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CORIX DGE 2025 TO 2028 REVENUE REQUIREMENTS AND RATES EXHIBIT B-1

June 3, 2025

Via eFile

British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, British Columbia V6Z 2N3

Attention: Commission Secretary

Dear Commission Secretary

RE: **Corix Dockside Green DE Limited Partnership**
Dockside Green Energy
2025-2028 Revenue Requirements and Rate Application

Corix Dockside Green DE Limited Partnership (Corix) hereby submits an application seeking approval from the British Columbia Utilities Commission (BCUC) of revenue requirements and rates for Dockside Green Energy (DGE) for 2025, 2026, 2027 and 2028, with rates proposed for July 1, 2025, January 1, 2026, January 1, 2027, and January 1, 2028 (Application). Corix submits the following documents.

1. DGE 2025-2028 Revenue Requirement and Rates Application; and
2. DGE Financial Model (Confidential).

The approvals sought have been outlined in Section 1.3 of the Application. Corix respectfully requests that, by June 27, 2025, the BCUC approve the proposed rates effective July 1, 2025, on an interim basis as discussed in Sections 1.3, 1.3.1, 1.3.2 and 12.4 of the Application. Approval of interim rates by the date mentioned above, would allow Corix adequate time to notify customers of the approved interim rates prior to the issuance of the first bill with the new rates.

Please feel free to contact us if you have any questions.

All of which is respectfully submitted,

Corix Dockside Green DE Limited Partnership

Per:

Errol South
Director, Regulatory Affairs

CORIX DOCKSIDE GREEN DE LIMITED PARTNERSHIP

2025-2028 REVENUE REQUIREMENTS AND RATES APPLICATION

Submitted To:

British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC, V6Z 2N3

Attention:

Commission Secretary

Submitted From:

Corix Dockside Green DE Limited Partnership
Suite 1160, 1188 West Georgia Street
Vancouver, BC, V6E 4A2

Contact: regulatory@corix.com

Date Submitted: June 3, 2025

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Executive Summary

Corix Dockside Green DE Limited Partnership (referred to in this Application as "Corix") is the regulated utility responsible for operating Dockside Green Energy (DGE), a district energy system serving the Dockside Green community in Victoria, British Columbia. Corix seeks approval from the British Columbia Utilities Commission (BCUC) of the revenue requirements and rates for customers of the DGE for 2025, 2026, 2027 and 2028 effective July 1, 2025, January 1, 2026, January 1, 2027 and January 1, 2028 respectively (Application). All proposals, including requests for confidentiality, update to the deemed debt interest rate, the establishment of two new deferral accounts, and transfer of non-rate base accounts into rate base are included in Section 1.3 of this Application. Corix proposes a written hearing with two rounds of information requests as outlined in the proposed regulatory timetable in Section 1.4. Corix requests that the BCUC approve on an interim basis, effective on July 1, 2025, and January 1, 2026, the proposed 2025 and 2026 rates in Table 27 in Section 12.4 of this Application.

Section 2 provides background on the utility, including its acquisition by Corix in 2018 and subsequent restructuring transactions. Section 3 outlines how Corix has addressed directives from previous BCUC decisions, including the 2019-2023 Revenue Requirements and Rates Application and subsequent flow-through energy cost and flow-through property tax applications. All previous directives have been addressed in this application.

Section 4 presents the updated buildout schedule and thermal energy demand forecast. As of 2024, only 52% of the total forecasted floor area has been connected to DGE. The remaining build-out is now expected to be completed by 2035, three years later than previously forecast. The delays have significantly impacted revenue projections and is a key driver of the growing Revenue Deficiency Deferral Account (RDDA) balance.

Sections 5, 6 and 7 detail the forecasted energy supply costs, operating and maintenance (O&M) costs, and property taxes respectively.

Section 8 outlines capital expenditures, which are focused on renewal and replacement during the test period, rather than new additions. Key investments include boiler burner replacements, pump rebuilds, and upgrades to monitoring systems. Section 9 presents the revenue requirement and rate base, incorporating updated cost of capital parameters approved by Order G-321-24, including a 10.40% return on equity and a 6.28% deemed interest rate.

Section 10 provides a detailed discussion of deferral and reconciliation accounts. Corix proposes to transfer the RDDA and Property Tax Deferral Account (PTDA) into the rate base to align the accounting practices of Corix's regulated utilities. Additionally, Corix proposes the creation of two new accounts: the Regulatory Costs Variance Account (RCVA) and the Insurance Costs Variance Account (ICVA). The RCVA will capture variances in external regulatory costs, including BCUC levies, participant cost awards, and external legal and consulting fees. The ICVA will capture variances in insurance costs. Corix proposes to amortize the balance in both accounts over the test period associated with the next revenue requirement application.

Section 11 identifies the key drivers of the proposed rate increases. The most notable increase is related to Property Taxes, these have increased more than fivefold since 2018 due to the expiration of a revitalization tax exemption of which Corix had no information at the time of filing the DGE 2019 Revenue Requirements and Rates Application (2019 RRRA), in addition other contributing factors are the depletion of the original $1 million contribution fund, which was intended to stabilize rates during the early years of Corix's operation. This fund has now been exhausted, removing a buffer against revenue shortfalls. Additionally, the delayed build-out of the Dockside Green development has resulted in lower-than-expected revenues, while fixed costs have continued to rise, and labour costs have grown due to regulatory requirements. Financing costs have also increased due to a larger rate base and higher cost of capital approved by Order G-321-24. These factors have contributed to a growing RDDA, which must now be recovered through customer rates.

To address these challenges, Corix proposes to smooth rates through the RDDA up to 2044. This approach balances the need for financial sustainability with the goal of minimizing customer impacts. Corix evaluated multiple recovery scenarios and selected a rate path that provides a reasonable balance between rate stability and RDDA recovery.

Section 12 presents the proposed rate structure and scenario analyses. Corix proposes to maintain the current two-part rate structure, consisting of a Basic Charge per square metre and a Variable Energy Charge per kilowatt-hour. The Basic Charge is proposed to increase on July 1, 2025 and then annually on January 1st from 2026 to 2028 inclusive. The Variable Energy Charge is updated each year, if required, based on a separate flow-through rate-setting mechanism previously approved by the BCUC, and is outside of the scope of this Application.

Section 13 summarizes the customer and end-user bill impacts. Utility customers are expected to see an average annual bill increase of approximately 9.9% per year over the four-year test period.The table below shows the current Basic Charge, effective since January 1, 2025, and the proposed Basic Charges for each year from 2025 to 2028 along with the indicative annual bill and annual bill change for a typical residential end-user with a 800 sq. ft. suite and an annual energy consumption of 5,513 kWh. This information is provided in detail in Section 13.3 of the Application.

DGE Rates and Indicative End-User Bills	Test Period			
	2025	2026	2027	2028
Existing Basic Charge* ($/m^2 per Month)	0.4260			
Proposed Basic Charge** ($/m^2 per Month)	**0.5538**	**0.6923**	**0.7961**	**0.8916**
800 sq. ft. Residential Suite				
Annual Bill	$788	$850	$958	$1,047
Annual Change in Bill (%)	15.80%	7.82%	12.75%	9.29%

* - The DGE 2025 existing Basic Charge has been effective since January 1, 2025.
** - The DGE 2025 proposed Basic Charge has a proposed effective date of July 1, 2025.

Section 13 also provides information about two customer information sessions that Corix held for DGE customers and end-users, to share details about the proposed rate increases, explain the rationale behind them, and respond to questions.

Section 14 includes proposed amendments to the DGE tariff, including housekeeping changes and updates to the rate schedule.

This Application also includes financial schedules and relevant documents attached in the appendices. Corix considers that sufficient information has been submitted to allow for a thorough review and determinations on the approvals sought. Corix requests that the BCUC review this application using a written process based on the proposed regulatory timetable presented in Section 1.4 of the Application.

Application for Revenue Requirement and Rates

1. Introduction

1.1 Application

Dockside Green Energy (DGE) is a district energy utility that provides thermal energy utility services to the Dockside Green community in Victoria, British Columbia. Corix seeks approval from the British Columbia Utilities Commission (BCUC) of the revenue requirements and rates for customers of the DGE for 2025, 2026, 2027 and 2028, pursuant to Sections 59-61 of the *Utilities Commission Act* ("Application" or "2025-2028 DGE RRRA").

Corix further requests that the BCUC approve the rates proposed in Section 12.4 of this Application on an interim basis effective July 1, 2025, pursuant to section 89 of the *Utilities Commission Act*. Corix requests that the interim rates be approved no later than June 27, 2025, to allow Corix adequate time to notify all customers of the approved interim rates prior to the issuance of the bill for service provided in July. Details of the approvals sought are in Section 1.3 and draft Orders are included in Appendices G and H.

1.2 Application Overview

Section 1 provides an introduction to the Application, outlines the regulatory approvals sought, proposed regulatory review process, and provides the relevant contact information.

Section 2 provides the background of the utility and relevant past proceedings.

Section 3 provides the previous directives from the BCUC regarding DGE and indicates how Corix has addressed each directive.

Section 4 presents the build-out schedule, load analysis and the thermal energy demand forecast.

Section 5 presents the energy and related costs.

Section 6 presents the operating and maintenance (O&M) costs.

Section 7 presents the property tax and other fees.

Section 8 presents information regarding the capital costs.

Section 9 presents the rate base and the revenue requirement. This includes information on utility plant in service, depreciation, amortization, contributions in aid of construction and general financing assumptions.

Section 10 provides a discussion on the existing and proposed deferral and reconciliation accounts, as well as the methodologies proposed to recover or refund balances accumulated in each of these accounts.

Section 11 presents details surrounding the key drivers of the rate increases proposed in this Application.

Section 12 presents the rate design and proposed rates for DGE customers, including the rate considerations and scenario analyses to determine the proposed rates.

Section 13 presents an estimate of the average bill impact for customers and the estimated impact to the bill for a typical end-user of the utility.

Section 14 presents proposed housekeeping and rate change amendments to the DGE tariffs.

The appendices includes additional supporting information for the Application such as Financial Schedules (Appendix A), acronyms and glossary (Appendix B), previous BCUC directives (Appendix C), proposed tariff with amendments (Appendices E and F), draft BCUC orders (Appendices G and H), and cost allocation methodology manuals (Appendices I and J), and a summary report for the customer information session (Appendix K).

1.3 Regulatory Approvals Sought

Pursuant to Sections 59 to 61 and Section 89 of the Utilities Commission Act (UCA), Corix requests:

1) Approval of the proposed revenue requirements for DGE for 2025, 2026, 2027 and 2028 as described in Section 9 Revenue Requirements. These are based on:
    a. The forecast operating and maintenance costs discussed in Section 6;
    b. The forecast property and other fees discussed in Section 7;
    c. The forecast rate base as presented in Section 9.4;
    d. The depreciation and amortization outlined in Section 9.2.5;
    e. A deemed capital structure of 51% debt and 49% equity, discussed in Section 9.2.3.1;
    f. Long-term deemed debt financing costs of 6.28% per annum in 2025, 2026, 2027 and 2028, as discussed in detail in Section 9.2.3.3; and
    g. A return on equity of 10.4%, as discussed in Section 9.2.3.2.
2) Approval of a capitalized overhead methodology for DGE to record capitalized overhead in the test years, as addressed in Section 8.5.
3) Approval to establish a Regulatory Cost Variance Account to record forecast variances of actual external regulatory costs, with full amortization of any balance within the test period of the next revenue requirement application, as discussed in Section 10.5.
4) Approval to establish an Insurance Cost Variance Account to record forecast variances of actual insurance costs, with full amortization of any balance within the test period of the next revenue requirement application as discussed in Section 10.6.
5) Approval to transfer the existing Revenue Deficiency Deferral Account (RDDA) from a non-rate base account to a rate base account as discussed in Section 10.3.5
6) Approval to transfer the existing Property Tax Deferral Account from a non-rate base account to a rate base account as discussed in Section 10.4.2.
7) Approval to fully amortize any balance in the Property Tax Deferral Account within the test period of the next revenue requirement application as discussed in Section 10.4.

8) Approval of the Basic Charges proposed for 2025, 2026, 2027 and 2028 as presented in Table 27 in Section 12.4.

9) That the Basic Charges proposed for July 1, 2025 and January 1, 2026 in request number 8 above be approved on an interim and refundable basis, as discussed in Sections 1.3.2 and 1.3.3.

10) Approval to discontinue the use of the DGE Rate Rider 1 and the associated Rate Rider 1 rate-setting mechanism effective April 1, 2026, as discussed in Section 10.4.1.

11) Approval of rate schedule amendments within the DGE tariff, as discussed in Section 14.1.

12) Approval of housekeeping amendments to the terms and conditions within DGE tariff, as discussed in Section 14.2.

13) Acceptance of the updated rate schedule pages for DGE, as included in Appendix E, based on approval of the proposals related to the Basic Charge and the Rate Rider 1.

14) That all confidential information submitted in this Application remain confidential as discussed in the Confidentiality section below (see Section 1.3.4).

1.3.1 Test Period and Start of Effective Proposed Rates

The test period for this Application is from July 1, 2025 to December 31, 2028. Corix is not requesting approval of revenue requirements for DGE beyond December 31, 2028. Figures that have been presented in this Application that are outside the test period are for informational purposes only. The revenue requirements and resulting monthly rates have been calculated using 6 months for 2025 and 12 months for each of 2026, 2027 and 2028.The implications of the 6-month test year are discussed on Section 9.1.

1.3.2 Proposed Interim Rates for Application

Corix is requesting that the BCUC approve interim rates, as outlined in Table 27 in Section 12.4, effective July 1, 2025 and January 1, 2026, at the levels proposed for final approval in Table 27.

In this Application, Corix has carefully considered all the relevant factors in arriving at its proposed rates and the effective dates for the test years. The proposed rates are driven by a number of factors that have been explained in detail in Section 11. If the interim rates are not set at the proposed rates and subsequently the final rates are approved as proposed, it would lead to higher RDDA balances in the interim rate period. It would also make the disposition of interim rates more challenging where the additional recovery of costs from customers would be needed to be recovered in a short duration after the final decision causing further bill volatility during the recovery period.

Given that the regulatory proceeding is expected to conclude in the first quarter of 2026, Corix believes that establishing interim rates at the proposed levels is both prudent and necessary. Corix requests that the BCUC approve the proposed interim rates effective July 1, 2025, and January 1, 2026, to ensure an orderly implementation of the final rates.

1.3.3 Disposition of Interim Rates

Corix typically requests that any difference in revenue, as a result of the difference between the interim rates and the final rates approved by the BCUC, be recovered from or refunded to customers with interest calculated based on Corix's weighted average cost of capital (WACC), from the effective date(s) of the interim rates. This Application is requesting delivery rates effective July 1, 2025.

Corix submits there are three broad approaches for the final disposition of interim rates from July 1, 2025 to the date when final rates can be implemented for customers. The three broad approaches are:

1. Place the variance in the period into the existing DGE RDDA.
2. Re-calculate the individual monthly bills of customers for final rates. Any resulting difference would be refunded or charged to customers in the billing month of the re-calculation.
3. Aggregate the final difference and then refund or charge customers through a rate rider. Depending on the quantum of the difference, the rate rider may be refunded in full in one month or spread over several months.

In the event the final rates are not approved as proposed, Corix proposes that it provide a compliance filing following the decisions from this Application for the final disposition of interim rates. In the compliance filing Corix will make a proposal for the disposition of final rates. Corix will outline the available options and recommend an approach that best meets regulatory and administrative efficiency. Based on the compliance filing for the disposition of interim rates, the BCUC will decide on the appropriate approach for the final disposition of interim rates.

1.3.4 Confidentiality

Corix submits the financial model (Appendix A) confidentially along with this Application.

Corix understands the need for and supports open and accessible regulatory proceedings. However, information contained in the DGE financial model is strictly confidential and privileged and are exclusively for use by the BCUC and its representatives/designees in connection with the review of this Application.

The financial model is a fully functional Microsoft Excel Macro-Enabled file that is used to calculate the revenue requirements and the proposed rates. It includes detailed information regarding the cost to operate, maintain and finance the DGE, as well as the relevant assumptions upon which the calculations are based.

In accordance with BCUC's Rules of Practice and Procedure, Corix respectfully requests that the BCUC keep the entire financial model confidential in perpetuity for the reasons outlined below.

<u>Reasons for Confidentiality Request</u>

(1) Corix's district energy business operates in a competitive environment where district energy utility operators often bid competitively for the opportunity to develop greenfield district energy utilities. In addition to regulated utilities, the competitive environment includes non-regulated or contract-based opportunities. The information contained in the DGE financial model would provide counterparties and competitors valuable insight into the financial modelling of Corix's district energy utilities enabling them to have significant leverage over Corix during negotiations and bidding processes respectively. Therefore, the release, use, or distribution of the financial model to any organization outside of the BCUC could subject Corix to substantial harm to Corix's

competitive and negotiating position, resulting in rates or agreements that are unfavorable for existing and/or future customers or financial loss to Corix.

(2) The financial model contains customer lots, plans, parcels, address, connection date, building names, account holder, and historical and forward-looking data linked to each customer related to peak load, floor area, energy consumption, capital expenditures per customer and depreciation; all of which is data protected under the *Personal Information Protection and Electronic Documents Act* (PIPEDA).

(3) The financial model includes confidential information regarding hourly wages for the Operator, Supervisor, and Manager positions to calculate the labour cost using a bottom-up approach. This is confidential information, especially since some of these positions are only filled by one individual. This information could be directly linked to individual salaries. Such data is protected as personal information in BC. This protected information and related data to historical and forward-looking estimates, are essential for the functionality of the model.

(4) Schedule 18 in the financial model is confidential as it contains detailed build-out information, including sensitive and confidential customer data for the DGE. This data includes customer building names/parcels, account holders, building gross floor area (GFA), and connection dates listed by building. The model has been designed to incorporate building names instead of generic reference names. This approach provides the following advantages for Corix:

   a. Using customer names enables direct linking of GFA, capital expenditures, and depreciation schedules in multiple sheets in the model. This eliminates the need for a conversion or cross-referencing process, significantly reducing the risk of errors and improving the model’s usability for Corix staff.

   b. By directly referencing customer names, the model allows Corix staff to efficiently compile and access all relevant information associated with DGE customers. This ensures that customer-specific data is readily available and the model can be quickly reviewed and updated by multiple staff at Corix.

   c. Using customer names provides clarity and organization of the model, safeguarding its structure and maintaining formula integrity. This is particularly valuable given the complexity and interconnectedness of the functional Excel model.

(5) Corix has summarized the gross floor area and the number of connected customers in Schedule 14. This summary schedule protects the confidential information of the DGE while enabling disclosure of the relevant data used to calculate the proposed rates.

(6) Due to the complexity and interconnectedness of the functional Excel financial model, Corix is unable to redact specific sections of the integrated model while retaining its full functionality. For example, Corix is unable to redact formulas and certain cells within the model without compromising the functionality of the model.

(7) The financial model also contains proprietary calculations and automation processes (macros) that are integrated in the model to make it functional. These macros are Corix’s intellectual property. Additionally, public access to the model exposes confidential data and include sensitive financial, personal or customer information, creating a Cybersecurity risk if data is breached. Filing this financial model confidentially is therefore essential to protect Corix’s competitive position, safeguard proprietary knowledge, ensure compliance with privacy and data security standards, and minimize any potential for Cybersecurity breaches.

(8) Furthermore, it is not reasonable to expect other participants in this proceeding to open a file that contains macros due to significant cybersecurity and compatibility risks. From a corporate cybersecurity standpoint, organizations are generally advised against opening external Excel files with macros, as these types of files may contain malicious code that poses a high risk of introducing viruses, ransomware, or other malware into their systems. Additionally, files with macros frequently encounter compatibility issues during transmission, as security protocols may block or alter the file content. Given these limitations, Corix advises against promoting distribution of macro-enabled files among proceeding participants, as doing so could weaken the cybersecurity culture in the industry.

(9) All the relevant information for the proceeding from the confidential financial model has been provided publicly in the financial schedules, which are located in Appendix A of this Application, and also in the various tables and charts throughout the body of the Application. This includes, but is not limited to, financial information such as financing assumptions, revenue requirements, rate base, plant, contributions in aid of construction, operating and maintenance costs, property and other fees, energy costs, energy sales, revenue and proposed rates. Corix is of the view that the information provided publicly is sufficient for parties to complete a thorough review of the Application. Corix submits that confidential information contained in the confidential financial model will not provide any more relevant and useful additional information to make any final arguments in the proceeding since Corix has already publicly disclosed all the relevant information within the Application.

Period of Confidentiality

The reasons above provide sufficient grounds for the entire financial model to remain confidential. The commercial sensitivity of the information will not diminish over time. As a result, Corix respectfully requests that the BCUC keep this information confidential in perpetuity.

1.4 Proposed Regulatory Review Process

Regulatory review processes often require the coordination of utility staff from multiple departments. A regulatory timetable planned from Publication of the Notice of Application through to the Reply Argument provides utilities the ability to plan and assign its limited resources accordingly by prioritizing deadlines. The BCUC has the ability to update the regulatory timetable at any time, if needed.

Corix requests that the BCUC review this application using a written process based on the proposed regulatory timetable presented in Table 1 that follows. When determining the proposed dates Corix took into consideration:

- Corix's request that the BCUC issue an Order approving interim rates and establishing the regulatory timetable by Friday, June 27, 2025;
- the regulatory timetable for other Corix filings currently being reviewed or scheduled to be reviewed by the BCUC; and
- compliance and application filing deadlines established by the BCUC for other Corix utilities;
- Corix staff's availability.

Corix considers the proposed regulatory timetable to be efficient and reasonable given the approvals sought. Corix notes that this timetable would result in a final order issued by March 2026.

Should BCUC staff contemplate issuing a regulatory timetable that is materially different from the one in Table 1, Corix respectfully requests that BCUC staff contact Corix to verify staff availability prior to issuing an order.

TABLE 1: PROPOSED REGULATORY TIMETABLE

Item	Action	Date (2025)
1	Corix publishes notices of Application, with the Order approving the Regulatory Timetable	Monday, July 7
2	Intervener Registration	Thursday, July 17
3	BCUC Issues Information Request (IR) No. 1	Thursday, July 24
4	Intervener(s) Issue IR No. 1	Thursday, July 31
5	Corix Response to BCUC and Intervener(s) IR No. 1	Thursday, September 04
6	BCUC and Intervener(s) Issue IR No. 2	Thursday, September 25
7	Corix Response to BCUC and Intervener(s) IR No. 2	Thursday, October 23
8	Letters of comment deadline	Thursday, October 30
9	Corix Final Argument and reply to Letters of comment	Thursday, November 13
10	Intervener(s) Final Argument	Thursday, November 27
11	Corix Reply Argument	Thursday, December 11

1.5 Contact Information

All communications with respect to this Application should be addressed to Errol South, Director, Regulatory Affairs and sent to Corix's Regulatory Affairs email address at regulatory@corix.com. This email inbox is monitored Monday to Friday, from 8am to 5pm.

For other matters, please contact Corix using the information provided on the DGE website at https://www.corix.com/dockside-green/contact-us/.

2. Background

2.1 Corix Dockside Green DE Limited Partnership

Corix Dockside Green DE Limited Partnership (referred to in this application as “Corix”) is the legal entity that houses the DGE, a district energy utility that provides thermal energy utility services to the Dockside Green community in Victoria, British Columbia. Corix Dockside Green DE Limited Partnership is a subsidiary of a privately held corporation, Corix District Energy Holdings GP Inc., which is indirectly owned by the British Columbia Investment Management Corporation (BCI). As a limited partnership, Corix Dockside Green DE Limited Partnership, is managed by its general partner, Corix Dockside Green DE GP Inc.

The utility assets of DGE were formerly owned by Corix Multi-Utility Services Inc. See Section 2.8 below regarding the Corix Restructuring and Business Combinations Transactions that essentially carved out the district energy utilities into a separate standalone business unit. Though the ownership structure has changed for DGE, the ultimate owner BCI has remained the same throughout the reorganization.

2.2 Transfer of DGELLP Assets to Corix Multi-Utility Services Inc.

The district energy utility, then Dockside Green Energy LLP (DGELLP), began providing thermal energy service to customers at Dockside Green in Victoria in 2008 under a CPCN granted by the BCUC through Orders C-1-08 and C-3-08. At that time, the Dockside Green community was being developed by Dockside Green Limited Partners (DGLP), which was jointly owned by Windmill West Properties LLP (Windmill) and Vancity Capital Corporation. Windmill purchased the land from the City of Victoria with Vancity as the financing partner.

DGELLP was a limited liability partnership with the following ownership interests:

i. Windmill West Properties LLP (“Windmill”) with 17% *(Windmill transferred their interest to Vancity in April 2009)*;
ii. Vancity Capital Corporation ("Vancity") with 49%, which increased to 66% after acquiring Windmill’s interest;
iii. Corix Utilities Inc. ("CUI") with 17%; and
iv. Fortis Alternative Energy Services ("FAES") with 17%

The Dockside Green community was forecasted to complete buildout by 2014. The original plan was to use wood-waste gasification to generate thermal heating energy, and with future growth, sewer waste heat recovery as an additional energy source.

Due to slower than anticipated build-out on the Dockside Green lands, revenues to the utility proved insufficient to cover operating costs and maintain a manageable balance in the utility’s long-term deferral account. In addition, DGELLP incurred operational challenges with the wood-waste gasification thermal energy due to the novelty of the technology and fuel supply issues. By 2018 only 24% of the buildout was completed, and with revenues being insufficient to cover operating costs, the utility partners incurred financial losses.

On June 4, 2018, DGELLP and Corix Multi-Utility Services Inc. (CMUS) submitted an application to the BCUC seeking approval of certain transactions and the transfer of DGELLP assets and Certificate of Public Convenience and Necessity (CPCN) to Corix. In September 2018 the BCUC issued Order G-166-18 approving the sale of the utility’s assets to Corix.

In the application to acquire the assets, Corix stated that the purpose of the acquisition was

> "… a restructuring of utility ownership and operations and are designed to return the utility to a position of financial viability and ensure long-term sustainable energy service to the Dockside Green community."[1]

As part of the asset acquisition:

- No debt was to be assumed by CMUS;
- The deferred revenue balance in the existing DGELLP long-term deferral account would not be transferred to CMUS;
- DGELLP would sell and dispose of its assets to CMUS for $1.00; and
- DGELLP would provide CMUS a $1 million payment to be used to cover revenue shortfalls and mitigate rate increases during the early years of CMUS' ownership as the Dockside development continued to be constructed.

This $1 million payment from DGELLP to CMUS was referred to as the Contribution Amount and the purpose of the Contribution Amount was to:

> "limit the need for the Utility to increase customer rates during the initial years of operation of the Utility by Corix while allowing the Utility to recover its cost of service and earn a fair rate of return on the Utility rate base as allowed by the BCUC."[2]

On September 4, 2018, BCUC issued Order G-166-18 granting approval of the proposed transactions which resulted in the sale and disposition of DGELLP assets to Corix.

G-166-18 also approved the establishment of a new Revenue Deficiency Deferral Account (RDDA) for DGE and the placement of the $1 million Contribution Amount into the RDDA. In addition, G-166-18 directed Corix to accrue interest on the $1 million Contribution Amount in the RDDA based on DGE's approved weighted average cost of capital (WACC).

G-166-18 also directed Corix to file an application for revenue requirements and expenditures associated with initial plans of installing new natural gas boilers in the DGE central energy plant.

2.3 2019 Revenue Requirements and Rate Application (2019 RRRA)

On April 1, 2019, Corix filed a revenue requirement, rate design and rates application for DGE pursuant the Commission directives outlined in Order G-166-18, which directed Corix to file an application for revenue requirements and expenditures associated with installing new natural gas boilers in the DGE central energy facility by the end of 2018. This filing date was facilitated through an interim rate application and extension request, which were approved through BCUC Orders G-247-18, dated December 20, 2018, and G-34-19, dated February 14, 2019.

[1] An Application by Dockside Green Energy LLP ("DGE") and Corix Multi-Utility Services Inc. ("Corix") for Approval of the Transfer of Partnership Interests in DGE to Vancity Capital Corporation and Dockside Green Limited Partnership and Subsequent Sale and Disposition of DGE Utility Assets to Corix, June 4, 2018, pp. 1-2.
[2] Application Approval of the Transfer of Partnership Interests and Subsequent Sale and Disposition of DGE Utility Assets to Corix, Exhibit B-1, Attachment 4, Contribution Agreement, clause 2(c), p.124

On October 16, 2019, the BCUC issued Order and Decision G-248-19 which approved the rate base, revenue requirement, rate structures and rates for DGE from 2019 through to 2023 inclusive. The project plan contemplated by Order and Decision G-248-19 included the installation of three high efficiency condensing natural gas boilers and associated pumps (Temporary Energy Centre [TEC] Equipment), to be transferred from a separate Corix-owned utility and, once installed, utilizing DGE's existing distribution pumps. The capital costs for this particular project would be calculated in a manner that included the net book value of the assets at the time of transfer and the associated equipment removal, transportation and installation costs.

Among other things, Order G-248-19 approved the following:

i. A five-year levelized rate structure, from 2019 to 2023 inclusive, which includes a Basic Charge to be escalated by three percent annually and the continuation of the use of the RDDA.

ii. A separate Variable Energy Charge which is set based on the forecast consumption and energy rates for FortisBC Energy Inc. and British Columbia Hydro and Power Authority; and

iii. The establishment of an Energy Cost Reconciliation Account to record variances between the actual energy costs and the revenue collected through the Variable Energy Charge, with the balance to be amortized over a one-year period.

2.4 Transfer of Boilers to DGE

On April 30, 2019, pursuant to section 52 of the UCA, CMUS applied to dispose of the TEC Equipment as referenced in the DGE 2019 RRRA from the Burnaby Mountain District Energy Utility (BMDEU) and transfer them to DGE. This transaction was made possible by the commissioning of the biomass central energy plant at the BMDEU, which was scheduled to take place in 2020. The establishment of the biomass central energy plant at the BMDEU would allow for the three 817 kW high-efficiency condensing boilers and associated equipment from Temporary Energy Centre No. 1 (TEC1 Assets), to be transferred to DGE without sacrificing the BMDEU's ability to provide reliable service to its customers.

On September 11, 2019, by Order G-220-19 the BCUC approved the disposition of the TEC1 Assets at BMDEU and the transfer the TEC1 Assets to DGE. Under this transaction, DGE would pay BMDEU an amount equal to the net book value of the TEC1 Assets at the time of transfer, which was estimated to be $98,005 at the time G-220-19 was issued.

Corix subsequently completed the transfer of the TEC1 Assets from BMDEU to DGE in February 2021 and confirmed the completion of the transfer in a letter to BCUC dated March 18, 2021. In the letter, Corix stated that the TEC1 Assets had a net book value of $80,674 at the time of transfer.

2.5 2020 Flow Through Energy Costs Application

Through Order G-248-19, the BCUC approved Corix's proposal to establish an Energy Cost Reconciliation Account (ECRA) to record variances between the actual energy costs and the revenue collected through the Variable Energy Charge.

On April 20, 2020, CMUS applied to the BCUC to establish the rate-setting mechanism for the Variable Energy Charge for DGE. The BCUC approved the application through Order G-269-20 with Reasons for Decision, effective May 1, 2020. The Variable Energy Charge Rate Setting Mechanism comprised of:

1) An ECRA Ratio formula;

2) Trigger Ratios, establishing a ±5 percent dead-band range of 0.95 and 1.05 for its ECRA ratio; and
3) A Minimum Rate Change Threshold of ±$0.011/kWh.

Pursuant to directive number 3 in G-269-20, Corix submitted a compliance filing on November 1, 2023 which analyzed the rate-setting mechanism and the resulting frequency and magnitude of rate changes, as well as the ECRA balances. In this filing, Corix proposed to amend the existing rate setting mechanism by removing the Minimum Rate Change Threshold resulting in a single-parameter Variable Energy Charge rate setting mechanism whereby a change in the Variable Energy Charge rate is triggered when the ratio of expected 12-month Variable Energy Charge recovery revenue to the sum of the expected 12-month energy costs, plus the ECRA balance at the beginning of the forecast period, is greater than 1.05 or less than 0.95.

On November 16, 2023, the BCUC issued G-315-23 which approved the amendment to the existing Variable Energy Charge rate setting mechanism for DGE by removing the minimum rate change threshold of ± $0.011 per kWh. This resulted in a single-parameter Variable Energy Charge rate setting mechanism whereby a change in the DGE Variable Energy Charge rate is triggered when the following condition is met:

- The ratio of expected 12-month Variable Energy Charge recovery revenue to the sum of the expected 12-month energy costs plus the ECRA balance at the beginning of the forecast period, is greater than 1.05 or less than 0.95.

Given that there is an existing and approved Variable Energy Charge Rate Setting Mechanism since May 1, 2020, this Application is only regarding the non-energy (or delivery) portion of DGE's cost of service and the Basic Charge and associated rate rider.

2.6 2023 Flow Through Property Tax Application

On May 31, 2023, CMUS applied to the BCUC for approval to establish a Property Tax Deferral Account (PTDA) to record the annual variance between the approved forecast property taxes and actual property taxes charged to DGE for 2023 onward, with an associated rate rider mechanism to recover from or refund to ratepayers the balance in the PTDA.

Through Order G-225-23 dated August 23, 2023 the BCUC granted DGE approval to establish a non-rate base PTDA to record the annual variance between the BCUC approved forecast and actual property taxes charged to DGE from 2023 onwards, attracting interest at DGE's weighted average cost of capital. The BCUC also approved the use of a rate rider mechanism (the PTDA Rate Rider) for the recovery or refund of the year-end balance in the PTDA over a one-year period. The PTDA Rate Rider is named “Rate Rider 1” in the rate schedule in the DGE tariff.

The PTDA Rate Rider is a monthly fixed charge rate rider using the same units as the Monthly Basic Charge that resets on April 1st each year using a 12-month amortization period to recover or refund the balance in the PTDA.

Corix applies annually to the BCUC for review and approval of the PTDA rate rider for recovering or refunding the balance in the PTDA. The most recent 12-month Rate Rider 1 was set on April 1, 2025 through BCUC Order G-78-25 and will be charged through to March 31, 2026. In this Application Corix proposes to discontinue the use of the Rate Rider 1 (see Section 10.4.1 for details).

2.7 BCUC's Generic Cost of Capital (GCOC) Proceeding

2.7.1 GCOC Stage 1

On March 8, 2021, the BCUC launched a Generic Cost of Capital Proceeding (Stage 1) (2021 GCOC Stage 1). On September 5, 2023, the BCUC issued Decision and Order G-236-23 for its 2021 GCOC Stage 1 Proceeding. In Order G-236-23 dated September 5, 2023, the BCUC approved the return on equity and deemed capital structure for FortisBC Energy Inc. (FEI) and FortisBC Inc. (FBC). In addition, Order G-236-23 in Directive No. 4 stated:

> "Interim rates are established, effective January 1, 2024, on a refundable or recoverable basis, for all other utilities, except FBC, that currently use the Benchmark Utility to set their capital structure and equity return pending the BCUC's final decision on Stage 2 of the GCOC proceeding."

DGE uses the Benchmark Utility to set its capital structure and return on equity, pursuant to BCUC Order G-47-14 regarding the previous 2014 Generic Cost of Capital Stage 2 proceeding.[3] In compliance with the above directive from Order G-236-23, Corix filed the interim DGE tariffs effective January 1, 2024 for BCUC acceptance and endorsement. On December 18, 2023, the BCUC accepted for filing the interim tariffs for DGE effective January 1, 2024. Interim rates due to G-236-23 would be subject to the BCUC final decision regarding the cost of capital for small utilities, including thermal energy systems, that rely on the Benchmark Utility to set their cost of capital.

2.7.2 GCOC Stage 2

On January 11, 2024, the BCUC by Order G-6-24 set the Benchmark Utility for the GCOC Stage 2 proceeding. The BCUC in Directive No. 1 in Order G-6-24 stated: "The Benchmark Utility will be FortisBC Energy Inc. for all utilities in Stage 2 of the GCOC proceeding."

On November 29, 2024, the BCUC issued its Decision and Order G-321-24 for the GCOC Stage 2 proceeding, which addressed the cost of capital for small utilities, including thermal energy systems such as DGE. Regarding the cost of equity, Order G-321-24 in Directive No. 2 states in part for DGE the following:

> "Effective January 1, 2024, the equity premium over the Benchmark Utility (i.e. deemed equity component) and ROE premium over the Benchmark Utility (i.e. allowed ROE) for the following thermal energy system (TES) utilities and the default TES as discussed in Section 3.3.4 of the decision accompanying this order (TES Default) are:"

"Utility	Equity Premium over the Benchmark Utility (i.e. Deemed Equity Component)	ROE Premium over the Benchmark Utility (i.e. Allowed ROE)
Corix Dockside Green DE Limited Partnership	4.0 percentage points (49.0 percent)	75 basis points (10.40 percent)"

Directive No. 2 in Order G-321-24 decided on the DGE capital structure and allowed rate of return that would be effective January 1, 2024.

[3] 2014 BCUC Generic Cost of Capital Proceeding Stage 2, Order G-47-14.

Regarding the cost of debt, the GCOC Stage 2 Decision and Order G-321-24 on page 82 states the following:

> "As already noted, the Fair Return Standard applies to both the deemed equity component and the deemed debt component of a utility's capital structure. Therefore, **the Panel finds that establishing a deemed interest rate continues to be warranted when a utility does not have third-party debt. The Panel further finds that a deemed interest rate serves as an effective mechanism for setting the appropriate cost of debt in determining a utility's fair return when there is no observable debt or where the utility does not incur actual financing costs.** A deemed interest rate methodology serves as a proxy that reflects the debt rate a utility may be able to obtain on its own rather than relying on its parent company, and thus, satisfies the Standalone Principle. Having a deemed interest rate also conforms with the Fair Return Standard because the utility's investors are afforded an opportunity to earn a fair return on the debt component of their invested capital at market rates."

The deemed interest rate methodology was addressed in the GCOC Stage 2 Decision and Order G-321-24 on page 86, which states:

> "The Panel determines that the deemed interest rate methodology should be based on the sum of:
>
> a. Government of Canada 10-year bond yields based on the average of the last trailing 12 months;
>
> b. The corporate credit spreads on the Government of Canada 10-year bonds for BBB and BBB(low) rated utilities based on the average of the last trailing 12 months;
>
> c. Non-investment grade lending premium of 92 basis points; and
>
> d. A deemed issuance fee of 50 basis points."

The GCOC Stage 2 Decision and Order G-321-24 further states on pages 88 and 89 the following:

> "**The Panel finds that the deemed interest rate methodology, as determined above, sufficiently accounts for changes in the market in the absence of an AAM by tracking the GoC 10-year bond yields and the BBB to BBB(low) utility corporate credit spreads, which would be updated based on the latest market information available at the time the deemed interest rate methodology is applied.** Given a deemed interest rate methodology has already been established, the Panel considers little regulatory efficiency and simplicity can be gained from the adoption of an AAM. For utilities that file revenue requirements applications with the BCUC on a regular interval, the <u>Panel expects the deemed interest rate would be reviewed regularly as part of the revenue requirements application process to ensure the deemed interest rate continues to meet the Fair Return Standard</u>." [Underline emphasis added.]

Additional information regarding the DGE cost of capital and implications of the Generic Cost of Capital proceeding are further discussed in Section 9.2 of this Application.

The GCOC Stage 2 Decision and Order G-321-24 on page 96 also states the following:

> "**For Corix UBC NDES and DGE, the Panel approves the previously established interim 2024 rates as permanent. Corix is directed to establish a new GCOC Variance Deferral Account for each utility, attracting Corix's WACC, to record the variance between the previously established interim**

> **2024 rates and the rates that would reflect the new cost of capital, effective January 1, 2024, under this decision.** For clarity, the GCOC Variance Deferral Accounts are separate from the existing Revenue Deficiency Deferral Accounts for UBC NDES and DGE, as these arrangements will provide flexibility for the utility and collection from ratepayers. The GCOC Variance Deferral Accounts will also capture the difference between any 2025 interim rates before and after incorporation of the new cost of capital under this decision. **The amounts to be added to the GCOC Variance Deferral Accounts and their disposition are to be addressed the earlier of (i) these Corix Utilities' next rates applications or (ii) a compliance filing to be filed with the BCUC by January 31, 2025. This filing should also include revised permanent rates that reflect the new cost of capital under this decision for UBC NDES's and DGE's rates for 2025 and beyond. As applicable, revised tariff pages are to be filed with the BCUC by January 31, 2025."** [Footnote removed]

As detailed above the 2024 GCOC Stage 2 Decision and Order G-321-24 approved the previously established 2024 interim rates as permanent and established a new GCOC Variance Deferral Account (GCOC VDA) attracting financing costs at the WACC effective January 1, 2024. The amounts to be added to the GCOC VDA and their disposition are to be addressed in this Application. Please refer to Section 10.2 for additional details regarding the GCOC VDA.

2.7.3 Compliance with GCOC Stage 2 Decision and Order G-321-24

<u>Compliance Filing made for Permanent 2024 and 2025 Rates</u>
On January 31, 2025, Corix filed its DGE compliance filing in regards to 2024 and 2025 permanent rates. The January 31st compliance filing covered the period from January 1, 2024 to December 31, 2024 which was made permanent when the Panel stated on page 96 of the GCOC Stage 2 Decision: "For Corix UBC NDES and DGE, the Panel approves the previously established interim 2024 rates as permanent."

In the compliance filing, Corix requested confirmation of the Generic Cost of Capital Variance Deferral Account balance (GCOC VDA) as of December 31, 2024 in the amount of $6,738 and calculation of the permanent January 1, 2025 Monthly Basic Charge Rate for DGE based on the updated cost of capital. The BCUC accepted the for filling the new rate schedule, which reflected the updated Monthly Basic Charge of $0.426 per square metre ($m^2$) effective January 1, 2025.

In the compliance filing, Corix explained that the remainder of the compliance requirements to Order G-321-24 regarding the GCOC VDA would be addressed in the upcoming DGE rate application.

<u>GCOC Variance Deferral Account and 2025 Rates</u>
The January 31, 2025 compliance filing mentioned that Corix planned to file its DGE rate application by Summer 2025 which means the GCOC VDA would be addressed in the DGE rate application. This Application addresses the remainder of the Order G-321-24 compliance requirements.

In this Application the proposed interim rate effective July 1, 2025 is based on revenue requirements that reflect the new cost of capital parameters from Order G-321-24. Therefore, the GCOC VDA does not include any variance for the period within 2025. The calculation of the DGE GCOC VDA and its disposition is discussed in Section 10.2 and 10.2.1 respectively.

2.8 Corix Restructuring and Business Combinations Transactions

On November 16, 2022, Corix Multi-Utility Services Inc. (CMUS) and SW Merger Acquisition Corp. (SWMAC) applied to the BCUC pursuant to sections 45, 46, 50, 52 and 54 of the UCA, for approvals with respect to certain steps of a proposed business combination (Business Combination) and associated internal reorganization of CMUS and its affiliates (Pre-Closing Restructuring). The Pre-Closing Restructuring and the Business Combination were collectively referred to as the Proposed Transactions.

The Business Combination would combine the Corix Infrastructure Inc (CII) water and wastewater utility businesses and energy distribution systems that are part of multi-utility systems (Multi-Utility Systems) in Canada and the US with the water utility and wastewater businesses of SouthWest Water Company (SouthWest) in the U.S. The Business Combination would not include the three BCUC-regulated Stream B Thermal Energy Systems (TES). Accordingly, as part of the Pre-Closing Restructuring the three BCUC-regulated Stream B TES (Transferred TES) would be transitioned out of CMUS and into separate entities, being the TES Limited Partnerships (TES LPs).

On October 18, 2023, the BCUC issued Decision and Order G-279-23 that approved the Business Combination and Pre-Closing Restructuring.

Directive No. 1 in Order G-279-23 stated:

> “CMUS is approved to transfer its interest in each of the following Stream B TES at the time of the Pre-Closing Restructuring to three limited partnerships as follows, pursuant to section 52 of the UCA:
>
> - BMDEU is approved to be transferred to Corix Burnaby Mountain DE Limited Partnership;
> - UBC NDES is approved to be transferred to Corix UBCDE Limited Partnership; and
> - DGDEU is approved to be transferred to Corix Dockside Green DE Limited Partnership”.

Directive No. 2 in Order G-279-23 stated:

> “A CPCN is granted to the following limited partnerships at the time of the Pre-Closing Restructuring, pursuant to sections 45 and 46 of the UCA: (I) Corix Burnaby Mountain DE Limited Partnership for the BMDEU; (ii) Corix UBCDE Limited Partnership for the UBCNDES; and (iii) Corix Dockside Green DE Limited Partnership for the DGDEU.”

Through a compliance filing dated November 30, 2023, CMUS submitted to the BCUC: (i) Certificate of Limited Partnership for each of the three limited partnerships; and (ii) Limited Partnership Agreements for each of the three limited partnerships.

2.8.1 Effects of the Carve-Out

This DGE 2025-2028 Revenue Requirements and Rates Application is mostly unaffected because the DGE utility operation within CMUS was always regulated by the BCUC as a standalone utility. Restructuring as a separate Corix Dockside Green DE Limited Partnership has not changed how the BCUC regulates the utility because the BCUC will continue to regulate the DGE as a standalone utility. The approvals sought in this application pertain only to the DGE utility operations and its customers and do not impact any other affiliates of Corix.

With the exception of the Corporate and Regional Services Costs outlined in Section 6.3, the changes in costs presented in this Application are unrelated to the restructuring and business combination transactions. The costs in this Application reflect the changes to market conditions over the last 6-year period since the previous rate application was submitted to the BCUC. The approvals requested in this application are formulated for DGE as a stand-alone utility and the revenue requirement is focused solely on the ongoing operations.

Corix underscores that this current DGE revenue requirement and rates application is not being submitted due to the restructuring and business combination. Instead, this application was part of Corix's planned regulatory schedule included in the 2025 Anticipated Filings Submission dated September 11, 2024, in which the DGE rates application was originally projected to be submitted by June 2025.

3. Directives From Prior Applications

3.1 Directives from the 2019 Rate Application

3.1.1 Accounting Treatment and Rate Structure

Order G-248-19, Directive No.1 stated:

> "The rate base, revenue requirement, rate structure and rates for DGE are approved as follows:
> …
> c. The following accounting treatment and rate structure is approved:
>
> i. A five-year levelized rate structure which includes a Basic Charge to be escalated by three percent annually and the continuation of the Revenue Deficiency Deferral Account (RDDA);
> ii. A separate Variable Energy Charge which is set based on the forecast consumption and energy rates for FortisBC Energy Inc. and British Columbia Hydro and Power Authority; and
> iii. The establishment of an Energy Cost Reconciliation Account to record variances between the actual energy costs and the revenue collected through the Variable Energy Charge, with the balance to be amortized over a one-year period."

Action Taken:
On October 29, 2019 Corix filed the DGE Tariff with 5 year rates from January 1, 2019 to December 31, 2023, in compliance with Order G-248-19. In addition, through Order G-269-20 the BCUC approved the Variable Energy Charge rate-setting mechanism for Dockside Green Energy further discussed in Sections 2.5 and 10.1.

3.1.2 Recovery of the Difference in Revenue Between Interim and Permanent 2019.

Order G-248-19, Directive No. 3 stated:

> "Corix's request to recover the difference in revenue between interim and permanent 2019 rates that exceed a threshold of $16,800 using a Fixed Charge Rate Rider is denied. Corix is directed to utilize the RDDA to recover all differences in revenue between interim and permanent 2019 rates."

Action Taken:
The Monthly Basic Charge revenue difference resulting from the variance between the 2019 interim and permanent rates was recorded in the Revenue Deficiency Deferral Account (RDDA) in compliance with Order G-248-19, Directive No. 3. Additionally, the Variable Energy Charge revenue difference resulting from the variance between the 2019 interim and permanent rates was not recorded in the ECRA. In compliance with Order G-248-19, Directive No. 3, Corix is making a reduction in the 2025 ECRA to account for the $16,254 revenue difference. This reduction will represent a reduction in the ECRA balance, which will have a downward impact on the Variable Energy Charge to be effective January 1, 2026.

3.1.3 Other Directives

3.1.3.1 2019 Compliance Filing

On Order G-248-19, Directive No. 4 stated:

> "Corix is directed to file as a compliance filing with the BCUC, within 30 days of the date of this order, the permanent tariff terms and conditions and rate schedule for DGE"

Action Taken:
In compliance with Order G-248-19, on October 29, 2019, Corix submitted its compliance filing for Order G-248-19 that addressed the permanent tariff terms and conditions and rate schedule for DGE.

3.1.3.2 Appropriate Capital Structure and ROE for DGE

On Decision and Order G-248-19, the BCUC on page 17 stated:

> "the Panel directs Corix to include a detailed analysis of the appropriate capital structure and ROE for DGE in the next revenue requirement application, which the Panel anticipates will likely be filed in 2023."

Action Taken:
In March 2021, the British Columbia Utilities Commission (BCUC) initiated the 2021 Generic Cost of Capital (GCOC) Proceeding – Stage 1, culminating in Decision and Order G-236-23 issued on September 5, 2023. This order approved the return on equity (ROE) and deemed capital structure for FortisBC Energy Inc. (FEI) and FortisBC Inc. (FBC). These decisions are significant because utilities like Corix's DGE use the Benchmark Utility's parameters to set their own capital structure and ROE, as established in the 2014 GCOC Stage 2 proceeding under Order G-47-14.

On January 11, 2024, the BCUC issued Order G-6-24, which designated FEI as the Benchmark Utility for all utilities participating in Stage 2 of the GCOC proceeding. Corix actively participated in both stages of the GCOC process and submitted expert evidence from the Brattle Group during Stage 2. The Brattle Evidence recommended that DGE continue to receive a 100 basis point (bps) equity risk premium over the Benchmark Utility, consistent with the 2014 GCOC Stage 2 Decision.

The Brattle Group's analysis emphasized that the business risks facing Corix's utilities had increased since 2014. As a result, it recommended a minimum ROE of 10.65% for DGE—100 bps above the Benchmark Utility's ROE—along with a minimum deemed equity ratio of 47.0% for all three Corix BC regulated utilities. These recommendations were positioned as the minimum threshold parameters necessary to reflect the elevated business risk and to maintain the cost of capital premium previously established.

Despite Corix's request to maintain the 100 bps premium, the BCUC, through Order G-321-24, approved a reduced premium of 75 bps for DGE. This decision results in a lower ROE than what was recommended by the Brattle Group, though it still acknowledges DGE's relatively higher risk profile compared to the Benchmark Utility. Corix maintains that DGE's risk remains elevated relative to other Corix utilities such as BMDEU and UBC NDES, justifying a continued premium above the Benchmark Utility's ROE. However, Corix considers that the recent participation on the GCOC Stage 2 proceeding and the outcome of the Order and Decision G-321-24 fulfills the directive above. As such Corix has not included additional analysis related to DGE capital structure and ROE.

3.1.3.3 Ten Percent O&M Mark-up

On Decision and Order G-248-19, the BCUC on page 17 stated:

> "The Panel agrees with Corix that the negative RDDA and the small initial rate base create a situation whereby Corix is not provided the opportunity to earn a reasonable return on its investment in the initial years of operating the DGE utility if the allowed return is based solely on the "standard rate base" approach. The Panel also agrees that such a scenario is not fair to the utility. Therefore, the Panel finds that Corix's proposal to include a ten percent mark-up on O&M, exclusive of energy costs and management/administration costs is reasonable until such time as the ROE on net base exceeds the ten percent O&M mark-up. The Panel notes this is consistent with the compensation method employed by DGE LLP when Corix was providing operational services and is easy to understand. **For these reasons, the Panel approves Corix's request to include a ten percent O&M mark-up, exclusive of energy costs and management/administration costs, in the DGE revenue requirement until such time as the ROE on net base exceeds the ten percent O&M mark-up.**"

<u>Action Taken:</u>
From 2019 until 2020 DGE operated with a small initial rate base, during which time the approved ten percent mark-up on operations and maintenance (O&M) costs excluding energy and management/administration costs exceeded the return on equity (ROE) calculated on the net rate base. This mark-up was implemented to ensure Corix had a fair opportunity to earn a reasonable return during the early years of utility operation, as approved by the BCUC.

Starting in 2021, DGE's ROE on net rate base surpassed the ten percent O&M mark-up threshold. In accordance with the Panel's directive, Corix subsequently discontinued the application of the O&M mark-up in the DGE revenue requirement.

3.2 Directives from the 2020 Flow Through Energy Costs Application

On April 20, 2020 Corix Multi-Utility Services Inc. applied to the BCUC to establish the Variable Energy Charge Rate Setting Mechanism for DGE. On October 26, 2020, the BCUC issued Final Order G-269-20 that approved the Application to Flow Through Energy Costs, effective since May 1, 2020.

Order G-269-20, Directive No. 1 stated:

> "Corix is approved to use a two parameter Variable Energy Charge rate-setting mechanism for Dockside Green Energy as set out in the Application, whereby a change in the Variable Energy Charge rate is triggered when the following conditions are met:
>
> > i) The ratio of expected 12-month variable energy charge recovery revenue to the sum of the expected 12-month energy costs, plus the ECRA balance at the beginning of the forecast period, is greater than 1.05 or less than 0.95; and
> >
> > ii) The minimum rate change threshold of ± $0.011 per kWh is exceeded."

Order G-269-20, Directive No. 2 stated:

> "Corix is directed to include in its annual report submissions:

i) Forecast ECRA balance as at the beginning of the month following the annual report submission;

ii) Forecast monthly energy costs incurred in each of the 12 months following the annual report filing and forecast annual energy costs for the year subsequent to those 12 months;

iii) Forecast monthly revenue from the Variable Energy Charge in each of the 12 months following the annual report filing and forecast annual revenue for the year subsequent to those 12 months, based on both the approved Variable Energy Charge at the time of the annual report filing and the proposed Variable Energy Charge, if applicable; and

iv) Forecast monthly ECRA balance at the end of each of the 12 months following the annual report filing and the forecast ECRA balance at the end of the year subsequent to those 12 months, based on both the approved Variable Energy Charge at the time of the annual report filing and the proposed Variable Energy Charge, if applicable."

Order G-269-20, Directive No. 3 stated:

> "Corix is directed to file an evaluation report on the rate-setting mechanism by no later than November 1, 2023, documenting all rate changes under the rate-setting mechanism, analyzing the effects of the rate-setting mechanism on the frequency and magnitude of rate changes and ECRA balance, and providing Corix's analysis of the overall performance of the rate-setting mechanism for DGE and its ratepayers."

Order G-269-20, Directive No. 4 stated:

> "Corix is approved, pursuant to section 60 of the Utilities Commission Act, to decrease the Variable Energy Charge for Dockside Green Energy from $0.055 per kWh to $0.042 per kWh effective May 1, 2020 on a permanent basis, until such time that the rate change mechanism is triggered."

Order G-269-20, Directive No. 5 stated:

> "Corix is directed to file revised tariff pages for acceptance by the BCUC within 30 days from the date of issuance of this Order."

Action Taken:
Corix confirms that Directive Nos. 1, 4 and 5 were completed and final tariffs were implemented on May 1, 2020.

Corix confirms that Direct No. 2 has been implemented. Corix filed its last DGE ECRA report on February 28, 2025, for a rate change effective April 1, 2025. The BCUC by Order G-78-25 approved the decrease of the DGE Variable Energy Charge from $0.042 per kWh to $0.0370 per kWh, effective April 1, 2024. The next ECRA filing will be filed no later than March 1, 2026, for rates effective April 1, 2026.

In compliance with Directive No. 3, on November 2023 Corix submitted the DGE Variable Energy Charge Evaluation Report and Request to amend the Variable Energy Charge Rate Setting Mechanism as described in Section 2.5.

3.3 Directives from the 2023 Property Tax Application

Order G-269-20, Directive No. 1 stated:

> "Corix is directed to discontinue recording the annual variance between the BCUC approved forecast and actual property taxes in DGE's existing RDDA, commencing in 2023."

Order G-269-20, Directive No. 4 stated:

> "Corix is directed to apply annually to the BCUC for review and approval of any rate rider for recovering or refunding the balance in the PTDA."

Order G-269-20, Directive No. 5 stated:

> "Corix is directed to include the following in its annual report for the DGE:
>
> a. Year-end actual property tax costs;
> b. The variance between the BCUC approved forecast and actual property taxes for the most recent calendar year; and
> c. The supporting calculations and explanations for the PTDA Rate Rider."

Order G-269-20, Directive No. 6 stated:

> "Corix is directed to submit a compliance filing to the BCUC by no later than June 30, 2026, assessing the need to continue the use of the PTDA Rate Rider for recovering or refunding the variance between the BCUC approved forecast and actual property taxes. This compliance filing should consider alternative methods of recovering or refunding PTDA balances."

<u>Action Taken:</u>
Corix confirms that Directives No. 1, 4 and 5 were completed. Corix filed its last DGE Annual Report on February 28, 2025, for approval for a Property Tax Rate Rider effective April 1, 2025. The BCUC by Order G-78-25 approved DGE Rate Rider 1 of $0.1834 per square meter per month effective April 1, 2025 to March 31, 2026.

Corix in Section 10.4 of this Application proposes to discontinue the Rate Rider 1 Mechanism and instead amortize the variances between the actual and forecast Property Tax costs in the next Revenue Requirements and Rates Application. Corix proposed treatment of the PTDA and ensures compliance of Directive 6 above.

4. Build-out and Thermal energy forecast

4.1 Build-out Schedule

The build-out schedule drives the revenue forecasts and calculation of DGE Basic Charge. Table 2 below provides the most recent build-out schedule and compares this to the build-out schedule from the 2019 Revenue Requirements and Rate Application buildout forecast. Corix periodically obtains updates to the build-out schedule from the master developer of DGE, with the most recent update occurring on February 28, 2025. By the end of 2024, 52% of the total buildout floor area was connected to DGE and is expected to remain at the same level at least until 2030 when two (2) additional buildings are expected to connect. The remaining buildings are expected to be completed and connected to DGE by the end of 2035, this is an additional 3 years compared to the forecast on the 2019 RRRA. However, Corix considers that the timing of this build-out is subject to a moderate to high level of uncertainty.

Based on the latest information, the forecasted total floor area for Dockside Green at full build-out has decreased by 3.6%, or 4,779 m² to a total of 125,648 m². Schedule 14 in Appendix A provides the forecast customer count and the beginning and ending connected floor area for each year through to 2030. It is worth noting that the total floor area for DGE at full build-out remains subject to future updates by the property developers.

TABLE 2: BUILD-OUT SCHEDULE AND FLOOR AREA COMPARISON

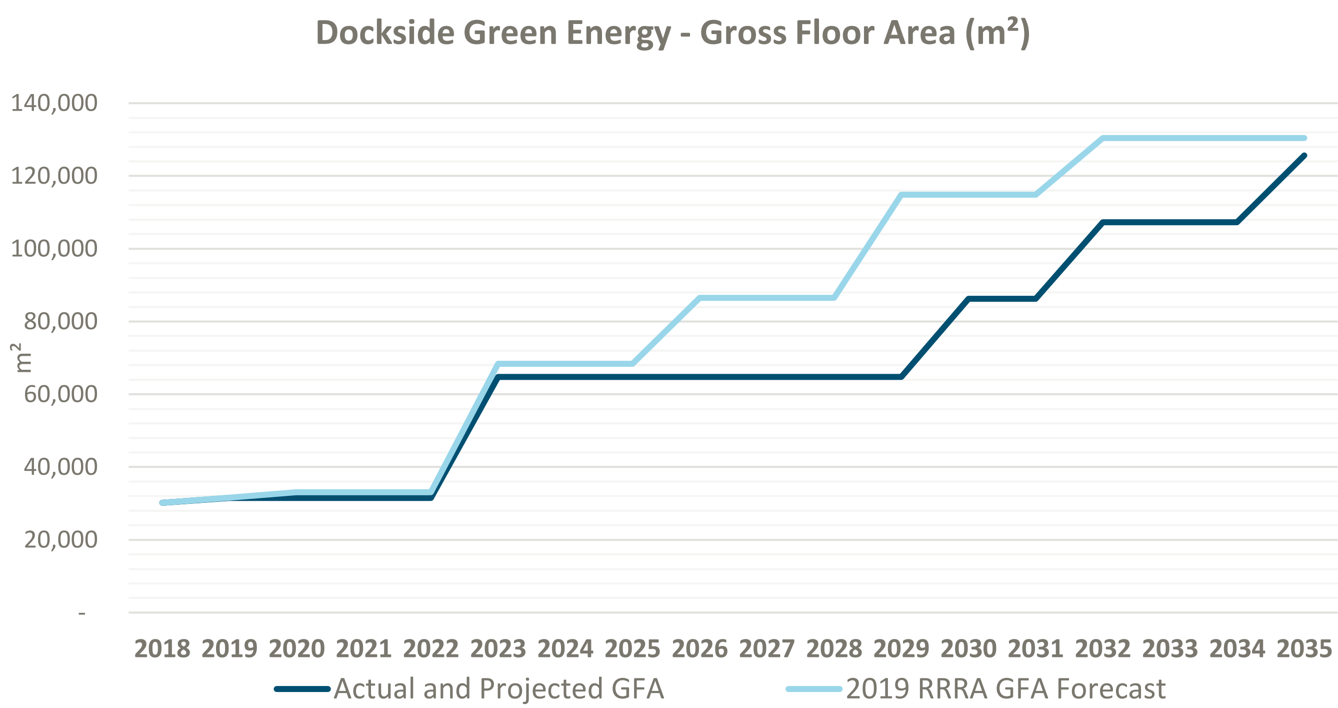
Connected Floor Area for Dockside Green Energy				
Year	2019 RRRA (m²)	Actuals and Projection (m²)	Variance (m²)	Variance (%)
2018	30,176	30,176	0	0.00%
2019	31,598	31,506	-91	-0.29%
2020	33,088	31,506	-1,582	-4.78%
2021	33,088	31,506	-1,582	-4.78%
2022	33,088	31,506	-1,582	-4.78%
2023	68,392	64,794	-3,598	-5.26%
2024	68,392	64,794	-3,598	-5.26%
2025	68,392	64,794	-3,598	-5.26%
2026	86,472	64,794	-21,678	-25.07%
2027	86,472	64,794	-21,678	-25.07%
2028	86,472	64,794	-21,678	-25.07%
2029	114,836	64,794	-50,042	-43.58%
2030	114,836	86,241	-28,595	-24.90%
2031	114,836	86,241	-28,595	-24.90%
2032	130,428	107,296	-23,131	-17.73%
2033	130,428	107,296	-23,131	-17.73%
2034	130,428	107,296	-23,131	-17.73%
2035	130,428	125,648	-4,779	-3.66%

Chart 1 illustrates how the Dockside Green floor area forecast has changed since the 2019 RRRA. Chart 1 offers a direct visual comparison between the actual and forecasted floor areas, as outlined in the previous revenue requirement and rate application. It is important to note that the financial model incorporates a mid-year building connection to account for the uncertainty regarding the specific month each building will connect to and begin receiving service from the DGE in a particular year.

Of particular interest is the GFA variance of the Connected Floor Area as shown in the table above. Since 2019 the buildout variance has remained slightly negative with a negative variance of 5.26%. However, due to delays in the connection of future buildings of the DGE, the shortfall in buildout magnifies in 2026 with a negative variance of 21,678 m^2 (-25.07%), which worsens in 2029 with a negative variance of 50,042 m^2 (-43.58%). This shortfall is due to delays in connecting customers to the DGE for reasons beyond Corix's control.

The buildout delay directly impacts the revenue and increases the revenue shortfall as compared with the original projections in the 2019 RRRA. This effect necessitates higher rates to mitigate against the shortfall in revenue, which would otherwise lead to a rapidly increasing RDDA balance. This issue is further discussed in Section 11.2.

CHART 1: DGE CUMULATIVE BUILD-OUT FLOOR AREA COMPARISON



4.2 Energy Demand Forecast

The annual energy demand for DGE is projected based on the floor area, in square metres (m²), and the Energy Use Intensity (EUI) of each building (in kilowatt-hours per square metre, kWh/m²). According to the buildout forecast, the annual energy demand for DGE through the end of the test period is detailed in Table 3 below and Schedule 17 of Appendix A.

These energy demand forecasts are provided for informational purposes only, as Corix is not seeking approval for the Variable Energy Charge for DGE in this application. The DGE Variable Energy Charge is reviewed and approved annually through the flow-through energy cost rate setting mechanism, as approved by the BCUC in Order G-248-19. Consequently, the annual energy demand figures and corresponding Variable Energy Charge for all years from 2025 onwards are subject to change based on the information available at that time. For further clarity, the annual energy demand does not affect the DGE delivery revenue requirement.

TABLE 3: DGE ANNUAL ENERGY DEMAND (2022-2028)

Annual Energy Demand	Actual 2022	Actual 2023	Actual 2024	Test Period			
				Forecast 2025	Forecast 2026	Forecast 2027	Forecast 2028
Annual Energy Demand (MWh)	2,353	3,378	4,482	4,806	4,806	4,806	4,806

4.3 System Capacity

There are three (3) KN-30 817 kW high-efficiency condensing natural gas-fired boilers planned to serve the current load at Dockside, with the Cleaver-Brooks 3.4 MW fire-tube boiler designated for system backup and redundancy.

On January 12, 2024, Victoria experienced unusually cold weather, with temperatures dropping to -11.7°C, the lowest recorded temperature since 1968. This extreme cold weather required all three KN-30 boilers to operate simultaneously at maximum capacity to maintain the system's demand. This situation underscored a significant redundancy shortfall during such extreme weather conditions. Corix initially forecasted that the three KN-30 boilers would be sufficient to cover the load of the DGE until 2029, at which time the Cleaver-Brooks boiler could be recommissioned. Although the total capacity of these boilers is listed at 2.4 MW. The actual maximum output observed in the system that day was just over 2 MW for all three boilers combined. This difference between the forecasted and actual output highlighted a potential shortfall in meeting the load demand as forecast in the 2019 Rate Application.

Additionally, the load of the A-1 Towers, connected in 2023, was initially forecast at 1,055 kW in the 2019 RRRA. However, a compatibility review prior the connection of the A-1 buildings revealed that the expected load was 57% higher than anticipated, reaching 1,652 kW. This significant increase in load further strained the overall system capacity.

Given these factors, Corix recommissioned the Cleaver-Brooks boiler in 2024. This decision was made to ensure the system could handle the increased demand and to provide additional peaking capacity and system redundancy. The Cleaver-Brooks boiler's higher capacity is crucial for preventing potential outages during peak load periods.

