

PATHWAY TO DECARBONIZATION FEASIBILITY STUDY

CITY OF TEMISKAMING SHORES

RIVERSIDE PLACE
55 Riverside Drive, New Liskeard, ON

WalterFedy Project No: 2023-0734-10

July 21, 2025



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Project Number: 2023-0734-10

July 21, 2025

Mathew Bahm
Director of Recreation
City of Temiskaming Shores
325 Farr Drive
Haileybury, ON POJ 1K0

Dear Mathew,

RE: Pathway to Decarbonization Feasibility Study

WalterFedy is pleased to submit the attached Pathway to Decarbonization Feasibility Study report to the City of Temiskaming Shores. This study covers the agreed-upon scope and provides a Pathway to Decarbonization Feasibility Study for the Riverside Place, which is located at 55 Riverside Drive in New Liskeard, ON. Certain parts of this report are designed to be viewed in digital/PDF format. This approach will enable the reader to zoom in on images and navigate the document using the provided hyperlinks.

The report was completed based on the information provided by the City of Temiskaming Shores, using the supplied and collected data, engineering judgment, and various analysis tools to arrive at the final recommendations.

All of which is respectfully submitted,

WALTERFEDY



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EXECUTIVE SUMMARY

WalterFedy was engaged by the City of Temiskaming Shores to complete a Pathway to Decarbonization Feasibility Study for the Riverside Place. The objective of this engagement is to identify and analyze measures that reduce utility use, GHG emissions, and utility costs at the Riverside Place, and to analyze various GHG Reduction Pathways consisting of combinations of measures. Based on these analyses, the objective is also to recommend the preferred GHG Reduction Pathway for implementation. To achieve this objective, the following steps were taken.

1. **Facility description.** The existing conditions of the facility were reviewed through available documentation and a site survey completed on 2024-04-17 to gain an understanding of the facility and its operations. A facility description, summarizing findings, is provided in Section 2.
2. **Utility use baseline.** Metered utility data provided by the City of Temiskaming Shores was reviewed to understand historical utility use trends, and to establish the utility use baseline for the Riverside Place. Findings are documented in Section 3.
3. **Energy model development.** A calibrated energy model was developed from a bottom-up hourly analysis considering historical weather patterns, and the insight gained from reviewing the facility's existing conditions and historical utility use data. Findings are documented in Section 4.
4. **Measure analysis.** Measures intended to achieve the City of Temiskaming Shores's goals were identified and analyzed. Analysis includes conceptual design development and utility analysis quantifying utility use impacts, GHG emissions and utility costs for each measure. Findings are documented in Section 5.
5. **Scenario analysis.** Scenario analysis was completed to estimate the costs and benefits expected from implementing various combinations (i.e. scenarios) of the measures that were individually analyzed in Section 5, accounting for the interactive effects between measures within each scenario. Findings are documented in Section 6.

All analysis was completed using the calibrated energy model, which matches metered yearly electricity and natural gas utilities used by the Riverside Place by precisely capturing existing conditions of the building within the model. The model tracks each utility end use for every hour of a complete year.

Based on the analysis completed and discussions with the client, the GHG reduction pathway that is recommended for implementation is as follows.

- **Organizational goal alignment**

The recommended plan scenario composition is presented in Figure 1, which is a measure implementation timeline plot indicating which measures were assumed to be implemented in which plan scenarios and when, and the estimated project cost of each measure. The measures are also colour-coded according to measure group.

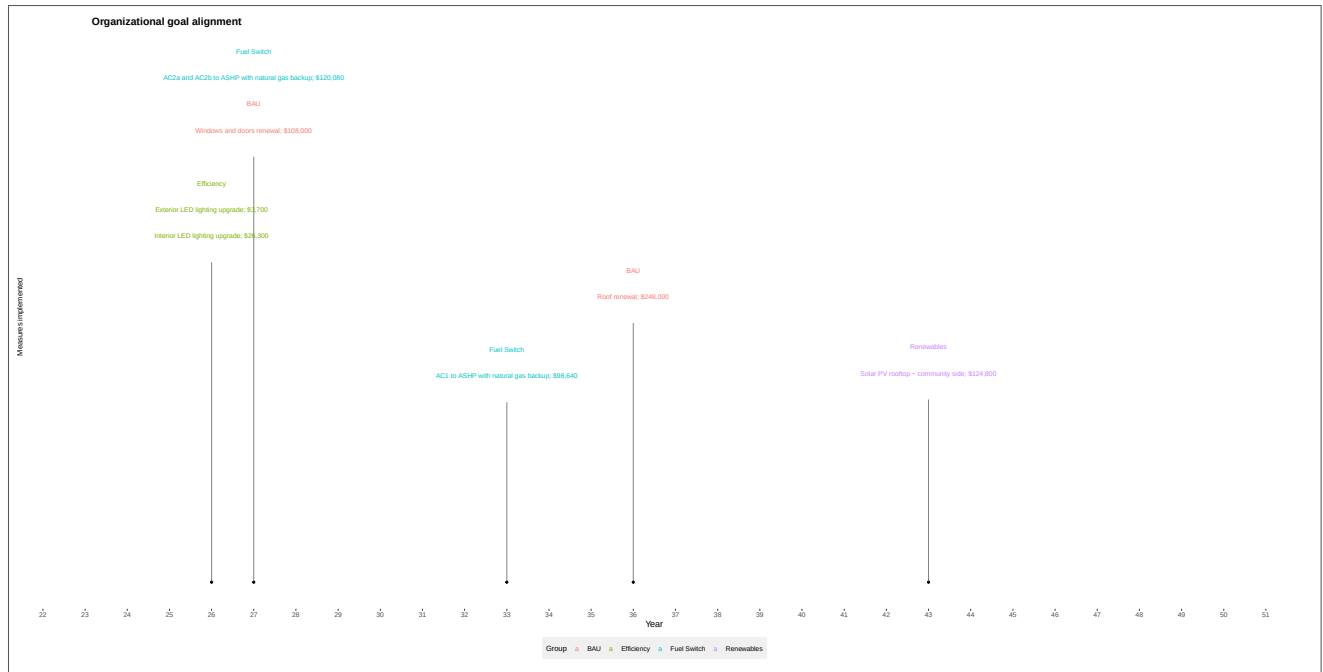


Figure 1: Recommended plan scenario composition, indicating which measures are implemented when and at what cost in each plan scenario

The following plots in Figure 2 show the results for the recommended GHG reduction pathway.

