NOV 2022

BLATCHFORD RENEWABLE ENERGY

2023 Rate Filing

Attachment 1 - FCS01479

Blatchford Renewable Energy

Edmonton

Table of Contents

1.0 Overview

This 2023 Blatchford Renewable Energy Rate Filing is the annual filing for approval of end use customer rates and fees for Blatchford Renewable Energy Utility ("BREU" or "Blatchford"). As per Section 3.0 the Blatchford District Energy Utility Fiscal Policy C597A ("Fiscal Policy");

> "The Utility Committee shall recommend annually to City Council the customer rates for the upcoming year, based on review of an annual rate filing prepared by the Utility subsequent to the preparation and presentation of the 4-year Business Plan."

This Rate Filing is requesting City Council approval of the following:

- Townhouse Monthly Charge for 2023, to be set based on the approved 2022 rate escalated by 10 per cent;
- A new Multi-Unit Monthly Charge for 2023, to be applicable to all buildings connecting to the District Energy Sharing System, other than Townhouses;
- Changing the name of the Residential Infrastructure Fee to Townhouse Lot - Residential and the Commercial Infrastructure Fee to Multi-Unit Lot - Commercial and the introduction of a new Multi-Unit Lot - Residential Infrastructure Fee, and;
- Townhouse Lot- Residential and Multi-Unit Lot - Commercial Infrastructure Fees for 2023, to be set based on the approved 2022 fees escalated by 2.7 per cent and the new Multi-Unit Lot - Residential Infrastructure Fee to be set at the same level as the Townhouse Lot - Residential fee .

In preparing this Rate Filing, BREU has followed the principles as set out in the Fiscal Policy. In particular, BREU established the forecast 2023 revenue requirement based on a traditional cost of service approach while taking into account a Policy Statement in the Fiscal Policy that end-use customers would pay "at most a comparable fee to what they would elsewhere in the City of Edmonton through their energy utility bills and annual maintenance costs" in establishing the proposed 2023 end use customer rates. This Policy Statement has guided the approach taken to design end use customer rates in Blatchford and will henceforth be referred to as Business as Usual ("BAU").

In December 2018, City Council approved the Blatchford Utility 2019 Annual Rate Filing which established the regulatory framework and customer rates for the initial year of operation of the Blatchford utility. For 2019, a "pegged approach" was used to set customer rates under which Blatchford utility customer bills were pegged to what typical utility bills would be elsewhere in the City of Edmonton in 2019 for heating, cooling, and hot water (i.e. BAU).

In December 2019, City Council approved the Blatchford Utility 2020 Annual Rate Filing, whereby a “levelized approach” was then used to update customer rates for 2020 based on escalating 2019 approved rates by 2.7 per cent, consistent with the rate setting methodology reflected in the business case presented to City Council on March 16, 2016, for the development of the District Energy Sharing System at Blatchford. Under the levelized approach, customer rates in the business case were increased by 2.7 per cent on average each year over the initial 50 years to ensure stable and consistent rate increases, with rates set to under-recover costs in the early years of the Utility’s operation when the customer base is small and to gradually recover past costs in the later years when the customer base is fully established. The levelized approach, and rate and fee increases annually of 2.7 per cent, was utilized again in establishing customer rates for 2021 and 2022.

In establishing 2023 Townhouse rate, BREU is proposing to continue to use the levelized approach but rather than a 2.7 percent increase, as was approved for 2020-2022, BREU is proposing to escalate the approved 2022 rates by 10.0 per cent. A more detailed discussion of the rationale for this increase, as well as the methodology utilized to establish the full set of rates and fees proposed for 2023, is included in Section 6.

The first customer connections to the BREU system occurred in August of 2020 and a total of 8 townhomes were connected to the system by the end of 2020. By the end of 2022 a total of 53 townhomes are expected to be connected to the system. A further 83 townhomes are forecast to connect in 2023 along with 4 medium density apartment buildings and the Airport Control Tower for a total of 143 BREU customer accounts forecast by the end of 2023. The 2023 forecast customer revenue will not be sufficient to fully recover BREU’s 2023 forecast revenue requirement and, as was the case with previous rate filings, BREU will continue to utilize a deferral account whereby the annual revenue shortfall amounts will be accumulated in the deferral account to be recovered in future years when customer revenues exceed BREU’s revenue requirement. Consistent with Section 1c of the Fiscal Policy, BREU will borrow (on a short term basis) from the City of Edmonton in order to meet the insufficient cash flow during its first years of operation. Further details are provided in Section 6.

BREU has provided a set of schedules with details of its 2023 revenue requirement and revenue on proposed rates in Appendix 3.0. These schedules utilize a very similar format and content to the Minimum Filing Requirements format utilized in the electric and gas utility industry in Alberta.

The Rate Filing is organized as follows:

Section 2.0 - Background on the Blatchford Development
Section 3.0 - Blatchford Fiscal Policy
Section 4.0 - Blatchford 2023-2026 Business Plan
Section 5.0 - 2023 Forecast Revenue Requirement
Section 6.0 - Cost of Service, Rate Design, Revenue on Proposed Rates & Bylaw 17943
Section 7.0 - Appendices 1.0 - 4.0

2.0 Background

The Blatchford development aims to be one of the world's largest sustainable communities and home to 30,000 residents. Blatchford will be comprised of two primarily residential spaces on the east and west side of the site, along with a town centre, an 80-acre central park and a civic plaza.

Blatchford Renewable Energy is a new public, city owned utility that has been established to own and operate a District Energy Sharing System ("DESS") and certain mechanical equipment within the customer buildings themselves. All buildings in Blatchford, with the exception of net-zero carbon buildings, must be connected to the DESS for all heating, cooling and domestic hot water services.

The strategic objectives of the utility remain the growth of the DESS and the integration of emerging technologies into the utility's operation to reach steady state reliable operation, financial sustainability and to achieve Council's vision for a carbon neutral community powered entirely by renewable energy. The growth of the new utility is, and will continue to be, closely connected to the land development and sales activities in Blatchford.

At the March 16, 2016, City Council meeting, the business case for developing the District Energy Sharing System at Blatchford was reviewed (Sustainable Development report CR_2977 District Energy Sharing System - Business Case and Detailed Rate Setting Analysis). The business case identified the need for a $98 million non-refundable cash infusion for the initial years of operation to offset the capital investment required to establish the utility and allow it to grow over time to achieve financial sustainability. The business case and assumptions were subsequently updated as part of the Blatchford Utility Fiscal Policy presented to City Council on March 22, 2018 resulting in a reduction in the non-refundable cash infusion from $98 million to $93 million.

The non-refundable cash infusion is a key element in enabling the Blatchford Renewable Energy Utility to achieve two principles reflected in both the business case and Fiscal Policy: (1) ensure that the utility becomes financially sustainable in the long run without any ongoing subsidy, and (2) ensure customers pay a comparable fee to what they would elsewhere in the City through their energy utility bills and annual maintenance costs.

BREU has recently updated the financial model presented in the original business case in order to determine the current non-refundable cash infusion required to still achieve these two principles. Key assumptions for that financial model were updated to reflect the latest information and data including, but not limited to; the current land development timelines, customer projections and energy requirements, capital and operating costs (including equipment maintenance and BREU administrative costs), utility rates & fees, and other economic assumptions as identified (e.g. interest rates, inflation, discount rate). Based on the latest data and information and updated assumptions in the financial model, the financial picture of Blatchford Renewable Energy remains similar to what it was in 2018, with a non-refundable cash infusion of $93 million still required.

Opportunities likely exist to lower that figure, should various assumptions or policy decisions change over time, including the appetite for slightly higher medium term utility rate and fee increases. It is important to note that there is a range to the cash infusion that is manageable in terms of the utility's long-term financial health, based on different decisions City Council may take looking at different assumptions involving future rate increases and debt financing, amongst others. Currently, looking at variations of these factors in the updated financial model, the required cash infusion could be in a range between $70 and $93 million. The utility is committed to frequent review of the financial model and will bring any long term considerations to Utility Committee and Council when they arise.

To support Edmonton's transition to a low carbon future, the 2023 - 2026 budget will be the first time a carbon budget is completed and delivered to Council in conjunction with the operating, capital, and utility budgets. Use of the Carbon Budgeting and Accounting Framework will guide the organization and Council in understanding how financial investment decisions impact the achievement of emissions reductions targets or reduce Edmonton's carbon deficit.

All budget requests have been assessed for both qualitative carbon impacts and more detailed quantitative carbon impacts where possible. The qualitative assessment links direct emissions impacts to the four pathways in the Energy Transition Strategy and indicates indirect emissions impacts. Carbon impacts have been presented for each capital project and operating service package under consideration in the 2023-2026 budget in the standalone 2023-2026 Carbon Budget document. Please refer to the 2023-2026 Carbon Budget for more details.

3.0 Fiscal Policy

On April 10, 2018, City Council approved the Blatchford District Energy Utility Fiscal Policy C597 that was later updated and approved on December 9, 2020 as C597A. The Fiscal Policy is the prerequisite required to support the first four year Utility Business Plan and Bylaw including rates. As stated in the Fiscal Policy, the purpose of the Policy is to:

1. Ensure that the Blatchford District Energy Utility is operated in a manner that reflects City Council's overall vision and philosophical objectives for BREU.
2. Ensure that there is a consistent approach year over year for the financial planning, budgeting, and rate setting for the City managed utility.
3. Ensure that BREU is financially sustainable over the long term.

In addition to the three statements noted above, the following four Policy Statements outlined in the Fiscal Policy helped establish the regulatory framework and methodology utilized in this Rate Filing:

1. The utility is to be operated in a manner that balances the best possible service at the lowest cost (public utility) while employing private sector approaches to rate setting.
2. Similar to private utilities, the utility will account for the cost of service under a full cost accounting approach. All customer charges will be based upon cost of service with the end user (customer) paying at most a comparable fee to what they would elsewhere in the City of Edmonton through their energy utility bills and annual maintenance costs.
3. Through a phased approach, the utility will generate positive net income, cash flow and a rate of return sufficient to cover current year expenses, working capital requirements, and to facilitate the funding for capital infrastructure and rehabilitation and replacement of capital assets.
4. The utility is to contribute towards achieving the City's Community Energy Transition Strategy.

BREU will fund its operating and capital requirements from a number of sources. The following sources of funding will be required and utilized during the initial years of operation:

- Rate Revenue
  BREU will generate revenue through monthly customer rates. Rates will be designed to be at most comparable to what customers would pay elsewhere in the City through their energy utility bills and annual maintenance costs.
- Infrastructure Fee
  BREU will collect a one time infrastructure fee for units and buildings from the builders that connect to the DESS. This fee creates an additional source of revenue for BREU that would otherwise need to be funded by utility rates or the non-refundable cash infusion.
- Non-refundable cash-infusions
  Non-refundable cash infusions are required for the initial years of operation to offset the capital investment required to establish BREU and allow it to grow over time to achieve financial sustainability. With more specific information and costs available the total non-refundable cash infusion of $93 million has been confirmed, with opportunities likely existing to lower that number in the future.
- Builder Contributed Capital
  The builder will pay for central mechanical room equipment in multi-unit buildings, which will then be owned, operated and maintained by BREU. These will be contributed assets on BREU's balance sheet and will not attract a net depreciation expense or a return on rate base.
- Debt Borrowing
  The initial capital expenditures for BREU may be financed with long term debt but will ultimately need to be funded (and the debt servicing costs repaid) by non-refundable cash-infusions to ensure the long-term financial sustainability of the utility.

During the review of the 2020 Annual Rate Filing on November 1, 2019, the Utility Committee requested that Administration review the Fiscal Policy to provide more flexibility in setting customer rates going forward. In particular, the Utility Committee raised concerns that the Fiscal

Policy as currently written could limit the ability for setting future customer rates if rates under the pegged approach in a given year were less than the levelized approach rates of 2.7 per cent per year. At the October 2, 2020 Utility Committee meeting, Administration recommended that specific rate setting principles be added to the fiscal policy which: (1) incorporate industry best practice utility rate setting principles; (2) further explain that customer rates may be set to recover the forecast cost of providing service over a longer term basis under the levelized approach; and (3) clarify that multiple years be used for comparison of Blatchford utility customer rates going forward to ensure they remain competitive. These rate setting principles were subsequently approved by Council on October 17, 2020 and a separate report (FCS00138 - Blatchford District Energy Utility Fiscal Policy C597 Update) was brought forward at the December 4, 2020 Utility Committee meeting that provided the full updated content of the Blatchford Fiscal Policy. City Council approved the updated Fiscal Policy C597A on December 9, 2020.

In respect of this 2023 Rate Filing and the end-use customer rates included herein, the second Policy Statement, along with the amendments to the Fiscal Policy discussed above, were instructive in establishing the framework for the setting of the end-use customer rates, both the rate levels and the rate structure. This will be discussed further in the Rate Design section of this Filing.

A copy of the updated Fiscal Policy has been provided in Appendix 1.0.

4.0 2023-2026 Business Plan

The 2023-2026 Business Plan was presented to the Utility Committee on November 4, 2022 (Integrated Infrastructure Services report IIS01397). The 2023-2026 BREU Business Plan provides an updated overview from the strategic and operational level for the utility. The first Blatchford residents have been connected to the District Energy Sharing System for two years. The system has worked without any interruptions or concerns and has provided comfortable heat and cooling energy services.

A review and update of the initial utility Master Plan was conducted in 2021. This Master Plan includes modeling and forecast tools which will help Blatchford Renewable Energy plan for the infrastructure needed as additional district energy nodes are constructed in the development. The updated utility Master Plan provides a roadmap for development of district energy infrastructure alongside the land development in Blatchford. The key input variable for the Master Plan is land development information, including sale activities and builder construction timelines. Based on the current forecast, about 1,500,000 m^2 of floor area will be connected to the utility, which will provide 47,000 and 44,000 Mwh of heating and cooling energy annually when the system is fully built out.

Over the next four years, the focus for Blatchford Renewable Energy will be on the continuation of the utility's operational performance, the extension of the distribution piping network, the growth of the existing Energy Center One and the development of the next energy center.

Guided by the sales activities of the Blatchford land development team and the construction activities by the builders, the utility is expecting to grow its customer base to 442 accounts by 2026, which represents over 400,000 m² of floor area connected to the District Energy Sharing System.

Several key internal initiatives were started which will have a significant impact on the future utility financial and regulatory operations. These include the update of the utility's financial model, the development of advanced rate design for multi-unit customers, and the potential adjustment of the utility's infrastructure fee. An updated business case was developed for the Sewer Heat Exchange Energy Center which also looked at other alternatives to further grow the Blatchford Renewable Energy Utility in line with Council's vision recognizing prudent fiscal development. Further information in respect of these initiatives are provided in the sections below.

The strategic objectives of Blatchford Renewable Energy continue to focus on the growth of the District Energy Sharing System and the integration of emerging technologies. The overall goal is to reach steady, reliable operation and financial sustainability while achieving Council's vision for a carbon neutral community powered by renewable energy.

5.0 2023 Forecast Revenue Requirement

5.1 Methodology and Key Assumptions

The 2023 BREU Rate Filing utilizes the methodology established in previous BREU rate filings and adheres to the principles set out in the Blatchford District Energy Utility Fiscal Policy, which establishes the framework for how BREU will set rates, finance its capital and manage its cash position. As per the Fiscal Policy, an annual rate filing will be submitted each year requesting City Council approval of end use customer rates for the following year.

The schedules provided in the 2023 Rate Filing include revenue and expenditure amounts for the following years: 2019, 2020 and 2021 actuals, 2021 and 2022 approved budgets; 2022 current forecast (with actuals to the end of August) and the 2023-2026 proposed operating budget. The revenues and expenditures for 2023-2026 included in the 2023 Annual Rate Filing have been incorporated into the 2023-2026 operating budget for Utility Committee and City Council approval.

This Rate Filing takes into account the most recent land development and sales forecast developed by the Blatchford Redevelopment Office. The first Blatchford customers connected to the system in August 2020. Thus far townhouses are the only building types to be connected to the system. The airport control tower as well as other types of residences, such as multi-unit townhouses and multi story apartment buildings, are expected to begin connecting to the system in 2023 and beyond. The following table summarizes the actual/forecast customer connections and energy consumption during the 2019-2026 time period.

Table 1: Customer Connections and Energy Consumption by End Use

	2019	2020	2021	2022	2023	2024	2025	2026
Item	**Actual**	**Actual**	**Actual**	**Current Forecast**	**Proposed**	**Proposed**	**Proposed**	**Proposed**
New Customer Connections - Buildings								
Townhouses - Single Unit	-	8	19	26	83	71	68	149
Townhouses - Multi-Unit	-	-	-	-	2	1	-	-
Apartments - Medium Density	-	-	-	-	4	-	2	-
Commercial/Office	-	-	-	-	-	-	-	-
NAIT	-	-	-	-	-	1	-	1
Residential Mixed-use	-	-	-	-	-	1	2	-
Retial Mixed Use	-	-	-	-	-	-	1	2
Municipal	-	-	-	-	-	-	1	-
Other - Control Tower	-	-	-	-	1	-	-	-
Total New Customer Connections	**-**	**8**	**19**	**26**	**90**	**74**	**74**	**152**
Energy Consumption (MWh)								
Townhouses - Single Unit	-	14.1	212.7	266.7	597.8	1,127.8	1,593.3	2,334.4
Townhouses - Multi-Unit	-	-	-	-	58.1	339.4	396.3	396.3
Apartments - Medium Density	-	-	-	-	714.4	2,702.6	3,140.3	3,242.0
Commercial/Office	-	-	-	-	-	-	-	-
NAIT	-	-	-	-	-	1,295.0	2,590.0	3,242.0
Residential Mixed-use	-	-	-	-	-	514.8	1,804.3	3,103.5
Retial Mixed Use	-	-	-	-	-	-	345.0	2,555.8
Municipal	-	-	-	-	-	-	21.0	63.0
Other - Control Tower	-	-	-	-	8.3	25.0	25.0	25.0
Total Energy Consumption	**-**	**14.1**	**212.7**	**266.7**	**1,378.6**	**6,004.6**	**9,915.3**	**14,962.1**

Up to this point, the only type of end use customer to connect to the DESS has been single unit Townhouses. BREU is expecting four new medium density apartment buildings, two new multi-unit townhouse complexes and the airport control tower to connect to the DESS by the end of 2023. In addition, BREU is forecasting several more new medium/high density apartment buildings, retail and residential mixed use buildings, a new student residence and a new fire hall to connect to the DESS during the 2024-2026 forecast period.

As stated in previous BREU business plans and rate applications, non-refundable cash infusions are required for the initial years of operation to offset the capital investment required to establish BREU and allow it to grow over time to achieve financial sustainability. As discussed in Section 2.0 above, the total non-refundable cash infusions required to achieve financial stability are still expected to be approximately $93 million. For purposes of calculating the revenue requirement and deferral account under Cost of Service in the 2023 Rate Filing, the non-refundable cash contribution for all of the capital investments required during the 2023-2026 forecast period has been assumed at this time, resulting in no long term interest expense or amortization being incorporated. The 2023 revenue requirement and deferral account under Cost of Service will be amended in future annual rate filings as the availability of the non-refundable cash infusion is further clarified.

In addition, builder contributed capital will be utilized to fund certain assets, specifically equipment in the mechanical rooms of multi-unit buildings. Accordingly, for purposes of this Rate Filing all capital expenditures required during the 2023-2026 forecast period are assumed to be funded through the non-refundable cash infusion or builder contributed capital resulting in BREU having no debt or rate base on its balance sheet during the forecast period.

5.2 Determination of Forecast Revenue Requirement

The total 2023 forecast revenue requirement and revenue for BREU is $1.691 million and $1.141 million respectively, resulting in a revenue shortfall of $0.549 million. The following table provides a summary of the annual revenue requirement and customer revenue.

Table 2: Revenue Requirement, Customer Revenue and Revenue Surplus/(Shortfall) ($000s)

	2019	2020	2021	2022	2022	2023	2024	2025	2026
Item	**Actual**	**Actual**	**Actual**	**Approved Budget**	**Update**	**Proposed Budget**	**Proposed Budget**	**Proposed Budget**	**Proposed Budget**
Revenue Requirement									
Operating Costs	896.7	726.2	907.6	1,218.0	1,021.0	1,690.5	1,612.7	1,648.6	1,636.4
Depreciation	-	-	-	-	-	-	-	-	-
Return on Rate Base	-	-	-	-	-	-	-	-	-
Revenue Offsets	-	-	-	-	-	-	-	-	-
Total Revenue Requirement	**896.7**	**726.2**	**907.6**	1,218.0	**1,021.0**	**1,690.5**	**1,612.7**	**1,648.6**	**1,636.4**
Revenue									
Revenue on Proposed Rates	-	0.1	10.8	51.0	67.3	145.5	694.3	1,224.8	2,007.4
Infrastructure Fee	7.0	29.8	43.1	121.8	13.7	995.8	755.1	1,590.0	1,932.6
Other - Government Grants	-	-	56.0	-	-	-	-	-	-
Total Revenue	**7.0**	**29.8**	**110.0**	172.8	**81.0**	**1,141.2**	**1,449.4**	**2,814.7**	**3,939.9**
Revenue Surplus (shortfall)	(889.7)	(696.4)	(797.6)	(1,045.2)	(939.9)	(549.2)	(163.4)	1,166.1	2,303.5

The revenue requirement for BREU does not include any depreciation or return on rate base as it is expected that all capital additions during the forecast period will be funded by a combination of the non-refundable cash infusion and builder contributions, as noted above. Accordingly, for rate filing purposes, BREU will have no assets on its balance sheet during the forecast period and no equity, debt, interest expenses, return on equity or depreciation expense.

OPERATING COSTS

The operation of the first stages of the DESS, with a small but growing number of connections and accounts, will be managed internally by BREU in partnership with other City departments, external contractors and technical experts. Operation and maintenance is being provided by the City's Facilities Maintenance Services (FMS) section within the City Operations department. BREU has been working with FMS to develop operating protocols and maintenance procedures.

Operations and maintenance started after commissioning, and engineering and operational support will primarily be provided internally with some support from external technical consultants and contractors. Service providers have been engaged for all aspects of utility operation. Within the next four years budget cycle BREU will determine an opportune time to engage an external partner as per City Council's direction.

The following table summarizes the forecast Operating Costs by major expense category.

Table 3: Operating Costs by Major Expense Category ($000s)

Item	2019 Actual	2020 Actual	2021 Approved Budget	2021 Actual	2022 Approved Budget	2022 Update	2023 Proposed Budget	2024 Proposed Budget	2025 Proposed Budget	2026 Proposed Budget
Operating Costs										
Utilities	15.7	69.3	74.9	46.8	80.4	64.1	59.4	70.2	76.0	77.0
Operations & Maintenance	630.9	445.3	557.7	429.7	581.4	561.2	949.9	868.5	836.4	855.6
Administration	223.9	208.8	464.4	418.1	472.5	364.6	558.4	578.7	578.4	556.9
Customer Billing Services	24.7	0.9	31.5	11.6	8.4	3.4	68.8	20.7	66.8	36.7
Corporate Administration/Shared Services	1.5	1.8	76.7	1.4	75.2	27.7	53.9	74.6	90.8	110.1
Total Operating Costs	**896.7**	**726.2**	**1,205.3**	**907.6**	**1,218.0**	**1,021.0**	**1,690.5**	**1,612.7**	**1,648.6**	**1,636.4**

The following sections provide further detail in respect of each of the major operating cost categories shown in Table 3 above.

UTILITIES

BREU requires electricity, natural gas and water/drainage/sewer utility services in order to operate the DESS. The following table summarizes the actual/forecast cost of utilities from 2019-2026.

Table 4: Utilities Cost ($000s)

Item	2019 Actual	2020 Actual	2021 Approved Budget	2021 Actual	2022 Approved Budget	2022 Update	2023 Proposed Budget	2024 Proposed Budget	2025 Proposed Budget	2026 Proposed Budget
Utility Costs										
Electricity	15.6	61.4	55.0	42.3	60.0	53.1	50.0	60.0	65.0	65.0
Natural Gas (incl. Carbon tax)	0.1	1.8	5.5	0.6	6.0	2.4	1.0	1.2	1.4	1.6
Telephones	-	0.7	2.4	0.02	2.4	0.8	2.4	2.4	2.4	2.4
Water/Drainage/Sewer	-	5.4	12.0	3.9	12.0	7.8	6.0	6.6	7.2	8.0
Total Utilities	**15.7**	**69.3**	**74.9**	**46.8**	**80.4**	**64.1**	**59.4**	**70.2**	**76.0**	**77.0**

OPERATION & MAINTENANCE COSTS

The forecast Operation & Maintenance costs for each year are comprised of the following cost categories: (1) Operation & Maintenance for all BREU owned assets, (2) Personnel, (3) Training & Development, (4) Equipment Rental and (5) Technical Consultants.

The infrastructure built and installed to serve customers at Blatchford requires ongoing maintenance as well as a workforce to manage BREU's day to day operations. The forecast operation and maintenance costs for 2023-2026 are based on a capital maintenance factor (i.e. a percentage of capital) for each class of assets (e.g. ground heat exchange equipment, energy center equipment, distribution piping, etc.) applied to the total capital in service each year for each class of assets and real time experience by FMS based on initial years of operation. The capital maintenance factors were based on industry standards for similar type of equipment. It also took into account initial warranty considerations for new equipment. Operation and maintenance of the Blatchford DESS are provided by the City's Facilities Maintenance Services Branch.

BREU currently has 5.1 FTEs responsible for the managing of day to day operations, which includes a co-op student and administration personnel. BREU is requesting City Council approval to add an additional 2.0 FTEs, for a new Project Coordinator and a Business Analyst position, both starting in 2023. With the anticipated utility growth, the management of additional energy center construction and capacity, the extension of the distribution piping network and increased customer connections, the utility will need these two additional internal resources to provide much needed business planning and engineering support.

The following table provides details of the current direct employees and the two new employees including position title and the portion of each employee's time that will be allocated to BREU (a percentage of some employee's time will be allocated to other renewable energy projects currently being undertaken by the City of Edmonton).

Table 5: BREU Personnel

	Full Time Equivalents								
	2019	2020	2021	2022	2022	2023	2024	2025	2026
Employee Title	**Actual**	**Actual**	**Actual**	**Approved**	**Update**	**Proposed**	**Proposed**	**Proposed**	**Proposed**
Director - Renewable Energy Systems	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Program Manager - Renewable Energy Systems	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Project Manager - Renewable Energy Systems	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Communication and Marketing Support	N/A	N/A	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Coop Engineering Student	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Administrative Assistant	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
NEW - PROJECT COORDINATOR	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	**1.0**	**1.0**	**1.0**	**1.0**
NEW - METHODS ANALYST	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	**1.0**	**1.0**	**1.0**	**1.0**

The total forecast cost of BREU personnel was determined by applying the full time equivalent factor in the table above to each employee's current total compensation (base salary plus benefits). The cost of all but the communication and marketing position is included in the Personnel cost category in the Operation and Maintenance cost grouping. The cost of the communication and marketing position has been included in the Marketing, Education and Communication cost category described in the Administration Costs section below.

In addition to the operation and maintenance costs and the direct BREU employees, consultants will be retained to assist with technical and operational aspects of running BREU. A cost of $150,000 has been forecast for technical consultants in 2023.

Forecast costs for training and development were also included in the Operation and Maintenance Cost Forecast. For 2023 an estimate of $7,349 was included.

Costs related to the leasing/rental of equipment has been included in the BREU budget. The 2023 forecast cost includes a total of $11,200 for the lease/rental of tools and computers.

In addition, Operation and Maintenance costs include $200,000 ($150,000 in 2023 and $50,000 in 2024) to address a motion made at Executive Committee on October 12, 2022. The increased cost of $200,000 is to undertake a feasibility study to expand the Blatchford Renewable Energy Utility to areas adjacent to Blatchford outside the current service area, including but not limited to Hangar 14.

The following table summarizes the total Operation and Maintenance Costs over the forecast period.

Table 6: Operation & Maintenance Cost ($000s)

Item	2019 Actual	2020 Actual	2021 Approved Budget	2021 Actual	2022 Approved Budget	2022 Update	2023 Proposed Budget	2024 Proposed Budget	2025 Proposed Budget	2026 Proposed Budget
Operations & Maintenance										
Energy Center 1/Main Distribution System	-	44.7	200.5	58.1	200.7	120.2	200.7	200.7	200.7	200.7
Customer Connections and Meters	-	-	-	-	-	-	-	-	-	-
Personnel	335.5	381.9	344.3	360.6	367.3	409.9	580.6	599.2	617.2	636.4
Training and Development	9.0	1.4	7.0	-	7.3	5.2	7.3	7.3	7.3	7.3
Equipment Rental	2.5	0.0	6.0	10.6	6.1	2.5	11.2	11.2	11.2	11.2
Technical Consultants	283.9	17.2	-	0.5	-	23.3	150.0	50.0	-	-
Total Operating Costs	**630.9**	**445.3**	**557.7**	**429.7**	**581.4**	**561.2**	**949.9**	**868.5**	**836.4**	**855.6**

ADMINISTRATION COSTS

The forecast Administration costs each year include: (1) Marketing, Education and Communication, and (2) External Professional Services Costs.