4.3.1 System Improvements

Since acquiring the DGE, Corix has implemented a series of strategic improvements that have enhanced the system's performance, reliability, and operational efficiency. One of the most notable achievements has been the substantial increase in overall system efficiency. Prior to Corix's acquisition, the system operated at an average annual efficiency of approximately 65% over the period from 2009 to 2017. In contrast, under Corix's stewardship, the system has achieved an average efficiency of 74% over the most recent three-year period (2022, 2023, and 2024). This improvement reflects Corix's commitment to optimizing energy use, ultimately delivering better value to customers.

In addition to efficiency gains, Corix has improved system reliability. Prior to the acquisition, the DGE system relied on a single large natural gas boiler, which posed a risk of service disruption in the event of equipment failure. Corix has since reconfigured the system to include four natural gas boilers—three smaller KN-10 boilers and one large Cleaver Brooks boiler, thereby introducing redundancy. This configuration enhances the system's resilience and ensures a more stable and reliable supply of thermal energy to customers, even during peak demand periods or maintenance events.

Operational improvements have also been realized through targeted technology upgrades. Corix has invested in advanced monitoring and control systems that provide real-time access to building-level thermal energy demand data. This data-driven approach enables operators to fine-tune system setpoints and optimize performance based on actual usage patterns. By leveraging this enhanced visibility, Corix can more effectively manage energy distribution, reduce operational costs, and further improve service quality.

These improvements collectively demonstrate Corix's commitment to delivering reliable, efficient, and sustainable energy services to the communities it serves.

4.3.2 Future Low-Carbon Energy Sources

DGE will be required to incorporate low-carbon energy sources for future building connections. This requirement is driven by the City of Victoria's adoption of the Zero Carbon Step Code for New Buildings, this initiative is part of Victoria's broader climate action strategy to reduce greenhouse gas emissions, as buildings account for over half of the city's emissions[4]. The city requires new developments to meet specific energy efficiency standards under the BC Energy Step Code to limit greenhouse gas emissions in new buildings. All new Building permits submitted on or after November 1, 2024, must be compliant with Zero Cabron Emissions Level 4[5]. Corix anticipates that buildings connecting to DGE after 2032 will be required to comply with the above, since all other buildings expected to connect to DGE have secured their Building Permits before the deadline.

In order to meet this requirement, Corix is currently undertaking a feasibility study that will evaluate a range of viable low-carbon energy alternatives. This study will consider technical, economic, and environmental factors to determine the most appropriate path forward for decarbonizing the system. Corix will also undergo public consultation and engagement and submit an application for a Certificate of Public Convenience and Necessity (CPCN) seeking the relevant approvals from the BCUC at the appropriate time.

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[4] https://www.victoria.ca/community-culture/climate-action/climate-friendly-homes/low-carbon-new-buildings
[5] ibid

5. Energy Supply Costs

Energy Supply costs are variable costs that include the costs for natural gas and electricity. These costs are necessary costs driven by customer consumption and supplier prices and are further discussed below.

5.1 Natural Gas

The three KN-30 boilers and the Cleaver-Brooks boilers operate with natural gas. Natural gas costs are forecasted based on projected consumption, daily demand, and applicable natural gas rates. Corix relies on the most recent FortisBC Energy Inc. (FEI) gas cost filing, approved by Order G-88-25 to forecast commodity charges. FEI demand and delivery charges were forecasted using Order G-313-24, which includes an approved rate increase of 7.75% for 2025. These rates serve as a proxy for natural gas costs during the 2025 test year. For the test years 2026, 2027 and 2028 Corix forecasts the commodity cost rate increases using Sproule weighted average of BC Westcoast Station 2 and Alberta Local Price (AECO-C) natural gas prices. The natural gas price forecast assumptions used in this Application are consistent with DGE Amendment No. 1 to the Energy Cost Reconciliation Account and Property Tax Deferral Account 2024 Annual Report dated March 19, 2025. Other FEI charges associated with the provision of natural gas are assumed to increase at 2.0% per year.

The forecast natural gas consumption was determined based on the forecast customer energy demand and the 3-year average system efficiency of 74.4%. The utility purchases natural gas from FEI at Rate Schedule 5 rates (General firm service rate for large volume commercial, institutional, multi-family and other accounts with consumption of approximately 5,000 GJ or more annually).

5.2 Electricity

Corix forecasts electricity costs using forecast consumption, peak load and electricity rates. Electricity consumption forecasts were determined using historical electricity consumption. DGE electricity consumption was under 35 kW until 2024. However, beginning in 2025 DGE switched to Hydro's Rate Schedule 1500 (Medium General Service, for BC Hydro customers whose Billing Demand (as defined in the BC Hydro Tariff) is equal to or greater than 35 kW but less than 150 kW and whose Energy consumption in any 12-month period is equal to or less than 550,000 kWh).

DGE is expected to remain at the Medium General Service rate for the test period. From 2025 onwards Corix assumes that the electricity rates escalate at the Bank of Canada's target Consumer Price Index (CPI) inflation forecast.

5.3 Energy Supply Costs Summary

The forecast energy supply costs for DGE are shown in Schedule 12 in Appendix A as indicative figures. The actual energy supply costs will be used to calculate the DGE Variable Energy Charge through the DGE Variable Energy Charge rate setting mechanism, previously approved by the BCUC (see Section 2.5).

Given the above, Corix is not seeking approval of energy supply costs or Variable Energy Charges within this Application. Energy supply costs have been shown in this Application for completeness to understand the total cost of providing service to customers.

6. Operating and Maintenance (O&M) Costs

Operating and Maintenance (O&M) costs for DGE are comprised of fixed costs required to operate and maintain the entire utility on an annual basis. O&M costs are forecast by applying escalators to historical results. Table 4 below includes the forecast annual total O&M costs for DGE for 2025 to 2028, as well as actuals for 2022, 2023 and 2024. These costs represent the aggregate actual O&M expenditures. Subsequently, the actual costs are first adjusted to reflect the approved costs associated with Corporate Services and Regional Services (Support Services) and then adjusted for any errors and corrections (Net Adjustment – Other), resulting in a total that is used to calculate the annual RDDA balance.

TABLE 4: DGE TOTAL O&M COSTS

O&M COSTS ($)	Actual 2022	Actual 2023	Actual 2024	Test Period			
				Forecast 2025	Forecast 2026	Forecast 2027	Forecast 2028
Total Actual O&M Costs	**332,319**	**359,730**	**538,979**	**590,096**	**615,231**	**623,178**	**643,432**
Net Adjustment – Support Services	(15,594)	(60,363)	(144,905)	(92,179)	-	-	-
Net Adjustment – Other	39,371	(2,381)	-	-	-	-	-
Total O&M Used to Calculate RDDA	***356,096***	***296,986***	***394,074***	***497,916***	***615,231***	***623,178***	***643,432***

The actual Net Adjustments – Support Services arise from variances in Corporate Services and Regional Services costs, for which the actuals exceeded the allowed amounts approved in the 2019 RRRA proceeding. For clarity:

- the "Total Actual O&M Costs" are the actual costs incurred to operate and maintain the utility; and
- the "Total O&M Used to Calculate RDDA" are the figures used to calculate the annual revenue shortfall, which is then applied to the RDDA.

It should be noted that the Net Adjustments – Support Services are not denials of cost recovery due to imprudent costs being incurred by the utility. Instead, these net adjustments merely reflect Corix's proposals and BCUC's approvals in the last rate application addressed through G-248-19. At that time Corix was part of a larger company with other utility and non-utility businesses. As a result, the approved Regional and Corporate Services Costs totaled $110,000 in 2018 dollars ($70,200 for Regional and $39,800 for Corporate), with an annual escalation rate of 2.0%. These approved amounts no longer reflect Corix's actual costs and Corix's shareholder had to bear the cost until the forecast could be updated as part of a subsequent rate application. In this Application Corix has updated these support services costs (see Section 6.3).

The sections that follow provide details on the O&M cost escalator assumptions and the O&M costs. Schedule 11 in Appendix A provides a detailed breakdown of the O&M costs from 2021 through to 2030

6.1 O&M Cost Escalators

Corix relies on the following escalators to forecast O&M costs.

1. O&M Inflation Escalator
   Corix has used an inflation escalator[6] to forecast most of the O&M costs in the test period. The Bank of Canada (BoC) aims to keep long term inflation at the 2 per cent midpoint of an inflation-control target range of 1 to 3 per cent.[7] In the April 2025 Monetary Policy Report[8], the Bank of Canada projects layers of uncertainty affecting the outlook for the Canadian economy. The first layer of uncertainty is around US trade policy and the second layer of uncertainty relates to how households, businesses and governments will react and adapt to tariffs.

   There is considerable uncertainty surrounding the evolution of US trade policies and their potential impact on the economy. As a result, the Bank of Canada has forecasted two scenarios, each with distinct implications for the Canadian economy and underlying inflation.

   - **Scenario 1:** Most tariffs imposed since the trade conflict began are negotiated away, but the process is unpredictable. Uncertainty about trade policy continues until the end of 2026.
   - **Scenario 2:** The uncertainty and limited tariffs in Scenario 1 persist, and other US tariffs are added. A long-lasting global trade war unfolds.

   Under these Scenarios the Bank of Canada CPI forecast is shown in the table below.

TABLE 5: BANK OF CANADA CPI INFLATION FORECAST

Bank of Canada CPI Inflation[9]	Test Period			
	Forecast 2025	Forecast 2026	Forecast 2027	Forecast 2028
Scenario 1	1.8%	2.0%	2.1%	2.0%
Scenario 2	2.0%	2.7%	2.0%	2.0%
Average	**1.90%**	**2.35%**	**2.05%**	**2.00%**

   Given the uncertainty around the Canadian economy and the underlying effects on the inflation, Corix has averaged Scenario 1 and 2 from the table above as a proxy to forecast O&M costs that rely on an inflation escalator in the test period.

2. Labour Escalator
   Labour-related costs are escalated based on Corix's senior leadership's direction regarding the workforce budgets. The annual escalation is 3.0% in 2025, 2026, 2027 and 2028. Given the challenges faced by companies today in attracting and retaining qualified staff, this figure represents a reasonable increase to encourage staff retention and maintain a level equal to or higher than the target inflation rate, while minimizing increases to fixed costs for Corix.

[6] The inflation escalator is expressed as the year-over-year increase in the total consumer price index (CPI).
[7] Bank of Canada Website, Inflation, https://www.bankofcanada.ca/core-functions/monetary-policy/inflation/.
[8] Bank of Canada Website, Monetary Policy Report, April 2025, https://www.bankofcanada.ca/publications/mpr/.
[9] Ibid.

These escalators were applied to produce forecasts for 2025, 2026, 2027, and 2028, with insurance costs being forecast as described in item 7 in the section below. In other cases, 2024 figures were adjusted based on known circumstances. Details for each of the O&M costs are provided below.

6.2 O&M Cost Categories

This section includes detailed descriptions of each O&M cost category and the relevant assumptions for each of the line items, as shown in Schedule 11 of Appendix A.

1) **Operating Labour –** This is the labour cost associated with operating the DGE, which is largely driven by mandatory technical safety requirements imposed by Technical Safety BC (TSBC) pursuant to the Power Engineers, Boiler, Pressure Vessel and Refrigeration Safety Regulation[10]. After recommissioning of the Cleaver-Brooks boiler, Corix notes that this would result in the classification of the plant as a "Continuous Supervision status, which would required that the person in charge of the plant be physically present at all times in the boiler room or the immediate vicinity within the plant premises while the plant is in operation, effectively resulting in a physical presence at all times during operation. However, in accordance with the TSBC regulations, Corix applied for the alternative General Supervision status in April 2024. General Supervision status requires the presence of a power engineer with the appropriate class of certificate of qualification as determined by a plant safety audit inspection and as required by a provincial safety manager.[11] The General Supervision status would allow for partial physical presence, supplemented with remote monitoring based on the risk factors of the plant. This would reduce the staffing requirements for the operations relative to what would be required under Continuous Supervision status.

   Corix forecasts that DGE requires the following FTE operating labour starting in 2025 to comply with TSBC General Supervision Status requirements.

   - 1.00 FTE[12] operators
   - 0.01 FTE supervisor
   - 0.08 FTE area manager

   The FTE for the test year is based on the operational requirements for 2024 in which DGE recorded through timesheets 0.88 FTE operators, 0.01 FTE supervisor and 0.12 FTE area manager, and driven by the anticipated General Supervision Status labour requirement by TSBC.

   The Operating Labour cost for 2025 is forecasted based on the FTEs stated above, combined with the compensation associated with each position (operator, supervisor, and area manager). The FTEs forecast for 2025 are held constant for the remainder of the years in the financial model. The 2025 Operating Labour cost is then escalated using the labour escalator described in the preceding section.

   At the time of filing, TSBC is still in progress of reviewing the General Supervision Status for DGE. Corix notes that TSBC's final determination could result in different FTE requirements and thus an Operating Labour cost variance to the 2025-2028 test year forecasts.

[10] Power Engineers, Boiler, Pressure Vessel and Refrigeration Safety Regulation, B.C. Reg. 104/2004 [Last amended February 21, 2024 by B.C. Reg. 27/2024].
[11] Ibid., Section 55(2).
[12] FTE is Full Time Equivalent.

2) **Repair & Maintenance** –The maintenance costs in this RRRA were forecasted based on the historical cost of repairing and maintaining the equipment and building. These forecasts are then escalated using the O&M inflation escalator. These costs encompass a range of repair and maintenance activities, including internal repairs, upkeep of electrical equipment, and procurement of necessary materials and supplies. Additionally, they cover expenses related to system maintenance that is outsourced to external contractors and consultants. Other than infrastructure-related expenditures, these costs also include vehicle repair and maintenance, and other miscellaneous maintenance-related expenses necessary for ensuring operational efficiency and compliance with safety standards.

3) **Maintenance (Unforeseen)** – This refers to unexpected major maintenance and repair needs arising from sudden equipment failures. It is forecasted at zero because such events are unpredictable and difficult to quantify in advance.

4) **Permits & Licenses** – This cost category captures all permitting and licensing costs associated with operating the DGE, with the exception of computer/software licensing. These costs are forecast based on historical costs and then escalated using the O&M inflation escalator.

5) **Chemicals/Water Treatment** – This cost category captures costs related to chemical treatment of the water contained in the district energy system's DPS. Costs are forecast based on average historical costs and then escalated using the O&M inflation escalator.

6) **Operating Expenses** – This cost category captures all costs associated with operating DGE that are not captured in the preceding O&M cost categories. Examples of costs captured in this category are landscaping, safety supplies, travel expenses, vehicle fuel and vehicle insurance. The test year was forecasted based on operational requirements for 2025 and subsequently escalated by the O&M inflation escalator.

7) **Insurance –** Corix receives an allocation of shared insurance costs incurred by the parent company for all relevant businesses. Following the restructuring transaction in 2024 (see Section 2.8), the insurance for Corix's parent company was renewed in October 2024, which resulted in a 13% decrease in insurance costs forecasted for DGE for 2025. These 2025 insurance costs are based on the latest insurance information available.

   The premium per $100 of assessed value of the owner insurance, the liability insurance and other insurance are escalated annually at 7.5% for 2025, 2026 and 2027 each, followed by 3.0% in each of the subsequent years. 3.0% was used for the long-term forecast because insurance costs can fluctuate greatly each calendar year depending upon catastrophic losses. Given this instability, Corix has been unable to establish a reliable methodology for accurately predicting future insurance costs especially for longer forecast periods. As a result, Corix used a broader escalation of target CPI inflation + 1%, to calculate 3.0%, from 2028 onwards. These escalators reflect the persistent and material year-over-year increases in insurance costs that is impacting the utility industry. The breakdown of the costs are as follows.

   a. <u>Liability Insurance</u>
      General Liability insurance is obtained to cover all DES fully-owned by Corix's parent company. Premiums are then allocated to utilities based on the respective utility revenues. The premium is calculated based on the Statement of Value for the DGE property, which covers the period from October to September of the next year. The insurance premium is determined by applying a rate per $100 of assessed value, with this rate escalating annually at 7.5% for 2025, 2026 and 2027, followed by 3.0% in each of the years that follow.

   b. <u>Owner Insurance</u>
      Property Insurance is obtained to cover all utilities DES fully-owned by Corix's parent company. Premiums are then allocated to utilities based on the value of the gross property, plant and equipment (PPE).

c. Other Insurance
Other insurance is obtained to cover Directors and Officers (D&O) liability, Errors and Omissions (E&O), and Cyber Insurance.

The total cost of insurance is projected to decrease by -13.4% in 2025, and increase by 9.1% in 2026, 8.9% in 2027 and 6.3% in 2028 primarily due to changes in the assessed property value of the DGE assets and the insurance escalators described above.

8) **Billing (Service Provider)** – In previous years, this cost was included as part of the Corporate Services cost allocation. However, following the restructuring transaction in 2024 (see Section 2.8) and the selection of a new billing service provider, this cost category was created to capture external service provider costs related to monthly customer billing. These costs are incurred on a shared basis and are direct charged to each utility based on the number of customer bills issued. Costs are forecast in 2025 based on the latest service provider cost information and then escalated using the O&M inflation escalator.

9) **Office and Admin Expenses** – These costs cover software licensing, office supplies and expenses, bank fees, mobile phones, and other office and administration miscellaneous expenses. Test year 2025 was forecasted based on administration requirements and then escalated using the O&M inflation escalator.

10) **External Regulatory Costs** – This cost category captures third party costs reasonably and prudently incurred for DGE due to and related to the regulation of the BCUC. It includes: (i) annual BCUC cost recovery levies assessed by the BCUC on DGE; (ii) costs awarded by the BCUC to participants in regulatory proceedings involving DGE, that DGE is directed to pay; (iii) costs incurred by the BCUC associated with the review of DGE filings or submissions that is invoiced to DGE by BCUC; (iv) external public consultation costs incurred by DGE if and when required by the BCUC; (v) external legal or consulting costs incurred as a direct result of participating in BCUC proceedings; and (vi) any other unforeseen third-party costs incurred as a result of regulation by the BCUC.

2024 External Regulatory Costs
External Regulatory Costs for 2024 include the BCUC annual levy and one-time external consultant costs incurred to facilitate Corix's participation in the Generic Cost of Capital (GCOC) Stage 2 proceeding that concluded with BCUC Order and Decision G-321-24. Corix's external consultant costs for the GCOC Stage 2 proceeding was incurred on a shared basis and allocated to each of Corix's BCUC-regulated utilities using net book value of utility plant as a proxy for invested capital. DGE received 2.4% of Corix's total external consultant costs for the GCOC Stage 2 proceeding. Corix's use of external consultants in this proceeding was driven by BCUC Order G-66-21, dated March 8, 2021, which identified Corix as the only district energy utility to be classified as an "Affected Utility". Page 1 of Appendix C to Order G-66-21 stated:

> "The Affected Utilities have been designated given their active participation in previous Cost of Capital proceedings that set a benchmark ROE or their anticipated interest in the GCOC Proceeding as investor-owned utilities. These Affected Utilities are expected to take a lead role in filing evidence for cost of capital matters that may impact them." [Underline emphasis added]

Given the complex and highly specialized topic of utility cost of capital, Corix required external support from expert consultants to be able to fulfill its designation and play a "lead role in filing evidence".

2025 External Regulatory Costs
The External Regulatory Costs for 2025 is forecast to include: (i) the BCUC annual levy; (ii) costs related to Participant Cost Award (PCA) for the BCUC GCOC Stage 2 proceeding; and (iv) external costs related to the DGE customer information session prior to the filling of the 2025-2028 RRRA. Corix considers that this information session was necessary to provide customers, stakeholders and end-users an opportunity to learn about the upcoming rate increase proposals, the key drivers behind the cost increases and provide them an

opportunity to ask questions. The customer information session and the feedback from participants is detailed in Section 13.4 of this Application.

<u>2026 External Regulatory Costs</u>
The External Regulatory Costs for 2026 is forecast to include: (i) the BCUC annual levy; and (ii) costs related to PCA payments for this Application. Corix has forecast the PCA costs based on past experience but notes that PCA costs can vary widely depending on the number of interveners, the number of years of experience for certain interveners and the level of intervener activity in a proceeding.

In future years, External Regulatory Costs is forecast to include the BCUC annual levy, and PCA for future DGE revenue requirement and rate applications occurring every three (3) years beginning in 2029. Both items are forecast with annual escalation based on the O&M inflation escalator.

11) **Regulatory Affairs** – This cost represents employee costs and third-party services costs incurred on a shared basis at the regional level (Regional Service cost) for utilities within Corix's parent company's DE West region that receive economic regulation. At a high level, this category captures the costs to ensure that DGE seeks and obtain all mandatory regulatory approvals and complies with all mandatory directives from regulators. A more detailed description of the services provided for this cost is included in Appendix B within the Regional Cost Allocation Methodology (CAM) Manual that has been filed as Appendix J with this Application. The Regional CAM Manual also includes a detailed description of the cost allocation methodology for this cost.

12) **Health, Safety and Environment** – This cost represents employee costs and third-party services costs incurred on a shared basis at the regional level (Regional Service cost) related to the health, safety and environment (HSE) program and compliance. At a high level, this category captures costs related to health, and safety programs, environmental compliance, incident management protocols and includes employee safety training and initiatives to maintain safe and sustainable operations. A more detailed description of the services provided for this cost is included in Appendix B within the Regional CAM Manual that has been filed as Appendix J with this Application. The Regional CAM Manual also includes a detailed description of the cost allocation methodology for this cost.

13) **Financial Planning and Analysis (FP&A) and Accounting** – This cost represents employee costs and third-party services costs incurred on a shared basis at the regional level (Regional Service cost) related to FP&A and accounting. At a high level, this category captures costs associated with utility accounting and bookkeeping, budgeting, financial modeling and forecasting, and supporting various departments including but not limited to Regulatory Affairs for the preparation of annual financial reports and annual ECRA reports for the BCUC. A more detailed description of the services provided for this cost is included in Appendix B within the Regional CAM Manual that has been filed as Appendix J with this Application. The Regional CAM Manual also includes a detailed description of the cost allocation methodology for this cost.

14) **Business Operations** – This cost represents employee costs incurred on a shared basis at the regional level (Regional Service cost) related to procurement, accounts payable and general business operations. At a high level, this category captures costs associated with procurement process management, accounts payable, fleet management, asset management support and data analysis and internal reporting. A more detailed description of the services provided for this cost is included in Appendix B within the Regional CAM Manual that has been filed as Appendix J with this Application. The Regional CAM Manual also includes a detailed description of the cost allocation methodology for this cost.

15) **Billing and Customer Care** – This cost represents employee costs incurred on a shared basis at the regional level (Regional Service cost) related to billing and customer care. Billing and customer care staff are often the first point of contact for utility customers. At a high level, this category captures costs associated with preparing customer bills, statements, and reports, processing rate changes in the billing system, responding to customer enquiries, and managing the accounts receivable processes. A more detailed description of the services provided for this cost is included in Appendix B within the Regional CAM Manual that has been filed

as Appendix J with this Application. The Regional CAM Manual also includes a detailed description of the cost allocation methodology for this cost.

16) **Operations Leadership and Strategy** – This cost represents employee costs and third-party services costs incurred on a shared basis at the regional level (Regional Service cost) related to the oversight, guidance, leadership and direction of daily operations to ensure the safe, compliant and efficient operations of all utilities and all related engineering and project management activities in the region. A more detailed description of the services provided for this cost is included in Appendix B within the Regional CAM Manual that has been filed as Appendix J with this Application. The Regional CAM Manual also includes a detailed description of the cost allocation methodology for this cost.

17) **Project Management Office** – This cost represents employee costs and third-party services costs incurred on a shared basis at the regional level (Regional Service cost) related to the management of the capital project program in the region. A more detailed description of the services provided for this cost is included in Appendix B within the Regional CAM Manual that has been filed as Appendix J with this Application. The Regional CAM Manual also includes a detailed description of the cost allocation methodology for this cost. As these costs are typically capitalized to the respective projects, they have been forecast to be $0 each year during the forecast period. However, there may be residual actual costs for time spent on general items, including but not limited to, providing support to the Regulatory Affairs team to respond to BCUC staff questions following a compliance filing or information requests.

18) **People and Culture** – This cost represents costs incurred on a shared basis at the corporate level (Corporate Service cost) associated with human resource management, employee engagement, and organizational culture initiatives. At a high level, it includes policy and practice development, people programs and services administration, payroll processing, benefits and medical plan administration, pension plan administration, recruitment, training, employee development, and initiatives to foster a positive organizational culture. A more detailed description of the services provided for this cost is included in Appendix B within the Corporate CAM Manual that has been filed as Appendix I with this Application. The Corporate CAM Manual also includes a detailed description of the cost allocation methodology for this cost.

19) **IT, OT and Cybersecurity** – This cost represents costs incurred on a shared basis at the corporate level (Corporate Service cost) associated with the provision and maintenance of information technology (IT) and operational technology (OT) infrastructure, applications, cybersecurity programs, and related support services for the organization. At a high level, it includes network and cloud infrastructure management, IT hardware and standard application provisioning and implementation, an enterprise-wide help centre, OT systems and site implementation and management of uniform IT security and cybersecurity protocols. A more detailed description of the services provided for this cost is included in Appendix B within the Corporate CAM Manual that has been filed as Appendix I with this Application. The Corporate CAM Manual also includes a detailed description of the cost allocation methodology for this cost.

20) **Communications** – This cost represents costs incurred on a shared basis at the corporate level (Corporate Service cost) for, at a high level: communications strategy development and execution; external and internal communications management; managing content on the external website and the intranet; management of the social media channels; and brand management. A more detailed description of the services provided for this cost is included in Appendix B within the Corporate CAM Manual that has been filed as Appendix I with this Application. The Corporate CAM Manual also includes a detailed description of the cost allocation methodology for this cost.

21) **Legal and Risk Management** – This cost represents costs incurred on a shared basis at the corporate level (Corporate Service cost) for a comprehensive suite of risk management services, which includes enterprise risk management; technical safety and compliance leadership; HSE leadership; internal audit services; and legal services. A more detailed description of the services provided for this cost is included in Appendix B within the Corporate CAM Manual that has been filed as Appendix I with this Application. The Corporate CAM Manual also includes a detailed description of the cost allocation methodology for this cost.

22) **Corporate Finance** – This cost represents costs incurred on a shared basis at the corporate level (Corporate Service cost) for corporate accounting, capital market engagement, corporate financial planning and analysis, insurance, taxation, and treasury services. Corporate Finance provides services that include, but is not limited to, securing debt and equity financing, managing liquidity, managing the preparation and consolidation of financial statements, and supervising the corporate income tax provision and compliance work. A more detailed description of the services provided for this cost is included in Appendix B within the Corporate CAM Manual that has been filed as Appendix I with this Application. The Corporate CAM Manual also includes a detailed description of the cost allocation methodology for this cost.

23) **Executive Management** – This cost represents costs incurred on a shared basis at the corporate level (Corporate Service cost) for the executive management function responsible for all businesses within Corix's parent company's portfolio as well as rent and associated costs for the parent company headquarters, located in Vancouver, B.C. A more detailed description of the services provided for this cost is included in Appendix B within the Corporate CAM Manual that has been filed as Appendix I with this Application. The Corporate CAM Manual also includes a detailed description of the cost allocation methodology for this cost.

6.3 Corporate and Regional Support Services Allocations

6.3.1 Corporate Services

Corporate services costs are shared costs incurred at the corporate level in order to provide a variety of necessary services to all affiliates. Of the cost categories listed in Section 6.2 above, corporate services and the associated costs include: people and culture; IT, OT and cybersecurity; communications; legal and risk management; corporate finance; and executive management. These costs are forecast and incurred at the corporate level and then allocated to each business, including DGE, using the approved Corporate Cost Allocation Methodology (CAM). Appendix I of this Application includes the Corporate CAM Manual that sets out the process to allocate corporate services costs. The process outlined in Section 4 of the Corporate CAM Manual remains consistent with that previously approved by the BCUC through Order G-349-20 with Reasons for Decision, issued December 24, 2020 following a public hearing review process. The Corporate CAM relies on the use of a functional allocator or a composite allocator to allocate indirect costs to business. Functional allocators are used where the costs can be allocated using an identified cost causation driver. Corporate services costs that do not have a direct correlation with any one particular cost causation driver are allocated using a composite allocator. The composite allocator is calculated using three equally weighted factors: (i) Gross Property, Plant & Equipment (Gross PPE); (ii) Gross Revenue; and (iii) Headcount. The composite allocator is used to represent the size, scope and complexity of each of the operating businesses. Table 6 below lists the corporate cost categories, and the corresponding allocator used.

TABLE 6: CORPORATE SERVICES COST CATEGORIES AND ALLOCATORS

Item	Corporate Service Cost Category	Allocator Used
1	People and Culture	Headcount
2	IT, OT and Cybersecurity	Composite Allocator
3	Communications	Composite Allocator
4	Legal and Risk Management	Composite Allocator

5	Corporate Finance	Composite Allocator
6	Executive Management	Composite Allocator

For additional details, please refer to the Corporate CAM Manual included in Appendix I of this Application which includes, among other things, a detailed description of the corporate cost allocation methodology, the scope of corporate services, a detailed description of each corporate service and a hypothetical example showing the application of the corporate cost allocation methodology.

The Corporate Services cost allocations have been identified as one of the key drivers of the revenue requirement increase in this Application. Please refer to Section 11.7 for additional information regarding the Corporate Services cost allocation driver.

6.3.2 Regional Services

Regional services costs are shared costs incurred at the regional level in order to provide a variety of necessary services to relevant affiliates. Of the cost categories listed in Section 6.2 above, regional services and the associated costs include: regulatory affairs; health, safety and environment; FP&A and accounting; business operations; billing and customer care; operations leadership and strategy; and project management office. These costs are forecast and incurred at the regional level and then allocated to each relevant business, including DGE, using the Regional CAM. Appendix J of this Application includes the Regional CAM Manual that sets out the process to allocate regional services costs. The process outlined in Section 4 of the Regional CAM Manual is consistent with that previously approved by the BCUC through G-349-20 regarding the Corporate CAM and briefly described in Section 6.3.1 above. Table 7 below lists the regional cost categories, and the corresponding allocator used.

TABLE 7: REGIONAL SERVICES COST CATEGORIES AND ALLOCATORS

Item	Regional Service Cost Category	Allocator Used
1	Regulatory Affairs	Composite Allocator
2	Health, Safety and Environment	Composite Allocator
3	FP&A and Accounting	Composite Allocator
4	Business Operations, Procurement and Accounts Payable	Composite Allocator
5	Billing and Customer Care	Customer Count
6	Operations Leadership and Strategy	Composite Allocator
7	Project Management Office	Composite Allocator

For additional details, please refer to the Regional CAM Manual included in Appendix J of this Application which includes, among other things, a detailed description of the regional cost allocation methodology, the scope of regional services, a detailed description of each regional service and a hypothetical example showing the application of the regional cost allocation methodology.

The Regional Services cost allocations have been identified as one of the key drivers of the revenue requirement increase in this Application. Please refer to Section 11.7 for additional information regarding the Regional Services cost allocation driver.

7. Property & Other Fees

7.1 Property & Other Fees Cost Categories

Property & Other Fees (P&O Fees) are part of the total delivery revenue requirements of the utility. Property Tax and Other Fees are necessary annual fees. P&O Fees for DGE consist of the following:

1) **Property Tax –** The landowner, Bosa Development (Dockside Holdings) Ltd. ("Bosa"), is charged property tax from the City of Victoria on an annual basis. Bosa then flows through the property tax to Corix without any markup. The amount forecasted by Corix is the amount of property tax Corix anticipates it would be billed annually by Bosa based on historical invoices with a forecast escalation of the property value and the property tax rates. The property value has been forecast to escalate at 2.3% per year in 2026, 2027 and 2028, with 2.0% from 2029 onwards. The various property tax rates have been forecasted to escalate at 1.7% per year from 2026 onwards.

Schedule 11 in Appendix A includes the forecast P&O Fees for DGE.

8. Capital Costs

This Section provides details regarding the capital costs, with a focus on the test period that will impact the revenue requirement and ultimately customer rates. At a high level, DGE capital costs fall into one of the following categories: (i) Central Energy Plant (CEP); (ii) Distribution Piping System (DPS); and (iii) Energy Transfer Station (ETS). Capital costs can also be grouped into new capital additions or renewal and replacement (R&R) capital costs. Details for each of the three categories, including new additions, are provided in the subsections that follow. R&R capital is discussed in Section 8.2. The total capital costs are summarized in Section 8.7.

8.1 New Capital Additions

8.1.1 Central Energy Plant (CEP)

No new capital additions for the CEP are forecasted to occur during the test period. However, Corix forecast renewal and replacement costs related to the CEP as discussed in Section 8.2.1. Total Capital expenditures are summarized in Section 8.7 and in shown detail in Schedule 5 in Appendix A.

The total capital expenditure for CEP new additions from 2018 to 2024 is $702,337. This amount includes the costs associated with the transfer and installation of the three kW KN-30 condensing boilers, along with expansion tanks and pump sensors, fittings and piping modifications, and the retrofit of the Central Energy Plant to incorporate the KN-30 boilers essential to integrate the new boilers into DGE existing infrastructure.

TABLE 8: CEP CAPITAL COSTS (NEW ADDITIONS)

Capital Costs ($)	Actuals	Test Period			
	2018-2024	2025	2026	2027	2028
CEP	702,337	-	-	-	-

8.1.2 Distribution Piping System (DPS)

The distribution piping system (DPS) is planned to continue expanding throughout the Dockside service area in coordination with the developer buildout schedule to serve future buildings. The DPS system will be installed in tandem with all municipal services (i.e. water, sewer, and storm) and the developer is contractually required to cover all civil costs related to DPS installation. The DPS design, material, fittings, installation, testing and project management to support the project are costs borne by Corix.

For the Test Period, Corix forecasts no new capital expenditures for the DPS given that no new buildings are expected to connect until 2030.

In the previous Rate Application, Corix initially forecasted capital expenditures for the DPS to be in the range of $560,200 to connect 4 customer buildings by 2023 (Ci-3, D-1, D-2 and A-1 Towers). However, due to development delays only 2 customer buildings (Ci-3 and A1 Towers) were connected to the system with a total DPS cost of $423,428 as shown in Table 8 below.

TABLE 9: DPS CAPITAL COSTS (NEW ADDITIONS)

Capital Costs ($)	Actuals	Test Period			
	2018-2024	2025	2026	2027	2028
DPS	423,428	-	-	-	-

Factors that increased the cost of the DPS included significant supply constraints and heightened price volatility during the COVID-19 pandemic, which led to extended lead times and elevated material costs. The piping market, in particular, experienced sharp price surges due to global supply chain disruptions, increased demand for construction materials, and limited manufacturing capacity. This volatility was further intensified by geopolitical events, especially the escalation of the Russia-Ukraine conflict in 2022. The war disrupted global energy supplies and reduced industrial output, complicating the market for key commodities such as hot-rolled steel used in the DGE distribution piping system. The destruction of the Azovstal Steel Plant in Mariupol—a major supplier—further constrained supply and drove up costs. These pressures were compounded by broader inflationary trends in 2023, which elevated the costs. Despite these challenges, the DPS installation was competitively tendered, and the contract was awarded to the lowest bidder, indicating that the final costs were reflective of prevailing market conditions at the time.

The Test Period R&R costs related to the DPS is discussed in Section 8.2.1. Total Capital expenditures are summarized in Section 8.7 and shown in detail in Schedule 5 of Appendix A for the years 2021 to 2028.

8.1.3 Energy Transfer Station (ETS)

Energy Transfer Stations include the necessary pipes, heat exchangers, associated controls, and energy meters to interface with the building heating systems. This equipment, is owned and operated by DGE and located inside the customer's building. An ETS can be located within the same mechanical room as the building heating and domestic hot water system equipment and is sometimes located in the basement or parkade. An ETS typically occupies approximately 20% of the space of a conventional single-site boiler plant.

DGE ETS' as described above are installed and paid for directly by the developer using the Corix' technical specification and final sign off. Once commissioned and completed, the asset is then transferred to Corix. Corix capital expenses in relation to the ETS include costs to:

- update the technical specifications as required;
- complete a compatibility review to ensure conformance with the Thermal Energy Delivery Parameters;
- complete shop drawing reviews;
- perform quality control to ensure selected equipment meets the needs of the project; and
- connect the ETS to the CEP through a fiber connection to facilitate remote monitoring and control.

Commissioning the ETS in conjunction with the developer including testing the ETS against the performance requirements is necessary before Corix takes ownership of the ETS.

For the Test Period, Corix forecasts no new capital expenditures for the ETS given that no new buildings are expected to connect until 2030.

In the previous Rate Application, Corix initially forecasted capital expenditures for the Energy Transfer Stations in the amount of $134,960 to connect 4 customer buildings by 2023 (Ci-3, D-1, D-2 and A-1 Towers). However, due to development delays only 2 customer buildings (Ci-3 and A1 Towers) were connected to the system with a total ETS cost of $46,387 as shown in Table 10 that follows.

TABLE 10: ETS CAPITAL COSTS (NEW ADDITIONS)

Capital Costs ($)	Actuals	Test Period			
	2018-2024	2025	2026	2027	2028
ETS	46,387	-	-	-	-

The Test Period R&R costs related to the ETS are discussed in Section 8.2.1. Total Capital expenditures are summarized in Section 8.7 and in shown detail in Schedule 5 in Appendix A for the years 2021 to 2028.

8.2 Renewal and Replacement Capital Expenditures

8.2.1 Test Period R&R Capital Expenditures

Since acquiring DGE, Corix has been operating the system for just over six (6) years. Corix has performed maintenance as per original equipment manufacturer (OEM) recommendations as well as maintenance repairs as needed. Corix continues to monitor the material condition of equipment and systems. Operational observations to date suggest that some equipment components will likely require replacing sooner than OEM timelines. The table that follows lists the components that are expected to be renewed or replaced during the test period.

TABLE 11: COMPONENTS TO BE RENEWED OR REPLACED

Year	Component	Amount ($)	Reason
2025	R&R CEPs 2025 - #2 Boiler Burner	21,000	▪ **#2 Boiler Burner** - End of life replacement. Replacing the KN-30 boiler burner is essential for maintaining the safe and efficient operation of a district energy system. Over time, burners can degrade, leading to issues such as incomplete combustion, gas leaks, or flame instability—all of which pose serious safety risks. In addition to safety, a new burner significantly improves heating efficiency by optimizing fuel-air mixing and combustion performance. This reduces fuel consumption, lowers emissions, and helps control operating costs. A reliable burner also minimizes the risk of unexpected breakdowns, ensuring consistent heat delivery and uninterrupted service to customers. Overall, timely burner replacement supports the long-term reliability, efficiency, and safety of the district energy system.
2026	R&R CEPs 2026 - #3 Boiler Burner	23,542	▪ **#3 Boiler Burner** - End of life replacement. Same justification as #2 Boiler Burner replacement above.
2026	R&R ETS 2026	32,957	▪ **Thermal energy meters** - Measurement Canada (MC) mandated that on or before Jan 1, 2028, all thermal energy meters used for billing must have MC approval or be replaced with an approved meter. Meters require upgrading to comply with regulation.
2027	R&R CEPs 2027	87,736	▪ **CB Boiler Combustion Fan** – End of life replacement. Replacing the CB Boiler Combustion Fan is critical to maintaining safe and efficient boiler operation within the district energy system. The combustion fan ensures proper airflow for fuel combustion, and any degradation in its performance can lead to incomplete combustion, increased emissions, or even flame instability—posing serious safety risks. A new fan improves air

Year	Component	Amount ($)	Reason
			delivery precision, enhancing combustion efficiency and reducing fuel consumption. It also supports consistent boiler performance, minimizing the risk of overheating or shutdowns, and ensuring reliable heat delivery to the network. ▪ **MCC Heat Pump** – End of life replacement of HVAC required to maintain operating environment of electrical & computer control room. The replacement of the MCC Heat Pump is necessary to uphold both energy efficiency and operational reliability. Heat pumps are central to transferring thermal energy efficiently, and aging units often suffer from reduced capacity, refrigerant leaks, or compressor failures. A modern heat pump operates with higher coefficients of performance (COP), reducing electricity use while delivering the same or greater heating output. This upgrade not only enhances system efficiency but also ensures stable service delivery providing optimal operating environment for the electrical and computer control room. This will help reduce the likelihood of unplanned outages. ▪ **Remote Monitoring Camera System** – System obsolete and requires upgrade to maintain reliability and internet security. Camera system required by TSBC for plant monitoring when operator not present. ▪ **M470 Distribution Pump** – end of service life - major rebuild required for service life extension. The M470 Distribution Pump plays a vital role in circulating heated water throughout the district energy system. Over time, pump wear can lead to reduced flow rates, cavitation, or seal failures, which compromise both safety and system performance. Replacing this pump ensures optimal hydraulic performance, maintaining consistent pressure and flow across the network. A rebuilt pump supports reliable heat distribution, while preventing service interruptions.
2028	R&R CEPs 2028	12,252	▪ **M450 Distribution Pump** – end of service life - major rebuild required for service life extension. Same justification as M470 rebuild above ▪ **#2 Boiler Pump & VFD** – end of service life - major rebuild required for service life extension. The #2 Boiler Pump and its Variable Frequency Drive (VFD) are crucial for regulating water circulation within the boiler system. As these components age, they can suffer from reduced responsiveness, mechanical wear, and electrical inefficiencies. Replacing both the pump and VFD ensures precise flow control, which is essential for maintaining safe boiler operation and avoiding thermal stress. A new VFD also allows for dynamic adjustment of pump speed based on demand, significantly improving energy efficiency and reducing wear. This upgrade enhances system reliability and supports continuous, stable heating service.

The above list includes the planned R&R only and are not exhaustive of the potential expenditures Corix may incur to meet operational requirements. It is important to note that actual replacement needs may vary depending on system demands, unforeseen circumstances, and other operational factors. Additionally, certain equipment may remain in service beyond the manufacturer's OEM replacement schedule, as longevity can exceed initial projections due to proper maintenance, upgrades, or favorable operating conditions. Therefore, Corix may adjust replacement timelines and costs as necessary to ensure the continued reliability, efficiency and security of the utility operations.

R&R capital costs for the for the period 2019 to 2028 are shown in Table 12 that follows Table 12. For the Test Period the components discussed above amount to a total of $144,528 for the CEP, $0 for the DPS, and $32,957 for the ETS.

TABLE 12: RENEWAL AND REPLACEMENT CAPITAL COSTS

Capital Costs ($)	Actuals	Test Period			
	2018-2024	2025	2026	2027	2028
CEP	247,310	21,000	23,541	87,736	12,252
DPS	388,459				
ETS	133,134		32,957		
TOTAL CAPITAL	**768,903**	**21,000**	**56,497**	**87,736**	**12,252**

8.2.2 Historical R&R

8.2.2.1 Central Energy Plant R&R

After Corix acquired DGE assets on 2018, Corix incurred $247,310 of Renewal and Replacement costs related to the Central Energy Plant as shown in Table 12 above. The historical costs can be broken down into: (1) general renewal and replacement, and (2) Lay-down and commissioning of the Cleaver Brooks Boiler.

General Renew and Replacement (R&R)

This category focused on extending the life of critical infrastructure and improving system safety and efficiency. The total amount related to mechanical system upgrades or replacement as per original equipment manufacturer (OEM) recommendations is $121,774, comprised of the R&R below.

Mechanical System Upgrades

- M460 Distribution Pump Rebuild – $2,820
- M460 Pump Motor Replacement – $6,250
- Boiler #1 Burner Replacement – $14,302
- Make-up Water Meter – $5,521
- Insulation and metal cladding to cover air louvers – $16,155
- Temporary Boiler Install – $17,541
- Flue Gas Boiler Removal – $19,789

These upgrades addressed critical mechanical components that had reached the end of their service life. The M460 pump and its motor are essential for circulating heated water throughout the district energy system. Over time, wear and degradation can lead to reduced flow, cavitation, and seal failures, compromising both safety and performance. Rebuilding and replacing these components restored optimal hydraulic function, ensuring consistent pressure and reliable heat distribution. Similarly, the replacement of the #1 boiler burner was vital for maintaining safe and efficient combustion. A degraded burner can cause incomplete combustion, gas leaks, and flame instability—posing serious safety risks. The new burner improves fuel-air mixing, reduces emissions, and enhances heating efficiency. During the installation of the KN-30 boilers a temporal boiler and the removal of a Flue Gas Boiler was required to provide continuous service. Additionally, the make-up water meter was replaced to maintain accurate system monitoring, which is essential for operational reliability and efficiency.

Safety and Monitoring Enhancements

- Carbon Monoxide (CO) Detector – $3,684
- Outdoor Air Temperature (OAT) Sensor – $4,317
- Firewall Device (Check Point) – $1,182

This group of renewal and replacement focused on enhancing the safety and intelligence of the energy system. The installation of a CO detector was a critical safety measure, as carbon monoxide is undetectable by human senses and poses a significant health risk. The detector ensures early warning and protection for building occupants. The OAT sensor was installed to enable dynamic control of boiler output based on real-time outdoor weather conditions. This not only improves energy efficiency but also enhances system responsiveness and stability. To protect the integrity of the plant's digital infrastructure, a new firewall device was deployed, securing the remote monitoring system against cyber threats and ensuring uninterrupted data flow and operational oversight.

Facility and Infrastructure Improvements

- CEP Roof Coating – $8,855
- Irrigation System Upgrade – $2,549
- Plant LED Lighting – $18,809

These improvements targeted the physical infrastructure of the facility, extending asset life and improving sustainability. The CEP's metal roofing was treated with a specialized coating to protect against rust, corrosion, and weathering, while also reflecting heat to reduce thermal load. The irrigation system, having reached the end of its service life, was upgraded to ensure efficient water use and support sustainable landscaping practices. Additionally, outdated lighting fixtures were replaced with high-efficiency LED systems, improving energy consumption, improving reliability, and lowering maintenance costs. Together, these upgrades contribute to the long-term resilience and environmental performance of the facility.

Lay-Down and Commissioning of the Cleaver-Brooks Boiler

These capital expenditures supported the initial lay-down and later the reactivation of the Cleaver-Brooks boiler system. The total amount related to the R&R of the Cleaver-Brooks boiler is $125,537 comprised of:

- De-rating the Cleaver Brooks Boiler – $11,464

De-rating allowed the plant to be reclassified, reducing staffing requirements by TSBC and operational costs in 2020.

- Cleaver Brooks Boiler Recommissioning – $114,073

In 2024 DGE recommissioned the Cleaver Brook boiler to meet increased capacity demands and provide operational redundancy, see further details in Section 4.3 above.

8.2.2.2 ETS and DPS R&R

As part of a broader effort, during 2023 and 2024 Corix upgraded the fiber and control equipment and Programmable Logic Controllers (PLCs), within its DPS and ETS, allocating $375,314 to the DPS and $97,034 to the ETS to ensure the system could be safely operated remotely. The total cost of the project was $472,348.

The Fiber and PLC Upgrade is an infrastructure modernization initiative undertaken by DGE to enhance the communication and control capabilities of the remote monitoring systems. It focuses on upgrading fiber optic cables and PLCs, which are essential for the remote monitoring and automation of the DGE system. As part of this broader effort, the fiber and PLC upgrades are intended to build on this foundation by improving the reliability and efficiency of data transmission across DGE.

During this period DGE replaced a heat exchanger due to end of life in the amount of $18,523. Additionally, in 2019 there were electrical & networking renewals and upgrades on the Distribution Piping System necessary for the correct functioning of the DPS and capitalized engineering related costs for the ETS of the building connected in 2019 in the amount of $5,298 and $16,489 respectively.

8.2.3 Replacement and Renewal Capital Plan (R&R Plan)

At this time the DGE does not have a Replacement and Renewal Capital Plan (R&R Plan) because low-carbon energy sources will be required in the future, which will require a decarbonization project.

As a result, Corix has not developed a long-term R&R plan for the existing system since there is expected to be a significant change to the system in the future. After the in-service date of the low-carbon central energy plant and following some years of operation of the new plant, Corix will have enough understanding and operational experience to be able to prepare a long-term R&R Plan for the new equipment.

The absence of a long-term R&R Plan does not preclude Corix from including near-term forecast R&R capital expenditure for test periods in the next rate application as has been done with this Application. These forecasts would be based on the OEM maintenance and replacement requirements as well as Corix staff's materials assessment through observations in the field.

8.3 Other Capital Expenditures

Other general capital costs include project development costs, capital costs associated with engineering studies to connect the DPS and ETS to the approved buildings of Dockside Green; a vehicle for utility operator transportation between customer buildings and along the DPS loop; and computer software to remotely monitor the CEPs and ETSs that automatically contact Corix operations personnel in the event of any unusual situation or problem with system performance.

8.4 Allowance for Funds Used During Construction (AFUDC)

Capital projects will attract Allowance for Funds Used During Construction (AFUDC) if both of the following criteria are met:

i. Actual costs are greater than $50,000; and
ii. It takes three (3) or more months to construct.

AFUDC is applied at the DGE's weighted average cost of capital (WACC) on a monthly basis.

The test year accounts for capital expenditures that attract AFUDC for new customer connections. The corresponding AFUDC amounts are incorporated into each of the Capital Cost categories. Over the Test Period there is no projected AFUDC added to capital costs as shown in Table 13 that follows.

TABLE 13: ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION (AFUDC)

AFUDC ($)	Actual 2024	Test Period		
		Forecast 2025	Forecast 2026	Forecast 2027
Allowance for Funds Used During Construction	-	-	-	-

8.5 Capitalized Overhead

Capitalization of a portion of corporate and regional overhead is a common practice in the capital-intensive utility industry. It reflects a reasonable approach to capitalize costs associated with capital activities that have not been directly charged to capital projects. This is because the use of a capitalization methodology is more cost efficient than attempting to directly charge every single cost to each individual project. In addition, there are also certain activities that are not directly attributable to a specific project but are also eligible to be capitalized from overhead. These activities include legal, regulatory, finance, human resources, operations management, and procurement. These support activities are an integral part of the construction or acquisition process in any capital program.

The BCUC has approved the capitalization of overhead costs into plant assets for a number of different utilities. These include BMDEU[13], FortisBC Energy Inc.[14], FortisBC Inc.[15], Creative Energy Vancouver Platforms Inc.[16], and Pacific Northern Gas[17]. Additionally, the BCUC Uniform System of Accounts recognizes overheads capitalized in the account "Overhead Charged to Construction".

In Decision and Order G-279-21, the BCUC approved the BMDEU – UniverCity capitalized overhead rates for the 2020 to 2023 test period. In that decision, the BCUC directed Corix to address the continuation of the policy in the next Revenue Requirement application for BMDEU – UniverCity.

BMDEU – UniverCity complied with BCUC directive by providing the information in Section 6.3 of the 2024 to 2025 BMDEU revenue requirement and rates application. In Section 6.3 of that BMDEU application Corix proposed that going forward capitalized overhead can be better attributed to capital projects with a direct causal approach to capitalized overhead that is driven by the amount of capital expenditures incurred. Corix proposed in the BMDEU test years to implement a direct capitalized overhead allocation methodology based on the actual direct hours from Corix's Project Management Office staff. The BCUC Panel through Order G-348-24 on page 14 stated:

> "The Panel is satisfied with the proposed direct causal approach of capitalizing overhead, which allocates overhead based on the actual direct labour hours of the Project Manager's Office. The Panel views that this approach is appropriate,

[13] Corix overheads capitalization approved by BCUC Order G-279-21, p. 31.
[14] FortisBC Energy Inc. overheads capitalization approved by BCUC Order G-138-14.
[15] FortisBC Inc. overheads capitalization approved by BCUC Order G-139-14.
[16] Creative Energy Vancouver Platforms Inc. overheads capitalization approved by BCUC Order G-167-16.
[17] Pacific Northern Gas overheads capitalization by BCUC Order G-92-11.

> particularly in situations where a new building is delayed due to market conditions, or an anticipated renewal project is delayed into the following year."

DGE presently does not have an approved overheads capitalized methodology. In this Application for DGE Corix proposes to adopt the overheads capitalized methodology using the same methodology in the recent BMDEU rate application that was approved in Order G-348-24. The updated approach for BMDEU is also directly applicable for DGE.

Corix has a Project Management Office (PMO) that is responsible for capital projects at Corix. The PMO is responsible for planning and managing the execution of capital projects for the district energy utilities. A project manager is assigned to each project and various individuals from the PMO working on the project would complete timesheets that code their time spent on the project. However, there are additional support personnel outside of the PMO that also provide oversight and support for the project that do not complete timesheets due to the relatively small time spent on these projects. These other personnel reside within the regional area that is known as Regional Services Costs (see Section 6.3). No overhead capitalization is being applied to Corporate Services Costs during this test period.

Corix proposes to implement a direct capitalized overhead allocation methodology based on the actual direct hours from PMO staff. This method aligns the capitalized overhead to the projects that are incurred. If a new building is delayed due to market conditions or an anticipated renewal project is delayed into the following year, the proposed methodology will also delay the capitalized overhead providing a better matching of capitalized overhead to actual project expenditures.

In this Application Corix proposes the following formula to capitalize overhead for DGE.

Capitalized Overhead ($) = (Direct labour hours charged from PMO personnel x Overhead Support Loading Hours Percentage) x Average Hourly Fully Loaded Cost of Overhead Support

Capitalized Overhead ($) = (Direct PMO hours x Overhead Hours %) x Fully Loaded Cost per hour

Corix proposes to use an Overhead Support Loading Hours Percentage equal to 10%, which would be combined with Corix's Average Hourly Fully Loaded Cost of Overhead Support, which is $66.91 per hour for 2025 and escalates using the labour escalator.

Hypothetical Example

A hypothetical example for Project "A" described below demonstrates the capitalized overhead methodology.

- Direct labour hours charged from PMO personnel: 300 hours
- Overhead Support Loading Hours Percentage: 10%
- Average Hourly Fully Loaded Cost of Overhead Support: $66.91 per hour

Therefore, the Capitalized Overhead attributable to Project "A" is calculated as:

= (300 hours x 10%) x $66.91 per hour

= 30 hours x $66.91 per hour

= $2,007.30

In the above hypothetical example for Project "A" it would take 300 hours of project management time to complete the project. Given the 300 hours of direct time, an additional 30 hours (300 x 10%) is included in the project for capitalized overhead support from the regional services based on a 10% loading. The 30 hours is equal to $2,007.30 (30 x $66.91) of support costs. Therefore, Project "A" would be charged $2,007.30 of capitalized overhead.

This direct causation methodology better aligns capitalized overhead to projects at DGE. When projects are small and involve little PMO labour time the corresponding capitalized overhead support costs would be small for the project. If a large project is complex and requires substantially more PMO labour time, then in turn the project would be obtaining more overhead support.

Corix submits the proposed methodology would be appropriate in years where there are a limited number of small projects and also appropriate to other years where there are significant and large projects that spans many months and involve increased complexity and support time to complete. While Corix does not expect to capitalize overhead during the test period, this methodology would align with the treatment of capitalized overhead for all other Corix regulated utilizes, Corix expects to capitalize overhead until 2030 when new building connections are forecast to be added to the system.

Table 14 below summarizes the calculation of the forecast overhead capitalization using this new approach.

TABLE 14: CAPITALIZED OVERHEAD

Overhead Capitalized	Test Period			
	Forecast 2025	Forecast 2026	Forecast 2027	Forecast 2028
Direct PMO Hours	0	0	0	0
Overhead Hours %	10%	10%	10%	10%
Overhead Hours	**0**	**0**	**0**	**0**
Fully Loaded Cost per hour ($)	67	69	71	73
Total Overhead Capitalized ($)	**-**	**-**	**-**	**-**

8.6 Contributions in Aid of Construction (CIAC)

Contributions in Aid of Construction provide financial benefits for district energy utilities by reducing upfront capital requirements for utilities and smoothing the effect of return of capital on infrastructure investments. These contributions, typically made by developers or customers, help utilities offset the costs of construction, enabling them to provide service at a lower cost and reduce the impact of accumulating financing costs. Developer contributions may be received in advance of the commencement of the provision of service for the respective customer.

The Developer is expected to install and pay for the Energy Transfer Stations for the remaining buildings of DGE, the first of which is expected to connect in 2030. Once the ETS is commissioned and completed, the asset is then transferred to Corix and booked as new capital addition with an equal offsetting CIAC, which will have a net $0 effect to rate base.

Although no grants or developer contributions or other CIAC have been included in the test period for this Application, Corix intends to seek all grant and other capital contribution opportunities in order to provide the greatest possible benefit to the DGE customers.

8.7 Total Capital Costs

The total capital costs for the DGE from 2024 through to the end of 2028 is presented in Table 15 below. Schedule 5 in Appendix A provides detailed information on DGE capital costs from 2021 to 2028.

TABLE 15: TOTAL CAPITAL COSTS

Capital Costs ($)	Actual 2024	Test Period			
		Forecast 2025	Forecast 2026	Forecast 2027	Forecast 2028
Central Energy Plant (CEP)	155,733	21,000	23,541	87,736	12,252
Distribution Piping System (DPS)	22,630	-	-	-	-
Energy Transfer Stations (ETS)	35,124	-	32,957	-	-
Project Start-up & Development	-	-	-	-	-
Capitalized Overhead	-	-	-	-	-
Vehicle	-	-	-	-	-
Studies & Reports	-	5,000	5,118	5,222	5,327
Computer Software	-	-	-	-	-
Computer Hardware	-	-	-	-	-
Total Capital Costs (a)	**213,487**	**26,000**	**61,615**	**92,958**	**17,579**
CIAC (c)	**-**	**-**	**-**	**-**	**-**
Total Capital Costs (a + b)	**213,487**	**26,000**	**61,615**	**92,958**	**17,579**

9. Revenue Requirements

9.1 Implications of a Half Test Year

Corix is proposing a rate increase effective July 1, 2025. As a result, the 2025 test year is effectively 6 months, covering only the period from July 1, 2025 to December 31, 2025. This half test year implementation affects some components of the revenue requirement and rate base for 2025.

The rate base in this application includes plant-in-service, working capital, and the Revenue Deficiency Deferral Account (RDDA), starting July 1, 2025. Corix is proposing to transfer the RDDA from a non-rate base account into the rate base. This change does not affect the total financing cost since the carrying cost of the RDDA remains the same under both treatments. Under the rate base method, the carrying cost is included in the revenue requirement alongside other components of the DGE rate base.

Another key implication of the half test year is how revenue shortfalls are tracked in the 2025 RDDA balance. The RDDA captures the difference between the revenue requirement and the revenue collected under existing rates from January to June 2025 which is presented on Schedule 9 of Appendix A; and the revenue shortfall that occurs from July 1, 2025 until RDDA recovery at the proposed and indicative rates as presented in Schedule 8 of Appendix A.

Additionally, certain cost elements, such as O&M and Property & Other Fees are split between the two halves of the year. A clear example is property tax, property tax is forecast at $17,230 for the first half of 2025, based on previously approved test year amounts, and increases to $128,152 in the second half to reflect the full property tax forecast in the amount of $145,383 for 2025.

Finally, Corix is updating the deemed interest rate effective July 1, 2025, in accordance with the methodology approved by BCUC Order G-321-24. This results in a blended interest rate for 2025 of 5.68% as shown in Schedule 10 of Appendix A. This is the result of the blend of the previously approved rate of 4.91% from Order G-248-18 with the new proposed deemed interest rate of 6.28%. this is further discussed in Section 9.2.3.3.

9.2 General Financing Assumptions

9.2.1 2023 Generic Cost of Capital Stage 1 Decision

On September 5, 2023, the BCUC issued Decision and Order G-236-23 for its 2023 Generic Cost of Capital Proceeding (Stage 1). In Stage 1 the BCUC approved for FortisBC Energy Inc. (FEI) a deemed capital structure of 45.0% equity and 55.0% debt. For FortisBC Inc. (FBC) the BCUC approved a deemed capital structure of 41.0% equity and 49.0% debt. Both FEI and FBC were approved a ROE of 9.65%. The BCUC approved an effective date of January 1, 2023 for FEI and FBC.

The 2023 GCOC Stage 1 Decision on page 138 stated:

> "FEI is the current benchmark (Benchmark Utility) for other utilities in BC that use a Benchmark Utility to set rates. In the April 2022 procedural conference, PNG, Corix, and RDE submitted that the choice of a Benchmark Utility is better addressed in Stage 2, after the BCUC determines FEI and FBC's cost of capital in Stage 1."

> "As previously determined, in Stage 2, the Panel will consider, amongst other matters, whether FEI remains the appropriate default Benchmark Utility for some or all other utilities in BC, whether FBC is a more appropriate benchmark, or whether each utility's allowed ROE and deemed capital structure should be individually determined."

Directive No. 4 of Order G-236-23 stated:

> "Interim rates are established, effective January 1, 2024, on a refundable or recoverable basis, for all other utilities, except FBC, that currently use the Benchmark Utility to set their capital structure and equity return pending the BCUC's final decision on Stage 2 of the GCOC proceeding."

2023 GCOC Stage 1 Decision set interim rates effective January 1, 2024 for DGE.

The 2023 GCOC Stage 1 Decision set the new cost of capital for FEI effective January 1, 2023. Order G-236-23 Directive No. 4 set interim rates effective January 1, 2024 for all other utilities, including DGE, who use the Benchmark Utility to set their capital structure.

9.2.2 2024 Generic Cost of Capital Stage 2 Decision

Section 2.7 in this Application explains the decisions of the 2023 GCOC Stage 1 Decision and Order G-236-23 dated September 5, 2023 and the 2024 GCOC Stage 2 Decision and Order G-321-24 dated November 29, 2024.

The key determinations from Order G-236-23 (setting the cost of equity for FEI) and Order G-6-24 (setting the Benchmark Utility as FEI) relevant for this Application are as follows:

- Benchmark Utility: FortisBC Energy Inc.
- Benchmark Utility Equity Component: 45.0%
- Benchmark Utility ROE: 9.65%

The key determinations from Order G-321-24 relevant for this Application are as follows:

- Deemed Equity Component: 49.0% *(4.0% equity premium over the Benchmark Utility)*
- Deemed Debt Component: 51.0%
- DGE ROE: 10.40% *(75 bps ROE premium over the Benchmark Utility)*
- Deemed Interest Rate Methodology is based on the sum of:
    1. Government of Canada 10-year bond yields based on the average of the last trailing 12 months;
    2. The corporate credit spreads on the Government of Canada 10-year bonds for BBB and BBB(low) rated utilities based on the average of the last trailing 12 months;
    3. Non-investment grade lending premium of 92 basis points; and
    4. A deemed issuance fee of 50 basis points."

2. The deemed interest rate would be reviewed regularly as part of the revenue requirements application.

9.2.3 Capital Structure, Interest on Debt, and Return on Equity

The last DGE Revenue Requirement and Rates Application for years 2019 to 2023 was approved by Order G-248-19 dated October 16, 2019. Directive No. 1 to Order G-248-19 approved the following

- a deemed capital structure of 57.5% debt and 42.5% equity;
- debt financing costs at 4.91%; and
- a return on equity (ROE) of 9.75% which was based on the current low risk benchmark ROE of 8.75% plus 100 basis points.

The GCOC Stage 2 Decision and Order G-321-24 cost of capital determinations are effective January 1, 2024 and impact the DGE revenue requirements within this Application.

The financing assumptions for DGE cost of capital as presented in the table below were used to prepare the revenue requirement in the test years for DGE. Corix in this Application has applied for the forecast test period with a deemed capital structure and deemed interest rate calculated as approved in accordance with BCUC Decision and Order G-321-24. Corix's financing assumptions are presented in Table 16 below.

TABLE 16: FINANCING ASSUMPTIONS FOR THE DGE FOR THE TEST PERIOD

Categories	Financing Assumptions	Rates and Ratios
Capital Structure	Debt/Capital	51.00%
	Equity/Capital	49.00%
Return on Equity	Return on Equity (ROE)	10.40%
Cost of Debt	Deemed Interest Rate	6.28%

Sections 9.2.3.1 through to 9.2.3.3 describe the implications of the recent GCOC Stage 1 and Stage 2 proceeding with regards to this current rate Application for DGE.

9.2.3.1 Capital Structure

In this Application for DGE the capital structure is updated with 49% equity and 51% debt, which is aligned with the Corix approved capital structure by BCUC Order and Decision G-321-24. The previous capital structure approved for DGE in Order G-84-15 was 42.5% for equity and 57.5% for debt.

9.2.3.2 Return on equity

Rates effective January 1, 2025 were accepted for filing on March 27, 2025 which accounted for changes to the cost of capital pursuant to Decision and Order G-321-24, issued on November 29, 2024 which included a ROE of 10.40%. The 10.40% is calculated as the sum of the Benchmark Utility ROE (9.65%) plus the approved equity risk premium of 75 basis points which is a decrease relative to the prior equity risk premium of 100 bps previously approved on the 2014 GCOC proceeding due to the additional risk inherent to the slower buildout of DGE. However, the risk of slower development than expected is persistent.

9.2.3.3 Implementation of the Approved Deemed Interest Rate Methodology for DGE

The BCUC in Decision and Order G-75-13 for the 2013 Generic Cost of Capital Stage 1 proceeding originally decided on a deemed interest rate methodology using BBB to BBB(low) rated utilities.[18] Subsequently in the Decision and Order G-47-2014 GCOC Stage 2 proceeding the BCUC in reference to the Stage 1 decision affirmed that the default debt component of the capital structure was to be set to track a benchmark credit spread that reflects BBB or BBB(low) rate debt relative to the 10 year Government of Canada bond yield.[19]

In accordance with the BCUC's determination regarding the Dockside Green Energy utility in the Generic Cost of Capital Stage 2 proceeding "Minimum Default Capital Structure and Equity Risk Premium".[20] The interest rate on debt financing was determined using the credit spread between BBB and BBB (low) rated debt and the 10 year Government of Canada bond yield, consistent with approach outlined for calculating a "default debt" rate for TES utilities from the Commission's GCOC Decision (Stage 1) and confirmed in the Commission's Stage 2 Decision. In the 2019 rate application Corix included a deemed interest rate of 4.91.%.[21] The financial model reflected the 4.91% interest rate as shown in capital structure for debt and equity from 2019 to 2023.[22]

Corix includes for DGE in this Application a deemed interest rate of 6.28% for the applied for test years that is based on the 2024 GCOC Stage 2 Decision and Order G-321-24 approved deemed interest rate methodology. The BCUC GCOC Stage 2 decision determined the deemed interest rate methodology should be based on the sum of:

1. GoC 10-year bond yields based on the average of the last trailing 12 months;
2. The corporate credit spreads on the GoC 10-year bonds for BBB and BBB(low) rated utilities based on the average of the last trailing 12 months;
3. Non-investment grade lending premium of 92 bps; and
4. A deemed issuance fee of 50 bps.