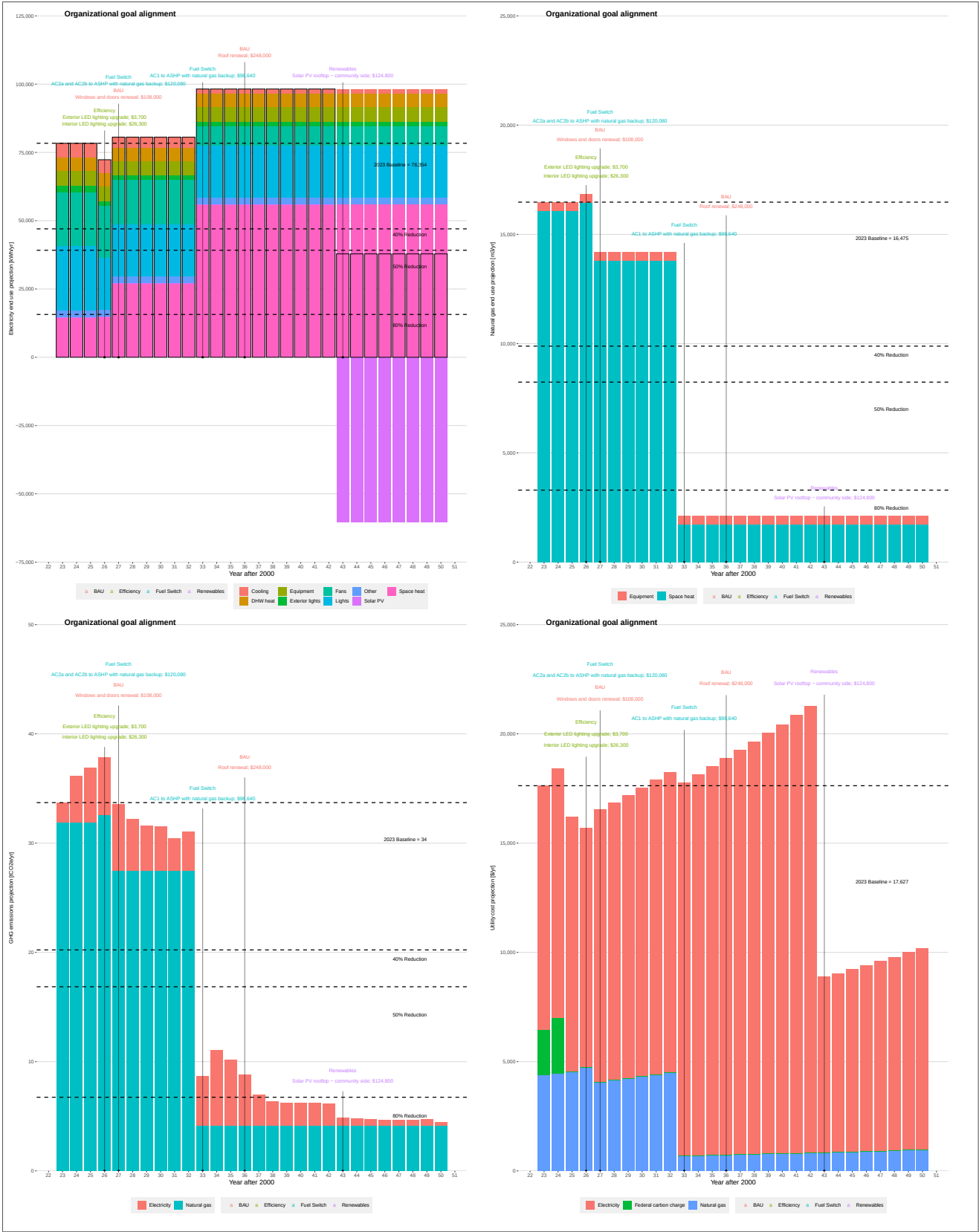


Figure 2: Recommended scenario performance

Table 1 summarizes the performance of all the plan scenarios with respect to utility use, GHG emissions, utility cost, and financial metrics. The recommended plan scenario is in **bold**. The first half of Table 1 represents the estimated performance in the final year (2050) of the evaluation period. The second half of Table 1 represents the estimated cumulative performance across the entire evaluation period (present to 2050). All final year dollar values are in the value of today's currency. All cumulative dollar values presented in Table 1 are calculated as the simple sum of expenditures over the evaluation period, except for the life cycle cost, which is discounted to present value (as illustrated in Figure 2).

Table 1: Recommended plan scenario performance summary

Section	Description	Unit	Minimum performance scenario	Aggressive deep retrofit	Comprehensive	Organizational goal alignment	Business as usual
Utility use final	Electricity use	[kWh/yr]	48,912	48,912	40,351	37,849	78,354
	Electricity monthly peak (av)	[kW]	30.6	30.6	28.9	21.6	25.3
	Electricity yearly peak (max)	[kW]	62.5	62.5	59.4	34.2	42.0
	Natural gas use	[m3/yr]	403	403	403	2,130	16,475
GHG emissions final	Electricity GHGs	[tCO2e/yr]	0.46	0.46	0.38	0.36	0.74
	Natural gas GHGs	[tCO2e/yr]	0.8	0.8	0.8	4.1	31.8
	Carbon offsets GHGs	[tCO2e/yr]	0.00	0.00	0.00	0.00	0.00
	Total GHGs	[tCO2e/yr]	1.2	1.2	1.2	4.5	32.6
Utility cost final	Electricity utility cost	[\$/yr]	11,925	11,925	9,838	9,228	19,103
	Natural gas utility cost	[\$/yr]	182	182	182	964	7,456
	Carbon offsets utility cost	[\$/yr]	0.00	0.00	0.00	0.00	0.00
	Federal carbon charge	[\$/yr]	0.00	0.00	0.00	0.00	0.00
	Total utility cost	[\$/yr]	12,107	12,107	10,020	10,192	26,559
Utility use cumulative	Electricity use	[kWh]	2,289,602	1,662,393	2,187,376	2,075,850	2,193,919
	Natural gas use	[m3]	156,276	75,930	156,276	189,735	461,295
GHG emissions cumulative	Electricity GHGs	[tCO2e]	89.1	67.5	87.3	82.9	80.4
	Natural gas GHGs	[tCO2e]	302	147	302	367	891
	Carbon offsets GHGs	[tCO2e]	0.00	0.00	0.00	0.00	0.00
	Total GHGs	[tCO2e]	391	214	389	450	972
Utility cost cumulative	Electricity utility cost	[\$]	423,653	303,849	401,292	380,031	414,682
	Natural gas utility cost	[\$]	45,871	21,627	45,871	58,540	161,857
	Carbon offsets utility cost	[\$]	0.00	0.00	0.00	0.00	0.00
	Federal carbon charge	[\$]	4,616	4,616	4,616	4,616	4,616
	Total utility cost	[\$]	474,141	330,092	451,779	443,187	581,155
Financial cumulative	Project cost	[\$]	1,032,639	960,542	2,723,432	974,756	669,737
	Replacement cost	[\$]	141,537	263,384	141,537	134,255	178,189
	Life cycle cost	[\$]	785,235	791,942	861,161	736,592	760,501

1 INTRODUCTION

1.1 Overview

WalterFedy was engaged by the City of Temiskaming Shores to complete a Pathway to Decarbonization Feasibility Study for the Riverside Place. This engagement aims to identify a recommended Greenhouse gas (GHG) reduction pathway by examining GHG reduction measures and various scenario developments. Based on a review of the Request For Proposal Document, the City's Corporate Greenhouse Gas Reduction Plan (GHGRP), and the Federation of Canadian Municipalities (FCM) Community Buildings Retrofit (CBR) funding program, the following scenarios will be developed:

- **Business as usual:** To follow the existing capital renewal plan and replace equipment at the end of its life with like-for-like equipment, meeting minimum energy-efficiency requirements of ASHRAE 90.1.
- **Minimum performance:** To achieve a 50% reduction in operational GHG emissions within 10 years and 80% within 20 years. This scenario addresses the minimum performance scenario of FCM's CBR program.
- **Aggressive deep retrofit:** Implement the same measures as in the minimum performance scenario but achieve an 80% reduction in GHG emissions within five years. This scenario addresses the additional scenario requirement of FCM's CBR program.
- **Organizational goal alignment:** To reduce emissions by 40% GHG emissions from 2019 levels by 2033 and 80% reduction by 2050 of on-site emissions. The remaining 20% is to be addressed through carbon offsets, as noted in the City's GHGRP.
- **Comprehensive:** To understand the limit of GHG reductions possible by implementing all measures with the greatest reduction on GHG emissions that are mutually exclusive.