The Marketing, Education & Communication costs include an estimate for time and materials required for marketing, communication and education of the Blatchford Community to utility customers during the forecast period.

A cost of $442,500 was forecast for 2023 for external professional services to assist with non-technical aspects of operating BREU.

The following table summarizes the Administration costs.

Table 7: Administration Cost ($000s)

Item	2019 Actual	2020 Actual	2021 Approved Budget	2021 Actual	2022 Approved Budget	2022 Update	2023 Proposed Budget	2024 Proposed Budget	2025 Proposed Budget	2026 Proposed Budget
Administration										
Marketing, Education & Communication	69.4	59.9	120.3	78.4	122.7	132.4	115.9	115.9	115.9	115.9
External Professional Services	154.6	148.9	344.2	339.6	349.8	232.3	442.5	462.8	462.5	441.0
Total Administration	**223.9**	**208.8**	**464.4**	**418.1**	**472.5**	**364.6**	**558.4**	**578.7**	**578.4**	**556.9**

CUSTOMER BILLING SERVICES COSTS

BREU has a service level agreement with EPCOR for billing and customer service support for Blatchford Renewable Energy's customers. EPCOR, along with the City's 311 services, are also involved in customer service functions as it relates to billing, technical and emergency communication and planning. BREU incurs a Monthly Base Services Fee of $6.50 per account per month for billing and customer service support in 2022. For the 2023-2026 forecast period, BREU has forecast an annual increase of 2.0 per cent in the Monthly Base Services Fee. In addition BREU will incur annual billing automation charge over the 2023-2026 forecast period (ending in 2031) to recover the cost of setting up Blatchford accounts in EPCOR's new billing system. BREU has also forecast a cost of $55,000 in 2023 to account for EPCOR's charge to program the new Multi-unit Monthly Charge into its billing system and an additional $40,000 in 2025 for the cost of programming expected additional BREU rate changes. The decrease in actual billing costs from 2021 to 2022 is as a result of the elimination of a manual billing charge effective January 1, 2022. The manual billing charge was an extra charge levied by EPCOR to manually bill BREUs customers in 2020 and 2021, prior to BREU's customers being set up in EPCOR's billing system. The 2023-2026 forecast Monthly Billing charges and the annual Billing Automation Charges are shown in Table 8 below.

Table 8: Customer Billing Services Cost ($000s)

	2019	2020	2021	2021	2022	2022	2023	2024	2025	2026
Item	Actual	Actual	Approved Budget	Actual	Approved Budget	Update	Proposed Budget	Proposed Budget	Proposed Budget	Proposed Budget
Customer Billing Services										
Monthly Billing Charges	-	0.9	31.5	11.6	8.4	3.4	7.3	14.4	20.8	31.0
Annual Billing Automation Charge	-	-	-	-	-	-	6.5	6.3	6.0	5.7
One-time Set up Costs	24.7	-	-	-	-	-	55.0	-	40.0	-
Total Customer Billing Services	**24.7**	**0.9**	**31.5**	**11.6**	**8.4**	**3.4**	**68.8**	**20.7**	**66.8**	**36.7**

CORPORATE ADMINISTRATION COSTS COSTS

The forecast Corporate Administration costs each year include: (1) Shared Services; (2) Asset Usage Fees, and; (3) Transportation and Insurance costs.

Financial, regulatory and legal support for the utility is provided by the Financial and Corporate Services department and the City's Legal Services Branch which has significant expertise in utility management. Both areas are involved in the management of the bylaw, the fiscal policy, annual rate filings and operating and capital budget development for the utility. The increase in Shared Services costs from 2023 to 2026 is a result of more financial and legal support being required as BREU continues to grow and develop and add more customers to the system.

The following table summarizes the Corporate Administration Costs over the forecast period.

Table 9: Corporate Administration Cost ($000s)

	2019	2020	2021	2021	2022	2022	2023	2024	2025	2026
Item	Actual	Actual	Approved Budget	Actual	Approved Budget	Update	Proposed Budget	Proposed Budget	Proposed Budget	Proposed Budget
Corporate Administration										
Shared Services	1.3	0.4	53.2	0.4	51.2	17.2	46.6	66.8	83.0	102.2
Asset Usage Fees	-	-	16.7	-	17.1	5.7	-	-	-	-
Other - Transportation and Insurance	0.2	1.4	6.7	1.1	6.8	4.8	7.3	7.8	7.8	7.8
Total Corporate Administration	**1.5**	**1.8**	**76.7**	**1.4**	**75.2**	**27.7**	**53.9**	**74.6**	**90.8**	**110.1**

FRANCHISE FEES AND PROPERTY TAXES

BREU, as a municipally owned utility, is currently not required to pay a franchise fee or property taxes on its facilities to the City of Edmonton. Accordingly there are no franchise fees or property tax amounts included in the 2023-2026 forecast revenue requirement.

DEPRECIATION/AMORTIZATION

BREU's revenue requirement does not include any amounts for depreciation/amortization during the forecast period. It is anticipated that BREU's capital requirements during the forecast period will be completely funded through a combination of the non-refundable cash infusion and builder contributions. As a result, contributed assets will be equal to gross assets on the balance sheet resulting in no rate base for BREU for the 2023-2026 forecast period.

RETURN ON RATE BASE/INTEREST EXPENSES

As noted above, BREU's assets will be fully funded via the non-refundable cash infusion as well as builder contributions resulting in no rate base during the forecast period. As a result BREU's revenue requirement will not include any return on rate base or interest expenses during the 2023-2026 forecast period.

REVENUE OFFSETS

Revenue offsets are miscellaneous revenues earned by a utility and can include items such as late payment penalties, revenue from rental of company owned property and miscellaneous fees and non-rate revenues. No revenue offsets are forecast during the 2023-2026 forecast period.

RATE BASE

As noted previously, all required capital for the BREU system during the forecast period is projected to be financed by a combination of the non-refundable cash infusion and builder contributions resulting in no rate base on BREU's balance sheet. The following table provides a summary of the mid year net property, contributions and rate base.

Table 10: Mid-Year Net Property, Contributions and Rate Base ($000s)

	2021	2022	2023	2024	2025	2026
Item	**Actual**	**Update**	**Proposed**	**Proposed**	**Proposed**	**Proposed**
Rate Base						
Mid-year Net Property	19,451.0	19,451.0	21,661.1	26,821.8	30,607.6	40,197.0
Mid-year Net Contributions	(19,451.0)	(19,451.0)	(21,661.1)	(26,821.8)	(30,607.6)	(40,197.0)
Net Mid-year Rate Base	-	-	-	-	-	-

CAPITAL ADDITIONS AND CAPITAL EXPENDITURES

Blatchford Renewable Energy has started the process of planning the anticipated growth in the community. The next four years will include a series of capital additions which are described in more detail below:

Energy Centre One Expansion

Current capacity at Energy Centre One is one (1) megawatt (MW) of heating and cooling energy respectively, which is enough to service the first few land development stages in Blatchford. The expansion of Energy Centre One is needed to provide energy for land development stages in Blatchford west and east which are anticipated to come online between 2023 and 2026. This also includes larger developments on the east side of Blatchford such as Hangar 11 and the anticipated initial NAIT buildings, which will also be serviced by Energy Centre One. At full capacity, Energy Centre One will be able to generate 4.25 MW of heating and 4 MW of cooling energy. Design effort for the expansion is underway in 2022 and the anticipated capital budget in 2023 and 2024 to extend the capacity is $3.2 million dollars.

Design and Construction of the Next Energy Centre

According to the current development scenario, additional energy capacity in the District Energy Sharing System, apart from Energy Centre One, will be needed by 2026. To keep in line with the vision for Blatchford and the original business case for the District Energy Sharing System, the next major renewable energy source would be the heat from the two combined sewer lines which meet under the future Blatchford market area. The majority of this energy demand would need to be provided by a new Sewer Heat Exchange Energy Centre. With the project in schematic design development, the utility has learned that updated sewer flow forecasts from EPCOR have reduced the expected future flow and hence the energy potential from the combined sewer system. After the review of the updated business case for the Sewer Heat Exchange Energy Center, the Utility is suggesting to advance a previously planned peaking Energy Center prior to the construction of the Sewer Heat Exchange Energy Center. At current estimations, the peaking Energy Center would be commissioned in 2026 at an approximate cost of $15.3 million dollars.

Extension of Distribution Piping Network

The distribution piping network distributes the energy from the energy centres to the buildings and utility customers. As the development grows, so will the piping network. In order to facilitate the anticipated Blatchford development scenario, additional distribution piping is expected to be needed over the next four years in Blatchford west, east and the market area. The total capital forecast for the 2023 to 2026 budget is $4.9 million dollars for the planned extension of the distribution piping network.

The following table provides a summary of the forecast capital additions and capital expenditures during the forecast period.

Table 11: Capital Additions and Capital Expenditures ($000s)

	2022	2023	2024	2025	2026
Item	**Update**	**Proposed**	**Proposed**	**Proposed**	**Proposed**
Construction Work in Progress - Previous Year Balance	-	1,986.4	5,523.0	4,123.9	10,348.0
Current Year Capital Expenditures - Energy Center 1	-	2,697.5	483.4	-	-
Current Year Capital Expenditures - Planning and Design	1,936.4	544.3	544.3	544.3	544.3
Current Year Capital Expenditures - Distribution Piping System	-	2,420.3	1,220.3	1,220.3	1,220.3
Current Year Capital Expenditures - Energy Transfer Stations	50.0	2,000.0	1,500.0	450.0	1,000.0
Current Year Capital Expenditures - Energy Center 4	-	294.8	754.2	5,679.9	8,559.6
Less: Current Year Capital Additions - Energy Center 1	-	-	(3,180.9)	-	-
Current Year Capital Expenditures - Planning and Design	-	-	-	-	-
Less: Current Year Capital Additions - Distribution Piping System	-	(2,420.3)	(1,220.3)	(1,220.3)	(1,220.3)
Less: Current Year Capital Additions - Energy Transfer Stations	-	(2,000.0)	(1,500.0)	(450.0)	(1,000.0)
Less: Current Year Capital Additions - Energy Center 4	-	-	-	-	(15,288.5)
Construction Work in Progress - Current Year Balance	**1,986.4**	**5,523.0**	**4,123.9**	**10,348.0**	**4,163.5**

6.0 Cost of Service, Rate Design and Revenue on Proposed Rates

The traditional regulatory approach in setting end use customer rates in the utility industry typically involves the preparation of a cost of service study which includes the grouping of the utility's customers into unique customer classes. The cost of service study then sets out to allocate the utility's total forecast revenue requirement to each of those customer classes based on well established cost functionalization, classification and allocation methodologies. End use customer rates are then designed to fully recover the forecast revenue requirement allocated to each of those customer classes. The resulting forecast revenue derived from the end use customer rates recovers the utility's total annual forecast revenue requirement.

6.1 Cost of Service Study

A cost of service study (COSS) was not completed in previous Rate Filings for several reasons. Firstly, using the previous approaches (as discussed further below) to set end-use customer rates did not align with a traditional cost of service study in that end use rates were not designed to recover the total revenue requirement allocated to each rate class in a given year. Secondly, there has been only one type of end use customer (i.e. residential townhouses) connecting to the BREU system thus far so there was no reason to complete a cost of service study to allocate costs to the different customer classes. Finally, given that the utility is in its very early years of operation there was very limited data available to complete a cost of service study such as consumption data/patterns for the various types of customers and information with respect to the impact (from both design and operational perspectives) of the various types of customers on the BREU system.

However, with customer connections for a second end use customer type (e.g. medium density residential apartment buildings) being forecasted to come online during 2023, BREU has completed an initial cost of service study. However, the results are preliminary as BREU still lacks enough detailed actual customer consumption and load pattern data, especially for the new end-use customer connections, as well as a detailed functional breakdown of asset and cost data. This initial COSS study was conducted to set the Utility on course and in recognition of the need for a complete COSS in the future.

The first step in a typical COSS involves the identification of the major asset/cost classes and then functionalizing all assets/costs to those major classes. For BREU, those major asset/cost classes are:

1. Generation -infrastructure related to the generation of thermal energy;
2. Distribution - infrastructure related to the delivery of thermal energy from the energy centers to the customer meter;
3. General plant - related to infrastructure required to support the generation and distribution of thermal energy but not included in any of those functional categories.

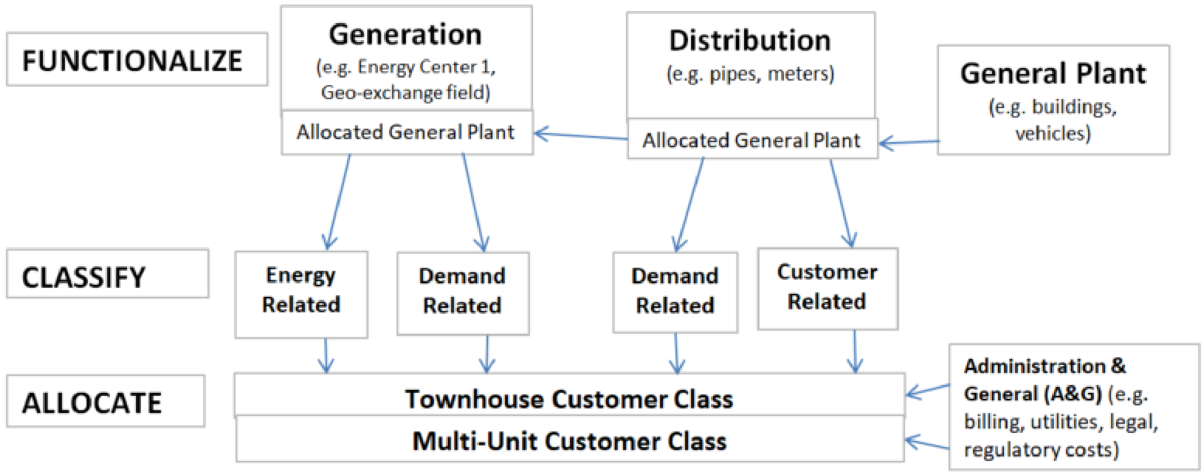
The second step in a typical COSS involves the identification of the major cost classification categories and then assigning or allocating the assets/costs that were functionalized in step one above to those major cost classification categories. For BREU the major cost classification categories are:

1. Customer - costs that vary with the number of customers served;
2. Demand - costs that vary with the peak demand for thermal energy generated by the thermal energy system;
3. Energy - costs related to the amount of thermal energy generated by the thermal energy system over a period of time.

The final step is to assign or allocate the functionalized and classified costs to each rate/customer class. For BREU in 2023 there are two customer classes taking thermal energy service; (1) Townhouse customers, and (2) Multi-Unit Customers.

The following diagram summarizes the COSS methodology described above.

Figure 1 COSS Methodology



The results of the initial COSS completed by BREU are preliminary and have not been utilized in the design of the proposed 2023 rates. As described below, the Business as Usual principle has been the main policy principle guiding the determination of the level of BREUs end-use customer rates and continues to be the guiding principle utilized in the 2023 Rate Filing. As the customer base grows and additional detailed customer consumption data, consumption patterns and more detailed cost data become available and as BREU obtains further experience operating the district energy system, it is anticipated that a traditional cost of service approach will be utilized to set customer rates and the Business as Usual principle will become secondary in terms of the setting of annual rates.

The following table summarizes the results of the COSS as well as the forecast revenue and resulting revenue to cost ratios for the Townhouse and Multi-Unit customer classes.

Table 12 Summary of COSS Results and Revenue/Cost by Rate Class

	Revenue ($)	Single Unit	Multi - Unit	Total
	Revenue on Proposed Rates	$80,625	$64,835	$145,460
	Infrastructure Fee Revenue	$219,918	$775,863	$995,781
(A)	**Total Revenue**	**$300,543**	**$840,698**	**$1,141,241**
(B)	**Total Allocated Costs**	**$748,040**	**$942,436**	**$1,690,476**
	Revenue to Cost Ratio [= (A) / (B)]	**40.18%**	**89.20%**	**67.51%**

Appendix 5.0 provides details of the COSS.

BREU's focus going forward will be to develop the necessary data infrastructure to complete an accurate and meaningful COSS such as e.g.:

- Customer load data for the two current customer classes including the peak load for a typical customer in the customer class, both the highest instantaneous heating and cooling peak kW loads (non-coincident peak) as well as the customer load at the time the BREU system is generating its peak thermal energy output (coincident peak);
- The further separation of current asset data into the generation, distribution and general plant asset functions as well as a further split of those functionalized assets into functional sub-components (e.g. boilers, heat exchangers, piping, meters, etc.), and;
- The further separation of current operation and maintenance cost data into the generation, transmission, distribution and general plant functional cost components.

BREU will frequently review the need and timing for a full COSS development and will begin to allocate time and resources to develop a more automated approach to obtaining customer meter readings as well as to create a load research program to assist in the development of the customer peak load data described above. It is expected that it will take several years to develop the type of robust load research program that larger and more mature utilities have, that can gather and analyze actual customer meter consumption data and develop customer load shape patterns and the peak demand data necessary to complete an accurate and full COSS.

6.2 Rate Design and Proposed End-Use Customer Rates

CUSTOMER RATES - BACKGROUND

The Blatchford Utility 2019 Annual Rate Filing established the regulatory framework and customer rates for the initial year of operation of the Blatchford Utility. The 2019 Rate Filing was guided by the overarching Policy Statement contained in the Blatchford District Energy Utility Fiscal Policy:

> “Similar to private utilities, the Utility will account for the cost of services under a full cost accounting approach. All customer charges will be based upon cost of service with the end user (customer) paying at most a comparable fee to what they would elsewhere in the City of Edmonton through their energy utility bills and annual maintenance costs.”

Under a traditional Cost of Service approach, customer rates would be established to allow BREU to recover its annual costs to operate (“revenue requirement”). However, given the small number of Blatchford residents and utility customers in the first few years of operation, customer rates established using the traditional Cost of Service approach would result in rates being significantly higher than comparable fees paid elsewhere in the City of Edmonton, and what BREU customers could reasonably be expected to incur. Therefore, an alternative method to set customer rates for the initial years of development and operation of BREU was required.

In order to develop the customer rates for the 2019 Rate Filing, Administration engaged Grant Thornton to assist in establishing the regulatory framework and identifying and quantifying customer rates using alternative methodologies. The customer rates proposed in the Blatchford Utility 2019 Annual Rate Filing, and ultimately approved by City Council, were based on Grant Thornton's recommendation to utilize a **"pegged approach"** to establish customer rates. Under this approach, Blatchford utility bills were pegged to what utility bills would be elsewhere in the City of Edmonton. Grant Thornton determined the typical utility bill (i.e. Business as Usual or BAU) in 2019 for heating, cooling, and hot water that would be paid elsewhere in the City of Edmonton for the types of dwellings that are to be built in the initial stages of the Blatchford development. In accordance with the Fiscal Policy, differences in the annualized maintenance costs to be paid by Business as Usual and BREU customers were also included as adjustments to the typical Business as Usual bills. BREU also used this approach to establish the Business as Usual amounts in the 2020 Rate filing as discussed further below.

Having initially set customer rates for 2019 based on the pegged approach, a **"levelized approach"** was then used to set rates for 2020, consistent with the rate setting methodology in the business case presented to City Council on March 16, 2016 for the development of the District Energy Sharing System at Blatchford. Under the levelized approach, customer rates in the business case are increased by 2.7 per cent on average each year over the initial 50 years to ensure stable and consistent rate increases (a key utility rate setting principle). Rates under-recover costs in the early years of the Utility's operation when the customer base is small, but gradually recover past costs in the later years when the customer base is fully established. In line with the levelized approach, customer rates recommended in each of the 2020, 2021 and 2022 Annual Rate Filings and approved by City Council increased the previous year's customer rates by 2.7 percent.

2023 CUSTOMER RATES

Administration is proposing to make some changes and additions to the rates and fees charged to BREU customers effective January 1, 2023. These changes, discussed in further detail below, are as follows:

- A 10 percent increase in the Townhouse Fixed Charge and the Variable Charge, compared to a 2.7 per cent increase in the 2019-2022 Rate Filings, in order to keep pace with current utility bills for heating, cooling and hot water elsewhere in the City of Edmonton
- Replacement of the Apartment Fixed Charge with a new Multi-Unit Monthly Charge that will be applicable to all buildings, other than Townhouses, connecting to the DESS;

<u>Townhouse Monthly Charge and Variable Charge</u>

As noted previously, the levelized approach to set the Townhouse Monthly Charge and the Variable Charge was utilized in the 2020, 2021 and 2022 rate filings wherein these rates were increased in each year by 2.7 percent. BREU is proposing a 10 per cent increase to the 2022 rates for 2023 in order to keep pace with BAU. BREU is proposing this level of increase due to the recent increase in natural gas and electricity commodity costs in Alberta, which has caused the increase in BAU.

As discussed in Section 3.0 above, on October 17, 2020 Council approved specific rate setting principles to be added to the Fiscal Policy, including the following principle that multiple years be used for comparison of Blatchford utility customer rates going forward to ensure they remain competitive.

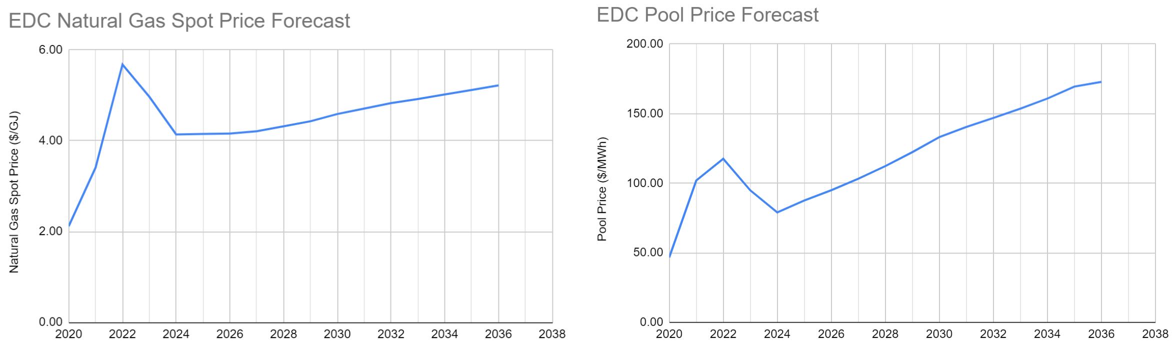
> “7. Customer rates based on the forecast cost of providing service will be assessed annually to ensure they remain competitive with other longer-term heating and cooling options.
>
> a. The Utility will strive for customers to pay at most a comparable fee to what they would elsewhere in the City of Edmonton through their energy utility bills and maintenance costs.
>
> b. The assessment will take into account the longer-term nature of utility infrastructure being used to provide services to customers, and market fluctuations that may occur annually in the commodity price of gas and electricity relative to the stable cost of providing thermal energy from the Blatchford District Energy Sharing System.”

Taking this principle into account, Administration has determined the BAU amounts for 2023 using the same methodology utilized in the 2021 and 2022 Rate Filings including utilizing a five year average (2020 actual to 2024 forecast) of annual BAU bill amounts to “peg” what utility bills would be elsewhere in the City of Edmonton. Administration used a five year average BAU bill amount to peg utility bills outside of Blatchford in order to take into account market fluctuations that may occur in commodity prices and potential swings in year to year electric and natural gas utility bills outside of Blatchford. In addition, to calculate the 2023 BAU amounts, BREU updated the following assumptions that were utilized to calculate the BAU bill amounts in the 2022 Rate Filing:

- The continued use of the current electricity and natural gas regulated rate options for determining both the electricity and natural gas portions of the BAU bill amounts for each year;
- The latest forecast (third quarter of 2022) of long term natural gas and electricity prices were utilized to determine the variable electricity and natural gas rates in the BAU bill calculations;
- Carbon pricing of:
    - $30/tonne in 2020 (actual Federal rate in 2020),
    - $40/tonne in 2021 (current Federal Rate for 2021)
    - $50/tonne in 2022 (published Federal Rate for 2022)
    - $65/tonne in 2023 (published Federal Rate for 2023)
    - $80/tonne in 2024 (published Federal Rate for 2024).

As a result of significant increases in the cost of electricity and natural gas in Alberta in the last year, BAU costs are currently considerably higher than total utility costs for Blatchford customers and it is expected that this will continue over the next several years. The following tables show the actual and forecast Alberta electricity pool prices and natural gas spot prices from 2020 to 2036.

Figure 2 Alberta Electricity Pool Price and Natural Gas Spot Price Forecast



Note: Electricity pool price and natural gas spot price data are from EDC Associates Ltd. Q3 2022 Quarterly Forecast Update

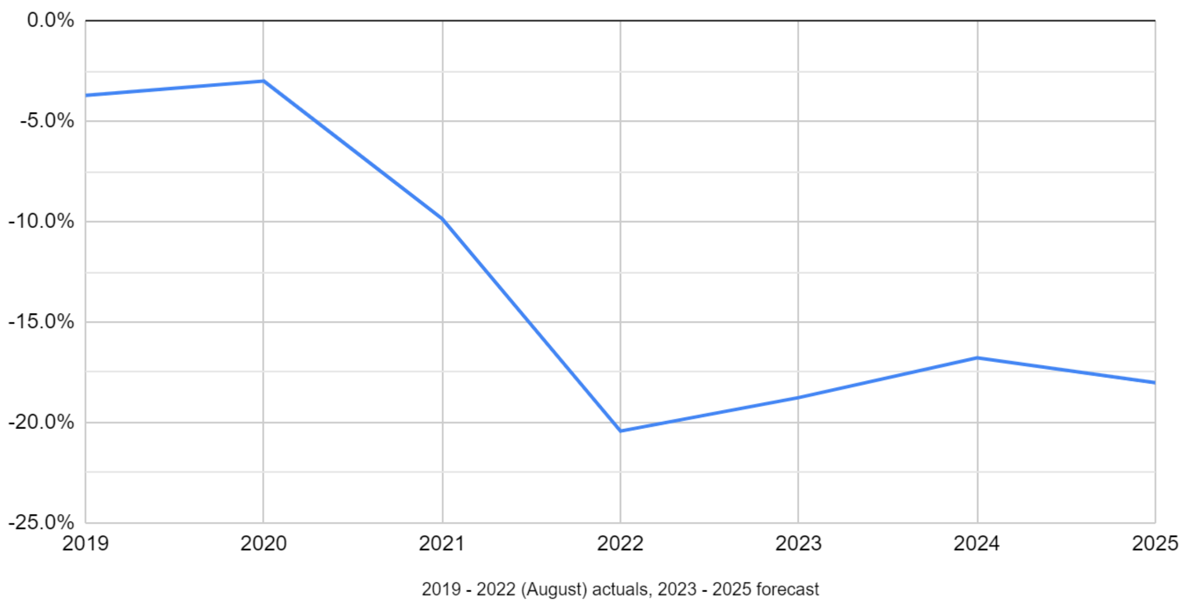
The following table provides a summary of the average annual energy costs (including utility bills and maintenance costs) for a BREU townhouse customer compared to a BAU townhouse customer, based on the projected five year costs from 2020-2024.

Table 13: Summary of Five -Year (2020 -2024) Average Annual BREU/BAU Energy Utility Bill and Maintenance Costs for a Typical Townhouse Customer ($)

	Blatchford Customers			Business as Usual Customers			Difference	
Customer Type	2020-2024 Average Annual BRE Energy Utility Bill	Average Annual BRE Maint. Costs	2020-2024 Annual Energy Utility bill and Maintenance Costs	2020-2024 Average Annual BAU Energy Utility Bill	Average Annual BAU Maint. Costs	2020-2024 Average Annual BAU Energy Utility Bill & Maintenance Costs	BRE less BAU ($)	BRE less BAU (%)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
			=(1) + (2)			=(4) + (5)	=(3) - (6)	=(7) / (6)
Townhouse	$ 1,486	$ 425	$ 1,911	$ 1,891	$ 283	$ 2,174	$ (263)	-12.1%

Accordingly, for 2023 BREU is recommending a 10 percent increase in the 2022 approved BREU Townhouse Monthly Charge and Variable Charge in order to close the current gap between BAU costs and utility costs for residents in Blatchford. As shown in the table above, based on the five year average utility bills and maintenance costs from 2020 to 2024, the annual utility costs for BREU townhouse customers (assuming 10 per cent increases in BREU rates in 2023 and 2024) are still projected to be 12 per cent lower than the BAU costs for comparable residents elsewhere in Edmonton. When viewed on an annual basis, BREU annual utility bill costs for a typical Townhouse customer were less than 5 per cent lower in 2020 and 2021 than the BAU costs of a similar non-Blatchford resident. But that differential has increased to over 20 per cent in 2022 due mostly to the large increases in electricity and natural gas commodity costs. The proposed 10 per cent increase in the Townhouse Monthly Charge and the Variable Charge in 2023 will help to reduce that initial differential, but further annual increases in the order of 10 per cent may be required in future rate filings if electricity and natural gas commodity costs continue to remain at these historically high levels. The following chart shows the 2019-2025 actual/forecast percentage difference between the annual utility bills and maintenance costs for a typical BREU townhouse customer and a similar customer living outside of the Blatchford community.