Based on the approved updated deemed interest rate methodology from the 2024 GCOC Stage 2 Decision and Order G-321-24, Corix has included an updated deemed interest rate for DGE in this revenue requirements application with an updated deemed interest rate that meets the Fair Return Standard. Table 17 shows the deemed interest rate using the recently approved BCUC deemed interest rate methodology commencing on July 1, 2025 which is the start of the Application's test year and based on information available in May 2025.

TABLE 17: PROPOSED DEEMED INTEREST RATE FOR DGE

Components	Interest Rate
Government of Canada (GOC) 10-Year Bond Yield (April 2025 trailing twelve-month average)	3.22%
BBB and BBB(low) credit spread on GOC 10-Year (April 2025 trailing twelve-month average)	1.65%
Non-investment grade lending premium	0.92%
Issuance Fee	0.50%
Deemed Interest Rate	**6.28%**

[18] 2013 GCOC Stage 1 proceeding, pp. 108-110.
[19] 2014 GCOC Stage 2 proceeding, p. 123.
[20] BCUC Generic Cost of Capital Proceeding Stage 2, Order G-47-14, p. 3.
[21] 2019 Rate Application, Exhibit B-1, Section 5.3.5 debt and Equity Financing p. 31.

The above approved interest rate methodology includes the approved non-investment lending premium component plus an update to the existing issuance fee parameter from 25 bp to 50 bps which more closely resembles actual issuance costs for utilities.

In accordance with the 2024 GCOC Stage 2 Decision and Order G-321-24 and DGE Compliance Filing dated on January 31, 2025 the proposed deemed interest rate of 6.28% in this Application would commence on July 1, 2025 and remain effective until the next rate application sets a new deemed interest rate for calculating revenue requirements.

9.2.4 Income Tax

The combined federal and provincial corporate tax rate on general income in British Columbia is forecast to be held at 27% for 2025 to 2028. If the income tax rate changes during the test period, Corix will reflect the revised tax rate in the actuals for the test years.

As indicated in Schedule 13 in Appendix A, there are no income tax payments anticipated during the test period.

9.2.5 Depreciation and Amortization

9.2.5.1 Depreciation

The asset categories and their associated depreciation rates are presented in Schedule 6 in Appendix A. Below Corix provides a description of the mapping of the capital costs to the asset categories since multiple capital cost categories can be mapped to one asset category.

1. Building – Capital costs assigned to the Building asset category are: (i) Civil Works Items; and (ii) Buildings and Foundations. These include, but are not limited to, the building site preparation and architectural enhancements.

2. CEP – Capital costs assigned to the Central Energy Plant, general structure, boiler breeching and gas trains. Additional subcategories are added for natural gas components with 5, 10, 15, and 25 years of service life.

3. DPS – Capital costs assigned to the DPS asset category are distribution piping costs.

4. ETS – Capital costs assigned to the ETS asset category are ETS costs. Additional subcategories are added for ETS components with 5 years of useful life.

5. Vehicle – Capital costs assigned to vehicles that support district energy utility operation. In 2024 Corix acquired one vehicle for the DGE operations.

6. Computer Software – Capital costs assigned to software that is place into service to support DGE operation. The capitalized cost includes license fees, testing fees, setup fees, delivery fees and any other cost required to place into service the purchased software. Computer software assets must have an estimated useful life of one year or more.

7. Computer Hardware – Capital costs assigned to computers and peripherals.

8. Other minor categories - Capital costs assigned to office furniture and equipment, communication equipment, miscellaneous equipment, and tools, shop, and garage equipment.

For this application, Corix has revised the useful life of the DPS from 50 to 66.67 years and for ETS from 25 to 33.33 years, hence changing the depreciation rates after 2027 for DPS and ETS to 1.5% and 3% respectively.

The extended useful life of the DPS and ETS reflects a reassessment of the assets' durability, performance, and maintenance strategies. Based on the assets' operational and maintenance history, the current preventative maintenance and condition monitoring programs have played a key role in supporting the justification for a longer operational lifespan.

Corix has reviewed the expected service life of ETS and DPS assets in DGE by comparing them with similar assets in its other utilities, BMDEU and UBC NDES. The analysis found no evidence suggesting that DGE assets have a shorter expected lifespan. As a result, Corix's updated depreciation rates align the expected life of ETS and DPS assets in DGE with its standard asset life assumptions.

9.2.5.2 Amortization

Studies and Reports – Corix capitalizes costs associated with engineering studies to connect the DPS and ETS to each of the approved buildings. These costs are amortized over a 25-year period from the date the costs are incurred.

Project Development – Corix capitalized $114.6 thousand in project development costs for recovery from ratepayers. These includes feasibility studies and due diligence ($79,183), regulatory cost associated to BCUC applications ($21,953), and the Asset Purchase Agreement (APA) costs ($13,554). These capitalized costs will be amortized over a 25-year period, ensuring gradual recovery of these costs.

Capitalized Overhead – Corix in this Application is proposing a direct capitalized overhead allocation methodology based on actual PMO staff hours, the proposed approach is discussed in Section 8.5 above.

CIAC – Although no CIACs have been assumed in the test period, Corix includes an annual rate of 3.0% to amortize CIACs.

Additional details regarding amortization rates are outlined in Schedule 6, Appendix A of this Application.

9.3 Plant in Service

DGE plant-in-service is presented in detail in Schedule 4 and Schedule 5 of Appendix A. The capital costs driving changes in the plant-in-service are summarized in Section 8.7. During the test period, capital costs are primarily focused on Renewal and Replacement costs.

9.4 Rate Base

Table 18 shows the mid-year rate base calculation for DGE, along with the associated debt and equity financing. Additional details for this calculation can be found in Schedule 3 in Appendix A

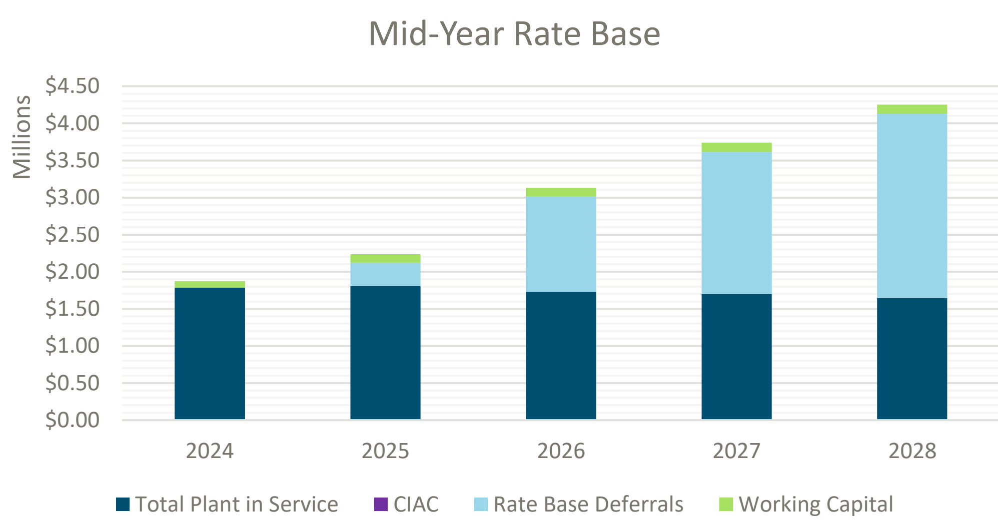
DGE rate base is calculated as the total sum of utility plant-in-service and the associated accumulated depreciation; CIACs and the associated accumulated amortization; rate base deferrals; and working capital. Rate base deferrals are presented in Schedule 8, while the calculation of Working Capital is presented in Schedule 7 in Appendix A

Total working capital for DGE is composed of Cash working capital based on the standard 45-day revenue lag experienced by Corix for utilities that do not have a specially negotiated energy service. Corix excludes depreciation, amortization, income tax, interest on debt and return on equity when determining cash working capital.

TABLE 18: DGE MID-YEAR RATE BASE

Mid-Year Rate Base ($)	Actual 2024	Test Period			
		Forecast 2025	Forecast 2026	Forecast 2027	Forecast 2028
Total Plant-in-service	1,786,728	1,803,091	1,730,179	1,695,099	1,644,470
CIAC	-	-	-	-	-
RDDA	-	315,462	1,279,036	1,920,833	2,482,631
Other Deferrals (PTDA, RCVA & ICVA)	-	-	-	-	-
Working Capital Allowance	87,986	115,296	121,160	124,099	126,854
Total Rate Base	**1,874,714**	**2,233,849**	**3,130,376**	**3,740,031**	**4,253,956**
Debt Financing *(see Schedule 10)*	1,077,960	1,139,263	1,596,492	1,907,416	2,169,517
Equity Financing *(see Schedule 10)*	796,753	1,094,586	1,533,884	1,832,615	2,084,438
Total Financing	**1,874,714**	**2,233,849**	**3,130,376**	**3,740,031**	**4,253,956**

CHART 2: MID-YEAR RATE BASE



9.4.1 Rate Base vs Non-Rate Base Accounts.

Corix has identified inconsistencies in the classification and treatment of rate base and non-rate base accounts across its utilities. To promote consistency and regulatory standardization throughout Corix regulated utilities, Corix is proposing the following regulatory approach below for the inclusion of assets and accounts in the rate base. This approach aligns with regulatory principles and ensures that all Corix-owned utilities apply a uniform methodology in their financial reporting and rate-setting processes.

9.4.1.1 **Rate Base Accounts**

Rate base accounts represent the net investment in utility assets upon which a regulated utility is permitted to earn a return, as approved by the BCUC. These accounts form the foundation of a utility's revenue requirement and typically include:

- Utility plant in service (net of accumulated depreciation)
- Construction work in progress (if allowed by BCUC)
- Working capital (if deemed necessary for operations)
- Deferred assets and other regulatory assets (as approved by BCUC)

The inclusion of these accounts in the rate base is grounded in the principle of cost recovery. Utilities are entitled to recover their prudent investments in infrastructure and to earn a fair return on those investments as compensation for the capital employed in providing essential services. This return is based on the utility's approved Weighted Average Cost of Capital (WACC). This is the DGE WACC as determined in the Generic Cost of Capital Proceeding (Decision and Order G-321-24).

Rate base accounts reflect capital that has been invested by the utility's shareholders in assets and regulatory assets that are used in the provision of regulated service. These assets are essential to delivering safe, reliable, and continuous utility service to customers. By including them in the rate base, regulators ensure that utilities are fairly compensated for the use of their capital while also protecting customers from paying returns on assets that do not serve them.

Deferred regulatory assets such as RDDA that attract WACC are meant to be included in the rate base. This is appropriate when the deferral account represents an invested capital outlay cost directly tied to the delivery of regulated service and reflects the utility's cost of capital. Furthermore, the RDDA is a tool to facilitate a levelized rate plan, which is aimed at increasing fairness between customers who join the system early and those who join the system later on. If the RDDA was not used, and the utility charged the full cost of service from the very first year of operations, all invested capital would be included in rate base. However, this approach would place undue burden on customers that connect to the system in the early years. Given that the RDDA is simply a tool to facilitate fairness through levelized rates, Corix does not see any reason why it should be excluded from rate base since the alternative of annual recovery of the full cost of service would see all invested capital placed into rate base. Given the above, regulatory assets or accounts qualify for inclusion in Rate Base. Furthermore, they also attract the utility's approved WACC, which is equal to financing costs for rate base so there is no cost impact.

Including eligible deferral accounts in the rate base avoids the inefficiencies and potential errors associated with maintaining parallel accounting structures (e.g., splitting delivery-related costs between rate base and non-rate base accounts). It ensures that all long-term delivery-related costs are captured in a single, unified structure, improving transparency for regulators and stakeholders and simplifying the rate-setting process.

9.4.1.2 **Non-Rate Base Accounts**

These accounts may earn a different rate of return (e.g., interest-bearing balances or cost-based recovery), but not the utility return. This distinction ensures that customers are not overcharged for assets that do not reflect shareholder investment or are not directly tied to the provision of regulated services. These accounts are excluded from the rate base because they do not represent capital invested by the utility's shareholders or are not used and useful in providing regulated service. Non-rate rate base deferral accounts should only be used for the following purposes.

- Accounts Recovered Through a Dedicated Rate Rider
  An example of this type of account is the The BMDEU–UniverCity GCOC Variance Deferral Account, which is recovered through its own rate rider (UniverCity Rate Rider 1, approved in Order G-73-25). In such cases, the deferral account has its own revenue requirement and recovery mechanism, justifying its exclusion from the delivery rate base.

- Accounts with Non-WACC Carrying Costs
  These accounts may be recovered through either delivery or non-delivery charges but do not attract the utility's WACC.

9.5 Revenue Requirements

Table 19 and Table 22 presents a summary of DGE's Delivery Revenue Requirements and the Energy Supply Revenue Requirements. Table 23 combines the two to present the total combined revenue requirements. Schedule 2 in Appendix A contains the detailed revenue requirements for DGE from 2021 through 2030. The DGE rates proposed in this Application addresses the recovery of the "Total Delivery Revenue Requirement" that excludes energy supply costs. The Total Delivery and Energy Supply Revenue Requirement presented provides contextual information for the full revenue requirement that drive customers' total bills for service.

THE DELIVERY REVENUE REQUIREMENT OUTLINED IN

Table 19 shows an average year-over-year increase of $157,185 from 2025 to 2028. Section 11 provides details surrounding the key underlying drivers behind the increase.

TABLE 19: DGE DELIVERY REVENUE REQUIREMENTS

Delivery Revenue Requirements ($)	Actual 2023	Actual 2024	Test Period			
			Forecast 2025	Forecast 2026	Forecast 2027	Forecast 2028
Operating and Maintenance (O&M) Costs	296,986	394,074	497,916	615,231	623,178	643,432
Lease & Property Tax, Fees and Levies	33,122	33,785	145,383	151,299	157,457	163,865
Others & Adjustments	(23,331)	-	(106,790)	-	-	-
Subtotal O&M and Lease & Property Tax, Fees and Levies	306,777	427,859	536,509	766,530	780,635	807,297
Depreciation	77,923	86,728	111,080	113,183	102,376	100,243
Amortization	5,690	4,365	4,588	12,141	4,588	4,588
Subtotal Depreciation & Amortization	83,613	91,092	115,668	125,324	106,963	104,830
Deemed Interest	38,223	52,928	64,700	100,260	119,786	136,246
Return on Equity	56,101	77,683	113,837	159,524	190,592	216,782
Subtotal Return on Rate Base	94,324	130,611	178,537	259,784	310,378	353,027

Delivery Revenue Requirements ($)	Actual 2023	Actual 2024	Test Period			
			Forecast 2025	Forecast 2026	Forecast 2027	Forecast 2028
Income Tax	-	-	-	-	-	-
Total Delivery Revenue Requirement	**484,715**	**649,562**	**830,714**	**1,151,638**	**1,197,976**	**1,265,155**

TABLE 20: DGE ENERGY SUPPLY REVENUE REQUIREMENTS

Energy Supply Revenue Requirements ($)	Actual 2023	Actual 2024	Test Period			
			Forecast 2025	Forecast 2026	Forecast 2027	Forecast 2028
Heating Energy Supply Costs	213,420	209,556	217,178	219,380	219,041	222,693
Total Energy Supply Revenue Requirement	**213,420**	**209,556**	**217,178**	**219,380**	**219,041**	**222,693**

TABLE 21: DGE TOTAL COST OF SERVICE

Revenue Requirements ($)	Actual 2023	Actual 2024	Test Period			
			Forecast 2025	Forecast 2026	Forecast 2027	Forecast 2028
Total Delivery Revenue Requirement	**484,715**	**649,562**	**830,714**	**1,151,638**	**1,197,976**	**1,265,155**
Total Energy Supply Revenue Requirement	**213,420**	**209,556**	**217,178**	**219,380**	**219,041**	**222,693**
Total Revenue Requirement	**698,135**	**859,118**	**1,047,892**	**1,371,018**	**1,417,017**	**1,487,848**

9.5.1 Adjustments Impacting the Revenue Requirement

Corix conducted a thorough review of the actual RDDA from 2018 to 2024 and identified discrepancies in the revenue deficiency recorded during those years. To address these differences and the associated financing costs resulting from the adjustments, Corix recorded an initial adjustment of ($106,790). This adjustment aligned the 2024 RDDA closing balance of $531,256 with the corrected closing balance of $424,466. These adjustments represent an overall benefit to the customers that effectively reduce the RDDA balance. Table 22 below summarizes the corrections and the recalculated RDDA balance.

TABLE 22: DGE ADJUSTMENTS SUMMERY FROM 2018 TO 2024

	2018	2019	2020	2021	2022	2023	2024	Total
Other revenues not included[1]	-	-	-1,024	-25	-	-1,772	-	-2,821
Energy Cost included[2]	-	14,058	-7,134	19,059	-24,153	-	-	1,830
O&M (accounting errors)[3]	-	-8,066	-819	-6,684	-38,134	3,585	518	-49,600
ROE/Margin not included[4]	9,122	23,041	11,789	-	-	-	-	43,951

Total corrections	**9,122**	**29,032**	**2,812**	**12,350**	**-62,287**	**1,814**	**518**	**-6,639**
Revenue deficiency booked	25,325	224,407	109,536	61,491	672,325	202,873	322,778	1,618,735
Corrections	9,122	29,032	2,812	12,350	-62,287	1,814	518	-6,639
Revenue deficiency corrected	**34,447**	**253,440**	**112,348**	**73,841**	**610,038**	**204,686**	**323,296**	**1,612,096**

RDDA - Recalculation	2018	2019	2020	2021	2022	2023	2024	Total
Opening balance	-1,000,000	-982,670	-788,865	-727,563	-701,835	-119,443	84,052	-1,000,000
Revenue deficiency	34,447	253,440	112,348	73,841	610,038	204,686	323,296	1,612,096
Return/Financing on deferral	-17,118	-59,634	-51,047	-48,112	-27,646	-1,191	17,118	-187,629
Closing balance	**-982,670**	**-788,865**	**-727,563**	**-701,835**	**-119,443**	**84,052**	**424,466**	**424,466**

Notes
1) Other revenues include late payments fees and connection fees.
2) Energy costs included refers to the energy cost difference (variable revenue charge minus energy costs) that was erroneously included in the RDDA calculation from 2019 to 2021.
3) O&M (accounting errors) summarizes accounting errors included in the RDDA.
4) ROE/Margin not included refer to the operations and maintenance (O&M) expense mark-up of 10% approved in BCUC Order G-248-19.

10. Deferral Accounts, Reconciliation Accounts and Rate Riders

This section provides a discussion of the existing and proposed deferral and reconciliation accounts for DGE, as well as the mechanisms that address the recovery/refund of the balances in each of these accounts.

10.1 Energy Cost Reconciliation Account

Order G-248-19 dated October 16, 2019, the BCUC approved, Corix's proposal to establish an Energy Cost Reconciliation Account (ECRA) to record variances between the actual energy costs and the revenue collected through the Variable Energy Charge, with the balance to be amortized over a one-year period.

On April 20, 2020, Corix applied to BCUC pursuant section 61 of the UCA for approval to establish a new Variable Energy Charge rate setting mechanism, to reduce the existing Variable Energy Charge for DGE, and to amend the DGE tariff sheet to reflect the proposed changes. On October 26, 2020, the BCUC issued Order G-269-20 that approved the new Variable Energy Charge rate-setting mechanism for DGE. This was later amended through G-315-23, dated November 16, 2023, which approved the amendment to the Variable Energy Charge rate setting mechanism.

The current approved DGE tariff has a two-part rate structure as follows:

1) Basic Charge Fixed Rate per Building Square Metre, and

2) Variable Energy Charge per kWh.

DGE has two separate rate-making processes: (1) Variable Energy Charge rate-setting process for the recovery of the energy supply costs; and (2) the revenue requirement and rate application process to adjust the Basic Charge associated with recovering the delivery revenue requirement.

10.2 GCOC Variance Deferral Account

As part of the 2023 GCOC Stage 1 Decision, the BCUC established interim rates, effective January 1, 2024, on a refundable or recoverable basis for all other utilities, except FBC, that currently use the Benchmark Utility to set their capital structure and equity return pending the BCUC's final decision on Stage 2 of the GCOC proceeding. The GCOC Stage 2 Proceeding determined the implementation of the new cost of capital parameters and:

1. the manner by which Stage 2 utilities will be eligible to collect the variance between permanent rates and interim rates arising from the Stage 2 decision from January 1, 2024 to the date of implementation of this decision; and
2. the timing of when utilities are able to change their rates to a level that appropriately reflects their allowed return as determined in this decision.

Subsequently, on page 99 of the Decision for G-321-24, the BCUC directed:

> **"For Corix UBC NDES and DGE, the Panel approves the previously established interim 2024 rates as permanent. Corix is directed to establish a new GCOC Variance Deferral Account for each utility, attracting Corix's WACC, to record the variance between the previously established interim 2024 rates and the rates that would reflect the new cost of capital, effective January 1, 2024, under this decision.** For clarity, the GCOC Variance Deferral Accounts are separate from the existing Revenue Deficiency Deferral Accounts for UBC NDES and DGE, as these arrangements will provide flexibility for the utility and collection from ratepayers. The GCOC Variance Deferral Accounts will also capture the difference between any 2025 interim rates before and after incorporation of the new cost of capital under this decision.

The amounts to be added to the GCOC Variance Deferral Accounts and their disposition are to be addressed the earlier of (i) these Corix Utilities' next rates applications or (ii) a compliance filing to be filed with the BCUC by January 31, 2025. This filing should also include revised permanent rates that reflect the new cost of capital under this decision for UBC NDES's and DGE's rates for 2025 and beyond. As applicable, revised tariff pages are to be filed with the BCUC by January 31, 2025." [Footnote 658 not included]

To comply with the BCUC directive, Corix established the GCOC Variance Deferral Account for the DGE, effective January 1, 2024. This account records the difference in costs due to the difference between the previous cost of capital parameters approved for DGE through the 2019 Rate Application and the cost of capital parameters approved for DGE through G-321-24, both of which are shown in Table 23 that follows.

TABLE 23: 2024 COST OF CAPITAL PARAMETER COMPARISON

Categories	Financing Assumptions	2024 Test Year Approved through G-248-19	2024 Test Year Approved through G-321-24
Capital Structure	Debt/Capital	57.50%	51.00%
	Equity/Capital	42.50%	49.00%
Return on Equity	Return on Equity	9.75%	10.40%
Cost of Debt	Interest Rate	4.91%	4.91%

As seen in Table 23 above, the 2024 GCOC Stage 2 Decision resulted in an:

- increase to the equity component from 42.5% to 49.0%, with a corresponding decrease in the debt component from 57.5% to 51.0%; and
- increase to the DGE ROE from 9.75% to 10.40%.

For DGE the debt interest rate for 2024 remained unchanged at 4.91%. As per Order G-321-24 the debt interest rate would be updated in the next revenue requirements application, which is this 2025-2028 RRRA. The variance resulting from the 2024 cost of capital differences approved in the GCOC Stage 2 Decision and Order G-321-24 resulted in an ending balance for the GCOC VDA in the amount of $6,994 (including financing costs) for the period from January 1, 2024 to December 31, 2024, as shown in Schedule 9 of Appendix A.

10.2.1 Disposition of GCOC Variance Deferral Account (VDA).

Decision and Order G-321-24 did not determine the disposition of the GCOC Variance Deferral Accounts. However, it acknowledged that the ultimate disposition of these accounts would be best addressed in a future BCUC proceeding reviewing the rates impacted by the deferral accounts. In this Application Corix seeks a determination on the disposition of the DGE GCOC VDA as follows.

- Corix proposes to amortize the balance in the DGE GCOC VDA through the Basic Fixed Charge beginning January 1, 2026, and ending by December 31, 2026 within the delivery revenue requirements.

In Corix's view, the balance of the GCOC VDA is relatively small and can be disposed through the basic charge during 2026 without the need for a Rate Rider. At this time Corix projects the approved GCOC VDA to have an ending balance of $7,553 as of December 31, 2025. The recovery is planned to amortize the balance over a 12-month period through the Basic Charge commencing on January 1, 2026, and conclude on December 31, 2026.

Corix does not expect to have any residual balance in the GCOC VDA. However in the case a residual balance is present by the end of December 31st, 2026, Corix proposes that the residual balance in the GCOC VDA on December 31, 2026 be collected and placed in the DGE's RDDA on January 1, 2027.

10.3 Revenue Deficiency Deferral Account

10.3.1 RDDA Balance Overview

Order G-166-18 approved the sale of the DGELLP utility's assets and transfer of the CPCN to Corix, as well as the establishment of a Revenue Deficiency Deferral Account (RDDA) for Corix DGE. Corix DGE would record the $1 million Contribution Amount (see Section 2.2) in the new RDDA. DGE was directed to accrue interest on the $1 million contribution in the RDDA based on DGE's approved weighted average cost of capital (WACC).

The $1 million was intended to mitigate rate increases in the initial years of operation of the utility by Corix while allowing the utility to recover its cost of service and earn a fair rate of return on the Utility rate base as allowed by the BCUC. The $1,000,000 was initially expected to last until the end of 2025. However, the cost of service was higher than expected and revenue was slightly lower than expected, leading to higher shortfalls that depleted the $1million contribution by the end of 2022 as shown in Chart 3.

Several aspects contributed to the increase in the RDDA. Section 11, discusses the reasons for the increase in the current revenue requirement and rate application that are intertwined with the increase in the RDDA balance.

CHART 3: RDDA YEAR-END BALANCE

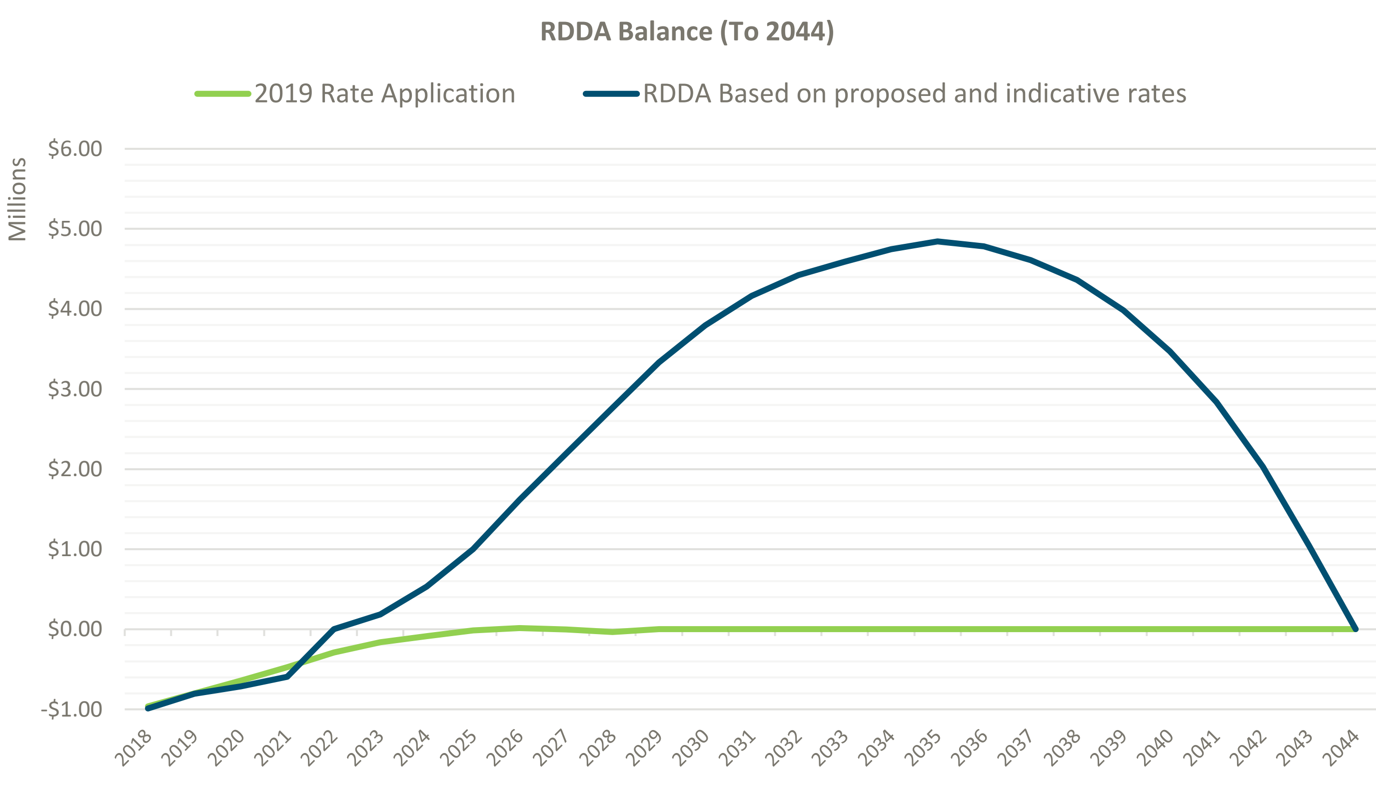
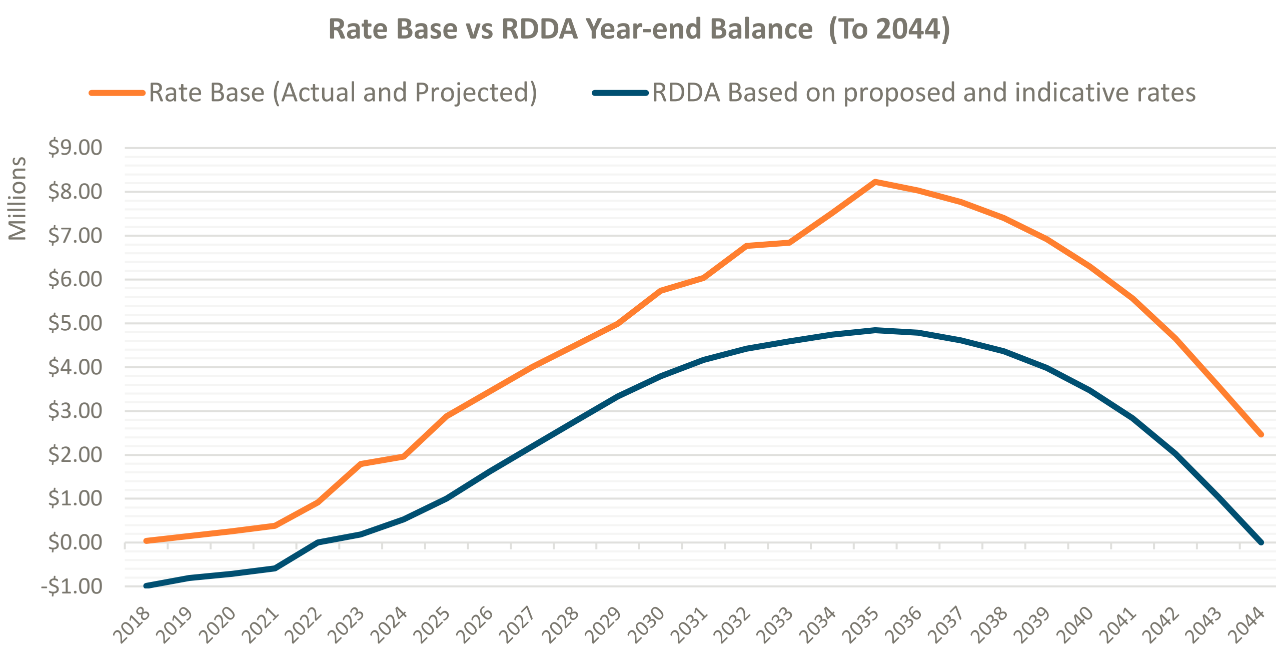


CHART 4: RDDA CLOSING BALANCE VERSUS RATE BASE



10.3.1.1 RDDA Breakdown

The $1 million Contribution Amount placed in the RDDA by the seller of Dockside Agreed to upon the sale and transfer of assets of DGE was initially forecast to last until the end of 2025. However various factors have resulted in an updated 2024 year-end projection of $531,256 which compared to the RDDA by the end of 2024 had a projected balance of ($87,644). This reflects an increase in the accumulated revenue deficiency of $618,900 over the period 2018 to 2024 as shown in Chart 5 below.

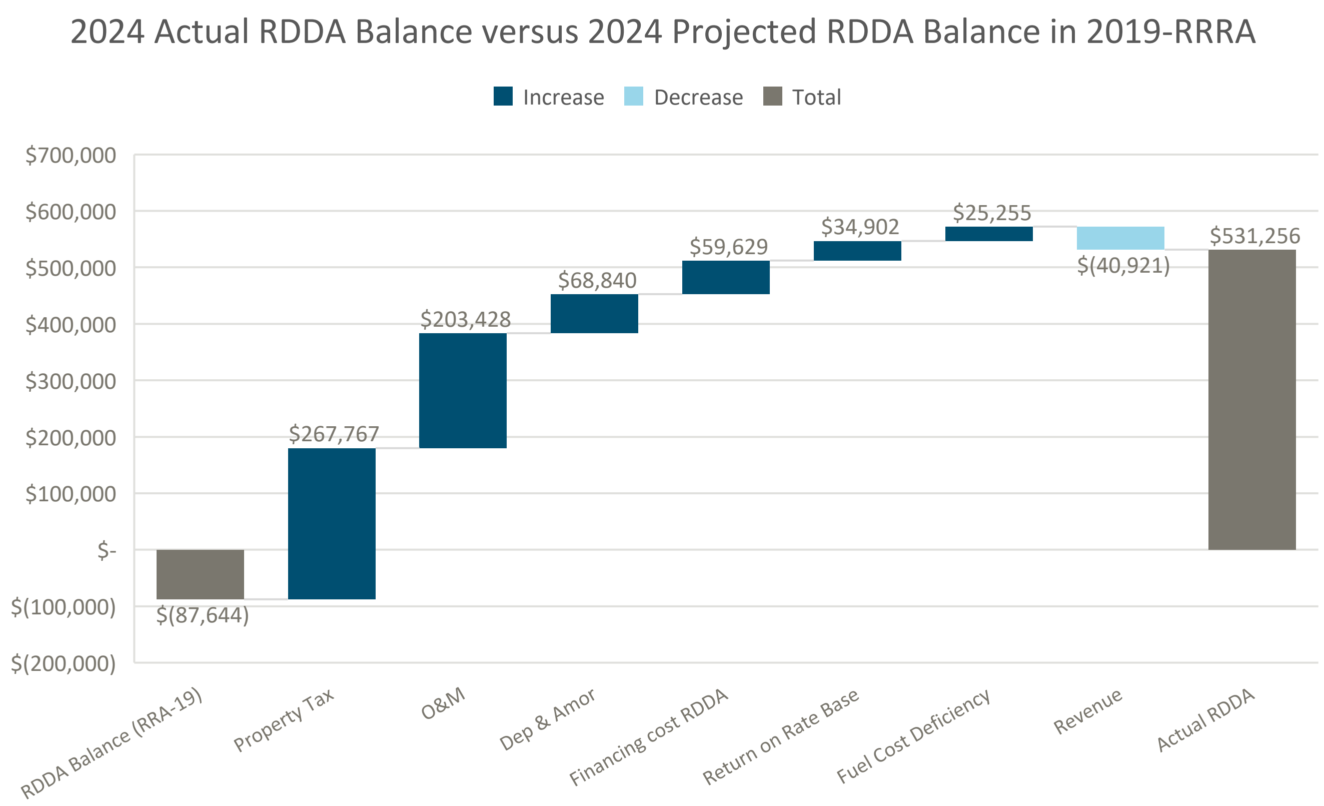
There are two (2) key factors that explain the 75% of the increase in the 2024 year-end RDDA balance compared to the 2024 year-end balance forecast in the 2015 Rate Application are discussed below.

i. Property Tax: Corix's 2019 RRRA forecasted these taxes based on historical amounts from 2016 to 2018. However, in 2020, Corix received a significantly higher property tax invoice. Upon investigation, it was discovered that the previous landowner, DGELLP, had benefited from a Revitalization Tax Exemption under a City of Victoria bylaw promoting sustainable energy developments. This exemption, which lasted up to 10 years, had kept property taxes artificially low and expired on December 31, 2019. With the exemption no longer in effect and no option for renewal, the full property tax liability was reinstated, resulting in the unexpected increase. The actual property tax has resulted in a variance of $267,767 which explains 43% of the increase in the accumulated revenue deficiency over the period 2018 to 2024. This amount does not consider the amounts that were added into the Property Tax Deferral Account. For reference, if the variances from 2023 and 2024 had been included into the RDDA, the total variance would be in the amount of $401,855.

ii. Operation and Maintenance the main component in the O&M that increase relatively to the 2019 RRRA was the operating labour. When Corix submitted its 2019 RRRA, it reasonably projected that only 0.50 FTE would be needed to operate the Dockside Green Energy (DGE) plant, assuming the Cleaver-Brooks boiler would remain offline during the test period. However, operational realities required maintaining a full-time (1.0 FTE) operator due to several constraints. The specialized qualifications needed for the role, combined with a limited labour pool on Vancouver Island, made it impractical to recruit a part-time operator. Additionally, following the carveout of Corix's water utilities from CMUS, the DGE operator could no longer be shared across utility functions, necessitating a dedicated full-time position. This need was further reinforced in 2024 when the Cleaver-Brooks boiler was reactivated, triggering requirements for General Supervision under provincial safety regulations. These combined factors have led to higher than forecast labour costs, in addition to small variances from other items the O&M contributed to $203,428 increase to the RDDA which explains 32% of the increase in the accumulated revenue deficiency over the period 2018 to 2024.

Additional variances, including the higher return on assets driven by increased capital, elevated financing costs due to a larger rate base, and financing costs due a growing RDDA, are further discussed in Section 11.

CHART 5: RDDA BALANCE INCREASE BREAKDOWN



10.3.2 RDDA Allowable Costs

On June 4, 2018 Corix filed its application for approval to acquire Dockside Green Energy. Through Order G-166-18 the BCUC approved the establishment of the Revenue Deficiency Deferral Account as set out in the Application is approved and interest is to be applied to the balance in the regulatory account based on DGE's approved weighted cost of capital-based return, until such time a revenue requirements application is filed by Corix.

As part of Information Request No. 1, Corix explained that the the $1 million contribution is intended to be used to offset any shortfall in the utility's cost of service. This would include operating costs as well as depreciation, interest, return on equity and income taxes related to future capital to mitigate rate increases until such time as future customer attachments provide additional revenues. [23]

In addition, Corix confirmed in the 2019 Revenue Requirements and Rates Application for DGE that under the proposed rate design, all variances between forecast and actual revenue requirements (i.e. load and costs) will be trued up to actual amounts in the RDDA.[24]

In other words, DGE RDDA allowable costs (costs trued up to actual amounts in the RDDA) includes operating costs, depreciation, interest, return on equity and income taxes. However, for the period 2019 to 2024 Corix did not true-up the Corporate and Regional Services costs to actual amounts. These cost variances have been borne by Corix shareholder to the benefit of customers. For the Test Period Corix has revised its delivery revenue requirement forecast with updated Corporate and Regional cost allocation forecasts based on the the approved Corporate and Regional Cost Allocation Methodology previously approved by the BCUC through Order G-349-20.

For clarity, Corix is not requesting any change in the treatment of the RDDA allowable costs.

However, in this Application Corix is requesting a carve-out of two (2) allowable cost categories from the RDDA due to the creation of new variance accounts. These are Insurance and External Regulatory costs. These two new proposed deferral accounts carved out from the RDDA would capture variances from test year approved amounts instead of recording the variances in the RDDA.

- For the External Regulatory Costs cost category, any variance from approved test years would be captured in the proposed Regulatory Costs Variance Account (RCVA) as described in Section 10.5.
- For the Insurance cost category, any variance from approved test years would be captured in the proposed Insurance Cost Variance Account (ICVA) as described in Section 10.6.

With the proposal, the RDDA in the test years would have the insurance costs and the regulatory cost held at test year forecast values and the proposed two variance accounts would capture the cost differences from test year to actual.

10.3.3 Recovery Period and Levelized Rates

At the current approved rates, the RDDA is projected to increase significantly with no foreseeable recovery, as illustrated in Chart 6 below. This trend indicates that existing rates are substantially insufficient to recover the cost of service, and that the current rate increases are inadequate to offset the growth of the RDDA, which has escalated for the reasons outlined in Section 10.3.1.1 and Section 11.

To address this issue, Corix has proposed the Basic Charges for the test period and with proposed recovery RDDA periods. In preparing this Revenue Requirement and Rates Application, Corix analyzed various recovery scenarios, beginning with a recovery horizon to 2039, as detailed in Section 12.3. The analysis considered ten key elements (also discussed in Section 12.2.1) to evaluate the trade-offs between RDDA peak balance, rate increases during the test years, uniform rate increases post-test years, and the financing costs associated with the RDDA recovery.

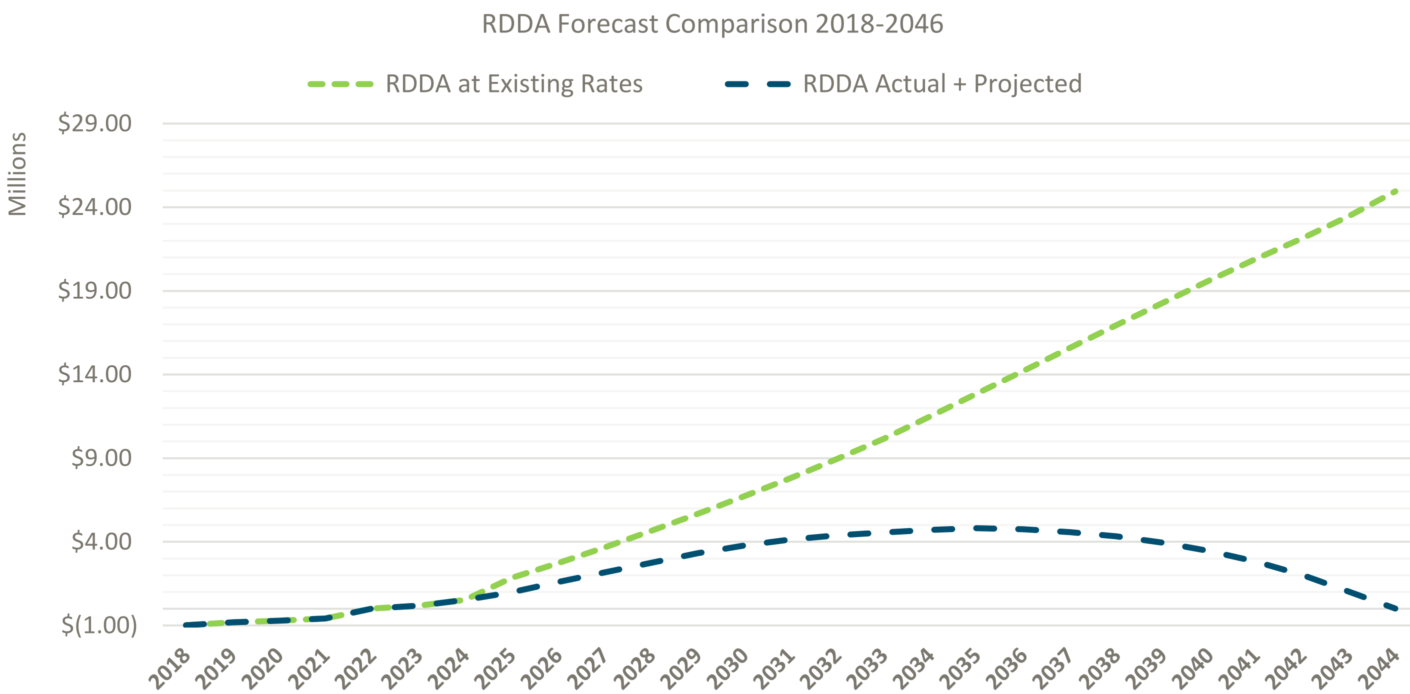
Following this comprehensive evaluation, Corix concluded that the proposed rates, coupled with a target recovery period on 2044 represents the most balanced and appropriate approach, as further explained in Section 12.3.1.

[23] Application for approval to acquire Dockside Green Energy, Corix response to BCUC IR No.1 1, IR 7.2.1 Exhibit B-2 August 10, 2018
[24] Corix 2019 Revenue Requirements and Rates for Dockside Green, Corix Responses to BCUC IR Request No. 1, Exhibit B-4

This conclusion is supported by several key considerations. The 2024 recovery period allows for more gradual rate increases, helping to minimize the steep rate increases that otherwise shorter recovery periods impose. The RDDA also considers the revenue shortfalls arising from the delays of the buildings delayed in the updated build-out schedule, ensuring that all customers contribute fairly to the RDDA recovery.

This proposed recovery strategy is contingent upon future building connections to the system, based on the latest buildout update from the property developer. The revised forecast now anticipates full buildout by 2035, representing a three-year delay from the original schedule. However, Corix acknowledges that this timeline may be subject to future revisions depending on developer activity and real estate market conditions. As the build-out progresses, Corix may reassess the recovery plan to ensure it continues to support rate levelization and minimizing customer impact.

CHART 6: RDDA BALANCE COMPARISON



In the year following full recovery of the RDDA balance, the rates would be adjusted to recover the full annual cost of service in each year. At this time, the forecasts show that rates would decrease in 2045 following full recovery of the RDDA by 2044. However, this is more than 19 years away and a wide possibility of events could occur before then.

Corix is looking at adding new customers outside of the original Dockside Green development plan. These customers would only be added if they do not result in rate increases to existing DGE customers. Depending on their peak demand requirements, the addition of these customers could lead to increasing economies of scale, resulting in a faster recovery of the RDDA balance. However, these potential customers are not parties to the Infrastructure Agreement with the Dockside Green property developer and so their connection is not guaranteed as they have the option not to connect to the DGE utility.

10.3.4 The RDDA Balance Relative to Rate Base

Chart 7 presents the RDDA balance relative to rate base based on the proposals in this Application and indicative figures from 2029 onwards.

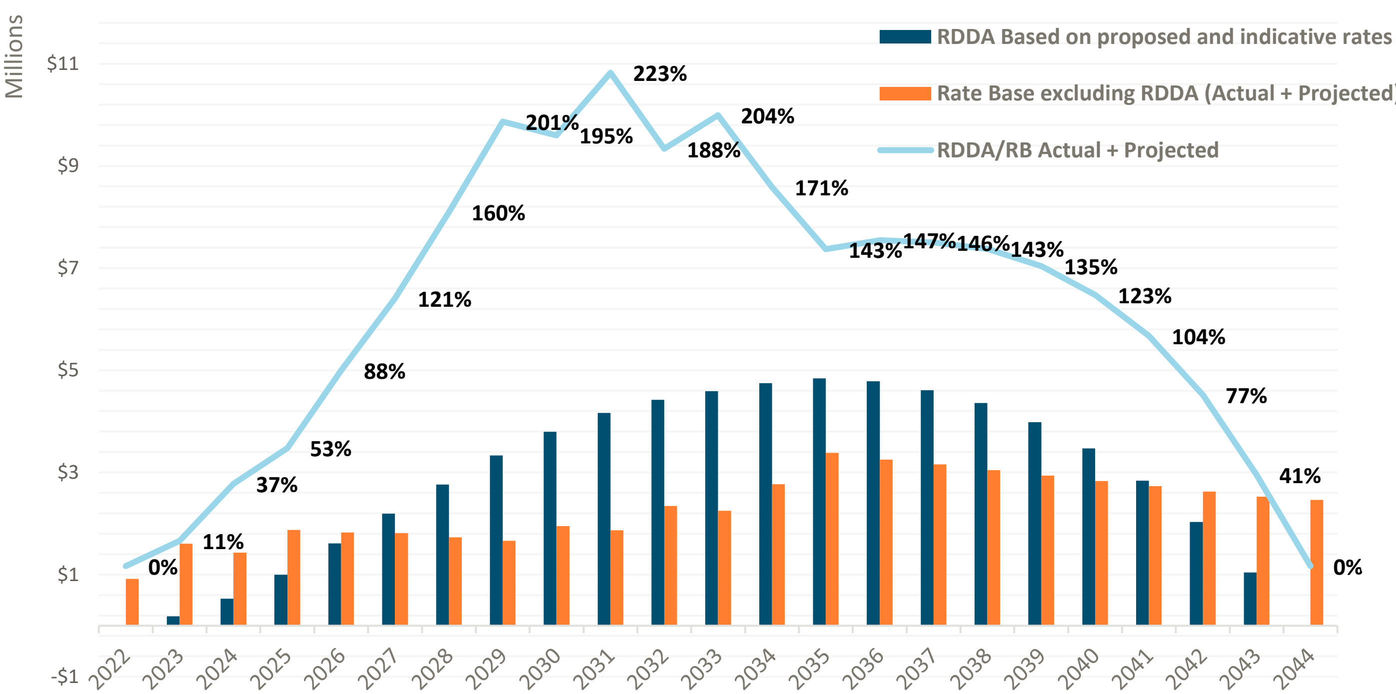
In 2018, the utility's physical assets were transferred to Corix for a nominal value of one dollar ($1), as opposed to net book value. In accounting terms, the net book value reflects the original cost of the assets minus any depreciation. Transferring the assets at such a low value meant that the utility's starting rate base was extremely low, and for this reason Corix was allowed by the BCUC during the early years of operation to earn a mark-up on its O&M costs in lieu of a ROE on rate base.

Since the acquisition, DGE has made capital investments to expand, improve and maintain the system. These include installing new boilers to increase capacity and performing necessary upgrades and repairs in line with manufacturer recommendations. These investments have gradually increased the rate base, but it still remains much lower than it would have been if the original assets had been transferred at their true book value.

As a result of the above, the RDDA, which has growth in recent years, appears very large in proportion to the rate base as shown in Chart 7. This is not because the RDDA itself is unusually high, but because the denominator the rate base is artificially low. This creates a distortion in DGE financial ratios and can make appear DGE financial position seem more strained than it actually is.

However, this imbalance is expected to correct itself over time. As more customers connect to the system and the RDDA is gradually recovered through rates, and as continued capital investments grow the rate base, the ratio of RDDA to rate base will normalize. In other words, the current skew is a temporary effect of the initial acquisition accounting treatment and will diminish as new customers are added to the system.

CHART 7: RDDA BALANCE AS A PERCENTAGE OF RATE BASE EXCLUDING RDDA



10.3.5 Proposal to Transfer the RDDA into Rate Base

On September 4, 2018, the BCUC issued Order G-166-18 approving the sale of the DGELLP utility's assets and transfer of the CPCN to Corix, as well as the establishment of a Revenue Deficiency Deferral Account for Corix DGE. Corix DGE would record the $1 million contribution in the new RDDA and was directed to accrue interest on the $1 million contribution in the RDDA based on DGE's approved weighted average cost of capital (WACC).

While Order G-166-18 through Directive 3 approved DGE's RDDA, the order did not provide specific direction related to the type of account whether the RDDA would be classified as a rate base or non-rate base account. However, Corix booked DGE's RDDA as a non-rate base account to demonstrate the interest costs (at WACC) of the negative RDDA ($1 million Vancity contribution) so it could calculate the approved 10% margin methodology. DGE is a special case because the RDDA started as a negative balance at $1 million and the BCUC in Order G-248-19.

As discussed in Section 9.4.1.2 , the treatment of the RDDA whether included in rate base or non-rate base does no impact have an impact on costs, since the same interest rate (the utility's approved Weighted Average Cost of Capital, or WACC) is applied to calculate financing costs. Given that rate base accounts earn the approved WACC, as is the case for the DGE RDDA, Corix proposes to transfer the positive RDDA to be treated as a rate base item. With the discontinuance of the 10% margin calculation the positive RDDA is now more appropriately placed into rate base to calculate the full revenue requirements of the utility.

Although this proposal does not affect carrying costs, customer rates, nor the variance treatment, it aligns with Corix's ongoing effort to standardize the accounting treatment across all of its regulated utilities. Therefore, Corix request to transfer the RDDA balance from a non-rate base account to a rate base account as shown in Schedule 8 of Appendix A.

For this reason Corix proposes to transfer the balance of the RDDA from non-rate base into a Rate Base account based on the following five (5) considerations:

1. **Consistency Across Utilities and Accounts**
Corix is committed to standardizing the accounting treatment across all of its regulated utilities. Currently, Corix has justified the same treatment for UBC NDES through its ongoing 2025 -2027 Revenue Requirement and Rates Application. Maintaining a non-rate base RDDA would therefore be inconsistent with the rate base treatment for UBC NDES' RDDA.

2. **Rate Base Accounts Earn the Utility's Approved WACC**
Another important consideration is that rate base accounts earn the utility's approved WACC, which reflects the return on capital invested by shareholders in providing regulated service. This is the case for the DGE RDDA, and Corix proposes the same treatment for the RDDA in question.

   In contrast, non-rate base accounts may earn a different rate of return—typically interest-only or cost-based recovery—and are generally reserved for items that do not represent shareholder investment or are not directly tied to the provision of regulated services. These accounts are excluded from the rate base to ensure customers are not overcharged for assets that do not reflect capital investment. Therefore, deferral accounts that are long-term in nature, attract WACC, and are directly related to the delivery revenue requirement such as the RDDA should be included in the rate base.

3. **Alignment with Revenue Requirement Principles**
Utility revenue requirements are often conceptualized as a "pie," where the total size represents the full cost of service, and rate design determines how that pie is divided among customer classes. Splitting the delivery revenue requirement into separate "pies"—one for rate base and another for non-rate base deferrals—only to

recombine them later, is inefficient and counterintuitive. It is akin to baking two pies and then merging them back into one, when a single, unified pie would have sufficed from the outset.

There is only one delivery revenue requirement. All long-term costs associated with delivering service—including those captured in the RDDA—should be transparently and consistently included in the rate base. This approach avoids the artificial parsing of costs and supports a more coherent and efficient rate-making process.

4. Transparency in Cost Recovery
Placing the RDDA outside the rate base obscures the true cost of delivery service. To determine the actual delivery revenue requirement, one must add the base delivery costs and then separately calculate the carrying costs of the RDDA and then add it into the delivery costs to get the total delivery costs. This fragmented approach reduces transparency and makes it more difficult for stakeholders to understand the full cost structure.

In contrast, including the RDDA in the rate base ensures that all delivery-related costs are visible and accounted for in a single, unified framework. This promotes clarity for regulators, customers, and other stakeholders.

5. Regulatory Efficiency and Simplicity
Using non-rate base deferral accounts for items that attract the Weighted Average Cost of Capital (WACC) introduces unnecessary complexity. When deferral accounts such as the RDDA are related to delivery revenue requirements and recovered through the Basic Charge, placing them outside the rate base creates a cumbersome and inefficient accounting structure. It requires additional steps to calculate and reconcile carrying costs, which are often immaterial in difference when comparing WACC to interest-only rates. This added complexity does not yield any material benefit to customers or regulators.

Moreover, as the number of non-rate base delivery deferral accounts increases, the inefficiencies compound. For example, if four of such accounts existed (RDDA, ICVA, RCVA, PTDA), the total delivery revenue requirement would need to be reconstructed by summing the base delivery costs and the carrying costs of each deferral account. This approach is unnecessarily complex and does not align with best practices in utility regulation.

By including the RDDA in the rate base, financial modeling becomes more streamlined. It eliminates the need to separately track and reconcile carrying costs, thereby reducing administrative burden and simplifying the overall rate-setting process, which in turns reduces the potential for errors.

10.3.6 Continued RDDA Variance Treatment

As discussed in previous sections, Corix is not proposing to change the variance treatment of the RDDA as previously approved, in which all variances between forecast and actual delivery revenue requirements except for Corporate and Regional Service costs are trued up to actual amounts in the RDDA. Corix submits that DGE RDDA must continue to capture actual revenues, not forecasts.

The existing and approved RDDA captures the difference between:

1) **Total actual revenues**, which are revenues from the Basic Charge; and
2) **Total allowed costs**, which are the sum of: (i) actual allowed costs; and (ii) forecast allowed costs.

Consistent with the approach used by other Corix utilities, Corporate and Regional Service Costs are not trued up to actuals in the RDDA calculation; instead, these costs remain at forecast amounts. As outlined in Section 6, any variance between actual and forecast costs is adjusted to reflect the amounts approved by the BCUC. These adjustments are detailed in Schedule 11, line 27 of Appendix A, and represent costs that have been absorbed by Corix shareholder.

In this Application, Corix is proposing two carve-outs of costs from RDDA deferral treatment: (1) external regulatory costs; and (2) insurance cost. Corix is proposing a Regulatory Costs Variance Account (RCVA) (see Section 10.5). Corix is also proposing an Insurance Cost Variance Account (ICVA) (see Section 10.6). The RCVA and ICVA will separately capture the variance from forecast to actual amounts for these specific types of costs. Given these two carve-outs from the RDDA, the RDDA will have the external regulatory costs and insurance cost (contained in Schedule 2 in Appendix A within O&M Costs) held at forecast approved amounts. By doing so, the RCVA and ICVA would capture the variances from forecast to actual amounts.

Corix maintains its position in favour of continuing to record actual revenues due to the future uncertainty associated with the timing of the build-out of the development. Based on the circumstances to date, it is clear that there is a potential for the build-out schedule to vary from forecast, thus impacting billed revenue from the Basic Charge (fixed charge based on floor area served). For example, assuming all else remains the same:

- If build-out were to occur slower than currently forecast (future delays), then cumulative billed revenue would be lower than forecast leading to a higher annual shortfall that must be financed by the utility. If the RDDA recorded forecast revenue instead of actual revenue this would artificially reduce the RDDA balance and result in an unfair denial of recovery of the costs incurred by the utility to fund the higher-than-expected annual shortfall over the same period.
- If build-out were to occur faster than currently forecast (earlier connections), then cumulative billed revenue would be higher than forecast leading to a lower annual shortfall. If the RDDA recorded forecast revenue instead of actual revenue this would artificially inflate the RDDA balance and result in an unfair burden to customers. This is because the utility would be approved to recover costs that were not incurred by the utility (based on the higher forecast annual shortfall) as opposed to the lower-than-expected annual shortfalls over the same period.

Given the buildout delays that the community has experienced (buildout completion was initially scheduled to occur in 2014), and that the current build-out is only at 52% of completion, Corix firmly maintains that it is necessary to continue the recording of actual revenue in the RDDA.

10.4 Proposed Changes to the Property Tax Deferral Account

In Order G-225-23, dated August 23, 2023, the BCUC approved Corix's proposal to establish a non-rate base PTDA for DGE to record the annual variance between the BCUC approved forecast and actual property taxes charged to DGE from 2023 onwards, attracting interest at DGE's weighted average cost of capital. Order G-225-23 also approved a rate rider mechanism for the recovery or refund of the year-end balance in the PTDA over a one-year period.

Corix in this application is proposing to:

1. discontinue the Rate Rider 1 effective April 1, 2026, as well as the associated rate rider rate-setting mechanism;
2. move the Property Tax Deferral Account from non-rate base to a rate base account; and
3. recover any test year realized property tax variance in the next DGE Rate Application.

10.4.1 Proposed PTDA and Recovery Processes

Corix proposes discontinuing the existing Rate Rider 1 and the associated rate rider rate-setting mechanism and instead recover the variances of DGE Property Tax Deferral Account (PTDA) through amortization in each subsequent revenue requirements and rate application. Under this revised approach, any variances between forecasted and actual costs would be captured within the DGE PTDA and subsequently amortized in full as part of the next revenue requirement application. This proposal is intended to simplify the regulatory filings for DGE.

In addition, there is an inherent difficulty of forecasting certain cost components of the property taxes. These costs are subject to fluctuations driven by municipal assessment practices, changes in tax rates, and evolving valuation methodologies. As a result, forecasting property tax expenses with precision is challenging and often leads to material variances. By capturing these variances in the DGE PTDA, Corix can ensure that customers are not unfairly burdened by overestimated costs, nor is DGE left under-recovered due to underestimated forecasts.

This proposed treatment is consistent with the approach outlined for other variance accounts, such as the DGE Regulatory Cost Variance Account described in Section 10.5 and the DGE Insurance Cost Variance Account detailed in Section 10.6. Aligning the treatment of these accounts under a unified methodology enhances regulatory coherence and simplifies the review process for both the utility and the BCUC. This proposal also reduces administrative burden by eliminating the need for a separate rate-setting mechanism for a rate rider.

The forecasted property tax costs referenced in this proposal are detailed in Schedule 11 of Appendix A.

10.4.2 Proposed Transfer from Non-Rate Base to a Rate Base Account

Corix proposes to transfer the Property Tax Deferral Account in Rate Base for DGE as presented in Schedule 8 of Appendix A. As discussed in Section 9.4.1 Regulatory Assets are permitted to earn the same rate of return as other assets included in the DGE Rate Base. This return is based on the Weighted Average Cost of Capital (WACC) approved for Corix in the Generic Cost of Capital Proceeding (Decision and Order G-321-24).

The Property Tax Deferral Account is functionally and financially similar to other regulatory assets already included and or proposed to be included rate base such as the Regulatory Cost Variance Account (RCVA) in Section 10.4 and the Insurance Cost Variance Account (IVCA) in Section 10.6. Since it earns the same WACC as other rate base items, including it in the rate base ensures consistent application across all qualifying assets.

Since the Property Tax Deferral Account already earns the approved WACC, its inclusion in the rate base does not affect the overall financing cost or the total revenue requirement. Whether the account is treated inside or outside the rate base, the same return is applied. Therefore, the proposed change is revenue-neutral and does not impact customer rates.

Including the Property Tax Deferral Account in the rate base simplifies financial modeling and regulatory reporting. It eliminates the need to track and reconcile carrying costs separately, which can obscure the true cost of service and complicate rate-setting. A unified treatment of all WACC-earning assets within the rate base promotes transparency and regulatory efficiency.

The rate base is intended to reflect the utility's net investment in assets used to provide regulated service. The Property Tax Deferral Account represents a legitimate cost incurred in the provision of service and is financed by the utility over time. Including it in the rate base aligns with the principle that utilities should be allowed to recover their prudent costs and earn a fair return on capital employed.

This proposal is part of Corix's broader initiative to standardize the classification and treatment of rate base and non-rate base accounts across all its regulated utilities. Establishing a consistent framework ensures fairness, reduces administrative burden, and aligns Corix's practices with those of other utilities regulated by the BCUC.

10.5 Proposal for a Regulatory Costs Variance Account

As with other Corix utilities, Corix proposes to standardize the treatment of External Regulatory Costs since these costs are associated with the regulation of the utility by BCUC. Further details of these costs are provided in item 10 in Section 6.2 and in the section below. Corix submits that these external regulatory costs should continue with deferral treatment but as part of a new Regulatory Cost Variance Account instead of inside the RDDA.

The BCUC has approved regulatory cost deferral accounts for other utilities including the FortisBC companies and Creative Energy. FortisBC Energy Inc. has historically had deferral account treatment for variances in BCUC levies. Recently FortisBC Inc. in its 2020-2024 Multi-year rate plan application applied for a new BCUC Levies Variance Account. Also, both FortisBC companies have established property taxes deferral accounts. The BCUC in Order G-165-20 and G-166-20 approved the BCUC Levies Forecast Variance deferral account. The FortisBC decision didn't directly address the already established property taxes deferral accounts for FortisBC, so those deferrals were also implicitly approved. Additionally, Creative Energy South Downtown has an approved regulatory cost deferral account for heating and cooling.

10.5.1 Proposed RCVA and Recovery Process

In this Application Corix proposes to create a Regulatory Costs Variance Account (RCVA) in rate base for DGE that would be carved-out of the currently approved RDDA.

The RCVA would capture variances from forecast for the following DGE external regulatory costs:

- annual BCUC cost recovery levies assessed by the BCUC on Corix;
- costs awarded by the BCUC to participate in regulatory proceedings involving Corix, that Corix is directed to pay;
- costs incurred by the BCUC in regulatory proceedings involving Corix before the BCUC and invoiced to Corix;
- external legal and consulting costs incurred by Corix in regulatory proceedings involving Corix before the BCUC; and
- external public consultation costs incurred by Corix if and when required of Corix by the BCUC.

There is uncertainty with regards to the above actual costs since these costs are completely outside of Corix's control.

- BCUC levy payments are levies charged to Corix over which Corix has no influence.
- BCUC participant assistance cost award payments depend on outside parties who register as interveners in a BCUC proceeding and those costs are charged to Corix DGE. Cost awards are fully outside the control of Corix and depend on the number of interveners, the time and effort spent by each intervener and the BCUC-approved rate for each intervener.
- BCUC proceeding invoice payments are also outside the control of Corix as this depends on BCUC's choice to use external consultants to review an application. Corix understands that this could be for various reasons, including but not limited to resource availability or subject matter expertise.

- External legal and consulting costs attributed to DGE are dependent on costs required to participate in BCUC proceedings. Corix has no influence on the types or timing of proceedings initiated by the BCUC. When BCUC-initiated proceedings arise relevant to DGE additional costs are sometimes required to participate in such proceedings.
- Public consultation costs related to DGE are dependent on BCUC's public consultation requirements for specific types of filings for DGE. These costs would be incurred for the purposed of hosting public consultations as required by the BCUC.

In each year, the RCVA would capture the variance between the forecast regulatory costs and the actual regulatory costs. The identified regulatory costs are included within the O&M Costs line item (see Schedules 8 and 11). With regards to the RDDA, the regulatory costs which are included within the O&M Costs will be based on forecast approved amounts. In other words, the regulatory costs contained in the O&M Costs will be held at forecast approved amounts for RDDA purposes.

Proposed Recovery of Regulatory Costs Variances in the RCVA.

- The RCVA would capture external regulatory costs variances from forecast to actual. Corix proposes any variance to be included in the DGE RCVA and amortized in full in the next revenue requirement application. This treatment is the same proposed for DGE Insurance Cost Variance Account proposed in Section 10.6.

Corix is proposing this treatment since the variance in external regulatory costs is not under Corix's control and with a short amortization period in the subsequent revenue requirement application it would better match the cost of service to the recovery in rates. A separate account for regulatory costs would also enhance transparency for recovery of these costs. In the absence of an approved RCVA, the external regulatory costs variance within the DGE O&M costs would instead be captured in the RDDA.

10.6 Proposal for an Insurance Cost Variance Account

10.6.1 Rationale for a Insurance Cost Variance Account

Insurance actual costs variances from forecast are recorded in the RDDA. Corix has been unable to establish a reliable methodology for accurately predicting future insurance costs. Insurance costs are particularly difficult to forecast due to the complex and unpredictable nature of the risks they are designed to cover. These costs are influenced by a wide range of dynamic factors, including changes in market conditions, inflation, and the frequency and severity of claims many of which are driven by external events such as natural disasters, economic downturns, or litigation trends.