1.2 Background

1.2.1 Corporate Greenhouse Gas Reduction Plan

The City of Temiskaming Shores has been dedicated to taking a leading role in the battle against climate change. As a committed member of the Partners for Climate Protection (PCP) program, they achieved Milestone 3 in May 2023 by creating the City's Corporate Greenhouse Gas Reduction Plan. The plan includes ambitious targets, aiming for a 40% reduction below 2019 levels by 2033 and striving for net zero emissions operations by 2050. After conducting an inventory of its greenhouse gas (GHG) emissions in 2019, the City discovered that its buildings and facilities accounted for 813 tCO₂e, representing 41.6% of its total GHG emissions inventory. A significant portion of these GHG emissions comes from natural gas, which makes up 41.7% of all energy sources for the City. To reach these sustainability goals, the City has implemented several measures, including:

- Establishing a Climate Action Committee
- Implementing a Climate Lens with regular reporting
- Utilizing a combination of EnergyCAP and ENERGY STAR Portfolio Manager to monitor and report building utility use, including electricity, natural gas, and propane
- Transitioning its fleet to biodiesel
- Initiating decarbonization studies of its buildings

This study will contribute to the decarbonization studies of its buildings. The Riverside Place is one of fourteen buildings being examined. Of these fourteen buildings, they represent over 77% of the buildings and facilities GHG emissions. In particular, the Riverside Place represented 37 tCO₂e in 2019, or 1.9% of the overall inventory.

1.2.2 Asset Management Plan

The City of Temiskaming Shores released Version 1.2 of their Asset Management Plan in 2024, providing a framework for prioritizing and optimizing asset management efforts from 2024 to 2034. The building and facility assets are estimated to have a total replacement cost of \$76,178,722, with City Hall alone having an estimated

replacement cost of \$8,613,308. The average annual financial requirements, including capital and operational expenditures, is \$2,153,014. Furthermore, the 2031 budget will see a significant increase in capital needs, nearing \$44 million. In 2032, this figure will exceed \$25 million, and in 2033, it will be more than \$5 million. Figure 2 summarizes the asset management data for the Riverside Place.

Table 2: Asset management summary for this facility

Group	Metric	Unit	Value
Financial	Content Value Estimated	[\$]	242,184
	Building Land Tank	[\$]	2,667,756
	Replacement Cost	[\$]	2,909,940
Information	Install Date	[yr]	1987
	Age	[yrs]	38
Condition Rating	Structure Condition Score	[-]	4.1
	Final Condition Score	[-]	4.1
Risk	Probability of Failure	[-]	1
	Consequence of Failure	[-]	5
	Risk Score	[-]	1.8

1.3 Contact information

Contact information for WalterFedy (the Consultant) and City of Temiskaming Shores (the Client) is provided in Table 3.

Table 3: Contact information

Description	Consultant	Client
Organization	WalterFedy	City of Temiskaming Shores
Address	Suite 111, 675 Queen St South	325 Farr Drive
Location	Kitchener, ON	Haileybury, ON
Postal code	N2M 1A1	P0J 1K0
Contact name	Jordan Mansfield	Mathew Bahm
Credentials	P.Eng., M.Eng., CEM, CMVP	-
Title	Energy Engineer	Director of Recreation
Phone	519 576 2150 x 336	705 672 3363 x 4106
Email	jmansfield@walterfedy.com	mbahm@temiskamingshores.ca

2 FACILITY DESCRIPTION

2.1 Facility description methodology

The facility was reviewed and described according to the following methodology. The intent of reviewing and describing the facility is to understand the pertinent operations and systems in the facility that use utilities so that the baseline (i.e. existing) utility use can be accurately quantified.

1. **Facility document review.** Facility documents from the following list were reviewed, if available. Further information on available documentation are available in Section 2.3.
 - Building drawings.
 - Building automation system graphics and points lists.
 - Previously completed Engineering studies, including Energy Audits, Feasibility Studies, and Building Condition Assessments.
 - Historical utility use data.
 - Other documentation made available by the City of Temiskaming Shores.
2. **Site survey.** A site survey was completed on 2024-04-17 to review the energy systems applicable to the desired retrofit scenario.

2.2 Facility overview

An overview of the Riverside Place is provided in Table 4.

Table 4: Facility overview

Description	Unit	Value
Name	[-]	Riverside Place
Address	[-]	55 Riverside Drive
Location	[-]	New Liskeard, ON
Type	[-]	Community centre
Construction year	[-]	1987
Gross floor area	[m2]	757
Gross floor area	[ft2]	8,150

An aerial view of the Riverside Place is provided in Figure 3.



Figure 3: Riverside Place aerial view

2.3 Building information

Renovations

The following renovations are known:

- **AC1 replacement (2013):** AC1 was replaced in 2013 with a new unit. AC2a and AC2b were not included in the renovation.
- **Shingle replacement (2016):** The roof shingles were replaced.
- **Window replacement (c. 2023):** Per staff comments, all windows on the radio side were replaced.
- **Lighting retrofit (c. 2019):** Per staff comments, all lighting fixtures in the hall were retrofitted to LED lamps.
- **HRV install:** During the site survey and through discussion with staff, it was observed that an HRV was installed on the radio side. The HRV is located in the ceiling plenum, and it appears to have been integrated into the existing ductwork. Based on a review of the exterior, there was only one pair of intake and exhaust ports.
- **Emergency power:** Two manual transfer switches were installed on the mezzanine at some point after the original design. There was no generator spotted at this site, and it was assumed that the emergency power was fed from a portable generator.

Additions

There have been no additions to this building.

Energy use not within the gross floor area

The following energy use is located outside the gross floor area of this building:

- Building-mounted exterior light fixtures

Utility bill responsibility

Utility bill responsibility is as follows:

- Natural gas meters: the City.
- Electricity meters: the City is responsible for the hall, and the tenant is responsible for the radio station meter.

Commissioning history

No commissioning history has been documented.

Previous studies

The following is a summary of known previous studies:

- Energy audits: None
- Engineering studies: None
- Building condition assessments: None

Documentation availability

In conjunction with the site survey, the following documents are being used to help us better understand this facility:

- Original drawings, including architectural, mechanical, and electrical.

- 2013 RFP document for an HVAC replacement.

2.4 Space use

Type summary

The following spaces were identified during the site survey and documentation review.

- Office, enclosed
- Computer/Server room
- Studio
- Electrical/Mechanical room
- Lunchroom
- Kitchen
- Server
- Multi-purpose space
- Washroom
- Meeting room
- Lobby
- Storage

All spaces are being used as originally intended. The kitchen was originally set to be storage. However, a change order moved the kitchen to its current spot.