Figure 3 Difference (%): Annual Utility Bills for a Typical BREU Townhouse Customer and Non-BREU Townhouse Customer (2019 Actual - 2025 Forecast)



In addition to the cost of natural gas and electricity in Alberta, the Federal Carbon pricing has been a significant driver in causing the BREU and BAU annual energy utility bill cost differential. BREU expects that these variables, and perhaps others, will continue to play an important role going forward in determining whether the annual BREU/BAU energy utility bill cost differential continues to widen, requiring continued greater than inflation increases in customer rates in 2024 and beyond. BREU completes the BREU/BAU energy utility bill analysis every year in preparation for its annual rate filings and will continue to monitor gas and electric utility rates and commodity prices in Alberta, federal and provincial policy direction regarding the Carbon pricing or any other potential taxes or levies and that may be implemented in the future. Any changes to these variables could have a considerable impact on BAU energy utility bills and the BREU/BAU annual energy utility bill differential.

Multi-Unit Rate

As discussed in previous rate filings, BREU identified a number of potential changes to the current customer rates including the option of setting rate classes based on size of customer load and adding a demand or capacity (e.g. $/kW) component to certain rate classes to encourage efficient use of the utility system. Administration is proposing to establish a new “Multi-Unit Monthly Charge” that will be applicable to all new buildings, other than Townhouses, connecting to the DESS beginning January 1, 2023. In discussion with potential builders of multi unit and multi end use buildings over the the last year it has become apparent that the current Apartment Rate ($1.21/unit/month and $0.0269/kW) was going to present some challenges to the economics of the ongoing operation of these types of buildings, especially the larger buildings with a greater number of suites. BREU engaged KPMG LLP (KPMG) to conduct a study to recommend an alternative rate setting approach for its multi-unit renewable energy utility customers in Blatchford. KPMG's study, Blatchford Renewable Energy Utility - Approach for Establishing a Multi-unit Customer Rate Design (Multi-unit Study), is provided in Appendix 2. The approach taken by KPMG in completing the Multi-Unit Study was to:

- Review Blatchford's multi-unit customer profile and planned build-out timeline;
- Prepare a BAU rate build-up model based on a sample of multi-unit buildings proposed for Blatchford (high density residential and retail mixed-use);
- Conduct a benchmarking exercise of seven comparable Canadian district energy systems and their approach to multi-unit customer rate design.

Based on the information gathered and data analyzed in the Multi-unit Study, KPMG is recommending the following approach:

Table 14: KPMG Recommended Multi-unit Rate Components and Proportions

Rate Component	Calculation	Target Bill Proportion
Fixed Charge	Capacity Charge by nominated capacity	60-70%
Variable Charge	Commodity consumption charge by kWh	30-40%

This recommended approach satisfied the rate design criteria of anticipated understandability for multi-unit building developers, service cost fairness for multi-unit residential developers, encouragement of usage efficiency and simplicity of administration and billing.

BREU considers that a capacity charge better reflects the principle of cost causation than the fixed daily charge per unit for multi-unit buildings that will contain multiple end-uses (e.g retail/commercial/office) and will also contain significant amounts of common area that would require heating and cooling. A capacity charge based on the peak demand of a building allows for better and more accurate billing of the thermal energy used by multi-unit buildings to be built in Blatchford, than a daily fixed charge per unit rate structure.

The first step in determining the Capacity Charge for 2023 was to determine the BREU annual energy utility bills for a "typical' multi-unit building. BREU utilized a representative multi-unit building containing 102 residential units over 8,503 square meters with 595 square meters of retail space. Once the annual BREU energy utility bill amount was determined, calculated using the current Apartment Charge ($1.21/unit/day) and Variable Charge, the Multi-unit Monthly (capacity)

Charge was calculated to achieve a similar annual BREU energy utility bill amount determined using the Apartment Fixed Charge. The following table provides details of the determination of the Multi-unit Capacity Charge.

Table 14: Determination of the Multi-Unit Monthly (Capacity) Charge

Annual BREU Bill on APARTMENT Rate	Billing Determinant		Rate					Annual Amount	Variable /Fixed Split
Variable Charge	632,000	kWh_T	$0.0269	$\$/kWh_T$			$	17,001	27%
Apartment Fixed Charge	102	*units*	$ 1.21	*$/unit*	12	*months*	$	45,048	73%
Total Annual BREU Bill on Apartment Rate							**$**	**62,049**	**100%**
Annual BREU Bill on MULTI-UNIT Rate	**Billing Determinant**		**Rate**					**Annual Amount**	
2023 Proposed Variable Charge	632,000	kWh_T	$0.0296	$\$/kWh_T$			$	18,707	30%
2023 Proposed Multi-Unit Capacity Charge	289	*kW*	$ 12.50	*$/kW*	12	*months*	$	43,350	70%
Total Annual BREU Bill on Multi-Unit Rate							**$**	**62,057**	**100%**
Difference in Annual BREU Bill							**$**	**8**	

As shown in the table above, the fixed/variable split of the annual utility bill is 70/30 for this representative customer, which is at the very high end of the target bill proportion as recommended by KPMG in its Multi-unit Study.

BREU will work with multi-unit builders in Blatchford during the design process to help establish the expected peak heating and cooling demands (in kW), not only for determining the demand to be used for billing purposes but also for the design of the energy transfer station in the building. As BREU obtains actual operating data for each multi-unit building, BREU is planning to revisit the peak heating and cooling demands established during the design phase to ensure those demand levels are still appropriate for ongoing customer billing purposes.

The proposed customer rates for 2023 are summarized in the table below:

Table 15: 2023 Proposed BREU Customer Rates

Rate Component		2023 Rate
Monthly Charge ($/day)	Townhouse Lots	$ 1.71
Monthly Charge ($/kW of peak capacity/month)	Multi-Unit Lots	$ 12.50
Variable Charge ($/kWh)	All Consumption	0.0296

BREU Rate Schedules with the proposed end use customer rates have been included in Appendix 4.0.

As BREU grows and matures and more operational information and consumption data become available, BREU will investigate in future rate filings possible adjustments to the current rates proposed in this Rate Filing, such as:

- Altering the current monthly (fixed daily charge and capacity charge) and variable charges to get a different fixed/variable split of the end-use customer bill.
- Adding rate classes as different end use customers (e.g. commercial/retail/office, institutional (e.g. NAIT), industrial, etc.) connect to the DESS.
- The option of setting rate classes based on a size (MW) or consumption (MWh) differentiation rather than end use.
- Implementing separate rate components for heating and cooling.
- Implementing a seasonal or time of use component.
- Basing the Townhouse Monthly Charge on a $/m^2 basis rather than a $/day basis.
- Utilizing actual coincident or non-coincident peaks for billing purposes vs the current nominated capacity.
- Incorporating a green energy adder when determining the customer BAU

BREU continues to gain experience with operating and maintaining the DESS system and gathering actual metered customer usage data (e.g. total consumption, consumption patterns, time of use, etc.) and will leverage that experience and analyze the data before implementing any of the alternatives noted above.

INFRASTRUCTURE FEE

Due to the addition of the Monthly Charge for Multi-Unit lots, Administration is proposing to add a new infrastructure fee category and to change the name of the other two current 2022 approved infrastructure fees. The current Residential fee will be renamed to Townhouse Lot - Residential and the current Commercial fee renamed to Multi-Unit Lot - Commercial. A new Multi-unit lot - Residential fee category will be introduced effective January 1, 2023 and will be the same dollar per unit charge as the Townhouse Lot - Residential Infrastructure Fee. It will be applied to all new multi-unit connections in Blatchford that include primarily residential space and uses. BREU is recommending a 2.7 per cent increase be applied to the 2022 approved Infrastructure Fees, similar to the increases approved in the 2019-2022 rate filings. The table below shows the recommended 2023 Infrastructure Fees based on a 2.7 per cent increase to the approved 2022 fees.

Table 16: 2023 Proposed Infrastructure Fee

Infrastructure Fee	2023 Fee
Townhouse Lot - Residential ($/unit)	$ 1,895.84
Multi-Unit Lot - Residential ($/unit)	$ 1,895.84
Multi Unit Lot - Commercial ($/m^2)	$ 21.66

BREU will be reviewing the current Infrastructure Fee structure and fee levels in 2023 and may bring forward changes to the fees in the next rate filing including, but not limited to;

- One fee for all new customer connections;
- Basing the one fee on a dollar per square meter basis or a dollar per kW basis.

BREU will provide the results of that review in the 2024 Rate Filing.

6.3 Revenue on Proposed Rates

RATE REVENUE

The proposed rates for 2023, as discussed above, were applied to the 2023 forecast customer billing determinants (i.e. number of accounts, peak demand and total consumption) to derive the 2023 forecast rate revenue.

INFRASTRUCTURE FEE REVENUE

The proposed Infrastructure Fee, as outlined above, was applied to the 2023 forecast number of customer connections to derive the 2023 forecast Infrastructure Fee revenue.

The following table summarizes the forecast Rate Revenue and Infrastructure Fee Revenue.

Table 17: Forecast Rate and Infrastructure Fee Revenue

Item	2019 Actual	2020 Actual	2021 Actual	2022 Approved Budget	2022 Update	2023 Proposed Budget	2024 Proposed Budget	2025 Proposed Budget	2026 Proposed Budget
Revenue									
Rate Revenue	-	0.1	10.8	51.0	67.3	145.5	694.3	1,224.8	2,007.4
Infrastructure Fee Revenue	7.0	29.8	43.1	121.8	13.7	995.8	755.1	1,590.0	1,932.6
Other - Government Grants	-	-	56.0	-	-	-	-	-	-
Total Revenue	**7.0**	**29.8**	**110.0**	**172.8**	**81.0**	**1,141.2**	**1,449.4**	**2,814.7**	**3,939.9**

6.4 Deferral Account and Interest on Financing

As shown in Table 2 in Section 5.2 above, BREU is forecasting a revenue shortfall in 2023 and 2024 and a revenue surplus in 2025 and 2026. Section 1c of the Fiscal Policy states: “Where the Utility’s cash position is insufficient to meet cash flow requirements, the Utility will borrow from the City of Edmonton on a short term basis, with the interest being paid by the Utility at an interest rate that compensates the City of Edmonton reflecting the Fund Balance were the cash was drawn.” Accordingly, it is assumed that the annual revenue shortfall during the forecast period will be financed by short-term debt obtained from the City of Edmonton at prevailing rates. The annual revenue shortfall/surplus amount and the interest expense associated with the deferral account balance each year are shown in the table below.

Table 18: Annual Revenue Shortfall and Interest Expense

	2019	2020	2021	2022	2023	2024	2025	2026
Item	**Actual**	**Actual**	**Actual**	**Update**	**Proposed Budget**	**Proposed Budget**	**Proposed Budget**	**Proposed Budget**
Total Revenue	7.0	29.8	110.0	81.0	1,141.2	1,449.4	2,814.7	3,939.9
Total Revenue Requirement	896.7	726.2	907.6	1,021.0	1,690.5	1,612.7	1,648.6	1,636.4
Annual Revenue Surplus (Shortfall)	(889.7)	(696.4)	(797.6)	(939.9)	(549.2)	(163.4)	1,166.1	2,303.5
Deferral Account Opening Balance	-	(898.6)	(1,623.0)	(2,471.2)	(3,539.9)	(4,265.8)	(4,641.3)	(3,683.3)
Annual Revenue Surplus (Shortfall)	(889.7)	(696.4)	(797.6)	(939.9)	(549.2)	(163.4)	1,166.1	2,303.5
Deferral Account Closing Balance	(889.7)	(1,595.0)	(2,420.6)	(3,411.1)	(4,089.2)	(4,429.1)	(3,475.1)	(1,379.8)
Annual Interest Costs	**(8.9)**	**(28.1)**	**(50.5)**	**(128.8)**	**(176.6)**	**(212.2)**	**(208.2)**	**(136.2)**
Deferral Account Closing Balance Including interest Costs	**(898.6)**	**(1,623.0)**	**(2,471.2)**	**(3,539.9)**	**(4,265.8)**	**(4,641.3)**	**(3,683.3)**	**(1,516.0)**

It is expected that as BREU continues to grow and more customers are connected to the system that annual customer revenue will exceed BREU's annual revenue requirement beginning in 2025 with the short term debt obtained to cover the deferral account balance fully paid back to the City of Edmonton as early as 2027.

6.5 Bylaw 17943

The purpose of this bylaw is to:

(a) Regulate connections between building mechanical systems and the Blatchford district energy sharing system;
(b) Regulate access to the Blatchford district energy sharing system;
(c) Prevent damage or misuse of the Blatchford district energy sharing system; and
(d) Prescribe fees and charges related to the Blatchford district energy sharing system.

Bylaw 17943 was approved by City Council in December 2018. Schedule B of Bylaw 17943 contained the Customer Rates and Infrastructure Fees for 2019. Bylaw 17943 was amended for the first time by Bylaw 19062 in December 2019 to reflect new Customer Rates and Infrastructure Fees for 2020. In December 2020, Bylaw 17943 was amended a second time, by Bylaw 19494, to reflect new customer rates and infrastructure fees for 2021 and for a third time in December 2021, by Bylaw 19899, to reflect new customer rates and infrastructure fees for 2022. Financial and Corporate Services Report FSC01480, to be presented at the November 25, 2022 Utility Committee Meeting, recommends the approval of Bylaw 20312, to amend Blatchford Renewable Energy Utility Bylaw 17943 for the fourth time to reflect the new fees and charges outlined in this Rate Filing to be effective for the period January 1,2023 to December 31, 2023.

7.0 Appendices

Council Policy
Blatchford District Energy Utility Fiscal Policy

Program Impacted	Financial Management *The City of Edmonton's resilient financial position enables both current and long-term service delivery and growth.*
Number	C597A
Date of Approval	December 9, 2020
Approval History	April 10, 2018
Next Scheduled Review	December 9, 2023

Statements

1. The Utility is to be operated in a manner that balances the best possible service at the lowest cost (public utility) while employing private sector approaches to rate setting.
2. Similar to private utilities, the Utility will account for the cost of service under a full cost accounting approach. All customer charges will be based upon cost of service with the end user (customer) paying at most a comparable fee to what they would elsewhere in the City of Edmonton through their energy utility bills and annual maintenance costs.
3. Through a phased approach, the Utility will generate positive net income, cash flow and a rate of return sufficient to cover current year expenses, working capital requirements, and to facilitate the funding for capital infrastructure and rehabilitation and replacement of its capital assets.
4. The Utility is to contribute towards achieving the City's Energy Transition Strategy.

The purpose of this policy is to:

1. Ensure that the Blatchford District Energy Utility is operated in a manner that reflects City Council's overall vision and philosophical objectives for the Utility.
2. Ensure that there is a consistent approach year over year for the financial planning, budgeting, and rate setting for the City managed Utility.
3. Ensure that the Utility is financially sustainable over the long term.

Rate Setting Principles

1. Customer rates will be understandable, practical and cost-effective to implement.
2. Customer rates will fairly apportion the cost of providing service among customers.
3. Customer rates will be stable and predictable from year to year.
4. Customer rates will provide revenue stability for the Blatchford Renewable Energy Utility.
5. Customer rates will promote the efficient use of energy.
6. Customer rates will be based on the forecast cost of providing service.
   a. In the initial years of operation as the customer base continues to grow, a levelized approach may be used to establish rates and recover the forecast costs of providing service over a longer-term basis.
   b. The under-recovery of costs under the levelized approach in the early years of the Utility's operations will be accumulated in a regulatory deferral account to be recovered in later years when the customer base is more fully established.
7. Customer rates based on the forecast cost of providing service will be assessed annually to ensure they remain competitive with other longer-term heating and cooling options.
   a. The Utility will strive for customers to pay at most a comparable fee to what they would elsewhere in the City of Edmonton through their energy utility bills and maintenance costs.
   b. The assessment will take into account the longer-term nature of utility infrastructure being used to provide services to customers, and market fluctuations that may occur annually in the commodity price of gas and electricity relative to the stable cost of providing thermal energy from the Blatchford District Energy Sharing System.

Financial Indicators

Financial indicators are measures that provide financial information about the sustainability of the Utility. Taken collectively, these indicators allow for periodic assessment on whether the Utility is moving towards or away from financial sustainability.

1. **Rate Sufficient to Meet Expenditures and Cash Flow (Positive Net Income and Positive Cash Position)**
   a. The Utility will generate positive net income, cash flow and a rate of return sufficient to cover current year expenses, working capital requirements, and to facilitate the funding for capital infrastructure and rehabilitation and replacement of its capital assets.
   b. The management of the Utility's cash position is the responsibility of Administration, taking into consideration current borrowing rates and current and future cash requirements.
   c. Where the Utility's cash position is insufficient to meet cash flow requirements, the Utility will borrow from the City of Edmonton on a short term basis, with the interest being paid by the Utility

at an interest rate that compensates the City of Edmonton reflecting the Fund Balance where the cash was drawn.

Indicator Targets:

i. Positive Net Income
ii. The target combined Cash Position of the Utility is the Pay As You Go funding required as identified in the Capital Plan.
iii. Stable consistent rate increases.

2. Debt Financing of Capital

a. The Utility will not utilize long-term Debt to finance current operating expenditures.
b. Debt will be considered for Capital Expenditures for:
   i. projects with long-term benefits;
   ii. major rehabilitation or upgrade of existing assets; and
   iii. emerging requirements to support corporate priorities and strategic plans.
c. The Utility will follow the City of Edmonton's process for debt issuance, including the term of the debt and will be consolidated with City debt in determining the City's position relative to the legislated debt limits.

Indicator Target:

The Debt to Net Assets Ratio is a measure of the extent that capital investment is financed through debt, presented on a combined basis and calculated as follows:

Total Long Term Debt
divided by
<u>Net book value of Non-Contributed Assets</u>
= Debt to Net Assets Ratio

The target for the Debt to Net Assets Ratio may vary between 50% and 70%, taking into consideration borrowing rates. Incremental targets, by year, are as follows:

2030 - 98% 2040 - 85% 2050 - 70% 2060 - 60%

Financial Planning

Budget and financial planning follow the general principles of budget, long range planning, and management of capital assets as established by the City of Edmonton and in accordance with Public Sector Accounting Standards defined by the Public Sector Accounting Board.

The Utility will prepare a 4-year Business Plan, to be presented annually to the Utility Committee, prior to the preparation of the multi-year operating and capital budgets or supplemental budget adjustments.

The Utility Committee shall recommend annually to City Council the customer rates for the upcoming year, based on review of an annual rate filing prepared by the Utility subsequent to the preparation and presentation of the 4-year Business Plan.

Definitions

Cash Flow - the ability of the Utility to meet its financial obligations as payments are due.

Capital Assets - assets of the Utility meeting the requirements defined under Public Sector Accounting Standard PS3150.

Capital Investment Outlook - a 10-year forecast of capital required to ensure that appropriate infrastructure are in place to meet service needs, including the replacement of Contributed Assets.

Capital Plan - a 4-year plan for funding capital infrastructure approved by City Council.

Contributed Assets - capital assets of the Utility for which funding was provided from non-rate sources. Examples may include infrastructure constructed by the Blatchford Development, partnership funding, grants, etc.

Debt to Net Assets Ratio - is a measure of the extent to which the net book value of non-contributed assets is being financed by debt.

Financial Indicators - a set of financial measures that provide signals on the financial health of the Utility.

Financial Sustainability - financial sustainability is achieved when all targets set for the Financial Indicators (as recommended by the Utility Committee and approved by City Council) are attained.

Full Cost Accounting - shall include cost allocation from services provided by City Administration and may include administration costs, and other shared services such as Communication, Human Resources, Information Technology, Law, Corporate Procurement and Supply Services, Financial Services, Fleet and Facility Maintenance, and general corporate overhead.

Investment in Utility Financed Assets - Net Book Value of Utility Financed Assets minus associated outstanding debt used to pay for the assets.

Net Book Value - acquisition costs of original costs of capital assets minus their accumulated depreciation.

Pay As You Go - the amount of cash required to implement the Capital Plan; annual amount to be funded from operating revenues.

Rate Revenue - revenue generated through monthly customer rates.

Regulated Activities - are activities that are core to the services provided by the Utility. Examples include, the provision of energy for heating and cooling and domestic hot water.

Utility - refers to the Blatchford District Energy Utility, a self-funded operation that provides energy services for heating, cooling and domestic hot water to customers on a fee for service basis at rates regulated by City Council.

Utility Financed Assets - assets of the Utility for which funding has been provided from rates either through debt or Pay As You Go funding.

Notice

This report has been prepared by KPMG LLP ("KPMG") for the City of Edmonton ("Client") pursuant to the terms of our engagement agreement with Client dated August 24, 2022 (the "Engagement Agreement"). KPMG neither warrants nor represents that the information contained in this report is accurate, complete, sufficient or appropriate for use by any person or entity other than Client or for any purpose other than set out in the Engagement Agreement. This report may not be relied upon by any person or entity other than Client, and KPMG hereby expressly disclaims any and all responsibility or liability to any person or entity other than Client in connection with their use of this report.

KPMG has not and will not perform management functions or make management decisions for the City of Edmonton. Comments in this report are not intended, nor should they be interpreted, to be legal advice or opinion. KPMG has no present or contemplated interest in the City of Edmonton, KPMG is independent of the City of Edmonton and acting objectively.

We have relied on information provided to us by the City of Edmonton. We have not audited or otherwise validated the data. The procedures we carried out do not constitute an audit, and as such, the content of this document should not be considered as providing the same level of assurance as an audit. None of KPMG, member firms of KPMG nor any of their respective directors, officers, partners, employees, agents, or representatives make any representations or warranties as to the accuracy, reasonableness, or completeness of this information, nor shall any of them have any liability for any representations, expressed or implied contained herein, or for any omissions from the Report or from any other written or oral communications transmitted in connection with this Report. KPMG expressly disclaims all and any responsibility or liability to any third party as a result of the circulation, publication, reproduction, reliance or use of this Report.

The information provided to us by the City of Edmonton was determined to be sound to support the analysis. Notwithstanding that determination, it is possible that the findings contained could change based on new or more complete information. KPMG reserves the right (but will be under no obligation) to review all calculations or analysis included or referred to and, if we consider necessary, to review our conclusions in light of any information existing at the document date which becomes known to us after that date. Content contained in this document includes financial analyses.

The analyses are based on assumptions and data provided by the City of Edmonton. Significant assumptions are included in the document and must be read to interpret the information presented. As with any financial analyses, analysis outputs will differ from actual results and such differences may be material. KPMG accepts no responsibility for loss or damages to any party as a result of decisions based on the information presented. Parties using this information assume all responsibility for any decisions made based on the information.

Table of Contents

Figures

Tables

Key Terms and Acronyms

BAU	Business as Usual; an illustrative comparative scenario using conventional utilities
BCUC	British Columbia Utilities Commission
BMDEU	Burnaby Mountain District Energy Utility (Burnaby, BC)
DE	District Energy
DES - Surrey	City of Surrey District Energy System (Surrey, BC)
DES - Whistler	Whistler Cheakamus Crossing District Energy System (Whistler, BC)
DESS	District Energy Sharing System (Edmonton, AB)
ETS	Energy Transfer Station
GHG	Greenhouse Gas
LEC	Lonsdale Energy Corporation (North Vancouver, BC)
LIEC	Lulu Island Energy Company (Richmond, BC)
Load Profile	A customer's energy usage pattern over a period of time
Multi-unit Customer	A multi-unit development that may consist of residential, commercial, and institutional developments or any such combination
NEU	Southeast False Creek Neighbourhood Energy Utility (Vancouver, BC)
Peak Load	The actual or estimated peak demand that the building would need to pull from the DESS to meet customers' energy consumption
DHW	Domestic Hot Water
HVAC	Heating, ventilation, and air conditioning
NAIT	Northern Alberta Institute of Technology
RRO	Regulated Rate Option
SFU	Simon Fraser University (Burnaby, BC)
SROW	Statutory Right of Way

1 Executive Summary

The City of Edmonton (the City or Edmonton) engaged KPMG LLP (KPMG) in July 2022 to conduct a study to recommend an alternative rate-setting approach for its multi-unit renewable energy utility customers in the Blatchford community (the Study). This Report constitutes the final deliverable for this engagement and illustrates the recommended approach for the City to establish a new multi-unit customer rate, and the supporting rationale. In this Report, KPMG does not propose actual utility rates for multi-unit customers, however the recommended approach may be subsequently implemented by the City to produce the finalized rates for Council approval.

Study Objective and Approach

Building on the City's previous work designing customer rates for its District Energy Sharing System (DESS), KPMG worked collaboratively with the City's Project Team to refine a starting hypothesis pertaining to the recommended rate-setting approach presented in this Report. As a starting point for the Study, the City requested an exploration of four rate components: fixed, consumption / variable, capacity and excess demand charges.

The aim of this Study was to:

- Review Blatchford's multi-unit customer profile and planned build-out timeline,
- Prepare a Business as Usual (BAU) rate build-up model based on a sample of multi-unit buildings proposed for Blatchford (i.e., high density residential and retail mixed use) to contrast proposed billing proportion, and
- Conduct a benchmarking exercise of seven comparable Canadian district energy systems and their approach to multi-unit customer rate design.

Recommended Approach

KPMG's synthesis of findings, culminating from analysis of the customer profile, BAU analysis and benchmarking insights, led to the development of a recommended approach to rate-setting for multi-unit customers, as illustrated in Table 1 on the following page.

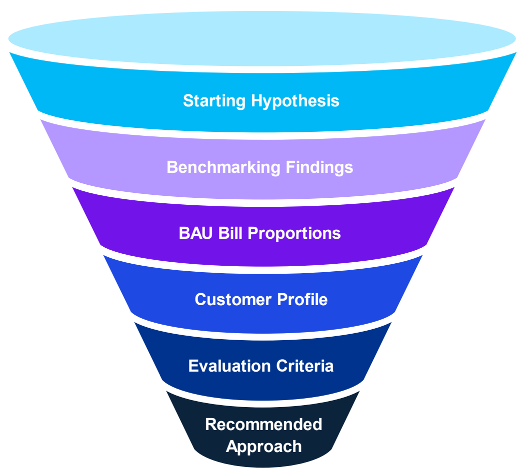
Table 1: Recommended Rate Components and Proportions

Rate Component	Calculation	Target Bill Proportion
Fixed Charge	Capacity charge by nominated capacity	60-70%
Variable Charge	Commodity consumption charge by kWh	30-40%

Source: Prepared by KPMG LLP.

To arrive at this recommended approach, KPMG worked with the City's Project Team to refine the starting hypothesis through successive layers of research and analysis, as illustrated in Figure 1 below and followed by a summary description of each step. For additional information on KPMG's approach and methodology, see Section 3 on page 10.

Figure 1: Starting Hypothesis Refinement Process



Source: Prepared by KPMG LLP.

Benchmarking Findings

Research and engagement focused on seven comparator organizations provided insights into the common challenges and unique approaches demonstrated among district energy utilities. As Blatchford's DESS includes primarily geothermal technology with limited natural gas peaking for its ambient loop distribution of heating, cooling and domestic hot water, not all benchmarking participants encompass the same services or delivery system. Similarly, KPMG noted variation in the regulatory environment that impacts rate design as the DESS utility rates are approved through municipal bylaw, whereas some other utilities must go through their provincial utility commission, such as the British Columbia Utilities Commission (BCUC). Despite these unique characteristics, several common findings emerged from the benchmarking exercise which supported the refinement of the City's starting hypothesis of a four-component rate design.

Overall, comparators conveyed a preference for a simplified rate-setting approach. To avoid complexity, most suggested employing no more than two rate components (i.e., fixed and variable) and to employ calculations that allow the actual rates to reflect differences in anticipated energy load profiles. Fixed charges by floor area were commonly used, however, they appear to operate as a proxy for nominated capacity (i.e., the highest energy load anticipated by the building's designers) – the other fixed charge approach that figured prominently among the benchmarking participants.

The following table highlights how the benchmarking findings informed the City's recommended approach.

Table 2: Application of Benchmarking Observations on the Recommended Approach

Dimensions	Observations	Relevance to Recommended Approach
Overall Approach	1. Minimization of Complexity in Rate Design	Only two rate components proposed – fixed and variable – to prioritize simplicity
	2. Rates Structured to Recover Full Costs Over Time	As a future consideration, the City may explore a levelized approach when determining revenue requirements and the calculation of actual rates.
	3. Promoting Transparency of Recovery Goals by Component	The City may consider communicating the cost recovery rationale that supports the recommended approach.
	4. Incentives for Multi-unit Customer Energy Efficiency	The nominated capacity fixed charge is proposed as a means to encourage energy efficient design.
Customer Profile	5. Primarily Residential Multi-unit Customers Served	While other utilities distinguish between different multi-unit customers, there is a recognition that Blatchford's anticipated customer profile may not warrant separate customer class types at this time.
	6. Unique Characteristics of Institutional Uses	As future consideration, the City may reevaluate the rate-setting approach for institutional customers.