Additionally, insurance premiums can fluctuate based on the insurer's own risk appetite, reinsurance availability, and broader industry losses. For utilities or infrastructure projects, the challenge is even greater, as insurance needs evolve with the scale and complexity of the build-out, and premiums may spike unexpectedly due to emerging risks or changes in asset valuation. As a result, relying on forecasted insurance costs can lead to significant variances from actual expenses, making it more prudent to track and recover these costs based on actuals. A description of insurance costs items is provided in Section 6.2 in item 7. Corix submits that insurance costs should continue with deferral treatment.

10.6.2 Proposed ICVA and Recovery Processes

Proposed Deferral Account: ICVA
In this Application Corix proposes to create an Insurance Cost Variance Account (ICVA) in Rate Base for DGE that would be carved-out of the currently approved RDDA.

The ICVA would capture variances from forecast for the following DGE insurance related costs:

- Liability Insurance;
- Property Insurance; and
- Other Insurance (Directors and Officers (D&O) liability, Errors & Omissions (E&O) and Cyber Insurance).

The forecast costs for insurance can be found in Schedule 11 in Appendix A within the Total O&M Costs. Corix submits these insurance costs are largely difficult to forecast for the reasons provided above and proposes that variances from actual be captured in the proposed ICVA and no longer in the RDDA.

Proposed Recovery of Insurance Variances in the ICVA.

- The ICVA would capture insurance cost variances from forecast to actual. Corix proposes any variance to be included in the DGE ICVA and amortized in full in the next revenue requirement application. This treatment is the same proposed for DGE Regulatory Costs Variance Account proposed in Section 10.4.

10.7 Deferral Account Filing Considerations

Table 24 below reviews the proposed deferral accounts with regards to the BCUC Regulatory Account Filing Considerations listed in the BCUC Regulatory Account Filing Guidelines.

TABLE 24: BCUC REGULATORY ACCOUNT FILLING CONISDERATIONS

ITEM / CONSIDERATION	NEW ACCOUNT: RCVA	NEW ACCOUNT: ICVA
I. Indicate if the request is: (a) for a modification or a change in scope to an existing Commission approved regulatory account; or (b) to establish a new regulatory account.	Modification to approved RDDA by carving out cost variances from the RDDA. Corix requests to establish a new RCVA to capture external regulatory costs variances. This proposal would carve-out these cost variances from the currently approved RDDA (Order G-166-18) and into a separate deferral account.	Modification to approved RDDA by carving out cost variances from the RDDA. Corix requests to establish a new ICVA to capture insurance cost variances. This proposal would carve-out these cost variances from the currently approved RDDA (Order G-166-18) and into a separate deferral account
a) If the request is for a modification or change in scope to an existing regulatory account, explain why the existing regulatory account is an appropriate account to use (specifically addressing the existing account's intended and approved purpose, mechanism for recovery, timeline for recovery and carrying costs).	The requested RCVA will specifically identify external regulatory costs for variance treatment promoting transparency. Any RCVA variance would be fully recovered within the next revenue requirements test period promoting a better matching of cost incurrence and recovery period.	The requested ICVA will specifically identify insurance cost for variance treatment promoting transparency. Any ICVA variance would be fully recovered within the next revenue requirements test period promoting a better matching of cost incurrence and recovery period.
b) If the request is for approval of a new regulatory account, state the purpose of the regulatory account and explain its intended use.	The RCVA account will be used to capture the variance from forecast costs to actual costs. This is a carve-out from the existing approved RDDA.	The ICVA account will be used to capture the variance from forecast costs to actual costs. This is a carve-out from the existing approved RDDA.

ITEM / CONSIDERATION	NEW ACCOUNT: RCVA	NEW ACCOUNT: ICVA
II. Propose a term (i.e. length of time) that the regulatory account should be approved for and explain why that term is appropriate.	Perpetuity. The term is appropriate because as a regulated utility it is expected regulatory costs will be incurred for the foreseeable future.	Perpetuity. The term is appropriate because the utility is expected to incur insurance costs annually.
III. Identify any alternate treatments that were considered, including an overview of what the accounting treatment would be in the absence of approval of the request to establish a regulatory account, and explain why these alternate treatments may not be appropriate.	In the absence of the RCVA deferral account the costs would be forecast within the O&M for each year. Any variance would be captured in the RDDA variance treatment.	In the absence of the ICVA deferral account the cost would be forecast within the O&M for each year. Any variance would be captured in the RDDA variance treatment.
IV. Address the following:		
a) whether, or to what extent, the item is outside of management's control;	These amounts are outside of management's control and consistent with Order G-166-18.	These amounts are outside of management's control and consistent with Order G-166-18.
b) the degree of forecast uncertainty associated with the item;	There is high uncertainty on what will be the actual costs. Costs cannot be accurately forecast since the cost driver arises from outside of DGE	For 2025 there is low uncertainly in insurance costs since an issued policy captures most of 2025. However, from 2026 onwards there is very high uncertainty since it is unknown what will be the future insurance costs based on market prices at that time upon insurance renewal.
c) the materiality of the costs; and	The materiality of costs and the resulting variances may be high.	The cost variance may be very material and large in 2026 and 2027 when Corix obtains insurance for those years when insurance is renewed. Historical insurance costs have been highly variable though with consistent cost increase trend.
d) any impact on intergenerational equity (note that this item is linked to the proposed timeline for recovery which is further outlined in item IX below).	There is no or limited intergenerational inequity since the recovery period is short. This is an improvement relative to RDDA recovery since the RDDA recovery period would be significantly longer.	There is no or limited intergenerational inequity since the recovery period is short. This is an improvement relative to RDDA recovery since the RDDA recovery period would be significantly longer.
V. Classify the regulatory account as either: (a) forecast variance account; (b) rate smoothing account; (c) benefit matching account; (d) retroactive expense account; or other.	Forecast variance account.	Forecast variance account.
VI. Identify if the regulatory account is a cash or non-cash account.	This is a cash account.	This is a cash account.
VII. Specify what additions to the regulatory account are being requested (i.e. type and amount of additions), including whether the account is intended to capture additions for a specific period of time or on an ongoing basis.	This account will capture the variance from the forecast amount in each test year to the actual amount.	This account will capture the variance from the forecast amount in each test year to the actual amount.
VIII. Propose a mechanism for recovery (e.g. how the balance in the regulatory account will be recovered or refunded to ratepayers) and explain why it is appropriate	Corix proposes to fully recover the balance through amortization in the next revenue requirement application. This is appropriate since this account captures variances with	Corix proposes to fully recover the balance through amortization in the next revenue requirement application. This is appropriate since this account captures variances with

ITEM / CONSIDERATION	NEW ACCOUNT: RCVA	NEW ACCOUNT: ICVA
	the approved test period of the revenue requirement.	the approved test period of the revenue requirement.
IX. Propose a timeline for recovery (e.g. the period over which the regulatory account balance is either collected or refunded; also referred to as the amortization period) and explain why it is appropriate.	The proposed full recovery period will be the test period in the next revenue requirement application. At this time, it is uncertain how many years will be applied for in the next test period. It can range from a single test year to a 5-year test period depending on the circumstances facing the utility at that time.	The proposed full recovery period will be the test period in the next revenue requirement application. At this time, it is uncertain how many years will be applied for in the next test period. It can range from a single test year to a 5-year test period depending on the circumstances facing the utility at that time.
X. Propose a carrying cost for the balance in the regulatory account and explain why it is appropriate.	Corix proposes the RCVA account be a rate base deferral account. This treatment would equivalent to the non-controllable regulatory cost variances that are captured in the RDDA within rate base in this Application.	Corix proposes the RCVA account be a rate base deferral account. This treatment would equivalent to the non-controllable regulatory cost variances that are captured in the RDDA within rate base in this Application.
XI. Outline a recommended regulatory process for the Commission's review of the application.	The BCUC's review of this account should occur as part of this Application's process.	The BCUC's review of this account should occur as part of this Application's process.

10.8 Summary of Approvals Sought Related to Deferral Accounts

Table 25 provides a summary of the request for approvals in this Application related to new deferral accounts.

TABLE 25: SUMMARY OF NEW DEFERRAL ACCOUNT REQUESTS

TYPE OF CHANGE	ACCOUNT	RETURN REQUESTS	DETAILS
Modification of approved RDDA -carve-out; Creation of New Account	RCVA	Rate-base. Approach is a carve-out from the rate base RDDA.	Any cost variance balance will be recovered in the next revenue requirement application within the test period of that rate application. See Section 10.5 for the proposed RCVA.
Modification of approved RDDA -carve-out; Creation of New Account	ICVA	Rate-base. Approach is a carve-out from the rate base RDDA.	Any cost variance balance will be recovered in the next revenue requirement application within the test period of that rate application. See section 10.6 for the proposed ICVA.

11. Key Drivers of Rate Increase

This is the first delivery rate application for DGE since the 2019 RRRA was filed on April 1, 2019. Given the length of time that has passed and the material changes to the delivery revenue requirements, Corix considered it reasonable to include a discussion on some of the key drivers behind the rate increases proposed in this Application.

11.1 Depletion of the $1 million Contribution Amount

As part of the negotiated asset acquisition arrangement, Corix did not assume any of the seller's outstanding debt obligations or deferred revenue from customers. Instead, the seller agreed to make a $1 million financial contribution, which was deposited into the RDDA. The primary purpose of this contribution was to stabilize rates during the early years of Corix's operation of DGE.

According to the terms of the agreement, the $1 million "Contribution Amount" was intended to:

> "limit the need for the Utility to increase customer rates during the initial years of operation of the Utility by Corix while allowing the Utility to recover its cost of service and earn a fair rate of return on the Utility rate base as allowed by the BCUC."

In addition to the funds contributed into the RDDA, Corix was directed to accrue interest on the $1 million balance using DGE's approved weighted average cost of capital (WACC). Corix credited approximately $204,753 in interest to the RDDA, increasing the total available funds to $1.2 million. This amount was strategically drawn down to offset revenue deficiencies and defer the need for larger rate increases during those years.

Thanks to the RDDA contribution, Corix was able to limit the average annual Basic Charge rate increase to just 2.9% per year between 2019 and 2023 significantly lower than would have been required in the absence of this financial support. In effect, the contribution allowed Corix to hold rates artificially low to protect customers during the early stages of utility operations.

However, by the end of 2022, the RDDA funds had been fully depleted. With the $1.2 million in support no longer available, Corix is no longer in a position to continue suppressing rate increases at historic levels. Accordingly, rate adjustments above 2.9% per year are now necessary to ensure the utility remains financially sustainable and capable of delivering reliable service over the long term.

11.2 Delays to the Dockside Green Buildout resulting in lower revenues

The Basic Charge is charged per building square metre per month. As a result, the revenue from the Basic Charge is directly linked to the total floor area connected to the utility and if the actual connected floor area is less than forecast, then the actual revenue from the Basic Charge will be less than forecast.

Delays in the planned buildout of the Dockside Green development have led to actual and forecast annual fixed charge revenues being significantly lower than initially forecasted in 2019, creating an upward pressure on rates. For example:

- in the previous rate application, Dockside Green was expected to be completed by 2032 with a total floor area of 130,428 m^2 connected to DGE.
- based on the latest schedule, Dockside Green is now expected to be mostly complete by 2035 with an updated total floor area of 125,648 m^2.

The most immediate and material impact is during the 2024 to 2029 period.

- in the previous rate application, Dockside Green was expected to add 46,444 m², representing 36% of total floor space, to DGE from 2026 to 2029 inclusive, with no buildings scheduled for 2024 or 2025.
- based on the latest schedule, Dockside Green is no longer expected to add any floor area from 2024 to 2029 inclusive, with the next building connections now scheduled for 2030. Furthermore, the same buildings are now forecast with a lower floor area of 40,830 m², which represents 32% of the updated buildout.
- This represents 6 years with no customer growth (2024-2029 inclusive) and a reduction in the floor area for those buildings by 12%.

Given the above, the revenue deficiency deferral account will grow rapidly if rates are not increased at this time.

11.3 Higher Property Taxes

In 2018 Bosa Development (Dockside Holdings) Ltd. ("Bosa") acquired all undeveloped land at Dockside Green with the intention of completing the development of the Dockside Green community. Bosa is the current owner of the land on which the utility's central energy plant (CEP) building is located. Bosa is charged a property tax from the City of Victoria and flows through the property tax to Corix without any markup. The amount forecasted by Corix in the 2019 RRA was the amount of property tax Corix anticipated it would be billed annually by Bosa, based on the three most recent years of actuals (2016, 2017 and 2018).

In 2020, Corix received a very large property tax invoice. After investigating, Corix learnt that DGELLP previously received low property tax invoices from the former landowner due to a tax exemption under the Revitalization Tax Exemption (Green Power Facilities) Bylaw. The purpose of this Bylaw was to establish a revitalization tax exemption program to encourage redevelopment of lands within the City of Victoria and the use of environmentally sustainable energy systems for those developments. Under the bylaw the maximum term of exemption for eligible land is 10 years. The exemption for the property relevant to the district energy utility expired on December 31, 2019 and has no ability for renewal. For each year of the exemption period the value of the eligible land and improvements were exempt from municipal property tax calculations. Once the exemption period expired, the property taxes were no longer discounted.

DGE was invoiced property taxes as outlined below.

- $27,597 in 2018
- $38,950 in 2019
- $124,793 in 2020
- $113,132 in 2021
- $117,014 in 2022
- $124,362 in 2023
- $143,541 in 2024

The resulting increase in property taxes from $27,597 in 2018 to $143,541 in 2024 represents a 420% increase in property tax experienced by DGE from 2018 to 2024. As Corix is obligated to reimburse BOSA for these property taxes on a flow-through basis with no markup, the utility cannot mitigate or defer these costs. To ensure financial viability, these cost must be reflected in customer rates going forward.

11.4 Higher Operating Labour Costs

When Corix prepared its 2019 RRRA it was reasonably anticipated that only 0.50 FTE would be necessary to operate DGE, based on the assumption that the large Cleaver-Brooks boiler would remain laid down and offline. However, in practice, Corix faced several operational and organizational constraints that required it to maintain a full-time (1.0 FTE) operator at the facility.

First, due to the specialized nature of the plant operator requiring both technical qualifications and familiarity with district energy systems Corix was unable to recruit and retain a part-time candidate in Vancouver Island's limited labour market. The geographic location and the relatively small scale of the utility further compounded recruitment challenges, making it infeasible to fill the position with a split or casual arrangement. Consequently, Corix had no viable alternative but to retain a full-time operator to ensure safe operations.

Historically, this position was part of the broader operations team, which managed both water and thermal energy utilities under Corix Multi-Utility Services Inc. (CMUS). However, following the carveout of Corix's district energy utilities from CMUS, Corix retained responsibility for DGE and its associated staffing needs. This structural change removed the possibility of cost-sharing the operator role across multiple utility functions, further requiring the need for a dedicated full-time resource assigned exclusively to DGE.

Moreover, as detailed in Section 8.1, the Cleaver-Brooks boiler was returned to service in 2024, reinstating the requirement for General Supervision Status under the Power Engineers, Boiler, Pressure Vessel and Refrigeration Safety Regulation. This mandatory supervision standard previously in place before the boiler was laid down further eliminates any remaining flexibility to reduce operator staffing levels.

Taken together these factors, the labour market constraints, organizational restructuring, and the TSBC requirements, have contributed to higher-than-forecast operating labour costs. In light of these uncontrollable and essential cost drivers, an increase in rates is necessary to reflect the true cost of safely and effectively operating the DGE utility.

11.5 Higher Cost of Capital (Financing Costs)

The most recent GCOC proceeding concluded in 2024 and through Order and Decision G-321-24, the BCUC decided that a just, fair and reasonable allowed return on equity for DGE would be 10.4%, which was calculated as 9.65% ROE for FEI plus a ROE premium of 0.75% for DGE due to its higher business risk profile compared to FEI. It should be noted that this was driven by an increase in the FEI ROE from 8.75% to 9.65%, while the ROE premium for DGE was reduced by the BCUC from 1.00% to 0.75%. The 10.4% ROE for DGE is the same allowed ROE given to most small utilities regulated by BCUC.

The BCUC also sets a deemed capital structure that must be used when calculating the cost of service. G-321-24 resulted in a capital structure of 49% equity and 51% debt for most small utilities, including DGE.

Corix has included the new cost of capital in the calculation of the 2025-2028 Rate Application to comply with BCUC's final decision in its Generic Cost of Capital Stage 2 proceeding.

11.6 Higher Inflation

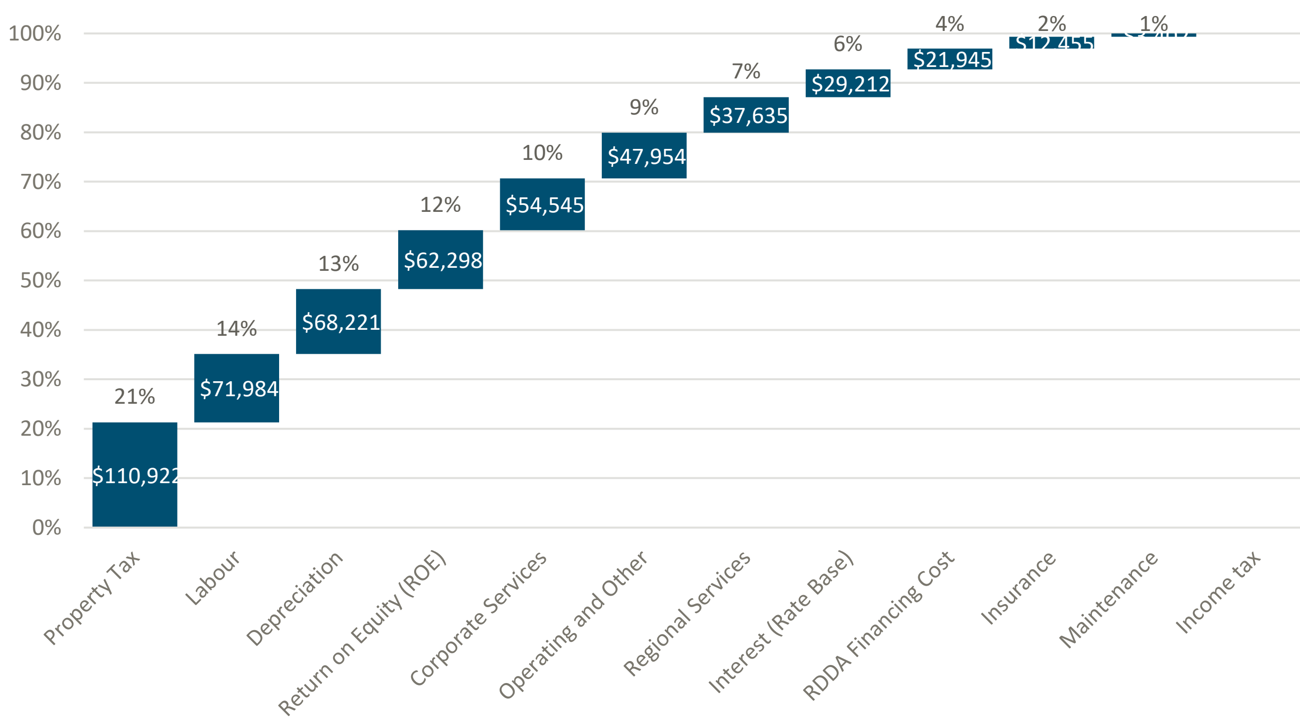
In 2019 when rates were initially approved, inflation was forecast to be 2.0% per year in alignment with the Bank of Canada's long-run target inflation rate, resulting in a total cumulative inflation of 10.4% from 2019 to 2024 inclusive. However, the actual Canada all-items consumer price index (CPI) cumulative inflation from 2019 to 2023, was 18.18%, which is an annual average inflation of 3.40% per year over the period. The majority of the actual inflation occurred in the three most recent years, 2021 (4.80%), 2022 (6.32%), and 2023 (2.79%), driven by the COVID-19 pandemic and associated fiscal and monetary policies, and supply chain disruptions including those associated with the war in the Ukraine. In some cases, inflation on specific goods or services vastly exceeded Canada all-items CPI inflation.

Over the same period from 2019 to 2024, DGE rates increased at an annualized rate of 2.38%, which is below the actual average annual inflation rate of 3.40%. This indicates that, in real terms, DGE rates grew at a rate approximately 1.0% per year below inflation, resulting in a cumulative erosion of cost recovery relative to general price levels.

11.7 Generalized Higher Cost of Service

The 2019 Rate Application was filed with the best information at a time after Corix purchased DGELLP assets, since that time, years of operating the utility has provided Corix with the operational experience to refine its cost forecasts by incorporating actual costs and management experience. Chart 8 shows the 2025 Cost of Service variance in this rate application by comparing the forecast 2025 Cost of Service from the 2019 RRRA with the 2025 forecasted Cost of Service in this Application. As seen in the chart below the key drivers in the Cost of Service variance are (1) property tax, (2) operating labour, (3) depreciation, (4) rate base (ROE; interest) and RDDA financing costs, and (5) corporate and regional services costs.

CHART 8: BREAKDOWN OF 2025 TEST YEAR INCREASE RELATIVE TO 2019-RRRA



The increases on property tax, operating labour, depreciation, financing costs and RDDA Financing costs are discussed in the sections above. In addition to those key factors Corix discusses the increase in Corporate and Regional Service cost increases in this section.

Corporate Services Cost Allocations

Corporate Services cost allocations are explained in Section 6.3.1, with explanations of each of the Corporate Services cost categories included the Corporate Cost Allocation Methodology (CAM) Manual filed as Appendix I and with this Application.

The Corporate CAM is used to fairly divide and allocate shared corporate services costs to a pool of businesses in an efficient manner that reflects cost causation. There are several variables involved and as a result, the allocations to each business can be impacted by changes to:

(i) the corporate services costs;
(ii) the corporate cost allocation methodology;
(iii) the factors for any, some or all of the businesses within the pool of businesses to which costs are allocated; or
(iv) the total pool of businesses to which the costs are allocated.

The Corporate CAM has not changed and remains consistent with that approved by BCUC through Order G-349-20. However, in the 2019 RRRA, the DGE management / administration and overhead charge was calculated based on an internal bottom-up estimate based on Corix's prior experience. In other words, the costs for support services (Corporate and Regional Services) that were forecast in the 2019 RRRA were forecast using a different methodology from the one subsequently approved by BCUC in G-349-20. This difference was to customer's benefit since it resulted in an under-recovery of DGE's overhead costs.

This Application includes the Corporate Services costs allocated using the BCUC-approved Corporate CAM. It should be noted that under normal circumstances, allocations to businesses such as DGE will change from year to year despite keeping the allocation methodology constant, due to changes in the corporate services costs from year to year, changes to factors at any one business (for example a material increase in Gross PPE at another utility), as well as changes to the pool of businesses from year to year through organic growth, acquisitions or dispositions. For example, if all else remains equal:

- an enterprise-wide project to improve cybersecurity within Corix resulting in higher corporate services costs would result in higher corporate services cost allocations for all businesses;
- if utility "A" implements a relatively significant capital project and is approved a subsequent rate increase, the increased gross PPE and gross revenue would result in utility "A" receiving a higher allocation (or percentage) of the corporate services costs while all other utilities' shares would experience a corresponding decrease;
- if a utility within the pool is sold to another company, reducing the number of utilities owned by Corix's parent company, then the total pool of businesses to which costs are allocated is reduced and the cost allocations to all remaining businesses increase; or
- if a utility is acquired or a new greenfield utility is constructed, this increases the number of utilities owned by Corix's parent company, and the total pool of businesses to which costs are allocated is increased, then the cost allocations to all remaining businesses decrease.

Above were some hypothetical examples to illustrate the nature of cost allocations by changing only one factor at a time. In reality, multiple factors change from year-to-year which results in an inherent difficulty in producing reliable long-term cost allocation forecasts.

In 2024, the corporate restructuring transaction (See Section 2.8) resulted in the district energy businesses being carved out of the much larger Corix Infrastructure Inc. (CII) multi-utility business that included utility businesses focused energy, water, wastewater, and other complementary utility services. DGE is a part of the district energy business, which remains wholly owned by British Columbia Investment Management Corporation. However, as a result of this 2024 restructuring, there were significant changes to the corporate services costs and to the pool of businesses to which the costs are allocated. The total corporate services costs are now lower than in previous years, but at the same time the pool of businesses receiving allocations is smaller and therefore each business receives a higher percentage allocation (portion) of the total corporate services cost. As a result of this most recent transaction, the 2025 corporate services forecast cannot reasonably be compared with the 2024 corporate services costs or any other prior year.

The 2025 corporate services forecast best represents the forecast costs to run the businesses as it stands today, following the restructuring transactions completed in early 2024. These forecast corporate services costs were then allocated to the pool of businesses using the Corporate CAM as approved by the BCUC.

While the forecast approvals were appropriate in 2019, there is now a BCUC-approved methodology that Corix has followed to allocate Corporate Services costs, and businesses circumstances have changed significantly resulting in corporate services costs that are materially different from those forecast in 2019.

Regional Services Cost Allocations

Regional services cost allocations are explained in Section 6.3.2, with explanations of each of the Regional Services cost categories included in the Regional CAM Manual filed as Appendix J with this Application.

The Regional CAM is used to fairly divide and allocate shared regional services costs to the relevant pool of businesses in an efficient manner that reflects cost causation. The methodology used is the same as the Corporate CAM and therefore, similar impacts as those experienced with the corporate services cost allocations are experienced due to changing factors.

Similar to the Corporate CAM, in the 2019 RRRA, the DGE management / administration and overhead charge was calculated based on an internal bottom-up estimate based on Corix's prior experience. In other words, the costs for support services (Corporate and Regional Services) that were forecast in the 2019 RRRA were forecast using a different methodology from the one subsequently approved by BCUC in G-349-20. This difference was to customer's benefit since it resulted in an under-recovery of DGE's overhead costs.

In addition, the 2024 restructuring transaction resulted in significant changes to the regional services costs and to the pool of businesses to which the costs are allocated. For example, there were several water, wastewater and other energy utilities that received a portion of the regional cost allocation for the region in which DGE is located. As a result of this most recent restructuring transaction, the 2025 regional services forecast cannot reasonably be compared with the 2024 regional services costs or any other prior year.

While the forecast approvals were appropriate in 2019, businesses circumstances have changed significantly as described above, resulting in regional services costs that are materially different from those forecast in 2019. As a result, this Application includes an update to the regional services cost forecast to one that is aligned with budgeted allocations for DGE.

12. Rates and Rate Structure

12.1 DGE Rate Structure

Currently Corix recovers DGE costs through a two-part rate structure with a monthly Basic Charge per square meter per month (fixed delivery charge) and a Variable Energy Charge per kilowatt-hour (variable energy charge) as approved in Order G-269-20 that approved the Application to Flow Through Energy Costs. The approved rate structure on customer bills is as follows:

- Basic Charge ($ / m2 / month)
- Variable Energy Charge ($ / kWh)

In addition to the two-part rate structure, Corix currently flows through property tax variances through a rate rider charged as a $ per square metre per month.

The request for approval of customer rates in this Application is in regard to the delivery revenue requirements and the Basic Charge only. Corix also has a request for approval to discontinue the property tax variance rate rider.

The Variable Energy Charge, together with the ECRA, facilitates the recovery of energy supply costs from DGE customers on a flow-through basis. The Variable Energy Charge and the associated rate setting mechanism is outside the scope of this Application.

12.2 Rate Considerations to Recover RDDA and Minimize Subsequent Rate Changes After the Test Period

12.2.1 Proposed Rates Considerations

When developing the proposed rates for the test period in this Application, Corix has considered the need to ensure fair and reasonable rates for customers with the utility's requirement to recover its costs, including the management of t he balance in the RDDA. As explained in Section 11 the Contribution Amount placed in the RDDA was quickly depleted and the RDDA is now forecasted to grow rapidly in the future (in the absence of rate increases) all due to a generalized higher cost of service and lower revenues. As is evidenced by the experience of the previous owners of DGE, the long-term financial viability of a utility can be quickly threatened by a rapidly growing RDDA balance.

The rate considerations that Corix used in proposing its rate increases during the test period are as follows:

1. Manageable annual RDDA balances until the year of full recovery.
2. RDDA balances that are reasonable relative to the rate base without the RDDA (i.e. plant in service or net book value).
3. The peak RDDA balance and the year it occurs in.
4. The RDDA full recovery year as soon as reasonably possible.
5. Avoiding or minimizing rates that exceed a 10% rate increase and/or rates that exceed a 10% increase on the bill.
6. Proposed rates in the test years that provides a reasonable moderate levelized rate in future years.

7. Rates that attempt to minimize the rate increases in the test period while maintaining reasonable future RDDA balances.
8. Rates that maintain reasonable carrying costs of future RDDA balances for a sustainable utility that does not place undue business risk for the utility.
9. Rate increases that include improved cash inflows to allow recovery of the utility's operating and maintenance expenses and meet financing cost obligations.
10. Higher billed revenue that allow the utility to maintain a reasonable financial position to withstand external unfavourable shocks.

The above ten rate considerations are not in order of any priority and are not weighted. All of the factors need to be considered to arrive at a balanced result where the proposed rate increases adequately address the 10 considerations where some of the factors are competing considerations.

After reviewing various feasible scenarios in Section 12.3, Corix has proposed rates in the Application that provides a reasonable balancing of the various considerations. Corix has attempted to minimize the test year rate increases while at the same time striving to moderate future RDDA increases to a manageable level. Corix understands that avoiding large rate increases are a very important consideration. However, avoidance of large rate increases must be considered in the context of manageable future RDDA balances while minimizing future carrying costs where possible.

12.3 Scenario Analyses

As discussed in section 12.2.1 above, in determining the rates for the test period, Corix considered the 10 rate considerations as factors to establish rates that are both reasonable for customers and sufficient for DGE's long-term financial stability, as shown in Table 26 that follows, Corix prepared four (4) Scenarios with a focus on the factors shown below.

- RDDA recovery year
- Basic Charge (delivery) rate increases;
  - Proposed rate increases for the 2025, 2026, 2027 and 2028 test years;
  - Indicative rate increases for 1 year after the test years (2029);
  - Indicative long-term rate increases from 2030 until full RDDA Recovery;
- Peak RDDA balance;
- The Maximum RDDA as a percentage of the rate base, excluding RDDA; and
- Cumulative RDDA Financing Costs from 2025 to RDDA Recovery.

In the 2019 RRRA, the forecast did not contemplate any significant RDDA deficit balance as buildout was expected to progress and the forecast timing of capital deployment and operating costs did not result in any material revenue shortfalls. Therefore, a RDDA recovery period was not previously an issue for consideration.

However, based on the current circumstances, Corix requires material rate increases during the test period to set rates with a RDDA recovery timeline that ensures the RDDA can be fully recovered over a reasonable time period. Corix discusses in this section the full recovery of the RDDA by 2039, 2042, 2044 and 2046.

To identify an optimal approach for RDDA recovery, Corix developed scenarios that balance the need for timely recovery while minimizing customer impacts. Each scenario outlines a specific RDDA recovery year and proposed rate increases. The analysis underscores the trade-offs between accelerating RDDA recovery to reduce financing costs, spreading recovery periods to alleviate steep rate increases for customers, and minimizing both the RDDA balance and its percentage of the rate base as a measure of risk.

TABLE 26: Scenario Analyses

Scenario Analyses	Scenario 1		Scenario 2		Scenario 3		Scenario 4	
RDDA Recovery Year	2039		2042		2044		2046	
	Rate Δ%	Bill Δ%	Rate Δ%	Bill Δ%	Rate Δ%	Bill Δ%	Rate Δ%	Bill Δ%
Rate Increase / Bill Impact 2025 (Test Year)	40.00%	18.58%	35.00%	17.19%	30.00%	15.80%	25.00%	14.41%
Rate Increase / Bill Impact 2026 (Test Year)	35.00%	21.64%	30.00%	16.68%	25.00%	11.85%	25.00%	10.16%
Rate Increase / Bill Impact 2027 (Test Year)	30.00%	20.26%	25.00%	16.16%	15.00%	8.69%	15.00%	8.52%
Rate Increase / Bill Impact 2028 (Test Year)	15.00%	12.16%	12.00%	9.60%	12.00%	9.29%	10.00%	7.75%
Rate Increase / Bill Impact 2029 (Indicative)	10.00%	8.46%	10.00%	8.28%	11.00%	8.81%	10.00%	7.96%
Subsequent annual delivery rate increases until full RDDA recovery (indicative)*	0.65%	0.86%	2.71%	2.54%	4.76%	4.19%	5.21%	4.57%
Test Year Cumulative Rate Increase / Bill Impact	182.56%	94.56%	145.70%	74.07%	109.30%	53.85%	97.66%	47.37%
Key Scenario Factors								
Peak RDDA Balance ($ millions)	$2.53		$3.39		$4.84		$5.71	
RDDA Max. Size Relative to Rate Base (excl. RDDA) (%)	146%		178%		223%		240%	
Cumulative RDDA Financing Costs from 2025 to RDDA Recovery ($ millions)	$1.91		$3.22		$5.08		$6.59	

Scenario 1

This scenario is based on the rate increases necessary to fully recover the RDDA balance by 2039. Corix discusses the pros and cons of Scenario 1 below.

Pros of Scenario 1

- The shortest RDDA recovery period, which ends in 2039 (4 years after full buildout).
- Achieves the lowest subsequent rate increases until full RDDA recovery, at 0.65% annually.
- Maintains the lowest peak RDDA balance.
- Reduces the RDDA peak relative to the rate base (excluding RDDA) at 146%.
- Minimizes cumulative RDDA financing costs from 2025 to RDDA recovery to $1.91 million.

Cons of Scenario 1

- Involves the highest cumulative rate increase of 183% over the test period.
- Leads to the highest bill impact over the test period, with a cumulative increase of 95%.
- Results in four years of bill impacts with bill increases exceeding 10%.

Scenario 1 results in full RDDA recovery by 2039, achieving the lowest expected rate increases and minimizing cumulative financing costs from 2030 onwards. However, it involves the highest cumulative rate increase and bill impact over the test period, with material rate increases from 2025 to 2029. This scenario is ideal for minimizing long-term financing costs that will eventually be borne by customers but may be challenging for customers in the near-term due to the high initial rate increases.

Scenario 2
This scenario is based on the rate increases necessary to fully recover the RDDA balance by 2042, 3 years more than Scenario 1.

Pros of Scenario 2
- Results in a lower cumulative rate increase during the test year compared to Scenario 1 of 146%
- Achieves low subsequent rate increase from 2030 until full RDDA recovery, at 2.74% annually.
- Maintains relatively low cumulative RDDA financing costs from 2025 to RDDA recovery at $3.22 million.

Cons of Scenario 2
- Increases the time for full recovery of the RDDA by 3 additional years compared to Scenario 1, which increases financing costs.
- Increases the RDDA peak relative to the rate base (excluding RDDA) at 178%.
- Leads to a material bill impact over the test period, with a cumulative increase of 74%.
- Results in three years of bill impacts with bill increases exceeding 10% during the test period.
- Increases the peak RDDA balance to $3.39 million (an increase of 34% relative to Scenario 1)

Scenario 2 proposes the RDDA recovery in 2042, reducing the rate increases in the initial years compared to Scenario 1. It achieves a low subsequent rate increase and maintains a moderate peak RDDA balance. While it involves higher cumulative financing costs than Scenario 1, it offers a more balanced approach with less immediate impact on customers' bills.

Scenario 3
This scenario is based on the rate increases necessary to fully recover the RDDA balance by 2044, 5 years more than Scenario 1.

Pros of Scenario 3
- Further reduces the cumulative rate increases in the initial years to 109%, which is lower than Scenarios 1 and 2
- The cumulative bill impact of 54% materially lower than Scenarios 1 and 2, while not substantially different than Scenario 4.
- Results in only two years of bill impacts with rate increases exceeding 10% which is 1 and 2 years under Scenarios 1 and 2 respectively and the same number of years as Scenario 4.

Cons of Scenario 3
- Increases the peak RDDA to $4.84 million, which is 43% higher than Scenario 2.
- Moderate cumulative financing costs on the RDDA at $5.08 million, which is $3.17 million and $1.86 million higher than Scenario 1 and 2 respectively, but $1.58 million lower than Scenario 4.
- Increases the RDDA peak relative to the rate base (excluding RDDA) to 223%.
- Achieves a moderate subsequent rate increase until full RDDA recovery, at 4.76% annually.

Scenario 3 proposes the RDDA recovery period by five years relative to Scenario 1. These additional years help to ease the immediate financial impact on customers by reducing the rate of bill increases in the early years. As a result, Scenario 3 offers more gradual increases compared to the steeper increases seen in Scenario 1. However, by deferring cost recovery over a longer period, Scenario 3 leads to higher cumulative financing costs than Scenarios 1 and 2, as the RDDA remains on the books for a longer duration. These additional costs would be born by customers. Despite this, the scenario still maintains financing costs at a moderate level compared to Scenario 4. Additionally, under Scenario 3, the subsequent annual delivery indicative rate increases remain below 5%.

Scenario 4
This scenario is based on the rate increases necessary to fully recover the RDDA balance by 2046, 7 years more than Scenario 1.

Pros of Scenario 4
- Lowest cumulative bill impact over the test period, with a cumulative increase of 47%
- Results in the lowest cumulative rate increase over the test period at 98%
- Results in two years of bill impacts with bill increases exceeding 10% which is 1 and 2 years lower than Scenarios 1 and 2 respectively and the same number of years as scenario 3.

Cons of Scenario 4
- Highest cumulative financing costs on the RDDA at $6.59 million, this is an additional $1.51 million in financing costs due to postponing the recovery of the RDDA compared to Scenario 3. This cost would be borne by customers.
- Results in the highest peak RDDA balance at $5.71 million.
- Increases the RDDA peak relative to the rate base (excluding RDDA) at 240%.
- The highest subsequent rate increase until full RDDA recovery, at 5.23 % annually.

Scenario 4 proposes the RDDA recovery to 2046, which reduces the initial rate increases compared to Scenario 3. It results in the highest financing costs and the highest subsequent rate increase after the test year above 5% and maintains the highest peak RDDA balance. However, this scenario offers the lowest cumulative rate increase over the test period. It should be noted that with Scenario 5, the annual rate increase from 2030 to 2044 (15 consecutive years) would be 5.23% every year. If there are any subsequent delays to the buildout or higher inflation or higher costs than forecast from 2030 through to 2044, it would place upward pressure on the 5.23% rate increases, resulting in even higher increases.

This prolonged deferral period shifts a larger portion of the rate increase to future customers, increasing the affordability benefits of lower near-term rate increases. However, the escalating financing costs, coupled with the compounding effect, erode the initial cost savings from deferring RDDA recovery. This highlights the trade-off between lower rates on early years and the long-term financial impact, emphasizing the need for a balanced approach to RDDA recovery that minimizes the impact of financing costs.

12.3.1 Scenario Selection and Justification

Scenario 3 presents a well-balanced approach to setting rates and managing the RDDA balances, financing costs and RDDA recovery. Scenario 3 offers a middle ground between the aggressive cost recovery of Scenario 1 and the long-term financial risks of Scenario 4. By prolonging the RDDA recovery period by five years to 2044, Scenario 3 allows Corix to significantly reduce the rate increases in the early years, easing the financial burden on customers in the near term. With a cumulative bill impact of 54%, it is notably lower than Scenarios 1 (95%) and 2 (74%), and only slightly higher than Scenario 4 (47%), making it a strong option when considering the rate increases without overstretching the recovery timeline. One of the key advantages of Scenario 3 is that it limits the number of years with double-digit rate increases to just two—compared to four in Scenario 1 and three in Scenario 2. The cumulative rate increase over the test period is 109%, which is significantly lower than Scenario 1 (183%) and with a similar outcome than Scenario 4 (98%).

While Scenario 3 does result in higher financing costs ($5.08 million) and a higher peak RDDA balance ($4.84 million) than Scenarios 1 and 2, these trade-offs are moderate and acceptable when weighed against the benefits of improved bill impact and subsequent rate increases. Importantly, Scenario 3 still maintains financing costs well below Scenario 4, which incurs $6.59 million in financing costs due to its delayed 2046 recovery timeline (additional 7 years).

Scenario 3 also achieves a moderate subsequent annual rate increase of 4.78%, which, while higher than in Scenarios 1 and 2, is still below the 5.23% projected in Scenario 4. This potentially mitigates against future upward pressures on rates that may arise due to buildout that slower than currently forecast or higher costs (for example due to higher inflation than currently forecast). Scenario 3 helps rates to remain predictable and within a reasonable range. The scenario avoids the steep post-test year increases that could arise from over-deferring recovery, as seen in Scenario 4.

In conclusion, Scenario 3 offers the most balanced path forward. It effectively reduces short-term customer impacts without incurring the excessive long-term financing costs associated with Scenario 4. While it does involve higher financing costs than Scenarios 1 and 2, these are justified by the improved bill impact and smoother rate trajectory. In Corix's view, Scenario 3 offers the most prudent choice.

12.4 Proposed Basic Charge for DGE

The existing rates for DGE customers are:

- Basic Charge: \$0.4260 /m^2 per month (effective since January 1, 2025);
- Variable Energy Charge: \$0.0370 /kWh (effective April 1, 2025); and
- Rate Rider 1: \$0.1834 /m^2 per month (effective since April 1, 2025).

Based on the information presented in this Application and the confidential financial model, Corix requests approval for DGE 2025, 2026 and 2027 Basic Charge (as presented in Table 29 below).

TABLE 27: EXISTING AND PROPOSED RATES FOR DGE

	Existing	Proposed	Proposed	Proposed	Proposed
EFFECTIVE DATE:	**JANUARY 1ST**	**JULY 1ST**	**JANUARY 1ST**	**JANUARY 1ST**	**JANUARY 1ST**
	2025	**2025**	**2026**	**2027**	**2028**
Basic Charge (\$/m^2 per Month)	**0.4260**	**0.5538**	**0.6923**	**0.7961**	**0.8916**

The above rates result in an annual rate change to the Basic Charge of 30.0% in 2025, 25.0% in 2026, 15.0% in 2027 and 12% in 2028. Schedule 15 in Appendix A provides additional information regarding past rates as well as indicative rates for 2029 and 2030, along with the annual rate change percentages. Sections 13.2 and 13.3 provide information on customer and end-user bill impacts based on the proposed rates.

13. Bill Impact Analyses

13.1 Customers Versus End-Users

DGE customers comprise of: (1) residential and commercial strata corporations (2) residential and commercial rental buildings, and (3) commercial owned buildings. In several cases, these buildings are managed through a property management company acting as an agent on behalf of the strata corporation or the building owner.

It is important to note that strata unit owners are not customers of DGE, though they are typically end-users of the thermal energy. Corix invoices the customers, as described in the preceding paragraph, who in turn recovers their costs from strata unit owners or tenants. Corix is not aware of how this is specifically done for each individual building. However, through the DGE's customer information session (see Section 13.4), Corix was made aware that in some cases, a third-party submetering company is used by some customers to allocate Corix's costs to tenants of the buildings. Generally speaking, Corix also understands that strata corporations sometimes recover Corix's costs as part of or in a similar manner to the fixed monthly strata fee where costs are payable based on the floor area (in square feet) of each strata unit. This approach could leads to bills that do not vary with consumption.

Given the above, Corix has provided two different types of bill impact analyses, which are presented in the following sections.

13.2 Customer Bill Impact Analyses

Schedule 19 - "Detailed Customer Bill Impact" is filed confidentially alongside the financial model, in accordance with the reasons for confidentiality outlined in Section 1.3.4. This schedule provides a detailed breakdown of the revenue attributed to each DGE customer, including floor area and forecast energy consumption, which is used to calculate the individual bill impacts.

The impact of the bill increase will vary for each customer due to differences in how their total bill is composed. Specifically, the proportion of the basic charge, energy charge, and Rate Rider 1 differs from one customer to another. These components contribute differently to the total bill depending on the building's energy usage characteristics.

A key factor influencing this variation is the Energy Use Intensity (EUI) of each building, which is measured in kilowatt-hours per square meter (kWh/m²). Buildings with higher EUI consume more energy per unit area, leading to a larger share of their bill being made up of the Variable Energy Charge. Conversely, buildings with lower EUI may see a higher proportion of their bill coming from fixed charges like the Basic Charge. In other words, customers whose bills are more heavily weighted toward energy consumption will experience a lower percentage increase in their total bill. On the other hand, customers with lower energy usage relative to fixed charges will see a larger percentage increase.

THE PERCENTAGE INCREASE IN EACH SPECIFIC CUSTOMER'S BILL IS INFLUENCED BY THE RELATIVE PORTIONS OF THE BILL THAT ARE MADE UP OF THE FIXED CHARGES VERSUS THE VARIABLE ENERGY CHARGE, WHICH IN TURN IS INFLUENCED BY THEIR BUILDING'S ENERGY USE INTENSITY.

Table 28 below presents the average customer bill impacts based on the proposed basic charges and indicative energy charges for DGE customers.

TABLE 28: AVERAGE BILL IMPACT TO DGE CUSTOMERS

Customer Annual Bill Impact	2025	2026	2027	2028	Cumulative	Annualized Rate
Average Bill Impact	**9.7%**	**7.9%**	**12.6%**	**9.5%**	**46.0%**	**9.9%**

Table 28 above shows that the average customer bill impacts from 2025 through 2028 from the proposed and indicative rates in this application would experience a cumulative rate increase of 46% which is equivalent to an annual bill increase of 9.9% during the test year.

As discussed in Section 3.1.2, Corix made an adjustment to the Energy Cost Reconciliation Account to book the difference in revenue between the interim and permanent rates approved by Order G-248-19. This adjustment effectively lowers the reported energy supply costs for 2026, creating what can be described as a "virtual reduction" in that year's energy cost baseline. As a result, when energy costs increase in 2027, the escalation appears more pronounced because it is calculated from this virtually lower 2026 base.

13.3 End-User Bill Impact Analyses

Corix expects that there will be approximately sixteen (16) customers that will be connected to the district energy system by full build-out (See Section 4.1). These DGE customers will primarily be residential buildings, who will then recover the costs from each individual unit through the mechanism outlined in their strata bylaws or tenancy agreements. Corix considers that an estimated annual cost impact for a typical residential end-user is a useful indicator for the reasonableness of the annual cost of residential heating services, as opposed to the annual estimated bill impact for an entire residential building customer. Table 29 presents a summary of the estimated total end-user cost impact based on the rates proposed in Section 12.4 and the indicative 2025 to 2028 energy charges. Detailed information supporting these calculations can be found in Schedule 16 in Appendix A.

Information provided in this section is based on a typical residential end-user with a 74 m^2 (800 sq. ft.) unit and an Energy Use Intensity (EUI) of 74 kWh/m^2 for heating, which is based on the actual historical average at DGE. This results in an annual energy consumption of 5,513 kWh.

TABLE 29: ESTIMATED ANNUAL BILL IMPACT TO A TYPICAL DGE END-USER

Annual Bill Impact	2024	2025	2026	2027	2028
Existing Basic Charge ($/$m^2$ per Month)	0.4150	0.4260	--	--	--
Proposed Basic Charge ($/$m^2$ per Month)	**--**	**0.5538**	**0.6923**	**0.7961**	**0.8916**
Variable Energy Charge ($/kWh) (indicative)	0.0420	0.0370	0.0446	0.0456	0.0463
Rate Rider 1 ($/$m^2$ per Month)	0.1210	0.1834	0.01834	--	--
Annual Change in Basic Charge (%)		**30.00%**	**25.00%**	**15.00%**	**12.00%**
Annual Change in Variable Charge (%)		-11.83%	20.45%	2.18%	1.67%
800 sq. ft. Residential Suite					
Basic Charge Cost ($)	369	435	615	707	792
Variable Energy Charge Cost ($)	232	204	214	251	255
Rate Rider 1 ($)	81	149	21	-	-
Total Annual Bill ($)(1)	**681**	**788**	**850**	**958**	**1,047**
Annual Change in Bill ($)		**108**	**62**	**108**	**89**
Annual Change in Bill (%)		**15.80%**	**7.82%**	**12.75%**	**9.29%**

Note: (1) Rate Rider 1 has been approved for the period from April 1, 2025, to March 31, 2026. The projected recovery amount required to bring the balance to zero for the last three months of 2026 is $18,292, which is equivalent to a rate of $0.0235 per square meter (m^2). Corix anticipates recovering the full amount from customers by March 31, 2026. And refund to customers any excess to close the PTDA balance to zero. Therefore, the amount of $21 in 2026, reflects the net amount recovered through the Rate Rider 1.

Schedule 16 in Appendix A provides additional end-user bill impact information through to 2030. The estimated bill impacts show that Corix's proposals would result in total annual bill increases for a typical residential end-user of 15.80% starting on July 1, 2025 (approximate increase of $108 for the year); 7.82% in 2026 (approximate increase of $62 for the year), 12.75% in 2027 (approximate increase of $108 for the year) and 9.29% in 2028 (approximate increase of $89 for the year).

It is important to note that while Corix's proposed rate increases may initially appear significant, the actual impact on customer bills is more moderate. In the first two years, the bill impact is projected to be roughly half of the Basic Charge rate increase. This is primarily because the Basic Charge represents a smaller portion of the total bill compared to the Variable Energy Charge, which is based on consumption. As a result, even a notable increase in the Basic Charge translates into a less pronounced effect on the overall bill.

Corix is proposing a steeper rate increase in the first half of 2025 as a risk prevention measure to recover a larger share of the cost of service early in the rate period. This approach is intended to curb the growth of the Revenue Deficiency Deferral Account (RDDA), which accumulates unrecovered costs and can lead to more substantial rate adjustments in the future if left unchecked. By front-loading the recovery, Corix aims to stabilize long-term rate trajectories and reduce the likelihood of sharp increases in subsequent years.

13.4 Customer Information Session and Feedback

Corix hosted two customer information sessions to share details about the proposed rate increases for the DGE, explain the rationale behind them, and respond to questions from customers and end-users. These sessions were part of Corix's stakeholder engagement in advance of this 2025-2028 Revenue Requirements and Rate Application to the BCUC. Appendix K includes a Customer Engagement Summary Report, which outlines the key feedback received during the sessions and includes the presentation materials used to support the discussions.

The two sessions were held on May 2, 2025. A total of 44 individuals attended, including residents, renters, strata council members, and a property manager representing five of the eight utility customers. Corix ensured broad awareness of the sessions through multiple email notifications and requests for visible postings in buildings.

During the sessions, participants raised several important topics. There was confusion about how the proposed rate changes would affect residents whose bills are managed by third-party submetering companies or allocated by strata councils. Attendees sought clarity on the distinction between basic and variable rates, the reasons for the proposed increases, and how future developments and technologies might impact system efficiency and emissions. Some expressed concern over the continued use of natural gas and voiced strong support for transitioning to a low- or zero-carbon energy system. Overall, participants appreciated the opportunity to engage directly with Corix and valued the information provided in the presentation.

In addition, Corix outlined its intention to transition the Basic Charge from a dollar-per-square-meter ($/m^2) rate to a dollar-per-kilowatt ($/kW) capacity rate. To implement this change, Corix would submit a Rate Design Application to the BCUC for approval. The exact timing of this application is unknown at this time. However the BCUC would be notified well in advance of filing. The transition from a $/m^2 Basic Charge to a $/kW capacity rate is intended to better align the rate structure with the actual cost drivers of district energy utilities.

While some Corix utilities in British Columbia still apply a fixed basic charge based on $/m^2, Corix is currently considering converting these to a capacity-based charge using $/kW. This approach more accurately reflects the cost of ensuring the utility has sufficient capacity to meet the relevant peak loads.

The shift to a $/kW capacity charge offers several benefits including but not limited to:

- Encourages efficient use: A $/kW rate incentivizes future buildings to design energy efficient buildings to reduce their peak load requirements. This leads to more efficient energy use and lower overall district energy system costs.
- Fairness in setting rates: A $/m^2 rate assumes all customers have the same energy efficiency. If future customers have materially different energy efficiency the rates charged would not reflect the cost to serve the new customers whose building may be built to a higher standard of efficiency.
- Rate adaptability: A capacity-based rate is more flexible allowing for different types of customers (with different load demands) to more easily be added to the system.

14. DGE Tariff

A clean copy and legal blackline version of the proposed DGE Tariff is included in Appendix E and Appendix F respectively. The proposed Tariff includes amendments to customer rates and housekeeping amendments as discussed below.

14.1 Rate Change Amendments

The proposed rate schedule within the tariff includes rate schedule amendments that removes the previous Monthly Basic Charges adds the proposed Basic Charge monthly rates effective:

- July 1, 2025;
- January 1, 2026;
- January 1, 2027; and
- January 1, 2028.

No amendment to the Variable Energy Charge or Rate Rider 1 approved through BCUC Order G-78-25 has been made.

The proposed rate schedule amendments also include the addition of a note that explains that the Variable Energy Charge is updated each year; and a note that explains that, subject to BCUC approval, the Rate Rider 1 will be discontinued effective April 1, 2026.

14.2 Housekeeping Amendments

The following housekeeping amendments are proposed for the DGE tariff to update definitions and terms and conditions of service, the company name and footers as necessary; address minor grammatical errors in the previous version, provide clarity and to facilitate the efficient application of terms and conditions in the provision of service to customers across Corix's BCUC-regulated utilities. This efficiency will be facilitated by harmonizing the terms and conditions in the DGE tariff with those in the tariff for the BMDEU – UniverCity and those proposed for UBC NDES[25]. This harmonization initiative avoids the situation where similar Corix district energy utilities regulated by the BCUC have different tariff terms and conditions of service, which creates efficiencies by reducing confusion and avoiding instances of incorrect application of a term in the tariff.

An explanation of the changes highlighted in the blackline version of the proposed tariff in Appendix F is provided below.

1. **Cover Page:** The format of the cover page has been updated to be consistent with the approved BMDEU – UniverCity tariff and the proposed UBC NDES tariff.

2. **Cover Page:** The available location(s) for public inspection of the tariff has been revised to remove the physical office location and only includes the utility's website to facilitate remote work flexibility.

3. **Section A – Definitions:** Definition for "Application for Service" removed to provide flexibility to update the application form as necessary.

[25] UBC NDES 2025-2027 Revenue Requirements and Rates Application, Section 14.2, pp. 113-115; Appendix F.

4. **Section A – Definitions:** Definition for “Basic Charge” updated to provide clarity regarding the components of the charge.

5. **Section A – Definitions:** Definition for “Building” updated to provide improved clarity.

6. **Section A – Definitions:** Definition for “Customer Agreement” revised to remove “application for service” as a defined term.

7. **Section A – Definitions:** Definition for “Rate Schedule” updated to provide improved clarity.

8. **Section A – Definitions:** Definition for “Service Area” added to provide clarity and supporting context for the updated definition for “Basic Charge”.

9. **Section A – Definitions:** Definition for “Standard Fees and Charges Schedule” updated to provide improved clarity regarding third-party payment processing fees.

10. **Section A – Definitions:** Definition for “Utility” updated due to the restructuring.

11. **Section A – Definitions:** Definition for “Variable Energy Charge” updates to provide clarity regarding the components of the charge.

12. **Section B – 1. Application for Energy Services:** Wording updated to reflect policy of accepting written applications only and to remove “application for service” as a defined term. Wording added to provide the customer with the ability to submit a request to update the area (square meters) to which the Basic Charge is applied, providing it is accompanied by a legal survey. Wording updated to reflect the proposed update to the definition of “Building”.

13. **Section B – 3. Use of Thermal Energy:** Wording updated to reflect the proposed update to the definition of “Building”.

14. **Section B – 5. Ownership and Care of Thermal Energy System:** Wording updated to reflect the proposed update to the definition of “Building”.

15. **Section B – 6. Meter Reading:** Wording updated to reflect the preferred billing unit of kilowatt-hour (kWh) instead of gigajoule and rounding to the nearest two-tenths of the billing unit instead of one-tenth for increased accuracy.

16. **Section B – 7. Meter Testing:** Wording updated to improve clarity regarding meter testing.

17. **Section B – 8. Maintenance:** Wording updated to reflect the proposed update to the definition of “Building”.

18. **Section B – 12. Billing:** Wording updated to provide better clarity on the meter reading process upon Customer termination of a Customer Agreement and payment due dates and remove in-person payment at a designated office as an accepted payment method to facilitate remote work flexibility.

19. **Section B – 13. Back-Billing:** Wording updated to reference the interest rate on the Standard Fees and Charges schedule for use in circumstances resulting in under-billing due to the removal of the application for service form from the tariff.

20. **Section B – 14. Late Payment Charge And Collection Charge:** Wording revised to eliminate the requirement for additional bills outside of standard billing cycles.

21. **Section B – 15. Dishonoured Payments Charge:** Wording updated to reflect additional payment methods and to provide improved clarity surrounding dishonoured payments.

22. **Section B – 16. Refusal to Provide Energy Services and Discontinuance of Energy Services:** Wording updated to reflect the proposed update to the definition of "Building".

23. **Section B – 21. Liability:** Wording updated to reflect the commonly used methods of communication and reflect the proposed update to the definition of "Building".

24. **Section B – 22. Access to Buildings and Equipment:** Wording updated to reflect the proposed update to the definition of "Building" and provide improved clarity.

25. **Section B – 23. Curtailment of Energy Services:** Wording updated to reflect the commonly used methods of communication.

26. **Section B – 27. Rate Schedule:** The available location for inspection of the Rate Schedule has been revised to remove the physical office location and only include the utility's website to facilitate remote work flexibility.

27. **Section C – Rate Schedule:** Wording revised to align with the defined term for Basic Charge.

28. **Section D – Standard Fees and Charges Schedule:** Definition for Dishonoured Payments Charge revised to reflect the current charge to allow the utility to recover the actual amount of the fee incurred.

29. An update to the company name throughout the document to reflect the restructuring of the DGE from "Corix Multi-Utility Services Inc." to "Corix Dockside Green DE Limited Partnership".

30. An update to the layout of the footer on all pages to improve document revision efficiency.

The revision number for all pages within the Terms and Conditions have been increased by one (1) to reflect the above amendments, and also to account for the fact that the material on some pages have shifted to the previous/following page due to the changes outlined above.

Appendix A: Financial Schedules

Schedule	**Description**
Schedule 1	Revenue Requirement and RDDA Summary
Schedule 2	Revenue Requirements
Schedule 3	Rate Base
Schedule 4	Plant Continuity
Schedule 5	Utility Plant in Service and CIAC
Schedule 6	Depreciation and Amortization Rates
Schedule 7	Working Capital – Cash
Schedule 8	Rate Base Deferred Charges
Schedule 9	Non-Rate Base Deferred Charges
Schedule 10	Cost of Capital and Return on Rate Base
Schedule 11	Operating and Maintenance Costs; Property & Other Fees
Schedule 12	Energy Supply Costs
Schedule 13	Income Tax and Capital Cost Allowance
Schedule 14	Customer Count and Floor Area
Schedule 15	Customer Rates
Schedule 16	Estimated End-User Bill Impact
Schedule 17	Revenue
Schedule 18	Detailed Build-out Schedule (Confidential)
Schedule 19	Detailed Customer Bill Impact (Confidential)

Dockside Green Energy
2025-2028 Revenue Requirements and Rates Application
Schedule 1 - Revenue Requirement and RDDA Summary

Line No.	*All figures in $s*	Actual 2021	Actual 2022	Actual 2023	Actual 2024	Forecast 2025	Forecast 2026	Forecast 2027	Forecast 2028	Forecast 2029	Forecast 2030
1											
2	At Existing Rates										
3	Revenue Requirement[1]	315,447	739,129	484,715	649,562	830,714	1,151,638	1,197,976	1,265,155	1,337,003	1,401,966
4	Revenue at Existing Rates[1]	(165,598)	(128,210)	(305,173)	(326,784)	(331,226)	(331,226)	(331,226)	(331,226)	(331,226)	(386,045)
5	Revenue Shortfall / (Surplus)	149,849	610,919	179,542	322,778	499,488	820,412	866,750	933,929	1,005,777	1,015,922
6											
7	RDDA Opening Balance	(711,461)	(593,074)	(0)	184,388	531,256	1,050,423	1,870,835	2,737,585	3,671,514	4,677,291
8	RDDA Closing Balance[2]	(593,074)	(0)	184,388	531,256	1,050,423	1,870,835	2,737,585	3,671,514	4,677,291	5,693,213
9											
10	At Proposed Rates										
11	Revenue Requirement[1]					830,714	1,151,638	1,197,976	1,265,155	1,337,003	1,401,966
12	Revenue at Proposed Rates[1]					(380,910)	(538,242)	(618,978)	(693,256)	(769,514)	(939,723)
13	Revenue Shortfall / (Surplus)					449,804	613,396	578,997	571,899	567,489	462,243
14											
15	RDDA Opening Balance					531,256	1,000,739	1,614,135	2,193,132	2,765,031	3,332,520
16	RDDA Closing Balance[2]					1,000,739	1,614,135	2,193,132	2,765,031	3,332,520	3,794,764
17											

Notes

(1) Following BCUC approval to flow-through energy supply costs via G-248-19, from January 1, 2019 onwards the revenue requirements exclude energy supply costs and the revenue excludes Variable Energy Charge revenue.

(2) From 2018 to 2025, the RDDA Closing Balance explicitly includes the associated financing costs as shown in Schedule 9, Line 11. From July 1, 2026 onwards, the RDDA is in rate base. From this point onwards the associated financing costs is included within rate base financing costs and is not explicitly placed in the RDDA.

Dockside Green Energy
2025-2028 Revenue Requirements and Rates Application
Schedule 2 - Revenue Requirements

Line No.	**Revenue Requirements** *All figures in $s*	**Actual** 2021	**Actual** 2022	**Actual** 2023	**Actual** 2024	**Forecast** 2025	**Forecast** 2026	**Forecast** 2027	**Forecast** 2028	**Forecast** 2029	**Forecast** 2030
1											
2	Delivery Revenue Requirement[(1), (3)]										
3	Operating and Maintenance (O&M) Costs[(4), (5)]	190,245	356,096	296,986	394,074	497,916	615,231	623,178	643,432	679,225	688,535
4	Lease & Property Tax, Fees and Levies	-	339,462	33,122	33,785	145,383	151,299	157,457	163,865	170,047	176,462
5	Others & Adjustments[(6),(7)]	88,358	(62,081)	(23,331)	-	(106,790)	-	-	-	-	-
6	Subtotal	278,603	633,477	306,777	427,859	536,509	766,530	780,635	807,297	849,272	864,997
7											
8	Depreciation	12,586	55,402	77,923	86,728	111,080	113,183	102,376	100,243	89,302	100,758
9	Amortization	1,992	5,107	5,690	4,365	4,588	12,141	4,588	4,588	4,588	(13,701)
10	Subtotal Depreciation & Amortization	14,578	60,509	83,613	91,092	115,668	125,324	106,963	104,830	93,890	87,057
11											
12	Deemed Interest	9,023	18,294	38,223	52,928	64,700	100,260	119,786	136,246	151,997	173,637
13	Return on Equity	13,243	26,850	56,101	77,683	113,837	159,524	190,592	216,782	241,844	276,275
14	Subtotal Return on Rate Base	22,265	45,143	94,324	130,611	178,537	259,784	310,378	353,027	393,842	449,912
15											
16	Income tax	-	-	-	-	-	-	-	-	-	-
17											
18	**Total Delivery Revenue Requirement**	**315,447**	**739,129**	**484,715**	**649,562**	**830,714**	**1,151,638**	**1,197,976**	**1,265,155**	**1,337,003**	**1,401,966**
19											
20	Energy Supply Revenue Requirement[(2)]										
21	Heating Energy Supply Costs	133,410	170,047	213,420	209,556	217,178	219,380	219,041	222,693	227,147	258,900
22	**Total Energy Supply Revenue Requirement**	**133,410**	**170,047**	**213,420**	**209,556**	**217,178**	**219,380**	**219,041**	**222,693**	**227,147**	**258,900**
23											
24	**Total Revenue Requirement[(3)]**	**448,856**	**909,176**	**698,135**	**859,118**	**1,047,892**	**1,371,018**	**1,417,017**	**1,487,848**	**1,564,150**	**1,660,867**

Notes
(1) DGE seeks approval of 2025, 2026, 2027 and 2028 Delivery Revenue Requirements only. Delivery Revenue Requirements for 2029 onwards are indicative only.
(2) DGE does not seek approval of any Energy Supply Revenue Requirements. Energy Supply Revenue Requirements are indicative only.
(3) The distinction between a Delivery Revenue Requirement and an Energy Supply Revenue Requirement began on January 1, 2019 following BCUC approval to flow-through energy supply costs via BCUC Order G-248-19.
(4) Operating and Maintenance (O&M) costs include BCUC-approved overhead expenses.
(5) Operating and Maintenance (O&M) costs include actual property tax between 2018 and 2022; and BCUC-approved property tax in 2023 and 2024.
(6) 2019-2021 had differences between the revenue requirement and the revenue taken from the negative deferral that were partially reversed in 2022 and 2023
(7) In 2025 an initial balance adjustment was made to correct errors in the revenue requirement in previous years and the financing cost associated.

