory should the customer's account remain unpaid for an extended period of time. For the fiscal year ended March 31, 2025, two customers made up 18% and 15% each of total fee for service revenue (March 31, 2024 — two customers, 17% and 14% each). Physical gas sales included within optimization, net were completed primarily through a fully collateralized physical natural gas clearing and settlement facility that requires counterparties to post margin deposits equal to 125% of their net position, which reduces the risk of default.

As at March 31, 2025, the Business had no allowances for doubtful accounts recorded (March 31, 2024 — $0.2 million) and bad debts expense of $0.1 million (March 31, 2024 — $0.2 million).

Included in the fair value of energy contracts at March 31, 2025 are one to five-year contracts to sell natural gas to customers in retail markets. We recorded a reduction in the fair value of these contracts of $0.7 million at March 31, 2025 (March 31, 2024 — $1.3 million), representing an estimate of the expected credit exposure from these counterparties over their contractual lives.

Exchange traded futures comprise approximately 41% of our commodity risk management assets at March 31, 2025 (March 31, 2024 — 6%). Exchange traded contracts have minimal credit exposure as the exchanges guarantee that contracts are margined on a daily basis. In the event of any default, our account on the exchange would be absorbed by other clearing members. Because every member posts an initial margin, the exchange can protect the exchange members if or when a clearing member defaults.

d. Interest Rate Risk

The Business assesses interest rate risk by continually identifying and monitoring changes in interest rate exposures that may adversely impact expected future cash flows. The Asset Backed Loan, Warwick Credit Facility and Term Loan due 2031 are exposed to variable interest rate risks at March 31, 2025.

To reduce its exposure to variable SOFR interest rates related to its Term Loan due 2031, the Business entered into interest rate swap contracts that are based on an index of three-month SOFR loans. The contracts took effect starting in November 2024. In conjunction with the March 19, 2025 Term Loan Credit Agreement interest rate amendments (see Note 7d), effective March 2025, the interest rate swap contracts were also amended. The amended contracts locked in a blended 3.66% SOFR interest rate, effectively a 6.66% all-in rate for SOFR denominated loans, on the hedged principal borrowings that are drawn using three-month SOFR terms. Prior to the amendment, these contracts locked in a blended 3.71% SOFR interest rate, effectively a 7.21% all-in rate. These contracts hedge 100.0% of the principal borrowings from November 2024 to September 2025, decreasing to 72.8%, or $900.0 million, from October 2025 to September 2026. Thereafter, the full principal balance is unhedged, which will expose us to interest rate fluctuations unless the debt is re-hedged. During the fiscal year ended March 31, 2024, we had similar contracts to reduce our exposure to variable SOFR interest rates related to the Term Loan due 2026, which was repaid during fiscal 2025. The interest rate swap contracts represent derivative products and have been accounted for at fair value through profit and loss (see Note 18).

Interest rate risk on the Asset Backed Loan and Warwick Credit Facility vary depending on drawings outstanding at a point in time. The Business minimizes its exposure to variable interest rates by ensuring excess available cash is applied to the reduce revolver drawings in a timely manner and by using lower cost letters of credit, when possible, rather than drawing cash. As there were no balances outstanding on the Asset Backed Loan as of March 31, 2025 and 2024, we were not exposed to interest rate risk as of those dates.

The following table, which demonstrates the sensitivity to changes in interest rates, with all other variables held constant, on financial instruments exposed to variable interest rates on the net earnings at the end of the reporting period.

	Fiscal Years Ended March 31,	
	2025	**2024**
SOFR – 100 basis points increase	**$11.7**	$ 7.1
CORRA – 100 basis points increase	**(0.1)**	(0.1)

e. Liquidity Risk

Liquidity risk is the risk that the Business will not be able to meet its financial obligations as they become due. Our approach to managing liquidity risk is to contract a substantial part of our facilities to generate constant cash flow and to ensure that we always have sufficient cash and credit facilities to meet our obligations when due, under both normal and stressed conditions, without incurring unacceptable losses or damage to its reputation. See Note 7 for details of the Business' debt.

In addition to the amounts included in trade payables and accrued liabilities, the following table summarizes by period the payments due for our estimated contractual obligations as of March 31, 2025:

		Payment due by period				
	Notes	Total	Less than 1 year	1 – 3 years	3 – 5 years	More than 5 years
Debt obligations	7	$1,260.4	$ 26.1	$ 25.0	$ 25.0	$1,184.3
Interest on debt obligations		516.1	83.1	158.5	158.0	116.5
Lease obligations	8	410.9	9.6	19.5	19.9	361.9
Gas storage obligations	10	19.7	—	19.7	—	—
Decommissioning obligations	11	258.2	0.2	1.2	0.1	256.7
Purchase obligations	20	144.8	98.1	46.7	—	—
Other(1)		78.5	68.2	9.0	1.0	0.3
Total		$2,688.6	$285.3	$279.6	$204.0	$1,919.7

(1) Other includes trade payables and accrued liabilities not included in separate categories above, committed costs of gas storage services, compensation obligations and firm storage transportation costs.

f. Foreign Currency Risk

Foreign currency risk is created by fluctuations in foreign exchange rates. As the Business' Canadian operations and subsidiaries conduct their activities in Canadian dollars, earnings and cash flows are subject to currency fluctuations. The performance of the Canadian dollar relative to the U.S. dollar could positively or negatively affect earnings. We are exposed to cash flow risk to the extent that Canadian currency outflows do not match inflows. We periodically enter into currency swaps to mitigate the impact of changes in foreign exchange rates. The net notional value of currency swaps as at March 31, 2025 was $12.5 million (March 31, 2024 — $19.0 million). These contracts expire on various dates between April 2025 and May 2025. We did not elect hedge accounting treatment, therefore, changes in fair value are recorded directly into earnings (see Note 18).

The following table demonstrates the sensitivity to changes in exchange rates, with all other variables held constant, of financial instruments denominated in CAD dollars and of net earnings and other comprehensive income at the end of the reporting period.

	Fiscal Years Ended March 31,	
	2025	2024
CAD – 10% increase	**$3.8**	$2.5
CAD – 10% increase (other comprehensive income)	**2.5**	3.1

g. Capital Management

The Business' objectives when managing its capital structure are to maintain financial flexibility so as to preserve our ability to meet our financial obligations and to finance internally generated growth capital requirements.

We manage our capital structure and make adjustments to it in light of changes in economic conditions and the risk characteristics of the underlying assets. The Business considers its capital structure as owners' capital, interest-bearing debt, including the ABL Facility and Warwick Credit Facility, (together the "Existing Revolving Credit Facilities"), Term Loan due 2031, lease liabilities, and working capital (see Notes 7, 8, 21). To maintain or adjust the capital structure, we may modify distributions to owners, refinance debt, or issue new debt.

Financing decisions are made by management based on forecasts of the expected timing and level of capital and operating expenditure required to meet commitments and development plans. Factors considered when determining whether to issue new debt or to modify distributions include the amount of financing required, the availability of financial resources, the terms on which financing is available and consideration of the balance between shareholder value creation and prudent financial risk management. The Business has complied with all externally imposed capital requirements as at March 31, 2025 (see Note 7).

18. Fair Value Measurements

The following table shows the fair values of the Business' risk management assets and liabilities:

Balance, March 31, 2025	Energy Contracts	Currency Contracts	Interest Rate Contracts	Total
Short-term risk management assets	$ 15.6	$0.1	$ 3.8	**$ 19.5**
Long-term risk management assets	9.3	—	—	**9.3**
Short-term risk management liabilities	(13.8)	—	(0.1)	**(13.9)**
Long-term risk management liabilities	(4.9)	—	(0.8)	**(5.7)**
	$ 6.2	$0.1	$ 2.9	**$ 9.2**

Balance, March 31, 2024	Energy Contracts	Currency Contracts	Interest Rate Contracts	Total
Short-term risk management assets	$ 27.4	$0.1	$ 2.0	$ 29.5
Long-term risk management assets	12.6	—	—	12.6
Short-term risk management liabilities	(16.7)	—	—	(16.7)
Long-term risk management liabilities	(8.9)	—	(2.0)	(10.9)
	$ 14.4	$0.1	$ —	$ 14.5

Information about the Business' risk management assets and liabilities that had netting or rights of offset arrangements are as follows:

Balance, March 31, 2025	Gross Amounts Recognized	Gross Amounts Offset in the Statement of Financial Position	Net Amounts Presented in the Statement of Financial Position	Margin Deposits not Offset in the Statement of Financial Position	Net Amounts
Assets					
Commodity derivatives	**$67.6**	$(42.7)	$24.9	$(10.1)	$14.8
Currency derivatives	**0.1**	—	0.1	—	0.1
Interest rate swaps	**3.8**	—	3.8	—	3.8
Total assets	**71.5**	(42.7)	28.8	(10.1)	18.7
Liabilities					
Commodity derivatives	**61.4**	(42.7)	18.7	(2.2)	16.5
Currency derivatives	**—**	—	—	—	—
Interest rate swaps	**0.9**	—	0.9	—	0.9
Total liabilities	**62.3**	(42.7)	19.6	(2.2)	17.4
Net	**$ 9.2**	$ —	$ 9.2	$ (7.9)	$ 1.3

Balance, March 31, 2024	Gross Amounts Recognized	Gross Amounts Offset in the Statement of Financial Position	Net Amounts Presented in the Statement of Financial Position	Margin Deposits not Offset in the Statement of Financial Position	Net Amounts
Assets					
Commodity derivatives	**$72.2**	$(32.2)	$40.0	$ (2.4)	$37.6
Currency derivatives	**0.1**	—	0.1	—	0.1
Interest rate swaps	**2.0**	—	2.0	—	2.0
Total assets	**74.3**	(32.2)	42.1	(2.4)	39.7
Liabilities					
Commodity derivatives	**57.8**	(32.2)	25.6	(15.9)	9.7
Currency derivatives	**—**	—	—	—	—
Interest rate swaps	**2.0**	—	2.0	—	2.0
Total liabilities	**59.8**	(32.2)	27.6	(15.9)	11.7
Net	**$14.5**	$ —	$14.5	$ 13.5	$28.0

The following amounts represent the Business' expected realization into earnings for derivative instruments, based upon the fair value of these derivatives as of March 31, 2025:

Fiscal Year Ending March 31,	Energy Contracts	Currency Contracts	Interest Rate Contracts	Total
2026	$1.8	$0.1	$ 3.7	$5.6
2027	2.9	—	(0.8)	2.1
2028	0.8	—	—	0.8
2029	0.5	—	—	0.5
2030 and thereafter	0.2	—	—	0.2
Total	$6.2	$0.1	$ 2.9	$9.2

Net realized and unrealized gains (losses) from the settlement of risk management contracts are summarized below as are contracts elected to be accounted for through fair value through profit and loss ("FVTPL") and contracts that are accounted for through FVTPL on a mandatory basis:

	Fiscal Years Ended March 31,			
	2025	2024	2023	Classification
Elected:				
Energy contracts				
Realized	**$ 37.0**	$54.9	$ (24.0)	Optimization, net
Unrealized	**(29.2)**	8.0	(69.3)	Optimization, net
Mandatory:				
Energy contracts				
Realized	**18.5**	(5.8)	158.9	Optimization, net
Unrealized	**21.1**	(1.9)	84.1	Optimization, net
Gas storage obligations				
Unrealized	**1.3**	1.8	(0.6)	Gains (losses) on gas storage obligations, net
Electricity contracts				
Realized	**(0.6)**	1.6	3.4	Operating expenses
Unrealized	**(0.1)**	(2.1)	1.8	Operating expenses
Interest rate swaps				
Realized	**3.8**	0.4	—	Financing costs
Unrealized	**2.9**	—	—	Financing costs
Currency contracts				
Realized	**1.1**	0.7	0.5	Optimization, net
Unrealized	**—**	0.2	(0.3)	Optimization, net
Total	**$ 55.8**	$57.8	$154.5	

The carrying amount of cash and cash equivalents, margin deposits, amounts due to affiliates, trade and accrued receivables and trade payables and accrued liabilities reported on the combined consolidated statements of financial position approximate fair value.