Dimensions	Observations	Relevance to Recommended Approach
Rate Components	7. Charge by Area for Multi-unit Residential	This method was considered as part of Options 2 and 3, however, the recommended approach scored more favorably against the evaluation criteria.
	8. Nominated Capacity for Multi-unit Non-Residential	Nominated capacity is proposed to calculate the fixed charge component for all multi-unit customers.
	9. Charge by Connection Size for Multi-unit Customers	Using the connection or meter size as a proxy for nominated capacity was not identified as a common approach.
Billing	10. Ratio of Fixed to Variable Charges	The proposed bill proportions appear consistent with Blatchford's closest comparator utilities.
	11. Monthly Billing at the Building Level	Monthly billing at the building / strata level is consistent with benchmarking results.
Future Considerations	12. Consideration of the Evolving Utility Context	As a future consideration, the City may revisit its rate-setting approach to adapt to changes in the operating environment.
	13. Revisiting the BAU to Inform Rate Adjustments	The City may consider adapting and applying BAU analyses over time to account for differences from the DESS and BAU customers (e.g., green energy costs).

Source: Prepared by KPMG LLP based on benchmarking research and interviews.

The benchmarking findings, categorized into dimensions, are described more detail in Section 4.3 on page 27.

BAU Bill Proportions

Analysis of BAU equivalent bills provided a perspective on the utility fees multi-unit customers might pay elsewhere in the City of Edmonton through their consumption of natural gas and electricity to meet comparable heating, cooling and domestic hot water needs. The findings suggest bill proportions between 50-57% variable charges and 43-50% fixed fees; however, it is recognized that DE utilities that include geothermal or sewer heat recovery for energy production may have higher fixed costs than electric and gas utilities, given these traditional utilities' reliance on commodity costs (i.e., natural gas).

For more details on the bill proportion calculations and assumptions, see Section 4.2 on page 24.

Customer Profile

Examining the anticipated customer profile in Blatchford suggested that across its 176 parcels outlined in the Blatchford land development plan, the largest share (42%) are designated as residential townhouses and were deemed out of scope of this Study. Of the remaining land uses, the estimated additional administrative complexity did not support the development of separate customer classes (e.g., residential vs. non-residential).

For additional information on the customer profile analysis, see Section 4.1 on page 21.

Evaluation Criteria

Applying the rate design evaluation criteria, outlined in Section 3.1.1 on page 12, the recommended approach scored high in terms of anticipated understandability for multi-unit residential developers, service cost fairness for multi-unit residential customers, encouragement of usage efficiency and the simplicity of administration and billing.

Implementation Considerations

The identified risks associated with the recommended rate-setting approach include a potential for under recovery of the DESS revenue requirement, limited flexibility to recover different lifecycle costs across this customer type, and the understandability of nominated capacity from the point of view of multi-unit building residents and tenants.

For each of these risks, KPMG prepared key future considerations and potential mitigations to inform effective implementation and monitoring of the recommended approach, as described in Section 5 on page 41.

Conclusion

In conclusion, the recommended approach includes a fixed charge by nominated capacity and a variable commodity consumption charge as the supporting evidence suggests that it is simple, understandable, and fair to customers. It also encourages efficient usage and design, and supports ease of administration and billing for the City.

2 Introduction

This section describes the context, scope and overarching objectives of this Study followed by an overview of the remaining sections of this Report.

2.1 The District Energy Sharing System

Located in the heart of Edmonton, the Blatchford community showcases the City of Edmonton's commitment to innovative development – where climate-friendly solutions are integrated from the ground up. Converting lands previously designated as a municipal airport, this greenfield development community is uniquely located near the City's core and is intended to support The City Plan's overall strategic direction.[1]

Another unique feature of the Blatchford community is its District Energy Sharing System (DESS), a renewable energy system that captures geothermal energy from beneath the earth's surface and distributes capacity for building heating, cooling and domestic hot water. Positioned by the City as a more efficient and "greener" alternative to conventional energy production, the DESS offers an ambient loop system that circulates thermal energy at temperatures below 25ºC and relies on equipment within buildings, such as Energy Transfer Stations (ETS), heat pumps or chillers, to channel that energy to meet customer needs.

As Blatchford's development is still in its initial phase, DESS customers are primarily townhouses. A townhouse lot, as defined by the City, includes a townhouse unit and may include a garage suite and/or basement suite.[2] Developed in 2018, the Utility's rate approach for townhomes employs a variable consumption charge and a fixed charge calculated per unit per day.[3]

Over time, the planned build out for the community envisions serving combination of medium density residential, mixed-use and institutional buildings over the next 30 years which, based on their unique energy needs, require a different rate-setting design than the current townhome approach.

2.2 Study Objectives and Scope

Building on the learnings from previous work to establish current utility rates for the Blatchford Renewable Energy Utility, the City hopes to refine its approach to establish a

[1] City of Edmonton, The City Plan (Municipal Development Plan and Transportation Master Plan), December 2020.
[2] City of Edmonton, Townhouse and Multi-unit Lot Definition provided to KPMG August 30, 2022.
[3] City of Edmonton, Bylaw 17943, Blatchford Renewable Energy Utility Bylaw, Consolidated January 1, 2022

renewable energy utility rate for multi-unit customers that connect to the DESS. The City defines multi-unit customers as utility ratepayers for buildings / structures with more than one dwelling or unit that have a single connection to the community's renewable energy system.

To guide the information collection and analysis process, the following key questions outlined the Study's objectives:

1. Based on the starting hypothesis provided by the City, what is the City hoping to achieve through its new rate-setting approach?
2. Based on rate-setting precedents of other district energy and similar utilities, what are the benefits and drawbacks of this starting hypothesis for rate payers, Blatchford Renewable Energy Utility, and the City?
3. Based on the analysis performed, what is the recommended approach to establish the new end use customer rate(s) for multi-unit customers, including the description and relative proportion of each rate component?

This Report describes the recommended approach to establishing a new multi-unit customer rate as well as the supporting rationale. Equipped with the results of this Study, the City will be in a position to seek approval from City Council's Utility Committee and calculate a final utility rate based on the refined approach and relevant inputs from City data (e.g., financial models, revenue forecasts).

Items beyond the scope of this Study included the provision or recommendation of the final rate for multi-unit customers, research or analysis related to infrastructure or connection fees, and an audit and / or verification of operational and financial data inputs provided by the City or participating benchmarking organizations.

KPMG has not and will not perform management functions or make management decisions for the City of Edmonton. Comments in this report are not intended, nor should they be interpreted, to be legal advice or opinion. KPMG has no present or contemplated interest in the City of Edmonton, KPMG is independent of the City of Edmonton and acting objectively.

2.3 How to Read this Report

This Report is intended to provide the City with a recommended approach in terms of establishing a new renewable energy utility rate for multi-unit customers who connect to the DESS, as well as related observations for the City's future consideration.

In addition to the Executive Summary and this Introduction, the Report is structured according to the following sections:

- **Section 3: Approach and Methodology**
  This section outlines the four-phased methodology and areas of analysis used to structure this Review.
- **Section 4: Analysis and Key Findings**
  This section includes the findings that emerged from the analysis and benchmarking conducted as well as the rate-setting options considered.
- **Section 5: Recommended Approach**
  This section describes the recommended rate-setting approach for multi-unit customers and identifies the benefits, risks and mitigation considerations as the City applies the approach to establish its utility rates.
- **Appendices:**
  Supplementary data, information and sources that support the study analysis and findings include:

  Appendix A: BAU Definition and Methodology

  Appendix B: Model Inputs

  Appendix C: BAU Equivalent Bills and Proportion

Acknowledgements

This Report acknowledges the following individuals for their valuable contributions to the Study analysis and findings:

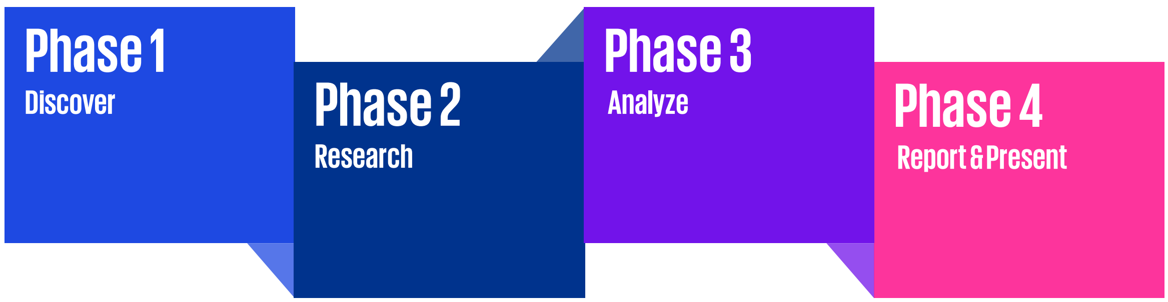
- Development Manager, Blatchford, City of Edmonton
- Director, Renewable Energy Systems, City of Edmonton
- Utilities Regulation (*Acting*), City of Edmonton
- Engineering Project Manager, Renewable Energy Systems, City of Edmonton
- Project Manager, Pinchin Ltd.

Limitations

This Report should be considered in its entirety. Selection of, or reliance on, specific portions of the Report could result in the misinterpretation of the findings and analysis.

3 Approach and Methodology

This section presents the approach and methodology employed by KPMG to test and refine the starting hypothesis and evaluate the recommended approach.



Building upon the City's previous experience exploring and developing its rate-setting approach, KPMG's work plan followed the four-phased approach which included the corresponding core objectives:

- **Phase 1: Discover**
  Establishment of a detailed workplan that confirmed the engagement scope, the City's objectives and the starting hypothesis for a potential alternative rate-setting approach for multi-unit customers.
- **Phase 2: Research**
  Review of documentation, Business as Usual analysis data collection and engagement with comparator organizations.
- **Phase 3: Analyze**
  Synthesis of research findings to refine a recommended approach for multi-unit customer rate design.
- **Phase 4: Report and Present**
  Preparation of this Report outlining the recommended rate-setting approach along with supporting rationale and future considerations.

3.1 Study Methodology

In order to meet the objectives of this Study, KPMG applied a methodology that focused on three areas of research and analysis, including Customer Landscape Review, Business as Usual Rate Build-up and Benchmarking District Energy Utilities, as described in Table 3 on the following page.

Table 3: Rate Design Study Areas of Analysis

1	**Customer Profile Review** The purpose of this analysis was to understand the characteristics of buildings/customers that would be impacted by the adoption of a new multi-unit rate-setting approach and determine if separate customer classes may be warranted. This included a review of any existing multi-unit buildings in Blatchford and those forecasted to be connected to the DESS. Because other district energy utilities may define and categorize customers differently than having a single multi-unit rate, this exercise set the context for the benchmarking analysis described below. *Analysis and findings in this area are included in Section 4.1.*
2	**Business as Usual Build-up** The purpose of this analysis was to inform the proposed fixed and variable rate proportions for multi-unit customers using a comparable traditional utility model. Using input data provided by the City (e.g., size and load characteristics for each building), an approximate Business as Usual (BAU) rate analysis was constructed for two sample multi-unit customers. This was used to identify the proportional utility costs charged to customers from conventional utilities, namely natural gas and electricity, to achieve similar outputs (i.e., energy for heating, cooling, and heating for domestic hot water). By undertaking this activity, the City was provided a perspective on the comparable fees for similar multi-unit customers to what they would be elsewhere in the City of Edmonton through their energy utility bills. *Analysis and findings in this area are included in Section 4.2.*
3	**Benchmarking District Energy Utilities** The purpose of this analysis was to filter the rate design components proposed in the starting hypothesis based on the experiences of other district energy utilities. Customer class definitions, rate components and fixed to variable bill proportions were researched and analyzed for seven comparator organizations. The benchmarking exercise focused on similar utilities to that of the Blatchford Renewable Energy Utility as well as comparators that included unique approaches initially considered in Edmonton's starting hypothesis. This included having mixed residential and non-residential uses, using publicly available rates (as opposed to commercially negotiated rates), services provided and rate components. The benchmarking exercise included both secondary research (i.e., information available in the public domain) and primary research with consultations directly with other district energy utilities. *Analysis and findings in this area are included in Section 4.3.*

Source: Prepared by KPMG LLP.

In addition to the areas of analysis described above, KPMG's subject matter advisors were leveraged in the development of this Study. These resources supplemented the core project team with a breadth and depth of utility experience to provide additional points of view, insights for the starting hypotheses and other perspectives for multi-unit customer rate-setting from across jurisdictions.

3.1.1 Starting Hypothesis

As part of Phase 1, the City confirmed its interest in exploring four broad utility rate components, which included various options for how to calculate them. These component categories were fixed, consumption / variable, capacity and excess demand charges, as outlined in Table 4.

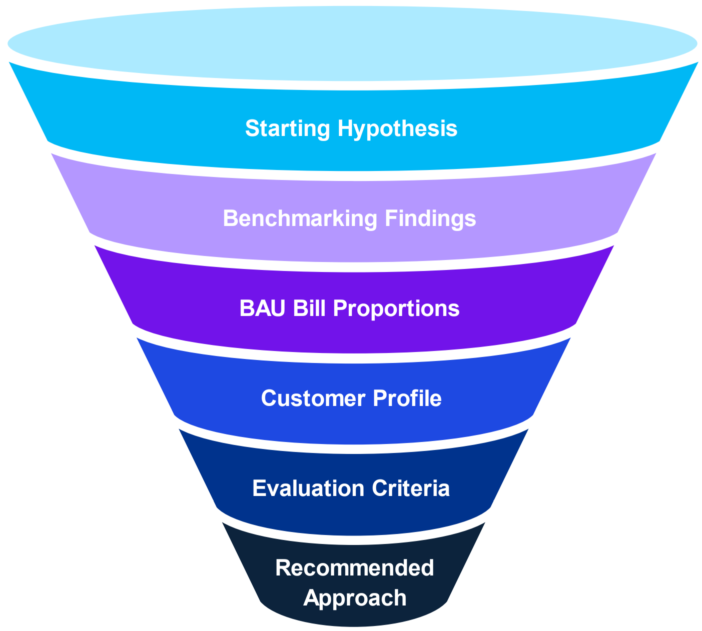
Table 4: Starting Hypothesis Rate Design Components

Fixed	**Consumption/ Variable**	**Capacity**	**Excess Demand**
Set monthly charge that may be calculated based on one of the following approaches: — Customer type — Meter size — Square footage — Per door / unit (current approach)	Commodity consumption charge based on: — Actual customer usage — Fee per kilowatt-hour	Demand charge calculated based on peak draw on the utility, which may consider: — Threshold for applicability — Value of builders' estimated peak load / nominated capacity	Premium charges for consumption beyond a specified load, which may consider: — instantaneous peak, monthly usage)

Source: Prepared by KPMG LLP in consultation with the City of Edmonton.

Taking a broad approach to the starting hypothesis was critical as the City's Project Team indicated their openness to testing innovative approaches in the knowledge that the benchmarking observations, BAU analysis and customer profile review would necessarily filter and refine the focus towards the recommended approach, as illustrated in Figure 2 on the following page.

Figure 2: Starting Hypothesis Refinement Process



Source: Prepared by KPMG LLP.

Rate Design Evaluation Criteria

In order to evaluate the potential suitability of the recommended rate-setting approach to multi-unit customers, assessment criteria were developed in consultation with the City’s project team and informed the refinement of the starting hypothesis described above. Many of the criteria are based on widely accepted foundational principles for public utility rates attributed to the work of James Bonbright, known colloquially as “Bonbright’s Principles”.

For the purposes of this Study, all criteria were assumed to have equal weighting and are outlined in Table 5 on the following page.

Table 5: Criteria Considered in the Assessment of Potential Rate Design Approaches

Criteria based on Bonbright's Principles	
1	Understandability for multi-unit residential developers
2	Understandability for multi-unit residential unit residents
3	Revenue stability / predictable cost recovery
4	Rate stability / frequency of rate adjustments
5	Service cost fairness for multi-unit customers
6	Encouragement of usage efficiency (variable consumption)
Other Criteria	
7	Incentive for more energy efficient building design for multi-unit residential customers
8	Ease of administration and billing simplicity

Source: Prepared by KPMG LLP based on James Bonbright's Principles of Public Utility Rates (1988) and information provided by the City of Edmonton.

3.1.2 Business as Usual Analysis

Analysis Objectives

A BAU rate build-up model was developed as the initial step to provide the City with a recommended approach in terms of establishing a new renewable utility rate for multi-unit customers who connect to the DESS. This analysis aimed to identify the utility costs charged to BAU multi-unit customers from gas and electric utilities to achieve similar outputs. (i.e., energy for space heating, space cooling, and heating for domestic hot water).

From there, the fixed / variable rate proportions billed to the customers were calculated, which, combined with findings from the benchmarking exercise and observations of Blatchford DESS, informed the recommended approach to establish a new utility rate for multi-unit customers. The BAU analysis also provided the City with perspective on the comparable fees for multi-unit customers to what they would be elsewhere in the City through their energy utility bills.

BAU Definition

The definition of BAU for the purposes of this analysis is: *the total costs incurred to a customer under natural gas and electricity utilities for equivalent energy consumption and services.* This definition is similar to what is used by several comparators who had taken a BAU approach in establishing their utility rates for customers who connect to district energy systems (see Appendix A: BAU Definition and Methodology for more details).

Based on information provided by the City, the assumption for BAU was further narrowed down to include only efficient customers in Edmonton (i.e., those with improved energy performance relative to older buildings in Edmonton given recent changes to Alberta building code requirements).[4] Efficient customers elsewhere in Edmonton under the scope of the BAU analysis are assumed to have similar energy efficiency and intensity as the new multi-unit customers to be built in Blatchford.

BAU Analysis Approach

The BAU rate build-up model was developed using a four-step, quantitative approach, including gather data, analyze, solicit findings, and identify recommended approach, as described in Table 6 below.

Table 6: Approach to Develop the Business as Usual Rate Build-up Model

1	**Gather Data** Two sample multi-unit customer buildings, high density residential and retail mixed use, were identified by the City as representation of the forecasted multi-unit customers who will connect to the DESS. The BAU model input data includes the estimated natural gas and electricity commodity requirements and peak demand to achieve equivalent space heating, space cooling and heating for domestic hot water outputs as provided by the City.[4] Natural gas rates, including energy charges and delivery charges, were sourced from ATCO Gas and Encor by EPCOR, as published on the companies' websites.[5] Electricity rates were similarly sourced from EPCOR.[6] *Input data gathered at this step are included in Appendix B: Model Inputs.*

[4] Energy Usage for Blatchford Sample Multi-unit Customers; Pinchin Ltd, September 20, 2022
[5] ATCO Gas, Rates and Billing, Accessed August 2022; Encor by EPCOR, Natural Gas Rates History, Accessed August 2022
[6] EPCOR, Tariff Schedules, Accessed August 2022; EPCOR, Default Supply, Accessed August 2022

2

Analyze

From the data gathered, a set of assumptions were developed and documented to construct the BAU model's parameters. Quantitative analysis was conducted to identify the BAU conventional utility rates and customer classes for the two sample multi-unit customer buildings. BAU equivalent bills for the sample buildings are developed by multiplying the expected natural gas and electricity energy consumption and peak demand with the BAU conventional utility rates.

Assumptions and analysis from this step are included in Appendix B: Model Inputs.

3

Identify Findings

Findings identified from the BAU equivalent bills include: the utility costs charged to BAU multi-unit customers from gas and electric utilities to achieve similar energy outputs; and the fixed/variable rate proportions billed by conventional utilities in Edmonton.

Analysis and findings from this step are included in Appendix B: Model Inputs.

Source: Prepared by KPMG LLP.

3.1.3 Benchmarking Exercise

This section outlines KPMG's steps in identifying relevant comparator organizations and describes some of the key characteristics of their district energy utilities.

Process for Determining Relevant Comparators

Preliminary desktop research was conducted on the 14 potential comparators, listed on the following page, that were provided by the City as well as organizations identified by KPMG. Based on the initial findings, seven organizations were identified for their potential to add value to the project's objectives.

The participating comparators are considered established systems serving multi-unit customers – many of which have seen their rate structure evolve with the pace of build out. Several of these jurisdictions also included unique rate components of interest to the City's starting hypothesis, such as peak demand, charge by meter size and an excess demand premium.

Table 7: District Energy Utilities Considered for Benchmarking

Preliminary List of Comparator Organizations	
Lulu Island Energy Company (LIEC); Richmond, BC	Markham District Energy Inc.; Markham, ON
Burnaby Mountain District Energy Utility (BMDEU) – SFU; Burnaby, BC	Cogswell Ambient Temperature District Energy System; Halifax, NS
Whistler Cheakamus Crossing District Energy System (DES); Whistler, BC	Dockside Green Energy; Victoria, BC
Southeast False Creek Neighbourhood Energy Utility (NEU); Vancouver, BC	Sapperton District Energy System; New Westminster, BC
Lonsdale Energy Corporation (LEC); North Vancouver, BC	Hybrid Geoexchange District Energy System; Whitehorse, YT
City of Surrey District Energy System (DES); Surrey, BC	Saanich Peninsula Wastewater Treatment Plant Heat Recovery; Victoria, BC
Community Energy System (CES); Langford, BC	Revelstoke District Energy System; Revelstoke, BC

Source: Prepared by KPMG LLP.

Participating Comparator Organizations

Seven (7) Canadian district energy utilities were selected to inform this Study and, as illustrated in Table 8 on the following page, represent a variety of services and approaches to delivering district energy (DE) to their communities.

For example, other DE systems may require a statutory right of way (SROW) to access and maintain DE-owned equipment (e.g., energy transfer stations, chillers, heat pumps) located within the multi-unit customer's building. In order to inform the benchmarking findings included in Section 4.3, it was important to distinguish the key similarities and differences between these benchmarks relative to the DESS at Blatchford.

Table 8: Multi-unit Customer Rate Design Benchmarking Organizations

Comparator	System Temperature[a]	Heating	Cooling	Domestic Hot Water	On-site DE Equipment[b]	Technical Specifications	Other Notes
Blatchford DESS – Edmonton	Ambient	✓	✓	✓	✓	Geothermal, natural gas peaking	
BMDEU – Burnaby	High Temp.	✓	X	✓	✓	Geothermal, wastewater heat recovery, natural gas peaking	Private operator Corix, regulated by British Columbia Utilities Commission (BCUC)
CES – Langford	Ambient	✓	✓	✓	✓	Geothermal, waste heat recovery from local area ice maker	Private operator SSL Ltd., regulated by BCUC
DES – Surrey	High Temp.	✓	X	✓	✓	Natural gas plus some solar, geothermal and waste heat recovery	SROW and covenant required for development
DES – Whistler	Ambient	✓	✓	✓	X	Wastewater treatment plant, natural gas peaking	No initial capital investment by the municipality to pay back, regulated through bylaw, customer owns and maintains equipment on their property
LEC – North Vancouver	High Temp.	✓	X	✓	✓	Geothermal and renewable natural gas	Regulated through bylaw
LIEC – Richmond	Ambient	✓	✓	✓	✓	Geothermal, natural gas peaking	
NEU - Vancouver	High Temp.	✓	X	✓	✓	Wastewater heat recovery, natural gas peaking	

Source: Prepared by KPMG LLP based on benchmarking interviews, publicly available information and information provided by the City of Edmonton.
Notes:
a) For the purposes of this Study, average distribution temperatures are understood to be below 25º Celsius for ambient loop DE systems and above 60º Celsius for high temperature systems.
b) That is, DE equipment located on the multi-unit customer's property that is owned and maintained by the DE utility (e.g., heat pump).

3.2 Key Assumptions

The findings observed through the benchmarking research and BAU analysis should be considered within the context of six key assumptions as follows.

1. Forecasted Future Land Development

As Blatchford's development is still in its initial phase and no multi-unit customers have yet to be constructed and connect to the DESS, the BAU analysis and recommended approach were identified based on the assumption that future land development will follow the Blatchford land development plan as provided by the City.[7]

2. Rate-setting Approach for Fee-Simple Townhouse

The current renewable utility fixed rate of $1.55 per unit per day and variable rate of $0.0269 per kWh for fee-simple townhouse has been established by the City and outlined in Schedule B, Bylaw 17943.[3] For this Study, as established with the City, the rate-setting approach for fee-simple townhouse was out of the scope of analysis.

3. Location of Comparators

Participating comparator organizations were all located within British Columbia and may be subject to a regulatory environment that does not apply to the Blatchford context. For example, several DE utilities described their rate-setting approach as being shaped by the expectations and regulatory authority of the British Columbia Utility Commission (BCUC), such as BMDEU and CES.

However, similar to Blatchford DESS, many other comparators are regulated through Council-approved bylaws, by their own municipality, in so far as the scope of service provision does not extend beyond their municipal borders.

4. Engagement with Comparators

KPMG conducted interviews with 5 out of the 7 identified comparator utilities (2 comparators were unavailable to participate in the Study). The purpose of the interviews was to gain first-hand perspective and information on other DE utilities to inform Blatchford's recommended rate-setting approach.

For the unavailable comparators, Lulu Island Energy Company (LIEC) in Richmond, BC and Community Energy System (CES) in Langford, BC, benchmarking research was

[7] Blatchford DESS Master Plan Modelling Tool, August 2, 2022

conducted based on the publicly available information as posted on their websites, and the written information that they provided to the City through email.

5. Information Accuracy

In preparing this document, KPMG relied on information and material provided in part by the City and other parties as engaged via stakeholder interviews and requests for information. KPMG has not audited nor independently verified any of the stakeholder information provided.

6. Rate Calculation

This document has been prepared for the sole purpose of assisting the City in reviewing a potential approach to district energy utility multi-unit customer rate design, to develop recommendations for the City's consideration as actual rates are to be set following the conclusion of this KPMG engagement. The City is responsible for performing the calculation of the actual rates for multi-unit customer based on future revenue recovery requirements, cost of service analyses, etc.

As such, KPMG did not consider the potential implications of lower total demand load on the DESS while Blatchford is being developed This may be addressed in the rate setting process, for example, using levelized costing to promote an equitable approach to rate setting for DESS customers over time.

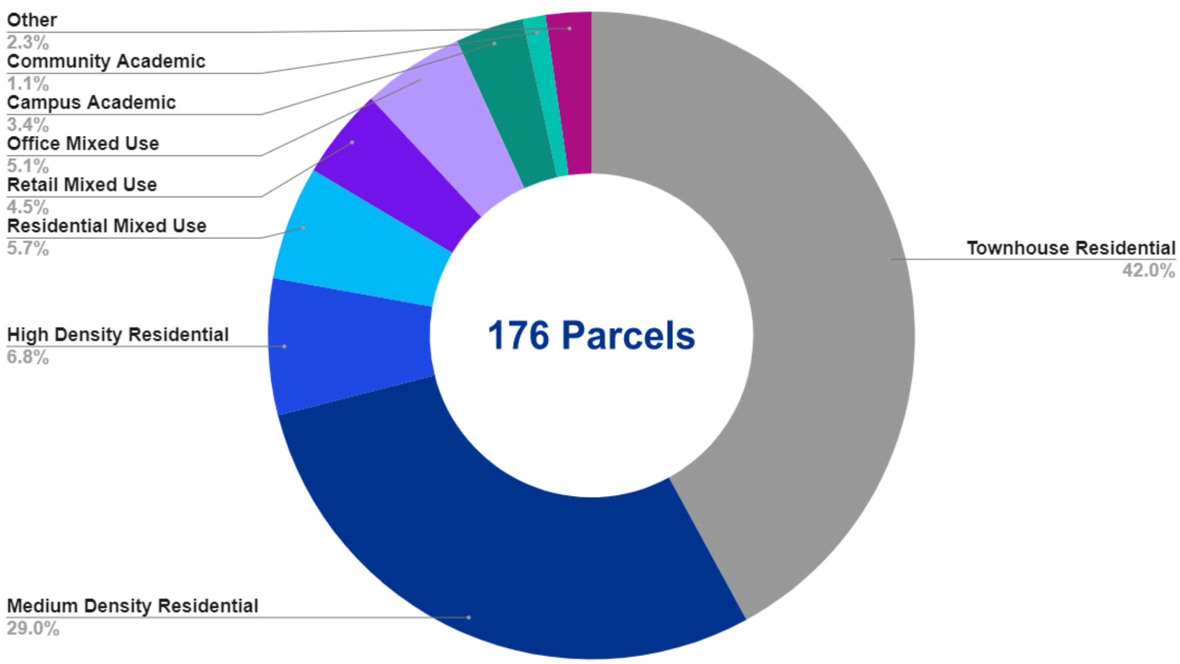
4 Analysis and Key Findings

This section describes the application of a comparable BAU analysis, and the most salient learnings gathered through benchmarking rate-setting approaches among relevant comparator organizations.

4.1 Customer Profile

As depicted in the Blatchford land development plan, the 176 land parcels are allocated across 11 customer land uses.[7] Figure 3 below illustrates the allocation.