Dockside Green Energy
2025-2028 Revenue Requirements and Rates Application
Schedule 3 - Rate Base

Line No.	**Rate Base** *All figures in $s*	**Actual** 2021	**Actual** 2022	**Actual** 2023	**Actual** 2024	**Forecast** 2025	**Forecast** 2026	**Forecast** 2027	**Forecast** 2028	**Forecast** 2029	**Forecast** 2030
1											
2	**Gross Plant in Service**										
3	Balance at beginning of year	226,387	378,071	914,850	1,893,186	2,106,673	2,132,673	2,194,288	2,287,246	2,304,825	2,323,298
4	Balance at end of year	378,071	914,850	1,893,186	2,106,673	2,132,673	2,194,288	2,287,246	2,304,825	2,323,298	3,304,382
5	Mid-Year Plant in Service	302,229	646,461	1,404,018	1,999,930	2,119,673	2,163,480	2,240,767	2,296,035	2,314,061	2,813,840
6											
7	Plant Accumulated Depreciation										
8	Balance at beginning of year	8,955	23,533	84,042	167,656	258,748	374,416	492,186	599,150	703,980	797,870
9	Balance at end of year	23,533	84,042	167,656	258,748	374,416	492,186	599,150	703,980	797,870	903,216
10	Mid-Year Plant Accumulated Depreciation	16,244	53,788	125,849	213,202	316,582	433,301	545,668	651,565	750,925	850,543
11											
12	Net Mid-Year Plant in Service	285,985	592,673	1,278,169	1,786,728	1,803,091	1,730,179	1,695,099	1,644,470	1,563,136	1,963,297
13											
14											
15	**Gross Contributions in Aid of Construction (CIAC)**[(2)]										
16	Balance at beginning of year	-	-	-	-	-	-	-	-	-	-
17	Balance at end of year	-	-	-	-	-	-	-	-	-	609,627
18	Mid-Year CIAC	-	-	-	-	-	-	-	-	-	304,813
19											
20	CIAC Accumulated Amortization										
21	Balance at beginning of year	-	-	-	-	-	-	-	-	-	-
22	Balance at end of year	-	-	-	-	-	-	-	-	-	18,289
23	Mid-Year CIAC Accumulated Amortization	-	-	-	-	-	-	-	-	-	9,144
24											
25	Net Mid-Year Contributions in Aid of Construction	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**295,669**
26											
27	**Rate Base**										
28	Mid-Year Plant in Service *(net of CIAC)*	285,985	592,673	1,278,169	1,786,728	1,803,091	1,730,179	1,695,099	1,644,470	1,563,136	1,667,628
29	Mid-Year Rate Base Deferrals[(1)]	-	-	-	-	315,462	1,279,036	1,920,833	2,482,631	3,050,980	3,616,265
30	Working Capital	33,668	55,363	75,704	87,986	115,296	121,160	124,099	126,854	131,651	137,520
31											
32	**Mid-Year Rate Base**	**319,653**	**648,036**	**1,353,873**	**1,874,714**	**2,233,849**	**3,130,376**	**3,740,031**	**4,253,956**	**4,745,767**	**5,421,413**

Notes
(1) See Schedule 8 (Rate Base Deferrals) for details on the rate base deferrals.
(2) The Developer will install and fund the ETS for the remaining DGE buildings, with the first connection expected in 2030. Once commissioned, the ETS is transferred to Corix as a CIAC (See Section 8.6 of the Application).

Dockside Green Energy
2025-2028 Revenue Requirements and Rates Application
Schedule 4 - Plant Continuity and Net Book Value

Line No.	*All figures in $s*	Actual 2021	Actual 2022	Actual 2023	Actual 2024	Forecast 2025	Forecast 2026	Forecast 2027	Forecast 2028	Forecast 2029	Forecast 2030
1	Gross Plant										
2	Balance at Jan 1st	226,387	378,071	914,850	1,893,186	2,106,673	2,132,673	2,194,288	2,287,246	2,304,825	2,323,298
3	Additions	151,684	536,778	978,336	213,487	26,000	61,615	92,958	17,579	18,474	981,084
4	Retirements	-	-	-	-	-	-	-	-	-	-
5	Adjustments	-	-	-	-	-	-	-	-	-	-
6	Balance at Dec 31st	378,071	914,850	1,893,186	2,106,673	2,132,673	2,194,288	2,287,246	2,304,825	2,323,298	3,304,382
7											
8	Accumulated Depreciation										
9	Balance at Jan 1st	8,955	23,533	84,042	167,656	258,748	374,416	492,186	599,150	703,980	797,870
10	Depreciation Provision	14,578	60,509	83,613	91,092	115,668	117,771	106,963	104,830	93,890	105,346
11	Retirements	-	-	-	-	-	-	-	-	-	-
12	Adjustments	-	-	-	-	-	-	-	-	-	-
13	Balance at Dec 31st	23,533	84,042	167,656	258,748	374,416	492,186	599,150	703,980	797,870	903,216
14											
15	Net Book Value										
16	Balance at Jan 1st	217,433	354,538	830,807	1,725,531	1,847,925	1,758,257	1,702,101	1,688,096	1,600,845	1,525,428
17	Balance at Dec 31st	354,538	830,807	1,725,531	1,847,925	1,758,257	1,702,101	1,688,096	1,600,845	1,525,428	2,401,167
18											

Line No.	**2021 - Actual** Category	Gross Plant Balance as at Jan 1st	Additions (New)	Additions (R&R)	Retirements	Adjustments	Balance as at Dec 31st	Accum. Depreciation / Accum. Amortization Balance as at Jan 1st	Depreciation Provision	Retirements	Adjustments	Balance as at Dec 31st	Net Book Value Balance as at Jan 1st	Balance as at Dec 31st
1	**Utility Plant**													
2	Central Energy Plant (CEP) - Heating Plant	58,880	120,599	28,859	-	-	208,338	3,419	11,006	-	-	14,425	55,461	193,913
3	Distribution Piping System (DPS)	5,298	-	-	-	-	5,298	318	159	-	-	477	4,981	4,822
4	Energy Transfer Stations (ETS)	16,489	-	-	-	-	16,489	395	206	-	-	601	16,094	15,888
5	Vehicles	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Computer Hardware/Software	33,556	-	-	-	-	33,556	1,059	1,215	-	-	2,273	32,497	31,282
7	Proj. Dev.	112,164	2,226	-	-	-	114,390	3,765	1,992			5,757	108,400	108,634
8	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Subtotal Utility Plant	**226,387**	**122,825**	**28,859**	**-**	**-**	**378,071**	**8,955**	**14,578**	**-**	**-**	**23,533**	**217,433**	**354,538**
10	Studies & Reports	-	-	-	-	-	-	-	-	-	-	-	-	-
11	**Total Plant**	**226,387**	**122,825**	**28,859**	**-**	**-**	**378,071**	**8,955**	**14,578**	**-**	**-**	**23,533**	**217,433**	**354,538**
12														
13	**Contribution In Aid of Construction (CIAC)**													
14	Developer Contributions	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Grants	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Other CIACs	-	-	-	-	-	-	-	-	-	-	-	-	-
17	**Total CIAC**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
18														
19	**Total Net Plant After CIAC**	**226,387**	**122,825**	**28,859**	**-**	**-**	**378,071**	**8,955**	**14,578**	**-**	**-**	**23,533**	**217,433**	**354,538**

Line No.	**2022 - Actual** Category	Gross Plant Balance as at Jan 1st	Additions (New)	Additions (R&R)	Retirements	Adjustments	Balance as at Dec 31st	Accum. Depreciation / Accum. Amortization Balance as at Jan 1st	Depreciation Provision	Retirements	Adjustments	Balance as at Dec 31st	Net Book Value Balance as at Jan 1st	Balance as at Dec 31st
1	**Utility Plant**													
2	Central Energy Plant (CEP) - Heating Plant	208,338	536,778	-	-	-	745,116	14,425	53,731	-	-	68,156	193,913	676,960
3	Distribution Piping System (DPS)	5,298	-	-	-	-	5,298	477	159	-	-	636	4,822	4,663
4	Energy Transfer Stations (ETS)	16,489	-	-	-	-	16,489	601	206	-	-	807	15,888	15,682
5	Vehicles	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Computer Hardware/Software	33,556	-	-	-	-	33,556	2,273	1,306	-	-	3,580	31,282	29,976
7	Proj. Dev.	114,390	-	-	-	-	114,390	5,757	5,107			10,863	108,634	103,527
8	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Subtotal Utility Plant	**378,071**	**536,778**	**-**	**-**	**-**	**914,850**	**23,533**	**60,509**	**-**	**-**	**84,042**	**354,538**	**830,807**
10	Studies & Reports	-	-	-	-	-	-	-	-	-	-	-	-	-
11	**Total Plant**	**378,071**	**536,778**	**-**	**-**	**-**	**914,850**	**23,533**	**60,509**	**-**	**-**	**84,042**	**354,538**	**830,807**
12														
13	**Contribution In Aid of Construction (CIAC)**													
14	Developer Contributions	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Grants	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Other CIACs	-	-	-	-	-	-	-	-	-	-	-	-	-
17	**Total CIAC**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
18														
19	**Total Net Plant After CIAC**	**378,071**	**536,778**	**-**	**-**	**-**	**914,850**	**23,533**	**60,509**	**-**	**-**	**84,042**	**354,538**	**830,807**

Line No.	**2023 - Actual**	**Gross Plant**						**Accum. Depreciation / Accum. Amortization**					**Net Book Value**	
	Category	**Balance as at Jan 1st**	**Additions (New)**	**Additions (R&R)**	**Retirements**	**Adjustments**	**Balance as at Dec 31st**	**Balance as at Jan 1st**	**Depreciation Provision**	**Retirements**	**Adjustments**	**Balance as at Dec 31st**	**Balance as at Jan 1st**	**Balance as at Dec 31st**
1	**Utility Plant**													
2	Central Energy Plant (CEP) - Heating Plant	745,116	46,249	2,549	-	-	793,915	68,156	61,169	-	-	129,325	676,960	664,590
3	Distribution Piping System (DPS)	5,298	423,428	360,531	-	-	789,257	636	9,461	-	-	10,097	4,663	779,160
4	Energy Transfer Stations (ETS)	16,489	46,387	81,521	-	-	144,396	807	2,762	-	-	3,570	15,682	140,827
5	Vehicles	-	6,968	-	-	-	6,968	-	-	-	-	-	-	6,968
6	Computer Hardware/Software	33,556	10,404	-	-	-	43,960	3,580	3,370	-	-	6,949	29,976	37,011
7	Proj. Dev.	114,390	299	-	-	-	114,690	10,863	5,690			16,553	103,527	98,137
8	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Subtotal Utility Plant	**914,850**	**533,736**	**444,600**	**-**	**-**	**1,893,186**	**84,042**	**82,452**	**-**	**-**	**166,494**	**830,807**	**1,726,692**
10	Studies & Reports	-	-	-	-	-	-	-	-	-	-	-	-	-
11	**Total Plant**	**914,850**	**533,736**	**444,600**	**-**	**-**	**1,893,186**	**84,042**	**82,452**	**-**	**-**	**166,494**	**830,807**	**1,726,692**
12														
13	**Contribution In Aid of Construction (CIAC)**													
14	Developer Contributions	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Grants	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Other CIACs	-	-	-	-	-	-	-	-	-	-	-	-	-
17	**Total CIAC**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
18														
19	**Total Net Plant After CIAC**	**914,850**	**533,736**	**444,600**	**-**	**-**	**1,893,186**	**84,042**	**82,452**	**-**	**-**	**166,494**	**830,807**	**1,726,692**

Line No.	**2024 - Actual**	**Gross Plant**						**Accum. Depreciation / Accum. Amortization**					**Net Book Value**	
	Category	**Balance as at Jan 1st**	**Additions (New)**	**Additions (R&R)**	**Retirements**	**Adjustments**	**Balance as at Dec 31st**	**Balance as at Jan 1st**	**Depreciation Provision**	**Retirements**	**Adjustments**	**Balance as at Dec 31st**	**Balance as at Jan 1st**	**Balance as at Dec 31st**
1	**Utility Plant**													
2	Central Energy Plant (CEP) - Heating Plant	793,915	(1,290)	157,023	-	-	949,647	129,325	56,837	-	-	186,162	664,590	763,486
3	Distribution Piping System (DPS)	789,257	7,847	14,783	-	-	811,887	10,097	16,174	-	-	26,271	779,160	785,616
4	Energy Transfer Stations (ETS)	144,396	1,088	34,036	-	-	179,521	3,570	7,305	-	-	10,874	140,827	168,647
5	Vehicles	6,968	-	-	-	-	6,968	-	5,516	-	-	5,516	6,968	1,452
6	Computer Hardware/Software	43,960	-	-	-	-	43,960	6,949	2,057	-	-	9,006	37,011	34,954
7	Proj. Dev.	114,690	-	-	-	-	114,690	16,553	4,365		-	20,918	98,137	93,772
8	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Subtotal Utility Plant	**1,893,186**	**7,645**	**205,842**	**-**	**-**	**2,106,673**	**166,494**	**92,253**	**-**	**-**	**258,748**	**1,726,692**	**1,847,925**
10	Studies & Reports	-	-	-	-	-	-	-	-	-	-	-	-	-
11	**Total Plant**	**1,893,186**	**7,645**	**205,842**	**-**	**-**	**2,106,673**	**166,494**	**92,253**	**-**	**-**	**258,748**	**1,726,692**	**1,847,925**
12														
13	**Contribution In Aid of Construction (CIAC)**													
14	Developer Contributions	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Grants	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Other CIACs	-	-	-	-	-	-	-	-	-	-	-	-	-
17	**Total CIAC**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
18														
19	**Total Net Plant After CIAC**	**1,893,186**	**7,645**	**205,842**	**-**	**-**	**2,106,673**	**166,494**	**92,253**	**-**	**-**	**258,748**	**1,726,692**	**1,847,925**

Dockside Green Energy
2025-2028 Revenue Requirements and Rates Application
Schedule 5 - Utility Plant in Service

Line No.	**2025 - Forecast** Category	Gross Plant Balance as at Jan 1st	Gross Plant Additions (New)	Gross Plant Additions (R&R)	Gross Plant Retirements	Gross Plant Adjustments	Gross Plant Balance as at Dec 31st	Accum. Depreciation / Accum. Amortization Balance as at Jan 1st	Accum. Depreciation / Accum. Amortization Depreciation Provision	Accum. Depreciation / Accum. Amortization Retirements	Accum. Depreciation / Accum. Amortization Adjustments	Accum. Depreciation / Accum. Amortization Balance as at Dec 31st	Net Book Value Balance as at Jan 1st	Net Book Value Balance as at Dec 31st
1	**Utility Plant**													
2	Central Energy Plant (CEP) - Heating Plant	949,647	-	21,000	-	-	970,647	186,162	73,291	-	-	259,453	763,486	711,194
3	Distribution Piping System (DPS)	811,887	-	-	-	-	811,887	26,271	16,238	-	-	42,509	785,616	769,378
4	Energy Transfer Stations (ETS)	179,521	-	-	-	-	179,521	10,874	7,181	-	-	18,055	168,647	161,466
5	Vehicles	6,968	-	-	-	-	6,968	5,516	1,394	-	-	6,910	1,452	58
6	Computer Hardware/Software	43,960	-	-	-	-	43,960	9,006	12,877	-	-	21,883	34,954	22,077
7	Proj. Dev.	114,690	-	-	-	-	114,690	20,918	4,588			25,505	93,772	89,184
8	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Subtotal Utility Plant	**2,106,673**	**-**	**21,000**	**-**	**-**	**2,127,673**	**258,748**	**115,568**	**-**	**-**	**374,316**	**1,847,925**	**1,753,357**
10	Studies & Reports	-	5,000	-	-	-	5,000	-	100	-	-	100	-	4,900
11	**Total Plant**	**2,106,673**	**5,000**	**21,000**	**-**	**-**	**2,132,673**	**258,748**	**115,668**	**-**	**-**	**374,416**	**1,847,925**	**1,758,257**
12														
13	**Contribution In Aid of Construction (CIAC)**													
14	Developer Contributions	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Grants	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Other CIACs	-	-	-	-	-	-	-	-	-	-	-	-	-
17	**Total CIAC**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
18														
19	**Total Net Plant After CIAC**	**2,106,673**	**5,000**	**21,000**	**-**	**-**	**2,132,673**	**258,748**	**115,668**	**-**	**-**	**374,416**	**1,847,925**	**1,758,257**

Line No.	**2026 - Forecast** Category	Gross Plant Balance as at Jan 1st	Gross Plant Additions (New)	Gross Plant Additions (R&R)	Gross Plant Retirements	Gross Plant Adjustments	Gross Plant Balance as at Dec 31st	Accum. Depreciation / Accum. Amortization Balance as at Jan 1st	Accum. Depreciation / Accum. Amortization Depreciation Provision	Accum. Depreciation / Accum. Amortization Retirements	Accum. Depreciation / Accum. Amortization Adjustments	Accum. Depreciation / Accum. Amortization Balance as at Dec 31st	Net Book Value Balance as at Jan 1st	Net Book Value Balance as at Dec 31st
1	**Utility Plant**													
2	Central Energy Plant (CEP) - Heating Plant	970,647	-	23,541	-	-	994,188	259,453	74,092	-	-	333,545	711,194	660,643
3	Distribution Piping System (DPS)	811,887	-	-	-	-	811,887	42,509	16,238	-	-	58,747	769,378	753,140
4	Energy Transfer Stations (ETS)	179,521	-	32,957	-	-	212,477	18,055	7,840	-	-	25,895	161,466	186,582
5	Vehicles	6,968	-	-	-	-	6,968	6,910	58	-	-	6,968	58	-
6	Computer Hardware/Software	43,960	-	-	-	-	43,960	21,883	14,653	-	-	36,537	22,077	7,424
7	Proj. Dev.	114,690	-	-	-	-	114,690	25,505	4,588			30,093	89,184	84,597
8	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Subtotal Utility Plant	**2,127,673**	**-**	**56,497**	**-**	**-**	**2,184,170**	**374,316**	**117,468**	**-**	**-**	**491,784**	**1,753,357**	**1,692,386**
10	Studies & Reports	5,000	5,118	-	-	-	10,118	100	302	-	-	402	4,900	9,715
11	**Total Plant**	**2,132,673**	**5,118**	**56,497**	**-**	**-**	**2,194,288**	**374,416**	**117,771**	**-**	**-**	**492,186**	**1,758,257**	**1,702,101**
12														
13	**Contribution In Aid of Construction (CIAC)**													
14	Developer Contributions	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Grants	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Other CIACs	-	-	-	-	-	-	-	-	-	-	-	-	-
17	**Total CIAC**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
18														
19	**Total Net Plant After CIAC**	**2,132,673**	**5,118**	**56,497**	**-**	**-**	**2,194,288**	**374,416**	**117,771**	**-**	**-**	**492,186**	**1,758,257**	**1,702,101**

Line No.	**2027 - Forecast** Category	Gross Plant Balance as at Jan 1st	Gross Plant Additions (New)	Gross Plant Additions (R&R)	Gross Plant Retirements	Gross Plant Adjustments	Gross Plant Balance as at Dec 31st	Accum. Depreciation / Accum. Amortization Balance as at Jan 1st	Accum. Depreciation / Accum. Amortization Depreciation Provision	Accum. Depreciation / Accum. Amortization Retirements	Accum. Depreciation / Accum. Amortization Adjustments	Accum. Depreciation / Accum. Amortization Balance as at Dec 31st	Net Book Value Balance as at Jan 1st	Net Book Value Balance as at Dec 31st
1	**Utility Plant**													
2	Central Energy Plant (CEP) - Heating Plant	994,188	-	87,736	-	-	1,081,924	333,545	76,018	-	-	409,562	660,643	672,361
3	Distribution Piping System (DPS)	811,887	-	-	-	-	811,887	58,747	12,178	-	-	70,925	753,140	740,962
4	Energy Transfer Stations (ETS)	212,477	-	-	-	-	212,477	25,895	6,374	-	-	32,269	186,582	180,208
5	Vehicles	6,968	-	-	-	-	6,968	6,968	-	-	-	6,968	-	-
6	Computer Hardware/Software	43,960	-	-	-	-	43,960	36,537	7,424	-	-	43,960	7,424	-
7	Proj. Dev.	114,690	-	-	-	-	114,690	30,093	4,588			34,681	84,597	80,009
8	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Subtotal Utility Plant	**2,184,170**	**-**	**87,736**	**-**	**-**	**2,271,906**	**491,784**	**106,582**	**-**	**-**	**598,365**	**1,692,386**	**1,673,541**
10	Studies & Reports	10,118	5,222	-	-	-	15,340	402	382	-	-	784	9,715	14,556
11	**Total Plant**	**2,194,288**	**5,222**	**87,736**	**-**	**-**	**2,287,246**	**492,186**	**106,963**	**-**	**-**	**599,150**	**1,702,101**	**1,688,096**
12														
13	**Contribution In Aid of Construction (CIAC)**													
14	Developer Contributions	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Grants	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Other CIACs	-	-	-	-	-	-	-	-	-	-	-	-	-
17	**Total CIAC**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
18														
19	**Total Net Plant After CIAC**	**2,194,288**	**5,222**	**87,736**	**-**	**-**	**2,287,246**	**492,186**	**106,963**	**-**	**-**	**599,150**	**1,702,101**	**1,688,096**

Line No.	**2028 - Forecast** Category	Gross Plant Balance as at Jan 1st	Gross Plant Additions (New)	Gross Plant Additions (R&R)	Gross Plant Retirements	Gross Plant Adjustments	Gross Plant Balance as at Dec 31st	Accum. Depreciation / Accum. Amortization Balance as at Jan 1st	Accum. Depreciation / Accum. Amortization Depreciation Provision	Accum. Depreciation / Accum. Amortization Retirements	Accum. Depreciation / Accum. Amortization Adjustments	Accum. Depreciation / Accum. Amortization Balance as at Dec 31st	Net Book Value Balance as at Jan 1st	Net Book Value Balance as at Dec 31st
1	**Utility Plant**													
2	Central Energy Plant (CEP) - Heating Plant	1,081,924	-	12,252	-	-	1,094,175	409,562	81,150	-	-	490,712	672,361	603,463
3	Distribution Piping System (DPS)	811,887	-	-	-	-	811,887	70,925	12,178	-	-	83,103	740,962	728,783
4	Energy Transfer Stations (ETS)	212,477	-	-	-	-	212,477	32,269	6,374	-	-	38,644	180,208	173,834
5	Vehicles	6,968	-	-	-	-	6,968	6,968	-	-	-	6,968	-	-
6	Computer Hardware/Software	43,960	-	-	-	-	43,960	43,960	-	-	-	43,960	-	-
7	Proj. Dev.	114,690	-	-	-	-	114,690	34,681	4,588			39,268	80,009	75,422
8	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Subtotal Utility Plant	**2,271,906**	**-**	**12,252**	**-**	**-**	**2,284,158**	**598,365**	**104,290**	**-**	**-**	**702,656**	**1,673,541**	**1,581,502**
10	Studies & Reports	15,340	5,327	-	-	-	20,667	784	540	-	-	1,324	14,556	19,342
11	**Total Plant**	**2,287,246**	**5,327**	**12,252**	**-**	**-**	**2,304,825**	**599,150**	**104,830**	**-**	**-**	**703,980**	**1,688,096**	**1,600,845**
12														
13	**Contribution In Aid of Construction (CIAC)**													
14	Developer Contributions	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Grants	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Other CIACs	-	-	-	-	-	-	-	-	-	-	-	-	-
17	**Total CIAC**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
18														
19	**Total Net Plant After CIAC**	**2,287,246**	**5,327**	**12,252**	**-**	**-**	**2,304,825**	**599,150**	**104,830**	**-**	**-**	**703,980**	**1,688,096**	**1,600,845**

Notes

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Dockside Green Energy
2025-2028 Revenue Requirements and Rates Application
Schedule 6 - Depreciation and Amortization Rates

Line No.	Category	Existing Rate	Life (Years)	Rate from Jan 1, 2027[3]	Life (Years) From Jan 1, 2027	Examples
1	**Utility Plant**					
2	Building	2.0%	50.00	2.0%	50.00	Building, building structures and improvements
3	Plant- TEC	6.7%	15.00	6.7%	15.00	Natural gas general structure, boiler breeching, gas trains
4	Plant- TEC- 5-years-life components	20.0%	5.00	20.0%	5.00	Pumps
5	Plant- TEC - 10-years-life components	10.0%	10.00	10.0%	10.00	Heat Exchangers, boiler circulation pumps, boiler management system
6	Plant- TEC- 15-years-life components	6.7%	15.00	6.7%	15.00	Commercial boilers, Industrial boilers, regulators
7	DPS[2]	2.0%	50.00	1.5%	66.67	Distribution pipes; Service lines
8	ETS[2]	4.0%	25.00	3.0%	33.33	Energy Transfer Station (ETS) main structure, Heat Exchangers, valves
9	ETS - 5-years-life components	20.0%	5.00	20.0%	5.00	Control panel
10	Other	4.0%	25.00	4.0%	25.00	Engineering studies.
11	Vehicles	20.0%	5.00	20.0%	5.00	Vehicles
12	Computer - Software	33.3%	3.00	33.3%	3.00	Computer software
13	Computer - Hardware	20.0%	5.00	20.0%	5.00	Computer and peripherals
14	Office Furniture and Equipment	10.0%	10.00	10.0%	10.00	Office furniture and equipment
15	Communication Equipment	20.0%	5.00	20.0%	5.00	Supervisory Control and Data Acquisition (SCADA)
16	Miscellaneous Equipment	20.0%	5.00	20.0%	5.00	Other equipment
17	Tools, Shop and Garage Equipment	20.0%	5.00	20.0%	5.00	Tools, shop and garage equipment
18	Project Development costs	4.0%	25.00	4.0%	25.00	Project develompent and startup cost
19						
20						
21	**Contribution In Aid of Construction (CIAC)**					
22	Developer Contributions	3.0%	33.33	3.0%	33.33	
23	Grants	3.0%	33.33	3.0%	33.33	
24	Other CIACs	3.0%	33.33	3.0%	33.33	

Notes
(1) The list of examples is intended to provide examples of category components and is not to be considered as an exhaustive list of all applicable components.
(2) Corix has reviewed the expected service life of ETS and DPS assets in DGE by comparing them with similar assets in its other utilities, BMDEU and UBC NDES. The analysis found no evidence suggesting that DGE assets have a shorter expected lifespan. As a result, Corix plans to align the expected life of ETS and DPS assets in DGE with its standard asset life assumptions.
(3) Corix will start new rates on January 1st of the year following BCUC final decision of this application (estimated in 2026).

Dockside Green Energy
2025-2028 Revenue Requirements and Rates Application
Schedule 7 - Working Capital

Line No.	*All figures in $s*	**Actual** 2021	**Actual** 2022	**Actual** 2023	**Actual** 2024	**Forecast** 2025	**Forecast** 2026	**Forecast** 2027	**Forecast** 2028	**Forecast** 2029	**Forecast** 2030
1											
2	Energy Supply Costs(1)	-	-	213,420	354,460	309,357	219,380	219,041	222,693	227,147	258,900
3	Operating & Maintenance Costs (2)	190,245	356,096	177,919	394,074	497,916	615,231	623,178	643,432	679,225	688,535
4	Lease & Property Tax, Fees and Levies	-	339,462	124,362	143,540	145,383	151,299	157,457	163,865	170,047	176,462
5	**Total for Working Capital**	**190,245**	**695,558**	**515,700**	**892,075**	**952,656**	**985,911**	**999,676**	**1,029,990**	**1,076,419**	**1,123,897**
6											
7	Revenue Lag (days)	45	45	45	45	45	45	45	45	45	45
8											
9	Working Capital(1)	23,781	86,945	64,462	111,509	119,082	123,239	124,959	128,749	134,552	140,487
10	Other working capital				-	-	-	-	-	-	-
11	**Mid-Year Working Capital(2)**	**33,668**	**55,363**	**75,704**	**87,986**	**115,296**	**121,160**	**124,099**	**126,854**	**131,651**	**137,520**

Notes
(1) Energy costs were inadvertently excluded from working capital calculation in 2021 and 2022
(2) Overhead was inadvertently excluded from working capital calculation in 2023

Dockside Green Energy
2025-2028 Revenue Requirements and Rates Application
Schedule 8 - Rate Base Deferrals

Line No.	*All figures in $s*	Actual 2021	Actual 2022	Actual 2023	Actual 2024	Forecast 2025	Forecast 2026	Forecast 2027	Forecast 2028	Forecast 2029	Forecast 2030
1	**(1) Revenue Deficiency Deferral Account (RDDA) (1)**										
2	Balance at Jan 1st (Opening Balance)					630,924	1,000,739	1,614,135	2,193,132	2,765,031	3,332,520
3											
4	Additions/Reductions (2)										
5	Revenue Requirement					585,112	1,151,638	1,197,976	1,265,155	1,337,003	1,401,966
6	Revenue Billed					(215,297)	(538,242)	(618,978)	(693,256)	(769,514)	(939,723)
7	Revenue Deficiency / (Surplus)					369,815	613,396	578,997	571,899	567,489	462,243
8											
9	Adjustments					-	-	-	-	-	-
10	Less Taxes					-	-	-	-	-	-
11	Net Change in RDDA					369,815	613,396	578,997	571,899	567,489	462,243
12											
13	**Balance at Dec 31st (Closing Balance)**					**1,000,739**	**1,614,135**	**2,193,132**	**2,765,031**	**3,332,520**	**3,794,764**
14											
15	**(2) Regulatory Cost Variance Account (RCVA) *(3)***										
16	Balance at Jan 1st (Opening Balance)					-	-	-	-	-	-
17											
18	Additions					12,818	16,192	1,058	1,332	17,595	1,386
19	Reductions					(12,818)	(16,192)	(1,058)	(1,332)	(17,595)	(1,386)
20	Adjustments					-	-	-	-	-	-
21	Less Taxes					-	-	-	-	-	-
22	Net Additions					-	-	-	-	-	-
23	Amortization					-	-	-	-	-	-
24	**Balance at Dec 31st (Closing Balance)**					**-**	**-**	**-**	**-**	**-**	**-**
25											
26	**(3) Insurance Cost Variance Account (ICVA) (4)**										
27	Balance at Jan 1st (Opening Balance)					-	-	-	-	-	-
28											
29	Additions					46,915	51,363	56,534	60,077	62,339	69,287
30	Reductions					(46,915)	(51,363)	(56,534)	(60,077)	(62,339)	(69,287)
31	Adjustments					-	-	-	-	-	-
32	Less Taxes					-	-	-	-	-	-
33	Net Additions					-	-	-	-	-	-
34	Amortization					-	-	-	-	-	-
35	**Balance at Dec 31st (Closing Balance)**					**-**	**-**	**-**	**-**	**-**	**-**

36							
37	**(3) Property Tax Deferral Account (PTDA)** [5]						
38	Balance at Jan 1st (Opening Balance)	-	-	-	-	-	-
39							
40	Additions	145,383	151,299	157,457	163,865	170,047	176,462
41	Reductions	(145,383)	(151,299)	(157,457)	(163,865)	(170,047)	(176,462)
42	Adjustments	-	-	-	-	-	-
43	Less Taxes	-	-	-	-	-	-
44	Net Additions	-	-	-	-	-	-
45	Amortization	-	-	-	-	-	-
46	**Balance at Dec 31st (Closing Balance)**	**-**	**-**	**-**	**-**	**-**	**-**
47							

Notes

(1) In this Application, Corix presents commencing July 1, 2025 the RDDA as a rate base account. The RDDA balance of $630,924 is both the June 30, 2025 closing balance (non-rate base) and the July 1, 2025 opening balance (rate base). Please refer to Schedule 9 (Non-Rate Base Deferrals) for the RDDA balances prior to July 1, 2025.

(2) Effective January 1, 2019, the RDDA excludes Energy Supply Costs and revenue from the Variable Energy Charge.

(3) The proposed RCVA will address the variance between actual and forecast external regulatory costs, including but not limited to BCUC annual levies, BCUC proceeding costs, intervener costs and external consulting/legal costs.

(4) The proposed ICVA will address the variance between actual and forecast insurance costs.

(5) In this Applicaction, Corix moved from a non-rate base deferral account to a rate base deferral account and beginning with a $0 balance. The PTDA addresses the variance between actual and forecast property tax costs.

Dockside Green Energy
2025-2028 Revenue Requirements and Rates Application
Schedule 9 - Non-Rate Base Deferrals

Line No.	*All figures in $s*	Actual 2018	Actual 2019	Actual 2020	Actual 2021	Actual 2022	Actual 2023	Actual 2024	Forecast 2025	Forecast 2026	Forecast 2027	Forecast 2028	Forecast 2029	Forecast 2030
1	**(1) Revenue Deficiency Deferral Account (RDDA)**													
2	Balance at Jan 1st (Opening Balance)	(1,000,000)	(989,401)	(806,130)	(711,461)	(593,074)	(0)	184,388	531,256					
3														
4	Additions/Reductions (2)													
5	Revenue Requirement	115,838	467,650	361,594	227,088	801,211	508,046	649,562	352,392					
6	Revenue Billed	(90,513)	(243,243)	(252,057)	(165,598)	(128,210)	(305,173)	(326,784)	(165,613)					
7	Revenue Deficiency / (Surplus)	25,325	224,407	109,536	61,490	673,000	202,873	322,778	186,779					
8														
9	Adjustments(3)	-	12,892	30,755	88,358	(62,081)	(23,331)	-	(106,790)					
10	Less Taxes	-	-	-	-	-	-	-	-					
11	RDDA Financing Costs(6)	(14,726)	(54,028)	(45,622)	(31,461)	(17,846)	4,846	24,090	19,679					
12	Net Change in RDDA	10,599	183,271	94,669	118,387	593,073	184,388	346,868	99,668					
13														
14	**Balance at Dec 31st (Closing Balance) (1)**	**(989,401)**	**(806,130)**	**(711,461)**	**(593,074)**	**(0)**	**184,388**	**531,256**	**630,924**					
15														
16	**(2) Energy Cost Reconciliation Account (ECRA)(2)**													
17	Balance at Jan 1st (Opening Balance)	-	-	2,247	10,404	6,972	7,594	(22,186)	(55,330)	(32,634)	-	-	-	-
18														
19	Additions	24,617	112,733	115,268	133,410	170,047	213,420	209,556	217,178	219,380	219,041	222,693	227,147	258,900
20	Reductions	(24,617)	(110,486)	(107,111)	(136,842)	(169,425)	(243,199)	(242,700)	(194,482)	(186,746)	(219,041)	(222,693)	(227,147)	(258,900)
21	Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Less Taxes	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Net Additions	-	2,247	8,158	(3,432)	622	(29,780)	(33,144)	22,696	32,634	-	-	-	-
24	Amortization								-	-	-	-	-	-
25	**Balance at Dec 31st (Closing Balance)**	**-**	**2,247**	**10,404**	**6,972**	**7,594**	**(22,186)**	**(55,330)**	**(32,634)**	**-**	**-**	**-**	**-**	**-**
26														
27	**(3) GCOC Variance Deferral Account (GCOC VDA)(5)**													
28	Balance at Jan 1st (Opening Balance)							-	6,994	7,553	-			
29														
30	Additions - Rate Base Financing Costs (excl. RDDA)							6,738	-	-	-			
31	Additions - RDDA Financing Costs							-	-	-	-			
32	Financing cost							256	559	-	-			
33	Adjustments							-	-	-	-			
34														
35	Net Additions							6,994	559	-	-			
36	Amortization							-	-	(7,553)	-			
37	**Balance at Dec 31st (Closing Balance)**							**6,994**	**7,553**	**-**	**-**			
38														

39													
40	**(4) PROPERTY TAX DEFERRAL ACCOUNT (PTDA)[6]**												
41	Balance at Jan 1st (Opening Balance)							94,070	141,904	17,563	(30)	0	0
42													
43	Additions	-	-	-	-	-	91,239	109,756	-	-	-	-	
44	Financing cost	-	-	-	-	-	2,831	8,639	6,128	699	(1)	0	
45	Adjustments	-	-	-	-	-	-	-	-	-	-	-	
46													
47	Net Additions						94,070	118,394	6,128	699	(1)		
48	Amortization	-	-	-	-	-	-	(70,560)	(130,469)	(18,292)	31	-	
49	**Balance at Dec 31st (Closing Balance)**						**94,070**	**141,904**	**17,563**	**(30)**	**0**	**0**	
50													

Notes

(1) In this Application, Corix presents commencing July 1, 2025 the RDDA as a rate base account. The RDDA balance of $630,924 is both the June 30, 2025 closing balance (non-rate base) and the July 1, 2025 opening balance (rate base). Please refer to Schedule 8 (Rate Base Deferrals) for the RDDA balances from July 1, 2026 onwards.

(2) Effective January 1, 2019, the RDDA excludes Energy Supply Costs and revenue from the Variable Energy Charge.

(3) Please refer to notes 6 and 7 on Schedule 2 (Revenue Requirements) for an explanation of the adjustments.

(4) RDDA Financing costs are calculated here since the RDDA is outside of rate base from 2015 to 2025 inclusive.

(5) BCUC Decision and Order G-321-24 directed Corix to establish a new GCOC Variance Deferral Account, attracting WACC, to record the variance between the previously established 2024 interim rates and the rates that would reflect the new cost of capital, effective January 1, 2024 under G-321-24.

(6) Per BCUC Order G-225-23, Corix established a non-rate base PTDA for DGE to track annual variances between approved and actual property taxes from 2023 onward, with interest at DGE's weighted average cost of capital. The PTDA balance is currently recovered through Rate Rider 1, which is proposed to be discontinued, with future variances to be amortized in the next DGE Rate Application (see Section 10.4.1)

Dockside Green Energy
2025-2028 Revenue Requirements and Rates Application
Schedule 10 - Cost of Capital and Return on Rate Base

Line No.	*All figures in $s*	Actual 2021	Actual 2022	Actual 2023	Actual 2024	Forecast 2025	Forecast 2026	Forecast 2027	Forecast 2028	Forecast 2029	Forecast 2030
1	Deemed Capital Structure[(1),(2)]										
2	Debt Ratio (Debt %)	57.5%	57.5%	57.5%	57.5%	51.0%	51.0%	51.0%	51.0%	51.0%	51.0%
3	Equity Ratio (Equity %)	42.5%	42.5%	42.5%	42.5%	49.0%	49.0%	49.0%	49.0%	49.0%	49.0%
4	Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
5											
6	Cost of Capital - Rates[(1),(2)]										
7	Deemed Debt Interest Rate[(3)]	4.91%	4.91%	4.91%	4.91%	5.68%	6.28%	6.28%	6.28%	6.28%	6.28%
8	Return on Equity (Benchmark Utility)	8.75%	8.75%	8.75%	8.75%	9.65%	9.65%	9.65%	9.65%	9.65%	9.65%
9	Equity Risk Premium (ERP)	1.00%	1.00%	1.00%	1.00%	0.75%	0.75%	0.75%	0.75%	0.75%	0.75%
10	Return on Equity (Allowed)	9.75%	9.75%	9.75%	9.75%	10.40%	10.40%	10.40%	10.40%	10.40%	10.40%
11											
12	**Mid-Year Rate Base ($)[(4)]**	**319,653**	**648,036**	**1,353,873**	**1,874,714**	**2,233,849**	**3,130,376**	**3,740,031**	**4,253,956**	**4,745,767**	**5,421,413**
13											
14	**Capital Financing**										
15	Debt ($)	183,801	372,620	778,477	1,077,960	1,139,263	1,596,492	1,907,416	2,169,517	2,420,341	2,764,921
16	Equity ($)	135,853	275,415	575,396	796,753	1,094,586	1,533,884	1,832,615	2,084,438	2,325,426	2,656,493
17	Total Capital Financing ($)	319,653	648,036	1,353,873	1,874,714	2,233,849	3,130,376	3,740,031	4,253,956	4,745,767	5,421,413
18											
19	**Cost of Capital ($)**										
20	Deemed Interest on Debt ($)	9,023	18,294	38,223	52,928	64,700	100,260	119,786	136,246	151,997	173,637
21	Return on Equity ($)	13,243	26,850	56,101	77,683	113,837	159,524	190,592	216,782	241,844	276,275
22	**Total Cost of Capital on Rate Base ($)**	**22,265**	**45,143**	**94,324**	**130,611**	**178,537**	**259,784**	**310,378**	**353,027**	**393,842**	**449,912**

Notes

(1) This Application reflects updated rates effective January 1, 2025 Accepted for filing on March 27, 2025 which accounted for changes to the cost of capital pursuant to Decision and Order G-321-24, issued on November 29, 2024

(2) The changes to the deemed capital structure and the allowed return on equity are effective January 1, 2024. In order to correctly reflect the balance in the GCOC VDA (See Schedule 9), the 2024 figures are held at the previous figures and the 2024 variance in cost of capital due to the difference between the previous figures and those approved through G-321-24 is captured in the GCOC VDA.

(3) Corix is updating the deemed interest rate effective July 1, 2025 to 6.28%, as per BCUC Order G-321-24. This results in a 2025 blended rate of 5.68%, combining the previously approved 4.91% approved by Order G-248-18, with the proposed 6.28% in this Application (See Section 9.2.3.3)

(4) In this Application, Corix presents commencing July 1, 2025 the RDDA as a rate base account rather than a non-rate base account attracting financing costs at the weighted average cost of capital. See Schedule 3 (Rate Base) and Schedule 8 (Rate Base Deferrals) for details.

Dockside Green Energy
2025-2028 Revenue Requirements and Rates Application
Schedule 11 - Operating and Maintenance Costs; Land Lease, Property Taxes, Fees and Levies

Line No.	*All figures in $s*	Actual 2021	Actual 2022	Actual 2023	Actual 2024	Forecast 2025	Forecast 2026	Forecast 2027	Forecast 2028	Forecast 2029	Forecast 2030
1											
2	**Operating and Maintenance (O&M) Costs** [3],[4]										
3	Operating Labour	23,533	119,415	111,362	134,442	135,162	139,217	143,393	147,695	152,126	156,690
4	Repair and Maintenance	16,367	38,155	24,416	44,450	40,160	41,104	41,947	42,786	43,641	49,520
5	Maintenance (Unforeseen)[1]	-	-	-	-	-	-	-	-	-	-
6	Permits and Licenses	100	1,144	631	1,336	1,828	1,871	1,909	1,947	1,986	2,026
7	Chemicals/Water Treatment	2,868	2,859	2,220	2,376	2,220	2,272	2,319	2,365	2,412	2,461
8	Operating expenses	5,722	19,973	12,715	13,328	21,942	18,084	18,735	19,165	19,605	20,056
9	Insurance	14,166	12,815	23,138	54,196	46,915	51,363	56,534	60,077	62,339	69,287
10	Billing (Service Provider)[2]	-	-	-	4,547	8,526	8,727	8,906	9,084	9,265	9,451
11	Office and Other Expenses	3,277	3,071	3,088	7,305	9,810	8,505	8,680	8,853	9,030	9,211
12	External Regulatory Costs	265	227	349	8,216	12,818	16,192	1,058	1,332	17,595	1,386
13	Regulatory Affairs	11,644	9,327	15,278	20,783	28,008	29,052	29,962	30,948	31,974	32,613
14	Health, Safety and Environment	7,462	5,977	9,791	13,319	7,252	7,491	7,734	7,992	8,263	8,428
15	Financing Planning & Analysis & Accounts Payable	13,756	11,019	18,050	24,554	36,059	37,444	38,693	39,975	41,318	42,144
16	Business Operations	7,800	6,249	10,235	13,923	24,708	25,789	26,697	27,616	28,600	29,172
17	Billing and Customer Care	3,509	2,811	4,604	6,263	9,168	9,487	9,818	10,170	10,554	10,765
18	Operations Leadership and Strategy	28,397	22,747	37,260	50,687	50,712	54,847	57,167	58,726	60,345	61,552
19	Project Management Office	-	-	-	-	-	-	-	-	-	-
20	People and Culture	4,910	8,098	9,162	14,734	27,224	28,864	29,474	30,411	31,397	32,025
21	IT, OT & Cybersecurity	14,688	24,223	27,409	44,076	36,660	37,700	38,747	39,836	41,130	41,953
22	Communications	4,320	7,124	8,061	12,963	19,180	19,437	20,067	20,730	21,430	21,859
23	Legal, Technical Safety & Compliance	6,302	10,393	11,759	18,910	27,607	30,181	31,634	32,601	33,617	34,289
24	Corporate Finance & Accounting	6,561	10,821	12,244	19,690	20,949	21,951	22,879	23,560	24,272	24,757
25	Executive Management	9,624	15,872	17,959	28,879	23,189	25,653	26,825	27,561	28,323	28,890
26	**Total Actual O&M Costs**	**185,269**	**332,319**	**359,730**	**538,979**	**590,096**	**615,231**	**623,178**	**643,432**	**679,225**	**688,535**
27	Net Adjustment for RDDA (Allowable Costs)[5]	(2,238)	(15,594)	(60,363)	(144,905)	(92,179)	-	-	-	-	-
28	Net Adjustment for RDDA (Other)[6]	7,215	39,371	(2,381)	-	-	-	-	-	-	-
29	**Total O&M Costs used to calculate RDDA balance**	**$ 190,245**	**$ 356,096**	**$ 296,986**	**$ 394,074**	**$ 497,916**	**$ 615,231**	**$ 623,178**	**$ 643,432**	**$ 679,225**	**$ 688,535**
30											
31	**Land Lease, Property Taxes, Fees and Levies**										
32	Property Tax	113,131	117,014	124,362	143,540	145,383	151,299	157,457	163,865	170,047	176,462
33	Service Levy	-	-	-	-	-	-	-	-	-	-
34	Franchise Fee	-	-	-	-	-	-	-	-	-	-
35	Licence Fee	-	-	-	-	-	-	-	-	-	-
36	Land Lease Costs	-	-	-	-	-	-	-	-	-	-
37	**Total Lease & Property Tax, Fees and Levies**	**$ 113,131**	**$ 117,014**	**$ 124,362**	**$ 143,540**	**$ 145,383**	**$ 151,299**	**$ 157,457**	**$ 163,865**	**$ 170,047**	**$ 176,462**
38											
39	Net Adjustment for RDDA (Allowable Costs)[7][8]	$ (113,131)	$ 222,448	$ (91,239)	$ (109,756)	$ -	$ -	$ -	$ -	$ -	$ -
40	**Total Lease & Property Tax, Fees and Levies used to (**	**$ -**	**$ 339,462**	**$ 33,122**	**$ 33,785**	**$ 145,383**	**$ 151,299**	**$ 157,457**	**$ 163,865**	**$ 170,047**	**$ 176,462**

Notes

(1) Maintenance (Unforeseen) refers to non-controllable costs due unexpected major maintenance and repair needs arising from sudden equipment failures. It is forecasted at zero because such events are unpredictable and difficult to quantify in advance.

(2) Prior to 2024, the Billing (Service Provider) cost was included as a part of the total corporate overhead allocated to Corix's utilities. From 2024 onwards this cost is being direct charged to each utility.

(3) Lines 13 to 19: Actual historical costs from 2018 to 2023 were allocated to DGE as one figure. These figures have been prorated to the current cost categories based on the 2024 actual allocation for illustrative purposes only.

(4) Lines 20 to 25: Actual historical costs from 2018 to 2023 were allocated to DGE as one figure. These figures have been prorated to the current cost categories based on the 2024 actual allocation for illustrative purposes only.

(5) Line 27 shows an adjustment to facilitate compliance with BCUC Order G-249-19 which required Corix to calculate the RDDA annual ending balance using only BCUC-approved forecast allocations for corporate and regional overhead allocations (lines 13-25 inclusive). For clarity, the historical actuals presented in lines 13 to 25 were not used for the RDDA due to the adjustment in line 27.

(6) Net Adjustment for RDDA (Other) accounts for errors and subsecuent corrections. The financing cost assotiated to the errors are included as initial adjustments in the RDDA (See note 7 in schedule 2).

(7) Between 2019 and 2021 Coirx booked estimated Property tax since there was an investigation into the validity of the amounts. In 2022 the investigation concluded and the accumulated difference was booked. Total adjustments between 2019 and 2022 net zero.

(8) BCUC order G-225-23 directed Corix to record the BCUC-approved property tax forecast into the RDDA from 2023 onwards. The annual variance between the BCUC approved forecast and actual property taxes charged to DGE is recorded in the PTDA from 2023 onwards.

Dockside Green Energy
2025-2028 Revenue Requirements and Rates Application
Schedule 12 - Energy Supply Costs

Line No.		Actual 2021	Actual 2022	Actual 2023	Projected 2024	Forecast 2025	Forecast 2026	Forecast 2027	Forecast 2028	Forecast 2029	Forecast 2030
1	Natural Gas										
2	Consumption (GJ)	11,392	11,969	11,574	20,932	23,249	23,249	23,249	23,249	23,249	27,113
3	Natural Gas Cost ($)	122,777	161,079	201,846	197,434	205,351	207,276	206,688	210,093	214,295	243,631
4											
5	Electricity										
6	Consumption (MWh)	84,960	58,680	91,440	93,960	100,763	100,763	100,763	100,763	100,763	117,513
7	Electricity Cost ($)	10,633	8,968	11,574	12,122	11,827	12,105	12,353	12,600	12,852	15,269
8											
9	**Energy Supply Costs (in $'s)**										
10	Natural Gas	122,777	161,079	201,846	197,434	205,351	207,276	206,688	210,093	214,295	243,631
11	Electricity	10,633	8,968	11,574	12,122	11,827	12,105	12,353	12,600	12,852	15,269
12	**Total Energy Supply Costs**	**133,410**	**170,047**	**213,420**	**209,556**	**217,178**	**219,380**	**219,041**	**222,693**	**227,147**	**258,900**

Notes
(1) Effective January 1, 2019, Energy Supply Costs are flowed through to customers via the Variable Energy Charge and the ECRA (See Schedule 9).
(2) From January 1, 2019 onwards, Energy Supply Costs are excluded from the RDDA.
(3) The Variable Energy Charge is updated each year on April 1st through the BCUC-approved rate setting mechanism.

Dockside Green Energy
2025-2028 Revenue Requirements and Rates Application
Schedule 13 - Income Tax and Capital Cost Allowance

Line No.	*All figures in $s*	Actual 2021	Actual 2022	Actual 2023	Actual 2024	Forecast 2025	Forecast 2026	Forecast 2027	Forecast 2028	Forecast 2029	Forecast 2030
1	**Income Tax**										
2	Earnings before tax	103,969	(3,579)	(117,426)	(151,152)	(332,184)	(460,661)	(388,437)	(355,117)	(325,645)	(185,968)
3	**Addback:** Depreciation	14,578	60,509	83,613	91,092	115,668	117,771	106,963	104,830	93,890	87,057
4	**Addback:** Amortization (negative)	-	-	-	-	-	-	-	-	-	-
5	**Deduct:** CCA	(33,034)	(52,953)	(136,829)	(210,310)	(136,460)	(110,943)	(118,661)	(99,168)	(89,325)	(259,701)
6	Taxable Income before LCF	85,513	3,977	(170,641)	(270,370)	(352,976)	(453,833)	(400,135)	(349,455)	(321,080)	(358,612)
7	Tax Loss Carryforward (LCF) (Utilized)	-	-	-	-	352,976	453,833	400,135	349,455	321,080	358,612
8	Taxable income after LCF	-	-	-	-	-	-	-	-	-	-
9	Tax Rate	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%
10	**Current Income Tax**	-	-	-	-	-	-	-	-	-	-
11											
12	**Tax Loss Carryforward (LCF)**										
13	Opening Balance	(74,691)	(160,205)	(164,182)	6,460	403,732	756,709	1,210,542	1,610,677	1,960,132	2,281,212
14	Additions	(85,513)	(3,977)	170,641	270,370	352,976	453,833	400,135	349,455	321,080	358,612
15	Adjustments	-	-	-	126,902	-	-	-	-	-	-
16	Losses Utilized	-	-	-	-	-	-	-	-	-	-
17	**Closing Balance**	**(160,205)**	**(164,182)**	**6,460**	**403,732**	**756,709**	**1,210,542**	**1,610,677**	**1,960,132**	**2,281,212**	**2,639,824**
18											
19	**UCC Pools**										
20	Opening Balance										
21	CCA Class 1	4,879	4,684	4,496	772,596	748,190	717,810	689,098	661,534	635,072	609,669
22	CCA Class 10	27,340	14,542	10,180	15,970	9,618	10,983	11,288	11,573	11,845	12,111
23	CCA Class 10.1	-	-	-	5,923	3,101	2,170	1,519	1,064	744	521
24	CCA Class 17	55,491	192,530	686,456	656,915	751,913	705,691	670,995	700,600	652,804	612,608
25	CCA Class 43.1	-	-	-	-	-	-	-	-	-	-
26	CCA Class 43.2	(7,823)	26,309	14,027	105,853	(37,758)	(20,393)	29,476	(12,423)	7,957	10,037
27	CCA Class 14.1	103,968	99,601	94,565	90,129	85,615	81,334	77,268	73,404	69,734	66,247
28	Subtotal Opening Balance	183,854	337,666	809,725	1,647,385	1,560,679	1,497,595	1,479,642	1,435,752	1,378,157	1,311,195
29											
30	Additions										
31	CCA Class 1	-	-	783,959	22,630	-	-	-	-	-	287,848
32	CCA Class 10	-	-	10,404	-	5,000	5,118	5,222	5,327	5,433	5,542
33	CCA Class 10.1	-	-	6,968	-	-	-	-	-	-	-
34	CCA Class 17	149,458	536,778	48,798	155,733	21,000	23,541	87,736	12,252	13,040	2,771
35	CCA Class 43.1	-	-	-	-	-	-	-	-	-	-
36	CCA Class 43.2	-	-	127,908	35,124	-	32,957	-	-	-	681,055
37	CCA Class 14.1	2,226	-	299	-	-	-	-	-	-	-
38	Subtotal Additions	151,684	536,778	978,336	213,487	26,000	61,615	92,958	17,579	18,474	977,216
39											

40	CCA Deductions										
41	CCA Class 1	(195)	(187)	(15,859)	(47,036)	(30,380)	(28,712)	(27,564)	(26,461)	(25,403)	(30,144)
42	CCA Class 10	(12,797)	(4,363)	(4,615)	(6,352)	(3,635)	(4,812)	(4,937)	(5,054)	(5,168)	(5,280)
43	CCA Class 10.1	-	-	(1,045)	(2,822)	(930)	(651)	(456)	(319)	(223)	(156)
44	CCA Class 17	(12,419)	(42,852)	(78,340)	(60,734)	(67,222)	(58,237)	(58,131)	(60,047)	(53,236)	(49,641)
45	CCA Class 43.1	-	-	-	-	-	-	-	-	-	-
46	CCA Class 43.2	(1,031)	(515)	(32,235)	(88,852)	(30,011)	(14,464)	(23,710)	(3,616)	(1,808)	(171,168)
47	CCA Class 14.1	(6,593)	(5,036)	(4,736)	(4,514)	(4,281)	(4,067)	(3,863)	(3,670)	(3,487)	(3,312)
48	Subtotal CCA Deductions	(33,034)	(52,953)	(136,829)	(210,310)	(136,460)	(110,943)	(118,661)	(99,168)	(89,325)	(259,701)
49											
50	UCC Balance										
51	CCA Class 1	4,684	4,496	772,596	748,190	717,810	689,098	661,534	635,072	609,669	867,373
52	CCA Class 10	14,542	10,180	15,970	9,618	10,983	11,288	11,573	11,845	12,111	12,374
53	CCA Class 10.1	-	-	5,923	3,101	2,170	1,519	1,064	744	521	365
54	CCA Class 17	192,530	686,456	656,915	751,913	705,691	670,995	700,600	652,804	612,608	565,738
55	CCA Class 43.1	-	-	-	-	-	-	-	-	-	-
56	CCA Class 43.2	26,309	14,027	105,853	(37,758)	(20,393)	29,476	(12,423)	7,957	10,037	521,999
57	CCA Class 14.1	99,601	94,565	90,129	85,615	81,334	77,268	73,404	69,734	66,247	62,935
58	Subtotal UCC Balance	337,666	809,725	1,647,385	1,560,679	1,497,595	1,479,642	1,435,752	1,378,157	1,311,195	2,030,784
59											

Dockside Green Energy
2025-2028 Revenue Requirements and Rates Application
Schedule 14 - Customer Count and Floor Area

Line No.		Actual 2021	Actual 2022	Actual 2023	Projected 2024	Forecast 2025	Forecast 2026	Forecast 2027	Forecast 2028	Forecast 2029	Forecast 2030
1											
2	Number of Customer Connections[(1),(2)]	7	7	8	8	8	8	8	8	8	10
3											
4	Floor Area (square metres)										
5	Beginning of year	31,506	31,506	31,506	64,794	64,794	64,794	64,794	64,794	64,794	64,794
6	End of year	31,506	31,506	64,794	64,794	64,794	64,794	64,794	64,794	64,794	86,241
7	Mid-Year[(3)]	31,506	31,506	61,280	64,794	64,794	64,794	64,794	64,794	64,794	75,517
8											

Notes

(1) One "Customer Connection" refers to one physical connection to the DGE that may provide with thermal energy to one or multiple customer buildings. A customer building may comprise of multiple small commercial units or a residential condominium or apartment building. These buildings are managed by either a Residential Strata Corporation or a Property Management Company acting as an agent.

(2) Number of customer connections is the year-end count of customer connections.

(3) Forecast rates and revenue are calculated using the mid-year floor area.

Dockside Green Energy
2025-2028 Revenue Requirements and Rates Application
Schedule 15 - Rates

Line No.		Approved 2021	Approved 2022	Approved 2023	Approved 2024	Forecast 2025	Forecast 2026	Forecast 2027	Forecast 2028	Indicative 2029	Indicative 2030
1											
2	**Existing Basic Charge ($/$m^2$ per month) (1)**	0.3910	0.4030	0.4150	0.4150	0.4260					
3	**Proposed Basic Charge ($/$m^2$ per month)(2),(3)**					0.5538	0.6923	0.7961	0.8916	0.9897	1.0370
4	**Variable Energy Charge ($/kWh) (4),(5)**	0.0720	0.0720	0.0720	0.0420	0.0370	0.0389	0.0456	0.0463	0.0473	0.0462
5	**Rate Rider 1 ($ /m^2 per month) (6)(7)**				0.1210	0.1834	0.1834				
6											
7	<u>Annual % Change in Rates</u>										
8	Basic Charge	2.89%	3.07%	2.98%	0.00%	30.00%	25.00%	15.00%	12.00%	11.00%	4.78%
9	Variable Energy Charge	71.43%	0.00%	0.00%	-41.67%	-11.83%	4.93%	17.29%	1.67%	2.00%	-2.27%
10	Rate Rider 1	0.00%	0.00%	0.00%	0.00%	51.57%	0.00%	-100.00%	0.00%	0.00%	0.00%

<u>Notes</u>

(1) The Basic Charge effective January 1, 2025 were accepted for filing on March 27, 2025 which accounted for changes to the cost of capital pursuant to Decision and Order G-321-24, issued on November 29, 2024.

(2) The Basic Charge changes on January 1st each year, subject to the necessary regulatory filing and BCUC approval.

(3) Corix seeks approval of the Basic Charge for July 1, 2025; and January 1, 2026, 2027, and 2028 only. The forecast Basic Charges for 2029 onwards are indicative only.

(4) Beginning in January 1, 2019, the Variable Energy Charge changes on April 1st each year, subject to BCUC approval based on the rate-setting mechanism.

(5) Corix does not seek approval of any Variable Energy Charge in this application as there is already an approved rate-setting mechanism.

(6) Rate Rider 1 is a temporary rate rider designed to amortize the balance in the Property Tax Variance Deferral Account (see Schedule 9), which was directed by BCUC Order G-225-23.

(7) Corix proposes to discontinue the Rate rider 1. Future Property Tax Variance Deferral Account balance is proposed to be amortized in the next DGE Rate Application (see Section 10.4.1).

Schedule 16 - Estimated End-User Bill Impact

Line No.		Approved 2021	Approved 2022	Approved 2023	Approved 2024	Forecast 2025	Forecast 2026	Forecast 2027	Forecast 2028	Forecast 2029	Forecast 2030
1	**Residential End-User**										
2	Floor Area: 74 m^2 (approx. 800 sq. ft.)	74	74	74.0	74	74	74	74	74	74	74
3	Heating Energy Use Intensity (EUI) (kWh/m^2)	74	74	74.5	74	74	74	74	74	74	74
4	Annual Heating Energy Consumption (kWh)	5,513	5,513	5,513	5,513	5,513	5,513	5,513	5,513	5,513	5,513
5											
6											
7	**Bill Impact of rate change to Basic Charge only**										
8	Amount for Basic Charge ($)	347	358	369	369	435	615	707	792	879	921
9	Amount for Variable Energy Charge ($)	397	397	397	232	204	204	204	204	204	204
10	Rate rider 1 ($)	-	-	-	81	149	21				
11	Total Bill ($)	744	755	765	681	788	840	911	996	1,083	1,125
12	Year-over-Year Total Bill Change ($)	175	11	11	(85)	108	52	71	85	87	42
13											
14	Annual % Change in:										
15	Basic Charge billed	2.89%	3.07%	2.98%	0.00%	18.05%	41.30%	15.00%	12.00%	11.00%	4.78%
16	Variable Energy Charge billed	71.43%	0.00%	0.00%	-41.67%	-11.83%	0.00%	0.00%	0.00%	0.00%	0.00%
17	Rate rider 1 billed					84.90%	-85.98%	-100.00%			
18	Total Bill	30.78%	1.43%	1.41%	-11.08%	15.80%	6.54%	8.49%	9.31%	8.75%	3.88%
19											
20											
21	**Bill Impact of rate change to Basic Charge with indicative Variable Energy Charge**										
22	Amount for Basic Charge ($)	347	358	369	369	435	615	707	792	879	921
23	Amount for Variable Energy Charge ($)	397	397	397	232	204	214	251	255	261	255
24	Rate rider 1 ($)	-	-	-	81	149	21	-	-	-	-
25	Total Bill ($)	744	755	765	681	788	850	958	1,047	1,139	1,175
26	Year-over-Year Total Bill Change ($)	175	11	11	(85)	108	62	108	89	92	36
27											
28	Annual % Change in:										
29	Basic Charge billed	2.89%	3.07%	2.98%	0.00%	18.05%	41.30%	15.00%	12.00%	11.00%	4.78%
30	Variable Energy Charge billed	71.43%	0.00%	0.00%	-41.67%	-11.83%	4.93%	17.29%	1.67%	2.00%	-2.27%
31	Rate rider 1 billed					84.90%	-85.98%	-100.00%			
32	Total Bill	30.78%	1.43%	1.41%	-11.08%	15.80%	7.82%	12.75%	9.29%	8.80%	3.17%

Notes

(1) The information above is shown to provide an indication of what an owner of a typical residential unit would pay if they were a direct customer of DGE.

(2) Actual customers are residential strata corporations and property management organizations.

(3) Estimated bill impact analysis excludes applicable taxes.

(4) Basic Charge amounts from 2029 onwards are indicative only and will be addressed in future filings to BCUC.

(5) Variable Energy Charge amounts from 2026 onwards are indicative only and will be addressed in future filings to BCUC.

Dockside Green Energy
2025-2028 Revenue Requirements and Rates Application
Schedule 17 - Revenue

Line No.		Actual 2021	Actual 2022	Actual 2023	Actual 2024	Forecast 2025	Forecast 2026	Forecast 2027	Forecast 2028	Forecast 2029	Forecast 2030
1											
2	Floor Area - Mid-year (sq. m.)	31,506	31,506	61,280	64,794	64,794	64,794	64,794	64,794	64,794	75,517
3	Annual Energy Demand (MWh)	2,257	2,353	3,378	4,482	4,806	4,806	4,806	4,806	4,806	5,605
4											
5	**Billed Revenue**										
6	From Basic Charge[1] ($)	146,563	152,363	306,945	326,784	380,910	538,242	618,978	693,256	769,514	939,723
7	From Variable Energy Charge ($)	136,842	169,425	243,199	242,700	177,973	186,746	219,041	222,693	227,147	258,900
8	From Rate Rider 1 ($)	-	-	-	70,560	130,469	18,292	(31)	-	-	-
10	Other Revenues[3]	-	-	1,772	4,113	-	-	-	-	-	-
9	Revenue from Vancity contribution[2],[3]	149,849	610,920	-	-	39,664					
11	**Total Revenue ($)**	**433,254**	**932,708**	**551,915**	**644,157**	**729,016**	**743,280**	**837,988**	**915,949**	**996,661**	**1,198,623**

Notes
(1) Forecast rates and revenue are calculated using the mid-year floor area.
(2) As part of the transfer agreement (approved by BCUC in Order G-166-18), in 2018 Vancity made a $1 million contribution to Corix which was included in the RDDA. In the following years the $1 million contribution earned interest at a WACC rate and offset revenue deficiencies.
(3) Not all the contribution from Vancity plus the earned interest were booked as revenue due to errors in the revenue requirements in prior years (See notes 6 and 7 in schedule 2 and note 6 in schedule 11) . Corix will book the remainder in 2025.