The Business' assets and liabilities that were accounted for or disclosed at fair value on a recurring and non-recurring basis are as follows:

Balance, March 31, 2025	Level 1	Level 2	Level 3	Total
Assets				
Commodity derivatives	$ —	$ 24.9	$ —	$ 24.9
Currency derivatives	—	0.1	—	0.1
Interest rate swaps	—	3.8	—	3.8
Total assets	$ —	$ 28.8	$ —	$ 28.8
Liabilities				
Commodity derivatives	$ —	$ 18.7	$ —	$ 18.7
Currency derivatives	—	—	—	—
Interest rate swaps	—	0.9	—	0.9
Gas storage obligations	—	17.4	—	17.4
Short-term debt	—	26.1	—	26.1
Long-term debt	—	1,229.7	—	1,229.7
Total liabilities	$ —	$1,292.8	$ —	$1,292.8

Balance, March 31, 2024	Level 1	Level 2	Level 3	Total
Assets				
Commodity derivatives	$ —	$ 40.0	$ —	$ 40.0
Currency derivatives	—	0.1	—	0.1
Interest rate swaps	—	2.0	—	2.0
Total assets	$ —	$ 42.1	$ —	$ 42.1
Liabilities				
Commodity derivatives	$ —	$ 25.6	$ —	$ 25.6
Currency derivatives	—	—	—	—
Interest rate swaps	—	2.0	—	2.0
Gas storage obligations	—	19.6	—	19.6
Short-term debt	—	—	—	—
Long-term debt	—	468.3	—	468.3
Total liabilities	$ —	$515.5	$ —	$515.5

The Business' financial assets and liabilities, recorded at fair value on a recurring basis, have been categorized as Level 2. The determination of the fair value of assets and liabilities for Level 2 valuations is generally based on a market approach. The key inputs used in our valuation models include transaction-specific details such as notional volumes, contract prices, and contract terms, as well as forward market prices and basis differentials for natural gas obtained from third-party service providers (typically the New York Mercantile Exchange, or NYMEX). In valuing our interest rate swaps, we used forward market data for three-month SOFR loans obtained from third-party service providers. There were no changes in our approach to determining fair value and there were no transfers out of Level 2 during the year ended March 31, 2025.

The fair value of debt is the estimated amount the Business would have to pay to transfer its debt, including any premium or discount attributable to the difference between the stated interest rate and market rate of interest at the period-end date. To value the Term Loan due 2031, we used bid and yield information provided by a third-party financial services company. Interest rates on the Asset Backed Loan and the Warwick Credit Facility are variable and therefore the fair values are approximated by the principal balances outstanding.

19. Related Party Transactions

We are subsidiaries of Brookfield and the Business had transactions and related balances with entities classified as related parties as follows:

	As at March 31,	
	2025	**2024**
Included in trade payables and accrued liabilities:		
Accrued interest payable	**$ —**	$ 8.9
Other accrued costs, including electricity costs	**0.3**	12.9
	0.3	21.8
Included in due to affiliates		
8.25% Promissory note due 2026	**—**	216.0
8.40% Promissory note due 2026	**—**	—
Total amounts owing to related parties	**$ 0.3**	$237.8
Included in due from affiliates	**$83.0**	$ —

	Fiscal Years Ended March 31,		
	2025	**2024**	**2023**
Interest on affiliated debt (financing costs)	**$ 8.6**	$18.6	$22.1
Electricity (operating)	**2.4**	3.2	3.7
General operating (operating)	**—**	0.1	0.1
Total transactions with related parties	**$11.0**	$21.9	$25.9

a. *Promissory Notes*

During the fiscal years ended March 31, 2025 and 2024, the Business had an outstanding promissory note due to affiliates of Brookfield Infrastructure bearing interest at 8.25%. This note was scheduled to mature on October 1, 2026 (the "8.25% Promissory Note due 2026"). We also had a promissory note outstanding with an affiliate of Brookfield Infrastructure for a portion of the year ended March 31, 2024, bearing an interest rate of 8.40% and also scheduled to mature on October 1, 2026 (the "8.40% Promissory Note due 2026"). Each of the agreements governing these notes provided for interest to be paid in cash, deferred or paid in-kind in lieu of cash at the option of the Business.

On September 18, 2024, the Business made principal and interest payments totaling $233.5 million on the 8.25% Promissory Note due 2026, which were made in advance of the maturity date, without premium or penalty. The amounts paid consisted of the entire then outstanding principal balance of $224.9 million and $8.6 million in accrued interest.

On June 8, 2023, the Business made principal and interest payments totaling $74.3 million on the 8.40% Promissory Note due 2026, which were made in advance of the maturity date, without premium or penalty. The amounts paid consisted of the entire then outstanding principal balance of $73.2 million and $1.1 million in accrued interest.

b. *Due from Affiliates*

On September 18, 2024, the Business advanced $83.0 million to Brookfield in the form of unsecured, non-interest-bearing promissory notes that are due on demand. As these non-interest-bearing advances to parent entities were part of a group of transactions related to the Term Loan due 2031, which impacted the size and composition of our borrowings, they have been presented as financing cash outflows.

c. Other related party transactions

The Business has market-based contracts with a related utility company for the purchase of electricity. In addition to the electricity costs noted in the table above, we have entered into contracts with this related party to manage the risk associated with changes in the price of electricity needed to operate two of our facilities. During the year ended March 31, 2025, we recognized losses of $0.6 million in operating costs from this counterparty (March 31, 2024 and 2023-realized gains of $1.6 million and $3.4 million, respectively) (see Note 18). As of March 31, 2025, we recognized accrued liabilities of $0.1 million with this related party (March 31, 2024 — negligible accrued payables).

20. Commitments and Contingencies

Commitments

Purchase and sale obligations arising as a result of forward purchase and sale contracts in place at March 31, 2025 were as follows:

For the fiscal year ending:	Unconditional purchase obligations	Unconditional sales obligations	Net
2026	$ (98.1)	$123.5	$25.4
2027	(39.0)	32.9	(6.1)
2028	(7.7)	11.9	4.2
2029	—	4.6	4.6
2030	—	1.6	1.6
2031 and thereafter	—	—	—
Total	**$(144.8)**	**$174.5**	**$29.7**

Purchase obligations consist of forward physical commitments related to future purchases of natural gas inventory and cushion gas. As the Business economically hedges substantially all of its natural gas purchases, there are forward sales that offset these commitments shown as “unconditional sales obligations” in the above table. Unconditional sales obligations include future sales of certain existing inventory at March 31, 2025.

As at March 31, 2025 and 2024, we had $32.8 million and $36.6 million of issued and outstanding letters of credit to various counterparties to support natural gas purchase commitments.

Subordinated Credit Agreement

Under a credit agreement entered into by BIF II Finco Borrower (Bermuda) L.P., an affiliate of Brookfield Infrastructure, for an amount of up to $175.0 million, Swan OpCo is jointly and severally liable as a guarantor for the obligations of other affiliated borrowers under the facility. As of the reporting date, no amounts have been called under the guarantee. Management has assessed the likelihood of default as remote. Accordingly, no liability has been recognized in respect of the guarantee. The guarantee was terminated on September 26, 2025.

See *Liquidity Risk* within Note 17 for further commitments.

Contingencies

The Business and its subsidiaries are subject to legal and tax proceedings and actions arising in the normal course of business. While the outcome of these proceedings and actions cannot be predicted with certainty, it is the opinion of management that the resolution of such proceedings and actions will not have a material impact on our combined consolidated financial position or results of operations.

In addition, the Business has implemented a long-term incentive arrangement for certain executives, under which a cash payment may become payable upon the occurrence of a change in control. As at the reporting date, no liability has been recognized in respect of this plan as the timing of a triggering event and the amount of such potential cash payment is unknown and may not occur.

21. Supplemental Cash Flow Disclosures

Changes in non-cash working capital include:

	Fiscal Years Ended March 31,		
	2025	**2024**	**2023**
Margin deposits	**$ 29.3**	$ 6.4	$ (68.4)
Trade receivables	**2.6**	(3.6)	1.2
Accrued receivables	**(7.5)**	44.8	(29.5)
Natural gas inventory	**56.6**	(9.2)	(89.8)
Prepaid expenses and other current assets	**1.4**	25.2	(7.5)
Other assets	**(1.8)**	0.5	(0.3)
Trade payables	**2.5**	(0.8)	(1.2)
Accrued liabilities	**(13.1)**	9.3	46.5
Accrued lease interest	**2.2**	2.2	2.3
Deferred revenue	**(0.9)**	0.6	(1.2)
Other long-term liabilities	**0.2**	0.4	(0.1)
Net changes in non-cash working capital	**$ 71.5**	$75.8	$(148.0)

Other supplemental cash flow information follows:

	Fiscal Years Ended March 31,		
	2025	**2024**	**2023**
Interest paid in cash	**$90.9**	$49.7	$43.9
Interest paid in-kind	**8.9**	19.7	15.3
Lease cash payments	**12.8**	12.1	10.6
Tax refunded	**—**	—	(0.1)
Non-cash investing activities:			
Changes in working capital related to property, plant and equipment	**$ (5.6)**	$ (0.9)	$ (0.5)

22. Subsequent Events

On April 30, 2025, the maturity date of the Warwick Credit Facility (see Note 7) was extended to May 31, 2026.

Subsequent to the quarter ended June 30, 2025, the Business entered into amending agreements for certain leases. As a result of these contract modifications, we recognized additional right-of-use assets of $8.3 million and a reduction in lease liabilities of $11.2 million. The remaining term of the leases is 30 years, which was not modified.

On August 31, 2025, the Business settled $83.0 million in promissory notes receivable from Brookfield by distributing its earnings in the form of promissory notes totalling the same amount and then offsetting the notes.

Rockpoint Gas Storage

Unaudited Interim Condensed Combined Consolidated Statements of Net Earnings and Comprehensive Earnings
(Millions of U.S. dollars)

	Notes	Three Months Ended June 30, 2025	Three Months Ended June 30, 2024
REVENUES			
Fee for service revenue	8	**$ 92.2**	$89.6
Optimization, net	8	**11.9**	2.1
Total revenues		**104.1**	91.7
EXPENSES (INCOME)			
Cost of gas storage services		**1.2**	1.5
Operating	10	**12.7**	11.9
General and administrative		**5.5**	6.5
Depreciation and amortization	4, 6	**8.1**	7.9
Financing costs	5, 10	**25.6**	15.8
Gains on gas storage obligation, net		**(1.6)**	(0.9)
Other expenses		**1.0**	1.1
		52.5	43.8
EARNINGS BEFORE INCOME TAXES		**51.6**	47.9
Income tax expense			
Deferred		**3.3**	2.3
		3.3	2.3
NET EARNINGS		**$ 48.3**	$45.6
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX			
Foreign currency translation adjustment		**$ 1.8**	$ (0.3)
NET EARNINGS AND COMPREHENSIVE EARNINGS		**$ 50.1**	$45.3

(The accompanying Notes to the Unaudited Interim Condensed Combined Consolidated Financial Statements are an integral part of these statements.)

Rockpoint Gas Storage

Unaudited Interim Condensed Combined Consolidated Statements of Financial Position (Millions of U.S. dollars)

	Notes	As at June 30, 2025	As at March 31, 2025
ASSETS			
Current Assets			
Cash and cash equivalents		**$ 20.3**	$ 204.1
Trade and accrued receivables	8,10	**54.7**	76.7
Natural gas inventory		**50.6**	28.6
Short-term risk management assets	9	**22.3**	19.5
Margin deposits		**3.2**	0.9
Prepaid expenses and other current assets		**3.9**	1.8
Due from affiliates	10, 13	**120.0**	83.0
		275.0	414.6
Long-term Assets			
Property, plant and equipment, net	4	**886.5**	884.6
Goodwill		**117.2**	117.2
Long-term risk management assets	9	**10.1**	9.3
Other assets		**5.4**	4.5
		1,019.2	1,015.6
TOTAL		**$1,294.2**	$1,430.2
LIABILITIES AND OWNERS' EQUITY			
Current Liabilities			
Trade payables and accrued liabilities	7, 10	**$ 46.3**	$ 59.5
Short-term debt	5	**25.1**	25.8
Short-term risk management liabilities	9	**11.5**	13.9
Short-term lease liabilities	6	**9.2**	9.1
Margin deposits		**—**	3.2
Deferred revenue	8	**1.2**	1.4
		93.3	112.9
Long-term Liabilities			
Long-term debt	5	**1,219.1**	1,208.1
Long-term risk management liabilities	9	**5.4**	5.7
Long-term lease liabilities	6	**102.2**	99.7
Gas storage obligations		**16.7**	17.4
Decommissioning obligations		**5.2**	5.0
Other long-term liabilities		**2.5**	2.2
Deferred income taxes		**68.3**	65.0
		1,419.4	1,403.1
Equity		**(218.5)**	(85.8)
TOTAL		**$1,294.2**	$1,430.2
Commitments and contingencies disclosures	11		

(The accompanying Notes to the Unaudited Interim Condensed Combined Consolidated Financial Statements are an integral part of these statements.)

Rockpoint Gas Storage

Unaudited Interim Condensed Combined Consolidated Statements of Changes in Owners' Equity
(Millions of U.S. dollars)

	Capital Contributions	Retained Earnings (Deficit)	Accumulated Other Comprehensive Loss	Owners' Capital (Deficiency)
Balance, April 1, 2024	$ 250.7	$ 105.6	$(20.8)	$ 335.5
Net earnings	—	45.6	—	45.6
Other comprehensive loss	—	—	(0.3)	(0.3)
Distributions	(112.7)	(0.7)	—	(113.4)
Balance, June 30, 2024	$ 138.0	$ 150.5	$(21.1)	$ 267.4
Balance, April 1, 2025	$ 127.0	$(190.2)	$(22.6)	$ (85.8)
Net earnings	—	48.3	—	48.3
Other comprehensive income	—	—	1.8	1.8
Distributions	—	(182.8)	—	(182.8)
Balance, June 30, 2025	**$ 127.0**	**$(324.7)**	**$(20.8)**	**$(218.5)**

(The accompanying Notes to the Unaudited Interim Condensed Combined Consolidated Financial Statements are an integral part of these statements.)