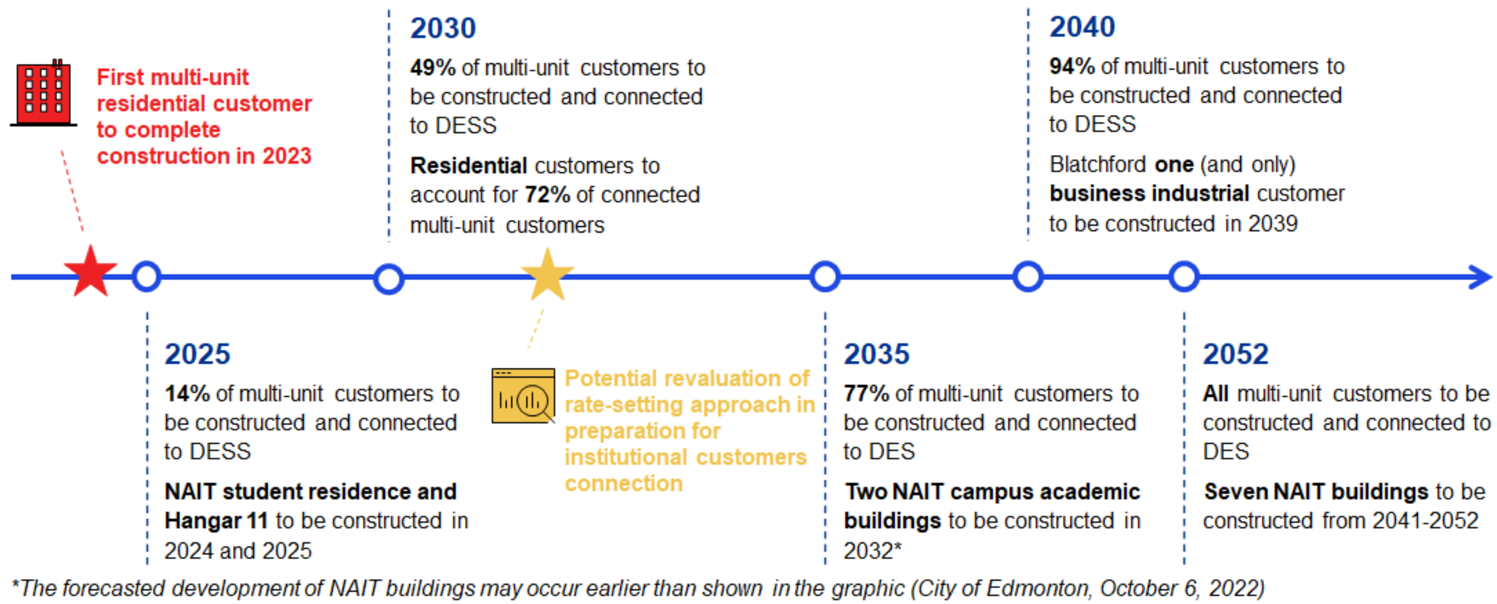
Figure 3: Forecasted Blatchford Land Parcels by Land Use



Source: Prepared by KPMG LLP with information provided by the City of Edmonton, August 2, 2022.

Figure 4 below illustrates the timeline of the forecasted land development in Blatchford over the next 30 years and highlights the key milestones of customers' connection to the DESS.

Figure 4: Timeline of Multi-unit Customers Construction



Source: Prepared by KPMG LLP with updated information provided by the City of Edmonton, October 6, 2022.[8]

[8] City of Edmonton, Updated Land Development Forecast for NAIT Buildings provided to KPMG October 6, 2022

Multi-unit Customer Land Uses

As defined by the City, a multi-unit customer is a multi-unit development that may consist of residential, commercial, and institutional developments or any such combination.[2] The current development timelines suggests that the following 10 multi-unit customer land uses are expected to be constructed and connected to the DESS. This timeline is subject to change depending upon a variety of factors including market conditions, economy and interest among developers and customers.

Medium Density Residential

Consisting of 51 land parcels, medium density residential is forecasted to be the largest multi-unit customer land use in Blatchford. Medium density residential parcels are expected to be constructed for primarily residential use. No parcels are expected to allocate more than 4% of total floor area to commercial use.

High Density Residential

Twelve high density residential parcels are expected to be connected to the DESS from 2029-2041. Similar to other residential land uses, high density residential parcels are expected to be constructed for primarily residential use, with commercial use accounts for no more than 7% of total floor area.

Residential Mixed Use

Residential mixed use are expected to account for 5.7% of total Blatchford land parcels, or 10% of total multi-unit customers land uses. Together with medium and high density residential, the three residential land uses are expected to account for 71% of the total 102 parcels for multi-unit customers. Residential mixed use land use includes a 1400-bed NAIT student residence that will be constructed in two phases. As per updated information provided by the City, the first phase has a target completion date of July 2024.[8]

Retail Mixed Use

Eight retail mixed use parcels are expected to be connected to the DESS starting from 2025. On average, the floor area of retail mixed use parcels is forecasted to comprise of 80% residential use and 20% commercial use. Hangar 11, a retail mixed use building, is forecasted to complete reconstruction in 2025.

Office Mixed Use

Nine office use parcels are expected to be connected to the DESS from 2030-2033. Office mixed use buildings are expected to be constructed primarily for office use, with possible commercial use floor area located at the building ground floors.

Campus Academic and Community Academic

Four NAIT campus academic and two NAIT community academic parcels are expected to be connected to the DESS starting from 2032. Campus academic parcels include the NAIT Plaza, NAIT Student Association Building, a Culinary Zonal Growth building, and a Learning Commons building. Community academic parcels include a Business Zonal Growth building, and NAIT Centre.

Other Land Uses

Other land uses include civic, business industrial, and school / park. With a total of four parcels, they are expected to account for 2% of the total 176 land parcels in Blatchford. The majority of other land use parcels are expected to complete construction and connect to the DESS in the later stage of land development in Blatchford.

Out of Scope

Townhouse Residential

A fee-simple townhouse is out scope for the analysis of this Study. As mentioned in Section 3.2, the rate-setting approach for fee-simple townhouse has been established by the City.

4.2 Bill Proportionality

This section summarizes the findings of the BAU analysis – the fixed / variable BAU equivalent rate proportions that would have been billed to the sample multi-unit customers by natural gas and electricity utilities for similar energy consumption.

Assumptions

The following outlines the set of key assumptions that were developed to construct the BAU model's parameters and guide the BAU analysis approach and methodology. The full list of all assumptions for the BAU analysis is included in Appendix B: Model Inputs and Appendix C: BAU Equivalent Bills and Proportion.

- Given the estimated BAU natural gas commodity requirements for the sample multi-unit customer buildings as provided by the City, both buildings would be classified as mid use (delivery service 1200-8000 GJ/yr) for natural gas delivery charges.
- For natural gas energy charge, the five-year fixed rate is chosen to be used in the BAU model over the RRO as the former is lower in 2022. We assumed that a rational customer elsewhere in the City would choose the lower electricity rate offering.

- Given the estimated BAU electricity peak loads for the sample multi-unit customer buildings as provided by the City, both buildings would be classified as commercial/industrial 150 kVA to < 5000 kVA for electricity delivery charges.
- For commercial/industrial electric energy charge, the default supply hedged rate is chosen to be used in the BAU model over the default supply flow-through rate as the former's five-year historical average rate is lower. We assumed that a rational customer elsewhere in the City of Edmonton would choose the lower electricity rate offering.
- Under BAU, gas and electricity are used in order to deliver the Energy Use (Outputs) Requirements.
- The BAU analysis is performed on efficient customers elsewhere in Edmonton. Efficient customers are assumed to have similar energy efficiency and intensity as the new multi-unit customers to be built in Blatchford.
- Infrastructure / connection fee is excluded from the scope of the BAU analysis.
- Maintenance cost is excluded from the scope of the BAU analysis.
- Electricity peak demand used in the calculation of the BAU equivalent bills excluded peak demand from other energy uses (e.g., plug loads, elevators, appliances).
- The BAU equivalent bills for both of the sample multi-unit customer buildings is assumed to be billed at the building level.
- BAU equivalent bills are developed on the five-year historical average natural gas and electricity rates.
- Demand charges is summed together with fixed charges as demand charge is relatively fixed in nature. Demand charges are calculated on metered peak demand or estimated peak demand, which does not fluctuate significantly for each customer.

BAU Equivalent Bills and Rate Proportions

Table 9 summarizes the components of the BAU equivalent bills developed for the sample high density residential and retail mixed use customer buildings using the five-year historical average (2018-2022) conventional utilities rates.

The BAU equivalent bills helps provided the City with perspective on the comparable fees for multi-unit customers to what they would be elsewhere in the City of Edmonton through their energy utility bills. Further detail of the BAU equivalent bills are illustrated in Appendix C: BAU Equivalent Bills and Proportion.

Table 9: Summary of BAU Equivalent Bills

Sample Customer Building	Natural Gas Variable Charge	Natural Gas Fixed Charge	Electricity Variable Charge - Total	Electricity Variable Charge – On-peak	Electricity Demand Charge	Electricity Fixed Charge	Total Charge
High Density Residential	$15,975	$667	$13,476	$708	$16,351	$12,713	**$59,893**
Retail Mixed Use	$55,162	$667	$57,736	$3,034	$72,318	$12,713	**$201,633**

Source: Prepared by KPMG LLP with publicly available information and information provided by the City of Edmonton, September 21, 2022.

From the BAU equivalent bills, the fixed / variable rate proportions were calculated as depicted in Table 10. Fixed and demand charge proportions are combined as together they reflect the non-variable component of customer rates. Further detail of the BAU rate proportions are illustrated in Appendix C: BAU Equivalent Bills and Proportion.

Table 10: BAU Rate Proportions

Multi-unit Customer	Total Variable Charges	Total Fixed + Demand Charges
High Density Residential	50%	50%
Retail Mixed Use	57%	43%

Source: Prepared by KPMG LLP with publicly available information and information provided by the City of Edmonton, September 21, 2022.

4.3 Benchmarking Findings

This section summarizes the key findings that emerged based on information collected through publicly available documents, such as BCUC rate filings, and interviews with representatives from the comparator DE utilities listed in Table 8 (see page 18). Relevant observations are grouped and presented according the five themes, as outlined in Table 11.

Table 11: Multi-unit Customer Rate Design Benchmarking Observations by Dimension

Dimension	Observations
Overall Approach	1. Minimization of Complexity in Rate Design
	2. Rates Structured to Recover Full Costs Over Time
	3. Promoting Transparency of Recovery Goals by Component
	4. Incentives for Multi-unit Customer Energy Efficiency
Customer Profile	5. Primarily Residential Multi-unit Customers Served
	6. Unique Characteristics of Institutional Uses

Dimension	Observations
Rate Components	7. Charge by Area for Multi-unit Residential
	8. Nominated Capacity for Multi-unit Non-Residential
	9. Charge by Connection Size for Multi-unit Customers
Billing	10. Ratio of Fixed to Variable Charges
	11. Monthly Billing at the Building Level
Future Considerations	12. Consideration of the Evolving Utility Context
	13. Revisiting the BAU to Inform Rate Adjustments

Source: Prepared by KPMG LLP based on benchmarking research and interviews.

Overall Approach

The following observations speak to common practices in the way comparator organizations approach utility rate-setting broadly.

1. Minimization of Complexity in Rate Design

Current approaches to general rate design, not limited to multi-unit customers, among peer jurisdictions tends to emphasize simplicity and ease of implementation. DE providers recognize that incorporating additional rate components presents a tradeoff in the form of increased complexity and leads to a utility rate that may be less transparent and understandable to developers and end users. For example, while minor administration fees were considered by some jurisdictions, there was no evidence of their current usage given the additional complexity.

For example, BMDEU - Burnaby and CES - Langford work within the direction of BCUC to follow James Bonbright's principles with an emphasis on simplicity.[9] Most observed DE rates have two components; only LIEC - Richmond and LEC - North Vancouver include three components to their rate design and DES – Whistler has one component.

[9] James Bonbright, Principles of Public Utility Rates, 1988

2. Rates Structured to Recover Full Costs Over Time

Utilities generally described using a levelized approach in calculating rate revenue targets, including deferral accounts and debt to finance the initial capital investment until a critical mass of DE users can sustain the cost of the system. Other comparators indicated that their cost recovery goals include planning for future investments in new technology and expanding energy stock to continue to “green” their system, increase efficiency and reduce greenhouse gas (GHG) emissions over time. Some DE utilities include a rate of return for equity financing provided by its shareholders, while others do not.

Engagement with BMDEU - Burnaby and NEU - Vancouver emphasized the levelized approach as well as the cost of “greening” their systems. BMDEU - Burnaby includes a return on equity similar to a commercially operated regulated utility. DES - Whistler is unique in that the initial capital investment was borne by other orders of government and the system gifted to the municipality following the decommissioning of the Olympic Village.

3. Promoting Transparency of Recovery Goals by Component

Clearly articulating what each rate component aims to recover in terms of the cost of service appears to support transparency, trust and overall receptiveness among stakeholders.

LEC - North Vancouver appears to be a utility that most clearly communicates its cost recovery drivers for each of their three rate components, which may offset any perceived concerns related to complexity in their rate design (i.e., having more than two rate components). For example, their commodity charge (variable) aims to recover cost of energy used to generate heat; their meter charge (fixed) aims to recover capital and operating costs for the meter and heat exchanger at the point of delivery; and their capacity charge (fixed) aims to recover capital and operating costs of boiler plants and distribution.

The above observation is based on what was communicated via the benchmarking interview and publicly available information for LEC – North Vancouver. KPMG did not verify if the recovery of specific costs was actually used to calculate their utility rates.

4. Incentives for Multi-Unit Customer Energy Efficiency

Rate components may be used as policy tools to influence development design and/or customer behaviors, depending on the approach. This may include an excess demand charge related to incentivizing reduced variable consumption or a fixed nominated capacity charge to motivate efficient design.

LEC - North Vancouver and DES - Surrey Class 2 (non-residential) include a fixed capacity charge based on nominated capacity. The variable component for CES - Langford includes an increased rate for monthly usage after the first 675 kWh consumed.

LIEC - Richmond includes an excess demand fee for each watt per square foot of the estimated peak heat/cooling demand that exceeds six watts per square foot.

Customer Profile

The following benchmarking findings relate to how comparators address any difference within the multi-unit customer type to reflect what may be unique DE load profiles (i.e., different energy needs at peak or over time).

5. Primarily Residential Customers Served

DE utilities in British Columbia appear to be primarily serving infill, residential and higher density developments. Commercial land uses and lower density dwellings, such as townhouses, are less common or make up a relatively small proportion of DE customers. Light commercial uses appear similar enough to residential energy use patterns that an additional rate or approach is not always warranted. The type of customers served and the rate of build out impact rate-setting, given their unique profiles and energy load requirements. For example, Simon Fraser University (SFU) is only interested in renewably-sourced energy from BMDEU - Burnaby.

Interestingly, NEU - Vancouver includes a non-residential class, however the rate approach is currently the same for their Class 2 residential. Also, DES - Surrey includes a non-residential class. Both are based on the percentage of net floor area dedicated to non-residential uses (50% and 20%, respectively).

6. Unique Characteristics of Institutional Uses

Incorporating institutional uses, such as post-secondary institutions, along with residential developments within the DE system works towards smoothing out some of the peak demand. Peak load times are spread out as institutions tend to be earlier in the day than residential hot water consumption peak. This diversification helps utilities to avoid additional peak demand on during periods of existing peak load requirements. Larger, institutional customers can often merit a separate rate design given their size and unique requirements.

BMDEU - Burnaby negotiated an annual surcharge from SFU to ensure availability. As noted above, SFU is only interested in consuming renewable DE (i.e., no natural gas peaking). NEU - Vancouver emphasized the importance of load profile diversification (e.g., Emily Carr University, Science World).

Rate Components

The following observations highlight the various mechanisms used by comparators to calculate multi-unit customer billing rates.

7. Charge by Area for Multi-unit Residential

Whether calculated by square foot or meter, some comparators multiply their rate by the net floor area to determine a fixed portion of the utility charge for those customer classes with similar load profiles. Comparators note that this approach offers simplicity of administration as well as understandability among stakeholders. Area may be calculated based on the gross interior area less areas that are not heated or habitable, such as a parkade, but would include common areas.

Reliance on an area calculation appears to be used as a proxy for nominated capacity as it assumes a peak load relative to the interior building space that requires heating and cooling. This assumption may not reflect differences in energy efficient design specific to each multi-unit building.

Both the BMDEU - Burnaby and DES - Surrey (Class 1) employ a fixed charge per square meter of net floor area, whereas LIEC - Richmond relies on gross floor area. DES - Whistler exclusively uses a fixed charge by area that is billed directly to individual units and common areas are billed to the building owner or condominium board.

8. Nominated Capacity for Multi-unit Non-residential

Several comparators rely on developers and their engineers to provide their estimated maximum usage at any given time, generally based on the coldest day of the year at peak time of day as many of these utilities only provide heating and DHW. DE directors indicate it is simpler and more cost effective to administer than actual peak demand. However, customers tend to oversubscribe with conservative estimates that result in oversized DE systems and higher utility charges for end users. It is more difficult to “right size” once the capital investment is made and cost recovery target need to be achieved. Real time capacity was contemplated by some however, they did not proceed due to the estimated administrative complexity.

Three comparators (LEC - North Vancouver, NEU - Vancouver and DES – Surrey) proactively work with developers and their teams to manage the level of contingency, encourage energy efficiency by design and look ahead to avoid unnecessary utility charges. NEU - Vancouver may consider moving towards actual peak demand capacity in future to inform rates.

9. Charge by Connection Size for Multi-unit Customers

A fixed charge based on meter size is relatively less common, only included in one comparator organization’s rate structure. CES - Langford incorporates a monthly service connection fee according to three connection sizes (25 mm, 37 mm and 50 mm), which appears to be used as a proxy for nominated capacity. This comparator utility notes that most single-family homes have a 25 mm service connection.

Billing

The following observations highlight the bill approaches considered by comparators.

10. Ratio of Fixed to Variable Charges

Comparators describe a range of proportions between fixed and variable charges for an average multi-unit customer's DE utility bill. Assuming that fixed charges are intended to recover capital and operating costs and that variable charges simply flow through commodity prices, the fixed proportion is more often higher than the variable proportion. Similar to other utilities, Blatchford, drawing on geothermal, sewer heat recovery, and natural gas boilers for peaking, has a relatively high fixed costs. It was noted as common for utilities to aim to match their cost structure to the fixed and variable rate proportions.

As depicted in Table 12, comparators reported a variety of average proportions between fixed and variable components. Notably, the proportion evidence in DES – Whistler is unique as the only benchmark with no variable component, only a fixed monthly fee based on habitable floor area calculations.

Table 12: Average Multi-unit Customer Bill Proportions by Benchmarking Organization

Comparator	Fixed Charges	Variable Charges
BMDEU – Burnaby	80%	20%
CES – Langford	10%	90%
DES – Surrey	60%	40%
DES – Whistler	100%	0%
LEC – North Vancouver	50%	50%
LIEC - Richmond	No Information Available*	
NEU - Vancouver	50-60%	40-50%

Source: Prepared by KPMG LLP based on information provided by participating district energy utility comparator organization through interviews and written responses to benchmarking questions.
** LIEC – Richmond was unable to provide the requested information within the timeframe of this engagement.*

11. Monthly Billing at the Program Level

Generally, comparators expressed a preference for billing at the building level (e.g., condominium board) and indicated that sub-metering, while allowed and may positively influence end user behavior, often increases the administrative burden to the utility pertaining to billing and obtain right of way for sub-meter reading (i.e., suggested for sub-meters to follow rate design of utility, not only based on consumption). All units benefit from the availability of the development's nominated capacity (i.e., not simply their own usage).

Several comparators (BMDEU - Burnaby, LEC – North Vancouver , NEU - Vancouver and DES – Surrey) bill monthly at the building level. LEC - North Vancouver considered billing at the unit level but determined it would not be cost effective and likely administratively burdensome. DES - Whistler appears to be an outlier in that it bills quarterly directly to individual units; only common areas are billed to the building owner or condominium board.

Future Considerations

The following benchmarking findings offer a forward-looking perspective that may inform future assessments of Blatchford's renewable energy utility rate design.

12. Consideration of the Evolving Utility Context

Rates may similarly evolve as demand for energy may be lower in future as buildings are required to have a lower carbon intensity as a result of changes to municipal strategies, regulations, bylaws and building codes. These may also impact alternatives to DE and influence the relevance of BAU scenarios. For example, the LEC - North Vancouver BAU model (based exclusively on electricity) may no longer be viable as electric baseboard heaters are not allowed under newer building requirements.

13. Revisiting the BAU to Inform Rate Adjustments

The exercise of preparing a BAU analysis and comparing it to DE rates is common practice among benchmarking participants as they developed their initial rate designs. However, some comparators elect to revisit their BAU analysis at a set interval (e.g., annually) to regularly assess actual DE rates and monitor competitiveness. BMDEU – Burnaby, for example, revisited its BAU calculations once the system added a biomass plant and impacted the fixed portion of its rate design.

Some DE utilities suggest making equitable "green-to-green" comparisons when completing BAU analyses. They noted the value of ensuring the BAU analysis is built to be a relevant comparison in terms of the energy efficiency of sample buildings and whether the energy sources are considered "green" (renewable).

Out of Scope Findings

Four observations were collected through the course of the benchmarking exercise were considered beyond the scope of this Study; however, they are included here as supplementary information for the City's consideration.

Connection Fee: LEC - North Vancouver collects a one-time connection fee calculated as a percentage of the nominated capacity – a proxy for the scale of infrastructure investment required to connect the new development. They recommend specifying a minimum fee. There may be a consideration related to customer equity around waiving connection fees for early entrants however, the argument could be made related to the increased risk associated with being among the first to connect to the DE system. For example, NEU – Vancouver and DES – Surrey did not initially charge a connection fee but have since incorporated it for all new DE connections.

Feed Stock: DE utility organizations anticipate changes to their rate structures as systems incorporate new forms of energy, move towards greening their systems and improving GHG emissions. While overall increases in efficiencies may signal longer-term savings, they may require additional investments upfront to realize that potential and integrate cleaner energy sources. Some DE utilities suggest making equitable “green-to-green” comparisons when completing BAU analyses.

Scaling: Several comparators described building out capacity in keeping with the pace of development build out – which is closely linked with requiring developers to express their nominated peak capacity. This allows DE utilities to more effectively scale their capital investment and infrastructure requirements to meet the evolving energy needs in communities.

Responsibility for Infrastructure: Ownership of DE infrastructure located within multi-unit buildings is an important factor in determining responsibility for ongoing operation and maintenance. In hindsight, some comparators, such as DES - Whistler, note that a potential improvement may have been to work with developers to ensure easier access to mechanical rooms and/or secured right of way access to private property. Further, most suggest incorporating the full lifecycle costs of onsite equipment (if owned and operated by the utility) in the BAU analysis (e.g., boilers and chillers that require replacement by building owner or condominium board).

4.4 Options Considered

Options Composition

This section discusses the alternative options that was considered in the process of identifying the recommended rate-setting approach. Based on the findings from BAU analysis and the benchmarking research, three options to determine the rate structure for multi-unit customers were shortlisted and considered:

- **Option 1:** Fixed Charge on Nominated Capacity and Variable Charge on Commodity Consumption
- **Option 2:** Fixed Charge on Floor Area OR Nominated Capacity and Variable Charge on Commodity Consumption

— **Option 3:** Fixed Charge on Floor Area AND Nominated Capacity and Variable Charge on Commodity Consumption

Table 13 illustrates the composition of each alternative option.

Table 13: Composition of Alternative Options

	Option 1: Variable & Fixed – Capacity	Option 2: Variable & Fixed – Area OR Capacity	Option 3: Variable & Fixed – Area AND Capacity
Fixed Charge Component ***Proportion 60-70%***	**All multi-unit customers:** Fixed capacity charge by nominated capacity	**Class 1 (Multi-unit Residential):** Fixed charge by floor area OR **Class 2 (Non-residential):** Fixed capacity charge by nominated capacity	**All multi-unit customers:** Fixed charge by floor area AND Fixed capacity charge by nominated capacity
Variable Charge Component ***Proportion 30-40%***	**All multi-unit customers:** Commodity consumption charge by kilowatt-hour (kWh)		
Total Charges	**All multi-unit customers:** $/kW (nominated capacity) + $/kWh	**Class 1 (Multi-unit Residential):** $/m^2 (floor area) + $/kWh **Class 2 (Non-residential):** $/kW (nominated capacity) + $/kWh	**All multi-unit customers:** $/m^2 (floor area) + $/kW (nominated capacity) + $/kWh

Source: Prepared by KPMG LLP.

Option 1: Fixed Charge on Nominated Capacity

As discussed in Section 4.3, using nominated capacity as the proxy for fixed charge is a common practice observed in other comparator utilities. In particular, LEC - North Vancouver and DES - Surrey Class 2 (non-residential) include a fixed capacity charge based on nominated capacity.

Under Option 1, a monthly variable charge, calculated by kWh consumed, is suggested to be billed at the building level. This methodology of designing variable charge is a common practice by other comparator utilities and conventional natural gas and electricity utilities, aims to recover the utility costs of energy production. This approach is also currently employed by Blatchford DESS for its fee-simple residential townhouses rate structure.

Option 2: Fixed Charge on Floor Area OR Nominated Capacity

A potential categorization of multi-unit customer by type (i.e., residential and non-residential) is suggested for Option 2. Based on findings of comparators' common practice as discussed in Section 4.3, a potential methodology of categorizing residential and non-residential multi-unit customers by percentage of residential uses is as follow:

— Class 1: Residential customers – greater than or equal to 80% of net floor area for residential uses.
— Class 2: Non-residential customers – less than 80% of net floor area for residential uses.

Under this categorization methodology, as depicted in the Blatchford land development plan, 72% of the forecasted multi-unit customers in Blackford would be classified as residential customers, and the remaining 28% as non-residential customers.

Option 3: Fixed Charge on Floor Area AND Nominated Capacity

This was formulated based on a comparator's (LEC) rate-setting approach as observed from the benchmarking research. Under Option 3, a fixed-charge structure with two components is suggested. As the overall DESS system capacity is required to be designed accordingly to be able to service the nominated capacity of the customers, the capital and operation costs of the DESS is highly correlated to the customers' nominated capacity. Thus, a fixed charge by nominated capacity is aimed to recover the capital and operating cost of the DESS. The remaining fixed costs (e.g., administration) are to be recovered by a fixed charge by floor area.

Fixed / Variable Proportions

The recommended proportions of the fixed / variable charges was identified based on the BAU equivalent rate proportions, the benchmarking utilities' fixed / variable revenue and rate proportions, and observations of the Blatchford DESS. Following this Study, the City will be in a position to refine the fixed / variable proportions using relevant inputs from City revenue model.

From the BAU analysis as illustrated in Section 4.2, the range of BAU rate proportions ranged from 43-50% for fixed charge, and 50-57% for variable charge across the two sample multi-unit customer buildings (high density residential and retail mixed use). From the benchmarking research, as depicted in Section 4.3, comparators reported a variety of rate proportion due to the differences in the DE systems specifications. The common range of proportion observed is 50-60% for fixed charge, and 40-50% for variable charge.

To identify the appropriate target rate proportions for Blatchford, these inputs are then filtered through the qualitative observations specifically to the DESS. As per the City and as commonly suggested by comparator utilities, the fixed charge proportion tends to be higher in early phases of the DE system development but tend to decrease over time as economies of scale are achieved, and initial capital costs are recovered.

Moreover, as discussed in Section 4.3, Blatchford, similar to other DE utilities, which draws on geothermal, sewer heat recovery, and natural gas boilers (for peaking) for energy production, may have higher fixed costs than traditional electric and gas utilities. Furthermore, as per the City, Blatchford DESS is anticipated to have relatively low commodity costs, given its reliance primarily on geothermal energy sources. As such, similar to other DE utilities, this also supports having higher proportion of fixed charge as compared to traditional BAU utilities.

For the above mentioned reasons, in the early phase of community's build out in Blatchford, it is recommended that the rate proportion for the DESS multi-unit customers rate structure to be targeted at the range of 60-70% for fixed charge and 30-40% for variable charge. As discussed in Section 4.3, it's common for utilities to aim to match their cost structure to the fixed and variable rate proportions. The proposed "60-70/30-40" split aligns with Blatchford having a higher fixed cost structure.

Relative Comparison of Options

In order to identify the recommended rate-setting approach from the three alternative options, a relative comparison of the options against the set of criteria, as outlined in Section 3.1.1, was conducted. In consultation with the City's project team, the criteria were assumed to be equally important and so are assigned equal weight.

Table 14: Relative Comparison of Alternative Options

	Option 1: Variable & Fixed – Capacity	Option 2: Variable & Fixed – Area OR Capacity	Option 3: Variable & Fixed – Area AND Capacity
Criteria based on Bonbright's Principles			
1. Understandability for multi-unit residential developers	3	1	2
2. Understandability for multi-unit residential residents	2	3	2
3. Revenue stability / predictable fixed cost recovery	1	3	2
4. Rate stability	1	3	2
5. Service cost fairness for multi-unit residential customers	3	1	2

	Option 1: Variable & Fixed – Capacity	Option 2: Variable & Fixed – Area OR Capacity	Option 3: Variable & Fixed – Area AND Capacity
6. Encouragement of usage efficiency (through variable charge)	3	3	3
Other Criteria			
7. Incentive for more energy efficient building design for multi-unit residential customers (through fixed charge)	3	1	2
8. Administration and billing simplicity	3	1	2
Average	2.38	2.00	2.13

3	High alignment with criteria	2	Medium / neutral alignment with criteria	1	Low alignment with criteria

Source: Prepared by KPMG LLP.