Occupancy scheduling

The facility operation hours are as follows:

- **Hall:** usage is intermittent and heavily dependent on rentals.
- **Radio:** a proper schedule was not obtained. It is assumed that this part of the building is occupied from 06:00 to 18:00 on weekdays.

The hall has a capacity of up to 270 people. On the radio side, the peak number of people is assumed to be 10.

Space use breakdown

A space use breakdown, which was estimated via calibrated measurements performed on available facility floor plans, is presented in Table 5.

Table 5: Space use summary

Space name	Floor area of space	HVAC System	Data source
-	[m2]	-	-
Event hall	372	AC1	Drawings.
Radio station	287	AC2a and AC2b	Drawings.
Kitchen and storage spaces	98	AC1	Drawings.

2.5 Building Envelope

Building envelope area data summary

Building envelope areas are summarized in Table 6.

Table 6: Building envelope summary

Area of roof	Area of exterior walls net	Area of exterior walls	Area of exterior windows	Area of exterior doors
[m2]	[m2]	[m2]	[m2]	[m2]
952	814	671	136	7.8

Roof

The roof exterior layer consisted of either asphalt shingles or 4-ply built up roof. There were four roof assemblies noted in the drawings. R-21 (over the hall) had the following composition (exterior to interior layer):

- Asphalt singles
- 15# roofing felts
- 10mm exterior grade plywood
- 64mm rigid insulation
- Vapour barrier
- 38mm T&G Wood Deck

R-23 (over the radio side):

- Asphalt singles
- Sheathing
- Air space
- 200 batt insulation
- Prefabricated roof trusses at 400mm O.C.
- 6mil ploy vapour barrier
- Gypsum board

The overall U-Values for these assemblies are assumed to be:

- R-21: 0.284 W/m2K
- R-23: 0.162 W/m2K
- The roof condition was in excellent condition.

Opaque Walls (above ground)

There were a total of 16 exterior wall assembly types identified via the assemblies list on drawing A1. W1 had the following composition (exterior to interior layer):

- 90mm brick
- 100mm split face concrete block
- 25mm air space
- 25mm sheathing
- 140mm batt insulation

- 38x140mm wood studs
- 6mil poly vapour barrier
- 12mm gypsum board

The main exterior walls tend to have a minimum of 140mm of batt insulation with wood studs. The other notable exterior layers include cedar siding and split face concrete block.

The overall U-Values for these assemblies are assumed to be 0.189 W/m²K

- The wall condition was in good condition.

Fenestration

Windows

- The facility has nine different window types, as per the drawings. Windows are typically insulated aluminum-framed, double-pane operable windows. The drawings indicate some vinyl windows, which were replaced.
- Windows appeared to be in excellent condition, including sealant around windows. However, there is damage to the curtain wall on the north elevation.
- The overall U-Value is assumed to be 0.625 Btu/hr.ft².F for the window system with a SHGC of 0.35.

Doors

- The facility has swing doors with glazing, sliding doors with glazing, hollow metal, and overhead doors with glazing.
- The overall fenestration-to-wall ratio is estimated to be 18%.

Overall Enclosure Tightness

It is difficult to determine a building's infiltration rate without performing a blower door test. However, an infiltration rate is required for energy modelling purposes. Based on the site survey, an infiltration rate of 0.25 Lps/m² of the above-grade building envelope area will be assumed here.

Building Envelope documentation

Building envelope documentation, including available drawings and photos from the site survey, is provided in the following images.



Figure 4: Brick and cedar siding



Figure 5: Curtain wall



Figure 6: Damaged panel



Figure 7: Gap in front entrance to the hall



Figure 8: Hall entrance



Figure 9: Hall windows and overhead door



Figure 10: Hollow metal doors



Figure 11: New window in room 27



Figure 12: Radio entrance



Figure 13: Roof



Figure 14: Roof above the kitchen



Figure 15: Typical operable window



Figure 16: Underside of the roof of the hall



Figure 17: Window sealant in excellent condition

2.6 HVAC

HVAC equipment summary

HVAC systems are summarized in Table 7, Table 8, and Table 9.

Table 7: Air distribution systems summary

Tag	Make	Model	Serves	Design flow	Motor output	Data source
-	-	-	-	[cfm]	[hp]	-
AC1	York	ZF180N32J2 AAA1B	Hall	6,000	5.00	Nameplate.
AC2a	York	NA	Radio - north	1,600	1.50	Assumption.
AC2b	York	NA	Radio - south	1,600	1.50	Assumption.
AC3	Carrier	50AH024300	Radio - east end	800	0.50	Assumption.
EF1	NA	NA	Hall washroom exhaust	150	0.25	Nameplate.
EF2	NA	NA	Radio washroom exhaust	75	0.06	Assumption.
EF3	FloAire	DUB5H	Kitchen hood	2,500	0.75	Nameplate.
HR1	Lifebreath	NA	Radio office	200	0.15	Assumption.

Table 8: Heating systems summary

Tag	Serves	Utility	Efficiency	Output	Data source
-	-	-	[decimal]	[btuh]	-
AC1_HEAT	Hall	Natural gas	0.80	320,000	-
AC2a_HEAT	Radio - north	Natural gas	0.75	90,000	-
AC2b_HEAT	Radio - south	Natural gas	0.75	90,000	-
WH1	Hall washrooms and servery	Electricity	1.00	15,355	-
WH2	Kitchen	Electricity	1.00	15,355	-
WH3	Radio	Electricity	1.00	5,118	-
EH1	Radio vestibule	Electricity	1.00	20,473	-
DH1	AC3	Electricity	1.00	25,591	-
FFH1	North entrance - Radio	Electricity	1.00	6,824	-

Table 9: Cooling systems summary

Tag	Serves	Efficiency	Output	Data source
-	-	[decimal]	[ton]	-
AC1_COOL	Hall	4.0	15	Nameplate.
AC2a_COOL	Radio - north	3.5	4	Drawings.
AC2b_COOL	Radio - south	3.5	4	Drawings.
AC3_COOL	Radio - east end	3.5	2	Drawings.

System type

The facility's system includes three RTUs (AC1, AC2a, and AC2b), a packaged air conditioning unit (AC3) with electric reheat, an HRV, some perimeter electric heat, and exhaust fans. A summary of the system is as follows:

- AC1, replaced in 2013, serves the hall. It is controlled by a programmable thermostat set to 18C and not on a schedule.

- AC1 has a natural gas-fired burner complete with DX cooling.
- AC2a and AC2b are identical units and are original to the building. AC2a serves the north section of the radio station, while AC2b serves the south section of the building.
- AC2a and AC2b both have natural gas-fired burners and DX cooling. It appears that the non-programmable thermostats for these units were replaced with new ones, while the old ones remained in place. AC2a and AC2b were set to 72F and 71F, respectively.
- AC3 is a cooling-only air conditioner unit located in the ceiling plenum. The unit is coupled with an electric duct heater that is controlled by a timer in the electrical room. Based on a review of the timer, there are no trippers installed, suggesting the unit does not run.
- Based on the drawings, AC3 has a thermostat located in one of the studio rooms, which were not accessible during the site visit.
- There is at least one HRV. However, there are at least two controllers that were spotted during the site visit. The HRVs were installed during the pandemic.
- A kitchen exhaust fan is manually controlled to extract air from the range hood.
- Two more exhaust fans extract air from the washrooms. The hall washroom's exhaust fan is controlled by a manual switch located in the attic space and is believed to be left on continuously.
- An air curtain is located in the vestibule of the hall.
- There is electric space heating on the radio side. A duct heater serving AC3, a forced fan heater at the north entrance, and a cabinet heater at the south entrance.