Appendix B: Acronyms and Glossary

Acronym / Glossary	Description
2019 RRRA	2019-2023 DGE Revenue Requirement and Rates Application
2025-2028 RRRA	2025-2028 DGE Revenue Requirement and Rates Application
2021 GCOC Stage 1	March 8, 2021 BCUC Generic Cost of Capital Proceeding (Stage 1)
AECO-C	Alberta Energy Company spot trading price for Alberta natural gas
AFUDC	Allowance for Funds Used During Construction
Application	2025-2028 DGE Revenue Requirement and Rates Application
BC Hydro	British Columbia Hydro and Power Authority
BCUC	British Columbia Utilities Commission
BMDEU	Burnaby Mountain District Energy Utility (a Corix district energy utility)
BoC	Bank of Canada
Capital structure	The mix of debt and equity to fund rate base
CAM	Cost Allocation Methodology
CEP	Central energy plant
CIAC	Contribution in Aid of Construction
CII	Corix Infrastructure Inc.
CMUS	Corix Multi-Utility Services Inc.
COVID-19	Infectious Coronavirus disease caused by the SARS-CoV-2 coronavirus
CPCN	Certificate of Public Convenience and Necessity
CPI	Consumer Price Index
CUI	Corix Utilities Inc.
D&O Liability	Directors and Officers Liability
DES	District energy system
DGE	Dockside Green Energy (a Corix district energy utility)
DPS	Distribution piping system

Acronym / Glossary	Description
E&O	Errors and Omissions
ECRA	Energy Cost Reconciliation Account
ETS	Energy Transfer Station
EUI	Energy Use Intensity, in kilowatt-hours per square metre
FBC	FortisBC Inc.
FEI	FortisBC Energy Inc.
FP&A	Financial Planning and Analysis
FTE	Full-time equivalent
GCOC	Generic Cost of Capital
GFA	Gross Floor Area
GOC	Government of Canada
ICVA	Insurance Cost Variance Account
IR	Information request
kW	Kilowatt; one thousand watts
kWh	Kilowatt-hour
MW	Megawatt; one million watts
MWh	Megawatt-hour
m2	Square metre
m^2	Square metre
No.	Number
O&M	Operating and Maintenance
OEM	Original Equipment Manufacturer
P&O Fees	Property & Other Fees
PCA	Participant Cost Award
PIPEDA	*Personal Information Protection and Electronic Documents Act*
PLC	Programmable Logical Controller
PMO	Project Management Office

Acronym / Glossary	Description
PPE	Property, plant and equipment
PTDA	Property Tax Deferral Account
R&R	Renewal and Replacement
R&R Plan	Renewal and Replacement Capital Plan
RCVA	Regulatory Cost Variance Account
RDDA	Revenue Deficiency Deferral Account
ROE	Return on Equity
RRRA	Revenue Requirement and Rates Application
SouthWest	SouthWest Water Company
sq. ft.	Square feet
Stream B TES	Stream B Thermal Energy System; category of TES regulated by the BCUC
SWMAC	SW Merger Acquisition Corp.
TEC	Temporary energy centre
TES	Thermal energy system
TSBC	Technical Safety BC
UBC NDES	Neighbourhood District Energy System at the University of British Columbia
UCA	*Utilities Commission Act*
WACC	Weighted average cost of capital

Appendix C: Previous BCUC Directives

No.	Decision Page No.	Directive No.	Topic	Description / Details	Status	Section in this Application
Final Order G-166-18 regarding Corix Application for approval to acquire Docside Green Energy						
1		1	Approval to transfer interest and disposition of assets to Corix	The transfer of partnership interests from DGE to Vancity and DGLP, and subsequent sale and disposition of DGE assets to Corix are in the public interest and are approved.	Completed	2.2
2		2	DGE Transfer of CPCN	The transfer of the DGE Certificate of Public Convenience and Necessity to Corix is approved.	Completed	2.2
3		3	Establishment of DGE RDDA	The establishment of the Revenue Deficiency Deferral Account as set out in the Application is approved and interest is to be applied to the balance in the regulatory account based on DGE's approved weighted cost of capital-based return, until such time a revenue requirements application is filed by Corix.	Completed	2.2
4		4	File a Revenue Requirement	Corix must prepare and file an application for revenue requirements and expenditure associated with installing new natural gas boilers in the central energy facility by the end of 2018. Corix is directed to work with BCUC staff to determine the appropriate form and substance of the revenue requirements application prior to its submission.	Completed	2.3
Final Orde with Reasons G-248-19 regarding DGE 2019-2023 Revenue Requriements Application						
5		1	Rate base, revenue requirement, rate structure and rates	The rate base, revenue requirement, rate structure and rates for DGE are approved as follows: a. The rate base as presented in the Application and updated in the amended financial model filed in Exhibit B-3-1 (Amended Financial Model) is approved. b. The revenue requirement as presented in the Application and updated in the Amended Financial Model is approved, including the following components: i. A deemed capital structure of 57.5 percent debt and 42.5 percent equity; ii. Long term debt financing costs estimated at 4.91 percent; iii. A return on equity (ROE) of 9.75 percent which is based on the current low risk benchmark ROE plus 100 basis points; iv. Annual operating costs; and v. An operations and maintenance (O&M) expense mark-up of 10 percent;	Completed	3.1.1

No.	Decision Page No.	Directive No.	Topic	Description / Details	Status	Section in this Application
				c. The following accounting treatment and rate structure is approved: i. A five-year levelized rate structure which includes a Basic Charge to be escalated by three percent annually and the continuation of the Revenue Deficiency Deferral Account (RDDA); ii. A separate Variable Energy Charge which is set based on the forecast consumption and energy rates for FortisBC Energy Inc. and British Columbia Hydro and Power Authority; and iii. The establishment of an Energy Cost Reconciliation Account to record variances between the actual energy costs and the revenue collected through the Variable Energy Charge, with the balance to be amortized over a one-year period.		
6		2	Permanent Rates	Corix is approved to set permanent rates effective January 1, 2019, as applied for in the Application, which includes a 2019 Basic Charge of $0.369 per month per square metre and a 2019 Variable Energy Charge of $0.051 per kilowatt-hour.	Completed	3.1.1
7		3	Treatment of difference between interim and permanent rates	Corix's request to recover the difference in revenue between interim and permanent 2019 rates that exceed a threshold of $16,800 using a Fixed Charge Rate Rider is denied. Corix is directed to utilize the RDDA to recover all differences in revenue between interim and permanent 2019 rates.	Completed	3.1.2
8		4	Compliance filing	Corix is directed to file as a compliance filing with the BCUC, within 30 days of the date of this order, the permanent tariff terms and conditions and rate schedule for DGE.	Completed	3.1.3.1
9	p. 17		ROE analysis	the Panel directs Corix to include a detailed analysis of the appropriate capital structure and ROE for DGE in the next revenue requirement application, which the Panel anticipates will likely be filed in 2023	Completed	3.1.3.2
10	p. 17		O&M mark-up	The Panel agrees with Corix that the negative RDDA and the small initial rate base create a situation whereby Corix is not provided the opportunity to earn a reasonable return on its investment in the initial years of operating the DGE utility if the allowed return is based solely on the "standard rate base" approach. The Panel also agrees that such a scenario is not fair to the utility. Therefore, the Panel finds that Corix's proposal to include a ten percent mark-up on O&M, exclusive of energy costs and management/administration costs is reasonable until such time as the ROE on net base exceeds the ten percent O&M mark-up. The Panel notes this is consistent with the		3.1.3.3

No.	Decision Page No.	Directive No.	Topic	Description / Details	Status	Section in this Application
				compensation method employed by DGE LLP when Corix was providing operational services and is easy to understand. **For these reasons, the Panel approves Corix's request to include a ten percent O&M mark-up, exclusive of energy costs and management/administration costs, in the DGE revenue requirement until such time as the ROE on net base exceeds the ten percent O&M mark-up.**		
Final Order with Reasons G-269-20 regarding DGE Variable Energy Charge and Rate Setting Mechanism						
11		1	Variable Energy Charge rate-setting mechanism	Corix is approved to use a two parameter Variable Energy Charge rate-setting mechanism for Dockside Green Energy as set out in the Application, whereby a change in the Variable Energy Charge rate is triggered when the following conditions are met: I) The ratio of expected 12-month variable energy charge recovery revenue to the sum of the expected 12-month energy costs, plus the ECRA balance at the beginning of the forecast period, is greater than 1.05 or less than 0.95; and ii) The minimum rate change threshold of ± $0.011 per kWh is exceeded.	Completed	3.2
12		2	Annual reports	Corix is directed to include in its annual report submissions: i)Forecast ECRA balance as at the beginning of the month following the annual report submission; ii) Forecast monthly energy costs incurred in each of the 12 months following the annual report filing and forecast annual energy costs for the year subsequent to those 12 months; iii) Forecast monthly revenue from the Variable Energy Charge in each of the 12 months following the annual report filing and forecast annual revenue for the year subsequent to those 12 months, based on both the approved Variable Energy Charge at the time of the annual report filing and the proposed Variable Energy Charge, if applicable; and iv) Forecast monthly ECRA balance at the end of each of the 12 months following the annual report filing and the forecast ECRA balance at the end of the year subsequent to those 12 months, based on both the approved Variable Energy Charge at the time of the annual report filing and the proposed Variable Energy Charge, if applicable.	Completed	3.2

No.	Decision Page No.	Directive No.	Topic	Description / Details	Status	Section in this Application
13		3	Evaluation report	Corix is directed to file an evaluation report on the rate-setting mechanism by no later than November 1, 2023, documenting all rate changes under the rate-setting mechanism, analyzing the effects of the ratesetting mechanism on the frequency and magnitude of rate changes and ECRA balance, and providing Corix's analysis of the overall performance of the rate-setting mechanism for DGE and its ratepayers.		3.2
14		4	Rate change	Corix is approved, pursuant to section 60 of the Utilities Commission Act, to decrease the Variable Energy Charge for Dockside Green Energy from $0.055 per kWh to $0.042 per kWh effective May 1, 2020 on a permanent basis, until such time that the rate change mechanism is triggered.		3.2
15		5	File revised tariff	Corix is directed to file revised tariff pages for acceptance by the BCUC within 30 days from the date of issuance of this Order.		3.2
Order and Decision G-279-23 reagrding Corix Restructuring and Business Combination						
16		1	Transfer of Interest	CMUS is approved to transfer its interest in each of the following Stream B TES at the time of the Pre-Closing Restructuring to three limited partnerships as follows, pursuant to section 52 of the UCA: a. BMDEU is approved to be transferred to Corix Burnaby Mountain DE Limited Partnership; b. UBCNDES is approved to be transferred to Corix UBCDE Limited Partnership; and c. DGDEU is approved to be transferred to Corix Dockside Green DE Limited Partnership.		2.8
17		2	CPCN is Granted for DGE	A CPCN is granted to the following limited partnerships at the time of the Pre-Closing Restructuring, pursuant to sections 45 and 46 of the UCA: i. Corix Burnaby Mountain DE Limited Partnership for the BMDEU; ii. Corix UBCDE Limited Partnership for the UBCNDES; and iii Corix Dockside Green DE Limited Partnership for the DGDEU.		2.8

No.	Decision Page No.	Directive No.	Topic	Description / Details	Status	Section in this Application
Final Order G-225-223 regarding DGE Application for Approval to flow through Property Tax						
18		1	Dicontinue Propoerty Tax variance into the RDDA	Corix is directed to discontinue recording the annual variance between the BCUC approved forecast and actual property taxes in DGE's existing RDDA, commencing in 2023.		3.3
19		2	Approved Property Tax Deferral Account (PTDA)	Corix is approved to establish a non-rate base PTDA for DGE to record the annual variance between the BCUC approved forecast and actual property taxes charged to DGE from 2023 onwards, attracting interest at DGE's weighted average cost of capital.		3.3
20		3	Rate Rider 1 Mechanism	Corix is approved to use a rate rider mechanism (the PTDA Rate Rider) for the recovery or refund of the year-end balance in the PTDA over a one-year period in accordance with the methodology established in Section 4.2.7 of the Application.		3.3
21		4	Rate Rider annual approval	Corix is directed to apply annually to the BCUC for review and approval of any rate rider for recovering or refunding the balance in the PTDA.		3.3
22		5	Annual report	Corix is directed to include the following in its annual report for the DGE: a. Year-end actual property tax costs; b. The variance between the BCUC approved forecast and actual property taxes for the most recent calendar year; and c. The supporting calculations and explanations for the PTDA Rate Rider.		3.3
23		6	Compliance Filing	Corix is directed to submit a compliance filing to the BCUC by no later than June 30, 2026, assessing the need to continue the use of the PTDA Rate Rider for recovering or refunding the variance between the BCUC approved forecast and actual property taxes. This compliance filing should consider alternative methods of recovering or refunding PTDA balances.	In progress	10.4
Order and Decision G-236-23 Generic Cost of Capital Proceeding (Stage 1)						
24		4	Interim Rates	Interim rates are established, effective January 1, 2024, on a refundable or recoverable basis, for all other utilities, except FBC, that currently use the Benchmark Utility to set their capital structure and equity return pending the BCUC's final decision on Stage 2 of the GCOC proceeding.	Completed	9.2.1

No.	Decision Page No.	Directive No.	Topic	Description / Details	Status	Section in this Application
Order and Decision G-321-24 Generic Cost of Capital Proceeding (Stage 2)						
25		2	Equity Premium	Effective January 1, 2024, the equity premium over the Benchmark Utility (i.e. deemed equity component) and ROE premium over the Benchmark Utility (i.e. allowed ROE) for the following thermal energy system (TES) utilities and the default TES as discussed in Section 3.3.4 of the decision accompanying this order (TES Default) are: … Utility Corix DGEDE Limited Partnership Equity Premium over the Benchmark Utility (i.e. Deemed Equity Component) 4.0 percentage points (49.0 percent) ROE Premium over the Benchmark Utility (i.e. Allowed ROE) 75 basis points (10.40 percent) …	Completed	9.2.2
26	p. 86		Deemed interest methodology	The Panel determines that the deemed interest rate methodology should be based on the sum of: 1. GoC 10-year bond yields based on the average of the last trailing 12 months; 2. The corporate credit spreads on the GoC 10-year bonds for BBB and BBB(low) rated utilities based on the average of the last trailing 12 months; 3. Non-investment grade lending premium of 92 bps; and 4. A deemed issuance fee of 50 bps.		9.2.3.3
27	p. 88-89		Deemed interest effective date	The Panel determines that the deemed interest rate methodology established above is effective January 1, 2024, for those utilities that use a deemed interest rate in setting their cost of debt.		9.2.3.3
28	p. 96		GCOC Variance Deferral Account and compliance filing	For Corix UBC NDES and DGE, the Panel approves the previously established interim 2024 rates as permanent. Corix is directed to establish a new GCOC Variance Deferral Account for each utility, attracting Corix's WACC, to record the variance between the previously established interim 2024 rates and the rates that would reflect the new cost of capital, effective January 1, 2024, under this decision. For clarity, the GCOC Variance Deferral Accounts are separate from the existing Revenue Deficiency Deferral Accounts for UBC NDES and DGE, as these arrangements will provide flexibility for		2.7.3

No.	Decision Page No.	Directive No.	Topic	Description / Details	Status	Section in this Application
				the utility and collection from ratepayers. The GCOC Variance Deferral Accounts will also capture the difference between any 2025 interim rates before and after incorporation of the new cost of capital under this decision. The amounts to be added to the GCOC Variance Deferral Accounts and their disposition are to be addressed the earlier of (i) these Corix Utilities' next rates applications or (ii) a compliance filing to be filed with the BCUC by January 31, 2025. This filing should also include revised permanent rates that reflect the new cost of capital under this decision for UBC NDES's and DGE's rates for 2025 and beyond. As applicable, revised tariff pages are to be filed with the BCUC by January 31, 2025.		

Appendix D: Financial Model

The DGE financial model is strictly confidential and privileged and has been filed as a separate and confidential document for the reasons provided in Section 1.3.4 (Confidentiality) of this Application. It has been submitted electronically exclusively for use by British Columbia Utilities Commission and its representatives / designees in connection with the evaluation of this Application.

Appendix E: Proposed Tariff (Clean Version)

CORIX DOCKSIDE GREEN DE LIMITED PARTNERSHIP

Dockside Green District Energy Service

Thermal Energy Services Tariff

Containing

Definitions, Terms and Conditions, Rates, and Fees for Service

This tariff is available for public inspection at the utility's website.

SECTION A - DEFINITIONS

Unless the context otherwise requires, in these Terms and Conditions the following terms have the following meanings:

Affiliate: has the meaning ascribed to it in the British Columbia *Business Corporations Act*.

Applicant: means a Person applying to become a Customer in accordance with these Terms and Conditions.

Basic Charge: means a fixed charge attributable to infrastructure and operating costs, other than fuel and consumable costs required to be paid by a Customer for Energy Services during a prescribed period as specified in the Rate Schedule and is applicable to the Service Area declared on the application for service once billing commences.

Building: means a single or multi-building residential development or other building or facility which is subject to a Customer Agreement.

Building System: means the system of water pipes and heat and domestic hot water delivery and / or storage equipment to be installed and used for distributing and storing Thermal Energy in a Building, connected to but downstream of and excluding the Service Connection and Energy Transfer Station for that Building.

Contaminants: means any radioactive materials, asbestos materials, urea formaldehyde, underground or above ground tanks, pollutants, contaminants, deleterious substances, dangerous substances or goods, hazardous, corrosive, or toxic substances, hazardous waste, waste, pesticides, defoliants, or any other solid, liquid, gas, vapour, odour, heat, sound, vibration, radiation, or combination of any of them, the storage, manufacture, handling, disposal, treatment, generation, use, transport, remediation, or Release into the environment of which is now or hereafter prohibited, controlled, or regulated under environmental laws.

Customer: means a Person receiving Energy Services pursuant to a Customer Agreement.

Customer Agreement: means an agreement between the Utility and a Customer for the provision of Energy Services to a Building or Buildings, which Agreement is comprised of an application for service and these Terms and Conditions.

Distribution Extension: means an extension or upgrade of the Distribution System less than a material dollar amount and thus not subject to the British Columbia Utilities Commission *Thermal Energy Systems Regulatory Framework Guidelines*.

Distribution System: means, collectively, the system of water pipes, fittings and ancillary components connecting the central thermal energy plant to the Service Connections.

Energy Services: means the provision by the Utility of Thermal Energy via the Thermal Energy System.

Energy Transfer Station: means the separate heat exchanger for space heating and domestic hot water (excluding domestic hot water storage tanks), energy meter including temperature sensors and flow meter, control panel and all pipes, fittings and other associated equipment that control the transfer, and measure Thermal Energy from the Distribution System to a Building System.

Person: means an individual or his or her legal personal representative, an unincorporated organization or association, or a corporation, partnership, trust, trustee, syndicate, joint venture, limited liability company, union, government agency or other entity or organization.

Rate Schedule: means that schedule attached to and forming part of these Terms and Conditions, which sets out the rates for Energy Services, exclusive of third-party payment processing fees, and certain related terms and conditions, as amended from time to time by the Utility with the approval of, and as filed with, the British Columbia Utilities Commission.

Release: means any release, spill, leak, pumping, pouring, emission, emptying or discharge, injection, escape, leaching, migration, disposal, or dumping.

Service Area: means the total area of the Building receiving Thermal Energy services, measured in square meters.

Service Connection: means the system of water pipes and all ancillaries and fittings necessary to connect a Building System to the Distribution System via the Energy Transfer Station.

Standard Fees and Charges Schedule: means that schedule attached to and forming part of these Terms and Conditions which sets out certain standard fees and charges, exclusive of third-party payment processing fees, which may be charged to the Customer in accordance with these Terms and Conditions.

Terms and Conditions: means these Thermal Energy Service Terms & Conditions, including the definitions and schedules hereto, all as amended from time to time by the Utility with the approval of, and as filed with, the British Columbia Utilities Commission.

Thermal Energy: means thermal energy for space heating and domestic hot water.

Thermal Energy System: means the district energy system by which the Utility delivers Thermal Energy to Customers, including the central thermal energy plant, the Distribution System, the Service Connections and the Energy Transfer Stations.

Utility: means Corix Dockside Green DE Limited Partnership (referred to as Corix Dockside Green District Energy Service) carrying on the business of a Thermal Energy distribution utility.

Utility's Representatives: means any Person who is an officer, director, employee, agent, contractor, subcontractor, consultant or advisor of either the Utility or any Affiliate of the Utility.

Variable Energy Charge: means a metered charge required to be paid by a Customer for energy costs associated with the provision of Energy Services during a prescribed period as specified in the Rate Schedule.

SECTION B - TERMS AND CONDITIONS

1. Application for Energy Services

The Utility will provide Energy Services to Customers solely in accordance with these Terms and Conditions. Persons seeking to become Customers must apply for Energy Services in accordance with this Section.

Application for Energy Services will be made in writing. Applicants will be required by the Utility to complete and sign an application for service form which, together with these Terms and Conditions, constitutes a Customer Agreement. The Customer Agreement will become binding on the parties thereto only and forthwith upon commencement by the Utility of Energy Services at the relevant Building. Applicants may be required to provide reference information and identification acceptable to the Utility in connection with an application for Energy Services.

The application for service form will include a declaration of Service Area for the purpose of billing the Basic Charge. If required, Customers may submit a request to update the Service Area in writing, which must be accompanied by a legal survey. Following review and acknowledgement of the request by the Utility, the updated Service Area will be reflected on the bill rendered as part of the next bill cycle. Prior bills will not be adjusted.

If an Applicant is requesting Energy Services at more than one Building, the Utility will determine in its sole discretion whether to consider the Applicant the same Customer for all Buildings or to consider the Applicant a separate Customer for each of the Buildings. If an Applicant is requesting Energy Services for more than one unit, area or premises within the same Building, the Applicant will be considered the same Customer for all such unit(s), area(s) or premises. The Utility intends that there will be no more than one Customer per Building.

The Utility may refuse to provide Energy Services to an Applicant if there is an unpaid account for Energy Services in respect of such Applicant or the relevant Building.

2. Assignment

A Customer may not assign a Customer Agreement or any of its rights or obligations thereunder without the prior written consent of the Utility, such consent not to be unreasonably withheld. The Utility may assign a Customer Agreement or any of its rights or obligations thereunder (including, without limitation, by way of the sale of the majority of its shares or business or its material assets or by way of an amalgamation, merger or other corporate reorganization) to any of its Affiliates or to any other Person without the consent of the Customer, provided such Affiliate or Person is duly qualified to carry out the Customer Agreement and agrees to be bound by the terms and conditions of the Customer Agreement. Forthwith upon such assignment, the Utility shall be released from its obligations and responsibilities under the Customer Agreement.

3. Use of Thermal Energy

A Customer will use Thermal Energy only for space heating and domestic hot water within the Building.

Unless authorized by the Utility in writing and in advance, a Customer will not sell or supply to any other Person Thermal Energy provided by the Utility, nor use Thermal Energy supplied by the Utility for any purpose other than as specified in this Section.

4. Applicable Rate Schedule

A Customer must not significantly change its connected load without the prior written approval of the Utility. The Utility may conduct periodic reviews of the quantity of Thermal Energy delivered and the rate of delivery of Thermal Energy to a Customer for the purpose of, among other things, determining whether to substitute a more applicable Rate Schedule.

5. Ownership and Care of Thermal Energy System

Notwithstanding any degree of annexation or affixation, or rule of law or equity to the contrary, the Utility owns all components of the Thermal Energy System and all additions or extensions thereto will be and remain the property of and vest in the Utility, whether located inside or outside of Building. No component of the Thermal Energy System shall be moved or removed from a Customer's lands (whether located inside or outside of Building) without the advance written permission of the Utility. The Utility will not, under any circumstances whatsoever (including, without limitation, if the Utility is not providing Energy Services for any reason or if the Customer Agreement is terminated for any reason), be required to remove any component of the Thermal Energy System from the Customer's lands (whether located inside or outside of Building).

The Customer will take reasonable care of and protect all components of the Thermal Energy System in, on or under the Customer's lands (whether located inside or outside of Building) against damage and must advise the Utility promptly of any damage to or disappearance of the whole or part of any such component. Further, the Customer will pay to the Utility promptly upon request the cost of any broken, missing or damaged component of the Thermal Energy System (or part thereof), except to the extent that the Customer demonstrates that such component (or part thereof) was broken, missing or damaged due to a defect therein or to any act or omission of the Utility or any of the Utility's Representatives.

6. Meter Reading

The amount of Thermal Energy registered by the Energy Transfer Station during each billing period will be converted to kilowatt-hours (kWh) and rounded to the nearest two-tenths of a kWh.

The interval between consecutive meter readings will be at the sole discretion of the Utility.

The meter will typically be read at monthly intervals.

7. Meter Testing

Any Customer who doubts the accuracy of a meter comprising part of an Energy Transfer Station may request to have the meter tested by the original equipment manufacturer.

If the testing indicates that the meter is recording correctly, the Customer must pay the Utility for all costs associated with the testing and continuing operations during the testing, which includes but it not limited to removing, replacing and/or testing the meter as set out in the Standard Fees and Charges Schedule and the reconnection charge as set out in Section 10.

If the meter is found to be inaccurate by the manufacturer, the Utility will incur the cost of removing, replacing and/or testing the meter or (if applicable) refund such costs to the Customer.

8. Maintenance

The Utility will repair, maintain and replace all components of the Thermal Energy System in, on or under the Customer’s lands (whether located inside or outside of Building), from time to time at its own cost to keep the same in good working order. For greater certainty, except for the Utility's obligation to repair, maintain and replace such components of the Thermal Energy System as aforesaid, the Utility is not, and will not be, responsible for repairing, maintaining or replacing any other facility or equipment in, on or under a Customer's lands (whether located inside or outside of Building), including without limitation any Building System(s).

The Customer will repair, maintain and replace the Building System in all Building from time to time at its own cost to keep the same in good working order.

9. Connections and Disconnections

No connection, disconnection, reconnection, extension, installation, replacement or any other change is to be made to any component of the Thermal Energy System by anyone except by the Utility's Representatives authorized by the Utility.

10. Energy Services Reconnections

If:

(a) Energy Services are discontinued to a Customer for any of the reasons specified in Section 16; or

(b) a Building System is disconnected from the Thermal Energy System or Energy Services are discontinued to a Customer:

(i) at the request of the Customer with the approval of the Utility; or

(ii) to permit a test of a meter at the request of the Customer, which meter is subsequently determined by the Utility to be accurate;

and such Customer or the employee, agent or other representative of such Customer re-applies for Energy Services for the same Building within 12 months of such discontinuance or disconnection (as applicable), then if the Building's Building System is reconnected to the Thermal Energy System or if Energy Services are restored to such Customer, such Customer will pay, as part of fees owing for the first month of Energy Services, a reconnection charge equal to the sum of:

(c) the costs that the Utility estimates it will incur in reconnecting the Building's Building System to the Thermal Energy System or restoring Energy Services to such Customer; and

(d) the Basic Charge that such Customer would have paid had Energy Services continued during the period between the date of discontinuance or disconnection (as applicable) and the date of such re-application.

If a Building System is disconnected from the Thermal Energy System or Energy Services are discontinued to a Customer for public safety or Utility service requirement reasons, there will be no reconnection charge to reconnect the Building's Building System to the Thermal Energy System or to restore Energy Services to such Customer.

11. Distribution Extensions

The Customer acknowledges the following terms and conditions which will apply to the Utility's determination of whether or not to complete a Distribution Extension in order to assess the economic impact of such Distribution Extension on existing Customers.

(a) Ownership. All components of Distribution Extensions will be and remain the property of the Utility.

(b) Economic Test. Applications to extend Energy Services to one or more new Customers will be subject to an economic test, a model which is accepted by the British Columbia Utilities Commission. The economic test will be a discounted cash flow analysis of the projected revenue and costs associated with the Distribution Extension. The Distribution Extension will be deemed to be economic and constructed if the results of the economic test indicate a zero or positive net present value.

(c) Revenue. The projected revenue used in the economic test will be established by the Utility by:

(i) estimating the number of Customers to be served by the Distribution Extension;

(ii) establishing consumption estimates for each Customer;

(iii) projecting when the new Customers will be connected to the Distribution Extension; and

(iv) applying appropriate revenue margins for each Customer's consumption.

The revenue projection will also take into consideration the effect of variations in weather conditions on consumption.

(d) Costs. The costs used in the economic test will include, without limitation:

(i) the full projected labour, material, and other costs necessary to serve the new Customers including such costs applicable to new mains (subject to the provisions of this paragraph (d)), Service Connection(s), Energy Transfer Station(s) and related facilities;

(ii) the appropriate allocation of Utility overhead associated with construction of the Distribution Extension; and

(iii) projected incremental operating and maintenance expenses necessary to serve the new Customers. In addition to these costs, the economic test will incorporate applicable taxes and the appropriate return on investment as approved by the British Columbia Utilities Commission.

In cases where a larger Thermal Energy distribution main is installed to satisfy anticipated future demand requirements, the difference in cost between the installed, larger main and a smaller main that would be adequate to serve only those Customers supporting the particular application may be eliminated from the economic test.[1]

(e) Contributions in Aid of Construction. If the economic test results indicate a negative net present value, the Distribution Extension may proceed provided that the shortfall in revenue is eliminated by contributions in aid of construction by or on behalf of Customers to be served by the Distribution

[1] From time to time the Utility may undertake larger expansions of the Thermal Energy System of a material dollar amount that fall outside of what is defined here as Distribution Extensions and are subject to the required applications to the British Columbia Utilities Commission under the *Thermal Energy Systems Regulatory Framework Guidelines*.

Extension, or if there are non-financial factors offsetting the revenue shortfall that are deemed to be acceptable by the British Columbia Utilities Commission, the Utility may finance the contributions in aid of construction for Customers.

(f) Security. In those situations where the financial viability of a Distribution Extension is uncertain, the Utility may require a security deposit in cash or an equivalent form acceptable to the Utility.

12. Billing

(a) Bills will be rendered to the Customer in accordance with the Customer's Customer Agreement, including the Rate Schedule.

(b) Subject to paragraph (d) below, if meter readings cannot be obtained for any reason, consumption may be estimated by the Utility for billing purposes and the next bill that is based on actual meter readings will be adjusted for the difference between estimated and actual use over the interval between meter readings.

(c) If any meter fails to register or registers incorrectly, the consumption may be estimated by the Utility for billing purposes, subject to Section 13.

(d) If the Customer terminates a Customer Agreement, Corix will make all reasonable efforts to obtain an actual meter reading for the final bill rendered to the Customer. If the actual meter reading cannot be reasonably obtained, consumption may be estimated by the Utility for the purpose of the final bill.

(e) Bills will be rendered as often as deemed necessary by the Utility, but generally on a monthly basis. The due date for payment of bills shown on the face of the bill will be the first business day after:

(i) the 21st calendar day following the billing date; or

(ii) such other period otherwise agreed in writing by the Customer and the Utility.

(f) Bills will be paid in the manner specified therein, which may include payment by regular mail, and/or payment by on-line banking or electronic funds transfer.

(g) Customers requesting historic billing information may be charged the cost of processing and providing this information.

13. Back-billing

Minor adjustments to a Customer's bill, such as an estimated bill or an equal payment plan billing, do not require back-billing treatment.

(a) Back-billing means the re-billing by the Utility for Energy Services rendered to a Customer because the original billings were discovered to be either too high (over-billed) or too low (under-billed). The discovery may be made by either the Customer or the Utility. The cause of the billing error may include any of the following non-exhaustive reasons or combination thereof:

(i) stopped meter;

(ii) metering equipment failure;

(iii) inaccurate meter, as determined pursuant to Section 7;

(iv) switched meters;

(v) double metering;

(vi) incorrect meter connections;

(vii) incorrect use of any prescribed apparatus respecting the registration of a meter;

(viii) incorrect meter multiplier;

(ix) the application of an incorrect rate;

(x) incorrect reading of meters or data processing; or

(xi) tampering, fraud, theft or any other criminal act.

(b) Where the Customer requests that the meter be tested, the provisions of Section 7 will apply in addition to those set forth in this Section.

(c) Where metering or billing errors occur and the Customer does not request that the meter be tested, the consumption and demand will be based on the records of the Utility for the Customer or on the Customer's own records to the extent they are available and accurate or, if not available, on reasonable and fair estimates made by the Utility. Such estimates will be on a consistent basis within each Customer class or according to a contract with the Customer, if applicable.

(d) If there are reasonable grounds to believe that the Customer has tampered with or otherwise used the Thermal Energy or any component of the Thermal Energy System in an unauthorized way, or there is evidence of fraud, theft or another criminal act, back-billing will be applied for the duration of the unauthorized use, subject to the applicable limitation period provided by law, and the provisions of paragraphs (g), (h), (i) and (j) below will not apply.

In addition, the Customer is liable for the direct (unburdened) administrative costs incurred by the Utility in the investigation of any incident of tampering, including the direct costs of repair, or replacement of equipment.

Under-billing resulting from circumstances described in this paragraph (d) will bear interest at the rate specified in the Standard Fees and Charges Schedule on unpaid accounts from the date of the original under-billed invoice until the amount under-billed is paid in full.

(e) In every case of under-billing or over-billing, the cause of the error will be remedied without delay, and the Customer will be promptly notified of the error and of the effect on the Customer's ongoing bill.

(f) In every case of over-billing, the Utility will refund to the Customer all money incorrectly collected for the duration of the error, subject to the applicable limitation period provided by law. Simple interest, computed at the short-term bank loan rate applicable to the Utility on a monthly basis, will be paid to the Customer.

(g) Subject to paragraph (d) above, in every case of under-billing, the Utility will back-bill the Customer for the shorter of:

(i) the duration of the error; or

(ii) one year, or as otherwise agreed by the Customer and the Utility in writing.

(h) Subject to paragraph (d) above, in every case of under-billing, the Utility will offer the Customer reasonable terms of repayment. If requested by the Customer, the repayment term will be equivalent in length to the back-billing period. The repayment will be interest free and in equal instalments corresponding to the normal billing cycle. Delinquency in payment of such instalments will be subject to the usual late payment charges.

(i) Subject to paragraph (d) above, if a Customer disputes a portion of a back-billing due to under-billing based upon either consumption, demand or duration of the error, the Utility will not threaten or cause the discontinuance of Energy Services for the Customer's failure to pay that portion of the back-billing, unless there is no reasonable ground for the Customer to dispute that portion of the back-billing. The undisputed portion of the bill will be paid by the Customer and the Utility may threaten or cause the discontinuance of Energy Services if such undisputed portion of the bill is not paid.

(j) Subject to paragraph (d) above, in all instances of back-billing where changes of occupancy have occurred, the Utility will make a reasonable attempt to locate the former Customer. If, after a period of one year, such Customer cannot be located, the over-billing or under-billing applicable to them will be cancelled.

14. Late Payment Charge And Collection Charge

If the amount due on any bill has not been paid in full on or before the due date shown on such bill, the bill rendered as part of the next bill cycle will include the overdue amount plus a late payment charge as set out in the Standard Fees and Charges Schedule. Notwithstanding the due date shown, to allow time for payments made to reach the Utility and to co-ordinate the billing of late payment charges with scheduled billing cycles, the Utility may, in its discretion, waive late payment charges on payments not processed until a number of days after the due date. If the Customer's account is overdue and requires additional effort to collect, the Utility may charge the Customer a collection charge as set out in the Standard Fees and Charges Schedule.

15. Dishonoured Payments Charge

If a cheque or direct debit received by the Utility from a Customer in payment of any account is returned by the Customer's bank, trust company or financial institution because of insufficient funds (NSF), or any reason other than clerical error, a dishonoured payments charge as set out in the Standard Fees and Charges Schedule will be added to the amount due and payable by the Customer whether or not the applicable Building System has been disconnected from the Thermal Energy System or Energy Services have been discontinued to the Customer.

16. Refusal to Provide Energy Services and Discontinuance of Energy Services

The Utility may refuse to provide Energy Services to any Applicant, or the Utility may, after having given 48 hours prior written notice, discontinue providing Energy Services to any Customer, who:

(a) fails to fully pay for any Energy Services provided to any Building on or before the due date for such payment; or

(b) fails to provide or pay by the applicable date required any security deposit, equivalent form of security or guarantee or any requisite increase thereof.

The Utility may refuse to provide Energy Services to any Applicant, or the Utility may, without having to give any notice, discontinue providing Energy Services to any Customer, who:

(a) refuses to provide reference information and identification acceptable to the Utility when applying for Energy Services or at any subsequent time on request by the Utility;

(b) breaches the terms and conditions of the applicable Customer Agreement (including, without limitation, these Terms and Conditions);

(c) has defective pipes, appliances, or Thermal Energy fittings in any part or parts of Building;

(d) uses the provided Thermal Energy in a manner that, in the opinion of the Utility, may:

(i) lead to a dangerous situation; or

(ii) cause undue or abnormal fluctuations in the temperature of any component of the Thermal Energy System;

(e) fails to make modifications or additions to the Customer's equipment as required by the Utility to prevent the danger or control the fluctuations described in paragraph (d) above;

(f) negligently or fraudulently misrepresents to the Utility its use of Thermal Energy or the Thermal Energy load requirements of, or Thermal Energy volume consumed within and by, any Building;

(g) terminates the applicable Customer Agreement pursuant to Section 20 or causes the termination of the applicable Customer Agreement for any reason; or

(h) stops consuming Thermal Energy in the Building.

The Utility will not be liable for any loss, injury or damage suffered by any Customer by reason of the discontinuation of or refusal to provide Energy Services as set out in this Section.

17. Security for Payment of Bills

(a) A Customer who has not established or maintained credit to the satisfaction of the Utility may be required to provide a security deposit or equivalent form of security, the amount of which may not exceed the estimated total bill for the two highest consecutive months' consumption of Thermal Energy by the Customer.

(b) A security deposit or equivalent form of security is not an advance payment.

(c) The Utility will pay interest on a security deposit at the rate and at the times specified in the Standard Fees and Charges Schedule. If a security deposit is returned to a Customer for any reason, the Utility will credit any accrued interest to the Customer's account at that time. No interest is payable on any unclaimed deposit left with the Utility after the account for which it is security is closed, or on a deposit held by the Utility in a form other than cash.

(d) A security deposit (plus any accrued interest) will be returned to the Customer after one year of good payment history, or when the Customer's Customer Agreement is terminated pursuant to Section 20, whichever occurs first.

(e) If a Customer's bill is not paid when due, the Utility may apply all or any part of the Customer's security deposit or equivalent form of security and any accrued interest towards payment of the bill. Under these circumstances, the Utility may still elect to discontinue Energy Services to the Customer for failure to pay for Energy Services.

(f) If a Customer's security deposit or equivalent form of security is appropriated by the Utility for payment of an unpaid bill, the Customer must re-establish the security deposit or equivalent form of security before the Utility will reconnect or continue Energy Services to the Customer.

18. <u>Account Charge</u>

When a change of Customer occurs, an account charge, as set out in the Standard Fees and Charges Schedule, will be paid by the new Customer with respect to each account in that Customer's name for which a separate bill is rendered by the Utility.

19. <u>Term of Customer Agreement</u>

The initial term of a Customer Agreement will be as follows:

(a) where a new Service Connection is required to provide Energy Services, five years; or

(b) where a Distribution Extension is required to provide Energy Services, for a period of time fixed by the Utility but not exceeding the number of years used to calculate the revenue in the Distribution Extension economic test.

The Customer Agreement will thereafter automatically be renewed from year to year unless:

(a) specified otherwise in a special contract or supplement referred to in Section 28; or

(b) the Customer Agreement is terminated pursuant to Section 20 below.

20. <u>Termination of Customer Agreement</u>

A Customer may, following the initial term specified in Section 19, terminate the applicable Customer Agreement by giving at least 30 days written notice to the Utility at the address specified in the most recent bill rendered to the Customer.

The Customer is not released from any previously existing obligations to the Utility by terminating the Customer Agreement.

The Customer acknowledges and agrees that if it terminates the Customer Agreement pursuant to this Section, the Utility may charge the Customer the full cost of all infrastructure associated with the provision of Energy Services to the Customer if the Utility determines that such charge is necessary to ensure other Customers on the Thermal Energy System are not adversely impacted by such termination.

Notwithstanding any termination by the Customer pursuant to this Section, and without derogating from the generality of Section 5, all components of the Thermal Energy System will remain the property of and vest in the Utility.

21. Liability

(a) The Utility will endeavour to provide a regular and uninterrupted supply of Thermal Energy, but it does not guarantee a constant supply of Thermal Energy or the maintenance of unvaried temperatures. Neither the Utility, nor any of the Utility's Representatives is responsible or liable for any loss, injury (including death), damage or expense incurred by any Customer or any Person claiming by or through a Customer, that is caused by or results from, directly or indirectly, any discontinuance, suspension, or interruption of, or failure or defect in the supply, delivery or transportation of, or any refusal to supply, deliver, or transport Thermal Energy, or provide Energy Services, unless the loss, injury (including death), damage or expense is directly and solely attributable to the gross negligence or wilful misconduct of the Utility or any of the Utility's Representatives, provided however that neither the Utility nor any of the Utility's Representatives is responsible for any loss of profit, loss of revenue or other economic loss, even if the loss is directly attributable to the gross negligence or wilful misconduct of the Utility or any of the Utility's Representatives.

(b) Energy Services may be temporarily suspended to make repairs or improvements to the Thermal Energy System or in the event of fire, flood or other sudden emergency. The Utility will, whenever reasonably practicable, give notice of such suspension to the Customer and will restore Energy Services as soon as possible. Telephone, flyer, or other acceptable announcement method may be used for notice purposes. The Utility will not be liable for any loss, injury or damage caused by or arising out of any such suspension of Energy Services.

(c) The Customer shall bear and retain the risk of, and hereby indemnifies and holds harmless the Utility and all of the Utility's Representatives from, all loss and damage to all components of the Thermal Energy System in, on or under the Customer's lands (whether located inside or outside of Building) except to the extent any loss or damage is directly attributable to the negligence of the Utility or any of the Utility's Representatives, or is caused by or results from a defect in the Thermal Energy System. The Customer must prove such negligence or defect.

(d) The Customer agrees to indemnify and hold harmless the Utility and all of the Utility's Representatives from all claims, losses, damages, liabilities, costs, expenses and injury (including death) suffered by the Customer or any person claiming by or through the Customer or any third party and caused by or resulting from the use of the Customer's lands by the Utility as contemplated herein or the use of Thermal Energy by the Customer or the presence of Thermal Energy on or in any part of the Building or from the Customer or the Customer's employees, contractors or agents damaging any component of the Thermal Energy System. This paragraph will survive any termination of the Customer Agreement.

(e) The Customer acknowledges and agrees that the Utility will not in any way be responsible for any aspect of the design, engineering, permitting, construction or installation of any Building System.

(f) The Customer will release, indemnify and hold harmless the Utility and all of the Utility's Representatives from any and all liabilities, actions, damages, claims (including remediation cost recovery claims), losses, costs, orders, fines, penalties and expenses whatsoever (including all consulting and legal fees and expenses on a solicitor-client basis) and the costs of removal, treatment, storage and disposal of Contaminants and remediation of the Customer's lands and any affected adjacent property which may be paid by, incurred by or asserted against the Utility or any of the Utility's Representatives arising from or in connection with the presence of Contaminants on, in or under the Customer's lands or any Release or alleged Release of any Contaminants at or from the Customer's lands related to or as a result of the presence of any pre-existing Contaminants at, on, under or in the Customer's lands, including without limitation surface and ground water at the date of the Customer Agreement or as a result at any time of the operations of the Customer or any act or omission of the Customer or its tenants or other occupants or any person for whom it is in law responsible.

(g) The Customer will obtain and maintain at its own expense appropriate insurance coverage (including property and liability) throughout the term of the Customer Agreement and will provide the Utility with evidence of same upon request.

22. Access to Buildings and Equipment

The Utility's Representatives will have, at all reasonable times, free access to all components of the Thermal Energy System in, on or under the Customer's lands (whether located inside or outside of Building) to ascertain the quantity or method of use of Energy Services, as well as for the purpose of reading, testing, repairing or removing the whole or any such component (or part thereof), turning Thermal Energy on or off, conducting system leakage surveys, stopping leaks, and examining pipes, fittings, connections and appliances.

In furtherance of the above, the Customer hereby grants and covenants to secure for the Utility and its subcontractors, agents, employees and representatives, by licenses, statutory rights of way, easements, leases or other agreements, and for nominal consideration, non-exclusive access to, on, over and under the Customer's lands for the purposes of performing its obligations under the Customer Agreement. Without limiting the generality of the foregoing, the Customer will, forthwith upon the Utility's request and at the cost of the Customer, grant or cause to be granted to the Utility and duly register in the relevant Land Title Office a statutory right of way in the Utility's standard form in respect of each lot comprising a part of the Customer's lands and otherwise as required to allow the Utility to perform its obligations under the Customer Agreement. Each statutory right of way granted pursuant to this Section will have priority over any financial encumbrance registered against title. For greater certainty, the access granted pursuant to this Section will be adequate, in the sole discretion and determination of the Utility, to allow the Utility to efficiently and effectively carry out its obligations pursuant to the Customer Agreement without undue disturbance or interference from the Customer or any of its contractors, agents, employees or representatives.

The Customer acknowledges and agrees that each statutory right of way, lease or other registrable interest granted pursuant to this Section may be registered by the Utility in the relevant Land Title Office, together with any priority agreements as the Utility may deem necessary or advisable.

To the extent there is a statutory right of way in favour of the Utility registered against the Customer's lands, the Customer hereby covenants and agrees to be bound by, and to comply with, such registered statutory right of way. If there is any inconsistency between the terms and conditions of the Customer Agreement and the terms and conditions of any such statutory right of way, the terms and conditions provided in the Customer Agreement will prevail.

23. Curtailment of Energy Services

In the event of a breakdown or failure of any component of the Thermal Energy System, or at any time to comply with the requirements of any law, the Utility will have the right to require any Customer or class or classes of Customers or all its Customers, until notice of termination of the requirement is given, or between specified hours, to discontinue use of Thermal Energy for any purpose or purposes or to reduce in any specified degree or quantity such Customer(s)' consumption of Thermal Energy for any purpose or purposes.

Any such requirement may be communicated to any Customer or Customers or to all Customers by either or both of notice in writing (via e-mail, regular mail or personal delivery, or left at the relevant Building) and oral communication (including by telephone). Any notice of the termination of any such requirement may be communicated similarly.

If in the opinion of any official of the Utility any Customer has failed to comply with any requirement of the Utility communicated in accordance with this Section, the Utility will be at liberty, after notice to the Customer is communicated in accordance with this Section, to discontinue Energy Service to such Customer.

The Utility will not be liable for any loss, injury, damage or expense occasioned to or suffered by any Customer for or by reason of any discontinuance of Energy Services as contemplated by this Section.

24. Disturbing Use

All equipment for which Thermal Energy is supplied will be subject to the reasonable approval of the Utility and the Customer will take and use the Thermal Energy so as not to endanger apparatus or cause any undue or abnormal fluctuations on the Thermal Energy System.

The Utility may require the Customer, at the Customer's expense, to provide equipment which will reasonably limit such fluctuations or disturbances and may refuse to supply Thermal Energy or suspend the supply thereof until such equipment is provided.

25. Sources of Energy

The Customer acknowledges and agrees that the Utility may, without the need to obtain any approval from the Customer and without any recourse by the Customer, from time to time incorporate other sources of energy or other energy supply systems into the Thermal Energy System, provided the Utility is still able to meet its obligations to the Customer hereunder.

26. Taxes

The rates and charges set out in these Terms and Conditions do not include social services tax, goods and services tax, harmonized sales tax or any other tax that the Utility may be lawfully authorized or required to add to its normal rates and charges.

27. Rate Schedule

The rates to be charged by, and paid to, the Utility for Energy Services will be the Basic Charge and Variable Energy Charge set out in the Rate Schedule from time to time in effect, which may be inspected on the Utility's website and at the office of the British Columbia Utilities Commission in Vancouver, British Columbia.

28. Special Contracts and Supplements

In unusual circumstances, special contracts and supplements to these Terms and Conditions may be negotiated between the Utility and the Customer and submitted for approval by the British Columbia Utilities Commission where:

(a) a minimum rate or revenue stream is required by the Utility to ensure that the provision of Energy Services to the Customer is economic; or

(b) factors such as system by-pass opportunities exist or alternative fuel costs are such that a reduced rate is justified to keep or to attach the Customer on the Distribution System.

29. Conflicting Terms and Conditions

Whenever anything in these Terms and Conditions is in conflict with any special terms or conditions provided in any Rate Schedule, the terms or conditions provided in the Rate Schedule will prevail and whenever anything in these Terms and Conditions or in any Rate Schedule is in conflict with the terms of any special contract the terms of such special contract will prevail.

30. Authority of Agents of the Utility

None of the Utility's Representatives has authority to make any promise, agreement or representation not incorporated in a Customer Agreement, and any such unauthorized promise, agreement or representation is not binding on the Utility.

SECTION C – RATE SCHEDULE

DOCKSIDE GREEN ENERGY
Schedule of Rates

Basic Charge:

Effective Date	$ per square metre (m^2) per month
July 1, 2025	$ 0.5538
January 1, 2026	$ 0.6923
January 1, 2027	$ 0.7961
January 1, 2028	$ 0.8916

Variable Energy Charge (1):

Effective Date	$ per kilowatt-hour (kWh)
April 1, 2025	$ 0.0370

Rate Rider 1 (2), (3):

Effective Date	$ per square metre (m^2) per month
April 1, 2025	$ 0.1834

Notes

(1) The Variable Energy Charge is calculated and updated on an annual basis in accordance with the approved rate setting mechanism.
(2) Rate Rider 1 amortizes the balance in the Property Tax Deferral Account based on the approved rate rider setting mechanism.
(3) Subject to approval by the BCUC, Rate Rider 1 will be discontinued effective April 1, 2026.

Accepted: [Month] [DD], 2025

Commission Secretary

SECTION D - STANDARD FEES AND CHARGES SCHEDULE

Account Charge: **$25.00**

The Account Charge is a single initial set up charge payable by each Applicant for Energy Services.

ADMINISTRATIVE CHARGES

Collection Charge: **$45.00**

Dishonoured Payments Charge: Equivalent to the Utility's lead bank's current NSF charge.

Late Payment Charge: Interest on outstanding balance equal to the lesser of 1.5% per month (19.6% compounded annually) and the maximum legal interest rate allowable.

Disputed Meter Testing Fees: Actual costs of removal, replacement and/or testing.

Interest on Cash Security Deposit:

The Utility will pay interest on any cash security deposit at the Utility's prime interest rate minus 2%. The Utility's prime interest rate is defined as the floating annual rate of interest which is equal to the rate of interest declared from time to time by the Utility's lead bank as its "prime rate" for loans in Canadian dollars.

Payment of interest will be credited to the Customer's account in January of each year.

Appendix F: Proposed Tariff (Blackline Version)

CORIX DOCKSIDE GREEN DE LIMITED PARTNERSHIP

Dockside Green District Energy Service

Thermal Energy Services Tariff

Containing

Definitions, Terms and Conditions, Rates, and Fees for Service

This tariff is available for public inspection at the utility's website.

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THERMAL ENERGY SERVICE TERMS & CONDITIONS¶
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RATES, FEES AND SERVICE APPLICATION¶
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Commission in Vancouver, British Columbia.¶
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Corix Multi-Utility Services Inc. Effective: January 1, 2019¶
Dockside Green Energy Accepted for filing: October 29, 2019¶
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SECTION A - DEFINITIONS

Unless the context otherwise requires, in these Terms and Conditions the following terms have the following meanings:

Affiliate: has the meaning ascribed to it in the British Columbia *Business Corporations Act*.

Applicant: means a Person applying to become a Customer in accordance with these Terms and Conditions.

Basic Charge: means a fixed charge attributable to infrastructure and operating costs, other than fuel and consumable costs required to be paid by a Customer for Energy Services during a prescribed period as specified in the Rate Schedule and is applicable to the Service Area declared on the application for service once billing commences.

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Application for Service: means the application referred to in Section 1.¶
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Building: means a single or multi-building residential development or other building or facility which is subject to a Customer Agreement.

Building System: means the system of water pipes and heat and domestic hot water delivery and / or storage equipment to be installed and used for distributing and storing Thermal Energy in a Building, connected to but downstream of and excluding the Service Connection and Energy Transfer Station for that Building.

Contaminants: means any radioactive materials, asbestos materials, urea formaldehyde, underground or above ground tanks, pollutants, contaminants, deleterious substances, dangerous substances or goods, hazardous, corrosive, or toxic substances, hazardous waste, waste, pesticides, defoliants, or any other solid, liquid, gas, vapour, odour, heat, sound, vibration, radiation, or combination of any of them, the storage, manufacture, handling, disposal, treatment, generation, use, transport, remediation, or Release into the environment of which is now or hereafter prohibited, controlled, or regulated under environmental laws.

Customer: means a Person receiving Energy Services pursuant to a Customer Agreement.

Customer Agreement: means an agreement between the Utility and a Customer for the provision of Energy Services to a Building or Buildings, which Agreement is comprised of an application for service and these Terms and Conditions.

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Distribution Extension: means an extension or upgrade of the Distribution System less than a material dollar amount and thus not subject to the British Columbia Utilities Commission *Thermal Energy Systems Regulatory Framework Guidelines.*

Distribution System: means, collectively, the system of water pipes, fittings and ancillary components connecting the central thermal energy plant to the Service Connections.

Energy Services: means the provision by the Utility of Thermal Energy via the Thermal Energy System.

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Energy Transfer Station: means the separate heat exchanger for space heating and domestic hot water (excluding domestic hot water storage tanks), energy meter including temperature sensors and flow meter, control panel and all pipes, fittings and other associated equipment that control the transfer, and measure Thermal Energy from the Distribution System to a Building System.

Person: means an individual or his or her legal personal representative, an unincorporated organization or association, or a corporation, partnership, trust, trustee, syndicate, joint venture, limited liability company, union, government agency or other entity or organization.

Rate Schedule: means that schedule attached to and forming part of these Terms and Conditions, which sets out the rates for Energy Services, exclusive of third-party payment processing fees, and certain related terms and conditions, as amended from time to time by the Utility with the approval of, and as filed with, the British Columbia Utilities Commission.

Release: means any release, spill, leak, pumping, pouring, emission, emptying or discharge, injection, escape, leaching, migration, disposal, or dumping.

Service Area: means the total area of the Building receiving Thermal Energy services, measured in square meters.

Service Connection: means the system of water pipes and all ancillaries and fittings necessary to connect a Building System to the Distribution System via the Energy Transfer Station.

Standard Fees and Charges Schedule: means that schedule attached to and forming part of these Terms and Conditions which sets out certain standard fees and charges, exclusive of third-party payment processing fees, which may be charged to the Customer in accordance with these Terms and Conditions.

Terms and Conditions: means these Thermal Energy Service Terms & Conditions, including the definitions and schedules hereto, all as amended from time to time by the Utility with the approval of, and as filed with, the British Columbia Utilities Commission.

Thermal Energy: means thermal energy for space heating and domestic hot water.

Thermal Energy System: means the district energy system by which the Utility delivers Thermal Energy to Customers, including the central thermal energy plant, the Distribution System, the Service Connections and the Energy Transfer Stations.

Utility: means Corix Dockside Green DE Limited Partnership (referred to as Corix Dockside Green District Energy Service) carrying on the business of a Thermal Energy distribution utility.

Utility's Representatives: means any Person who is an officer, director, employee, agent, contractor, subcontractor, consultant or advisor of either the Utility or any Affiliate of the Utility.

Variable Energy Charge: means a metered charge required to be paid by a Customer for energy costs associated with the provision of Energy Services during a prescribed period as specified in the Rate Schedule.

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SECTION B - TERMS AND CONDITIONS

1. Application for Energy Services

The Utility will provide Energy Services to Customers solely in accordance with these Terms and Conditions. Persons seeking to become Customers must apply for Energy Services in accordance with this Section.

Application for Energy Services will be made in writing. Applicants will be required by the Utility to complete and sign an application for service form which, together with these Terms and Conditions, constitutes a Customer Agreement. The Customer Agreement will become binding on the parties thereto only and forthwith upon commencement by the Utility of Energy Services at the relevant Building. Applicants may be required to provide reference information and identification acceptable to the Utility in connection with an application for Energy Services.

The application for service form will include a declaration of Service Area for the purpose of billing the Basic Charge. If required, Customers may submit a request to update the Service Area in writing, which must be accompanied by a legal survey. Following review and acknowledgement of the request by the Utility, the updated Service Area will be reflected on the bill rendered as part of the next bill cycle. Prior bills will not be adjusted.

If an Applicant is requesting Energy Services at more than one Building, the Utility will determine in its sole discretion whether to consider the Applicant the same Customer for all Buildings or to consider the Applicant a separate Customer for each of the Buildings. If an Applicant is requesting Energy Services for more than one unit, area or premises within the same Building, the Applicant will be considered the same Customer for all such unit(s), area(s) or premises. The Utility intends that there will be no more than one Customer per Building.

The Utility may refuse to provide Energy Services to an Applicant if there is an unpaid account for Energy Services in respect of such Applicant or the relevant Building.

2. Assignment

A Customer may not assign a Customer Agreement or any of its rights or obligations thereunder without the prior written consent of the Utility, such consent not to be unreasonably withheld. The Utility may assign a Customer Agreement or any of its rights or obligations thereunder (including, without limitation, by way of the sale of the majority of its shares or business or its material assets or by way of an amalgamation, merger or other corporate reorganization) to any of its Affiliates or to any other Person without the consent of the Customer, provided such Affiliate or Person is duly qualified to carry out the Customer Agreement and agrees to be bound by the terms and conditions of the Customer Agreement. Forthwith upon such assignment, the Utility shall be released from its obligations and responsibilities under the Customer Agreement.

3. Use of Thermal Energy

A Customer will use Thermal Energy only for space heating and domestic hot water within the Building.

Unless authorized by the Utility in writing and in advance, a Customer will not sell or supply to any other Person Thermal Energy provided by the Utility, nor use Thermal Energy supplied by the Utility for any purpose other than as specified in this Section.

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4. Applicable Rate Schedule

A Customer must not significantly change its connected load without the prior written approval of the Utility. The Utility may conduct periodic reviews of the quantity of Thermal Energy delivered and the rate of delivery of Thermal Energy to a Customer for the purpose of, among other things, determining whether to substitute a more applicable Rate Schedule.

5. Ownership and Care of Thermal Energy System

Notwithstanding any degree of annexation or affixation, or rule of law or equity to the contrary, the Utility owns all components of the Thermal Energy System and all additions or extensions thereto will be and remain the property of and vest in the Utility, whether located inside or outside of Building. No component of the Thermal Energy System shall be moved or removed from a Customer's lands (whether located inside or outside of Building) without the advance written permission of the Utility. The Utility will not, under any circumstances whatsoever (including, without limitation, if the Utility is not providing Energy Services for any reason or if the Customer Agreement is terminated for any reason), be required to remove any component of the Thermal Energy System from the Customer's lands (whether located inside or outside of Building).

The Customer will take reasonable care of and protect all components of the Thermal Energy System in, on or under the Customer's lands (whether located inside or outside of Building) against damage and must advise the Utility promptly of any damage to or disappearance of the whole or part of any such component. Further, the Customer will pay to the Utility promptly upon request the cost of any broken, missing or damaged component of the Thermal Energy System (or part thereof), except to the extent that the Customer demonstrates that such component (or part thereof) was broken, missing or damaged due to a defect therein or to any act or omission of the Utility or any of the Utility's Representatives.

6. Meter Reading

The amount of Thermal Energy registered by the Energy Transfer Station during each billing period will be converted to kilowatt-hours (kWh) and rounded to the nearest two-tenths of a kWh.

The interval between consecutive meter readings will be at the sole discretion of the Utility.

The meter will typically be read at monthly intervals.

7. Meter Testing

Any Customer who doubts the accuracy of a meter comprising part of an Energy Transfer Station may request to have the meter tested by the original equipment manufacturer.

If the testing indicates that the meter is recording correctly, the Customer must pay the Utility for all costs associated with the testing and continuing operations during the testing, which includes but it not limited to removing, replacing and/or testing the meter as set out in the Standard Fees and Charges Schedule and the reconnection charge as set out in Section 10.

If the meter is found to be inaccurate by the manufacturer, the Utility will incur the cost of removing, replacing and/or testing the meter or (if applicable) refund such costs to the Customer.

8. Maintenance

The Utility will repair, maintain and replace all components of the Thermal Energy System in, on or under the Customer's lands (whether located inside or outside of Building), from time to time at its own cost to keep the

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same in good working order. For greater certainty, except for the Utility's obligation to repair, maintain and replace such components of the Thermal Energy System as aforesaid, the Utility is not, and will not be, responsible for repairing, maintaining or replacing any other facility or equipment in, on or under a Customer's lands (whether located inside or outside of Building), including without limitation any Building System(s).

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The Customer will repair, maintain and replace the Building System in all Building from time to time at its own cost to keep the same in good working order.

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9. Connections and Disconnections

No connection, disconnection, reconnection, extension, installation, replacement or any other change is to be made to any component of the Thermal Energy System by anyone except by the Utility's Representatives authorized by the Utility.

10. Energy Services Reconnections

If:

(a) Energy Services are discontinued to a Customer for any of the reasons specified in Section 16; or

(b) a Building System is disconnected from the Thermal Energy System or Energy Services are discontinued to a Customer:

  (i) at the request of the Customer with the approval of the Utility; or

  (ii) to permit a test of a meter at the request of the Customer, which meter is subsequently determined by the Utility to be accurate;

and such Customer or the employee, agent or other representative of such Customer re-applies for Energy Services for the same Building within 12 months of such discontinuance or disconnection (as applicable), then if the Building's Building System is reconnected to the Thermal Energy System or if Energy Services are restored to such Customer, such Customer will pay, as part of fees owing for the first month of Energy Services, a reconnection charge equal to the sum of:

(c) the costs that the Utility estimates it will incur in reconnecting the Building's Building System to the Thermal Energy System or restoring Energy Services to such Customer; and

(d) the Basic Charge that such Customer would have paid had Energy Services continued during the period between the date of discontinuance or disconnection (as applicable) and the date of such re-application.

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(d)

If a Building System is disconnected from the Thermal Energy System or Energy Services are discontinued to a Customer for public safety or Utility service requirement reasons, there will be no reconnection charge to reconnect the Building's Building System to the Thermal Energy System or to restore Energy Services to such Customer.

11. Distribution Extensions

The Customer acknowledges the following terms and conditions which will apply to the Utility's determination of whether or not to complete a Distribution Extension in order to assess the economic impact of such Distribution Extension on existing Customers.

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(a) Ownership. All components of Distribution Extensions will be and remain the property of the Utility.

(b) Economic Test. Applications to extend Energy Services to one or more new Customers will be subject to an economic test, a model which is accepted by the British Columbia Utilities Commission. The economic test will be a discounted cash flow analysis of the projected revenue and costs associated with the Distribution Extension. The Distribution Extension will be deemed to be economic and constructed if the results of the economic test indicate a zero or positive net present value.

(c) Revenue. The projected revenue used in the economic test will be established by the Utility by:

(i) estimating the number of Customers to be served by the Distribution Extension;

(ii) establishing consumption estimates for each Customer;

(iii) projecting when the new Customers will be connected to the Distribution Extension; and

(iv) applying appropriate revenue margins for each Customer's consumption.

The revenue projection will also take into consideration the effect of variations in weather conditions on consumption.

(d) Costs. The costs used in the economic test will include, without limitation:

(i) the full projected labour, material, and other costs necessary to serve the new Customers including such costs applicable to new mains (subject to the provisions of this paragraph (d)), Service Connection(s), Energy Transfer Station(s) and related facilities;

(ii) the appropriate allocation of Utility overhead associated with construction of the Distribution Extension; and

(iii) projected incremental operating and maintenance expenses necessary to serve the new Customers. In addition to these costs, the economic test will incorporate applicable taxes and the appropriate return on investment as approved by the British Columbia Utilities Commission.

In cases where a larger Thermal Energy distribution main is installed to satisfy anticipated future demand requirements, the difference in cost between the installed, larger main and a smaller main that would be adequate to serve only those Customers supporting the particular application may be eliminated from the economic test.[1]

(e) Contributions in Aid of Construction. If the economic test results indicate a negative net present value, the Distribution Extension may proceed provided that the shortfall in revenue is eliminated by contributions in aid of construction by or on behalf of Customers to be served by the Distribution

[1] From time to time the Utility may undertake larger expansions of the Thermal Energy System of a material dollar amount that fall outside of what is defined here as Distribution Extensions and are subject to the required applications to the British Columbia Utilities Commission under the *Thermal Energy Systems Regulatory Framework Guidelines*.

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Extension, or if there are non-financial factors offsetting the revenue shortfall that are deemed to be acceptable by the British Columbia Utilities Commission, the Utility may finance the contributions in aid of construction for Customers.

(f) Security. In those situations where the financial viability of a Distribution Extension is uncertain, the Utility may require a security deposit in cash or an equivalent form acceptable to the Utility.

12. Billing

(a) Bills will be rendered to the Customer in accordance with the Customer's Customer Agreement, including the Rate Schedule.

(b) Subject to paragraph (d) below, if meter readings cannot be obtained for any reason, consumption may be estimated by the Utility for billing purposes and the next bill that is based on actual meter readings will be adjusted for the difference between estimated and actual use over the interval between meter readings.

(c) If any meter fails to register or registers incorrectly, the consumption may be estimated by the Utility for billing purposes, subject to Section 13.

(d) If the Customer terminates a Customer Agreement, Corix will make all reasonable efforts to obtain an actual meter reading for the final bill rendered to the Customer. If the actual meter reading cannot be reasonably obtained, consumption may be estimated by the Utility for the purpose of the final bill.

(e) Bills will be rendered as often as deemed necessary by the Utility, but generally on a monthly basis. The due date for payment of bills shown on the face of the bill will be the first business day after:

(i) the 21st calendar day following the billing date; or

(ii) such other period otherwise agreed in writing by the Customer and the Utility.

(f) Bills will be paid in the manner specified therein, which may include payment by regular mail, and/or payment by on-line banking or electronic funds transfer.

(g) Customers requesting historic billing information may be charged the cost of processing and providing this information.

13. Back-billing

Minor adjustments to a Customer's bill, such as an estimated bill or an equal payment plan billing, do not require back-billing treatment.

(a) Back-billing means the re-billing by the Utility for Energy Services rendered to a Customer because the original billings were discovered to be either too high (over-billed) or too low (under-billed). The discovery may be made by either the Customer or the Utility. The cause of the billing error may include any of the following non-exhaustive reasons or combination thereof:

(i) stopped meter;

(ii) metering equipment failure;

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<object>[1] From time to time the Utility may undertake larger expansions of the Thermal Energy System of a material dollar amount that fall outside of what is defined here as Distribution Extensions and are subject to the required applications to the British Columbia Utilities Commission under the *Thermal Energy Systems Regulatory Framework Guidelines*.¶
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(iii) inaccurate meter, as determined pursuant to Section 7;

(iv) switched meters;

(v) double metering;

(vi) incorrect meter connections;

(vii) incorrect use of any prescribed apparatus respecting the registration of a meter;

(viii) incorrect meter multiplier;

(ix) the application of an incorrect rate;

(x) incorrect reading of meters or data processing; or

(xi) tampering, fraud, theft or any other criminal act.

(b) Where the Customer requests that the meter be tested, the provisions of Section 7 will apply in addition to those set forth in this Section.

(c) Where metering or billing errors occur and the Customer does not request that the meter be tested, the consumption and demand will be based on the records of the Utility for the Customer or on the Customer's own records to the extent they are available and accurate or, if not available, on reasonable and fair estimates made by the Utility. Such estimates will be on a consistent basis within each Customer class or according to a contract with the Customer, if applicable.

(d) If there are reasonable grounds to believe that the Customer has tampered with or otherwise used the Thermal Energy or any component of the Thermal Energy System in an unauthorized way, or there is evidence of fraud, theft or another criminal act, back-billing will be applied for the duration of the unauthorized use, subject to the applicable limitation period provided by law, and the provisions of paragraphs (g), (h), (i) and (j) below will not apply.

In addition, the Customer is liable for the direct (unburdened) administrative costs incurred by the Utility in the investigation of any incident of tampering, including the direct costs of repair, or replacement of equipment.

Under-billing resulting from circumstances described in this paragraph (d) will bear interest at the rate specified in the Standard Fees and Charges Schedule on unpaid accounts from the date of the original under-billed invoice until the amount under-billed is paid in full.

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(e) In every case of under-billing or over-billing, the cause of the error will be remedied without delay, and the Customer will be promptly notified of the error and of the effect on the Customer's ongoing bill.

(f) In every case of over-billing, the Utility will refund to the Customer all money incorrectly collected for the duration of the error, subject to the applicable limitation period provided by law. Simple interest, computed at the short-term bank loan rate applicable to the Utility on a monthly basis, will be paid to the Customer.

(g) Subject to paragraph (d) above, in every case of under-billing, the Utility will back-bill the Customer for the shorter of:

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(i) the duration of the error; or

(ii) one year, or as otherwise agreed by the Customer and the Utility in writing.

(h) Subject to paragraph (d) above, in every case of under-billing, the Utility will offer the Customer reasonable terms of repayment. If requested by the Customer, the repayment term will be equivalent in length to the back-billing period. The repayment will be interest free and in equal instalments corresponding to the normal billing cycle. Delinquency in payment of such instalments will be subject to the usual late payment charges.