Criterion 1: Understandability for Developers

As per the City, all multi-unit developers are required to provide the City with the building's nominated capacity, estimated by their engineers based on the building specifications. Thus, the developers in Blatchford are anticipated to have a good understanding of what nominated capacity is and why it is a fair proxy for their energy fixed charge. Thus, Option 1 has the highest alignment with criterion 1, while option 2, which suggest a two rate classes, is expected to be more difficult for developers to comprehend.

Criterion 2: Understandability for Residents

Residential customers might not be familiar with the technical specifications of the building and how nominated capacity is defined and calculated. Thus, the rationale for using nominated capacity as the proxy for the customers' energy fixed charge, as suggested in Option 1 and 3, might not be easily accepted by end customers. Floor area, in contrast, is a familiar physical measurement that residential customers can easily understand.

Criterion 3: Revenue Stability / Predictable Fixed Cost Recovery

Should nominated capacities among multi-unit customers decrease (either based on higher initial estimates for the development forecast, increases in building efficiency, potential for onsite electrical production, etc.), the DESS may under recover fixed charges as compared to planned budgets. Thus, Option 1 and 3, which rely or partly rely on using nominated capacity as a proxy to recover fixed costs, are expected to achieve a lower level of revenue stability for the DESS. Nonetheless, the City may be able to adjust the rate applied to nominated capacity. However, there may be a time delay where annual revenue requirements are not achieved.

Criterion 4: Rate Stability

Similar to criterion 3, in the event that nominated capacity is lower than the acceptable level for revenue recovery requirements, the DESS may need to increase fixed charge to the customers (in addition to the regular periodic rate increases). Thus, by employing Option 2, which suggest using floor area as the only proxy for fixed charge, the DESS will have more control in forecasting a predictable revenue recovery model that will enable a high level of rate stability for the customers.

Criterion 5: Service Cost Fairness for Multi-unit Customers

Nominated capacity is used as a proxy for fixed charge to promote a level of fairness for the multi-unit customers. Buildings that are anticipated to have higher peak energy needs are expected to estimate a higher nominated capacity at the design phase, which would result in a higher energy fixed charge for those multi-unit customers. Under Option 2, in the event where a building has larger floor area but is more energy efficient and requires lower peak demand, it still has to pay a higher fixed charge, which might not be fair for the customer.

Criterion 6: Encouragement of Energy Usage Efficiency

All three options suggest using actual energy consumption as the proxy for variable charge. This is anticipated to encourage better energy use efficiency among end-users. Understanding that they can directly reduce their energy bill, customers are expected to conserve energy usage and eliminate unnecessary energy consumption.

Criterion 7: Incentive for More Energy Efficient Building Design

As discussed in collaboration with the City, using nominated capacity to calculate the fixed charge is anticipated to provide an incentive for the developers to incorporate green building practices and encourage more energy efficient building design. As summarized in Section 4.3, this benefit is commonly observed at comparator utilities who also implement a fixed charge by nominated capacity. As per the City, there is evidence of interest in the Blatchford's developer community to be able to design for maximum building energy efficiency. Looking ahead, this may also incentivize customers to renovate the buildings to higher energy efficiency standards. Thus, Options 1 and 3 may provide incentives and allow the customers to realize financial rewards from employing more energy efficient design.

Criterion 8: Administration and Billing Simplicity

Option 1, which suggested a two-component rate structure for all multi-unit customers, emphasizes ease of administration and billing simplicity. As stated by the City, information on buildings' nominated capacity for billing purpose are readily accessible and available for all multi-unit customers as they move through the development application process. Moreover, Option 1 reduces the administrative burden that may be associated with identifying and billing separate customer classes. The use of multiple classes was evidenced in the benchmarking exercise and, if the City were to re-assess the need for multiple customers classes, there may be utility software solutions that can mitigate challenges related to administration.

Based on the Study methodology, Option 1 – applying a fixed charge on nominated capacity for all multi-unit customers in addition to a variable consumption charge, was identified as the recommended rate-setting approach as it has the highest alignment with the assessment criteria co-developed with the City of Edmonton. The recommended approach is discussed further in Section 5.

5 Recommended Approach

This section summarizes the identified recommended rate-setting approach as built upon from the previous sections. KPMG's synthesis of findings, culminating from analysis of the customer profile, BAU analysis and benchmarking insights, led to the development of a recommended approach to rate-setting for multi-unit customers, as illustrated in Table 15.

Table 15: Rate Components and Proportions

Rate Structure	Description	Rationale
Customer Class	All multi-unit customers	Employ one uniform rate structure to ensure understandability, transparency, fairness, and simplicity
Fixed Charge ***Proportion 60-70%***	Capacity charge by nominated capacity	In keeping with benchmarked proportions, aims to recover capital, operating, and administration costs
Variable Charge ***Proportion 30-40%***	Commodity consumption charge by $/kWh	In keeping with benchmarked proportions, aims to recover cost of energy production, namely commodity costs

Source: Prepared by KPMG LLP.

5.1 Risks and Mitigations

As illustrated in Section 4.4, among the options explored, there appears to be merit in having a single fixed charge based on nominated capacity for all multi-unit customers. However, the following questions may be examined by the City and mitigation strategies considered, if deemed necessary:

Risk: Potential Under Recovery of the Revenue Requirement (Effect on the DESS)

Should nominated capacities among multi-unit customers decrease (either based on higher initial estimates for the development forecast, increases in building efficiency, potential for onsite electrical production, etc.), the DESS may under recover fixed charge as compared to planned budgets.

Potential mitigating actions that the City may consider include:

— While there may be a time delay where annual revenue requirements are not achieved should nominated capacities decrease beyond forecast levels, the City may be able to adjust the rate applied to nominated capacity. The utility should be able to recover reasonably incurred and approved cost as part of its rate setting and regulatory process (through the monitoring of the deferral account used for the levelized rate approach).

- The DESS will need to monitor planned to actual (i.e., once building design is approved) nominal capacities among multi-unit buildings and gauge the impact on changes in the DESS financial model.
- If indications suggest nominated capacity are lower than an acceptable level of variance, the DESS may need to increase fixed charge to the customers (in addition to the regular periodic rate increase). This may require communication to existing customers who had invested in greater efficiency initially. However, these customers would have benefited from the initial low fixed charge established and continued to benefit from greater efficiency when fixed charges may need to increase. This consideration becomes more relevant as Blatchford nears full build out, as variances in its early stages may be mitigated in planning for future infrastructure investments based on scale.
- The DESS could review building designs during the building permit stage to perform a high-level assessment of the requested nominated capacity submitted by developers for reasonableness.
- The DESS can use forecast and actual peak capacity to inform the timing of capital expenditures for capacity expansions (i.e., scale costs to match the pace of development).
- For both the DESS' and customers' benefit and to promote service cost fairness, a review protocol may be required for customers whose actual capacity are consistently different from the nominated capacity submitted during the building design stage.

Risk: Limited Flexibility to Reflect Unique Building System Lifecycle Costs (Effect on the DESS and its customers)

A single uniform fixed charge assumes that each multi-unit building is charge similarly based on its nominated capacity (i.e., nominated capacity is the only variable to differentiates fixed charges between customers). However, the City may need to consider other variables/factors that can impact the fixed costs for the DESS delivery services (e.g., fixed costs such as administration and billing, utility connection, ETS) regardless of nominated capacity.

Considerations for the City when examining this potential risk may include:

- In the event where it is more expensive (e.g., administration costs, equipment maintenance and replacement) for the DESS to provide services to a larger building with the same nominal capacity as a smaller building, the DESS might need to consider introducing other rate component or one-time fee to ensure rate fairness.
- Following this Study, if there is additional information that becomes available which suggested that there are factors other than nominal capacity that might influence the capital, operation, or administration costs for the DESS, the City might need to reevaluate the appropriateness of using nominated capacity as the sole proxy for the recovery of fixed costs.

In order to mitigate this potential risk, the DESS may consider exploring other cost recovery mechanisms such as:

— Infrastructure / connection fee (out of scope for this engagement) that may be used to recover one-time capital costs. However, it will be important for the Utility to forecast and assess the lifecycle cost of service among multi-unit customers for the building specific utility infrastructure (e.g., energy transfer stations), which may warrant a surcharge for the higher level of services required by the customer.
— Fixed costs that may be unique for a multi-unit building (e.g., a hypothetical scenario of larger building with greater costs to service despite similar nominated capacity, or a building that requires two energy transfer stations for on-site distribution).

Risk: Understandability of Nominated Capacity by Multi-unit Building Residents and Tenants (Effect on end use customers)

As mentioned, all multi-unit developers are required to provide the City with the building's nominated capacity, estimated by their engineers based on the building specifications. Thus, the developers in Blatchford are anticipated to have a good understanding of what nominated capacity is and why it is a fair proxy for their energy fixed charge. However, this might not be the case for end use customers. End use customers might not be familiar with the technical specifications of the building and how nominated capacity is defined and calculated. Thus, the rationale for using nominated capacity as the proxy for the customers' energy fixed charge might not be easily accepted by end use customers.

Potential mitigating actions that the City may consider include:

— While some building owners or condominium boards may have a higher degree of familiarity with building energy requirements and nominated capacity (as compared to individual unit residents), it might be necessary for the DESS to increase communication and education efforts to explain the proposed fixed component of the DESS customer's bill.
— Although sub-metering is currently assumed not to be offered by the DESS, the City may consider providing some guidance to support the strata in developing an appropriate approach to translate the fixed nominal charges to per unit charges, if required.

5.2 Next Steps and Future Considerations

Next Steps

Subsequent to the approval of the recommended rate-setting approach through City Council's Utility Committee, it is anticipated that the City will need to perform the following actions in order to finalize the design of the rate structure for multi-unit customers in Blatchford.

Next Step: Calculation of the Actual Rates

Equipped with the results of this Study, the City will be in a position to prepare a final utility rate based on the refined approach and relevant inputs from City revenue model. Consideration are to be given to the revenue recovery requirements of the DESS, the cost of services occurred by the DESS to produce, distribute, and administrate utility energy to the customers in Blatchford, and other cost and revenue drivers.

Next Step: Technical Definition of Nominated Capacity

As identified in the recommended approach, nominated capacity is suggested to be the sole proxy for fixed charge in the early phase of the DESS development. Thus, it is crucial that the technical definition of nominated capacity is thoroughly examined and established by the City to ensure appropriate fixed costs recovery. As a reference, nominated capacity is defined by some comparator utilities as the instantaneous peak demand that the building would need to pull from the system to satisfy its energy consumption during the coldest day of the year. As those comparators do not provide cooling, the City may consider both the hottest and coldest days of the year to determine the highest forecasted peak draw of the DESS. To that end, the City will also need to investigate the proper approach to consider the difference in nominated capacity for heating and cooling purposes.

Future Considerations

As the DESS moves toward the later stage of community development and mature, additional information surrounding the assumptions and unknown factors at the present will become available. This will allow the DESS to make new considerations to refine the rate-setting approach optimize the design of the rate structure. In addition to the next steps that the City will need to take in order to calculate the actual utility rates, following are some of the future considerations for the City moving forward.

Future Consideration: Reevaluation of Rate-setting Approach for Institutional Customers

As depicted in Section 4.1, it is forecasted that the construction of the majority of business industrial, civic, office mixed use, and NAIT buildings will be completed between 2030 and 2035. These are likely customers with large connection sizes and high capacity demand who have a wide array of differences in energy consumption patterns, peak loads and energy intensity.

As per the City, to meet their large capacity demand, a more advanced ETS system, which are more expensive for the DESS to maintain and eventually replace, would potentially require to be installed for these customers. Thus, a potential revaluation of the rate-setting approach prior to the connection of the institutional customers with consideration for a privately negotiated contract with NAIT might be warranted.

There are several methods that the City may consider in order to promote rate appropriateness and fairness among institutional customers. A common practice employed by comparator utilities (e.g., LEC - North Vancouver) to is to introduce an infrastructure / connection fee as a one-time payment to recover the disparity in capital costs. Another method is to negotiate a private contract with customized rate structure for selected institutional customers. As mentioned in Section 4.3, BMDEU - Burnaby negotiated a contract with an additional annual surcharge for SFU to ensure accommodation for energy use requirements and availability.

Future Consideration: Separate Rate Structure for Heating and Cooling

As suggested by the City, there may be different thermal energy and electrical requirements to provide similar level of heating and cooling outputs. As a result, there may be merit for the DESS to explore employing different rate structure to provide for heating and cooling to customers.

Future Consideration: Re-evaluation of Rate-setting Approach for Fee-simple Townhouse Customers

As summarized in Section 3.2, for this Study, as established with the City, the rate-setting approach for fee-simple townhouse is out of the scope of analysis and assumed to be not changed. However, it should be noted that there are findings from the benchmarking research, as included in Section 4.3, of a rate-setting approach employed by some comparator utilities in which a uniform rate structure is applied for both fee-simple townhouse and multi-unit residential customers.

Moreover, the implementation of the new utility rates for multi-unit customers might have impacts on the current rate-setting approach for fee-simple townhouse, given the difference in how fixed charge is determined. Thus, to enable rate appropriateness and fairness for both fee-simple townhouse and multi-unit customers, further investigation by the City can be conducted to evaluate the benefits and drawbacks of revaluating the rate structure for fee-simple townhouse customers, as well as potential cross subsidization as the utility matures.

Appendix A: BAU Definition and Methodology

A.1 BAU Definition

Table 16 summarizes the definition of BAU that was used by comparator organizations as part of their approach for establishing a utility rate for customers who connect to the DE systems.

Table 16: Definition of Business as Usual By Comparators

Comparator	Service Provided	BAU Definition
Blatchford District Energy (BAU model); Edmonton, AB	— Space heat — Space cooling — Domestic hot water	Heating, cooling and domestic hot water costs billed by natural gas and electricity utilities to efficient customers elsewhere in Edmonton
Lulu Island Energy Company (LIEC); Richmond, BC	— Space heat — Space cooling — Domestic hot water	No information available
Burnaby Mountain District Energy Utility (BMDEU) – SFU; Burnaby, BC	— Space heat — Domestic hot water	Heating and domestic hot water costs incurred under natural gas and electricity utilities
Whistler Cheakamus Crossing District Energy System (DES); Whistler, BC	— Space heat — Domestic hot water	Costs incurred using natural gas baseboard heating
Southeast False Creek Neighbourhood Energy Utility (NEU); Vancouver, BC	— Space heat — Domestic hot water	Heating and domestic hot water costs incurred under natural gas, electricity, and thermal utilities
Lonsdale Energy Corporation (LEC); North Vancouver, BC	— Space heat — Domestic hot water	Heating and domestic hot water costs incurred under FortisBC and other district energy system

Comparator	Service Provided	BAU Definition
City of Surrey District Energy System (DES); Surrey, BC	— Space heat — Domestic hot water	Heating and domestic hot water costs incurred under natural gas and electricity utilities and other district energy system
Community Energy System (CES); Langford, BC	— Space heat — Space cooling — Domestic hot water	No information available

Source: Prepared by KPMG LLP based on information provided by participating district energy utility comparator organization.

A.2 BAU Analysis Methodology

The methodology to perform the BAU analysis consists of three steps, including gather data, analyze, and identify findings.

Step 1: Gather Data

Two sample multi-unit customer buildings, high density residential and retail mixed use, were identified by the City as representative of the forecasted multi-unit customers who will connect to the DESS. The objective of the BAU analysis was set to develop the BAU equivalent bills and calculate the rate proportions for the two sample multi-unit customer buildings, which will help provide the City with perspectives on the rate-setting approach for multi-unit customers in Blatchford.

In order to develop the BAU equivalent bills, two groups of input data are needed: BAU energy commodity requirements and conventional utilities rates. The estimated natural gas and electricity commodity requirements and peak demand to achieve equivalent space heating, space cooling and heating for domestic hot water outputs are provided by the City of Edmonton.[4] Historical natural gas rates from 2018-2022, including energy charges and delivery charges, were sourced from ATCO Gas and Encor by EPCOR, as published on the companies' websites.[5] Historical electricity rates were similarly sourced from EPCOR.[6]

Other information to help support the robustness of the BAU analysis are also gathered through various sources. Publicly available Information on conventional utilities regulations, municipal franchise fee, and federal carbon tax are acquired from the websites of City of Edmonton, Government of Alberta, and Government of Canada. Clarification on the customer classification for electricity delivery charges was obtained by contacting EPCOR customer services. Input data is further discussed in Appendix B: Model Inputs.

Step 2: Analyze

A set of assumptions were developed and documented to construct the BAU model's parameters. The full list of all assumptions for the BAU analysis is included in Appendix B: Model Inputs and Appendix C: BAU Equivalent Bills and Proportion.

BAU equivalent bills for the sample multi-unit customer buildings are developed by multiplying the expected natural gas and electricity energy consumption and peak demand with the conventional utility rates. As mentioned, both sample buildings are classified as mid use (delivery service 1200-8000 GJ/yr) for BAU natural gas delivery charges. For natural gas energy use charges, the five-year fixed rate is chosen to be applied to the BAU equivalent bills as it is the lower of the 2 available rate options for the customers. The five-year historical average natural gas energy use and delivery charges for this customer class are calculated and grouped into fixed rate ($1.83 / day) and variable rate ($0.027 / kWh). As provided by the City, the estimated annual natural gas commodity requirements for the high density residential and retail mixed use buildings are 578 MWh and 1,997 MWh respectively.

The electricity charges of the BAU equivalent bills are calculated in a similar method. The sample buildings are classified as commercial/industrial 150 kVA to < 5000 kVA for electricity delivery charges. For electricity energy use charges, the default supply hedged rate is chosen to be applied to the BAU equivalent bills as it is the lower of the 2 available rate options for this customer class. The electricity charges are calculated and grouped into fixed rate ($34.83 / day), variable rate on total consumption ($0.115 / kWh), excess variable rate on on-peak consumption ($0.0141 / kWh), and demand rate ($0.462 / kWh). As provided by the City, the estimated annual electricity total commodity requirements for the high density residential and retail mixed use buildings are 116 MWh and 499 MWh respectively. The estimated annual electricity on-peak commodity requirements for the two sample buildings are 50 MWh and 215 MWh. The estimated electricity peak demand for the two sample buildings are 97 kW and 429 kW. Further detail on the data sources and calculations are included in Appendix B: Model Inputs.

Step 3: Identify Findings

From the analysis and inputs calculated in Step 2: Analyze, the BAU equivalent bills are developed. Key findings illustrated in the BAU equivalent bills include the utility costs charged to BAU multi-unit customers from natural gas and electric utilities to achieve similar energy outputs; and the fixed/variable rate proportions billed by conventional utilities in Edmonton.

Appendix B: Model Inputs

B.1 Natural Gas BAU Rates

Assumptions

a. Given the estimated BAU natural gas commodity requirements for the sample multi-unit customer buildings as provided by the City, both buildings would be classified as mid use (delivery service 1200-8000 GJ/yr) for natural gas delivery charges

b. Historical natural gas delivery charges are sourced from ATCO Gas which include fixed charge, variable energy charge, 24 hour demand charge, and riders (source ATCO Gas | Rates and Billing, accessed August 2022).

c. Natural gas delivery charges (exclude federal carbon tax) are grossed up from the regulatory posted rate by 35% to account for the franchise fee paid to City of Edmonton (source: ATCO Gas | North Rate Schedule, accessed August 2022).

d. Municipal franchise fee is only applied to delivery charges and exclude energy charges (Source: City of Edmonton | Municipal Franchise Fees White Paper, accessed August 2022).

e. Federal carbon tax is only applied to natural gas bills. No carbon tax is applied to electricity bills (source: ATCO Gas Understand Your Energy Bill, accessed August 2022).

f. Historical federal carbon tax is sourced from ATCO Energy. Federal carbon tax is billed by natural gas distributors on behalf of the federal government starting from January 2020 (source: ATCO Energy | Alberta Natural Gas Rates and Prices, accessed August 2022).

g. Historical natural gas regulated rates (RRO) and five-year fixed rates are sourced from Encor by EPCOR (source: Encor by EPCOR | Natural Gas Rates History, accessed August 2022).

h. Historical admin charges are sourced from Encor by EPCOR (source: Encor by EPCOR | Natural Gas Plans and Rates, accessed August 2022).

i. For natural gas energy charge, the five-year fixed rate is chosen to be used in the BAU model over the RRO as the former is lower in 2022. We assumed that a rational customer elsewhere in the City of Edmonton would choose the lower electricity rate offering.

j. Delivery charges calculation excludes utility payment deferral program rider H as it was only in effect from November 2021 to February 2022 (source Alberta.ca | Utility Payment Deferral, accessed August 2022).

k. Delivery fixed charges calculation includes distribution fixed charge, fixed charge riders, and franchise fee.

l. Delivery variable charges calculation includes variable energy charge, variable charge riders, franchise fee, and federal carbon tax.

m. Delivery demand charges calculation includes 24-hour demand charge, demand charge riders, and franchise fee.

n. Variable gas rates are converted from $/GJ to $/kWh using a factor of 277.778. This was done as thermal rates charged by the District Energy utility are measured in $/kWh.

BAU Model

Table 17 below shows the annual average natural gas energy use and delivery charges from 2018-2022 in Edmonton. As mentioned, the mid-use customer class for natural gas delivery charges is applied to both sample multi-unit customer buildings.

Table 17: 2018-2022 Historical Natural Gas Energy Use and Delivery Charges in Edmonton – Mid-use Customer Class

Mid Use (Delivery Service 1200-8000 GJ/Yr)																	
	Fixed Chg			Variable En Chg	Tr. Serv Chg	Variable Chg	Load Balance	Variable Chg	Weather Def Act	Carbon Tax	Natural Gas Energy Charges			Delivery Charges		Total Charges	
	Fixed Chg	Rider H	Rider S		Rider T	Rider H	Rider L	Rider S	Rider W		RRO Rate	5-yr Fixed	Ad. Chg	Fixed	Variable	Fixed	Variable
Year	($/day)	($/day)	($/day)	($/GJ)	($/GJ)	($/GJ)	($/GJ)	($/GJ)	($/GJ)	($/GJ)	($/GJ)	Rate ($/GJ)	($/day)	($/day)	($/GJ)	($/day)	($/GJ)
2018	0.878	0	0	0.836	0.584	0	0	0	0	N/A	1.695	4.190	0.230	1.18496	1.91711	1.41496	6.10711
2019	0.930	0	0.041	0.923	0.809	0	0	0.042	-0.027	N/A	1.908	3.757	0.230	1.31096	2.35856	1.54096	6.11523
2020	0.916	0	0.007	0.912	0.776	0	0	0.007	-0.052	1.445	2.293	3.740	0.230	1.24605	3.66229	1.47605	7.40229
2021	0.916	0	0.048	0.912	1.011	0.006	0	0.055	-0.026	1.971	3.697	4.007	0.230	1.30140	4.60621	1.53140	8.61288
2022	2.025	0	0.162	1.124	1.030	0.011	0	0.079	0	2.403	5.689	4.704	0.230	2.95245	5.41770	3.18245	10.12199

Source: Prepared by KPMG LLP with publicly available information.

The grouping of natural gas energy use and delivery charges into fixed and variable charges is depicted in Table 18 below. Calculation of the five-year historical average charges was also performed. This will be used as inputs to develop the BAU equivalent bills.

Table 18: Summary of Historical Natural Gas Rates – Mid-use Customer Class

Charges	Unit		2018	2019	2020	2021	2022	5-yr Average	5-yr Average (kWh)	July 2022	July 2022 (kWh)
Natural Gas Energy Charges											
Natural Gas Usage Charge (5-yr Fixed Rate)	$/GJ		4.19000	3.75667	3.74000	4.00667	4.70429	4.07952	0.01469	5.49000	0.01976
		Annual Change	*N/A*	*-10.34%*	*-0.44%*	*7.13%*	*17.41%*	*3.44%*			
Administration Charge	$/day		0.23000	0.23000	0.23000	0.23000	0.23000	0.23000		0.23000	
		Annual Change	*N/A*	*0.00%*	*0.00%*	*0.00%*	*0.00%*	*0.00%*			
Delivery Charges											
Delivery Fixed Charges (including Riders)	$/day		1.18496	1.31096	1.24605	1.30140	2.95245	1.59917		2.73375	
		Annual Change	*N/A*	*10.63%*	*-4.95%*	*4.44%*	*126.87%*	*34.25%*			
Delivery Variable Charges	$/GJ		1.91711	2.35856	3.66229	4.60621	5.41770	3.59238	0.01293	5.53681	0.01993
(including Riders, Franchise Fee and Carbon Tax)		*Annual Change*	*N/A*	*23.03%*	*55.28%*	*25.77%*	*17.62%*	*30.42%*			
Total Fixed Charges	$/day		**1.41496**	**1.54096**	**1.47605**	**1.53140**	**3.18245**	**1.82917**		**2.96375**	
		Annual Change	*N/A*	*8.90%*	*-4.21%*	*3.75%*	*107.81%*	*29.06%*			
Total Variable Charges	$/GJ		**6.10711**	**6.11523**	**7.40229**	**8.61288**	**10.12199**	**7.67190**	**0.02762**	**11.02681**	**0.03970**
		Annual Change	*N/A*	*0.13%*	*21.05%*	*16.35%*	*17.52%*	*13.76%*			

Source: Prepared by KPMG LLP with publicly available information.

B.2 Electricity BAU Rates

Assumptions

a. Given that the sample multi-unit customer buildings will have a central electricity commercial meter and electricity sub-meter for individual unit, under BAU the buildings would be classified as commercial for electricity energy use and delivery charges (Source: information provided by EPCOR agent in August 2022).

b. Given the estimated BAU electricity peak loads for the sample multi-unit customer buildings as provided by the City, both buildings would be classified as commercial/industrial 150 kVA to < 5000 kVA for electricity delivery charges.

c. Historical electricity delivery charges are sourced from EPCOR Utilities Inc. which include distribution charges, transmission charges, riders, and local access fee (source EPCOR | Tariff Schedules, accessed August 2022).

d. Local access fee is billed by EPCOR on behalf of City of Edmonton to allow access to municipal lands (Source: EPCOR | Tariff Schedules, accessed August 2022).

e. Historical admin charges are sourced from EPCOR Utilities Inc. (Source EPCOR | Tariff Schedules, accessed August 2022).

f. Delivery charges calculation excludes utility payment deferral program rider L as it was only in effect from Nov 2021 to Feb 2022 (Source: Alberta.ca | Utility Payment Deferral, accessed August 2022).

g. Based on information provided by the City, the estimated annual electricity consumption of the sample multi-unit customer buildings exceed 250 MWh. Therefore, BAU sample buildings would not be eligible for electricity RRO or five-year fixed rate and would be enrolled for default supply energy charges (Source: EPCOR | Default Supply Historical Electricity Rates, accessed August 2022).

h. Historical default supply energy charge rates are sourced from EPCOR Utilities Inc. (Source: EPCOR | Default Supply Historical Electricity Rates, accessed August 2022).

i. For commercial/industrial electric energy charge, the default supply hedged rate is chosen to be used in the BAU model over the default supply flow-through rate as the former's five-year historical average rate is lower. We assumed that a rational customer elsewhere in the City of Edmonton would choose the lower electricity rate offering.

j. Delivery fixed charges calculation includes distribution fixed charge.

k. Delivery variable charges calculation includes distribution variable charge, transmission variable charge, riders, and local access fee.

l. Delivery demand charges calculation includes distribution demand charge, transmission demand charge and OSS charge.

BAU Model

Table 19 below shows the annual average electricity energy use and delivery charges from 2018-2022 in Edmonton. As mentioned, the commercial/industrial 150 kVA to < 5000 kVA customer class for electricity delivery charges is applied to both of the sample multi-unit customer buildings.

Table 19: 2018-2022 Historical Electricity Energy Use and Delivery Charges in Edmonton – Commercial/Industrial 150 kVA to < 5000 kVA Customer Class

Commercial/Industrial 150 kVA to < 5000 kVA - Secondary (DAS-TOU/SAS-TOU)															
	Distribution Access					Tr. Access								Electric Energy Charges	
Year	Cust Chg ($/day)	Dem Chg ($/kW/day)	En Chg - Onpk ($/kWh)	En Chg - Offpk	Rider DJ En Chg - Onpk	En Chg ($/kWh)	Dem Chg ($/kW/day	OSS Chg ($/kW/day	Rider J En Chg ($/kWh)	Rider K En Chg ($/kWh)	Rider G En Chg ($/kWh)	Rider L En Chg ($/kWh)	LAF ($/kWh)	DS Flow-through	DS Hedged ($/kWh)
2018	31.67532	0.08059	0.01080	0.00000	-0.00120	0.00218	0.38181	0.00124	-0.00186	0.00087	0.00318	N/A	0.00810	0.07474	0.07870
2019	33.67039	0.08566	0.01148	0.00000	0.00384	0.02240	0.39371	0.00100	0.00032	0.00043	0.00297	N/A	0.00850	0.07934	0.08370
2020	35.17647	0.08949	0.01200	0.00000	0.00324	0.00217	0.40365	0.00083	0.00129	0.00056	0.00256	N/A	0.00900	0.07082	0.07501
2021	36.71552	0.09342	0.01253	0.00000	0.00265	0.00220	0.43082	0.00066	-0.00076	-0.00492	0.00236	0.00043	0.00970	0.13560	0.12109
2022	36.91655	0.09376	0.01255	0.00000	0.00265	0.00219	0.25202	0.00059	-0.00255	-0.00122	0.00226	0.00039	0.00990	0.14169	0.13790

Commercial/Industrial 150 kVA to < 5000 kVA - Secondary (DAS-TOU/SAS-TOU)							
	Delivery Charges				Total Charges		
Year	Fixed ($/day)	Variable - Total	Variable - On-peak ($/kWh)	Demand + OSS	Fixed ($/day)	Variable ($/kWh)	Demand ($/kWh/da
2018	31.67532	0.01247	0.00960	0.46364	31.67532	0.09117	0.46364
2019	33.67039	0.03462	0.01532	0.48037	33.67039	0.11832	0.48037
2020	35.17647	0.01557	0.01524	0.49396	35.17647	0.09058	0.49396
2021	36.71552	0.00858	0.01518	0.52490	36.71552	0.12967	0.52490
2022	36.91655	0.01058	0.01520	0.34637	36.91655	0.14848	0.34637

Source: Prepared by KPMG LLP with publicly available information.