Rockpoint Gas Storage

Unaudited Interim Condensed Combined Consolidated Statements of Cash Flows
(Millions of U.S. dollars)

	Notes	Three Months Ended June 30, 2025	Three Months Ended June 30, 2024
OPERATING ACTIVITIES			
Net earnings		**$ 48.3**	$ 45.6
Adjustments to reconcile net earnings to net cash provided by operating activities:			
Deferred income tax expense		**3.3**	2.3
Unrealized risk management gains		**(6.3)**	(8.6)
Depreciation and amortization	4, 6	**8.1**	7.9
Other		**(0.8)**	(0.8)
Changes in non-cash working capital	12	**(14.9)**	63.7
Net cash provided by operating activities		**37.7**	110.1
INVESTING ACTIVITIES			
Property, plant and equipment expenditures		**(10.9)**	(4.7)
Net cash used in investing activities		**(10.9)**	(4.7)
FINANCING ACTIVITIES			
Proceeds from revolving credit facilities		**21.1**	28.3
Payments of revolving credit facilities		**(9.5)**	(36.0)
Payments of term loans	5	**(3.1)**	—
Notes extended to related parties	10	**(37.0)**	(50.0)
Payments of financing costs		**(0.2)**	(0.1)
Payments of lease liabilities	6	**(0.1)**	(0.1)
Distributions		**(182.8)**	(113.4)
Net cash used in financing activities		**(211.6)**	(171.3)
Effect of translation on foreign currency cash and cash equivalents		**1.0**	(0.2)
Net changes in cash and cash equivalents		**(183.8)**	(66.1)
Cash and cash equivalents, beginning of the year		**204.1**	100.1
Cash and cash equivalents, end of the period		**$ 20.3**	$ 34.0
Supplemental cash flow disclosures	12		

(The accompanying Notes to the Unaudited Interim Condensed Combined Consolidated Financial Statements are an integral part of these statements.)

Rockpoint Gas Storage
Notes to the Unaudited Interim Condensed Combined Consolidated Financial Statements
(Millions of U.S. dollars, unless otherwise noted)

1. Description of Business

We are the largest independent operator of natural gas facilities in North America. These financial statements represent the unaudited interim condensed combined consolidated financial statements of Swan Equity Aggregator LP ("Swan OpCo"), BIF II CalGas (Delaware) LLC ("BIF OpCo"), Warwick Gas Storage LP and Warwick Gas Storage Ltd. (collectively "WGS LP" or the "Partnership"), BIF II SIM Limited, SIM Energy LP and SIM Energy Limited (collectively "SIM") and Swan Debt Aggregator LP ("Swan Debt") and their subsidiaries (collectively, "we", "us", "our", "Rockpoint Gas Storage", or "the Business").

Swan OpCo is an Ontario limited partnership that independently owns and operates 229.0 billion cubic feet ("Bcf") of effective natural gas storage capacity in North America. It operates the AECO Hub™ ("AECO"), which consists of the Countess and Suffield gas storage facilities in Alberta, Canada and the Wild Goose Storage, LLC ("Wild Goose") gas storage facility in California. Each of its facilities market natural gas storage services in addition to optimizing storage capacity with gas purchases. Swan OpCo also operates a natural gas marketing business that is an extension of its propriety optimization activities in Canada.

BIF OpCo owns Lodi Gas Storage L.L.C. ("Lodi"), a Delaware limited liability company, which owns and operates a natural gas storage facility in northern California. The facility has 28.7 Bcf of effective working natural gas storage capacity in two underground natural gas storage reservoirs and is connected to Pacific Gas and Electric's ("PG&E") intrastate natural gas pipeline system that services demand in the San Francisco and Sacramento areas in California.

WGS LP owns and operates a natural gas storage facility with 21.5 Bcf of effective working gas capacity and is engaged in the storage of third-party natural gas. The facility was originally developed in 2009 and is located east of Edmonton in central Alberta.

The Business consists of entities that are ultimately subsidiaries of Brookfield Asset Management Private Institutional Capital Advisor (Canada), L.P. ("Brookfield Infrastructure", and together with its affiliates, "Brookfield") and its institutional partners. Rockpoint Gas Storage Inc. has been formed to acquire an approximate 40% interest in the Business.

2. Statement of Compliance and Basis of Presentation

These unaudited interim condensed combined consolidated financial statements have been prepared in accordance with IAS 34, "Interim Financial Reporting", as issued by the International Accounting Standards Board ("IASB"). The accounting policies applied are in accordance with IFRS Accounting Standards as issued by the IASB and are consistent with our Audited Combined Consolidated Financial Statements as at March 31, 2025 and March 31, 2024 and for the fiscal years ended March 31, 2025, March 31, 2024 and March 31, 2023 (the "Annual Financial Statements").

These Unaudited Interim Condensed Combined Consolidated Financial Statements as at June 30, 2025 and March 31, 2025, and for the three months ended June 30, 2025 and 2024, do not include all disclosures required for the preparation of annual combined consolidated financial statements and should be read in conjunction with the Annual Financial Statements.

The results of operations for the three months ended June 30, 2025 are not necessarily representative of the results to be expected for the full fiscal year ending March 31, 2026. Generally, the optimization of proprietary gas purchases is seasonal with the majority of the revenues and costs associated with the physical sale of proprietary gas occurring during the third and fourth fiscal quarters, when demand for natural gas is typically the strongest.

These unaudited interim condensed combined consolidated financial statements were authorized for issue by the Board of Directors of Rockpoint Gas Storage Inc. on October 7, 2025.

3. Material Accounting Policy Information

Future accounting policies

IFRS 18 — Presentation and Disclosure in Financial Statements (“IFRS 18”)

In April 2024, the IASB issued IFRS 18, Presentation and Disclosure of Financial Statements. IFRS 18 is effective for periods beginning on or after January 1, 2027, with early adoption permitted. IFRS 18 is expected to improve the quality of financial reporting by requiring defined subtotals in the statement of profit or loss, requiring disclosure about management defined performance measures, and adding new principles for aggregation and disaggregation of information. The Business is in the process of determining the impact of adopting IFRS 18 on its financial statements.

Amendments to IFRS 9 Financial Instruments and IFRS 7 Financial Instruments: Disclosures

On May 30, 2024, the IASB issued targeted amendments to IFRS 9, “Financial Instruments”, and IFRS 7, “Financial Instruments: Disclosures”. The amendments include new requirements not only for financial institutions but also for corporate entities which include clarifying the date of recognition and derecognition of some financial assets and liabilities, with a new exception for some financial liabilities settled through an electronic cash transfer system. These new requirements will apply from January 1, 2026, with early application permitted. The Business is in the process of determining the impact of the amendments on its financial statements.

4. Property, Plant and Equipment

Property, plant and equipment is comprised of the following:

Cost	Cushion gas	Pipelines and interconnects	Wells	Land and storage formations	Facilities and other	Total
Balance, April 1, 2025	$169.4	$152.5	$323.3	$101.1	$415.1	$1,161.4
Additions	0.3	0.3	4.3	—	1.8	6.7
Changes in decommissioning obligations	—	—	(0.1)	—	—	(0.1)
Remeasurements of leases	—	—	—	(0.1)	—	(0.1)
Migration/disposals	(0.3)	—	(0.8)	—	(0.1)	(1.2)
Foreign currency translation adjustment	1.0	—	1.1	0.2	2.7	5.0
Balance, June 30, 2025	**$170.4**	**$152.8**	**$327.8**	**$101.2**	**$419.5**	**$1,171.7**

Accumulated depreciation	Cushion gas	Pipelines and interconnects	Wells	Land and storage formations	Facilities and other	Total
Balance, April 1, 2025	$ —	$(39.1)	$(78.2)	$(17.9)	$(141.6)	$(276.8)
Depreciation expense	—	(1.1)	(2.0)	(0.8)	(3.9)	(7.8)
Disposals	—	—	0.6	—	0.1	0.7
Foreign currency translation adjustment	—	—	(0.4)	—	(0.9)	(1.3)
Balance, June 30, 2025	**$ —**	**$(40.2)**	**$(80.0)**	**$(18.7)**	**$(146.3)**	**$(285.2)**

Net book value	Cushion gas	Pipelines and interconnects	Wells	Land and storage formations	Facilities and other	Total
Balance, April 1, 2025	$169.4	$113.4	$245.1	$83.2	$273.5	$884.6
Balance, June 30, 2025	**$170.4**	**$112.6**	**$247.8**	**$82.5**	**$273.2**	**$886.5**

Depreciation expense for the period ended June 30, 2025 includes $0.3 million (June 30, 2024 — $0.3 million) related to cushion gas migration.

5. Debt

The Business' debt consisted of the following:

	As at June 30, 2025	As at March 31, 2025
Asset Backed Loan	**$ 13.0**	$ —
Warwick Credit Facility	**13.0**	13.6
Term Loan due 2031	**1,243.8**	1,246.8
Total principal amount of debt	**1,269.8**	1,260.4
Less:		
Portion classified as current, net	**(25.1)**	(25.8)
Unamortized discount and deferred financing costs	**(25.6)**	(26.5)
Total long-term debt, net	**$1,219.1**	$1,208.1

a) Asset Backed Loan

As of June 30, 2025, borrowings of $13.0 million were outstanding under the senior secured asset-backed revolving credit facility (the "Asset Backed Loan" or the "ABL Facility") at a weighted average interest rate of 6.82%. There were no borrowings outstanding under the ABL Facility as of March 31, 2025. Issued letters of credit amounted to $46.2 million and $32.8 million as of June 30 and March 31, 2025, respectively. As of June 30, 2025, the borrowing base collateral totaled $163.6 million (March 31, 2025 — $325.2 million). Of the total borrowing base collateral available to us, $104.4 million was unutilized as of June 30, 2025 (March 31, 2025 — $217.2 million).

As of June 30, 2025, the Business was in compliance with all covenant requirements and there were no restrictions on our ability to borrow up to the total amount of liquidity available.

b) Warwick Credit Facility

As of June 30, 2025, we had drawn $13.0 million on the revolving operating line of credit ("Warwick Credit Facility") (March 31, 2025 — $13.6 million) at an interest rate of 5.55% and had an insignificant amount of letters of credit outstanding as of each period end. As of June 30, 2025, $14.5 million of the Warwick Credit Facility's availability remained unutilized (March 31, 2025 — $12.5 million). The Partnership's parent company, BAIF Warwick Storage L.P., and its general partner guarantee the Warwick Credit Facility.

As of June 30, 2025, the Business was in compliance with all covenant requirements of the Warwick Credit Facility.

c) Term Loan due 2031

As of June 30, 2025, $1,243.8 million of the principal of the Term Loan due 2031 remained outstanding (March 31, 2025 — $1,246.8 million), which is inclusive of $12.5 million in current amounts owing (March 31, 2025 — $12.5 million). Each of these amounts are prior to unamortized discount and deferred financing costs of $25.6 million (March 31, 2025 — $26.5 million). As of June 30, 2025, before considering associated hedges, the Term Loan due 2031 bore a weighted average interest rate of 7.30%. To limit exposure to changes in interest rates, the Business uses interest rate swap contracts which effectively lock in a 6.66% all-in rate over the hedged period. All of the outstanding principal balance is hedged until September 2025, at which point the hedged portion decreases to $900.0 million from October 2025 until September 2026. Thereafter, the full principal balance is unhedged, which will expose us to interest rate fluctuations unless the debt is re-hedged.

As of June 30, 2025, the Business was in compliance with all covenant requirements under the Term Loan due 2031.

6. Right of Use Assets and Lease Liabilities

The Business' lease liabilities consist of the following:

	Three Months Ended June 30,	
	2025	**2024**
Opening lease liabilities	**$108.8**	$106.8
Lease interest expense	**2.7**	2.6
Principal repayments	**(0.1)**	(0.1)
Interest payments	**(0.2)**	(0.2)
Foreign exchange and other	**0.2**	—
Total lease liabilities	**111.4**	109.1
Less:		
Portion classified as current	**(9.2)**	(8.6)
Long-term lease liabilities	**$102.2**	$100.5

During the three months ended June 30, 2025, the Business recorded $0.9 million of depreciation related to its right-of-use assets (June 30, 2024 — $0.9 million), and made cash payments of $6.3 million on variable leases (June 30, 2024 — $3.2 million).