(i) Subject to paragraph (d) above, if a Customer disputes a portion of a back-billing due to under-billing based upon either consumption, demand or duration of the error, the Utility will not threaten or cause the discontinuance of Energy Services for the Customer's failure to pay that portion of the back-billing, unless there is no reasonable ground for the Customer to dispute that portion of the back-billing. The undisputed portion of the bill will be paid by the Customer and the Utility may threaten or cause the discontinuance of Energy Services if such undisputed portion of the bill is not paid.

(j) Subject to paragraph (d) above, in all instances of back-billing where changes of occupancy have occurred, the Utility will make a reasonable attempt to locate the former Customer. If, after a period of one year, such Customer cannot be located, the over-billing or under-billing applicable to them will be cancelled.

14. Late Payment Charge And Collection Charge

If the amount due on any bill has not been paid in full on or before the due date shown on such bill, the bill rendered as part of the next bill cycle will include the overdue amount plus a late payment charge as set out in the Standard Fees and Charges Schedule. Notwithstanding the due date shown, to allow time for payments made to reach the Utility and to co-ordinate the billing of late payment charges with scheduled billing cycles, the Utility may, in its discretion, waive late payment charges on payments not processed until a number of days after the due date. If the Customer's account is overdue and requires additional effort to collect, the Utility may charge the Customer a collection charge as set out in the Standard Fees and Charges Schedule.

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15. Dishonoured Payments Charge

If a cheque or direct debit received by the Utility from a Customer in payment of any account is returned by the Customer's bank, trust company or financial institution because of insufficient funds (NSF), or any reason other than clerical error, a dishonoured payments charge as set out in the Standard Fees and Charges Schedule will be added to the amount due and payable by the Customer whether or not the applicable Building System has been disconnected from the Thermal Energy System or Energy Services have been discontinued to the Customer.

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16. Refusal to Provide Energy Services and Discontinuance of Energy Services

The Utility may refuse to provide Energy Services to any Applicant, or the Utility may, after having given 48 hours prior written notice, discontinue providing Energy Services to any Customer, who:

(a) fails to fully pay for any Energy Services provided to any Building on or before the due date for such payment; or

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(b) fails to provide or pay by the applicable date required any security deposit, equivalent form of security or guarantee or any requisite increase thereof.

The Utility may refuse to provide Energy Services to any Applicant, or the Utility may, without having to give any notice, discontinue providing Energy Services to any Customer, who:

(a) refuses to provide reference information and identification acceptable to the Utility when applying for Energy Services or at any subsequent time on request by the Utility;

(b) breaches the terms and conditions of the applicable Customer Agreement (including, without limitation, these Terms and Conditions);

(c) has defective pipes, appliances, or Thermal Energy fittings in any part or parts of Building;

(d) uses the provided Thermal Energy in a manner that, in the opinion of the Utility, may:

(i) lead to a dangerous situation; or

(ii) cause undue or abnormal fluctuations in the temperature of any component of the Thermal Energy System;

(e) fails to make modifications or additions to the Customer's equipment as required by the Utility to prevent the danger or control the fluctuations described in paragraph (d) above;

(f) negligently or fraudulently misrepresents to the Utility its use of Thermal Energy or the Thermal Energy load requirements of, or Thermal Energy volume consumed within and by, any Building;

(g) terminates the applicable Customer Agreement pursuant to Section 20 or causes the termination of the applicable Customer Agreement for any reason; or

(h) stops consuming Thermal Energy in the Building.

The Utility will not be liable for any loss, injury or damage suffered by any Customer by reason of the discontinuation of or refusal to provide Energy Services as set out in this Section.

17. Security for Payment of Bills

(a) A Customer who has not established or maintained credit to the satisfaction of the Utility may be required to provide a security deposit or equivalent form of security, the amount of which may not exceed the estimated total bill for the two highest consecutive months' consumption of Thermal Energy by the Customer.

(b) A security deposit or equivalent form of security is not an advance payment.

(c) The Utility will pay interest on a security deposit at the rate and at the times specified in the Standard Fees and Charges Schedule. If a security deposit is returned to a Customer for any reason, the Utility will credit any accrued interest to the Customer's account at that time. No interest is payable on any unclaimed deposit left with the Utility after the account for which it is security is closed, or on a deposit held by the Utility in a form other than cash.

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(d) A security deposit (plus any accrued interest) will be returned to the Customer after one year of good payment history, or when the Customer's Customer Agreement is terminated pursuant to Section 20, whichever occurs first.

(e) If a Customer's bill is not paid when due, the Utility may apply all or any part of the Customer's security deposit or equivalent form of security and any accrued interest towards payment of the bill. Under these circumstances, the Utility may still elect to discontinue Energy Services to the Customer for failure to pay for Energy Services.

(f) If a Customer's security deposit or equivalent form of security is appropriated by the Utility for payment of an unpaid bill, the Customer must re-establish the security deposit or equivalent form of security before the Utility will reconnect or continue Energy Services to the Customer.

18. Account Charge

When a change of Customer occurs, an account charge, as set out in the Standard Fees and Charges Schedule, will be paid by the new Customer with respect to each account in that Customer's name for which a separate bill is rendered by the Utility.

19. Term of Customer Agreement

The initial term of a Customer Agreement will be as follows:

(a) where a new Service Connection is required to provide Energy Services, five years; or

(b) where a Distribution Extension is required to provide Energy Services, for a period of time fixed by the Utility but not exceeding the number of years used to calculate the revenue in the Distribution Extension economic test.

The Customer Agreement will thereafter automatically be renewed from year to year unless:

(a) specified otherwise in a special contract or supplement referred to in Section 28; or

(b) the Customer Agreement is terminated pursuant to Section 20 below.

20. Termination of Customer Agreement

A Customer may, following the initial term specified in Section 19, terminate the applicable Customer Agreement by giving at least 30 days written notice to the Utility at the address specified in the most recent bill rendered to the Customer.

The Customer is not released from any previously existing obligations to the Utility by terminating the Customer Agreement.

The Customer acknowledges and agrees that if it terminates the Customer Agreement pursuant to this Section, the Utility may charge the Customer the full cost of all infrastructure associated with the provision of Energy Services to the Customer if the Utility determines that such charge is necessary to ensure other Customers on the Thermal Energy System are not adversely impacted by such termination.

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Corix Multi-Utility Services Inc. Effective: January 1, 2019¶
Dockside Green Energy Accepted for filing: October 29, 2019¶
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Notwithstanding any termination by the Customer pursuant to this Section, and without derogating from the generality of Section 5, all components of the Thermal Energy System will remain the property of and vest in the Utility.

21. Liability

(a) The Utility will endeavour to provide a regular and uninterrupted supply of Thermal Energy, but it does not guarantee a constant supply of Thermal Energy or the maintenance of unvaried temperatures. Neither the Utility, nor any of the Utility's Representatives is responsible or liable for any loss, injury (including death), damage or expense incurred by any Customer or any Person claiming by or through a Customer, that is caused by or results from, directly or indirectly, any discontinuance, suspension, or interruption of, or failure or defect in the supply, delivery or transportation of, or any refusal to supply, deliver, or transport Thermal Energy, or provide Energy Services, unless the loss, injury (including death), damage or expense is directly and solely attributable to the gross negligence or wilful misconduct of the Utility or any of the Utility's Representatives, provided however that neither the Utility nor any of the Utility's Representatives is responsible for any loss of profit, loss of revenue or other economic loss, even if the loss is directly attributable to the gross negligence or wilful misconduct of the Utility or any of the Utility's Representatives.

(b) Energy Services may be temporarily suspended to make repairs or improvements to the Thermal Energy System or in the event of fire, flood or other sudden emergency. The Utility will, whenever reasonably practicable, give notice of such suspension to the Customer and will restore Energy Services as soon as possible. Telephone, flyer, or other acceptable announcement method may be used for notice purposes. The Utility will not be liable for any loss, injury or damage caused by or arising out of any such suspension of Energy Services.

(c) The Customer shall bear and retain the risk of, and hereby indemnifies and holds harmless the Utility and all of the Utility's Representatives from, all loss and damage to all components of the Thermal Energy System in, on or under the Customer's lands (whether located inside or outside of Building) except to the extent any loss or damage is directly attributable to the negligence of the Utility or any of the Utility's Representatives, or is caused by or results from a defect in the Thermal Energy System. The Customer must prove such negligence or defect.

(d) The Customer agrees to indemnify and hold harmless the Utility and all of the Utility's Representatives from all claims, losses, damages, liabilities, costs, expenses and injury (including death) suffered by the Customer or any person claiming by or through the Customer or any third party and caused by or resulting from the use of the Customer's lands by the Utility as contemplated herein or the use of Thermal Energy by the Customer or the presence of Thermal Energy on or in any part of the Building or from the Customer or the Customer's employees, contractors or agents damaging any component of the Thermal Energy System. This paragraph will survive any termination of the Customer Agreement.

(e) The Customer acknowledges and agrees that the Utility will not in any way be responsible for any aspect of the design, engineering, permitting, construction or installation of any Building System.

(f) The Customer will release, indemnify and hold harmless the Utility and all of the Utility's Representatives from any and all liabilities, actions, damages, claims (including remediation cost recovery claims), losses, costs, orders, fines, penalties and expenses whatsoever (including all

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Dockside Green Energy Accepted for filing: October 29, 2019

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consulting and legal fees and expenses on a solicitor-client basis) and the costs of removal, treatment, storage and disposal of Contaminants and remediation of the Customer's lands and any affected adjacent property which may be paid by, incurred by or asserted against the Utility or any of the Utility's Representatives arising from or in connection with the presence of Contaminants on, in or under the Customer's lands or any Release or alleged Release of any Contaminants at or from the Customer's lands related to or as a result of the presence of any pre-existing Contaminants at, on, under or in the Customer's lands, including without limitation surface and ground water at the date of the Customer Agreement or as a result at any time of the operations of the Customer or any act or omission of the Customer or its tenants or other occupants or any person for whom it is in law responsible.

(g) The Customer will obtain and maintain at its own expense appropriate insurance coverage (including property and liability) throughout the term of the Customer Agreement and will provide the Utility with evidence of same upon request.

22. Access to Buildings and Equipment

The Utility's Representatives will have, at all reasonable times, free access to all components of the Thermal Energy System in, on or under the Customer's lands (whether located inside or outside of Building) to ascertain the quantity or method of use of Energy Services, as well as for the purpose of reading, testing, repairing or removing the whole or any such component (or part thereof), turning Thermal Energy on or off, conducting system leakage surveys, stopping leaks, and examining pipes, fittings, connections and appliances.

In furtherance of the above, the Customer hereby grants and covenants to secure for the Utility and its subcontractors, agents, employees and representatives, by licenses, statutory rights of way, easements, leases or other agreements, and for nominal consideration, non-exclusive access to, on, over and under the Customer's lands for the purposes of performing its obligations under the Customer Agreement. Without limiting the generality of the foregoing, the Customer will, forthwith upon the Utility's request and at the cost of the Customer, grant or cause to be granted to the Utility and duly register in the relevant Land Title Office a statutory right of way in the Utility's standard form in respect of each lot comprising a part of the Customer's lands and otherwise as required to allow the Utility to perform its obligations under the Customer Agreement. Each statutory right of way granted pursuant to this Section will have priority over any financial encumbrance registered against title. For greater certainty, the access granted pursuant to this Section will be adequate, in the sole discretion and determination of the Utility, to allow the Utility to efficiently and effectively carry out its obligations pursuant to the Customer Agreement without undue disturbance or interference from the Customer or any of its contractors, agents, employees or representatives.

The Customer acknowledges and agrees that each statutory right of way, lease or other registrable interest granted pursuant to this Section may be registered by the Utility in the relevant Land Title Office, together with any priority agreements as the Utility may deem necessary or advisable.

To the extent there is a statutory right of way in favour of the Utility registered against the Customer's lands, the Customer hereby covenants and agrees to be bound by, and to comply with, such registered statutory right of way. If there is any inconsistency between the terms and conditions of the Customer Agreement and the terms and conditions of any such statutory right of way, the terms and conditions provided in the Customer Agreement will prevail.

23. Curtailment of Energy Services

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Corix Multi-Utility Services Inc. Effective: January 1, 2019¶
Dockside Green Energy Accepted for filing: October 29, 2019¶
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In the event of a breakdown or failure of any component of the Thermal Energy System, or at any time to comply with the requirements of any law, the Utility will have the right to require any Customer or class or classes of Customers or all its Customers, until notice of termination of the requirement is given, or between specified hours, to discontinue use of Thermal Energy for any purpose or purposes or to reduce in any specified degree or quantity such Customer(s)' consumption of Thermal Energy for any purpose or purposes.

Any such requirement may be communicated to any Customer or Customers or to all Customers by either or both of notice in writing (via e-mail, regular mail or personal delivery, or left at the relevant Building) and oral communication (including by telephone). Any notice of the termination of any such requirement may be communicated similarly.

If in the opinion of any official of the Utility any Customer has failed to comply with any requirement of the Utility communicated in accordance with this Section, the Utility will be at liberty, after notice to the Customer is communicated in accordance with this Section, to discontinue Energy Service to such Customer.

The Utility will not be liable for any loss, injury, damage or expense occasioned to or suffered by any Customer for or by reason of any discontinuance of Energy Services as contemplated by this Section.

24. Disturbing Use

All equipment for which Thermal Energy is supplied will be subject to the reasonable approval of the Utility and the Customer will take and use the Thermal Energy so as not to endanger apparatus or cause any undue or abnormal fluctuations on the Thermal Energy System.

The Utility may require the Customer, at the Customer's expense, to provide equipment which will reasonably limit such fluctuations or disturbances and may refuse to supply Thermal Energy or suspend the supply thereof until such equipment is provided.

25. Sources of Energy

The Customer acknowledges and agrees that the Utility may, without the need to obtain any approval from the Customer and without any recourse by the Customer, from time to time incorporate other sources of energy or other energy supply systems into the Thermal Energy System, provided the Utility is still able to meet its obligations to the Customer hereunder.

26. Taxes

The rates and charges set out in these Terms and Conditions do not include social services tax, goods and services tax, harmonized sales tax or any other tax that the Utility may be lawfully authorized or required to add to its normal rates and charges.

27. Rate Schedule

The rates to be charged by, and paid to, the Utility for Energy Services will be the Basic Charge and Variable Energy Charge set out in the Rate Schedule from time to time in effect, which may be inspected on the Utility's website and at the office of the British Columbia Utilities Commission in Vancouver, British Columbia.

28. Special Contracts and Supplements

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Corix Multi-Utility Services Inc. Effective: January 1, 2019¶
Dockside Green Energy Accepted for filing: October 29, 2019¶
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In unusual circumstances, special contracts and supplements to these Terms and Conditions may be negotiated between the Utility and the Customer and submitted for approval by the British Columbia Utilities Commission where:

(a) a minimum rate or revenue stream is required by the Utility to ensure that the provision of Energy Services to the Customer is economic; or

(b) factors such as system by-pass opportunities exist or alternative fuel costs are such that a reduced rate is justified to keep or to attach the Customer on the Distribution System.

29. Conflicting Terms and Conditions

Whenever anything in these Terms and Conditions is in conflict with any special terms or conditions provided in any Rate Schedule, the terms or conditions provided in the Rate Schedule will prevail and whenever anything in these Terms and Conditions or in any Rate Schedule is in conflict with the terms of any special contract the terms of such special contract will prevail.

30. Authority of Agents of the Utility

None of the Utility's Representatives has authority to make any promise, agreement or representation not incorporated in a Customer Agreement, and any such unauthorized promise, agreement or representation is not binding on the Utility.

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Dockside Green Energy Accepted for filing: October 29, 2019

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SECTION C – RATE SCHEDULE

DOCKSIDE GREEN ENERGY
Schedule of Rates

Basic Charge:

Effective Date	$ per square metre (m^2) per month
July 1, 2025	$ 0.5538
January 1, 2026	$ 0.6923
January 1, 2027	$ 0.7961
January 1, 2028	$ 0.8916

Variable Energy Charge [(1)]:

Effective Date	$ per kilowatt-hour (kWh)
April 1, 2025	$ 0.0370

Rate Rider 1 [(2), (3)]:

Effective Date	$ per square metre (m^2) per month
April 1, 2025	$ 0.1834

Notes
(1) The Variable Energy Charge is calculated and updated on an annual basis in accordance with the approved rate setting mechanism.
(2) Rate Rider 1 amortizes the balance in the Property Tax Deferral Account based on the approved rate rider setting mechanism.
(3) Subject to approval by the BCUC, Rate Rider 1 will be discontinued effective April 1, 2026.

Accepted: [Month] [DD], 2025

Commission Secretary

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Dockside Green Energy Accepted for filing: October 29, 2019¶
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SECTION D - STANDARD FEES AND CHARGES SCHEDULE

Account Charge: **$25.00**

The Account Charge is a single initial set up charge payable by each Applicant for Energy Services.

ADMINISTRATIVE CHARGES

Collection Charge: **$45.00**

Dishonoured Payments Charge: Equivalent to the Utility's lead bank's current NSF charge.

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Late Payment Charge: Interest on outstanding balance equal to the lesser of 1.5% per month (19.6% compounded annually) and the maximum legal interest rate allowable.

Disputed Meter Testing Fees: Actual costs of removal, replacement and/or testing.

Interest on Cash Security Deposit:

The Utility will pay interest on any cash security deposit at the Utility's prime interest rate minus 2%. The Utility's prime interest rate is defined as the floating annual rate of interest which is equal to the rate of interest declared from time to time by the Utility's lead bank as its "prime rate" for loans in Canadian dollars.

Payment of interest will be credited to the Customer's account in January of each year.

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Customer Information

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Corix Multi-Utility Services Inc. Effective: January 1, 2019¶
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Appendix G: Draft Order for 2025 Interim Rates

bcuc
British Columbia
Utilities Commission

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bcuc.com

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F: 604.660.1102

DRAFT ORDER
ORDER NUMBER
G-XX-25

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

Corix Dockside Green DE Limited Partnership
Dockside Green Energy
2025 – 2028 Revenue Requirements and Rates Application

BEFORE:
[Panel Chair]
Commissioner
Commissioner

on June [DD], 2025

ORDER

WHEREAS:

A. On June 3, 2025, Corix Dockside Green DE Limited Partnership (Corix) submitted an application seeking British Columbia Utilities Commission ("BCUC") approval of its Dockside Green Energy (DGE) revenue requirements for 2025, 2026, 2027, and 2028 with rates effective July 1, 2025, January 1, 2026, January 1, 2027, and January 1, 2028 respectively (Application);

B. In the Application, among other things, Corix requests interim approval of the Basic Charge for DGE, effective July 1, 2025 and January 1, 2026, as set out in the rate schedule filed in Section C of Appendix E to the Application;

C. Along with the Application Corix submitted separately a fully functional Microsoft Excel financial model (financial model) and requests that the financial model remain confidential for the various reasons provided in Section 1.3.4 of the Application;

D. ….; and

E. The BCUC has commenced review of the Application and determines that approving an interim Basic Charge for DGE and establishing a regulatory timetable are warranted.

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NOW THEREFORE pursuant to sections 59 to 61 and 89 of the *Utilities Commission Act*, the British Columbia Utilities Commission orders as follows:

1) A written hearing process is established for the review of the Corix Dockside Green DE Limited Partnership (Corix) Dockside Green Energy (DGE) 2025-2028 Revenue Requirement and Rates Application as set out in the regulatory timetable attached as Appendix A to this order.

2) Corix is approved to charge a Basic Charge of:
    a. $0.5538 per square metre per month effective July 1, 2025, on an interim and refundable or recoverable basis, with interest calculated at Corix's weighted average cost of capital; and

    b. $0.6923 per square metre per month effective January 1, 2026, on an interim and refundable or recoverable basis, with interest calculated at Corix's weighted average cost of capital.

3) The treatment of any variance between interim rates and permanent rates will by determined by the BCUC in a future order.

4) Corix is directed to file the tariff rate schedule for BCUC endorsement by Wednesday, July 9, 2025. The tariff rate schedule for BCUC endorsement should exclude the proposed Basic Charges for January 1, 2027 and January 1, 2028.

5) On or before Monday, July, 7, 2025, Corix is directed to:
    i. Provide notice of the Application and this order, or post the Public Notice attached as an appendix to this order, on DGE's website and Corix's existing social media platforms.

    ii. Provide a copy of this order and the Public Notice attached as an appendix to this order, electronically where possible, to all customers of the DGE. Corix is further directed to request each customer to post the Public Notice attached to this order on major notice boards of the customer's buildings served by the DGE and request each customer to provide confirmation of this posting to Corix.

    iii. Provide a copy of this order and the Public Notice attached as an appendix to this order, electronically where possible, to registered non-utility interveners in the Corix Restructuring and Business Combination Transactions proceeding, the DGE 2020 Variable Energy Charge

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and Rate Setting Mechanism proceeding; and the DGE 2019-2023 Revenue Requirements and Rates Application proceeding.

6) Corix is directed to provide to the BCUC confirmation of compliance with Directive 5 by [Month] [DD], 2025.

DATED at the City of Vancouver, in the Province of British Columbia, this [DD] day of June, 2025.

BY ORDER

(X. X. last name)
Commissioner

Appendix H: Draft Order for Final Rates

British Columbia Utilities Commission

Suite 410, 900 Howe Street
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DRAFT ORDER
ORDER NUMBER
G-XX-26

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

Corix Dockside Green DE Limited Partnership
Dockside Green Energy
2025 – 2028 Revenue Requirements and Rates Application

BEFORE:
[Panel Chair]
Commissioner
Commissioner

on [Month] [DD], 2026

ORDER

WHEREAS:

A. On June 3, 2025, Corix Dockside Green DE Limited Partnership (Corix) submitted an application seeking British Columbia Utilities Commission ("BCUC") approval of its Dockside Green Energy (DGE) revenue requirements for 2025, 2026, 2027, and 2028 with rates effective July 1, 2025, January 1, 2026, January 1, 2027, and January 1, 2028 respectively (Application);

B. Along with the Application Corix submitted separately a fully functional Microsoft Excel financial model (financial model) and requests that the financial model remain confidential for the various reasons provided in Section 1.3.4 of the Application;

A. .....;

B. ....; and

A. The BCUC has reviewed the Application and considers that approval of final rates is warranted.

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Utilities Commission

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NOW THEREFORE pursuant to sections 59 to 61 of the *Utilities Commission Act*, the British Columbia Utilities Commission orders as follows:

1) The delivery revenue requirements for 2025, 2026, 2027 and 2028 as presented in the Application is approved for DGE, including the following components for the test period:
    a. the operating and maintenance costs;
    b. the property and other fees;
    c. the rate base;
    d. the depreciation and amortization;
    e. a deemed capital structure of 51% debt and 49% equity;
    f. long-term deemed debt financing costs of 6.28% per annum in 2025, 2026, 2027 and 2028; and
    g. a return on equity of 10.4%.

2) The Monthly Basic Charges for Dockside Green Energy (DGE) is approved as:
    a. $ 0.5538 per building square metre, effective July 1, 2025;
    b. $ 0.6923 per building square metre, effective January 1, 2026
    c. $ 0.7961 per building square metre, effective January 1, 2027; and
    d. $ 0.8916 per building square metre, effective January 1, 2028.

3) Corix is approved to establish a Regulatory Cost Variance Account to record forecast variances of actual external regulatory costs, with full amortization of any balance within the test period of the next revenue requirement application.

4) Corix is approved to establish an Insurance Cost Variance Account to record forecast variances of actual insurance costs, with full amortization of any balance within the test period of the next revenue requirement application.

5) Corix is approved to transfer the existing Revenue Deficiency Deferral Account (RDDA) from a non-rate base account to a rate base account.

6) Corix is approved to transfer the existing Property Tax Deferral Account from a non-rate base account to a rate base account and to fully amortize any balance in the Property Tax Deferral Account within the test period of the next revenue requirement application.

7) Corix is approved to discontinue the use of DGE's Rate Rider 1, which was used to amortize the balance in the Property Tax Deferral Account, and the associated rate rider rate-setting mechanism effective April 1, 2026.

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8) Corix is approved to use the capitalized overhead methodology, as described in Section 8.5 of the Application, to record capitalized overhead in the test years.

9) Corix's proposed housekeeping amendments and rate change amendments to the tariff pages included in Appendix E of the Application, are approved.

10) Corix is directed to submit the complete tariff for acceptance by the BCUC within 30 days of the date on this order.

11) Corix is directed to comply with all other determinations included in the Decision issued concurrently with this order.

12) The BCUC will hold all the confidential information submitted with the Application and during the review of the Application as confidential in perpetuity.

DATED at the City of Vancouver, in the Province of British Columbia, this XX day of [Month], 2026.

BY ORDER

(X. X. last name)
Commissioner

Appendix I: Corporate Services Cost Allocation Manual

COST ALLOCATION MANUAL FOR CORPORATE COSTS

FOR FISCAL YEARS: 2024 AND 2025

TABLE OF CONTENTS

Revision History

VERSION	FOR FISCAL YEAR(S)	APPROVED BY	APPROVAL DATE
1.0	2024 and 2025[1]	Corix Executive Leadership Team (via email)	December 6, 2024

[1] 2024 Fiscal Year is a partial year from April 1, 2024 to December 31, 2024 following the completion of a corporate restructuring. 2025 Fiscal Year is a full year from January 1, 2025 to December 31, 2025.

1. INTRODUCTION

Corix District Energy Holdings Limited Partnership, with its general partner Corix District Energy Holdings GP Inc. (together "Corix") is a leader in the implementation of district energy utility infrastructure solutions for small to medium-sized communities across North America. Corix is a privately held company that is wholly owned by affiliates of the British Columbia Investment Management Corporation (BCI). Corix owns utilities and has investments (together "businesses") that operate in Canada and the United States.

Corix, through its Board of Directors and the Executive Leadership Team (ELT), is responsible for providing strategic direction, business oversight, and corporate governance for the business activities of the operating subsidiaries directly and indirectly owned by Corix.

The ELT consists of the following six (6) positions.

i. Chief Executive Officer (CEO)
ii. Chief Financial Officer (CFO)
iii. Chief Operating Officer – East (COO East)
iv. Chief Operating Officer – West (COO West)
v. Chief Legal Officer (CLO)
vi. Chief Growth Officer (CGO) & Vice President, Administration

The Board of Directors comprise employees of Corix's owner, BCI, and Corix's CEO. The Board of Directors ultimately is responsible for governing the business and affairs of Corix and its operating subsidiaries. The Board of Director's oversight responsibilities include:

- Reviewing and approving corporate strategy;
- Measuring progress towards achieving corporate strategic goals;
- Reviewing, approving, and monitoring all major capital projects;
- Monitoring actual spending in comparison to budgeted expenditures; and
- Monitoring and ensuring that Corix and its operating subsidiaries deliver high quality service in compliance with all applicable laws, rules, and regulations.[2]

Each ELT member is accountable for an organization with employees who are aligned to deliver operational services and support services necessary to provide district energy utility services to the communities served by Corix's operating subsidiaries.

Corporate support services are necessary for the operation of any business, including the safe and efficient operation of district energy utilities. Corix uses a centralized corporate support service organization to provide these services to the businesses, as well as regional support services in the East and West regions. The services and the costs of the COO East and COO West are not included in the corporate support services as they are included in the regional support services for which they oversee. This manual does not address regional support services or the allocation of regional costs.

The corporate Cost Allocation Methodology (CAM) has been designed to facilitate equitable cost sharing among businesses and to ensure that there is no subsidization of non-regulated services by regulated entities. In a manner consistent with the NARUC Guidelines for Cost Allocations and Affiliate Transactions[3] (NARUC Guidelines), Corix maintains this Corporate CAM Manual (Manual) that includes:

- a chart showing the corporate support services cost flows to all Corix businesses (Appendix A);

[2] At this time Corix does not incur costs pertaining to Board of Directors fees. However, in the future there may be external Board Members, whose costs would be allocated to the relevant Corix businesses using the methodology in this manual.
[3] NARUC Guidelines for Cost Allocations and Affiliate Transactions, https://pubs.naruc.org/pub/539BF2CD-2354-D714-51C4-0D70A5A95C65, accessed October 15, 2024.

- a description of the corporate cost allocation methodology and allocators used to allocate corporate support services costs to the Corix operating businesses (Section 4); and
- a description of the corporate support services provided to Corix businesses (Section 5 and Appendix B).

In addition to the above, this manual includes a hypothetical example of the corporate cost allocation methodology (Appendix C).

This manual is reviewed annually and updated to reflect organizational changes, if any. Updates to this manual are finalized through approval by the ELT.

2. DEFINITIONS

- **Corix District Energy Holdings Limited Partnership, with its general partner Corix District Energy Holdings GP Inc.** (together "Corix") is the corporate parent of Corix subsidiaries. As a pure play utility business, Corix enjoys a wide spectrum of technical and industry expertise in all facets of district energy utilities, including innovative technologies, operating tools, and regulatory resources required to develop sustainable utility services.

- **Corporate CAM Manual** (Manual) is this corporate cost allocation methodology manual, as updated by the relevant staff from time to time and approved by the ELT.

- **Corporate Support Services** refer to the administrative and general support services and functions provided to the whole organization. Corix's corporate support services include corporate governance; management control; strategic planning and execution; legal mandates, and risk mitigation; technical safety and compliance; health, safety and environment leadership; corporate finance and accounting, treasury, taxes and insurance services; people and culture and payroll; information technology and cybersecurity; and communications, all of which are necessary for the operation of a utility business of this size. In this Manual, Section 5 (Scope of Corporate Support Services) and Appendix B (Description of Corporate Support Services) provide details regarding the corporate support services provided to the whole organization.

- **Investments** refers to businesses in which Corix has a non-majority interest, which includes Doyon Utilities LLC, Oakridge Energy Limited Partnership and Entegrus Inc. Investments do not receive the complete suite of corporate support services since Corix does not have majority control. Where permitted, investments receive an allocation of costs based on the support service functions necessary to support their operation.

3. CORPORATE SUPPORT SERVICES COSTS

Corporate Support Services costs (also referred to as “corporate costs”) are identified, budgeted and tracked using homogenous corporate cost categories. The various corporate support services, corporate cost categories and the responsible ELT member are listed in the first three columns of Table 3 in Section 5 of this Manual.

The ELT members are accountable for expenses incurred within their budget. The importance of controlling costs is key, with targets being set for the company, and a portion of employee compensation is linked to responsible cost management. Headcount planning is conducted in the annual budgeting process; any headcount addition must be supported with a demonstration of need. The process takes several months with budgets undergoing rigorous analysis by the budget owners and multiple levels of review. Budgets are presented and subject to questions and answer sessions to test proposed costs including headcount addition requests. After thorough review by the relevant corporate support service teams, the budgets are then carefully reviewed by the ELT and the Board of Directors. At each level, costs are heavily scrutinized to evaluate efficiency of operations, including when appropriate, benchmarking exercises to compare costs, including labour costs, to members of relevant peer groups.

3.1 DIRECTLY ASSIGNABLE COSTS AND INDIRECT COSTS

Costs within the homogenous categories are either: (i) Directly Assignable Costs; or (ii) Indirect Costs.

Directly Assignable Costs

Directly Assignable Costs are costs incurred by one company for the exclusive benefit of, or specifically identified with, one or more companies, and which are directly charged to the company or companies that specifically benefited. This is consistent with the NARUC Guidelines, which on page 2 defines “Direct Costs” as “costs which can be specifically identified with a particular service or product.”

Direct Costs can be incurred on a shared basis. For example, Corix incurs “Shared Operating Costs”, which are costs that are managed centrally for administrative efficiency, cost savings and have vendor management by dedicated resources. These Shared Operating Costs are directly charged to the respective businesses before the corporate cost allocation process. Examples of this include business insurance, and the vendor costs associated with customer billing.

Direct Costs are not subject to the discussion of this corporate CAM as they are readily and clearly identified with a specific service and are directly assigned to the appropriate businesses.

Indirect Costs

Indirect Costs are costs incurred by one company that are for the benefit of either: (i) all; or (ii) some of the Corix companies, and which are charged to the benefited companies using a methodology and allocation factors that link cost causation and cost recovery. Under the NARUC Guidelines, “Indirect Costs” are defined on page 2 as “costs that cannot be identified with a particular service or product. This includes but not limited to overhead costs, administrative and general, and taxes.”

Indirect Costs are incurred on a shared basis for the benefit of several businesses. After assignment of direct costs, the indirect costs are the subject of discussion of this corporate CAM. Indirect costs are allocated to the companies that benefit from the indirect costs using the methodology for allocating corporate support services costs that is outlined in Section 4 of this manual.

Figure 1 in Appendix A outlines the cost flows from corporate support services to the various affiliate groups and entities.

4. CORPORATE COST ALLOCATION METHODOLOGY

The following steps are used for allocating the indirect costs within corporate support services costs.

1. The basis of variability of each category of indirect cost is assessed by reviewing what causes the costs in each category to change.
2. Indirect costs are then allocated either:
   - Using a functional allocator on the basis of variability in instances where this method is clearly applicable; or
   - Using a composite allocator for all other instances.

4.1 FUNCTIONAL ALLOCATOR

Functional allocators are used where the costs can be allocated using an identified cost causation driver. One example of this is using headcount to allocate indirect costs that are directly correlated to the number of employees.

4.2 COMPOSITE ALLOCATOR

Corix's indirect corporate support services costs that do not have a direct correlation with any one particular cost causation driver are allocated using a composite allocator. A composite allocator was chosen to represent the size, scope and complexity of each of the operating businesses with a goal of fairly putting businesses on a level standing for comparison purposes.

Corix's composite allocators comprise of three equally weighted factors as shown in Table 1 below. The equal weighting reflects that cost allocations are inherently an estimating exercise to fairly allocate costs and therefore no factor is over-weighted compared to another relevant factor. These weightings are kept constant in order to avoid introducing unnecessary complexity and administrative burden into the cost allocation methodology.

Table 1: Composite Allocator, Factors and Weighting

Factor	Weight
Gross Property, Plant & Equipment	33.33%
Gross Revenue	33.33%
Headcount	33.33%
Total	**100%**

The composite allocator based on the factors and weighting shown in Table 1 allows for a just and reasonable allocation of costs in a transparent, sustainable and cost-effective manner that reflects cost causality for shared costs which do not exhibit direct correlation with any one particular cost causation driver.

4.3 UPDATING ALLOCATOR INPUTS

Corix uses a point-in-time approach to calculate the forecast allocation percentages for the following year. This provides stability for budget preparations and actual allocations as well as a reference point for year-over-year comparisons. Allocation percentages are updated annually as outlined in Table 2 below.

Table 2: Allocator Input Reference Time Periods

Inputs	Reference
Gross Property, Plant & Equipment (Gross PPE)[4]	**As of June 30th of prior year**
Gross Revenue[5]	**Trailing Twelve Months as of June 30th of prior year**
Headcount	**As of June 30th of prior year**

For example, the 2025 budget and actual allocation would be based on a Composite Allocator that's calculated based on:

- Gross PPE at June 30, 2024;
- Gross Revenue from July 1, 2023 to June 30, 2024; and
- Headcount at June 30, 2024.

June 30th was chosen as the most appropriate point-in-time to allow for the allocation percentages to be determined, and the forecast corporate support service costs to be allocated to each operating utility/business prior to the completion of the annual budgets. A date earlier than June 30th would result in the unnecessary use of outdated information. A date after June 30th would yield more current information but would cause delays to the annual budget process for Corix.

4.3.1 Adjustments for Specific Unique Circumstances and Known and Measurable Changes

In unique circumstances, adjustments to the inputs (Gross PPE; Gross Revenue; Headcount) are to be made for known and measurable changes that would otherwise result in a cost allocation that does not appropriately reflect cost causality. The Known and Measurable Changes accounted for are:

1) Bargain Acquisition Adjustment;
2) Asset Impairment Adjustment; and
3) Approved Major Capital Projects

(1) Bargain Acquisition Adjustment
In some situations, utility assets are acquired for one dollar ($1), or purchased for an amount significantly below the net book value of the assets. For the purpose of allocating Corporate Support Services Costs, these purchases will be considered as though the utility assets were acquired at cost (for new assets) or fair market value (for assets previously in use). The fair market value may be equal to the net book value of the assets just prior to acquisition.

This adjustment recognizes the fact that utilities require continuous ongoing management oversight and stewardship as they provide service to customers, even in instances where the assets were acquired at a bargain price.

[4] Gross Property, Plant & Equipment is defined as gross property, plant, and equipment independent of the way it has been financed.
[5] Gross Revenue is defined as recorded gross revenue.

(2) Asset Impairment Adjustment

In instances where assets have been written down for accounting impairment purposes, the assets would continue to be recognized at their historical Gross PPE input value for the calculation of each composite allocator, provided that such assets continue to be used and are useful in the provision of service to customers.

This adjustment accounts for the situation where assets that have been written down for accounting impairment purposes continue to require ongoing management oversight and stewardship as the utility continues to provide service to customers.

(3) Approved Major Capital Projects

This is an adjustment to include approved major capital projects that are about to go into service after the June 30th cut-off date for inputs that year. It recognizes that the June 30th cut-off in the year for actual inputs to calculate the following year's corporate cost allocation may omit impending known and measurable changes that were previously approved by regulators. This is because the six-month period from July 1st to December 31st does not get reflected in the following year's cost allocations. As the corporate cost allocation is inherently an estimate to calculate a reasonable allocation of costs any minor changes or activity is immaterial. However, in some cases an approved major capital project that is to be placed in service during the July 1st to December 31st period may have a material impact on the revenue requirement for several utilities. This adjustment, with regard to allocation of corporate costs, recognizes that conceptually a project placed in service in the latter half of the year is treated the same as if a project is placed in service on June 30th of that same year.

This adjustment will be made using the latest available projected figures, if all three of the following apply to the situation:

(1) Corix has previously received regulatory approval for the execution of a major capital project, such as a Certificate of Public Convenience and Necessity ("CPCN");

(2) there is reasonable certainty that the major capital project will be completed, and the associated assets will be placed in service between July 1st and December 31st, after the June 30th cut-off date of the same year; and

(3) there is a material impact and change to the allocation of corporate costs to the utility and other utilities absent such an adjustment.

4.4 CHANGES TO THE CORPORATE COST ALLOCATION METHODOLOGY

In some jurisdictions, external regulatory agencies review and approve the Corporate CAM (as described in Section 4 of this Manual), for allocating indirect corporate costs to regulated utilities in Corix's portfolio. Please consult with a member of Corix's regulatory team when contemplating changes to Section 4 of this Manual, since external regulatory approvals may be required in advance of implementation.

5. SCOPE OF CORPORATE SUPPORT SERVICES

Corix is responsible for providing strategic direction, business oversight, and corporate governance for the business activities of the directly and indirectly owned operating businesses. Corporate support services maintain enterprise-wide standards and support for many functions as described in detail in Appendix B (Description of Corporate Support Services). These services are necessary for all the businesses to have access to capital for projects and operations providing efficiencies and expertise across the businesses. The use of shared expertise provides each of the businesses with benefits it could not economically achieve on a stand-alone basis.

The following are some of the benefits of consolidating executive, professional and operational support services into a centralized support service organization.

- **Governance** – centralized support service departments provide direct oversight and management control that improves operations and processes; for instance, monthly financial reporting and analysis comparing actual expenditures to budgeted expenditures ensures accountability and can improve operational efficiency.

- **Compliance** – support services departments help improve compliance with legal, financial, technical safety and other obligations of each individual operating company and holding companies.

- **Economies** – one of the primary benefits of the centralized support service model is that it helps the customers of smaller companies realize the benefits of scale enjoyed by much larger companies; among other things, the centralized service model allows Corix to leverage the buying power of the combined group of companies and more efficiently utilize staff through workload balancing and specialization.

- **Continuity of Service** – centralized support organizations mitigate the risk of disruptions in service caused by absences and departures.

- **Enterprise Standards** – centralized support service models play an important role in improving the quality of service by ensuring that standard policies, procedures, and practices are established and followed; in addition, centralized support service models also facilitate the sharing and adoption of best practices.

Table 3 that follows designates the benefits each corporate support service team provides, which demonstrates that support services are necessary for the safe and efficient delivery of utility operations and businesses.

Table 3: Support Service with corresponding benefits, listed by Corporate Cost Category and responsible ELT Member[6]

Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8
ELT Member	**Corporate Cost Category**	**Support Service Provided**	**Governance**	**Compliance**	**Economies**	**Continuity of Service**	**Enterprise Standards**
CEO	Executive Management	Executive Management	X	X	X	X	X
CFO	Finance	Finance	X	X	X	X	X
		Corporate Accounting	X	X	X		X
		Treasury	X	X	X		X
		Taxes	X	X	X	X	X
		Insurance	X	X	X	X	X
CLO	Legal and Risk Management	Legal	X	X	X		X
		Technical Safety & Compliance and HSE[7] Leadership	X	X	X		X
		Risk Management	X	X	X	X	X
		Internal Audit	X	X	X	X	X
CGO & VP Administration	People & Culture	People & Culture	X	X	X		X
	IT, OT & Cybersecurity	Information Technology	X	X	X	X	X
		Cybersecurity	X	X	X	X	X
		Operational Technology	X	X	X	X	X
	Communications	Communications	X	X	X	X	X

[6] This table excludes COOs since their costs are addressed through the Regional Cost Allocation Methodology.
[7] Health, Safety and Environment.

Appendix B provides a detailed description of the scope of corporate support services provided, grouped by ELT member. Table 4 below summarizes the scope of corporate support services and shows the allocator applied to each category of cost. The allocator may be a functional allocator or a composite allocator. The functions and categories are as of approval date of this Manual[8] and are subject to change based on potential changes in the needs of the operating businesses. If organizational restructuring or realignments are implemented, any allocations of new or modified categories would be completed in a manner consistent with the cost allocation methodology described in Section 4 of this document.

Table 4: Summary of Corporate Support Services, Functions and Allocators[9]

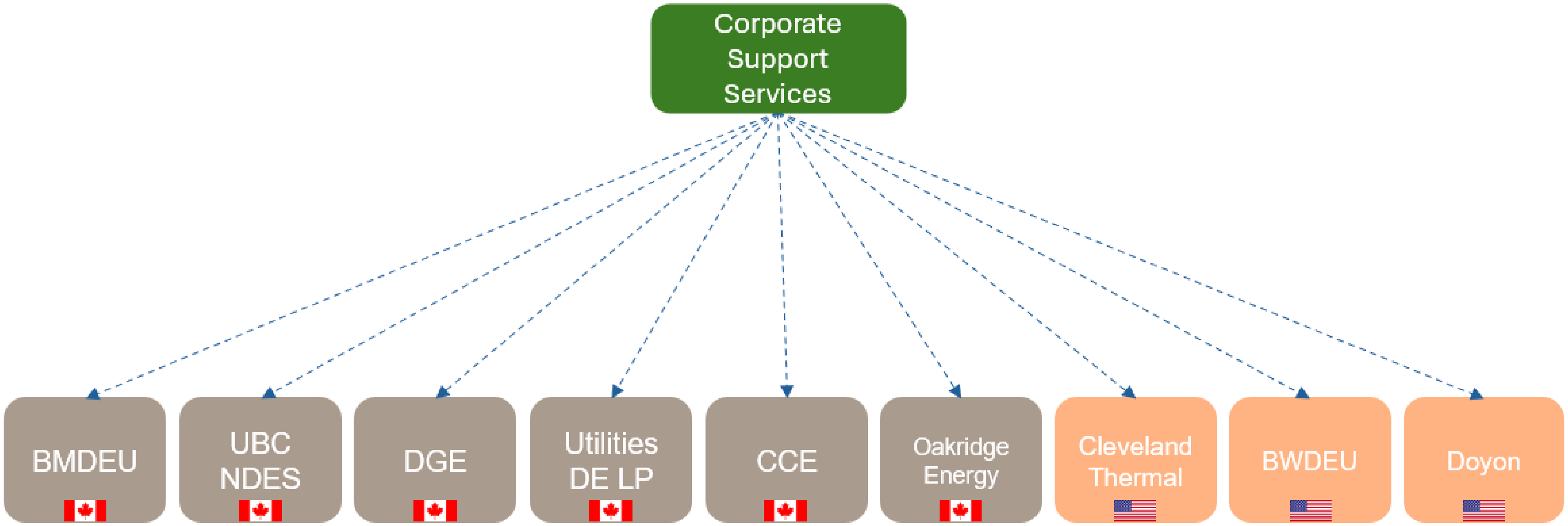
Column 1	*Column 2*	*Column 3*	*Column 4*
ELT Member	**Corporate Cost Category[10]**	**Allocator**	**Functions**
CEO	Executive Management	Composite Allocator[11]	Set overall direction and enterprise strategy; provide guidance to operational leadership; ensure the organization is acting with honesty, integrity, transparency, and accountability to customers.
CFO	Finance	Composite Allocator	Ensure financial integrity and secure debt and equity financing; perform all corporate accounting activities, prepare external and internal financial reports; oversee the preparation of the budget and analysis of planned versus actual spending; perform tax accounting and compliance.
CLO	Legal and Risk Management	Composite Allocator	Provide legal advice and services; ensure compliance with technical safety requirements and oversee the HSE programs within Corix. Identify, report on and develop plans for managing/mitigating significant risks to the enterprise; and conduct audits to identify compliance with corporate policies and procedures.
CGO & VP Administration[12]	People & Culture (“P&C”)	Headcount	Provides support services including people and culture management such as payroll administration, wage and salary design, benefit and medical plan design and administration, pension plan administration; information technology, operational technology and cybersecurity services; and enterprise-wide internal and external communications.
	IT, OT & Cybersecurity	Composite Allocator	
	Communications	Composite Allocator	

[8] See Revision History on page 1 of this document.
[9] A detailed description of the corporate support services is included in Appendix B.
[10] Refer to Table 3 for a breakdown of the components of each corporate cost category.
[11] The Composite Allocator is discussed in Section 4.2 of this document.
[12] The CGO is also the VP Administration and spends approximately 50% of their time on business development and 50% of their time leading administrative support services for Corix. As a result, 50% of the cost associated with the CGO and VP Administration is excluded from regulated utility cost recovery.

APPENDICES

APPENDIX A – CORPORATE SUPPORT SERVICES COST FLOWS DIAGRAM

Figure 1: Corporate Support Services Cost Flows



Notes

1) This structure reflects the corporate services cost distribution and does not indicate the corporate structure. Corporate holding intermediaries are not shown on this diagram.
2) Doyon and Oakridge Energy are allocated only (i) Corporate Administration and (ii) Corporate Finance and Accounting since these are the only applicable departments that provide support services.
3) The actual costs invoiced to Oakridge Energy from Corix are direct charged based on that permitted by the Services Agreement between Corix and Oakridge Energy. The difference between the actual costs invoiced and the amount calculated using this allocation methodology is not redistributed to the remaining utilities.

APPENDIX B – DESCRIPTION OF CORPORATE SUPPORT SERVICES

This appendix describes the services and functions provided by Corix's centralized corporate support service team and explains the nature of the costs for each corporate support service.

1) **CEO Office**

The CEO Office includes direct employee labour and non-labour costs, as well as rent and associated costs for the Corix headquarters, in addition to third-party consulting services.

This area represents the Executive Management function. The CEO Office sets overall direction and enterprise strategy; provides guidance to operational leadership to optimize Corix's lines of business; identifies complementary aspects of Corix's businesses to achieve synergies where possible for the benefit of multiple stakeholders including the customers of the operating companies; interacts with shareholders to source capital; and at a high-level works with other members of the ELT and the debt holders to secure appropriate financing and rates. The CEO reviews Corix's and its subsidiaries' activities to foster an enterprise-wide culture of honesty, integrity, transparency and accountability to customers, regulators, and Corix's shareholder. The CEO is the main conduit to shareholders on all matters of governance and ensures an appropriate governance structure exists throughout Corix.

2) **CFO Office**

The CFO Office costs include direct employee labour and non-labour costs, as well as other costs such as third-party services related to audit, insurance administration and tax services, external financial compliance costs, and bank service fees.

This area represents the Finance function provided by the CFO's organization, which includes corporate accounting, capital market engagement, corporate financial planning and analysis, insurance, taxation, and treasury services. Specifically, these services include the following.

- Securing debt and equity financing for Corix and all of its operating subsidiaries
- Management of the capital structure
- Managing liquidity
- Monitoring the financial markets that impact Corix and its operating subsidiaries
- Supervising the preparation and consolidation of financial statements
- Supervising the preparation and consolidation of Corix's annual business plan, which includes annual operation and maintenance and capital budgets for a multi-year forecast period
- Consolidating and reporting periodic financial statements, analyzing and reporting on actual to budget variances
- Supervising the corporate income tax provision and compliance work
- Ensuring compliance with affirmative, negative and financial covenants contained in short- and long-term debt securities when issued by Corix and its operating subsidiaries

The corporate financial planning and analysis staff provide oversight of the financial affairs of all Corix subsidiaries including long-term strategic planning and financial analysis. This also includes full scope management reporting to the Board of Directors, Corix's shareholder and lenders to Corix. This team oversees the consolidated insurance program, insurance renewals and claims management with the support of third-party insurance administration services.

Corporate accounting support includes compliance with ASPE, US GAAP, reconciliations, ERP support and transactional support. Corporate consolidation and controllership provide review and preparation of reports to achieve the "full picture" lens required to access debt and equity financing. In addition, this group oversees all corporate holding companies, accounting for reorganizations and tax planning initiatives, and presents results and budgets to the Board of Directors. Financial reporting policy and technical research originates from this function.

Tax support includes the coordination of the tax planning activities for all Corix businesses and either undertakes tax compliance activities, directs tax compliance activities taking place in businesses or oversees outside tax professionals who provides services to Corix or individual businesses. Staff providing the tax support function also works with external auditors for annual audit tax provision and audits of Corix's consolidated financial statements and tax returns.

Treasury services include long- and short-term capital needs planning for both debt and equity. Staff providing the treasury services support function interact with the shareholder and the capital markets to arrange, extend, or change terms of financing. The team also monitors the use of revolvers and monitors covenant coverage and help to ensure interest spreads relative to coverage ratios are optimized to minimize interest costs.

In summary, the CFO's organization plays a key role in ensuring that Corix and its subsidiaries have access to debt and equity capital, meet financial obligations and operate in an efficient and cost-effective manner to the benefit of our stakeholders.

3) <u>CLO Office</u>

The CLO Office costs include direct employee labor and non-labor costs, as well as other costs such as third-party services related to the internal audit function and external legal services.

The CLO Office provides a comprehensive suite of risk management services, which includes: enterprise risk management; technical safety and compliance, and health, safety, and environmental (HSE) leadership; internal audit services, and legal services.

The risk management service function includes consolidating risk reports and providing the Corix Board of Directors and executive leadership team with a comprehensive view of inherent and residual risks faced by Corix and its operating subsidiaries.

Corix cultivates an enterprise-wide culture that supports the safe delivery of essential services to the communities served by Corix's operating subsidiaries. The technical safety and compliance function provides strategic and technical regulatory leadership regarding code and standards compliance for the safe and efficient operation of all thermal energy plants, distribution systems, infrastructure, and technical equipment. In addition, this staff provides oversight for the development and execution of company HSE programs and processes for new and existing activities within Corix. More specifically, this staff has regulatory responsibility for all boiler and pressure vessel regulated equipment and ensures code compliance to NBIC, CSA and ASHRAE standards as well as all legal, regulatory, environmental, and organizational HSE standards both in Canada and the US. Also captured in this category are costs for safety incentive programs, software licenses costs for HSE programs, and third-party services for safety assessments, surveys, training, reviews, and audits at the enterprise level. It should be noted that while the HSE leadership resides at the corporate level, there are specific HSE staff dedicated to each of the West and East regions and the costs associated with these staff are recorded at the regional level.

Legal support provides a variety of legal services and advice to Corix and its operating subsidiaries. These matters span a broad spectrum of legal issues, including labor relations and employment matters, internal investigations, litigation, administrative proceedings, and contract review. Where necessary, external third-party legal consulting services may also be commissioned to support internal staff. Internal staff communicate with and manage outside legal counsel to ensure the effective and efficient management of these legal matters. The legal team also provides advice on corporate matters, including governance and compliance. In addition, the legal team supports the finance organization by providing legal advice and counsel related to debt and equity financing.

Finally, the CLO Office provides internal audit services to Corix and its operating subsidiaries. Internal audit evaluates a company's internal controls, including its governance and accounting processes to ensure compliance with laws and regulations, accurate and timely financial reporting, and data collection. This group provides internal audit services based on annual risk analyses of key areas and based on requests from Corix businesses who may require assessments of processes, fraud investigations or IT control assessments. Their assessment findings are generally available to all businesses unless there is some issue of confidentiality or litigation.

4) <u>CGO and VP, Administration Office</u>

The CGO and VP, Administration Office provides a dual role for Corix given its responsibility for growing the overall business as well as providing a broad range of administrative support services necessary to support the delivery of district energy services to customers.

Growing the overall business results in increasing economies of scale for the entire organization, with the benefit being that fixed costs are shared over a broader base of assets resulting in lower costs for each business compared to what they would otherwise have to incur if they were stand-alone businesses. These costs include direct employee labour and non-labour costs for overall business development oversight and associated third-party services to support the evaluation and execution of potential acquisitions. The CGO Office’s mandate is to generate corporate growth consistent with the goals and objectives of the company. Seeking and executing large and/or complex acquisitions and winning project bids, the business development staff facilitates the economies of scale required to share costs across the organization in a meaningful way. Business development will help on strategy, evaluating complex issues that arise, will lend resources and expertise to execute a transaction and provide general oversight. Because of the number of opportunities to grow the business with small or large opportunities, the business development team is a group of mobile resources with the ability to engage prospective sellers. These opportunities will ultimately create a bigger customer base over which to spread the costs more efficiently (thus mitigating the impact of rising costs). However, Corporate Business Development costs are notionally allocated to businesses and these costs are excluded from cost recovery in regulated utility revenue requirements and rates.

The Administration Support Office provides support services including people and culture management, information technology (IT), operational technology (OT), cybersecurity services, and communications.

After isolating Business Development costs, the CGO and VP, Administration Office’s remaining costs include direct employee labour and non-labour costs, as well as third-party services costs associated with:

- the administration of the day-to-day people and culture programs and services, recruitment expenses, surveys, training, payroll functions and compensation studies;
- the provision and maintenance of IT and OT infrastructure, applications, cybersecurity programs, and related support services for the organization; and
- the provision of corporate communications services, including but not limited to external and internal communications, management of Corix’s website, content creation, customer education, media monitoring, as well as associated license costs.

Some notable elements of these services are described in the subsection below.

i. **People and Culture**

The People and Culture team supports the entire organization through a range of services that ensure effective workforce management, operational efficiency, and regulatory compliance. Services provided by People and Culture include:

- **Policy and Practice Development** – developing, updating and managing company-wide policies and practices for all aspects of human resources. This ensures that the organization remains compliant with legal standards, follows best practices, and operates consistently across all departments.
- **People Programs and Services Administration** – managing the day-to-day administration of people-related programs, providing overall guidance and direction to employees at all levels. This includes offering support for both general human resource (HR) inquires and strategic guidance and ensuring that the workforce management aligns with organizational goals.
- **Payroll Administration** – overseeing payroll processing for all employees, ensuring timely and accurate compensation. This function supports all departments and is fundamental to maintaining employee satisfaction and operational stability.
- **Wage and Salary Design and Administration** – designing and administering wage and salary structures across the organization, ensuring competitive and equitable compensation. These efforts are crucial for talent retention and alignment with market standards.
- **Benefits and Medical Plan Administration** – managing the design and administration of the company's benefit and medical plans, which are available to all employees. By sourcing company-wide benefits programs, the team achieves significant economies of scale, providing cost efficiencies and risk-sharing benefits across the organization.
- **Group Pension Plan and 401k Administration** – managing the administration of group pension plans and 401k services, ensuring compliance and providing retirement planning options for employees. This planning service supports employee retention and satisfaction, with broad benefits across departments.
- **Performance Management** – facilitating performance management processes, ensuring that employee performance is regularly evaluated and aligned with organizational objectives. This function drives productivity and helps identify areas for employee development, ultimately benefiting all teams.
- **Recruitment and Onboarding Support** – providing recruitment and onboarding support, ensuring that new employees are hired, integrated, and trained effectively. Additionally, P&C team manages resignation and termination processes, ensuring smooth transitions and minimizing operational disruptions.
- **Vendor Management for Economies of Scale** – optimizing operational efficiency by sourcing company-wide vendors for services related to Total Rewards, Talent Management, and Human Capital Management (HCM) systems. By consolidating these services, the organization achieves economies of scale.
- **Executive Recruitment and Administration** – managing the recruitment and HR administration of executive positions, working closely with senior leadership and reporting to the Board of Directors. This ensures that the organization's leadership structure remains strong and aligned with strategic objectives.
- **Compensation Reviews** – managing comprehensive compensation reviews, which are conducted by third party vendors to ensure fair and market-competitive pay structures.
- **Employee Relations and DEI** – fostering a positive organizational culture through employee relations support and initiatives focused on Diversity, Equity, and Inclusion (DEI). These efforts help create a healthy, inclusive work environment by promoting collaboration and a sense of belonging.

ii. Information Technology, Operational Technology & Cybersecurity

This team is responsible for:

- **Network and Cloud Infrastructure Management:** The IT team is responsible for the development, implementation, and maintenance of stable, consistent, and secure network and cloud infrastructures across Canada and the US, ensuring seamless productivity and collaboration for end users.
- **IT Hardware Provisioning and Implementation**: The IT team is responsible for provisioning, preparing and implementing hardware, software, peripherals and accessories to users and sites. By providing the end users with the tools they need will enable the users to work efficiently.
- **Standard Applications**: The IT team is responsible for providing and maintaining standard applications. Standardizing applications allows for quick deployment to end users, cost savings for licensing and consistent support.
- **Uniform IT Security and Cybersecurity Protocols:**
    - **IT Security Platform, Policies, Procedures:** The IT team is responsible for upholding a uniform IT security platform to maintain company security, providing support to enhance IT security protocols.
    - **Security Operations, Response, and Monitoring (SOC):** The IT team is responsible for 24/7 Cybersecurity threat monitoring and escalations via the SOC, with active monitoring and response to protect systems and users.
    - **Cybersecurity Training and Awareness**: The IT team is responsible for developing and implementing a comprehensive Cybersecurity Training Program for all users. Metrics collected from the training sessions help identify areas where employees may need additional support to strengthen overall cybersecurity practices. Regular security awareness training is also provided to all employees, promoting a robust cybersecurity culture and reducing organizational vulnerabilities.
    - **Legislative Monitoring and Compliance**: IT continuously monitors data privacy legislation and security requirements across contracts, ensuring compliance and adapting protocols as regulations evolve.
- **An Enterprise-Wide Help Center:** The team provides an enterprise-wide help center through the corporate ticketing system as well as a 24/7 call support line. The support will reduce operational disruptions and will aid in keeping business continuity.
- **Operational Technology (OT) Systems and Site Implementations**: Planning, design, installation, monitoring and maintenance of OT systems and site-specific implementation in collaborations with OT vendors and integrators.
- **Technology Optimization and Support**: Providing and maintaining a set of technologies to optimize the operation of assets safely, securely, and efficiently. Key technologies include: SCADA (Secure Control and Data Acquisition); EAMS (Enterprise Asset Management Software); and AMI (Automated Meter Infrastructure), among others.
- **Enterprise Support and Strategic Functions**: Supporting frontline operations and the broader business in areas such as:
- **Governance and Solution Standards** – Establishing and enforcing governance and standards across solutions.
- **Technology Consistency and Vendor Management** – Ensuring consistency in technology selection and vendor management.
- **Scalable Solution Design** – Designing OT solutions that are scalable from site-specific to enterprise-wide levels.
- **Best-Practices Delivery and Operationalization**: Implementing best practices and supporting operationalization across the business.

- **Business and Capital Support** – Assisting businesses with project needs and capital deployments.
- **Mergers, Acquisitions, and Divestments** – Providing OT support for business growth initiatives.
- **Customer-Centric Cybersecurity and Data Protection**: All IT security and compliance functions support robust cybersecurity and data protection practices, which contribute directly to customer confidence and data protection.

iii. Communications

The Communications team is responsible for developing and executing effective communication strategies that reach internal and external target audiences and help to build relationships. The Communications teams works collaboratively with all areas of the business to ensure cohesive brand messaging and spearheads initiatives that enhance stakeholder and customer engagement, and drive growth. Below is a summary of the major accountabilities of the Communications team:

- **Strategic Planning and Execution:** The team leads, develops and implements comprehensive communication and marketing strategies that align with business goals and support growth objectives.
- **External Communications:** The team manages Corix's public image and media relations, including press releases and media outreach. The team is responsible for ensuring effective external communication across various channels, including Corix's website and social media, while meeting the unique needs of the local stakeholders across Corix's geographically diverse footprint.
- **Internal Communications:** The team is responsible for developing and maintaining all content on Corix's intranet, to connect employees and enhance culture across the organization.
- **Content Creation and Thought Leadership:** The team is responsible for the creation of high-quality written and visual content for various channels, including website, social media, marketing collateral and business proposals. This involves maintaining a current knowledge of trends, research, and best practices.
- **Research and Analytics:** The team leverages research and data analytics to scan external market conditions, optimize visibility and reach, and identify marketing opportunities that align with business goals.
- **Brand Management:** The team ensures all marketing and communication materials are consistent with the brand guidelines, overseeing the development and maintenance of the company's brand identity, including messaging, visual identity and voice.
- **Event Planning and Execution:** The team plans and executes various business-related events, including but not limited to community outreach, employee events, and Corix's attendance in industry trade shows.

APPENDIX C – HYPOTHETICAL EXAMPLE SHOWING CORPORATE COST ALLOCATION METHODOLOGY

This appendix provides a hypothetical example of the corporate cost allocation methodology using Composite and Functional Allocators for a business called “UtilityCo”. In this example, businesses are equivalent to separate identifiable utilities.

UtilityCo receives corporate support services that are necessary for either: (i) all businesses within Corix’s portfolio; or (ii) only some businesses within Corix’s portfolio. This distinction impacts the totals for the pool of businesses to be allocated the specific cost.

This simplified example assumes that there are only three (3) corporate cost categories and three (3) corporate cost allocators.

Table 5: Hypothetical Corporate Cost Allocation Example – Step 1 – Determining the Allocators

Line No.	Description	Total for pool of Businesses to be Allocated Corporate Costs ($ millions)	UtilityCo ($ millions)	Factor Ratio	Weighting	Weighted Factor
	(a)	(b)	(c)	(d) = (c) / (b)	(e)	(f) = (d) x (e)
1	Allocator #1: Composite Allocator					
2	Gross Property, Plant, and Equipment	$650	$60	9.2308%	0.3333	3.077%
3	Gross Revenue	$120	$8	6.6667%	0.3333	2.222%
4	Headcount	170	20	11.7647%	0.3333	3.922%
5						
6	**Allocator #1 for UtilityCo**					**9.22%**
7						
8						
9	Allocator #2: Composite Allocator					
10	Gross Property, Plant, and Equipment	$400	$60	15.0000%	0.3333	5.000%
11	Gross Revenue	$75	$8	10.6667%	0.3333	3.556%
12	Headcount	100	20	20.0000%	0.3333	6.667%
13						
14	**Allocator #2 for UtilityCo**					**15.22%**
15						
16						
17	Allocator #3: Functional Allocator					
18	Headcount	170	20	11.7647%	1.0000	11.765%
19						
20	**Allocator #3 for UtilityCo**					**11.76%**

Table 5 above shows Step 1 of the Corporate Cost Allocation Example. Allocator #1 and Allocator #2 are calculated using the composite allocator method and Allocator #3 is calculated using the functional allocator method. For each particular allocator to be calculated, the totals for the relevant pool of businesses are identified (column b) based on the corporate support services and benefits received.

- Allocator #1 is associated with the corporate support services that are necessary and beneficial for all businesses within Corix’s portfolio. One example of a corporate cost category that would use Allocator #1 is Executive Management.
- Allocator #2 is associated with the corporate support services that are necessary and beneficial for only some businesses within Corix’s portfolio. Therefore, the pool of businesses receiving services for Allocator #2 is a subset of the pool of businesses receiving services for Allocator #1. One

example of a corporate cost category that would use Allocator #2 is Legal and Risk Management in the case where an investment entity performs this function inhouse or with their own third-party legal counsel.

- Allocator #3 is associated with the corporate support services that are necessary and beneficial for all businesses within Corix's portfolio. One example of a corporate cost category that would use Allocator #3 is People & Culture.

Figures are obtained for the three input factors (gross PPE, gross revenue, and headcount) for the respective pool of businesses and for UtilityCo. UtilityCo is one of the many businesses in the pool. The Functional Allocator is dependent on one factor only since a specific cost causation driver is identified. For each of the Composite Allocators, the three factors are equally weighted at 1/3rd each (column e). The weighted factors (column f) are then summed to arrive at the Composite Allocator percentage for each allocator for UtilityCo (line 6 for Allocator #1 and line 14 for Allocator #2).

Allocator #1 is a percentage of 9.22%, which would result in UtilityCo receiving 9.22% of the specific corporate support service cost incurred for all businesses within Corix's portfolio. In contrast, Allocator #2 has a smaller pool of businesses receiving services. Allocator #2 is a percentage of 15.22%, which would result in UtilityCo receiving 15.22% of the specific corporate support service costs incurred for the service and benefit received by that subset of businesses only. Allocator #3 is a percentage of 11.76%, which would result in UtilityCo receiving 11.76% of that specific corporate support service cost incurred for all businesses within Corix's portfolio.

The Allocator #1 percentages when summed for all businesses in the pool equals 100%. This is the same for Allocators #2 and #3. This means when the corporate costs are allocated to the businesses in the pool all the costs are allocated out. UtilityCo would receive a portion of the corporate costs based on the calculated percentages for each of the three allocators.

Table 6: Hypothetical Corporate Cost Allocation Example – Step 2 – Allocating Corporate Costs

Line No.	Description	Businesses to receive allocation	Total Corporate Costs to be Allocated	Allocator to use	UtilityCo Percentage Allocator	Corporate Costs Allocated to UtilityCo
	(a)	(b)	(c)	(d)	(e)	(f) = (c) x (e)
1	Corporate Cost Categories					
2	Corporate Cost A	All	$1,500,000	Allocator #1	9.22%	$138,311
3	Corporate Cost B	Relevant Businesses only	$600,000	Allocator #2	15.22%	$91,333
4	Corporate Cost C	All	$900,000	Allocator #3	11.76%	$105,882
5	**Total**		**$3,000,000**			**$335,526**

Table 6 above shows Step 2 of the Corporate Cost Allocation Example. After the allocator percentages are calculated in Step 1, the allocators are applied to the related corporate cost categories. In the example for UtilityCo:

- Corporate Cost A is allocated to all businesses using Allocator #1 (a Composite Allocator) at 9.22%;
- Corporate Cost B is allocated to only the relevant businesses using Allocator #2 (a Composite Allocator) at 15.22%; and

- Corporate Cost C is allocated to all businesses using Allocator #3 (a Functional Allocator) at 11.76%.