Table 20 below summarizes the grouping of electricity energy use and delivery charges into fixed and variable charges. Calculation of the five-year historical average charges was also performed. This will be used as inputs to develop the BAU equivalent bills.

Table 20: Summary of Historical Electricity Rates – Commercial/Industrial 150 kVA to < 5000 kVA Customer Class

Charges	Unit		2018	2019	2020	2021	2022	5-yr Average	July 2022
Electric Energy Charges									
Electricity Usage Charge (Default Supply Hedged Rate)	$/kWh		0.07870	0.08370	0.07501	0.12109	0.13790	0.09928	0.18340
		Annual Change	*N/A*	*6.35%*	*-10.38%*	*61.44%*	*13.88%*	*17.82%*	
Delivery Charges									
Delivery Fixed Charges (including Riders)	$/day		31.67532	33.67039	35.17647	36.71552	36.91655	34.83085	36.91655
		Annual Change	*N/A*	*6.30%*	*4.47%*	*4.38%*	*0.55%*	*3.92%*	
Delivery Variable Charges - Total (including Riders and LAF)	$/kWh		0.01247	0.03462	0.01557	0.00858	0.01058	0.01636	0.02614
		Annual Change	*N/A*	*177.61%*	*-55.02%*	*-44.90%*	*23.31%*	*25.25%*	
Delivery Variable Charges - On-peak (including Riders and LAF)	$/kWh		0.00960	0.01532	0.01524	0.01518	0.01520	0.01411	0.01520
		Annual Change	*N/A*	*59.49%*	*-0.47%*	*-0.41%*	*0.13%*	*14.68%*	
Delivery Demand Charges (Including OSS)	$/kW/day		0.46364	0.48037	0.49396	0.52490	0.34637	0.46185	0.23892
		Annual Change	*N/A*	*3.61%*	*2.83%*	*6.26%*	*-34.01%*	*-5.33%*	
Total Fixed Charges	$/day		**31.67532**	**33.67039**	**35.17647**	**36.71552**	**36.91655**	**34.83085**	**36.91655**
		Annual Change	*N/A*	*6.30%*	*4.47%*	*4.38%*	*0.55%*	*3.92%*	
Total Variable Charges - Total	$/kWh		**0.09117**	**0.11832**	**0.09058**	**0.12967**	**0.14848**	**0.11564**	**0.20954**
		Annual Change	*N/A*	*29.78%*	*-23.44%*	*43.16%*	*14.50%*	*16.00%*	
Total Variable Charges - On-peak	$/kWh		**0.00960**	**0.01532**	**0.01524**	**0.01518**	**0.01520**	**0.01411**	**0.01520**
		Annual Change	*N/A*	*59.49%*	*-0.47%*	*-0.41%*	*0.13%*	*14.68%*	
Total Demand Charges	$/kW/day		**0.46364**	**0.48037**	**0.49396**	**0.52490**	**0.34637**	**0.46185**	**0.23892**
		Annual Change	*N/A*	*3.61%*	*2.83%*	*6.26%*	*-34.01%*	*-5.33%*	

Source: Prepared by KPMG LLP with publicly available information.

B.3 Sample Multi-unit Customer Buildings

Assumptions

a. The scope of multi-unit customers includes building/structures with more than one dwelling/business with a single connection/meter to DESS Mechanical system description for BAU assumed baseline building mechanical system type. Assuming the same water-air heat pump in customer suites allows easier "apples to apples" comparison between DES and BAU (both provide cooling, similar maintenance, capital cost, etc.). Other BAU building HVAC system options exist and could be evaluated (Source: Energy Usage for Blatchford Sample Multi-unit Customers, September 20, 2022).

b. DESS mechanical system description: Water-to-air heat pump in each customer dwelling unit providing heating and cooling to the suite with electricity paid by the customer at the same rate as their other in-suite electric loads.

   Central ETS is owned by the Utility and contains heat pumps and peaking gas boilers to provide: DHW heating, and hot water for garage space heating and driveway snowmelt heating. Boiler also provides backup/peaking energy for the space HP loop. Electricity and gas used by the ETS are paid by the customer at the building-level gas/electric meter rates.

   Net DESS thermal heating and cooling energy is metered at one ETS meter for all loads in the building (Source: Energy Usage for Blatchford Sample Multi-unit Customers, September 20, 2022).

c. BAU mechanical system description: Water-to-air heat pump in each customer dwelling unit providing heating and cooling to the suite with electricity paid by the customer at the same rate as their other in-suite electric loads. (Same as DESS).

   Central mechanical room is owned by the Customer and contains gas boilers to provide all: space heating thermal energy to the HP loop, DHW heating, and hot water for garage space heating and driveway snowmelt heating. Mechanical room includes cooling tower for waste heat rejection in summer. Electricity and gas used by the mechanical room are paid by the customer at the building-level gas/electric meter rates (Source: Energy Usage for Blatchford Sample Multi-unit Customers, September 20, 2022).

BAU Model

As depicted in Table 21, descriptions of the identified sample multi-unit customer buildings is provided by the City of Edmonton. Both buildings are comprised of floor area intended for commercial and residential uses. Commercial uses occupied 6.5% of total floor area of the high density residential building, while that of the retail mixed use building is 20.0%.

Table 21: Sample Multi-unit Customer Buildings Descriptions

Building Specification	High Density Residential	Retail Mixed Use
Lot Size (ha)	0.34	1.22
Expected # of Dwelling Units	102	335
Probable Accessible Building Floor Area (m^2)	9,098	35,078
Commercial (m^2)	595	7,088
Residential (m^2)	8,503	27,989

Source: Prepared by KPMG LLP with information provided by the City of Edmonton, September 20, 2022.

B.4 Energy Use Requirements

Assumptions

a. The BAU billing approach for the sample multi-unit customer buildings is assumed to be at the building level. This approach assumed the same rates and billing treatment for the residential and commercial floor areas of the building. Thus, the estimated energy use and commodity requirements are for the whole building.

BAU Model

The annual energy consumption requirements of the sample multi-unit customer buildings are summarized in Table 22 below. Energy uses include space heating, space cooling, heating for domestic hot water, snowmelt heating, and garage heating.

Table 22: Estimated Energy Use Requirements

Energy Use	Unit	High Density Residential	Retail Mixed Use
Annual Space Heating	MWh	168	720
Annual Space Cooling	MWh	279	1,193

Energy Use	Unit	High Density Residential	Retail Mixed Use
Annual DHW	MWh	187	851
Annual Snowmelt Heating	MWh	133	133
Annual Garage Heating	MWh	25	95
Total Energy Use Requirements	**MWh**	**790**	**2,991**

Source: Prepared by KPMG LLP with information provided by the City of Edmonton, September 20, 2022.

B.5 BAU Commodity Requirements

Assumptions

a. Under BAU, gas and electricity are used in order to deliver the Energy Use (Outputs) Requirements.

b. Under BAU, one boiler plant is assumed to serve all loads within the building (Source: Energy Usage for Blatchford Sample Multi-unit Customers, September 20, 2022).

c. Under BAU, space cooling commodity requirement includes cooling tower electricity (Source: Energy Usage for Blatchford Sample Multi-unit Customers, September 20, 2022).

d. Under BAU, internal energy sharing for DHW is assumed to be zero as there is a separate DHW system in BAU building (Source: Energy Usage for Blatchford Sample Multi-unit Customers, September 20, 2022).

e. Annual other electricity consumptions (e.g., plug loads, elevators, household appliances) are estimated at 65 kWh per square meter for sample multi-unit customer buildings. Annual other electricity consumptions are only used to determine the classification of electricity delivery charges. As each units have individual electricity sub-meter and would pay for these consumptions regardless, other electricity consumptions are excluded from BAU bills (Source: Energy Usage for Blatchford Sample Multi-unit Customers, September 20, 2022).

f. The BAU analysis is performed on efficient customers elsewhere in Edmonton. Efficient customers are assumed to have similar energy efficiency and intensity as the new multi-unit customers to be built in Blatchford.

g. Under BAU, the percentage of total electricity consumption occur during peak hours (Monday to Friday 8:00 AM to 9:00 PM, excluding statutory holidays) is estimated by taking the three-year historical average of the medium commercial on-peak electricity consumption percentage (Source: Information provided by EPCOR through the City of Edmonton in August 2022).

BAU Model

The estimated total BAU natural gas and electricity commodity requirements for the sample multi-unit customer buildings are depicted in Table 23 below.

Table 23: Estimated Total BAU Commodity Requirements

Commodity Requirement	Unit	High Density Residential	Retail Mixed Use
Space Heating			
Space Heating - Natural Gas	MWh	159	683
Space Heating - Electricity	MWh	37	160
Space Cooling			
Space Cooling - Electricity	MWh	79	339
DHW			
DHW - Natural Gas	MWh	227	1,037
Garage and Snowmelt Heating			
Garage and Snowmelt Heating - Natural Gas	MWh	192	277
Total Natural Gas Requirements	**MWh**	**578**	**1,997**
Total Electricity Requirements	**MWh**	**117**	**499**

Source: Prepared by KPMG LLP with information provided by the City of Edmonton, September 20, 2022.

The following Table 24 shows the annual average percentage of electricity consumption of medium commercial customers in Edmonton from 2019-2021 that occurred on peak hours, as provided by EPCOR to the City. Peak hours is defined by EPCOR as from Monday to

Friday 8:00 AM to 9:00 PM, excluding salutary holidays. The estimated on-peak BAU electricity commodity requirements will be calculated by multiplying the three-year average percentage with the estimated total BAU commodity requirements as showed in Table 23.

Table 24: Estimated On-peak Electricity Commodity Requirements

Customer Class	2019	2020	2021	3-yr Average
Medium Commercial	42.96%	42.85%	43.44%	**43.08%**

Source: Prepared by KPMG LLP with information provided by the City of Edmonton, September 21, 2022.

The estimated BAU peak electricity demand, which measure the highest capacity that the sample multi-unit customer buildings would require to draw from the power grid to meet the energy outputs, is summarized in Table 25 below.

Table 25: Estimated Electricity Peak Demand

Electricity Peak Demand	Unit	High Density Residential	Retail Mixed Use
Space Heating	kW	28	145
Space Cooling	kW	69	284
DHW	kW	0	0
Garage and Snowmelt Heating	kW	0	0
Total Electricity Peak Demand	**kW**	**97**	**429**

Source: Prepared by KPMG LLP with information provided by the City of Edmonton, September 21, 2022.

The estimated BAU electricity consumption for other energy uses (e.g., plug loads, elevators, appliances, etc.) of the sample multi-unit customer buildings are depicted in Table 26, on the following page. Together with the estimated electricity consumption for heating, cooling, and DHW, this helped determine the buildings' customer class (commercial/industrial 150 kVA to < 5000 kVA) for electricity delivery charges. However, as mentioned, the electricity consumption for other energy uses was not included in the BAU equivalent bills.

Table 26: Estimated Electricity Consumption for Other Energy Uses

Electricity Peak Demand	Unit	High Density Residential	Retail Mixed Use
Annual Other Electricity Consumption	MWh/m^2	0.065	0.065
Probable Accessible Building Floor Area (m^2)	m^2	9,098	35,078
Total Annual Other Electricity Consumption	**MWh**	**591**	**2,280**

Source: Prepared by KPMG LLP with information provided by the City of Edmonton, September 21, 2022.

B.6 BAU Model Inputs

Assumptions

a. Infrastructure / connection fee is excluded from the scope of the BAU analysis

b. Maintenance cost is excluded from the scope of the BAU analysis

c. Electricity peak demand used in the calculation of the BAU equivalent bills excluded peak demand from other energy uses (e.g., plug loads, elevators, appliances).

BAU Model

The inputs used in developing the BAU equivalent bills and other outputs of the BAU model are summarized in this section. Sources and calculations of the inputs are included in the previous sections of Appendix B: Model Inputs.

Table 27, on the following page, summarizes the inputs of natural gas and electricity rates that would be charged by conventional utilities to the BAU equivalent multi-unit customers buildings elsewhere in Edmonton.

Table 27: Inputs for Natural Gas and Electricity Rates

Rate	Unit	Amount
Electricity Rates		
Electricity Fixed Rate	$/day	34.83085
Electricity Variable Rate - Total Consumption	$/kWh	0.115644
Electricity Variable Rate - On-peak Consumption	$/kWh	0.014108
Electricity Demand Rate	$/kW/day	0.461848
Natural Gas Rates		
Natural Gas Fixed Rate	$/day	1.82917
Natural Gas Variable Rate	$/kWh	0.02762

Source: Prepared by KPMG LLP with publicly available information.

Table 28 shows the inputs of the estimated BAU natural gas and electricity commodity requirements required to achieve equivalent space heating, space cooling, and heating for domestic hot water outputs.

Table 28: Inputs for Estimated BAU Commodity Requirements

Commodity Requirement	Unit	High Density Residential	Retail Mixed Use
Total Commodity Requirement			
Total Natural Gas Requirements	MWh	578	1997
Total Electricity Requirements	MWh	117	499
On-peak Commodity Requirements			
On-Peak Electricity Requirements	MWh	50	215

Source: Prepared by KPMG LLP with information provided by the City of Edmonton, September 21, 2022.

The inputs for the estimated BAU electricity peak demand of the sample multi-unit customer buildings are depicted in Table 29 below.

Table 29: Inputs for Estimated BAU Electricity Peak Demand

Electricity Peak Demand	Unit	High Density Residential	Retail Mixed Use
Electricity Peak Demand	kW/day	97	429

Source: Prepared by KPMG LLP with information provided by the City of Edmonton, September 21, 2022.

Appendix C: BAU Equivalent Bills and Proportion

C.1 BAU Equivalent Bills

Assumptions

a. The BAU equivalent bills for both of the sample multi-unit customer buildings is assumed to be billed to the strata at the building level.

b. BAU equivalent bills are developed on the building's estimated annual energy consumption.

c. Infrastructure / connection fee is not included in the BAU equivalent bills.

d. Maintenance cost is not included in the BAU equivalent bills.

e. BAU equivalent bills are developed on the five-year historical average natural gas and electricity rates.

BAU Model Outputs

Figure 5, on the following page, illustrates the BAU equivalent bill for the sample high density residential building.

Another BAU scenario was also calculated using the natural gas and electricity rates in July 2022. Under this scenario, the total charges of the BAU equivalent bill for the sample high density residential building is $71,159.76, as compared the five-year historical average results described on the following page.

Figure 5: BAU Equivalent Bill for Sample High Density Residential Building

Blatchford

Billing Date	Due Date	Account Number
2022	2022	XXXX-XXXXXX

Amount Due	Amount Paid
$59,893.69	

Usage, Fees, and Charges			
Description	**Amount**		
Natural Gas Usage		578,442	kWh
Current Natural Gas Variable Rates	$	0.02762	/kWh
Natural Gas Variable Charge	**$**	**15,975.88**	
Electricity Usage - Total		116,537	kWh
Current Electricity Variable Rates - Total	$	0.11564	/kWh
Electricity Variable Charge - Total Consumption	**$**	**13,476.84**	
Electricity Usage - On-peak		50,208	kWh
Current Electricity Variable Rates - On-peak	$	0.01411	/kWh
Electricity Variable Charge - On-peak Consumption	**$**	**708.34**	
Electricity Peak Demand		97.00	kW/day
Current Electricity Demand Rates	$	0.46185	/kW/day
Electricity Demand Charge	**$**	**16,351.74**	
Natural Gas Fixed Rate	$	1.83	/day
Electricity Fixed Rate	$	34.83	/day
Fixed Charge	**$**	**13,380.91**	
Total Due	**$**	**59,893.69**	

Source: Prepared by KPMG LLP with publicly available information and information provided by the City of Edmonton, September 21, 2022.

Figure 6, on the following page, illustrates the BAU equivalent bill for the sample retail mixed use building.

Another BAU scenario was also calculated using the natural gas and electricity rates in July 2022. Under this scenario, the total charges of the BAU equivalent bill for the sample retail mixed use building is $239,137.48, as compared the five-year historical average results described on the following page.

Figure 6: BAU Equivalent Bill for Sample Retail Mixed Use Building

Blatchford

Billing Date	Due Date	Account Number
2022	2022	XXXX-XXXXXX
Amount Due	**Amount Paid**	
$201,633.21		

Usage, Fees, and Charges			
Description	**Amount**		
Natural Gas Usage		1,997,278	kWh
Current Natural Gas Variable Rates	$	0.02762	/kWh
Natural Gas Variable Charge	**$**	**55,162.46**	
Electricity Usage - Total		499,263	kWh
Current Electricity Variable Rates - Total	$	0.11564	/kWh
Electricity Variable Charge - Total Consumption	**$**	**57,736.72**	
Electricity Usage - On-peak		215,099	kWh
Current Electricity Variable Rates - On-peak	$	0.01411	/kWh
Electricity Variable Charge - On-peak Consumption	**$**	**3,034.62**	
Electricity Peak Demand		429.00	kW/day
Current Electricity Demand Rates	$	0.46185	/kW/day
Electricity Demand Charge	**$**	**72,318.51**	
Natural Gas Fixed Rate	$	1.83	/day
Electricity Fixed Rate	$	34.83	/day
Fixed Charge	**$**	**13,380.91**	
Total Due	**$**	**201,633.21**	

Source: Prepared by KPMG LLP with publicly available information and information provided by the City of Edmonton, September 21, 2022.

C.2 BAU Equivalent Bills Components and Proportion

Assumptions

a. Demand charges is summed together with fixed charges as demand charge is relatively fixed in nature. Demand charges are calculated on metered peak demand or estimated peak demand, which does not fluctuate significant for each customer.

b. Rate proportion excluded maintenance costs.

BAU Model

Table 30 below summarizes the proportions of natural gas and electricity charges for the sample multi-unit customer buildings as calculated from the BAU equivalent bills.

As shown below, natural gas fixed charges only accounted for a small percentage of the total BAU equivalent bills for the two sample buildings. A reason for this observation can be that both sample buildings are subjected to the mid-use customer class for natural gas charges, which has a low five-year historical average fixed rate of $1.82 per day. Moreover, the BAU equivalent bills is assumed to be billed to the strata at the building level. This reduces the administration and billing costs occurred by the natural gas utility, which resulted in a lower fixed charge for the building (i.e., one fixed charge for the whole building as opposed to the similar fixed charge being applied to each unit in the building).

Table 30: BAU Equivalent Bills Components and Proportions

Multi-unit Customer	Electricity Variable Charges	Electricity Demand Charges	Electricity Fixed Charges	Gas Variable Charges	Gas Fixed Charges	Total Variable Charges	Total Fixed + Demand Charges
High Density Residential	23.68%	27.30%	21.23%	26.67%	1.11%	**50.36%**	**49.64%**
Retail Mixed Use	30.14%	35.87%	6.31%	27.36%	0.33%	**57.50%**	**42.50%**

Source: Prepared by KPMG LLP with publicly available information and information provided by the City of Edmonton, September 21, 2022.

Blatchford Renewable Energy
2023 Rate Filing
Index of MFR Schedules

Blatchford Renewable Energy
2023 Rate Filing
Summary of Total System Revenue Requirement
($000s)

Line No.	Description	Cross Reference	2019 Actual	2020 Actual	2021 Approved Budget	2021 Actual	2022 Approved Budget	2022 Update	2023 Proposed Budget	2024 Proposed Budget	2025 Proposed Budget	2026 Proposed Budget
	Revenue Requirement											
1	Operating Costs	S. 5-1	896.73	726.21	1,205.27	907.62	1,217.96	1,020.95	1,690.48	1,612.74	1,648.56	1,636.40
2												
3	Depreciation		-	-	-	-	-	-	-	-	-	-
4												
5	Revenue Offsets		-	-	-	-	-	-	-	-	-	-
6												
7	Return on Rate Base		-	-	-	-	-	-	-	-	-	-
8												
9	**Total System Revenue Requirement**		**896.73**	**726.21**	**1,205.27**	**907.62**	**1,217.96**	**1,020.95**	**1,690.48**	**1,612.74**	**1,648.56**	**1,636.40**
10												
11												
12	**Revenue**											
13	Revenue on Proposed Rates		$ -	$ 0.10	$ 29.48	$ 10.84	$ -	$ 67.34	$ 145.46	$ 694.30	$ 1,224.75	$ 2,007.38
14												
15	Infrastructure Fee		$ 7.00	$ 29.75	$ -	$ 43.13	$ 3.69	$ 13.70	$ 995.78	$ 755.09	$ 1,589.96	$ 1,932.57
16												
17	Other Revenue - Government Grants		$ -	$ -	$ -	$ 56.04	$ -	$ -	$ -	$ -	$ -	$ -
18												
19	**Total Revenue**		**$ 7.00**	**$ 29.85**	**$ 29.48**	**$ 110.01**	**$ 3.69**	**$ 81.04**	**$ 1,141.24**	**$ 1,449.39**	**$ 2,814.71**	**$ 3,939.94**
20												
21	**Revenue Surplus/(shortfall)**		(889.73)	(696.36)	(1,175.79)	(797.61)	(1,214.26)	(939.91)	(549.24)	(163.35)	1,166.15	2,303.54

Schedule 5-1

Blatchford Renewable Energy
2023 Rate Filing
Summary of Operating Costs
($000s)

Line No.	Description	Cross Reference	2019 Actual	2020 Actual	2021 Approved Budget	2021 Actual	2022 Approved Budget	2022 Update	2023 Proposed Budget	2024 Proposed Budget	2025 Proposed Budget	2026 Proposed Budget
1	Utilities & Other	S.6-1	$ 15.74	$ 69.35	$ 74.89	$ 46.81	$ 80.44	$ 64.07	$ 59.44	$ 70.24	$ 76.04	$ 77.04
2												
3	Operations and Maintenance Cc	S. 7-1	630.92	445.30	557.71	429.70	581.44	561.17	949.88	868.52	836.44	855.64
4												
5	Administration Costs	S. 8-1	223.92	208.82	464.41	418.07	472.50	364.64	558.43	578.68	578.43	556.93
6												
7	Customer Billing Services Costs	S. 9-1	24.68	0.90	31.55	11.63	8.41	3.35	68.81	20.68	66.81	36.72
8												
9	Corporate Administration Costs	S. 10-1	1.48	1.85	76.71	1.41	75.16	27.73	53.91	74.62	90.84	110.06
10												
11	Franchise Fees and Property Taxes		-	-	-	-	-	-	S. 5-1	-	-	-
12												
13	**Total Operating Costs**		**$ 896.73**	**$ 726.21**	**$1,205.27**	**$ 907.62**	**$1,217.96**	**$1,020.95**	**$1,690.48**	**$1,612.74**	**$1,648.56**	**$1,636.40**

Schedule 6-1

Blatchford Renewable Energy
2023 Rate Filing
Utilities & Other Costs
($000s)

Line No.	Description	Cross Reference	2019 Actual	2020 Actual	2021 Approved Budget	2021 Actual	2022 Approved Budget	2022 Update	2023 Proposed Budget	2024 Proposed Budget	2025 Proposed Budget	2026 Proposed Budget	Cross Reference
1	Utilities		$ 15.74	$ 69.35	$ 74.89	$ 46.81	$ 80.44	$ 64.07	$ 59.44	$ 70.24	$ 76.04	$ 77.04	
2													
3	Other		-	-	-	-	-	-					
4													
5	**Total Utilities**		**$ 15.74**	**$ 69.35**	**$ 74.89**	**$ 46.81**	**$ 80.44**	**$ 64.07**	**$ 59.44**	**$ 70.24**	**$ 76.04**	**$ 77.04**	S. 5-1

Schedule 7-1

Blatchford Renewable Energy
2023 Rate Filing
Operations and Maintenance Costs by Function
($000s)

Line No.		Cross Reference	2019 Actual	2020 Actual	2021 Approved Budget	2021 Actual	2022 Approved Budget	2022 Update	2023 Proposed Budget	2024 Proposed Budget	2025 Proposed Budget	2026 Proposed Budget	Cross Reference
1	**Energy Centers & Main Distribution System**												
2	Operation & Maintenance		-	44.74	200.50	58.06	200.74	120.18	200.74	200.74	200.74	200.74	
3			-	-		-	-	-	-	-	-	-	
4	Subtotal		-	44.74	200.50	58.06	200.74	120.18	200.74	200.74	200.74	200.74	
5													
6	**Customer Connection and Meters**												
7	Operation & Maintenance		-	-	-	-	-	-	-	-	-	-	
8			-	-		-	-	-	-	-	-	-	
9	Subtotal		-	-	-	-	-	-	-	-	-	-	
10													
11	**Quality Assurance**		-	-		-	-	-					
12													
13	**Operations Support Services**												
14	Personnel		335.50	381.90	344.27	360.61	367.25	409.90	580.59	599.23	617.15	636.36	
15	Training and Development		9.03	1.43	6.97	-	7.35	5.20	7.35	7.35	7.35	7.35	
16	Equipment Rental		2.51	0.05	5.98	10.59	6.10	2.55	11.20	11.20	11.20	11.20	
17	Technical Consultants		283.88	17.19	-	0.45	-	23.34	150.00	50.00	-	-	
18	Less: Recovery of Costs		-	-		-	-	-	-	-	-	-	
19	Subtotal		630.92	400.56	357.22	371.65	380.71	440.99	749.14	667.78	635.70	654.91	
20													
21	**Total Operations and Maintenance Costs**		**$ 630.92**	**$ 445.30**	**$ 557.71**	**$ 429.70**	**$ 581.44**	**$561.17**	**$ 949.88**	**$ 868.52**	**$ 836.44**	**$ 855.64**	S. 5-1

Schedule 8-1

Blatchford Renewable Energy
2023 Rate Filing
Administration Costs by Function
($000s)

Line No.	Description	Cross Reference	2019 Actual	2020 Actual	2021 Approved Budget	2021 Actual	2022 Approved Budget	2022 Update	2023 Proposed Budget	2024 Proposed Budget	2025 Proposed Budget	2026 Proposed Budget	Cross Reference
1	Marketing, Education and Communication		$ 69.36	$ 59.87	$ 120.25	$ 78.44	$ 122.66	$132.36	$ 115.93	$ 115.93	$ 115.93	$ 115.93	
2	Consultants		154.56	148.95	344.16	339.63	349.84	232.28	442.50	462.75	462.50	441.00	
3							-	-					
4	Subtotal		223.92	208.82	464.41	418.07	472.50	364.64	558.43	578.68	578.43	556.93	
5													
6	Less:												
7	Allocations to Other Business Units		-	-		-	-	-	-	-	-	-	
8	Capital Overhead Recoveries		-	-		-	-	-	-	-	-	-	
9			-	-		-	-	-	-	-	-	-	
10													
11	**Total Administration Costs**		**$ 223.92**	**$ 208.82**	**$ 464.41**	**$418.07**	**$ 472.50**	**$364.64**	**$ 558.43**	**$ 578.68**	**$ 578.43**	**$ 556.93**	S. 5-1

Schedule 9-1

Blatchford Renewable Energy
2023 Rate Filing
Customer Billing Costs
($000s)

Line No.	Description	Cross Reference	2019 Actual	2020 Actual	2021 Approved Budget	2021 Actual	2022 Approved Budget	2022 Update	2023 Proposed Budget	2024 Proposed Budget	2025 Proposed Budget	2026 Proposed Budget	Cross Reference
1	Monthly Billing Charges		$ -	$ 0.90	$ 31.55	$ 11.63	$ 8.41	$ 3.35	$ 7.29	$ 14.42	$ 20.81	$ 30.98	
2	Annual Billing Automation Charge		$ -	$ -	$ -	$ -	$ -		$ 6.52	$ 6.26	$ 6.00	$ 5.74	
3	One-time Set-up Charges		$24.68	$ -	$ -	$ -	$ -	$ -	$ 55.00		$ 40.00		
4	Bad Debts		-	-		-	-	-					
5	Write-offs and Adjustments		-	-		-	-	-					
6													
7	**Total Customer Billing Costs**		**$ 24.68**	**$ 0.90**	**$ 31.55**	**$ 11.63**	**$ 8.41**	**$ 3.35**	**$ 68.81**	**$ 20.68**	**$ 66.81**	**$ 36.72**	S. 5-1

Blatchford Renewable Energy
2023 Rate Filing
Corporate Administration Costs
($000s)