Central Plant

There is no central plant at this facility.

Distribution system

There are no pumps present at this site.

Ductwork in the community hall utilizes supply ductwork and return grilles. The radio station uses supply and return ductwork.

Controls

- No BAS is present at this site.

HVAC system documentation

HVAC system documentation, including available drawings and photos from the site survey, is provided in the following images.



Figure 18: AC1



Figure 19: AC1 thermostat



Figure 20: AC2a



Figure 21: AC2a thermostat



Figure 22: AC2b

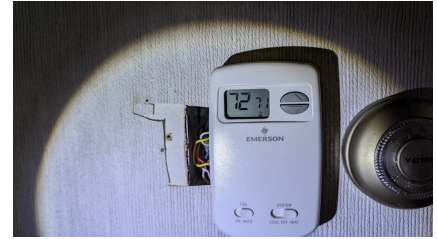


Figure 23: AC2b thermostat



Figure 24: Air curtain



Figure 25: EF2 grille



Figure 26: HRV1 Exhaust ports



Figure 27: Heater in vestibule to radio



Figure 28: HRV controller in room 27



Figure 29: HRV controller in room 28



Figure 30: Kitchen exhaust



Figure 31: Kitchen exhaust fan



Figure 32: Modified ductwork to supply air to community hall washroom

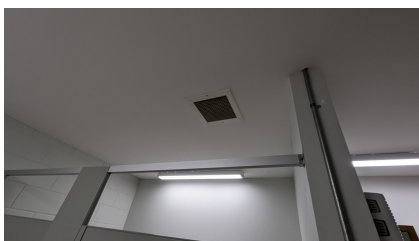


Figure 33: Washroom exhaust

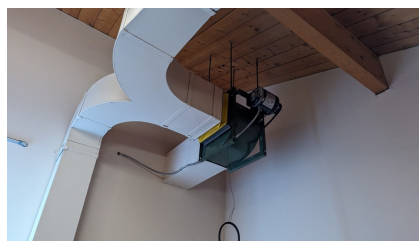


Figure 34: Washroom exhaust fan

2.7 Domestic hot water

Overview

Three electric DHW heaters are serving this building. WH1 and WH2 have tank capacities of 46 USG and 48 USG, respectively. The third tank located in the radio room was not accessible during the site survey.

Domestic Hot Water documentation

Domestic Hot Water documentation, including available drawings and photos from the site survey, is provided in the following images.



Figure 35: WH1



Figure 36: WH2

2.8 Lighting

Lighting system summary

Lighting systems are summarized in Table 10.

Table 10: Lighting systems summary				
Space name	Floor area of space	Light power density	Light power input	Data source
-	[m2]	[W/m2]	[W]	-
Event hall	372	8.2	3,050	Assumed based on SB10 2016 standard for convention centres.
Radio station	287	8.5	2,440	Assumed based on SB10 2016 standard for office spaces.
Kitchen and storage spaces	98	8.2	804	Assumed based on SB10 2016 standard for convention centres.

Interior lighting

Overview

Fixtures

The following interior light fixtures were observed during the site survey:

- Type E: Pot light, incandescent, 60 W (assumed)
- Type E1: Pot light, CFL, 13 W (assumed)
- Type E2: Pot light, LED, 8 W
- Type F: strip light, LED, 30W (assumed)
- Type G: 1'x4', suspended, T8 LED lamp, 28W (assumed)
- Type H: 2'x4', recessed, T8 LED lamp, 56W (assumed)
- Type I: 2'x4', recessed, LED, 42 W (assumed)

Controls

Interior lighting control is done through manual switches and ceiling-mounted occupancy sensors in the hall washrooms.

Exterior lighting

Fixtures

The following exterior light fixtures were observed during the site survey:

- Type A: Wall pack, LED, 10 W (assumed)
- Type A1: Wall pack, CFL, 20 W (assumed)
- Type B: Wall pack, LED, 30 W (assumed)
- Type C: Wall pack, LED, 50 W (assumed)

- Type D: Wall pack, CFL, 20 W (assumed)

Controls

Exterior lighting is controlled by photocell.

Lighting system documentation

Lighting system documentation, including available drawings and photos taken during the site survey, is provided in the following images.



Figure 37: Hall switches



Figure 38: Occupancy sensor in the men's washroom



Figure 39: Type A1



Figure 40: Type A



Figure 41: Type B



Figure 42: Type C



Figure 43: Type D

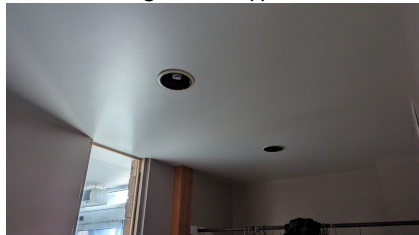


Figure 44: Type E1

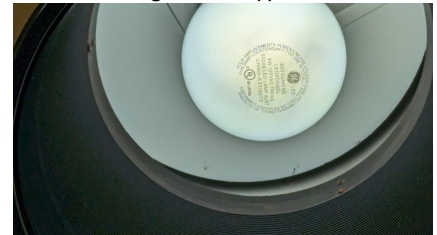


Figure 45: Type E2



Figure 46: Type E



Figure 47: Type F



Figure 48: Type G



Figure 49: Type G - LED lamps



Figure 50: Type H

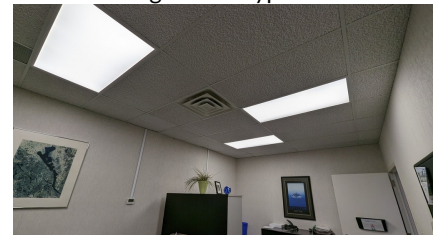


Figure 51: Type I



Figure 52: Type J



Figure 53: Type K

2.9 Process and plug loads

Process

Various process loads are present at the facility, including:

- Two gas-fired stoves
- IT equipment
- Studio equipment

Plug loads

Various plug loads are present at the facility, including:

- Office equipment (photocopier, plot printer, etc.)
- Personal computers
- Appliances (e.g., cooler, refrigerators, microwave, kettle, etc.)

Process and plug loads documentation

Process and plug loads documentation, including available drawings and photos from the site survey, is provided in the following images.



Figure 54: Break room appliances



Figure 55: Cooler



Figure 56: Freezer



Figure 57: Gas-fired stoves



Figure 58: IT equipment



Figure 59: IT equipment in room 39



Figure 60: Kitchen appliances



Figure 61: Office equipment in the lobby



Figure 62: Studio equipment

2.10 Water fixtures

Water fixture summary

Water fixtures at Riverside Place are summarized in Table 11.