In the above example UtilityCo is allocated a total of $335,526 from corporate costs totaling $3.0 million, representing 11.18% of the total corporate costs. Therefore, based on the allocators used, it is estimated that $335,526 of the total corporate costs were incurred to provide these corporate support services to UtilityCo.

The above process provides a simplified example of how the corporate cost allocation methodology at Corix is applied using different allocators for different categories of corporate costs. This example with hypothetical figures for the allocator percentages and allocated cost amounts are not indicative of the Corix allocations and is intended solely for the purpose of explaining how the allocators in Corix's cost allocation model are calculated and applied to each corporate cost category.

Appendix J: Regional Services Cost Allocation Manual

COST ALLOCATION MANUAL FOR DE WEST REGIONAL COSTS

FOR FISCAL YEAR: 2025

TABLE OF CONTENTS

Revision History

VERSION	FOR FISCAL YEAR	APPROVED BY	APPROVED
1.0	2025	COO (DE West) (via email)	December 6, 2024

1. INTRODUCTION

Corix District Energy Holdings Limited Partnership, with its general partner Corix District Energy Holdings GP Inc. (together "Corix") is a leader in the implementation of district energy utility infrastructure solutions for small to medium-sized communities across North America. Corix is a privately held company that is wholly owned by affiliates of the British Columbia Investment Management Corporation (BCI). Corix owns utilities and has investments (together "businesses") that operate in Canada and the United States.

Corix, through its Board of Directors and the Executive Leadership Team (ELT), is responsible for providing strategic direction, business oversight, and corporate governance for the business activities of the operating subsidiaries directly and indirectly owned by Corix.

The ELT consists of the following six (6) positions.

i. Chief Executive Officer (CEO)
ii. Chief Financial Officer (CFO)
iii. Chief Operating Officer – East (COO East)
iv. Chief Operating Officer – West (COO West)
v. Chief Legal Officer (CLO)
vi. Chief Growth Officer (CGO) & Vice President, Administration

Support services are necessary for the operation of any business, including the safe and efficient operation of district energy utilities. Corix uses a centralized corporate support service organization to provide these services to the businesses, as well as regional support services in the East and West regions. The services and the costs of the COO East and COO West are not included in the corporate support services as they are included in the regional support services for which they oversee.

This manual addresses regional support services and the allocation of regional costs for the DE West.

The DE West regional Cost Allocation Methodology (CAM) has been designed to facilitate equitable cost sharing among businesses and to ensure that there is no subsidization of non-regulated services by regulated entities. In a manner consistent with the NARUC Guidelines for Cost Allocations and Affiliate Transactions[1] (NARUC Guidelines), Corix maintains this Regional CAM Manual (Manual) that includes:

- a chart showing the regional support services cost flows to Corix's businesses in the DE West region (Appendix A);
- a description of the regional cost allocation methodology and allocators used to allocate regional support services costs to the applicable businesses (Section 4); and
- a description of the regional support services provided to Corix's DE West businesses (Section 5 and Appendix B).

In addition to the above, this manual includes a hypothetical example of the regional cost allocation methodology (Appendix C).

This manual is reviewed annually and updated to reflect organizational changes, if any. Updates to this manual are finalized through approval by the COO West.

[1] NARUC Guidelines for Cost Allocations and Affiliate Transactions, https://pubs.naruc.org/pub/539BF2CD-2354-D714-51C4-0D70A5A95C65, accessed November 12, 2024.

2. DEFINITIONS

- **Corix District Energy Holdings Limited Partnership, with its general partner Corix District Energy Holdings GP Inc.** (together “Corix”) is the corporate parent of Corix subsidiaries.

- **Corix (CA) DE Services Limited Partnership** is the subsidiary that houses the costs incurred for the provision of regional support services, which is described in this Manual.

- **Regional CAM Manual** (Manual) is this regional cost allocation methodology manual, as updated from time to time and approved by the COO West.

- **Regional Support Services** refer to the administrative and general support services and functions provided to the DE West region within Corix’s organization. These regional support services include operations leadership and strategy; regulatory affairs management; health, safety and environment management; financial planning and analysis, and accounting; business operations and accounts payable; billing and customer care; and project management, all of which are necessary for the operation of a utility business of this size. In this Manual, Section 5 (Scope of Regional Support Services) and Appendix B (Description of Regional Support Services) provide details regarding the DE West regional support services.

- **Investments** refers to businesses in which Corix has a non-majority interest, which for the purpose of this Manual includes Oakridge Energy Limited Partnership. Through its affiliates, Corix owns 50% of Oakridge Energy Limited Partnership. Where permitted, investments receive an allocation of costs based on the support service functions necessary to support their operation.

3. REGIONAL SUPPORT SERVICES COSTS

Regional Support Services costs (also referred to as “regional costs”) are identified, budgeted and tracked using homogenous regional cost categories. The various regional support services and regional cost categories are listed in the first two columns of Table 3 in Section 5 of this Manual.

The importance of controlling costs is key. Headcount planning is conducted in the annual budgeting process; any headcount addition must be supported with a demonstration of need. The process takes several months with budgets undergoing rigorous analysis by the budget owners and multiple levels of review. Budgets are presented and subject to questions and answer sessions to test proposed costs including headcount addition requests. After thorough review by the leaders of the relevant regional support service teams, the budgets are then carefully reviewed by the ELT and the Board of Directors. At each level, costs are heavily scrutinized to evaluate efficiency of operations and cost effectiveness.

3.1 DIRECTLY ASSIGNABLE COSTS AND INDIRECT COSTS

Costs within the homogenous categories are either: (i) Directly Assignable Costs; or (ii) Indirect Costs.

Directly Assignable Costs

Directly Assignable Costs are costs incurred by one company for the exclusive benefit of, or specifically identified with, one or more companies, and which are directly charged to the company or companies that specifically benefited. This is consistent with the NARUC Guidelines, which on page 2 defines “Direct Costs” as “costs which can be specifically identified with a particular service or product.”

Direct Costs are not subject to the discussion of this regional CAM as they are readily and clearly identified with a specific service and are directly assigned to the appropriate businesses.

Indirect Costs

Indirect Costs are costs incurred by one company that are for the benefit of either: (i) all; or (ii) some of the businesses within the DE West region, and which are charged to the benefited companies using a methodology and allocation factors that link cost causation and cost recovery. Under the NARUC Guidelines, “Indirect Costs” are defined on page 2 as “costs that cannot be identified with a particular service or product. This includes but not limited to overhead costs, administrative and general, and taxes.”

Indirect Costs are incurred on a shared basis for the benefit of several businesses. After assignment of direct costs, the indirect costs are the subject of discussion of this regional CAM. Indirect costs are allocated to the companies that benefit from the indirect costs using the methodology for allocating regional support services costs that is outlined in Section 4 of this manual.

Figure 1 in Appendix A outlines the cost flows from regional support services to the various businesses.

4. REGIONAL COST ALLOCATION METHODOLOGY

The following steps are used for allocating the indirect costs within regional support services costs.

1. The basis of variability of each category of indirect cost is assessed by reviewing what causes the costs in each category to change.
2. Indirect costs are then allocated either:
    - Using a functional allocator on the basis of variability in instances where this method is clearly applicable; or
    - Using a composite allocator for all other instances.

The regional cost allocation methodology is consistent with the cost allocation methodology used for allocating Corix's indirect corporate support services costs.

4.1 FUNCTIONAL ALLOCATOR

Functional allocators are used where the costs can be allocated using an identified cost causation driver. One example of this is using customer count to allocate indirect costs that are directly correlated to the number of customers at a utility.

4.2 COMPOSITE ALLOCATOR

The indirect regional support services costs that do not have a direct correlation with any one particular cost causation driver are allocated using a composite allocator. A composite allocator was chosen to represent the size, scope and complexity of each of the businesses within DE West, with a goal of fairly putting businesses on a level standing for comparison purposes.

The composite allocators comprise of three equally weighted factors as shown in Table 1 below. The equal weighting reflects that cost allocations are inherently an estimating exercise to fairly allocate costs and therefore no factor is over-weighted compared to another relevant factor. These weightings are kept constant in order to avoid introducing unnecessary complexity and administrative burden into the cost allocation methodology.

Table 1: Composite Allocator, Factors and Weighting

Factor	Weight
Gross Property, Plant & Equipment	33.33%
Gross Revenue	33.33%
Headcount	33.33%
Total	**100%**

The composite allocator based on the factors and weighting shown in Table 1 allows for a just and reasonable allocation of costs in a transparent, sustainable and cost-effective manner that reflects cost causality for shared costs which do not exhibit direct correlation with any one particular cost causation driver.

4.3 UPDATING ALLOCATOR INPUTS

Corix uses a point-in-time approach to calculate the forecast allocation percentages for the following year. This provides stability for budget preparations and actual allocations as well as a reference point for year-over-year comparisons. Allocation percentages are updated annually as outlined in Table 2 below.

Table 2: Allocation Time Periods

Inputs	Reference
Gross Property, Plant & Equipment (Gross PPE)[2]	**As of June 30th of prior year**
Gross Revenue[3]	**Trailing Twelve Months as of June 30th of prior year**
Headcount	**As of June 30th of prior year**

For example, the 2025 budget and actual allocation would be based on a composite allocator that is calculated based on:

- Gross PPE at June 30, 2024;
- Gross Revenue from July 1, 2023 to June 30, 2024; and
- Headcount at June 30, 2024.

June 30th was chosen as the most appropriate point-in-time to allow for the allocation percentages to be determined, and the forecast regional support service costs to be allocated to each operating utility/business prior to the completion of the annual budgets. A date earlier than June 30th would result in the unnecessary use of outdated information. A date after June 30th would yield more current information but would cause delays to the annual budget process for DE West.

4.3.1 Adjustments for Specific Unique Circumstances and Known and Measurable Changes

In unique circumstances, adjustments to the inputs (Gross PPE; Gross Revenue; Headcount) are to be made for known and measurable changes that would otherwise result in a cost allocation that does not appropriately reflect cost causality. The Known and Measurable Changes accounted for are:

1) Bargain Acquisition Adjustment;
2) Asset Impairment Adjustment; and
3) Approved Major Capital Projects

(1) Bargain Acquisition Adjustment
In some situations, utility assets are acquired for one dollar ($1), or purchased for an amount significantly below the net book value of the assets. For the purpose of allocating regional costs, these purchases will be considered as though the utility assets were acquired at cost (for new assets) or fair market value (for assets previously in use). The fair market value may be equal to the net book value of the assets just prior to acquisition.

This adjustment recognizes the fact that utilities require continuous ongoing management oversight and stewardship as they provide service to customers, even in instances where the assets were acquired at a bargain price.

[2] Gross Property, Plant & Equipment is defined as gross property, plant, and equipment independent of the way it has been financed.
[3] Gross Revenue is defined as recorded gross revenue.

(2) Asset Impairment Adjustment
In instances where assets have been written down for accounting impairment purposes, the assets would continue to be recognized at their historical Gross PPE input value for the calculation of each composite allocator, provided that such assets continue to be used and are useful in the provision of service to customers.

This adjustment accounts for the situation where assets that have been written down for accounting impairment purposes continue to require ongoing management oversight and stewardship as the utility continues to provide service to customers.

(3) Approved Major Capital Projects
This is an adjustment to include approved major capital projects that are about to go into service after the June 30th cut-off date for inputs that year. It recognizes that the June 30th cut-off in the year for actual inputs to calculate the following year's regional cost allocation may omit impending known and measurable changes that were previously approved by regulators. This is because the six-month period from July 1st to December 31st does not get reflected in the following year's cost allocations. As the regional cost allocation is inherently an estimate to calculate a reasonable allocation of costs any minor changes or activity is immaterial. However, in some cases an approved major capital project that is to be placed in service during the July 1st to December 31st period may have a material impact on the revenue requirement for several utilities. This adjustment, with regard to allocation of regional costs, recognizes that conceptually a project placed in service in the latter half of the year is treated the same as if a project is placed in service on June 30th of that same year.

This adjustment will be made using the latest available projected figures, if all three of the following apply to the situation:

(1) Corix has previously received regulatory approval for the execution of a major capital project, such as a Certificate of Public Convenience and Necessity ("CPCN");
(2) there is reasonable certainty that the major capital project will be completed, and the associated assets will be placed in service between July 1st and December 31st, after the June 30th cut-off date of the same year; and
(3) there is a material impact and change to the allocation of regional costs to the utility and other utilities absent such an adjustment.

Given that the DE West regional cost allocation methodology is consistent with Corix's corporate cost allocation methodology, any input adjustments for specific unique circumstances and known and measurable changes that are used in the corporate cost allocation methodology are also applied to the DE West regional cost allocation methodology.

4.4 CHANGES TO THE REGIONAL COST ALLOCATION METHODOLOGY

The Regional CAM (as described in Section 4 of this Manual) has been designed in a manner consistent with the Corporate Cost Allocation Methodology, which is a separate methodology used to allocate indirect corporate costs to businesses in Corix's portfolio. Please consult with a member of Corix's Corporate Finance team when contemplating changes to Section 4 of this Regional CAM Manual.

5. SCOPE OF REGIONAL SUPPORT SERVICES

The support services provided by Corix's DE West team are necessary for the effective and efficient operations of a utility business this size. These include regulatory affairs management; health, safety and environment management; financial planning and analysis and utility accounting; business operations management and procurement, and accounts payable; billing and customer care; operations leadership and strategic management and project management. These services could have been provided with dedicated staff in each of the businesses. However, Corix consolidates these support services into regional support services which facilitates effective and efficient operations through access to shared expertise. The use of shared expertise provides each business with benefits they could not economically achieve on a stand-alone basis. The key benefits are discussed below.

- **Governance** – support service departments provide direct oversight and management control that improves operations and processes; for instance, monthly financial reporting and analysis comparing actual expenditures to budgeted expenditures ensures accountability and can improve operational efficiency.

- **Compliance** – support services departments help improve compliance with regulatory, health, safety and environment, and other obligations of each individual operating business.

- **Economies** – one of the primary benefits of the centralized support service model is that it helps the customers of smaller companies realize the benefits of scale enjoyed by much larger companies; among other things, the regional service model more efficiently utilize staff through workload balancing and specialization.

- **Continuity of Service** – centralized support organizations mitigate the risk of disruptions in service caused by absences and departures.

- **Standardization** – the regional support service model plays an important role in improving the quality of service by ensuring that standard policies, procedures, and practices are established and followed; in addition, it also facilitates the sharing and adoption of best practices.

Table 3 on the following page outlines the key benefits of each regional support service, which demonstrates that these support services are necessary for the safe, effective and efficient operations for each of the businesses.

Table 3: Regional Support Services and the Benefits

Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7
Regional Cost Category	**Support Service Provided**	**Governance**	**Compliance**	**Economies**	**Continuity of Service**	**Standardization**
Regulatory Affairs	Regulatory Affairs	X	X	X	X	X
Health, Safety and Environment (HSE)	HSE	X	X	X	X	X
Financial Planning & Analysis (FP&A) and Accounting	FP&A	X	X	X	X	X
	Utility Accounting	X	X	X	X	X
Business Operations, Procurement and Accounts Payable	Business Operations	X	X	X	X	X
	Procurement	X	X	X	X	X
	Accounts Payable	X	X	X	X	X
Billing and Customer Care	Billing	X	X	X	X	X
	Customer Care	X	X	X	X	X
Operations Leadership and Strategy	Operations Leadership and Strategy	X	X	X	X	X
Project Management Office	Project Management Office	X	X	X	X	X

Appendix B provides a detailed description of the scope of regional support services provided. Table 4 below lists the regional cost categories and shows the allocator applied to each category of cost. The functions and categories are as of approval date of this manual[4] and are subject to change based on potential changes in the needs of the operating businesses. If organizational restructuring or realignments are implemented, any allocations of new or modified categories would be completed in a manner consistent with the cost allocation methodology described in Section 4 of this document.

Table 4: Regional Support Services and Allocation Method

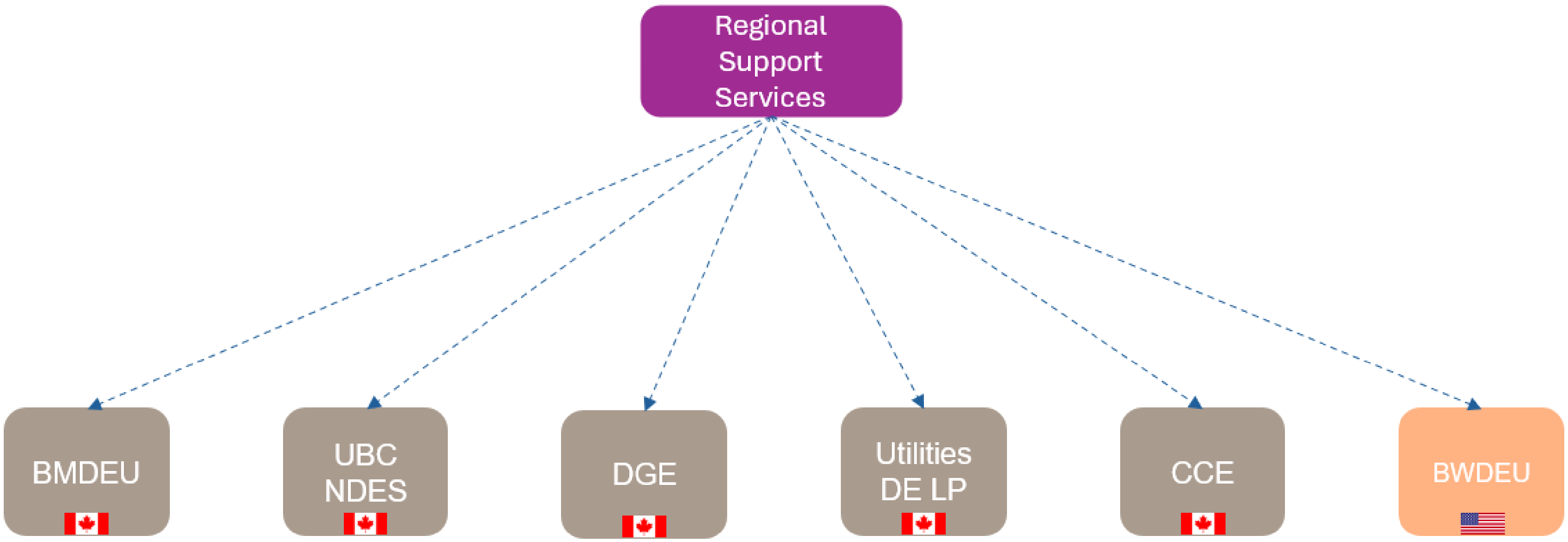
Column 1	*Column 2*
Regional Cost Category[5]	**Allocator**
Regulatory Affairs	Composite Allocator[6]
Health, Safety and Environment (HSE)	Composite Allocator
Financial Planning & Analysis (FP&A) and Accounting	Composite Allocator
Business Operations, Procurement and Accounts Payable	Composite Allocator
Billing and Customer Care	Customer Count
Operations Leadership and Strategy	Composite Allocator
Project Management Office	Composite Allocator

[4] See Revision History on page 1 of this document.
[5] Refer to columns 1 and 2 in Table 3 for a breakdown of the components of each regional cost category.
[6] The composite allocator is discussed in Section 4.2 of this document.

APPENDICES

APPENDIX A – DE WEST REGIONAL SUPPORT SERVICES COST FLOWS DIAGRAM

Figure 1: DE West Regional Support Services Cost Flows



Notes

1) This structure reflects the DE West regional services cost distribution and does not indicate Corix's DE West regional structure.
2) Regional support services for Oakridge Energy are direct charged to Oakridge Energy pursuant to the Services Agreement between Corix and Oakridge Energy and are removed from the regional services cost pools before allocation using the allocation methodology.
3) Costs associated with the DE West's Business Development team are tracked separately and are not allocated to the DE West businesses.

APPENDIX B – DESCRIPTION OF DE WEST REGIONAL SUPPORT SERVICES

This appendix describes the regional support services provided by the DE West regional team. It explains the nature of the costs for each support service and provides a description of the functions provided.

1. **Regulatory Affairs**

Regulatory Affairs costs include (i) direct employee labour and non-labour costs; and (ii) third-party services costs incurred on a shared basis for utilities within DE West that receive economic regulation. Not all utilities in DE West receive economic regulation and therefore these costs are only allocated to a portion of the businesses in DE West. Key services provided by Regulatory Affairs are listed below.

- **Regulatory Approvals** – ensuring that regulated utilities seek and obtain all mandatory regulatory approvals pursuant to the relevant legislation, rules and regulatory frameworks in place for each of the respective jurisdictions. Generally, regulatory approvals are required for: the construction and operation of new utilities; any changes to customer rates; any changes to customer terms and conditions of service; major capital projects; utility acquisitions; amalgamations, mergers, or certain change in control/ownership; and certain dispositions.

  In order to seek regulatory approvals, Regulatory Affairs manages the preparation of regulatory applications and filings, which includes jurisdictional and industry research, reviews of past regulator decisions, financial model reviews, reviews of engineering feasibility studies and reports, prefiling meets with the regulator, gathering information from staff in various departments, and leading content preparation and consolidation.

- **Regulatory Compliance** – ensuring that regulated utilities comply with all mandatory directives from regulators. Generally, directives originate from a utility application, proceedings initiated by a regulator or through the regulator resolution of a customer complaint. Directives span a wide variety of topics touching on many areas of the business, including but not limited to, the provision of energy service to customers, customer care, customer notification, the financial and accounting treatment of costs or revenue, equity and debt financing cost, and ongoing reporting.
- **Regulatory Review Processes** – managing the utility's participation and preparation of responses to information requests, submissions and arguments in regulatory review processes that are either initiated by a utility application or initiated by the regulator. In some cases, external consulting services are required due to the specialized nature of the regulatory proceeding (for example, a Cost of Capital proceeding).
- **Public Consultation** – preparing content, planning, coordinating and executing public consultation processes as required by the regulator.
- **Tariff Management** – managing the tariff for each regulated utility, including proposing and seeking regulatory approval for updates to the rate schedules, standard fees and charges, or the terms and conditions of service.
- **Customer Correspondence** – responding to ad hoc customer or stakeholder enquiries related to regulatory affairs.
- **Regulatory Support** – providing ongoing support to other departments within Corix by responding to ad hoc enquiries, providing guidance on standard regulatory practice, researching different aspects of utility regulation, and providing periodic reporting to senior leadership
- **Internal Training** – providing internal regulatory training to foster a greater understanding of implication of owning and operating regulated energy utilities and regulator expectations.

2. **Health, Safety and Environment**

Health, Safety and Environment (HSE) costs include (i) direct employee labour and non-labour costs; and may include (ii) third-party services costs incurred on a shared basis for all utilities within DE West. Key services provided by HSE are listed below.

- **HSE Regulatory Compliance** – continual monitoring of requirements set forth by occupational health and safety authorities through the applicable legislation, regulations, and guidelines. This also includes ensuring that all Occupational Health testing is organized and completed as required (for example, annual audiometric testing, respirator fit testing).
- **Compliance Monitoring and Mentorship** – conducting periodically scheduled or informal site inspections of work carried out according to established safety procedures.
- **HSE Program Development** – ongoing review and improvement to HSE Manual and associated directive documentation. This includes preparing Spill Response and Environmental plans for new and existing utility operations.
- **HSE Procedural Development** – ongoing review and improvement of safe work procedures; and conducting and reviewing formal hazard assessments (i.e. Job Hazard Assessments, Site Hazard Assessments).
- **Internal Communication** – conducting regular Safety Meetings for Operations personnel; and holding focused information sessions for all staff regarding safety sensitive aspects of their scope of work.
- **Operational HSE Documentation Administration** – collecting, reviewing, providing feedback, and filing safety forms completed in the field (e.g. Field Level Hazard Assessments, Fall Protection Plans, Confined Space Entry Permits and Atmospheric Testing Logs).
- **Internal Training and Competency Assessment** – developing and facilitating HSE orientations for new hires; developing and facilitating training programs addressing safety-sensitive tasks required by employees to carry out; conducting on-site competency assessments to verify training in the field; and recordkeeping for existing training certifications, tracking expiries and scheduling required training.
- **Incident and Near Miss Administration** – reviewing work observation, near miss, and incident reports to assess for next steps; determining whether they are reportable to an external body (e.g. Ministry of Environment, occupational health and safety authority, insurance, police); and conducting on-site investigation for incidents.
- **Injury Management** – working with other Corix staff to plan and see through injury management plans, including worker's compensation insurance claims for work related injuries and disability claims for non-work related injuries; and preparing return-to-work plans where required.

3. **Financial Planning & Analysis (FP&A) and Accounting**

Financial Planning & Analysis (FP&A) and Accounting costs include (i) direct employee labour and non-labour costs; and (ii) third-party services costs incurred on a shared basis for all utilities in DE West. Key services provided by FP&A and Accounting are listed below.

- **Accounting and Bookkeeping** – recording daily financial transactions; maintaining accurate financial records and efficient recordkeeping practices in compliance with accounting standards; performing monthly account reconciliations; providing enterprise resource planning (ERP) support; supporting integration and data validation of expense and billing system data into ERP; and generating and reviewing business financial statements.

- **Budgeting** – creating and managing annual and long-term budgets and providing strategic support on business goals, spending controls, resource availability and project prioritization.
- **Forecasting** – creating and revising monthly forecasts of each individual business's future financial performance with up-to-date information on the business. Analyzing financial trends to detect and mitigate risks and to provide management with predictive analysis to inform strategic decisions.
- **Financial Modelling** – creating and revising financial models for individual businesses used in budgeting, forecasting, regulatory filings, valuation analysis, management reporting, profitability analysis, and liquidity analysis.
- **Management Reporting** – creating clear reports that communicate financial standing to facilitate informed decision making.
- **Variance Analysis** – identifying cost drivers, analyzing and effectively communicating revenue or cost variances to budgets/forecasts for reporting and decision making.
- **Audit support** – preparing, reviewing and providing analysis during annual audits.
- **Tax support and filings** – staying updated on and preparing local tax returns where necessary, managing tax liabilities, and providing records support, data validation, and analysis for corporate level tax filings.
- **Insurance support** – compiling and validating financial data needed for accurate insurance assessments.
- **Regulatory Financial Support** – supporting regulatory filings and reporting with financial reports, variance analyses, modelling, scenario building, drafting the relevant sections in applications and responding to information requests.

4. Business Operations, Procurement and Accounts Payable

Business Operations, Procurement and Accounts Payable costs include direct employee labour and non-labour costs incurred on a shared basis for all utilities in DE West. Key services provided by Business Operations are listed below.

- **Procure-to-Pay** – managing the Procure-to-Pay process from the initial transaction (e.g., purchase order or credit card) through to paying the supplier. This can be further subdivided as follows.
  - **Purchase Orders** – creating and managing purchase orders, purchase invoices and new suppliers within the enterprise resource planning system; managing custom broker contracts for cross-border shipments and tracking associated taxes and duties; communicating with supplier; and coding and submitting purchase invoices to accounts payable.
  - **Credit Card Program** – administering the credit card program which includes issuing/cancelling credit cards, managing the credit card policy, managing cardholder spend profiles, troubleshooting cardholder issues, managing the expense management software, and auditing expense reports.
  - **Accounts Payable** – generating payments for external supplier and intercompany invoices, reimbursing employee expenses, facilitating bank reconciliation, and processing 1099 forms for US suppliers.
  - **Legal Contracts** – drafting procurement contracts and contract management.

- **Asset Management** – overall responsibility for the strategy and implementation for asset management including management of the Computerized Maintenance Management System software.
- **Data Analysis & Reporting** – gathering and analyzing operational key performance indictor data for internal and external reporting.
- **Fleet** – administering the fuel/maintenance card program, acquiring/disposing vehicles, managing vehicle insurance, facilitating annual driver abstract reviews, managing reimbursable mileage rates, reviewing and compiling monthly mileage reports.
- **Special Projects/Strategic Initiatives** – leading projects as a project manager or supporting projects with communications, change management, planning/logistics and/or admin.
- **Continuous Improvement/Process Improvement** – planning, executing and supporting continuous improvement activities and ongoing monitoring of progress and controls.
- **General Administrative Tasks** – including managing business licenses, recording meeting minutes, and general office administration.

5. Billing & Customer Care

Billing & Customer Care costs include direct employee labour and non-labour costs incurred on a shared basis for all utilities in DE West. These costs exclude the costs of the billing service provider software, which are directly charged to each utility operation. Key services provided by Billing & Customer Care are listed below.

- **Billing** – generating customer bills, statements, and reports, processing rate changes, analyzing customer consumption, supporting regulatory filings, monitoring customer accounts and overall management of the billing software.
- **Customer Care** – responding to customer enquiries received via email, the customer portal or the call center (email, web and phone); managing the resolution of customer complaints which may include historical research and creating work orders for field operators and responding to customers upon rectification of issues (if any); executing and managing customer contracts; negotiating and managing payment plans; hosting information sessions; attending strata corporation annual general meetings and managing customer relationships.
- **Accounts Receivable/Collections** – generating accounts receivable (AR) aging reports, receiving and posting payments, preparing bank deposits, reconciling accounts, applying finance charges/fees, collections courtesy calls, and monitoring overdue accounts.

6. Operations Leadership and Strategy

Operations Leadership and Strategy costs include (i) direct employee labour and non-labour costs; and (ii) third-party services costs incurred on a shared basis for all utilities in DE West.

Operations Leadership and Strategy includes the cost of the COO West, as well as senior leadership staff responsible for the oversight, guidance, leadership and direction of daily operations to ensure the safe, compliant and efficient operations of all utilities and all related engineering and project management activities in the regional service area.

Operations Leadership and Strategy also provides support for business development opportunities. Growing the overall business results in increasing economies of scale for the organization, with the benefit being that fixed costs are shared over a broader base of assets resulting in lower costs for each business compared to what they would otherwise have to incur if they were stand-alone businesses. The costs incurred by Operations Leadership and Strategy team in support of business development are excluded from the regional Operations Leadership and Strategy cost pool before the costs are allocated using the methodology outlined in this Manual. The costs associated with business development are excluded from the forecast based on an estimated portion of time that will be spent on business development and are excluded from actuals based on direct charges to business development.

Key services provided include:

- **Oversight and Strategic Management** – Overseeing and coordinating all regional activity in support of daily operations and establishing work priorities and goals for relevant directors to achieve the company's strategic objectives. Regional activity covers areas including regulatory affairs, HSE, FP&A and accounting, business operations, procurement and AP, billing and customer care, operations and engineering and project management.
- **Regional Performance Management** – Managing the overall performance of the region with a focus on safety, compliance, cost control, operational excellence, reliability and availability.
- **Direct Operations and Project Management** – Directly managing the effective and efficient utilization of operations and project management resources and leading the associated staff in the performance of their duties to achieve company objectives and target performance. This includes motivating and challenging teams to focus on safe and efficient execution of day-to-day operations and continuous improvement concepts.
- **Capital and Operational Budget Planning** – Overseeing and guiding the development of:
    - system asset management plans, which inform 5-year capital expenditure plans, that ultimately form the capital budget; and
    - the operating budget for the region, which includes operating and maintenance costs, administrative expenses, and the capital budget.
- **Facility and Equipment Maintenance Management –** Overseeing the maintenance of facilities, company vehicles, tools and equipment to ensure they are in good operating condition per industry standards.
- **Leadership Succession Planning and Implementation** – Recruiting, retaining, and developing regional leadership staff and succession plans to ensure the regional support teams, and the operations, engineering and project management teams are all prepared for future growth
- **Technical Safety and Compliance Support** – Coordinating with the technical safety and compliance staff and providing support to operations and project management teams to ensure technical and environmental compliance with all applicable local, state/provincial and federal regulations.
- **Customer Care Support** – Coordinating with customer care staff to analyze and ensure follow-up to all service issues, whether identified internally or via customer communication.

7. Project Management Office

Project Management Office (PMO) costs include (i) direct employee labour and non-labour costs; and (ii) third-party services costs incurred on a shared basis for all utilities in DE West. The PMO manages and delivers the western regions capital program. The PMO team ensures that capital projects and their budgets are aligned, use standardized processes, and continually optimize processes to ensure project success to meet organizational goals and requirements.

PMO costs are typically directly charged to a specific capital project for a specific utility. However, there may be shared PMO costs that are incurred on a general basis and not specific to any one project. As a result:

- the forecast PMO support service allocations are set to $0 for each utility business on the basis that all PMO costs will be charged to specific projects during the forecast period; but
- the actual PMO support service allocations may include some shared PMO costs that were incurred on a general basis and not specific to any capital project.

Key services provided by PMO are listed below.

- **Capital Program Management** – managing and developing a 5-year capital plan, as well as developing the strategy and cost-efficient delivery for the capital program. This includes: researching, developing, standardizing, and evaluating techniques, procedures, and delivery methods to improve the efficiency and effectiveness of project management for the western region; and ensuring that project plans are prepared and conducted in accordance with project methodologies and standards.

- **Capital Project Management** – managing project capital expenditures and construction for the utilities in the region with a goal of balancing budget, quality of work, and project delivery scheduling. This includes continually reviewing budget reports to ensure all reported costs are tracked accurately; identifying and taking corrective action against any cost variances.

- **External Relationship Management** – managing and developing external relationships and liaising with consulting engineers, municipalities, regulatory authorities, contractors, other utilities, government bodies, customers, clients and the general public to optimize processes for successful project delivery.

- **Capital Project Reporting** – tracking, monitoring, and reporting on the status of projects and major issues/obstacles encountered and making recommendations regarding capital projects to senior management.

- **Contract Management -** Maintains consistent specifications and contract management across the region.

- **Internal Stakeholder Support** – managing and supporting capital project needs for internal business partners such as the Operations department, FP&A, Regulatory Affairs and Business Development by coordinating, consulting and proving guidance and information on project specifications, scope, conceptual design, technical compliance, scheduling needs, construction market conditions, pricing and commissioning.

APPENDIX C – HYPOTHETICAL EXAMPLE SHOWING REGIONAL COST ALLOCATION METHODOLOGY

This appendix provides a hypothetical example of the regional cost allocation methodology using Composite and Functional Allocators for “UtilityCo”. In this example, businesses are equivalent to separate identifiable utilities.

UtilityCo receives regional support services that are necessary for either: (1) all businesses within DE West; or (2) only some businesses within the DE West. This distinction impacts the totals for the pool of businesses to be allocated a specific cost.

This simplified example assumes that there are only three (3) regional cost categories and three (3) regional cost allocators.

Table 5: Hypothetical Regional Cost Allocation Example – Step 1 – Determining the Allocators

Line No.	Description	Total for pool of Businesses to be Allocated DE West Regional Costs ($ millions)	UtilityCo ($ millions)	Factor Ratio	Weighting	Weighted Factor
	(a)	(b)	(c)	(d) = (c) / (b)	(e)	(f) = (d) x (e)
1	Allocator #1: Composite Allocator					
2	Gross Property, Plant, and Equipment	$300	$60	20.0000%	0.3333	6.667%
3	Gross Revenue	$50	$8	16.0000%	0.3333	5.333%
4	Headcount	90	20	22.2222%	0.3333	7.407%
5						
6	**Allocator #1 for UtilityCo**					**19.41%**
7						
8						
9	Allocator #2: Composite Allocator					
10	Gross Property, Plant, and Equipment	$180	$60	33.3333%	0.3333	11.111%
11	Gross Revenue	$30	$8	26.6667%	0.3333	8.889%
12	Headcount	65	20	30.7692%	0.3333	10.256%
13						
14	**Allocator #2 for UtilityCo**					**30.26%**
15						
16						
17	Allocator #3: Functional Allocator					
18	Customer Count	60	15	25.0000%	1.0000	25.000%
19						
20	**Allocator #3 for UtilityCo**					**25.00%**

Table 5 above shows Step 1 of the Regional Cost Allocation Example. Allocator #1 and Allocator #2 are calculated using the composite allocator method and Allocator #3 is calculated using the functional allocator method. For each particular allocator to be calculated, the totals for the relevant pool of business units are identified (column b) based on the regional support services and benefits received.

- Allocator #1 is associated with the regional support services that are necessary and beneficial for all businesses within DE West.
- Allocator #2 is associated with the regional support services that are necessary and beneficial for only some businesses within DE West. Therefore, the pool of business units receiving services for Allocator #2 is a subset of the pool of business units receiving services for Allocator #1.

- Allocator #3 is associated with the regional support services that are necessary and beneficial for all businesses within DE West's portfolio.

Figures are obtained for the three input factors (gross PPE, gross revenue, and headcount) for the respective pool of businesses and for UtilityCo. UtilityCo is one of the many businesses in the pool. The Functional Allocator is dependent on one factor only since a specific cost causation driver is identified. For each of the Composite Allocators, the three factors are equally weighted at 1/3rd each (column e). The weighted factors (column f) are then summed to arrive at the Composite Allocator percentage for each allocator for UtilityCo (line 6 for Allocator #1 and line 14 for Allocator #2).

Allocator #1 is a percentage of 19.41%, which would result in UtilityCo receiving 19.41% of the specific regional support service cost incurred for all businesses within DE West. In contrast, Allocator #2 has a smaller pool of business units receiving services. Allocator #2 is a percentage of 30.26%, which would result in UtilityCo receiving 30.26% of the specific regional support service costs incurred for the service and benefit received by that subset of businesses only. Allocator #3 is a percentage of 25.00%, which would result in UtilityCo receiving 25.00% of that specific regional support service cost incurred for all businesses within DE West.

The Allocator #1 percentages when summed for all businesses in the pool equals 100%. This is the same for Allocators #2 and #3. This means when the regional costs are allocated to the businesses in the pool all the costs are allocated out. UtilityCo would receive a portion of the regional costs based on the calculated percentages for each of the three allocators.

Table 6: Hypothetical Regional Cost Allocation Example – Step 2 – Allocating Regional Costs

Line No.	Description	Businesses to receive allocation	Total Regional Costs to be Allocated	Allocator to use	UtilityCo Percentage Allocator	Regional Costs Allocated to UtilityCo
	(a)	(b)	(c)	(d)	(e)	(f) = (c) x (e)
1	Regional Cost Categories					
2	Regional Cost A	All	$800,000	Allocator #1	19.41%	$155,259
3	Regional Cost B	Relevant Businesses only	$400,000	Allocator #2	30.26%	$121,026
4	Regional Cost C	All	$250,000	Allocator #3	25.00%	$62,500
5	**Total**		**$1,450,000**			$338,785

Table 6 above shows Step 2 of the Regional Cost Allocation Example. After the allocator percentages are calculated in Step 1, the allocators are applied to the related regional cost categories. In the example for UtilityCo:

- Regional Cost A is allocated to all businesses using Allocator #1 (a Composite Allocator) at 19.41% for UtilityCo;
- Regional Cost B is allocated to only the relevant business units using Allocator #2 (a Composite Allocator) at 30.26% for UtilityCo; and
- Regional Cost C is allocated to all business units using Allocator #3 (a Functional Allocator), at 25.00% for UtilityCo.

In the above example UtilityCo is allocated a total of $338,785 from regional costs totaling $1.45 million, representing 23.36% of the total regional costs. Therefore, based on the allocators used, it is estimated that $338,785 of the total regional costs were incurred to provide these regional support services to UtilityCo.

The above process provides a simplified example of how the regional cost allocation methodology is applied using different allocators for different categories of regional costs. This example with hypothetical figures for the allocator percentages and allocated cost amounts are not indicative of Corix's DE West allocations and is intended solely for the purpose of explaining how the allocators are calculated and applied to each regional cost category. For additional details regarding the methodology, please refer to Sections 3, 4 and 5 of this Manual.

Appendix K: Customer Information Session Report

DOCKSIDE GREEN ENERGY REVENUE REQUIREMENTS AND RATES APPLICATION

CUSTOMER ENGAGEMENT SUMMARY REPORT

MAY 2025

Table of Contents

1. PURPOSE

As part of its Revenue Requirements and Rate Application process to the BC Utilities Commission (BCUC), Corix is proposing rate increases for the Dockside Green District Energy (DE) system. As a regulated utility, Corix recognizes the importance of engaging with its customers, residents and stakeholders in advance of filing its application; to share information, explain the rationale for the proposed rate increase, and to respond to questions.

Corix organized two information meetings for customers, residents and stakeholders. This report provides a record of those sessions and summarizes the key feedback themes that emerged during the sessions.

2. OVERVIEW

On May 2, 2025, Corix held two Customer Information Sessions with customers, residents and stakeholders from the Dockside Green development. These meetings were designed to inform participants of the upcoming Revenue Requirements and Rates Application, provide background on the role of the regulator, and explain the reasons behind the proposed rate increases.

The sessions included a presentation from Corix with facilitated questions and answers throughout. The same presentation content was delivered in both sessions to ensure all participants received consistent information.

3. ENGAGEMENT

3.1 Participation

Two group meetings took place on May 2, 2025, at a conference room in the Delta Hotel Ocean Pointe Resort in Victoria. The location was chosen because there was no available meeting space in the Dockside Green property itself, and the hotel is located a short walk from the community. The first session took place from 3:00 PM to 4:30 PM, followed by the second session from 6:00 PM to 7:30 PM.

- In total, 44 people attended the two information sessions.
- One of the attendees was the property manager for Proline Property Management, who manages five of the eight customers of the utility.
- Attendees included a variety of stakeholders, such as unit owners, renters, and owners that were on strata council.

3.2 Notification

Customer Notification

Emails were sent on April 14 to all customers of the utility, informing them of the information sessions and requesting that notice of the upcoming Customer Information Sessions be distributed to all strata councils, owners, and tenants. Corix also requested that the notice be prominently displayed on building notice boards, in mail rooms, hallways, and elevators to ensure maximum visibility for residents. Follow-up emails were then sent on April 23, and April 30 to all customers reminding them of the upcoming information sessions.

Stakeholder Notification

As Bosa Development is the property developer for the Dockside Green development, Corix emailed Bosa Development directly on April 14, 2025, requesting a meeting to provide the same information that would be provided to customers. Corix followed up by email on April 17, 2025, but no response was received.

4. ENGAGEMENT MATERIALS

Refer to page 6/Appendix A to view the customer contact list.
Refer to page 7/Appendix B to view examples of the request to post meeting notices.
Refer to page 10/Appendix C to view the notice of customer information meetings.
Refer to page 11/Appendix D to view the customer information meeting presentation.

5. FEEDBACK

5.1 Key Themes

- Participants expressed confusion regarding how Corix's proposed rate changes would impact residents:
  - whose utility bills are generated by third-party submetering companies; and
  - where the strata property management company/the strata council/building owner apportions each unit's share of the building's thermal energy costs.
- Participants were interested in understanding the difference between the basic rate and variable rate and how that is reflected in their energy bills.
- Participants were interested in understanding the reasons for proposed rate increases.
- Participants were interested in plans for future buildings and how that will impact efficiency of the system.
- Participants were interested in plans for future technology innovations and how that might improve efficiency and reduce carbon emissions.
- Some participants expressed disappointment at the continued use of natural gas by Dockside Green Energy and voiced enthusiastic support for a future with low-carbon or zero-carbon district energy system. Participants also noted the importance of properly allocating the costs of the low-carbon solution to the appropriate customers.
- Participants expressed appreciation for the presentation and Corix team's responses to their questions.

The following is a summary of comments from the two customer information sessions.

Topic	Number of Mentions
Billing, rates, and reasons for proposed increases	11
Submetering and third-party billing confusion	6
Feasibility study and future technology innovation plans	5
Natural gas phase-out and zero carbon code	5
System efficiency and performance	4
Greenhouse gas emissions and environmental impact	4
Plant capacity and infrastructure planning	4
Timeline for full build-out and customer impacts	4
Application process, BCUC filing, and public input	4
Impact of Development growth and energy system	3
Billing responsibility and utility’s role	3
Customer support, communication and accountability	3
Company ownership, size, and other projects	3
Technical system questions (heat, temperature, and design)	3
Customer opinions and general sentiments	2

Throughout the presentation and in follow up discussion, Corix team members provided responses to all questions and comments. Customers, residents, and stakeholders expressed appreciation for the presentation and the teams’ responses.

APPENDIX

Appendix A: Customer Contact List

Building	Company
A1-1/2/3	Bosa Development, c/o Prospero International Realty Inc.
A1-1	Strata Plan EPS 9197, c/o Proline Property Management
A1-2	Strata Council
CI1 (Inspiration)	Strata Plan VIS 6708, c/o Proline Property Management
CI2 (Prosperity)	Strata Plan VIS 6801, c/o Proline Property Management
R1 (Synergy)	Strata Plan VIS 6511, c/o Proline Property Management
R2 (Balance)	Strata Plan VIS 6763, c/o Proline Property Management
CI3 (Acheson Law)	1258122 BC Ltd., The Truffles Group (Acheson Law)
CI4 (Farmer Construction)	GDP Properties Ltd., c/o Farmer Construction
R4/5 (Madrona)	Catalyst Community Developments Society, c/o Pacific Quorum (Vancouver Island) Properties Inc.,

Appendix B: Request to Post Meeting Notices

Email Notification #1 – April 14, 2025
Subject: Important Notice: Dockside Green Energy Customer Information Sessions

Good afternoon Jane,

Bosa Development c/o Prospero International Realty Inc.,

Please find attached notice from Corix Dockside Green DE Limited Partnership regarding upcoming Customer Information Sessions on proposed rate changes for Dockside Green Energy customers.

Key details from the notice:

- **Purpose:** To inform customers about the proposed rate changes, provide customers with an opportunity to ask questions and learn about the BCUC regulatory review process.
- **Dates and Times**: Friday, May 2, 2025
  - **Session 1**: 3:00 PM – 4:30 PM
  - **Session 2:** 6:00 PM – 7:30 PM
- Location: Delta Hotels Victoria Ocean Pointe Resort, Executive Meeting Room (3rd Floor)

We kindly request that this notice be distributed to all strata councils, owners, and tenants. Additionally, please ensure it is posted on notice boards and in high-traffic areas such as mail rooms, hallways, and elevators. For any questions, please contact us at 1-866-457-7273 or customersupport@corix.com.

Thank you,

Corix Customer Care

Email Notification #2 – April 23, 2025

Subject: Reminder: Upcoming Customer Information Sessions on Proposed Rate Changes

Good afternoon Jane,

Bosa Development c/o Prospero International Realty Inc.,

This is a courteous reminder regarding the upcoming Customer Information Sessions organized by Corix Dockside Green DE Limited Partnership. These sessions will address the upcoming rate Application for Dockside Green Energy.

Key details:

- **Purpose**: To inform customers about the rate changes to be proposed, provide an opportunity to ask Questions, and explain the regulatory review process.
- **Date and Times:** Friday, May 2, 2025
  - **Session 1**: 3:00 PM – 4:30 PM

- **Session 2:** 6:00 PM – 7:30 PM

- **Location**: Delta Hotels Victoria Ocean Pointe Resort, Executive Meeting Room (3rd Floor)

For additional details, please refer to the PDF attached titled “Notice of Customer Information Sessions”, dated April 14, 2025 (April 14th Notice) that was included in the email sent to you on April 14, 2025.

We kindly request that the April 14th Notice be distributed to all strata councils, owners, and tenants. Additionally, please ensure it is prominently displayed on notice boards and in high-traffic areas such as mail rooms, hallways, and elevators.

Should you have any inquiries, please do not hesitate to contact us at 1-866-457-7273 or customersupport@corix.com.

Thank you for your cooperation. We look forward to your participation in the sessions.
Yours sincerely,

Corix Customer Care

Email Notification #3 – April 30, 2025

Subject: Final Reminder: Upcoming Customer Information Sessions on Proposed Rate Changes – May 2

Good afternoon Jane,

Bosa Development c/o Prospero International Realty Inc.,

This is a final reminder of the upcoming Customer Information Sessions on Friday, May 2 organized by Corix Dockside Green DE Limited Partnership. These sessions will address the upcoming rate application for Dockside Green Energy.

Key details:

- **Purpose**: To inform customers about the rate changes to be proposed, provide an opportunity to ask Questions, and explain the regulatory review process.
- **Date and Times:** Friday, May 2, 2025
    - **Session 1**: 3:00 PM – 4:30 PM
    - **Session 2:** 6:00 PM – 7:30 PM
- **Location**: Delta Hotels Victoria Ocean Pointe Resort, Executive Meeting Room (3rd Floor)

For additional details, please refer to the attached PDF titled “Notice of Customer Information Sessions”, dated April 14, 2025 (April 14th Notice) that was included in the email sent to you on April 14, 2025.

We kindly request that the April 14th Notice be distributed to all strata councils, owners, and tenants. Additionally, please ensure it is prominently displayed on notice boards and in high-traffic areas such as mail rooms, hallways, and elevators.

Should you have any inquiries, please do not hesitate to contact us at 1-866-457-7273 or customersupport@corix.com.

Thank you for your cooperation. We look forward to your participation in the sessions.
Yours sincerely,

Corix Customer Care

Appendix C: Notice of Customer Information Meetings

CORIX DOCKSIDE GREEN DE LIMITED PARTNERSHIP NOTICE OF CUSTOMER INFORMATION SESSIONS

Dated: April 14, 2025

RE: Proposed rate changes for Dockside Green Energy customers

Corix Dockside Green DE Limited Partnership (Corix) owns and operates the district energy utility that provides thermal energy in the form of heat, which is used for space heating and domestic hot water at the Dockside Green development. Corix is regulated by the British Columbia Utilities Commission (BCUC).

In May 2025, Corix will be submitting a Revenue Requirement and Rates Application (Rate Application) to the BCUC, seeking approval of new Basic Charge rates for the Dockside Green Energy utility effective July 1, 2025, January 1, 2026, January 1, 2027, and January 1, 2028.

Corix will be holding two Customer Information Sessions, with the details provided below.

Date: Friday, May 2, 2025

Location: Delta Hotels Victoria Ocean Pointe Resort – Executive Meeting Room (3rd Floor, accessible by the main elevators via the lobby or parkade)

Address: 100 Harbour Road, Victoria, BC
Time: Information Session #1: 3:00 – 4:30 PM

Information Session #2: 6:00 – 7:30 PM

Details: Light refreshments will be provided. Corix will provide the same information in each session, including:

- the key drivers necessitating the new rates;
- a discussion on proposed rate design changes;
- the new Basic Charges that will be proposed in the Rate Application; and
- the estimated impact on the utility bill for a typical residential unit.

Attendees will have the opportunity to ask questions and learn how to get involved in the BCUC regulatory review process once the Rate Application has been submitted.

If you have any questions about this notice, please contact us by phone at 1-866-457-7273 or by email at customersuppport@corix.com. This phone number and email address are monitored Monday to Friday from 8 AM to 5 PM (PT).

Sincerely,

Corix Dockside Green DE Limited Partnership

Appendix D: Customer Information Meeting Presentation

WELCOME

Dockside Green Energy

Rate Application Customer Information Meeting

May 2, 2025

corix

Panel Members

Nancy Spooner – Facilitator

<u>Corix Team</u>

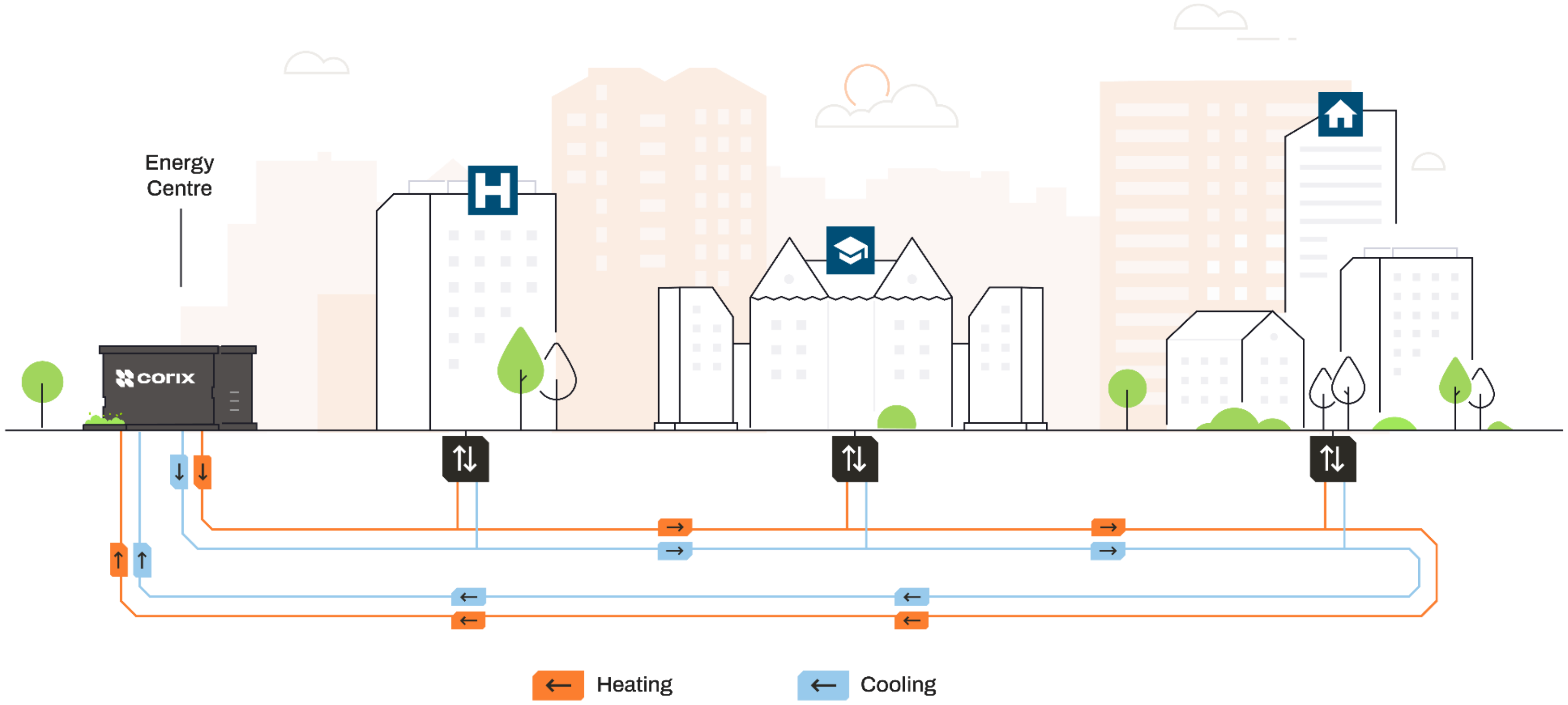
- Errol South – Director, Regulatory Affairs
- David Saldana – Senior Regulatory Analyst
- Robin Johnson – Area Manager (Operations)
- Jason Owen – Director, District Energy Development
- Hang Hockley – Director, Business Operations

Purpose of this Meeting

- Overview of District Energy
- Background on Dockside Green Energy
- The Role of BC Utilities Commission (BCUC)
- Upcoming Revenue Requirement and Rates Application
- Proposed Rates and End-User Bill Impact
- Future Rate Design
- A Low-Carbon Future
- Next Steps
- Q&A

What is District Energy?

- District Energy is a way of centralizing equipment and efficiently sharing energy across a network of buildings.
- It's a powerful tool to facilitate reductions in carbon emissions while delivering reliable and competitively priced heating, cooling, and hot water.



Benefits of District Energy

More Efficient Energy

Adaptability and Resilience

Reduced Carbon Footprint

Reliability

Simplicity

Competitive Costs

Additional Usable Space

Developer Cost Savings

Background of Dockside Green Energy

- DGELLP began operations in 2008

- Original plan was to use wood-waste gasification to generate thermal energy, and with future growth, sewer waste heat recovery as an additional energy source

- DGELLP faced major issues
  i. Significant delays to the property development buildout schedule
  ii. Operational challenges preventing the use of the gasification system
  iii. Costs that significantly exceeded revenue

- DGELLP suffered significant financial losses, and in October 2018 the utility assets were sold to Corix

Utility System Improvements

- Increased system efficiency
  - Annual average efficiency prior to full ownership = 65%
  - Annual average efficiency over 3 most recent years = 74%

- Improved reliability
  - Previously only 1 large boiler
  - Now 4 boilers (3 small + 1 large)

- Enhanced operations through technology upgrades

- Improved building energy demand monitoring

- Optimized operational setpoints

British Columbia Utilities Commission (BCUC)

- An independent regulatory agency of the Government of British Columbia
- Regulates energy utilities in BC, in addition to other things
- Ensures customers have access to safe, reliable energy service at just and reasonable rates
- Reviews and approves all rates before the utility can charge them to customers
- For more information, visit the BCUC website: bcuc.com

Revenue Requirement and Rates Application

Revenue Requirement (Rev. Req.)

- It is the utility's "cost of service"
- Cost to provide safe and reliable service to customers
- **Total Rev. Req. = Delivery Costs + Energy Costs**

Recovering Costs from Customers

- BCUC allows utilities to recover from customers the prudently incurred costs, which include an opportunity to earn a fair return on invested capital only
- Utility investments or expenses determined to be excessive, wasteful and/or unnecessary are not allowed to be recovered from customers.

Upcoming Revenue Requirement and Rates Application

- Target filing date is May 30, 2025
- Will review Delivery Costs and propose increases to the Basic Charge

Delivery Costs

- Operating Labour
- Repairs and Maintenance
- Insurance
- Customer Billing
- Support Services Overhead
- Other Operating Expenses
- Property Tax, Fees, Levies
- Depreciation
- Interest on Debt
- Return on Equity
- Income Tax

Rate Structure and Recovery of Costs

Utility Rates

Utility Rates		
Basic Charge ($/m^2) (fixed)	**Operations & Maintenance and General & Administrative**	Operating Labour Repairs and Maintenance Insurance; Billing; Overhead; Property Taxes Other
	Financing Costs	Depreciation Return on Equity Interest on Debt
Variable Energy Charge ($/kWh) (variable)	**Energy Costs**	Natural Gas Electricity
Rate Rider 1 ($/m^2) (fixed)	**Property Tax Variance** (Actual – Forecast)	Property Tax Variance

Reasons behind the Proposed Rate Increases

- **Depleted $1,000,000 Contribution**
  - Corix received a $1M contribution to limit the need to increase customer rates during the initial years following acquisition
  - The $1M was used to artificially lower the rate increases to 2.9% per year from 2019 to 2023
  - The $1M contribution is fully depleted, indicating a need for rate increases

- **Lower Revenue**
  - Revenue was forecast based on the development buildout schedule in 2019
  - Due to buildout delays, the current and future revenue is lower than previously forecast

- **Higher Cost of Service**
  i. **Higher Property Taxes** – Unanticipated and significant increase in property taxes

  ii. **Higher Labour Costs** – An increase in a full-time employee was needed sooner than expected to meet mandatory Technical Safety BC (TSBC) staffing requirements for the plant due to the recent recommissioning of the large natural gas boiler for peaking and backup purposes. Previously this wasn’t anticipated to occur until 2028.

  iii. **Higher Financing Costs** – The cost of financing operations through debt and equity has increased

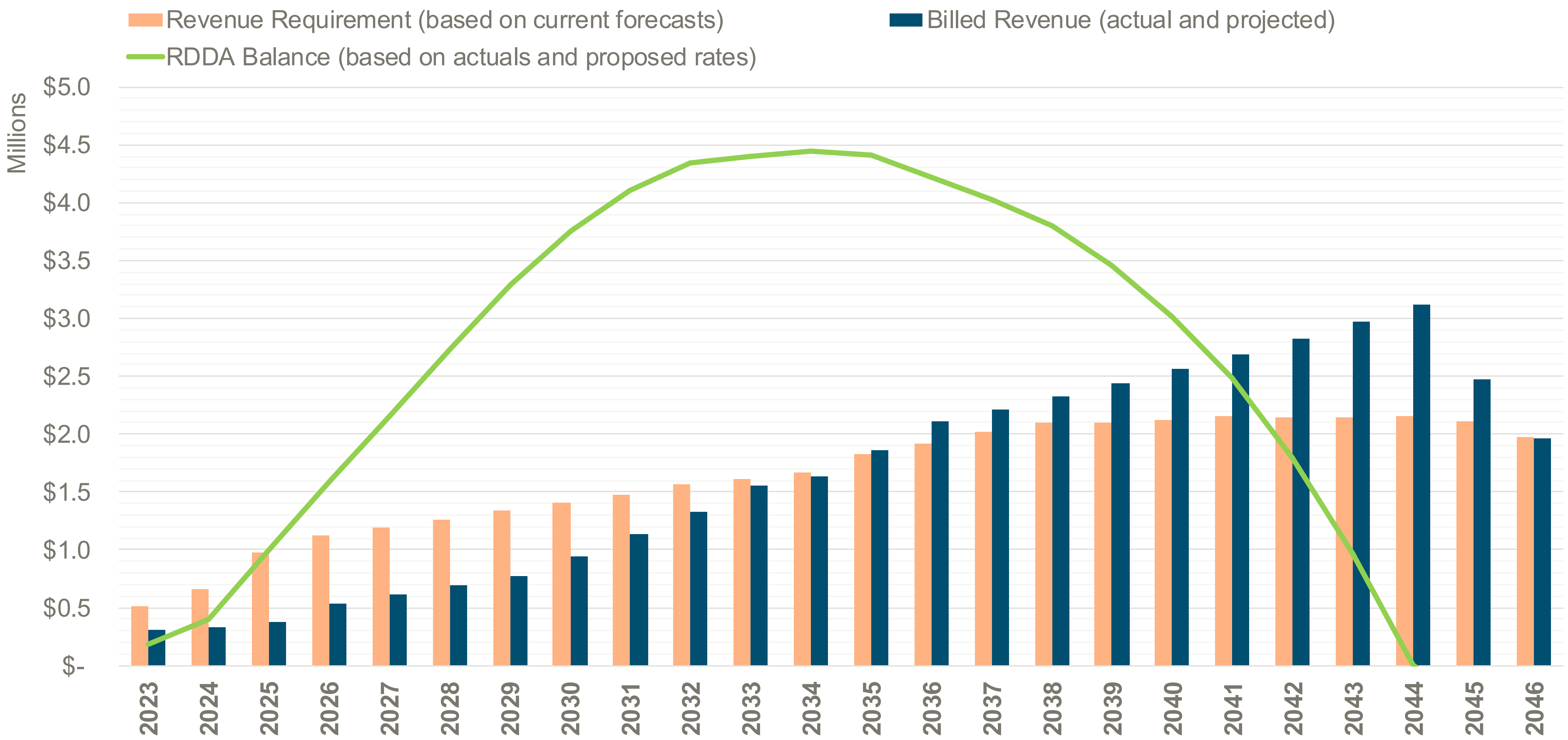
  iv. **Higher Operating Costs** – The cost to operate the utility is materially higher than forecast in the previous rate application due to higher capital costs, higher support services costs and higher insurance costs.

Proposed Rates and Residential End-User Bill Impact

	April 1, 2025 (current)	July 1, 2025 (proposed)	2026 (proposed)	2027 (proposed)	2028 (proposed)
Basic Charge ($/m^2 per month)	**0.426**	**0.5538**	**0.6923**	**0.7961**	**0.8916**
Basic Charge Increase	*n/a*	*30%*	*25%*	*15%*	*12%*
Variable Energy Charge ($/kWh)	0.0370	0.0370	0.0447	0.0455	0.0462
Rate Rider 1 ($/m^2 per month)	0.1834	0.1834	n/a	n/a	n/a
Combined Increase in Total Annual Bill	n/a	**16%**	**12%**	**9%**	**9%**
Residential End-User Suite – 74 sq. m. (800 sq. ft.)					
Amount for Basic Charge ($)	369	435	615	707	792
Amount for Variable Energy Charge ($)	231	204	246	251	255
Amount for Rate Rider 1 ($)	81	149	21	--	--
Total Annual Bill	**$681**	**$788**	**$882**	**$958**	**$1,047**
Combined Increase in Total Annual Bill	n/a	**$107**	**$94**	**$76**	**$89**

- The Variable Energy Charge is updated April 1st each year via a formula and a streamlined process approved by BCUC
- An average residential end-user is represented by a 74m^2 condominium (800 sq. ft.) with an annual heating consumption of 5,513 kWh
- The impact to the average end-user would be an average increase of $91.50 each year over the 4 years from 2025 to 2028

Billed Revenue, Revenue Requirements and RDDA



Future Rate Design and Low-Carbon Energy

Future Rate Design Changes

Before	After
Basic Charge **Monthly Fixed Rate per m^2** (Based on floor area)	**Capacity Charge** **Monthly Fixed Rate per kW** (Based on capacity)
Variable Energy Charge Monthly Variable Charge per kWh	**Variable Energy Charge** Monthly Variable Charge per kWh

Benefits of a Capacity Charge

- **Encourages efficient design**
- **Fairness in setting rates**
- **Rate adaptability**
- **No Impacts to Current Customers**

A Low-Carbon Future

<u>Low Carbon Requirements for New Buildings</u>

- City of Victoria Zero Carbon Step Code implementation
- Requirement for new buildings to meet carbon performance standard (tonnes/m^2/yr)
- New low-carbon energy investment will be required at DocksideGreen before next new building comes online
- Corix feasibility study underway

Low-Carbon Feasibility Study

- Evaluating suitable technologies for cost effective decarbonization of existing DGE plant
  - Heat pumps
  - Waste heat from cooling
  - Proven, right-sized biomass technology
- Options will include low-carbon energy supply to existing buildings
- Includes expansion opportunities
  - Increases options for low-carbon supply
  - Improves economy of scale on capital investment
  - Expanded customer base helps distribute operating and overhead costs

Next Steps

- Corix will file the Rate Application by May 30, 2025

- BCUC is expected to establish a public hearing process to review the Application
  - Customers will be notified after BCUC publishes the review schedule

- Customers can get involved in public hearing processes in three (3) ways:
  - **Stay Informed** – receive email notifications
  - **Share your Views** – submit a letter of comment
  - **Join the Process** – participate as an intervener
  - For more information, visit bcuc.com/GetInvolved/GetInvolvedProceeding

- Corix will post relevant links on its Regulatory Affairs page of the DGE website:
  - corix.com/dockside-green/regulatory-affairs/

- For any questions, please contact us by phone at 1-866-457-7273 or by email at customersuppport@corix.com

Questions?