Line No.	Description	Cross Reference	2019 Actual	2020 Actual	2021 Approved Budget	2021 Actual	2022 Approved Budget	2022 Update	2023 Proposed Budget	2024 Proposed Budget	2025 Proposed Budget	2026 Proposed Budget	Cross Reference
1	Shared Corporate Service Costs		$ 1.26	$ 0.40	$ 53.23	$ 0.35	$ 51.24	$ 17.23	$ 46.57	$ 66.78	$ 82.99	$ 102.22	
2	Asset Usage Fees		-	-	16.74	-	17.08	5.69	-	-	-	-	
3	Other - Transportation and Insurance		0.22	1.45	6.73	1.06	6.85	4.80	7.35	7.85	7.85	7.85	
4	Subtotal		1.48	1.85	76.71	1.41	75.16	27.73	53.91	74.62	90.84	110.06	
5													
6	Less: Allocation to Other Business Units												
7	Shared Corporate Service Costs		-	-		-	-	-					
8	Asset Usage Fees		-	-		-	-	-					
9	Subtotal		-	-	-	-	-	-	-	-	-	-	
10													
11	**Total Corporate Administration Costs**		**$ 1.48**	**$ 1.85**	**$ 76.71**	**$ 1.41**	**$ 75.16**	**$ 27.73**	**$ 53.91**	**$ 74.62**	**$ 90.84**	**$ 110.06**	S. 5-1

Schedule 15-1

Blatchford Renewable Energy
2023 Rate Filing
Rate Base
($000s)

Line No.	Description	Cross Reference	2021 Actual	2022 Update	2023 Proposed Budget	2024 Proposed Budget	2025 Proposed Budget	2026 Proposed Budget	Cross Reference
1	Prior Year Property, Plant and Equipment	S. 15-2	$19,451.00	$19,451.00	$19,451.00	$23,871.25	$29,772.43	$31,442.68	
2	Prior Year Accumulated Depreciation		-	-	-	-	-	-	
3	Prior Year Net Property		19,451.00	19,451.00	19,451.00	23,871.25	29,772.43	31,442.68	
4									
5	Current Year Property, Plant and Equipmen	S. 15-2	19,451.00	19,451.00	23,871.25	29,772.43	31,442.68	48,951.39	
6	Current Year Accumulated Depreciation		-	-	-	-	-	-	
7	Current Year Net Property		19,451.00	19,451.00	23,871.25	29,772.43	31,442.68	48,951.39	
8									
9	Mid-Year Net Property		19,451.00	19,451.00	21,661.12	26,821.84	30,607.56	40,197.04	
10									
11	Materials and Supplies		-	-	-	-	-	-	
12									
13	Working Capital		-	-	-	-	-	-	
14									
15	Gross Mid-Year Rate Base		19,451.00	19,451.00	21,661.12	26,821.84	30,607.56	40,197.04	
16									
17	Mid-Year Net Contributions	S. 15-6	(19,451.00)	(19,451.00)	(21,661.12)	(26,821.84)	(30,607.56)	(40,197.04)	
18									
19	**Net Mid-Year Rate Base**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	

Schedule 15-2

Blatchford Renewable Energy
2023 Rate Filing
Property, Plant & Equipment
($000s)

Line No.		Cross Reference	2021 Actual	2022 Update	2023 Proposed Budget	2024 Proposed Budget	2025 Proposed Budget	2026 Proposed Budget	Cross Reference
1	Previous year balance		$ 19,451.0	$ 19,451.0	$ 19,451.0	$ 23,871.2	$ 29,772.4	$ 31,442.7	S. 15-1
2									
3	Additions to Property, Plant & Equipment								
4	BREU Funded	S. 15-4	$ -	$ -	$ 2,420.3	$ 4,401.2	$ 1,220.3	$ 16,508.7	
5	Developer Additions		$ -	$ -	$ 2,000.0	$ 1,500.0	$ 450.0	$ 1,000.0	
6			$ -	$ -	$ 4,420.3	$ 5,901.2	$ 1,670.3	$ 17,508.7	
7									
8	Retirements and Adjustments		$ -	$ -	$ -	$ -	$ -	$ -	
9									
10	**Current year balance**		**$ 19,451.0**	**$ 19,451.0**	**$ 23,871.2**	**$ 29,772.4**	**$ 31,442.7**	**$ 48,951.4**	S. 15-1

Blatchford Renewable Energy
2023 Rate Filing
Construction Work in Progress
($000s)

Line No.		Cross Reference	2022 Update	2023 Proposed Budget	2024 Proposed Budget	2025 Proposed Budget	2026 Proposed Budget	Cross Reference
1	Previous year balance		$ -	$ 1,986.4	$ 5,523.0	$ 4,123.9	$ 10,348.0	
2								
3	Capital Expenditures							
4	Energy Center 1		$ -	$ 2,697.5	$ 483.4	$ -	$ -	
5	Sewer Heat Exchange		$ 1,936.4	$ 544.3	$ 544.3	$ 544.3	$ 544.3	
6	Distribution Piping System		$ -	$ 2,420.3	$ 1,220.3	$ 1,220.3	$ 1,220.3	
7	Energy Transfer Stations		$ 50.0	$ 2,000.0	$ 1,500.0	$ 450.0	$ 1,000.0	
8	Energy Center 4		$ -	$ 294.8	$ 754.2	$ 5,679.9	$ 8,559.6	
9								
10	Less: Capital Additions Energy Center 1		$ -	$ -	$ (3,180.9)	$ -	$ -	S. 15-2
11	Less: Capital Additions Sewer Heat Exchange		$ -	$ -	$ -	$ -	$ -	
12	Less: Capital Additions Distribution Piping System		$ -	$ (2,420.3)	$ (1,220.3)	$ (1,220.3)	$ (1,220.3)	
13	Less: Capital Additions Energy Transfer Stations		$ -	$ (2,000.0)	$ (1,500.0)	$ (450.0)	$ (1,000.0)	
	Less: Capital Additions Energy Center 4		$ -	$ -	$ -	$ -	$ (15,288.5)	
12	**Current year balance**		$ 1,986.4	$ 5,523.0	$ 4,123.9	$ 10,348.0	$ 4,163.5	

Schedule 15-6

Blatchford Renewable Energy
2023 Rate Filing
Contributions in Aid of Construction
($000s)

Line No.	Description	2021 Actual	2022 Update	2023 Proposed Budget	2024 Proposed Budget	2025 Proposed Budget	2026 Proposed Budget	Cross Reference
1	Prior Year Gross Contributions	(19,451.00)	$(19,451.00)	$(19,451.00)	$(23,871.25)	$(29,772.43)	$(31,442.68)	
2								
3	City Contributions	-	-	(2,420.25)	(4,401.19)	(1,220.25)	(16,508.71)	
4	Customer Contributions	-	-	-	-	-	-	
5	Developer Contributions	-	-	(2,000.00)	(1,500.00)	(450.00)	(1,000.00)	
6	Retirements, Transfers & Disposals							
7								
8	**Current Year Gross Contributions**	(19,451.00)	(19,451.00)	(23,871.25)	(29,772.43)	(31,442.68)	(48,951.39)	
9								
10	Prior Year Accumulated Amortization	-	-	-	-	-	-	
11								
12	Gross Amortization	-	-					
13	Retirements, Transfers & Disposals							
14								
15	**Current Year Accumulated Amortization**	-	-	-	-	-	-	
16								
17								
18	**Mid Year Net Contributions**	**$(19,451.00)**	**$(19,451.00)**	**$(21,661.12)**	**$(26,821.84)**	**$(30,607.56)**	**$(40,197.04)**	S. 15-1

Schedule 19-1

Blatchford Renewable Energy
2023 Rate Filing
Customers and Consumption
($000s)

Line No.	Description	2019 Actual	2020 Actual	2021 Actual	2022 Update	2023 Proposed Budget	2024 Proposed Budget	2025 Proposed Budget	2026 Proposed Budget	Cross Reference
1	**TOTAL CUSTOMERS - YEAR END**									
2	Townhouses	-	8	27	53	136	207	275	424	
3	Multi-Unit	-	-	-	-	7	10	16	19	
4	Other	-	-	-	-	-	-	-	-	
5										
6	**Total Customers - Year End**	**-**	**8**	**27**	**53**	**143**	**217**	**291**	**443**	
7										
8	**TOTAL CONSUMPTION (MWh)**									
9										
10	Townhouses	-	14.1	212.7	266.7	655.9	1,467.2	1,989.7	2,730.8	
11	Multi-Unit	-	-	-	-	722.8	4,537.4	7,925.6	12,231.4	
12	Other	-	-	-	-	-	-	-	-	
13	Subtotal	-	14.1	212.7	266.7	1,378.6	6,004.6	9,915.3	14,962.1	
14										
15										
16	**Total Consumption (kWh)**	**-**	**14**	**213**	**267**	**1,379**	**6,005**	**9,915**	**14,962**	

Blatchford Renewable Energy
2023 Rate Filing
Revenue on Proposed Rates
($000s)

Line No.	Description	Cross Reference	2019 Actual	2020 Actual	2021 Actual	2022 Update	2023 Proposed Budget	2024 Proposed Budget	2025 Proposed Budget	2026 Proposed Budget
1	**Total Revenue on Proposed Rates**									
2	Townhouses		$ 7.00	$ 29.85	$ 53.97	$ 81.04	$ 300.54	$ 384.70	$ 431.01	$ 724.91
3	Multi-Unit		-	-	-	-	840.70	1,064.69	2,383.70	3,215.03
4			-	-	-	-	-	-	-	-
5	Other		-	-	-	-	-	-	-	-
6	**Total Revenue on Proposed Rates**		**$ 7.00**	**$ 29.85**	**$ 53.97**	**$ 81.04**	**$ 1,141.24**	**$ 1,449.39**	**$ 2,814.71**	**$ 3,939.94**
7										
8	**Rate Revenue on Proposed Rates**									
9	Townhouses		-	0.10	10.84	67.34	80.62	197.78	295.04	418.93
10					-		-	-	-	-
11	Multi-Unit		-	-	-	-	64.83	496.52	929.72	1,588.45
12	Other		-	-	-	-	-	-	-	-
13	**Rate Revenue on Proposed Rates**		**$ -**	**$ 0.10**	**$ 10.84**	**$ 67.34**	**$ 145.46**	**$ 694.30**	**$ 1,224.75**	**$ 2,007.38**
14										
15	**Infrastructure Fee**									
16	Townhouses		7.00	29.75	43.13	13.70	219.92	186.91	135.97	305.98
17			-	-	-	-	-	-	-	-
18	Multi-Unit			-			775.86	568.17	1,453.98	1,626.58
19	Other		-	-	-	-	-	-	-	-
20	**Total Infrastructure Fee**		**$ 7.00**	**$ 29.75**	**$ 43.13**	**$ 13.70**	**$ 995.78**	**$ 755.09**	**$ 1,589.96**	**$ 1,932.57**
21										
22	**Other Revenue**									
23	Grants - Government of Alberta		-	-	56.04	-	-	-	-	-

Schedule 20-1

Blatchford Renewable Energy
2023 Rate Filing
Proposed End Use Customer Rates and Fees

Line No.	Description	2019 Approved	2020 Approved	2021 Approved	2022 Approved	2023 Proposed
1	**Fixed Charge ($/day)**					
2	Townhouses	$1.43	$1.47	$1.51	$1.55	**$1.71**
3	Apartment	$1.12	$1.15	$1.18	$1.21	**N/A**
4						
5						
6	**Variable Charge ($/kWh)**					
7	Townhouse & Multi-Unit	$0.0248	$0.0255	$0.0262	$0.0269	**$0.0296**
8						
9	**Demand/Capacity Charge ($/kW/month)**					
10	Multi-Unit	N/A	N/A	N/A	N/A	**$12.50**
11						
12	**Infrastructure Fee**					
13	Townhouses	$ 1,750	$1,750	$1,797	$1,846	**$1,896**
14	Multi-Unit (Commercial)	$ 20.00	$20.00	$20.54	$21.09	**$21.66**

Note: Approval is being sought for End Use Customer Rates and Fees for 2023 only.

Schedule 21-1

Blatchford Renewable Energy
2023 Rate Filing
Interest on Financing
($000s)

Line No.	Description	Cross Reference	2019 Actual	2020 Actual	2021 Actual	2022 Update	2023 Proposed Budget	2024 Proposed Budget	2025 Proposed Budget	2026 Proposed Budget
1	**Deferral Account Opening Balance**		-	(898.63)	(1,623.04)	(2,471.19)	(3,539.92)	(4,265.77)	(4,641.28)	(3,683.32)
2										
3	Current Year Surplus/shortfall	S. 3-1'	(889.73)	(696.36)	(797.61)	(939.91)	(549.24)	(163.35)	1,166.15	2,303.54
4										
5	**Deferral Account Closing Balance**		(889.73)	(1,594.98)	(2,420.65)	(3,411.10)	(4,089.16)	(4,429.13)	(3,475.14)	(1,379.78)
6										
7	Interest Costs		(8.90)	(28.05)	(50.55)	(128.82)	(176.61)	(212.16)	(208.19)	(136.20)
8										
9	**Deferral Account Closing Balance Including Interest Costs**		**(898.63)**	**(1,623.04)**	**(2,471.19)**	**(3,539.92)**	**(4,265.77)**	**(4,641.28)**	**(3,683.32)**	**(1,515.97)**
10										
11	Interest Rate on Financing		2.00%	2.25%	2.50%	4.38%	4.63%	4.88%	5.13%	5.38%

NOV 2022

BLATCHFORD RENEWABLE ENERGY

2023 Rate Schedules for Thermal Energy
Effective January 1, 2023 to December 31, 2023

Attachment 1.0_Appendix 4.0

Blatchford Renewable Energy

Edmonton

Blatchford Renewable Energy (BRE) Rate BRE 1

For Thermal Energy Service for all customers throughout the Service Area served by Blatchford Renewable Energy.

Rate

Rate Component		2023 Rate
Monthly Charge ($/day)	Townhouse Lots	$ 1.71
Monthly Charge ($/kW of peak capacity/month)	Multi-Unit Lots	$ 12.50
Variable Charge ($/kWh)	All Consumption	0.0296

The minimum charge for Townhouse Lots is the Monthly Charge ($1.71 per day).
The minimum charge for Multi-Unit Lots is the Monthly Charge ($12.50 per kW of peak capacity).

Application

Price Adjustments

Rate BRE 1 may be adjusted by applicable riders or rate adjustments, from time to time, as approved by Edmonton City Council.

Bylaw 17943 shall apply to customers taking service under Rate BRE 1.

1.0 Overview

This is the first Cost of Service Study (COSS) completed for the Blatchford Renewable Energy Utility (BREU), in what is expected to be annual studies that will be submitted with BREU annual rate filings.

The purpose of a COSS is to allocate a utility's overall revenue requirement (costs) to the various classes of customers served by the utility, in a manner that reflects the relative costs of providing service to each of those classes. Cost studies are a fundamental tool in utility ratemaking. Among other things, utility rates should reflect the principle of cost causation, that is, customers that cause the utility to incur specific costs should pay for those costs. A COSS groups the customers of a utility into separate classes of service, driven by specific customer consumption characteristics with customers of each class grouped by similar demand and usage patterns.

In previous rate filings, BREU did not complete a COSS as it only provided service to one class of customers: single unit townhouse lots. In 2023, BREU is expecting buildings to connect to its district energy sharing system that will be of a significantly different size and likely have different consumption patterns than the single unit townhouse lots that it currently provides service to. For the purpose of the 2023 BREU Rate Filing, a new customer class and end use customer rate will be developed for these new types of buildings; Multi-Unit Lots. The following sections provide the methodology utilized by BREU in its inaugural COSS and the results of the allocation of costs to the two classes of customers.

2.0 Cost of Service - Methodology

The first step in a typical COSS involves the identification of the major asset/cost classes and then functionalizing all assets/costs to those major classes. For BREU, those major asset/cost classes are:

- Generation - infrastructure related to the generation of thermal energy (e.g. geo-exchange field, energy centers);
- Distribution - related to the delivery of thermal energy from the energy centers to the customer meter (e.g. pipes, meters), and;
- General plant - related to infrastructure required to support the generation and

distribution of thermal energy but not included in any of those functional categories (e.g. vehicles, buildings).

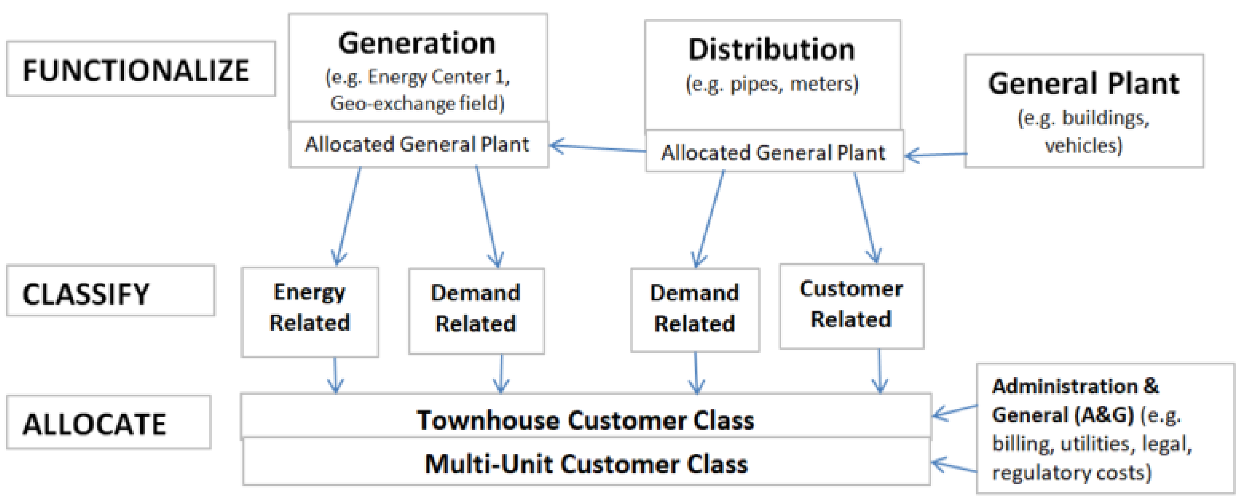
The second step in a typical COSS involves the identification of the major cost classification categories and then assigning or allocating the assets/costs that were functionalized in step one above to those major cost classification categories. For BREU the major cost classification categories are:

- Customer - costs that vary with the number of customers served;
- Demand - costs that vary with the peak thermal demand generated by the thermal energy system, and;
- Energy - costs related to the amount of thermal energy generated by the thermal energy system over a period of time.

The final step is to assign or allocate the functionalized and classified costs to each rate/customer class. As stated above, for BREU in 2023 there are two customer classes taking thermal energy service; (1) Townhouse Lot customers, and (2) Multi-Unit Lot customers.

The following diagram summarizes the COSS methodology described above.

Figure 5.1 COSS Methodology



Functionalization of Assets

BREU does not currently have the appropriate actual asset data details to properly functionalize its assets into the three functions noted above. Currently, all of BRE's actual assets are recorded in two functional categories; (1) $8.755 million in assets related to Energy Center 1, and; (2) $10.706 in assets related to the geo-exchange field. A total of

$4.420 million in assets related to the distribution piping system and energy transfer stations are forecast to be added in 2023. The following table provides details of the 2023 mid-year balance of currently available asset functionalization data.

Table 5.1 BREU Gross Assets by Function - 2023 Mid-year Balance ($millions)

Asset Function/Sub-function	2023 Forecast Mid-year Balance
Generation	
Energy Center 1	
EC1 STRUCTURE AND SUPERSTRUCTURE	$4.85
HEAT PUMPS AND BOILERS	$1.75
BUILDING MECHANICAL	$0.81
BUILDING ELECTRICAL AND CONTROLS	$1.34
Total Energy Center 1	**$8.74**
Geo-exchange field	**$10.71**
Total Generation	**$19.45**
Distribution	
Meters	$0.21
Pipes	$1.00
ETS	$1.00
Total Distribution	**$2.21**
Total BREU	**$21.66**

Going forward, BREU will need to allocate time and resources to further functionalize current actual asset data and to also separate that data into sub-functions. For example, the $2.21 million in distribution assets could be further separated into sub-functions such as the main distribution pipe assets and the pipe assets connecting the main piping system to the customer meter.

Classification of Assets

The functionalized assets shown in Table 5.1 above were then classified to the major cost classification categories. The 2023 forecast mid-year generation related assets are classified as 100 percent demand related as all generation assets, as currently tracked and recorded, are designed to meet the peak system demand for thermal energy. The 2023 forecast mid-year distribution piping system and energy transfer station assets, as currently forecast, are also 100 percent classified as demand related as they too are designed and sized to meet the peak demand for thermal energy. Meter assets are classified 100 percent customer related as a meter is required to serve each customer regardless of the peak demand or energy consumption of these customers.The following table provides details of the 2023 mid-year functionalized and classified asset balances .

Table 5.2 BREU Gross Assets by Function - 2023 Mid-year Balance ($millions)

Asset Function	Customer	Demand	Energy	Total
Generation	N/A	$19.45	$0	**$19.45**
Distribution	$0.21	$2.00	$0	**$2.21**
Total	**$0.21**	**$21.45**	**$0**	**$21.66**

As noted above, BREU will need to allocate time and resources to further functionalize and sub-functionalize current actual asset data and then complete the necessary studies to classify that data into customer, demand and energy related. For example, the distribution assets connecting to the main distribution piping system for single unit townhouses would typically be classified as 100 percent customer related, as those assets are required to serve each of these customers regardless of the peak demand or energy consumption of these customers.

Allocation/Assignment of Assets to Rate Class

The classified assets shown in Table 5.2 above were then allocated or assigned to the Single Unit and Multi-Unit customer classes. As the total meter related assets are currently comprised of only the 2023 forecast capital additions (i.e. no actual meter assets are recorded) BREU has allocated the meter assets to rate class based on the number of new customers of each rate class forecast to connect to the BREU system in 2023. The energy transfer station assets were assigned to the Multi-unit customer class as energy transfer stations are only located in multi-unit buildings. Distribution pipe assets as well as all generation related assets are allocated to rate class based on the share of total annual energy consumption (MWh) of each of the two rate classes. The following table provides details of the 2023 mid-year functionalized and classified asset balances and the assignment/allocation to rate class.

Blatchford Renewable Energy Utility - 2023 Cost of Service Study
Attachment 1 Appendix 5.0

Table 5.3 BREU 2023 Mid-year Gross Assets Assigned/Allocated to Rate Class ($millions)

	Single Unit Customers	Multi-Unit Customers	Total	
Asset Allocators				
1 - Annual Energy Consumption (MWh)	**655.9**	**722.8**	**1,378.7**	
1- Annual Energy Consumption (% of BREU total)	47.6%	52.4%	100.0%	
2 - Forecast # of Customer Additions - 2023	**83**	**6**	**89**	
2 - Forecast # of Customer Additions 2023 (% of BREU total)	93.3%	6.7%	100.0%	
Asset Function/Sub-function	**Single Unit Customers**	**Multi-Unit Customers**	**Total**	**Allocation Methodology**
Generation				
Energy Center 1	$4.16	$4.58	$8.74	1 - Annual Energy Consumption
Geo-exchange Field	$5.09	$5.61	$10.71	1 - Annual Energy Consumption
Total Generation ($)	**$9.25**	**$10.20**	**$19.45**	
Distribution				
Meters	$0.19	$0.01	$0.21	2 - Forecast # of Customer Additions - 2023
Distribution Pipes	$0.48	$0.53	$1.00	1 - Annual Energy Consumption
Energy Transfer Stations	$0.00	$1.00	$1.00	Direct Assignment
Total Distribution ($)	**$0.67**	**$1.54**	**$2.21**	

Ideally BREU would recommend allocating the generation demand related assets to rate class based on the coincident peak demand (in kW) of each rate class in future rate filings. The coincident peak demand of each rate class would be the sum of all the individual customer peak demands in the rate class at the exact time during the year (i.e. day, hour and minute, if possible) that the BREU district energy sharing system is providing the maximum amount of thermal energy to the customers connected to the system (the system peak). In addition,in future rate filings BREU would recommend using a non-coincident peak demand (in kW) to allocate all distribution demand related assets to rate class. The non-coincident peak demand of a rate class is the sum of all peak demands of the customers in that class, regardless of when the customer peaks occur (i.e. the peaks do not have to be at the same time as the BREU system peak). BREU is unable to determine actual coincident and non-coincident peak demands for any of its customers at this time as customer meters are currently read manually by a meter reader, once per month. BREU would need to invest in the necessary infrastructure and software to be able to read customer meters more frequently, at least once per hour, and then based on those detailed meter readings determine both the coincident and non-coincident peak demand of each rate class.

Allocation of Revenue Requirement to Rate Class

The final step in the COSS is to allocate BREU's revenue requirement (i.e. costs) to each rate class. As noted in the 2023 Rate Filing, all required capital for the BREU system during the forecast period is projected to be financed by a combination of the non-refundable cash infusion and builder contributions resulting in no rate base on BREU's balance sheet and no capital related revenue requirement (depreciation, interest costs or return on equity).

BREU has allocated or assigned its 2023 forecast revenue requirement to rate class based on one of the following allocators: (1) direct assignment to a rate class of a cost incurred entirely to serve that class; (2) allocated based on 2023 forecast annual energy consumption; (3) allocated based on number of customer bills forecast to be issued in 2023; (4) allocated based on the allocation of the 2023 mid year balance of generation and distribution related assets, and: (5) allocated based on the sum of the assignment/allocation of costs allocated to rate class from (1) to (4). The following table provides details of the assignment/allocation of the 2023 forecast BREU revenue requirement to rate class..

Table 5.4 Assignment/Allocation of 2023 Forecast Revenue Requirement to Rate Class

	Single Unit Customers	Multi-Unit Customers	Total
Revenue Requirement Allocation Method			
1 - Annual Energy Consumption (MWh)	**655.9**	**722.8**	**1,378.7**
1- Annual Energy Consumption (% of BREU total)	47.6%	52.4%	100.0%
2 - Forecast # of Customer Bills Issued - 2023	**1,178**	**18**	**1,196**
2 - Forecast # of Customer Bills Issued 2023 (% of BREU total)	98.5%	1.5%	100.0%
3 - Allocation of Mid-year Generation/Distribution Assets ($M)	**$9.92**	**$11.74**	**$21.66**
3 - Forecast # of Customer Bills Issued 2023 (% of BREU total)	45.8%	54.2%	100.0%

Revenue Requirement Component ($)	Single Unit	Multi - Unit	Total	Allocation Method
Utilities	$28,278	$31,162	**$59,440**	1 - Annual Energy Consumption
Operations and Maintenance (All Functions)	$435,194	$514,686	**$949,880**	3 - 2023 Mid Year Assets
Billing - One-time set up charge (new Multi-unit Rate)	$0	$55,000	**$55,000**	Assigned to Multi-unit Customer Class
Billing - Monthly Billing charges	$13,605	$208	**$13,813**	2 Forecast Number of Bills Issued
(Z) Subtotal	**$477,077**	**$601,056**	**$1,078,133**	
(z) Subtotal (%)	**44.25%**	**55.75%**	**100.00%**	(Z)
Corporate Administration Costs	$23,856	$30,055	**$53,911**	Z - Subtotal of costs above
Administration Costs	$247,108	$311,324	**$558,432**	Z - Subtotal of costs above
Total Assigned/Allocated Costs	**$748,040**	**$942,436**	**$1,690,476**	

In a typical rate filing for a large established utility, the total revenue requirement allocated to each rate class determined in the COSS is compared to the revenue recovered from the customers of each rate class, normally referred to as the revenue to cost ratio. In an ideal scenario, the goal would be to have a 100 percent revenue to cost ratio for each rate class. This would mean that the revenue collected from each rate class on the proposed rates would equal the costs allocated to each rate class and no cross subsidization of one class of customers by another class of customers was occurring. But given that a COSS is a somewhat subjective or theoretical exercise and not an exact science, many established utilities will set their end use customer rates such that the revenue to cost ratios for each rate class are within a range of 100 percent, for example 95 to 105 percent. The following table provides a summary of the revenue and the costs allocated to the two rate classes and the resulting revenue to cost ratios.

Table 5.5 Revenue to Cost Ratio by Rate Class

	Revenue ($)	Single Unit	Multi - Unit	Total
	Revenue on Proposed Rates	$80,625	$64,835	$145,460
	Infrastructure Fee Revenue	$219,918	$775,863	$995,781
(A)	**Total Revenue**	**$300,543**	**$840,698**	**$1,141,241**
(B)	**Total Allocated Costs**	**$748,040**	**$942,436**	**$1,690,476**
	Revenue to Cost Ratio [= (A) / (B)]	**40.18%**	**89.20%**	**67.51%**

The results of the initial COSS completed by BREU are preliminary and have not been incorporated in the design of the proposed 2023 rates. As described in the 2023 Rate Filing, the Business as Usual principle has been the main policy principle guiding the determination of the level of BREUs end-use customer rates and continues to be the guiding principle utilized in the 2023 Rate Filing. As the customer base grows and additional detailed customer consumption data, consumption patterns and more detailed asset and cost data become available and as BREU obtains further experience operating the district energy sharing system, it is anticipated that a traditional cost of service approach will be utilized to set customer rates and the Business as Usual principle will become secondary in terms of the setting of annual rates.