7. Trade Payables and Accrued Liabilities

The Business' trade payables and accrued liabilities consisted of the following:

	As at June 30, 2025	As at March 31, 2025
Trade payables	**$ 0.5**	$ 2.7
Accrued gas purchases	**23.9**	27.7
Accrued interest, non-affiliated debt	**1.0**	1.0
Employee-related accruals	**5.7**	10.3
Other accrued liabilities, affiliated	**4.9**	0.3
Other accrued liabilities, non-affiliated	**10.3**	17.5
Total	**$46.3**	$59.5

8. Revenues and Contract Assets and Liabilities

The following table summarizes the Business' fee for service revenue earned from contracts with customers, by geographic area:

	Three Months Ended June 30,	
	2025	**2024**
Take-or-pay contract revenue		
U.S.	**$51.6**	$40.7
Canada	**6.9**	5.5
Short-term storage service revenue		
U.S.	**13.7**	13.5
Canada	**20.0**	29.9
Total fee for service revenue from contracts with customers	**$92.2**	$89.6

Optimization, net consists of the following:

	Three Months Ended June 30,	
	2025	**2024**
Retail realized optimization	**$ 4.0**	$ 4.5
Storage realized optimization	**0.8**	(10.2)
Realized optimization, net	**4.8**	(5.7)
Retail unrealized optimization losses	**(0.9)**	(3.3)
Storage unrealized optimization gains	**8.0**	11.1
Unrealized optimization gains, net	**7.1**	7.8
	$11.9	$ 2.1

As at June 30, 2025, the balance of trade and accrued receivables included $29.7 million (March 31, 2025 — $36.9 million) related to take-or-pay and short-term storage service contracts with customers. In accordance with industry practice, the Business normally collects its contractual receivables on the 25th day following the month in which the revenue was earned.

As at June 30, 2025, our recorded deferred revenue of $0.9 million (March 31, 2025 — $1.2 million) related to contracts with customers.

The Business' inventory is valued at the lower of weighted-average cost or net realizable value. During the three months ended June 30, 2025 and 2024, there were no adjustments recorded to inventory.

9. Fair Value Measurements

The following table shows the fair values of the Business' risk management assets and liabilities:

Balance, June 30, 2025	Energy Contracts	Currency Contracts	Interest Rate Contracts	Total
Short-term risk management assets	$ 19.3	$ —	$ 3.0	$ 22.3
Long-term risk management assets	10.1	—	—	10.1
Short-term risk management liabilities	(10.9)	(0.1)	(0.5)	(11.5)
Long-term risk management liabilities	(4.4)	—	(1.0)	(5.4)
	$ 14.1	$(0.1)	$ 1.5	$ 15.5

Balance, March 31, 2025	Energy Contracts	Currency Contracts	Interest Rate Contracts	Total
Short-term risk management assets	$ 15.6	$0.1	$ 3.8	$ 19.5
Long-term risk management assets	9.3	—	—	9.3
Short-term risk management liabilities	(13.8)	—	(0.1)	(13.9)
Long-term risk management liabilities	(4.9)	—	(0.8)	(5.7)
	$ 6.2	$0.1	$ 2.9	$ 9.2

The carrying amount of cash and cash equivalents, margin deposits, trade and accrued receivables and trade payables and accrued liabilities reported on the Unaudited Interim Condensed Combined Consolidated Statements of Financial Position approximate fair value.

The Business' assets and liabilities that were accounted for or disclosed at fair value on a recurring and non-recurring basis are as follows:

Balance, June 30, 2025	Level 1	Level 2	Level 3	Total
Assets				
Commodity derivatives	$ —	$ 29.4	$ —	$ 29.4
Currency derivatives	—	—	—	—
Interest rate swaps	—	3.0	—	3.0
Total assets	$ —	$ 32.4	$ —	$ 32.4
Liabilities				
Commodity derivatives	$ —	$ 15.3	$ —	$ 15.3
Currency derivatives	—	0.1	—	0.1
Interest rate swaps	—	1.5	—	1.5
Gas storage obligations	—	16.7	—	16.7
Short-term debt	—	25.5	—	25.5
Long-term debt	—	1,234.4	—	1,234.4
Total liabilities	$ —	$1,293.5	$ —	$1,293.5

Balance, March 31, 2025	Level 1	Level 2	Level 3	Total
Assets				
Commodity derivatives	$ —	$ 24.9	$—	$ 24.9
Currency derivatives	—	0.1	—	0.1
Interest rate swaps	—	3.8	—	3.8
Total assets	$ —	$ 28.8	$—	$ 28.8
Liabilities				
Commodity derivatives	$ —	$ 18.7	$—	$ 18.7
Interest rate swaps	—	0.9	—	0.9
Gas storage obligations	—	17.4	—	17.4
Short-term debt	—	26.1	—	26.1
Long-term debt	—	1,229.7	—	1,229.7
Total liabilities	$ —	$1,292.8	$—	$1,292.8

The Business' financial assets and liabilities, recorded at fair value on a recurring basis, have been categorized as Level 2. The determination of the fair value of assets and liabilities for Level 2 valuations is generally based on a market approach. The key inputs used in our valuation models include transaction-specific details such as notional volumes, contract prices, and contract terms, as well as forward market prices and basis differentials for natural gas obtained from third-party service providers (typically the New York Mercantile Exchange, or NYMEX). In valuing our interest rate swaps, we used forward market data for three-month SOFR loans obtained from third-party service providers. There were no changes in our approach to determining fair value and there were no transfers out of Level 2 during the three months ended June 30, 2025.

The fair value of debt is the estimated amount the Business would have to pay to transfer its debt, including any premium or discount attributable to the difference between the stated interest rate and market rate of interest at the period-end date. To value the Term Loan due 2031, we used bid and yield information provided by a third-party financial services company. Interest rates on the Asset Backed Loan and the Warwick Credit Facility are variable and therefore the fair values are approximated by the principal balances outstanding.

10. Related Party Transactions

We are subsidiaries of Brookfield and the Business had transactions and related balances with entities classified as related parties as follows:

	As at June 30, 2025	As at March 31, 2025
Included in trade payables and accrued liabilities:		
Due to Brookfield affiliates	**$ 4.7**	$ —
Other accrued costs, including electricity costs	**0.2**	0.3
Total amounts owing to related parties	**$ 4.9**	$ 0.3
Included in due from affiliates	**$120.0**	$83.0

	Three Months Ended June 30, 2025	Three Months Ended June 30, 2024
Interest on affiliated debt (financing costs)	**$ —**	$4.6
Electricity (operating)	**0.5**	0.5
Total transactions with related parties	**$0.5**	$5.1

a. Due from Affiliates

On May 29, 2025, we advanced $37.0 million to a Brookfield parent entity in exchange for an unsecured, non-interest-bearing, promissory note that is due on demand. As this promissory note was part of a group of transactions related to distributions paid in May 2025, it has been presented as a financing cash outflow.

As of June 30, 2025, the Business had receivable, inclusive of the $37.0 million note referenced above, amounts evidenced by $120.0 million of unsecured, non-interest-bearing promissory notes due from certain Brookfield parent entities that are due on demand (March 31, 2025 — $83.0 million).

Included in trade and accrued receivables as of June 30, 2025 was $5.1 million related to advances made to Brookfield affiliates (March 31, 2025 — nil).

b. Other related party transactions

The Business has market-based contracts with a related utility company for the purchase of electricity. In addition to the electricity costs noted in the table above, we have entered into contracts with this related party to manage the risk associated with changes in the price of electricity needed to operate two of our facilities. During the three months ended June 30, 2025, we recognized realized losses of $0.1 million in operating costs from this counterparty (June 30, 2024 — realized losses of $0.2 million). As of June 30, 2025, we recognized negligible accrued liabilities with this related party (March 31, 2025 — $0.1 million of accrued liabilities).

The $4.7 million due to Brookfield affiliates relates to certain withholding taxes paid by Brookfield.

11. Commitments and Contingencies

Commitments

Purchase and sale obligations arising as a result of forward purchase and sale contracts in place at June 30, 2025 were as follows:

For the fiscal year ending:	Unconditional purchase obligations	Unconditional sales obligations	Net
2026	$ (64.0)	$ 97.6	$33.6
2027	(53.0)	47.4	(5.6)
2028	(9.9)	17.2	7.3
2029	(3.3)	8.4	5.1
2030	—	3.8	3.8
2031 and thereafter	—	0.6	0.6
Total	**$(130.2)**	**$175.0**	**$44.8**

Purchase obligations consist of forward physical commitments related to future purchases of natural gas inventory and cushion gas. As the Business economically hedges substantially all of its natural gas purchases, there are forward sales that offset these commitments shown as "unconditional sales obligations" in the above table. Unconditional sales obligations include future sales of certain existing inventory at June 30, 2025.

As of June 30, 2025 and March 31, 2025, we had $46.2 million and $32.8 million of issued and outstanding letters of credit to various counterparties to support natural gas purchase commitments.

12. Supplemental Cash Flow Disclosures

Changes in non-cash working capital include:

	Three Months Ended June 30,	
	2025	2024
Margin deposits	**$ (5.5)**	$ 23.9
Trade receivables	**2.8**	2.9
Accrued receivables	**24.7**	22.4
Natural gas inventory	**(22.0)**	33.8
Prepaid expenses and other current assets	**(2.3)**	(1.9)
Other assets	**(0.7)**	(0.2)
Trade payables	**(2.1)**	0.9
Accrued liabilities	**(12.5)**	(18.8)
Accrued lease interest	**2.5**	2.5
Deferred revenue	**(0.1)**	(1.4)
Other long-term liabilities	**0.3**	(0.4)
Net changes in non-cash working capital	**$(14.9)**	$ 63.7

Other supplemental cash flow information follows:

	Three Months Ended June 30,	
	2025	2024
Interest paid in cash	**$21.2**	$ 8.9
Interest paid in-kind	**—**	8.9
Lease cash payments	**6.6**	3.5
Non-cash investing activities:		
Changes in working capital related to property, plant and equipment	**$ 4.2**	$(0.9)

13. Subsequent Events

Subsequent to June 30, 2025 the Business entered into amending agreements for certain leases. As a result of these contract modifications, we recognized additional right-of-use assets of $8.3 million and a reduction to our lease liabilities of $11.2 million. The remaining term of the leases is 30 years, which was not modified.

On August 31, 2025 the Business settled $83.0 million in promissory notes receivable from Brookfield by distributing its earnings in the form of promissory notes totalling the same amount, which offset the notes.

Rockpoint Gas Storage Inc.

Pro Forma Statement of Financial Position
(Millions of U.S. dollars)
(Unaudited)

	As at June 30, 2025				
		Pro Forma Adjustments			
	Rockpoint Gas Storage Inc.	Issuance of Class A & Class B Shares	Acquisition of Equity Investees	Notes	Rockpoint Gas Storage Inc. Pro Forma
ASSETS					
Current Assets					
Cash and cash equivalents	**$ —**	$504.6		2(a)	$ —
		—		2(b)	
			(504.6)	2(c)	
	—	504.6	(504.6)		—
Long-term Assets					
Equity Method Investments	—		838.8	2(c)	**838.8**
	—	—	838.8		**838.8**
TOTAL	**$ —**	$504.6	$ 334.2		$**838.8**
LIABILITIES AND OWNERS' EQUITY					
Current Liabilities					
Trade payables and accrued liabilities	—				**—**
	—				**—**
Equity					
Class A Shares	—	504.6		2(a)	**838.8**
			334.2	2(c)	
Class B Shares	—	—		2(b)	**—**
Equity	**$ —**	$504.6	$ 334.2		**$838.8**
TOTAL	**$ —**	$504.6	$ 334.2		**$838.8**

(See accompanying notes)

Rockpoint Gas Storage Inc.

Pro forma Statement of Net Earnings
(Millions of U.S. dollars, except per share amounts)
(Unaudited)

	Three months ended June 30, 2025			
	Rockpoint Gas Storage Inc.	Pro Forma Adjustments	Notes	Rockpoint Gas Storage Inc. Pro Forma
INCOME (EXPENSES)				
General and administrative	—	—		**—**
Other expenses	—	—		**—**
	—	—		**—**
Share of income from equity accounted investments	—	19.1	2(d)	**19.1**
		(7.8)	2(d)	**(7.8)**
EARNINGS BEFORE INCOME TAXES	—	11.3		**11.3**
Income tax expense				
Current	—	—	2(e)	**—**
	—	—		**—**
NET EARNINGS ATTRIBUTABLE TO CLASS A SHAREHOLDERS	**$ —**	$11.3		**$11.3**
Net income per Class A share				
Class A Shares – basic & diluted	**$ —**			**$0.21**

(See accompanying notes)

Rockpoint Gas Storage Inc.

Pro forma Statement of Net Earnings
(Millions of U.S. dollars, except per share amounts)
(Unaudited)

	Year ended March 31, 2025			
	Rockpoint Gas Storage Inc.	**Pro Forma Adjustments**	**Notes**	**Rockpoint Gas Storage Inc. Pro Forma**
INCOME (EXPENSES)				
General and administrative	—	—		—
Other expenses	—	—		—
	—	—		—
Share of income from equity accounted investments	—	83.0	2(d)	**83.0**
		(31.1)	2(d)	**(31.1)**
EARNINGS BEFORE INCOME TAXES	—	51.9		**51.9**
Income tax expense				
Current	—	—	2(e)	—
	—	—		—
NET EARNINGS ATTRIBUTABLE TO CLASS A SHAREHOLDERS	$ —	$ 51.9		**$ 51.9**
Net income per Class A share				
Class A Shares – basic & diluted	$ —			**$ 0.98**

(See accompanying notes)

Rockpoint Gas Storage Inc.