Table 11: Water fixture summary				
Serves	Unit count	Flow	Volume	Data source
-	-	[gpm]	[gpc]	-
Kitchen faucets	5	2.20	-	Assumption.
Washroom faucets	6	0.50	-	Assumption.
Slop sink	1	0.50	-	Assumption.
Toilets	9	-	1.6	Assumption.
Urinals	2	-	1.0	Assumption.

Overview

A summary of water fixtures is as follows:

- Six handwashing faucets. They are equipped with motion sensors on the hall side (qty. 4) and manual on the radio side (2).
- Five kitchen sinks.
- One slop sink.
- 9 toilets.
- 2 urinals.

Water fixture documentation

Water fixture documentation, including available drawings and photos taken during the site survey, is provided in the following images.



Figure 63: Faucet in radio washroom



Figure 64: Handwashing faucets in men's washroom



Figure 65: Server sink



Figure 66: Slop sink



Figure 67: Three kitchen sinks



Figure 68: Toilet



Figure 69: Toilet in radio washroom



Figure 70: Urinals

2.11 Utility services

Utility services summary

Overview

The building utilizes electricity from Hydro One Networks Inc. and natural gas from Enbridge.

The two electricity meters operate on a General Energy rate structure. One meter serves the hall, and the other serves the radio station. WalterFedy only has the electricity data for the hall side.

There are two natural gas meters at this facility. One for the hall, the other for the radio station.

Utility services documentation

Utility services documentation, including available drawings and photos from the site survey, is provided in the following images.



Figure 71: Electricity meter - hall



Figure 72: Electricity meter - radio



Figure 73: Natural gas meter - hall



Figure 74: Natural gas meter - radio

2.12 Onsite energy sources

Overview

There is emergency power infrastructure on-site. However, there is no emergency generator present. It is assumed that a portable generator is brought in when required.

There are no renewable energy systems present at this facility.

2.13 Electrical infrastructure

Overview

The existing system is 800 A at 208 V - 3Ph service running at a maximum load of 27.75 kW, which is approximately 12% of the full load of 230.57 kW of the building. The main 800 A incoming switchboard has two empty spaces. The building disconnect is rated for 800A, 120/208V, 3 phase. It serves a 400A service on the radio side, and 600A service on the hall side. There is also a 75 kVA transformer that serves two manual transfer switches for emergency power. No emergency generator was present at this site.

Electrical infrastructure documentation

Electrical infrastructure documentation, including available drawings and photos from the site survey, is provided in the following images.



Figure 75: 100A emergency power disconnect



Figure 76: 200A disconnect for AC1



Figure 77: 200A disconnect for Panel C



Figure 78: 200A disconnect for Panel D



Figure 79: 75kVA transformer



Figure 80: Emergency power disconnects



Figure 81: Main disconnect - hall



Figure 82: Main disconnect - radio



Figure 83: Main disconnect - building

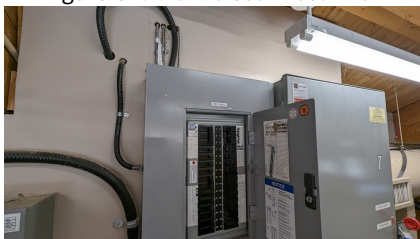


Figure 84: Mezz panel



Figure 85: Panel D

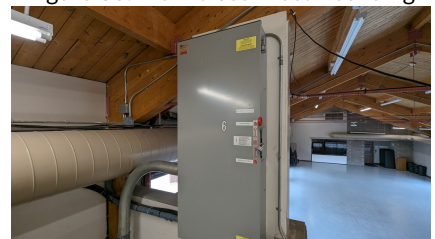


Figure 86: Transfer switch - hall



Figure 87: Transfer switch - radio station

3 UTILITY USE ANALYSIS

3.1 Utility analysis methodology

The utility use analysis was completed according to the following methodology. Note that the results achieved from applying this methodology are presented in the same order in Sections 3.2 through 3.8.

1. **Utility analysis assumptions.** Assumptions applied in the utility use analysis were identified and summarized in Section 3.2.
2. **Metered utility use.** Metered utility use data, as available, were analyzed and summarized in a subsection corresponding to the utility. Metered utility use data were available for the following utilities for Riverside Place.
 - Electricity; see Section 3.3.
 - Natural gas; see Section 3.4.
3. **Utility use baseline.** The utility use baseline was summarized in Section 3.5, and includes the following.
 - Baseline year: A baseline year was determined as the most recent year with the fewest anomalies in facility operations and utility metering. The baseline year was used to establish the historical weather data used for the energy model development, as explained in Section 4.1. If valid metered utility data was available for the baseline year, then the metered utility use data for the baseline year was used to establish baseline performance and for energy model calibration.
 - Baseline performance: Yearly utility use, GHG emissions and utility costs. For each utility, the baseline performance was derived from the metered utility use for the baseline year if available for that utility, or from the energy model described in Section 4 if metered data were unavailable or invalid for that utility. Table 12 summarizes the data source of the baseline performance for each utility.

Table 12: Baseline performance data source for each utility

Utility	Source
Electricity	Meter
Natural gas	Meter

4. **Benchmarking analysis.** The yearly baseline energy use and GHG emissions of Riverside Place was compared with those of similar facilities in Section 3.6. Data for similar facilities were obtained from the Government of Ontario's website, made available for the Broader Public Sector (BPS) through O. Reg. 25/23. The list below includes all municipalities considered for the benchmarking process. If this building is the only one presented, it indicates that similar buildings are not being reported to the database.
 - City of Greater Sudbury
 - City of North Bay
 - City of Temiskaming Shores
 - City of Timmins
 - Municipality of Temagami
 - Municipality of West Nipissing
 - Town of Iroquois Falls
 - Town of Kirkland Lake
 - Township of Armstrong
 - Township of Black River-Matheson
 - Township of Brethour
 - Township of Casey

- Township of Chamberlain
 - Township of Gauthier
 - Township of Harley
 - Township of Harris
 - Township of Hilliard
 - Township of Hudson
 - Township of James
 - Township of Kerns
 - Township of Larder Lake
 - Township of Matachewan
 - Township of McGarry
5. **Portfolio benchmarking analysis.** A portfolio benchmarking analysis was also performed, where Energy Star Portfolio Manager was used to benchmark the energy analysis of Riverside Place.
6. **Utility use analysis discussion.** Results of the utility use analysis were studied and discussed in Section 3.8.

3.2 Utility analysis assumptions

Assumptions applied throughout the methodology are summarized as follows.

- GHG emissions factors were assumed as per Table 13.

Table 13: GHG emissions factor assumptions

Utility	Unit	Value	Source
Electricity	[tCO ₂ e/kWh]	0.0000239	Environment and Climate Change Canada Data Catalogue, Electricity Grid Intensities-1
Natural gas	[tCO ₂ e/m ³]	0.0019324	National Inventory Report, 1990-2023, Table 1-1, Table A61.1-1 and Table A61.1-3

- Utility cost rates for the baseline year of 2023 were assumed as per Table 14. Electricity utility cost rates were assumed based on typical wholesale rates for the General Service Energy billing structure. Throughout this document, the Federal Carbon Charge ("FCC") was treated separately with respect to applicable fuels, rather than being blended into the utility cost rate for those fuels. As such, all other utility cost rates exclude the federal carbon charge. The Federal Carbon Charge was removed on April 1, 2025, as such, this document has been updated to have the FCC set to \$0/tCO₂e for 2025 and onward.

Table 14: Utility cost rate assumptions for the baseline year (2023)

Utility	Line item	Unit	Value
Electricity	Electricity consumption - Class B	[\$/kWh]	0.0200
Electricity	Global adjustment - Class B	[\$/kWh]	0.0735
Electricity	Regulatory	[\$/kWh]	0.0057
Natural gas	Natural gas (blended)	[\$/m ³]	0.2600
GHG emissions	Federal carbon charge	[\$/tCO ₂ e]	50.0000

3.3 Electricity metered utility use

Hourly electricity use is plotted in Figure 88.

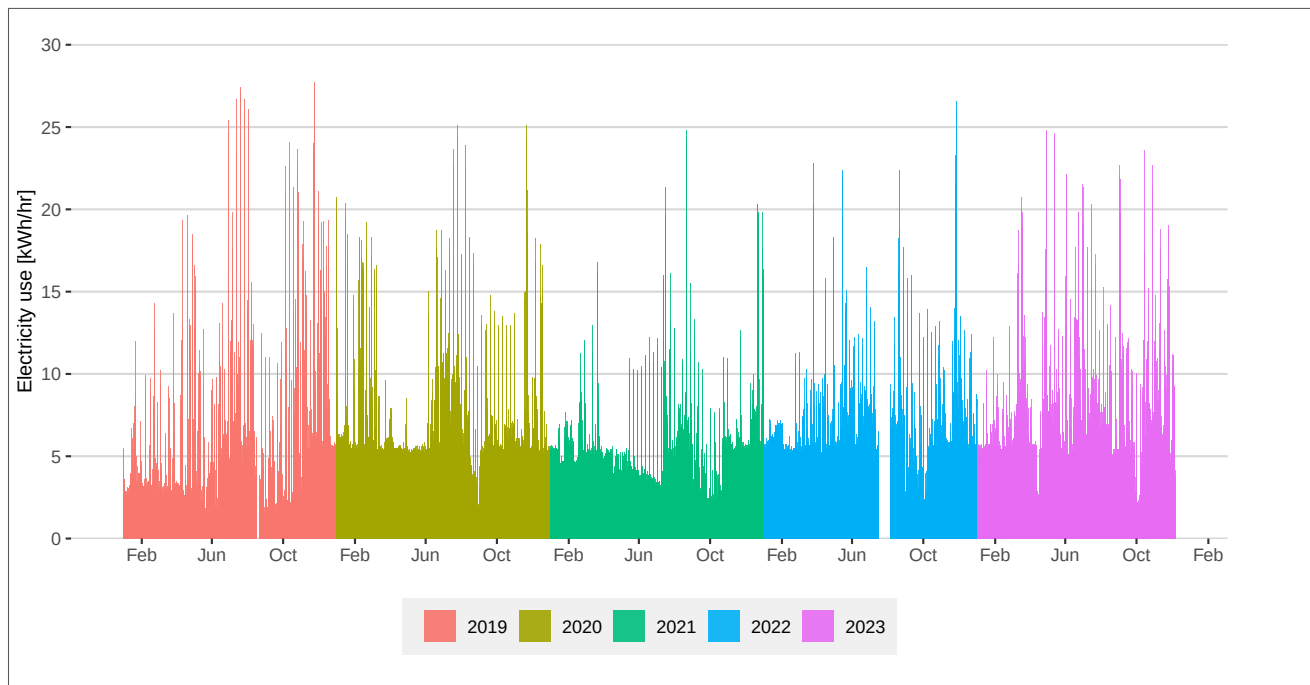


Figure 88: Hourly electricity use

The same hourly electricity use data is plotted in Figure 89, which highlights how electricity use is influenced by year, season, day of week and hour of day. The vertical axis on Figure 89 may be rescaled relative to in Figure 88 for greater resolution.

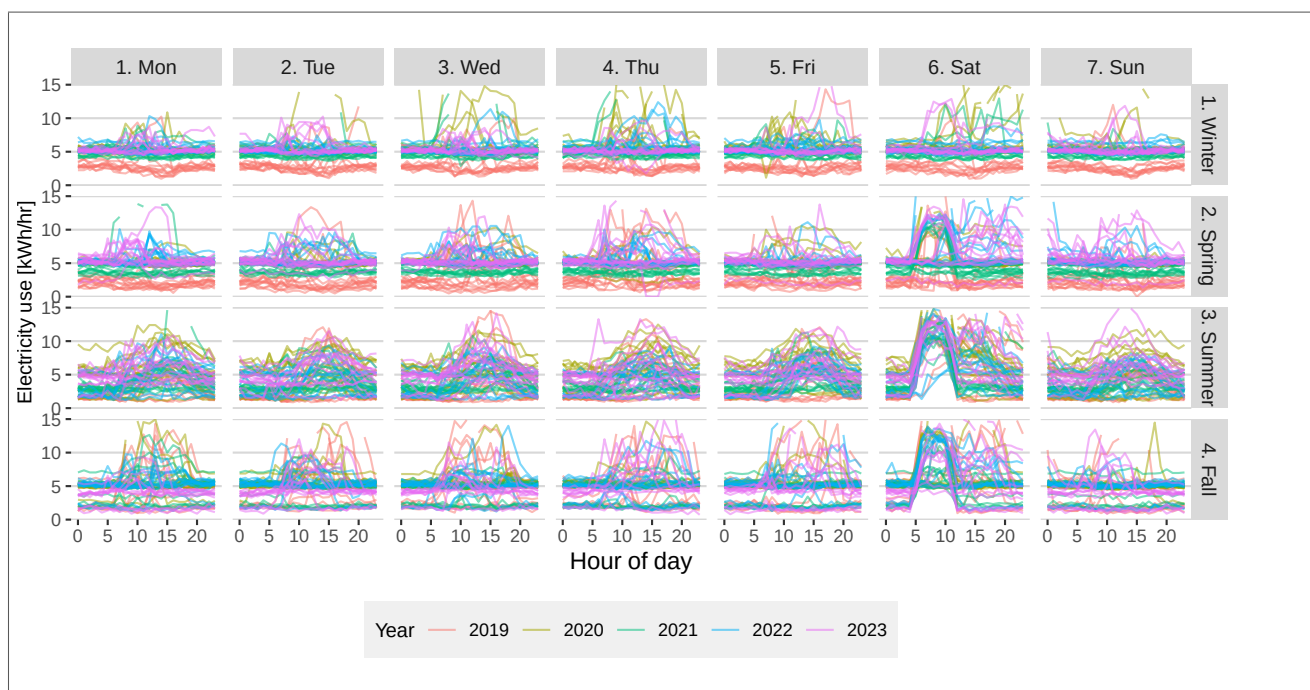


Figure 89: Hourly electricity use hairball plot

Monthly electricity use is plotted in Figure 90.