Notes to the Unaudited Pro Forma Financial Statements
(Millions of U.S. dollars, unless otherwise noted)

1. Description of the Transaction and Basis of Pro Forma Presentation

Description of the Transaction

Rockpoint Gas Storage Inc. ("Rockpoint" or the "Company") was incorporated by Brookfield Infrastructure Holdings (Canada) Inc. under the *Business Corporations Act* (Alberta) on July 28, 2025. Rockpoint was incorporated with nominal assets for the purpose of facilitating an offering (the "Offering") of class "A" common shares (the "Class A Shares") and acquiring approximately 40% of the limited partner units (each a "Swan OpCo Unit") of Swan Equity Aggregator LP, an Ontario limited partnership ("Swan OpCo"), and approximately 40% of the common shares (each a "BIF OpCo Share") of BIF II CalGas (Delaware) LLC, a Delaware limited liability company ("BIF OpCo", and together with Swan OpCo, the "OpCos"), from affiliates of Brookfield Asset Management Private Institutional Capital Adviser (Canada), L.P. ("Brookfield Infrastructure" and, together with its affiliates ("Brookfield")) in exchange for cash and Class A Shares pursuant to a Business Transfer Agreement (the "Reorganization"). Following the completion of the Offering, the Reorganization and other related transactions (collectively, the "Transactions"), the OpCos, Warwick Gas Storage Ltd., Warwick Gas Storage LP, BIF II SIM Limited, SIM Energy LP, SIM Energy Limited and Swan Debt Aggregator LP will continue to own and operate, natural gas marketing and transportation services in British Columbia, Alberta, Manitoba, Ontario and Québec and natural gas storage facilities in California and Alberta (the "Business").

To facilitate the Transactions, Rockpoint and the OpCos entered into the following agreements:

- A Business Transfer Agreement among Rockpoint and Brookfield;
- A Relationship Agreement among Rockpoint, Brookfield and the OpCos; and
- An Exchange Agreement among Rockpoint Brookfield and the OpCos.

In addition, Rockpoint expects to enter into the following agreements before completion of the Transactions:

- A Shareholder Agreement among Rockpoint and Brookfield; and
- A Registration Rights Agreement among Rockpoint and Brookfield.

Upon completion of the Transactions it is expected that Rockpoint will equity account for its interests in Swan OpCo and BIF OpCo. The unaudited pro forma financial statements of Rockpoint (the "Unaudited Pro Forma Financial Statements") have been prepared in connection with the Transactions.

These Unaudited Pro Forma Financial Statements reflect the following:

- AECO Gas Storage Partnership, a wholly-owned subsidiary of Swan OpCo, will borrow $135.6 million from Brookfield (such amount, the "Warwick Receivable") and will use the proceeds to acquire Warwick Gas Storage Ltd. and Warwick Gas Storage LP (collectively, "WGS LP");
- Rockpoint will sell 79,800,000 newly issued class "B" voting shares (the "Class B Shares") to Brookfield Infrastructure Holdings (Canada) Inc. for nominal consideration to align Brookfield's voting interest in the Company with its economic interest in the OpCos;
- Rockpoint will sell 32,000,000 newly issued Class A Shares to the public pursuant to the Offering at a price of C$22.00 per Class A Share for aggregate gross proceeds of C$704.0 million;
- Rockpoint will purchase: (i) approximately 40% of the Swan OpCo Units and approximately 40% of the BIF OpCo Shares, from Brookfield for $450.4 million of cash and 21,200,000 newly issued Class A Shares; and (ii) approximately 40% of the Warwick Receivable from Brookfield for $54.2 million of cash;
- Rockpoint and Brookfield will transfer their interests in the Warwick Receivable to Swan OpCo in exchange for additional Swan OpCo Units, following which the Warwick Receivable will be contributed to AECO Gas Storage Partnership and cancelled by operation of law; and

- a wholly-owned subsidiary of Swan OpCo will acquire the entity in which the executive officers of the Company and the OpCos are employed by purchasing 100% of the shares of SIM Energy Limited, 99% of the class B units of SIM Energy LP and 100% of the shares of BIF II SIM Limited from Brookfield for $3.0 million of cash, funded by cash on hand.

Basis of Pro Forma Presentation

The information in the Unaudited Pro Forma Statements of Net Earnings gives effect to the Transactions as if they had been consummated on April 1, 2024. The information in the Unaudited Pro Forma Statement of Financial Position gives effect to the Transactions as if they had been consummated on June 30, 2025. All financial data in the Unaudited Pro Forma Financial Information is presented in U.S. dollars and has been prepared using accounting policies that are consistent with IFRS Accounting Standards as issued by the International Accounting Standards Board. The Unaudited Pro Forma Financial Statements have been derived by the application of pro forma adjustments to the financial statements of Rockpoint as at July 28, 2025 and the historical unaudited combined consolidated financial statements of our Business as at June 30, 2025 and March 31, 2025 and for the three months ended June 30, 2025 and 2024 (the "Interim Financial Statements"), and the historical audited combined consolidated financial statements of our Business as at March 31, 2025 and March 31, 2024 and for each of the three years ended March 31, 2025 (the "Annual Financial Statements"), included elsewhere in this prospectus, to give effect to the Transactions.

The Unaudited Pro Forma Financial Statements are based on preliminary estimates, accounting judgments and currently available information and assumptions that management believes are reasonable. The notes to the Unaudited Pro Forma Financial Statements provide a detailed discussion of how such adjustments were derived and presented. The Unaudited Pro Forma Financial Statements should be read in conjunction with the discussions under the headings "Consolidated Capitalization", "Selected Historical Financial Information", "Management's Discussion and Analysis", the Interim Financial Statements and the Annual Financial Statements, and the accompanying notes to such financial statements, and the audited financial statements of Rockpoint as at July 28, 2025 and related notes thereto included elsewhere in this prospectus.

The Unaudited Pro Forma Financial Statements have been prepared for illustrative purposes only and are not necessarily indicative of Rockpoint's financial position or results of operations had the Transactions for which Rockpoint is giving pro forma effect occurred on the dates or for the periods indicated, nor is such pro forma financial information necessarily indicative of the results to be expected for any future period. A number of factors may affect Rockpoint's results. All Canadian Dollar values have been translated at rate of C$1.00 to US$0.7167 based on the Bloomberg mid-market exchange rate as at October 3, 2025.

2. Rockpoint Gas Storage Inc.

(a) Initial public offering of 32.0 million Class A Shares for C$22.00 per share (US$15.77). Issuance costs of C$45.1 million (US$32.3 million) will be borne by Brookfield and reflected as a shareholder contribution.

(b) Issuance of 79.8 million Class B Shares for nominal consideration per share to Brookfield Infrastructure.

(c) Acquisition of (i) approximately 40% of the Warwick Receivable, (ii) approximately 40% of the Swan OpCo Units; and (iii) approximately 40% of the BIF OpCo Shares, with an aggregate value of C$1,170.4 million (US$838.8 million). The total gross proceeds of $504.6 million from the initial public offering as well as the further issuance of 21,200,000 Class A Shares will be paid as consideration.

(d) Adjustment to reflect pro forma equity earnings attributable to Rockpoint from the investees. Rockpoint's share of income from the Business is $19.1 million for three months ended June 30, 2025 and $83.0 million for the year ended March 31, 2025, respectively. The basis difference of $932.5 million which represents the difference between the cost of the investment in equity accounted investees and their net asset value as at June 30, 2025 has been allocated to property, plant and equipment and is amortized over an average useful life of 30 years.

(e) Due to tax depreciation, the equity earnings of our investees is not expected to be taxable for Rockpoint for the respective periods.

3. Earnings per Share

Following the Transactions, Rockpoint is expected to have approximately 53.2 million Class A Shares and 79.8 million Class B Shares outstanding. The Class B Shares only have voting rights and do not participate in the earnings of Rockpoint. As a result, the Class B Shares are not included in the calculation of earnings per share.

Pro forma basic earnings per share is computed by dividing net income by the weighted average number of ordinary shares outstanding during the period. Pro forma earnings per share calculations are as follows:

(U.S. millions, except share data)	Three months ended June 30, 2025	Year ended March 31, 2025
Net income	11.3	51.9
Weighted average Class A Shares outstanding – basic & diluted	53,200,000	53,200,000
Earnings per Class A Share – basic & diluted	**$ 0.21**	**$ 0.98**

4. Our Business

The Interim Financial Statements and Annual Financial Statements present the financial results of Swan OpCo, BIF OpCo and the other entities described therein on a combined basis as the entities are commonly controlled through the historical periods presented.

The following tables reflect the pro forma adjustments made to give effect to the Transactions as if they had occurred as at June 30, 2025 for the Unaudited Pro Forma Statement of Financial Position and, with respect to the Unaudited Pro Forma Statements of Net Earnings, as if they had occurred April 1, 2024.

Rockpoint Gas Storage

Notes to Pro Forma Statement of Financial Position
(Millions of U.S. dollars)
(Unaudited)

	As at June 30, 2025			
	Our Business	**Pro Forma Adjustments**	**Notes**	**Our Business Pro Forma**
ASSETS				
Current Assets				
Cash and cash equivalents	**$ 20.3**	(3.0)	(a)	**$ 17.3**
Trade and accrued receivables	**54.7**			**54.7**
Natural gas inventory	**50.6**			**50.6**
Short-term risk management assets	**22.3**			**22.3**
Margin deposits	**3.2**			**3.2**
Prepaid expenses and other current assets	**3.9**			**3.9**
Due from affiliates	**120.0**	27.3	(b)	**147.3**
	275.0	24.3		**299.3**
Long-term Assets				
Property, plant and equipment, net	**886.5**			**886.5**
Goodwill	**117.2**			**117.2**
Long-term risk management assets	**10.1**			**10.1**
Other assets	**5.4**			**5.4**
	1,019.2	—		**1,019.2**
TOTAL	**$1,294.2**	$ 24.3		**$1,318.5**
LIABILITIES AND OWNERS' EQUITY				
Current Liabilities				
Trade payables and accrued liabilities	**46.3**			**46.3**
Short-term debt	**25.1**			**25.1**
Short-term risk management liabilities	**11.5**			**11.5**
Short-term lease liabilities	**9.2**			**9.2**
Margin deposits	**—**			**—**
Deferred revenue	**1.2**			**1.2**
	93.3	—		**93.3**
Long-term Liabilities				
Long-term debt	**1,219.1**	40.0	(b)	**1,259.1**
Long-term risk management liabilities	**5.4**			**5.4**
Long-term lease liabilities	**102.2**			**102.2**
Gas storage obligations	**16.7**			**16.7**
Decommissioning obligations	**5.2**			**5.2**
Other long-term liabilities	**2.5**			**2.5**
Deferred income taxes	**68.3**			**68.3**
Due to affiliates	**—**			**—**
	1,419.4	40.0		**1,459.4**
Equity				
Capital contributions	**127.0**			**127.0**
Retained deficit	**(324.7)**	(3.0)	(a)	**(340.4)**
		(12.7)	(b)	
Accumulated other comprehensive losses	**(20.8)**			**(20.8)**
Equity	**$ (218.5)**	$(15.7)		**$ (234.2)**
TOTAL	**$1,294.2**	$ 24.3		**$1,318.5**

(See accompanying notes)

Rockpoint Gas Storage Inc.

Notes to Pro Forma Statement of Net Earnings
(Unaudited)
(Millions of U.S. dollars, except per share amounts)

	Three months ended June 30, 2025			
	Our Business	Pro Forma Adjustments	Notes	Our Business Pro Forma
REVENUES				
Fee for service revenue	**$ 92.2**			**$ 92.2**
Optimization, net	**11.9**			**11.9**
Total revenues	**104.1**	—		**104.1**
EXPENSES (INCOME)				
Cost of gas storage services	**1.2**			**1.2**
Operating	**12.7**			**12.7**
General and administrative	**5.5**			**5.5**
Depreciation and amortization	**8.1**			**8.1**
Financing costs	**25.6**	0.7	(b)	**26.3**
Gains on gas storage obligation, net	**(1.6)**			**(1.6)**
Other expenses	**1.0**			**1.0**
	52.5	0.7		**53.2**
EARNINGS BEFORE INCOME TAXES	**51.6**	(0.7)		**50.9**
Income tax expense (benefit)				
Current	**—**	(0.1)	(c)	**(0.1)**
Deferred	**3.3**			**3.3**
	3.3	(0.1)		**3.2**
NET EARNINGS	**$ 48.3**	$(0.6)		**$ 47.7**

(See accompanying notes)

Rockpoint Gas Storage Inc.

Notes to Pro Forma Statement of Net Earnings
(Unaudited)
(Millions of U.S. dollars, except per share amounts)

	Year ended March 31, 2025			
	Our Business	Pro Forma Adjustments	Notes	Our Business Pro Forma
REVENUES				
Fee for service revenue	**$366.8**			**$366.8**
Optimization, net	**48.5**			**48.5**
Total revenues	**415.3**	—		**415.3**
EXPENSES (INCOME)				
Cost of gas storage services	**11.0**			**11.0**
Operating	**49.5**			**49.5**
General and administrative	**24.2**			**24.2**
Depreciation and amortization	**33.1**			**33.1**
Financing costs	**93.1**	2.6	(b)	**95.7**
Gains on gas storage obligation, net	**(1.3)**			**(1.3)**
Other expenses	**6.9**			**6.9**
	216.5	2.6		**219.1**
EARNINGS BEFORE INCOME TAXES	**198.8**	(2.6)		**196.2**
Income tax (benefit) expense				
Current	**0.6**	(0.6)	(c)	**—**
Deferred	**(11.2)**			**(11.2)**
	(10.6)	(0.6)		**(11.2)**
NET EARNINGS	**$209.4**	$(2.0)		**$207.4**

(a) The acquisition by a subsidiary of Swan OpCo of interests in BIF II SIM Limited, SIM Energy Limited and SIM Energy LP for $3.0 million of cash. As the net assets and results of BIF II SIM Limited, SIM Energy Limited and SIM Energy LP are included in the combined consolidated financial statements of our Business, the pro forma impact of the acquisition to our Business is the $3.0 million distribution of cash to Brookfield.

(b) Concurrent with the closing of the Transactions, the Board of Directors of Swan Holdings GP (Canada) Inc., as the general partner of Swan OpCo, and the Board of Managers of BIF OpCo will declare and pay a dividend in the aggregate of up to $12.7 million and advance loan receivables of up to $27.3 million to Brookfield. The payments of these amounts will be financed through a drawdown on existing credit facilities. The financing costs related to this draw down are calculated using an assumed interest rate of 6.5%.

(c) Tax effect of pro forma adjustments.

(See accompanying notes)

APPENDIX A — BOARD MANDATE

ROCKPOINT GAS STORAGE INC.

BOARD OF DIRECTORS CHARTER[1]

1. ROLE OF THE BOARD

The role of the board of directors (the "**Board**") of Rockpoint Gas Storage Inc. (the "**Corporation**") is to oversee, directly and through its committees (the "**Committees**", and each a "**Committee**"), the business and affairs of the Corporation, which are conducted by the Corporation's officers and employees under the direction of the Chief Executive Officer ("**CEO**").

2. AUTHORITY AND RESPONSIBILITIES

The Board meets regularly to review reports by management on the Corporation's performance and other relevant matters of interest. In addition to the general supervision of management, the Board performs the following functions:

(a) Strategic Planning — overseeing the long-term strategic-planning process within the Corporation and, at least annually, reviewing, approving, and monitoring the strategic plan and budget for the Corporation, including fundamental financial and business strategies and objectives;

(b) Material Contracts and Partnerships and JVs — approving and monitoring the entering into, amendments to or terminations of material contracts and overseeing entering into or terminating any material partnership, joint venture, or similar arrangement with a third party;

(c) Material Business Changes — approving and monitoring any material business acquisitions or dispositions outside of the ordinary course, entering into any new line of business and any material changes to any existing line of business;

(d) Litigation — approving and monitoring the institution or settling of any litigation, mediation, or arbitration;

(e) Financing — assessing and approving any financing, refinancing, or material amendments to any financing facility;

(f) Restructuring — reviewing, approving, and overseeing any corporate restructuring involving the Corporation;

(g) Risk Assessment — assessing the major risks facing the Corporation and reviewing, approving, and monitoring the manner of managing those risks;

(h) CEO — selecting the CEO; reviewing and approving the position description for the CEO including the corporate objectives that the CEO is responsible for meeting; and reviewing and approving the compensation of the CEO as recommended by the Governance, Nominating and Compensation Committee;

(i) Executive Officers — overseeing the selection of executive officers and the evaluation and compensation of such executive officers;

(j) Succession Planning — monitoring the succession of key members of senior management;

(k) Communications and Disclosure Policy — adopting a communications and disclosure policy for the Corporation that ensures the timeliness and integrity of communications to shareholders, and establishing suitable mechanisms to receive stakeholder views;

(l) Sustainability — overseeing the Corporation's approach to Sustainability matters as reported to the Board by the Governance, Nominating and Compensation Committee;

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[1] Capitalized terms used in this Charter but not otherwise defined herein have the meaning attributed to them in the Board's "Definitions for Board and Committee Charters" which is annexed hereto as "Annex A".

(m) Corporate Governance — developing and promoting a set of effective corporate governance principles and guidelines applicable to the Corporation;

(n) Internal Controls — reviewing and monitoring the controls and procedures within the Corporation to maintain its integrity, including its disclosure controls and procedures, and its internal controls and procedures for financial reporting and compliance;

(o) Culture — on an ongoing basis, satisfy itself that the CEO and other executive officers create a culture of integrity throughout the Corporation, including compliance with the Corporation's Code of Business Conduct and Ethics and its anti-bribery and corruption policies and procedures; and

(p) Whistleblowers — in conjunction with the Audit Committee of the Board, establish whistleblower policies for the Corporation providing employees, officers, directors and other stakeholders, with the opportunity to raise, anonymously or not, questions, complaints or concerns regarding the Corporation's practices, including fraud, policy violations, any illegal or unethical conduct, and any accounting, auditing or internal control matters. The Audit Committee will provide oversight over the Corporation's whistleblower policies and practices, with management being responsible for reviewing the Corporation's Whistleblowing Policy on an annual basis, to ensure that any questions, complaints, or concerns are adequately received, reviewed, investigated, documented, and resolved.

3. COMPOSITION AND PROCEDURES

(a) Size of Board and Selection Process — The directors of the Corporation are elected each year by the shareholders at the annual meeting of shareholders. Subject to nomination rights granted to certain shareholder(s) of the Corporation pursuant to which such shareholder(s) are entitled to nominate directors to the Board, the Governance, Nominating and Compensation Committee recommends to the full Board the nominees for election to the Board and the Board proposes individual nominees to the shareholders for election. In addition to specific contractual nomination rights provided to certain shareholder(s), any shareholder may propose a nominee for election to the Board either by means of a shareholder proposal or at the annual meeting itself, upon compliance with the requirements prescribed by the *Business Corporations Act* (Alberta) and any advance-notice provisions then in force. The Board also recommends the number of directors on the Board to shareholders for approval. Subject to the Corporation's articles, between annual meetings, the Board may appoint directors to serve until the next annual meeting.

(b) Qualifications — Directors should have the highest personal and professional ethics and values and be committed to advancing the best interests of the Corporation. They should possess skills and competencies in areas that are relevant to the Corporation's activities. The Lead Independent Director and, other than in temporary circumstances,[2] a majority of the directors will be Independent Directors, based on the rules and guidelines of applicable stock exchanges and securities regulatory authorities. The Board is committed to enhancing diversity on the Board.

(c) Director Education and Orientation — The Corporation's management team is responsible for providing an orientation program for new directors in respect of the Corporation and the role and responsibilities of directors. In addition, directors will, as required, receive continuing education about the Corporation to maintain a current understanding of the Corporation's business and operations, industries, and sectors in which we operate globally, material developments and trends in asset management and the Corporation's strategic initiatives.

(d) Meetings — The Chair is responsible for approving the agenda for each Board meeting. Prior to each Board meeting, the Chair of the Board reviews agenda items for the meeting with the CEO, Chief Financial Officer, and Corporate Secretary, before circulation to the full Board. The Board meets at least once each quarter to review and approve the Corporation's quarterly earnings report and consider dividend payments and to review specific items of business including transactions and strategic initiatives. The Board holds additional meetings as necessary to consider special business.

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[2] Temporary circumstances include vacancies or changes to the Board's composition or size that are approved by the Board in its discretion, provide that the duration of such circumstances is expected to be less than one year.

The Board also meets once a year to review the Corporation's annual business plan and long-term strategy. Materials for each meeting are distributed to the directors in advance of the meeting. At the conclusion of each Board meeting, the independent directors meet without any other person present. The Lead Independent Director chairs these in-camera sessions.

(e) Committees — The Board has established the following standing Committees to assist it in discharging its responsibilities: (i) Audit and (ii) Governance, Nominating and Compensation. Special Committees are established, from time to time, to assist the Board in connection with specific matters. The Chair of each Committee reports to the Board following meetings of their Committee. The governing charter of each standing Committee is reviewed and approved annually by the Board.

(f) Evaluation — The Governance, Nominating and Compensation Committee performs an annual evaluation of the effectiveness of the Board as a whole, the standing committees of the Board and the contributions of individual directors and provides a report to the Board on the findings of this process. In addition, each individual director and each standing committee assesses its own performance annually.

(g) Compensation — The Governance, Nominating and Compensation Committee recommends to the Board the compensation for non-management directors (it is the policy of the Corporation that management directors do not receive compensation for their service on the Board). In reviewing the adequacy and form of compensation, the Governance, Nominating and Compensation Committee seeks to ensure that director compensation reflects the responsibilities and risks involved in being a director of the Corporation and aligns the interests of the directors with the best interests of the Corporation.

(h) Access to Outside Advisors — The Board and any committee may at any time retain outside financial, legal, or other advisors at the expense of the Corporation. Any director may, subject to the approval of the Chair of the Board, retain an outside advisor at the expense of the Corporation.

(i) Charter of Expectations — From time to time, the Board may adopt a Charter of Expectations for Directors which outlines the basic duties and responsibilities of directors and the expectations the Corporation places on them in terms of professional and personal competencies, performance, behaviour, attendance and engagement and Board and Committee meetings, share ownership, conflicts of interest, change of circumstances and resignation events.

Annex A

Definitions for Board and Committee Charters

"**Audit Committee**" means the audit committee of the Board.

"**Board**" means the Board of Directors of the Corporation.

"**Board Interlocks**" means when two directors of one public company sit together on the board of another company.

"**Committee Interlocks**" means when a Board Interlock exists, plus the relevant two directors also sit together on a board committee for one or both of the companies.

"**Financially Literate**" means the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of the issues that can reasonably be expected to be raised by the Corporation's financial statements.

"**GAAP**" means Canadian generally accepted accounting principles, as amended from time to time.

"**Governance, Nominating and Compensation Committee**" means the Governance, Nominating and Compensation Committee of the Board.

"**Immediate Family Member**" means an individual's spouse, parent, child, sibling, mother or father-in-law, son or daughter-in-law, brother or sister-in-law, and anyone (other than an employee of either the individual or the individual's immediate family member) who shares the individual's home.

"**Independent Director(s)**" means a director who has been affirmatively determined by the Board to have no material relationship with the Corporation, either directly or as a partner, shareholder or officer of an organization that has a relationship with the Corporation. A material relationship is one that could reasonably be expected to interfere with a director's exercise of independent judgment. In addition to any other requirement of applicable securities laws or stock exchange provisions, the following individuals are considered to have a material relationship with the Corporation:

(a) an individual who is, or has been within the last three years, an employee or executive officer of the Corporation;

(b) an individual whose Immediate Family Member is, or has been within the last three years, an executive officer of the Corporation;

(c) an individual who: (i) is a partner of a firm that is the Corporation's internal or external auditor, (ii) is an employee of that firm, or (iii) was within the last three years a partner or employee of that firm and personally worked on the Corporation's audit within that time;

(d) an individual whose spouse, minor child or stepchild, or child or stepchild who shares a home with the individual: (i) is a partner of a firm that is the Corporation's internal or external auditor, (ii) is an employee of that firm and participates in its audit, assurance or tax compliance (but not tax planning) practice, or (iii) was within the last three years a partner or employee of that firm and personally worked on the Corporation's audit within that time;

(e) an individual who, or whose Immediate Family Member, is or has been within the last three years, an executive officer of an entity if any of the Corporation's current executive officers serves or served at that same time on the entity's compensation committee; and

(f) an individual who received, or whose immediate family member who is employed as an executive officer of the Corporation received, more than $75,000 in direct compensation from the Corporation during any 12-month period within the last three years.

For the purposes of clauses (c) and (d) above, a "partner" does not include a fixed income partner whose interest in the firm that is the internal or external auditor is limited to the receipt of fixed amounts of compensation (including deferred compensation) for prior service with that firm if the compensation is not contingent in any way on continued service.

For the purposes of clause (f) above, direct compensation does not include: (i) remuneration for acting as a member of the board of directors or of any board committee of the Corporation, and (ii) the receipt of fixed amounts of compensation under a retirement plan (including deferred compensation) for prior service with the issuer if the compensation is not contingent in any way on continued service.

An individual will not be considered to have a material relationship with the Corporation solely because the individual or their Immediate Family Member: (i) has previously acted as an interim chief executive officer of the Corporation, or (ii) acts, or has previously acted, as a chair or vice-chair of the board of directors or of any board committee of the Corporation on a part-time basis.

An individual who: (a) accepts, directly or indirectly, any consulting, advisory or other compensatory fee from the Corporation or any subsidiary entity of the Corporation, other than as remuneration for (i) acting in their capacity as a member of the Board, any Committee, or as a Chair, Vice-Chair or Lead Director of the Board, or (ii) acting in their capacity as a member of the board of directors or any committee of the board of directors or as chair, vice-chair or lead director of the board of directors of a subsidiary entity of the Corporation, (b) is an affiliated entity (within the meaning of National Instrument 52-110 — Audit Committees) of the Corporation or any of its subsidiary entities, is considered to have a material relationship with the Corporation. "Indirect acceptance" by an individual of any consulting, advisory or other compensatory fee includes acceptance of a fee by (a) an individual's spouse, minor child or stepchild, or a child or stepchild who shares the individual's home; or (b) an entity in which such individual is a partner, member, an officer such as a managing director occupying a comparable position or executive officer, or occupies a similar position (except limited partners, non-managing members and those occupying similar positions who, in each case, have no active role in providing services to the entity) and which provides accounting, consulting, legal, investment banking or financial advisory services to the Corporation or any subsidiary entity of the Corporation. For the purposes of the foregoing, compensatory fees do not include the receipt of fixed amounts of compensation under a retirement plan (including deferred compensation) for prior service with the Corporation if the compensation is not contingent in any way on continued service.

For the purposes of the definition of Independent Director, the term "Corporation" includes any parent or subsidiary in a consolidated group with the Corporation and currently includes Brookfield Asset Management, Brookfield Infrastructure Partners L.P., Brookfield Infrastructure Corporation, Brookfield Corporation, or any of their respective affiliates.

"**Lead Independent Director**" means an Independent Director responsible for facilitating the functioning of the Board independent of management and a non-independent Chair.

"**Sustainability**" includes but is not limited to responsibility or experience overseeing and/or managing: climate change risks; GHG emissions; natural resources; waste management; energy efficiency; biodiversity; water use; environmental regulatory and/or compliance matters; health and safety; human rights; labour practices; diversity and inclusion; talent attraction and retention; human capital development; community/stakeholder engagement; board composition and engagement; business ethics; anti-bribery & corruption; audit practices; regulatory functions; and data protection and privacy.

APPENDIX B — AUDIT COMMITTEE CHARTER

ROCKPOINT GAS STORAGE INC.

AUDIT COMMITTEE CHARTER[1]

A committee of the board of directors (the "**Board**") of Rockpoint Gas Storage Inc. (the "**Corporation**") to be known as the Audit Committee (the "**Committee**") shall have the following terms of reference:

MEMBERSHIP AND CHAIR

Following each annual meeting of shareholders, the Board shall appoint from its number three or more directors (the "**Members**" and each a "**Member**") to serve on the Committee until the close of the next annual meeting of shareholders of the Corporation or until the Member ceases to be a director, resigns or is replaced, whichever occurs first.

The Members will be selected by the Board on the recommendation of the Governance, Nominating and Compensation Committee. Any Member may be removed from office or replaced at any time by the Board. All of the Members will be Independent Directors. In addition, every Member will be Financially Literate. Members may not serve on more than three public company audit committees, except with the prior approval of the Board. Any such determination shall be disclosed in the Corporation's Management Information Circular.

The Board shall appoint one Member as the chair of the Committee (the "**Chair**"). If the Chair is absent from a meeting, the Members shall select a Member from those in attendance to act as Chair of the meeting.

SUBCOMMITTEES

The Committee may form subcommittees for any purpose and may delegate to a subcommittee such of the Committee's powers and authorities as the Committee deems appropriate.

RESPONSIBILITIES

The Committee shall:

Auditor

(a) oversee the work of the Corporation's external auditor (the "**Auditor**") engaged for the purpose of preparing or issuing an auditor's report or performing other audit, review or attest services for the Corporation and its subsidiaries;

(b) require the Auditor to report directly to the Committee;

(c) review and evaluate (taking into account the opinions of management and the Independent Auditor (as defined below)) the Auditor's independence, experience, qualifications and performance (including the performance of the lead audit partner) and determine whether the Auditor should be appointed or re-appointed, and recommend the Auditor to the Board for appointment or re-appointment by the shareholders;

(d) where appropriate, recommend to the Board to terminate the Auditor;

(e) when a change of Auditor is proposed, review all issues related to the change, including the information to be included in the notice of change of auditor as required, and the orderly transition of such change;

(f) review the terms of the Auditor's engagement and the appropriateness and reasonableness of the proposed audit fees and recommend the compensation of the Auditor to the Board;

[1] Capitalized terms used in this Charter but not otherwise defined herein have the meaning attributed to them in the Board's "*Definitions for Board and Committee Charters*" which is annexed hereto as "Annex A". The Governance, Nominating and Compensation Committee will review the Definitions for Board and Committee Charters at least annually and submit any proposed amendments to the Board for approval as it deems necessary and appropriate.

(g) at least annually, obtain and review a report by the Auditor describing:

  (i) the Auditor's internal quality-control procedures; and

  (ii) any material issues raised by the most recent internal quality control review, or peer review, of the Auditor, or review by any independent oversight body such as the Canadian Public Accountability Board, or inquiry or investigation by any governmental or professional authorities within the preceding five years respecting one or more independent audits carried out by the Auditor, and the steps taken to deal with any issues raised in any such review;

(h) at least annually, confirm that the Auditor has submitted a formal written statement describing all of its relationships with the Corporation; discuss with the Auditor any disclosed relationships or services that may affect its objectivity and independence; obtain written confirmation from the Auditor that it is objective and independent within the meaning of the Rules of Professional Conduct/Code of Ethics adopted by the provincial institute or order of chartered accountants to which it belongs and is an independent public accountant within the meaning of the Independence Standards of the Chartered Professional Accountants of Canada, and is in compliance with any independence requirements adopted by the Public Company Accounting Oversight Board; and, confirm that the Auditor has complied with applicable laws respecting the rotation of certain members of the audit engagement team;

(i) ensure the regular rotation of the audit engagement team members as required by law, and periodically consider whether there should be regular rotation of the Auditor;

(j) meet privately with the Auditor as frequently as the Committee feels is appropriate to fulfill its responsibilities, which will not be less frequent than annually, to discuss any items of concern to the Committee or the Auditor, including:

  (i) planning and staffing of the audit;

  (ii) any material written communications between the Auditor and management;

  (iii) whether or not the Auditor is satisfied with the quality and effectiveness of financial recording procedures and systems;

  (iv) the extent to which the Auditor is satisfied with the nature and scope of its examination;

  (v) whether or not the Auditor has received the full co-operation of management of the Corporation;

  (vi) the Auditor's opinion of the competence and performance of the Corporation's Chief Financial Officer ("**CFO**") and other key financial personnel of the Corporation;

  (vii) the items required to be communicated to the Committee in accordance with generally accepted auditing standards;

  (viii) all critical accounting policies and practices to be used by the Corporation;

  (ix) all alternative treatments of financial information within GAAP that have been discussed with management, ramifications of the use of such alternative disclosures and treatments, and the treatment preferred by the Auditor;

  (x) any difficulties encountered in the course of the audit work, any restrictions imposed on the scope of activities or access to requested information, any significant disagreements with management and management's response; and

  (xi) any illegal act that may have occurred and the discovery of which is required to be disclosed to the Committee;

(k) implement, review, revise and approve any Audit and Non-Audit Services Pre-Approval Policy, as needed, which sets forth the parameters by which the Auditor can provide certain audit and non-audit services to the Corporation and its subsidiaries not prohibited by law and the process by which the Committee pre-approves such services. At each quarterly meeting of the Committee, the Committee will ratify all audit and non-audit services provided by the Auditor, as applicable, to the Corporation and its subsidiaries for the then-ended quarter;

(l) resolve any disagreements between management and the Auditor regarding financial reporting; and

(m) set clear policies for hiring partners and employees and former partners and employees of the external Auditor.

Financial Reporting

(a) prior to disclosure to the public, review, and, where appropriate, recommend for approval by the Board, the following:

    (i) audited annual financial statements, in conjunction with the report of the Auditor;

    (ii) interim financial statements;

    (iii) annual and interim management discussion and analysis of financial condition and results of operation;

    (iv) reconciliations of the annual or interim financial statements, to the extent required under applicable rules and regulations; and

    (v) all other audited or unaudited financial information, as appropriate, contained in public disclosure documents, including without limitation, any prospectus, or other offering or public disclosure documents and financial statements required by regulatory authorities;

(b) review and discuss with management prior to public dissemination earnings press releases and other press releases containing financial information (to ensure consistency of the disclosure to the financial statements), as well as financial information and earnings guidance provided to analysts including the use of "pro forma" or "adjusted" non-GAAP information in such press releases and financial information. Such review may consist of a general discussion of the types of information to be disclosed or the types of presentations to be made;

(c) review the effect of regulatory and accounting initiatives, as well as any of the Corporation's and its subsidiaries' asset or debt financing activities that are not required under GAAP to be incorporated into their financial statements (commonly known as "off-balance sheet financing");

(d) review disclosures made to the Committee by the Chief Executive Officer ("**CEO**") and CFO of the Corporation during their certification process for applicable securities law filings about any significant deficiencies and material weaknesses in the design or operation of the Corporation's and its subsidiaries' internal control over financial reporting which are reasonably likely to adversely affect the Corporation's and its subsidiaries' ability to record, process, summarize and report financial information, and any fraud involving management or other employees;

(e) review the effectiveness of management's policies and practices concerning financial reporting, any proposed changes in major accounting policies, the appointment and replacement of management responsible for financial reporting and the internal audit function;

(f) review the adequacy of the internal controls that have been adopted by the Corporation to safeguard assets from loss and unauthorized use and to verify the accuracy of the financial records and any special audit steps adopted in light of material control deficiencies; and

(g) for the financial information of any other subsidiary entity below the Corporation that has an audit committee which is comprised of a majority of Independent Directors, and which is included in the Corporation's consolidated financial statements, it is understood that the Committee will rely on the review and approval of such information by the audit committee and the board of directors of each such subsidiaries.

Internal Audit; Controls and Procedures; and Other

(a) meet privately with the team responsible for the Corporation's internal audit and/or controls function as frequently as the Committee feels appropriate to fulfill its responsibilities, which will not be less frequent than annually, to discuss any items of concern;

(b) require the team responsible for the Corporation's internal audit and/or controls function to report directly to the Committee;

(c) discuss with the team responsible for the Corporation's internal audit and/or controls function, and management, the appropriate authority, role, responsibilities, scope, and services of the Internal Auditor;

(d) review the mandate, budget, planned activities, performance, staffing and organizational structure of the Corporation's internal audit and/or controls function (which may be outsourced to a third-party firm, other than the Corporation's Auditor) to confirm that, it is staffed by adequately qualified persons and has sufficient resources to effectively carry out its mandate and, as necessary, it operates and reports to the Committee independent of management. The Committee will discuss this mandate with the team responsible for the Corporation's internal audit and/or controls function and Senior Management, review the appointment and replacement of the team responsible for the Corporation's internal audit and/or controls function, review significant results of the activities of the Corporation's internal audit and/or controls function, and the results of such function's quality assurance program. As part of this process, the Committee reviews and approves the internal audit and controls plan, budget, and communication plan on an annual basis;

(e) review the controls and procedures that have been adopted to confirm that material financial information about the Corporation and its subsidiaries that is required to be disclosed under applicable law or stock exchange rules is disclosed, review the public disclosure of financial information extracted or derived from the Corporation's financial statements and periodically assess the adequacy of such controls and procedures;

(f) oversee the Corporation's cybersecurity program and practices; and periodically review management's reports and updates on cybersecurity risks and issues;

(g) review of allegations of fraud related to financial reporting that are brought to or come to the attention of the Committee through the Corporation's reporting hotline, a referral by management, or otherwise;

(h) periodically review the status of taxation matters of the Corporation;

(i) periodically review the Corporation's policies with respect to risk assessment and management, particularly financial risk exposure, including the steps taken to monitor and control risks; and

(j) consider other matters of a financial nature as directed by the Board.

OpCos

(a) for so long as the Corporation holds less than a majority of (i) the limited partnership units of Swan Equity Aggregator LP ("**Swan OpCo**"), and (ii) the common shares BIF II CalGas (Delaware) LLC ("**BIF OpCo**", together with Swan OpCo, the "**OpCos**"), engage directly with the external and internal auditors of each OpCo and consult with the OpCos and auditors in the review and preparation of the quarterly and annual financial statements, as applicable, of each OpCo.

LIMITATION OF AUDIT COMMITTEE ROLE

The Committee's function is one of oversight. The Corporation's management is responsible for preparing the Corporation's financial statements and, along with the team responsible for the Corporation's internal audit and/or controls function, for developing and maintaining systems of internal accounting and financial controls. The Auditor will assist the Committee and the Board in fulfilling their responsibilities for review of the financial statements and internal controls, and the Auditor will be responsible for the independent audit of the financial statements. The Committee expects the Auditor to call to its attention any accounting, auditing, internal accounting control, regulatory or other related matters that the Auditor believes warrant consideration or action. The Committee recognizes that the Corporation's finance team, the team responsible for the Corporation's internal audit and/or controls function and the Auditor have more knowledge and information about the Corporation's financial affairs than do the Committee's members. Accordingly, in carrying out its oversight responsibilities, the Committee does not provide any expert or special assurance as to the Corporation's financial statements or internal controls or any professional certification as to the Auditor's work.

REPORTING

The Committee will regularly report to the Board on:

(a) the Auditor's independence;

(b) the performance of the Auditor and the Committee's recommendations regarding its reappointment or termination;

(c) the performance of the team members responsible for the Corporation's internal audit and/or controls function;

(d) the adequacy of the Corporation's internal controls and disclosure controls;

(e) its recommendations regarding the annual and interim financial statements of the Corporation and, to the extent applicable, any reconciliation of the Corporation's financial statements, including any issues with respect to the quality or integrity of the financial statements;

(f) its review of any other public disclosure document including the annual report and the annual and interim management's discussion and analysis of financial condition and results of operations;

(g) the Corporation's compliance with legal and regulatory requirements, particularly those related to financial reporting; and

(h) all other significant matters it has addressed and with respect to such other matters that are within its responsibilities.

In addition, if and when required or appropriate from time to time, the Committee may also report to another committee of the Board.

COMPLAINTS PROCEDURE

The Corporation's Code of Business Conduct and Ethics (the "**Code**") requires employees to report to their supervisor or internal legal counsel any suspected violations of the Code, including (i) fraud or deliberate errors in the preparation, maintenance, evaluation, review or audit of any financial statement or financial record; (ii) deficiencies in, or noncompliance with, internal accounting controls; (iii) misrepresentations or false statements in any public disclosure documents; and (iv) any deviations from full, true and plain reporting of the Corporation's financial condition, as well as any other illegal or unethical behavior. Alternatively, employees may report such behavior anonymously through the Corporation's reporting hotline which is managed by an independent third party. The Corporation also maintains a Whistleblowing Policy which reinforces the Corporation's commitment to providing a mechanism for employees to report suspected wrongdoing without retaliation.

The Audit Committee will periodically review the procedure for the receipt, retention, treatment, and follow-up of complaints received by the Corporation through the Corporation's reporting hotline or otherwise regarding accounting, internal controls, disclosure controls or auditing matters and the procedure for the confidential, anonymous submission of concerns by employees of the Corporation regarding such matters.

REVIEW AND DISCLOSURE

The Committee will review this Charter at least annually and submit it to the Governance, Nominating and Compensation Committee together with any proposed amendments. The Governance, Nominating and

Compensation Committee will review this Charter and submit it to the Board for approval with such further amendments as it deems necessary and appropriate.

This Charter will be posted on the Corporation's website and the Management Information Circular of the Corporation will state that this Charter is available on the Corporation's website. This Charter will also be reproduced in full as an appendix to the Corporation's Annual Information Form.

ASSESSMENT

At least annually, the Governance, Nominating and Compensation Committee will review the effectiveness of this Committee in fulfilling its responsibilities and duties as set out in this Charter. The Committee will also conduct its own assessment of the Committee's performance on an annual basis.

ACCESS TO OUTSIDE ADVISORS AND SENIOR MANAGEMENT

The Committee may retain any outside advisor, including legal counsel, at the expense of the Corporation, without the Board's approval, at any time. The Committee has the authority to determine any such advisor's fees and any other retention terms.

The Corporation will provide for appropriate funding, for payment of compensation to any auditor engaged to prepare or issue an audit report or perform other audit, review or attest services, and ordinary administrative expenses of the Committee.

Members will meet privately with senior management as frequently as they feel is appropriate to fulfill the Committee's responsibilities, but not less than annually.

MEETINGS

Meetings of the Committee may be called by any Member, the Chair of the Board, the CEO or CFO of the Corporation, the team responsible for the Corporation's internal audit and/or controls function or the Auditor. Meetings will be held each quarter and at such additional times as is necessary for the Committee to fulfill its responsibilities. The Committee shall appoint a secretary to be the secretary of each meeting of the Committee and to maintain minutes of the meeting and deliberations of the Committee.

The powers of the Committee shall be exercisable at a meeting at which a quorum is present. Subject to the Corporation's articles, by-laws or other governing agreement, quorum shall be not less than a majority of the Members at the relevant time. Matters decided by the Committee shall be decided by majority vote. Subject to the foregoing, the *Business Corporations Act* (Alberta) and the articles, by-laws, or other governing agreement of the Corporation, and, unless otherwise determined by the Board, the Committee shall have the power to regulate its procedures.

Notice of each meeting shall be given to each Member, the team responsible for the Corporation's internal audit and/or controls function, the Auditor, the Chair of the Board, and the CEO of the Corporation. Notice of a meeting may be given orally or by letter, electronic mail, telephone, or other generally accepted means not less than 24 hours before the time fixed for the meeting. Members may waive notice of any meeting and attendance at a meeting is deemed waiver of notice. The notice need not state the purpose or purposes for which the meeting is being held.

The Committee may invite from time to time such persons as it may see fit to attend its meetings and to take part in discussion and consideration of the affairs of the Committee. The Committee may require the auditors and/or members of the Corporation's management to attend any or all meetings.

Annex A

Definitions for Board and Committee Charters

"**Audit Committee**" means the audit committee of the Board.

"**Board**" means the Board of Directors of the Corporation.

"**Board Interlocks**" means when two directors of one public company sit together on the board of another company.

"**Committee Interlocks**" means when a Board Interlock exists, plus the relevant two directors also sit together on a board committee for one or both of the companies.

"**Financially Literate**" means the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of the issues that can reasonably be expected to be raised by the Corporation's financial statements.

"**GAAP**" means Canadian generally accepted accounting principles, as amended from time to time.

"**Governance, Nominating and Compensation Committee**" means the Governance, Nominating and Compensation Committee of the Board.

"**Immediate Family Member**" means an individual's spouse, parent, child, sibling, mother or father-in-law, son or daughter-in-law, brother or sister-in-law, and anyone (other than an employee of either the individual or the individual's immediate family member) who shares the individual's home.

"**Independent Director(s)**" means a director who has been affirmatively determined by the Board to have no material relationship with the Corporation, either directly or as a partner, shareholder or officer of an organization that has a relationship with the Corporation. A material relationship is one that could reasonably be expected to interfere with a director's exercise of independent judgment. In addition to any other requirement of applicable securities laws or stock exchange provisions, the following individuals are considered to have a material relationship with the Corporation:

(a) an individual who is, or has been within the last three years, an employee or executive officer of the Corporation;

  (i) an individual whose Immediate Family Member is, or has been within the last three years, an executive officer of the Corporation;

  (ii) an individual who: (i) is a partner of a firm that is the Corporation's internal or external auditor, (ii) is an employee of that firm, or (iii) was within the last three years a partner or employee of that firm and personally worked on the Corporation's audit within that time;

  (iii) an individual whose spouse, minor child or stepchild, or child or stepchild who shares a home with the individual: (i) is a partner of a firm that is the Corporation's internal or external auditor, (ii) is an employee of that firm and participates in its audit, assurance or tax compliance (but not tax planning) practice, or (iii) was within the last three years a partner or employee of that firm and personally worked on the Corporation's audit within that time;

  (iv) an individual who, or whose Immediate Family Member, is or has been within the last three years, an executive officer of an entity if any of the Corporation's current executive officers serves or served at that same time on the entity's compensation committee; and

  (v) an individual who received, or whose immediate family member who is employed as an executive officer of the Corporation received, more than $75,000 in direct compensation from the Corporation during any 12-month period within the last three years.

For the purposes of clauses (c) and (d) above, a "partner" does not include a fixed income partner whose interest in the firm that is the internal or external auditor is limited to the receipt of fixed amounts of compensation (including deferred compensation) for prior service with that firm if the compensation is not contingent in any way on continued service.

For the purposes of clause (f) above, direct compensation does not include: (i) remuneration for acting as a member of the board of directors or of any board committee of the Corporation, and (ii) the receipt of fixed amounts of compensation under a retirement plan (including deferred compensation) for prior service with the issuer if the compensation is not contingent in any way on continued service.

An individual will not be considered to have a material relationship with the Corporation solely because the individual or their Immediate Family Member: (i) has previously acted as an interim chief executive officer of the Corporation, or (ii) acts, or has previously acted, as a chair or vice-chair of the board of directors or of any board committee of the Corporation on a part-time basis.

An individual who: (a) accepts, directly or indirectly, any consulting, advisory or other compensatory fee from the Corporation or any subsidiary entity of the Corporation, other than as remuneration for (i) acting in their capacity as a member of the Board, any Committee, or as a Chair, Vice-Chair or Lead Director of the Board, or (ii) acting in their capacity as a member of the board of directors or any committee of the board of directors or as chair, vice-chair or lead director of the board of directors of a subsidiary entity of the Corporation, (b) is an affiliated entity (within the meaning of National Instrument 52-110 — *Audit Committees*) of the Corporation or any of its subsidiary entities, is considered to have a material relationship with the Corporation. "Indirect acceptance" by an individual of any consulting, advisory or other compensatory fee includes acceptance of a fee by (a) an individual's spouse, minor child or stepchild, or a child or stepchild who shares the individual's home; or (b) an entity in which such individual is a partner, member, an officer such as a managing director occupying a comparable position or executive officer, or occupies a similar position (except limited partners, non-managing members and those occupying similar positions who, in each case, have no active role in providing services to the entity) and which provides accounting, consulting, legal, investment banking or financial advisory services to the Corporation or any subsidiary entity of the Corporation. For the purposes of the foregoing, compensatory fees do not include the receipt of fixed amounts of compensation under a retirement plan (including deferred compensation) for prior service with the Corporation if the compensation is not contingent in any way on continued service.

For the purposes of the definition of Independent Director, the term "Corporation" includes any parent or subsidiary in a consolidated group with the Corporation and includes Brookfield Asset Management, Brookfield Infrastructure Partners L.P., Brookfield Infrastructure Corporation, Brookfield Corporation, or any of their respective affiliates.

"**Lead Independent Director**" means an Independent Director responsible for facilitating the functioning of the Board independent of management and a non-independent Chair.

"**Sustainability**" includes but is not limited to responsibility or experience overseeing and/or managing: climate change risks; GHG emissions; natural resources; waste management; energy efficiency; biodiversity; water use; environmental regulatory and/or compliance matters; health and safety; human rights; labour practices; diversity and inclusion; talent attraction and retention; human capital development; community/ stakeholder engagement; board composition and engagement; business ethics; anti-bribery & corruption; audit practices; regulatory functions; and data protection and privacy.

CERTIFICATE OF THE COMPANY AND PROMOTER

Dated: October 8, 2025

The prospectus constitutes full, true and plain disclosure of all material facts relating to the securities offered by this prospectus as required under securities legislation of each of the provinces and territories in Canada.

ROCKPOINT GAS STORAGE INC.

(signed) "*Tobias McKenna*"
Mr. Tobias McKenna
Chief Executive Officer

(signed) "*Jon Syrnyk*"
Mr. Jon Syrnyk
Chief Financial Officer

On behalf of the Board of Directors

(signed) "*Brian Baker*"
Mr. Brian Baker
Director

(signed) "*William Burton*"
Mr. William Burton
Director

THE PROMOTER

BROOKFIELD ASSET MANAGEMENT PRIVATE INSTITUTIONAL CAPITAL ADVISER (CANADA), L.P.,
by its general partner,
BROOKFIELD INFRASTRUCTURE GP ULC

(signed) "*Carl Ching*"
Mr. Carl Ching
Senior Vice President

CERTIFICATE OF THE OPERATING ENTITIES

Dated: October 8, 2025

The prospectus constitutes full, true and plain disclosure of all material facts relating to the securities offered by this prospectus as required under securities legislation of each of the provinces and territories in Canada.

BIF II CALGAS (DELAWARE) LLC

(signed) "*Tobias McKenna*" Mr. Tobias McKenna Chief Executive Officer	(signed) "*Jon Syrnyk*" Mr. Jon Syrnyk Chief Financial Officer

On behalf of the Board of Managers

(signed) "*Brian Baker*" Mr. Brian Baker Manager	(signed) "*William Burton*" Mr. William Burton Manager

SWAN EQUITY AGGREGATOR LP

(signed) "*Tobias McKenna*" Mr. Tobias McKenna Chief Executive Officer of the General Partner on behalf of the Partnership	(signed) "*Jon Syrnyk*" Mr. Jon Syrnyk Chief Financial Officer of the General Partner on behalf of the Partnership

On behalf of the Board of Directors of the General Partner, Swan Holdings GP (Canada) Inc.,
on behalf of Swan Equity Aggregator LP

(signed) "*Brian Baker*" Mr. Brian Baker Director	(signed) "*William Burton*" Mr. William Burton Director

CERTIFICATE OF THE UNDERWRITERS

Dated: October 8, 2025

To the best of our knowledge, information and belief, this prospectus constitutes full, true and plain disclosure of all material facts relating to securities offered by this prospectus as required under the securities legislation of each of the provinces and territories in Canada.

(signed) "*Curtis Dunford*"
RBC DOMINION SECURITIES INC.

(signed) "*Sam Johnson*"
J.P. MORGAN SECURITIES CANADA INC.

(signed) "*Darin Deschamps*"
WELLS FARGO SECURITIES CANADA, LTD.

(signed) "*Tim Lisevich*"
BMO NESBITT BURNS INC.

(signed) "*Douglas Pearce*"
CIBC WORLD MARKETS INC.

(signed) "*Tuc Tuncay*"
NATIONAL BANK FINANCIAL INC.

(signed) "*David Baboneau*"
SCOTIA CAPITAL INC.

(signed) "*Taso Arvanitis*"
TD SECURITIES INC.

(signed) "*Robyn Hemminger*"
ATB SECURITIES INC.

(signed) "*Alan Fidler*"
DESJARDINS SECURITIES INC.

(signed) "*Benjamin Gazdic*"
PETERS & CO. LIMITED