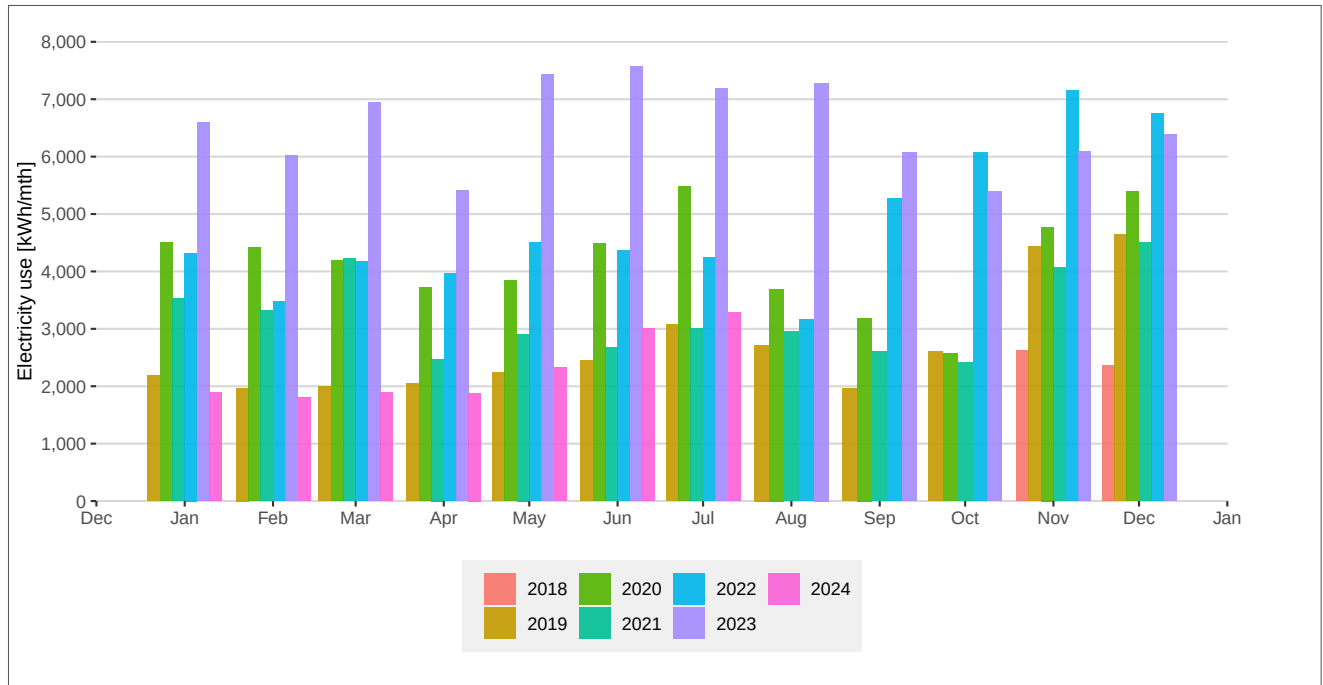


Figure 90: Monthly electricity use

3.4 Natural gas metered utility use

Monthly natural gas use is plotted in Figure 91.

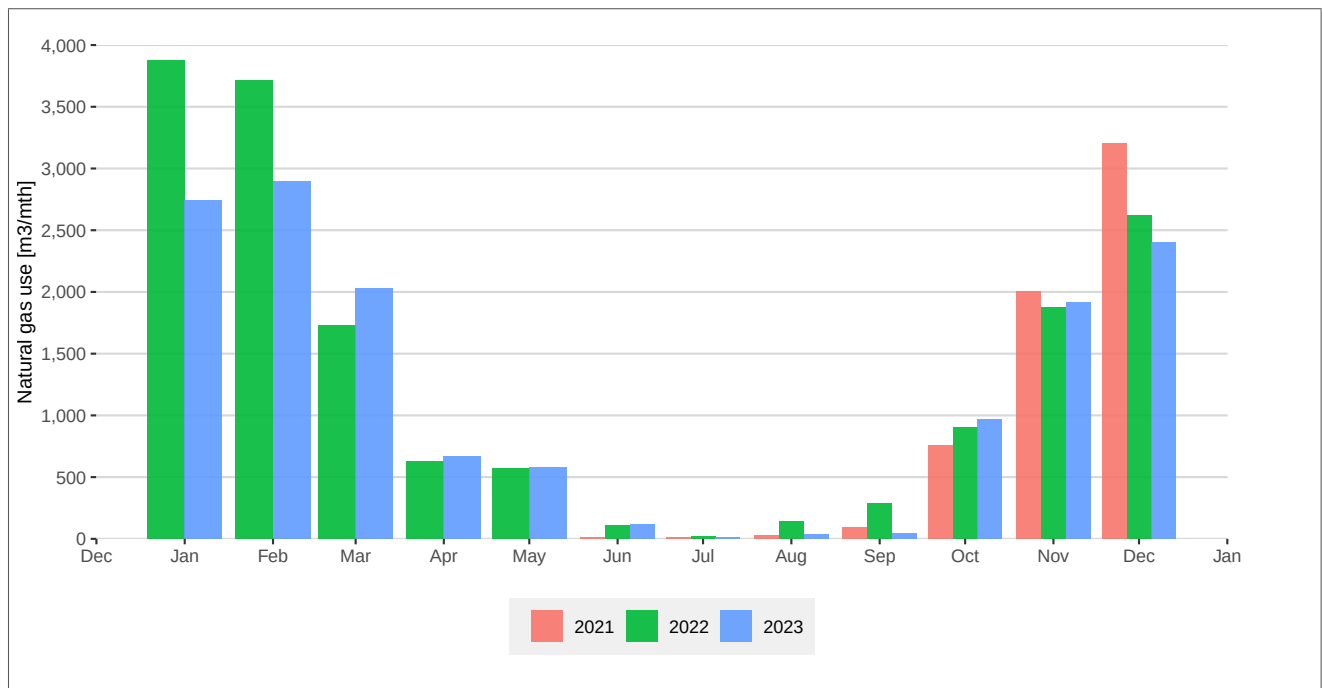


Figure 91: Monthly natural gas use

3.5 Utility use baseline

Baseline year

The baseline year for Riverside Place, which is used to establish the baseline performance through the metered utility use data from that year, is as follows.

- **Baseline year:** 2023.

Baseline performance

Baseline utility use performance for the baseline year of 2023 is summarized in Table 15.

Table 15: Baseline utility use performance

Category	Utility	Unit	Value
Utility use	Electricity use	[kWh/yr]	78,354
	Natural gas use	[m3/yr]	16,475
	Carbon offset use	[tCO2e/yr]	0
Equivalent energy use	Electricity energy	[kWh/yr]	78,354
	Natural gas energy	[kWh/yr]	173,920
	Total energy	[kWh/yr]	252,274
GHG emissions	Electricity GHGs	[tCO2e/yr]	2
	Natural gas GHGs	[tCO2e/yr]	32
	Carbon offsets GHGs	[tCO2e/yr]	0
	Total GHGs	[tCO2e/yr]	34
Utility cost	Electricity utility cost	[\$/yr]	7,773
	Natural gas utility cost	[\$/yr]	4,283
	Carbon offsets utility cost	[\$/yr]	0
	Federal carbon charge	[\$/yr]	1,592
	Total utility cost	[\$/yr]	13,648

3.6 Benchmarking analysis

Benchmarking analysis results are presented in the following figures.

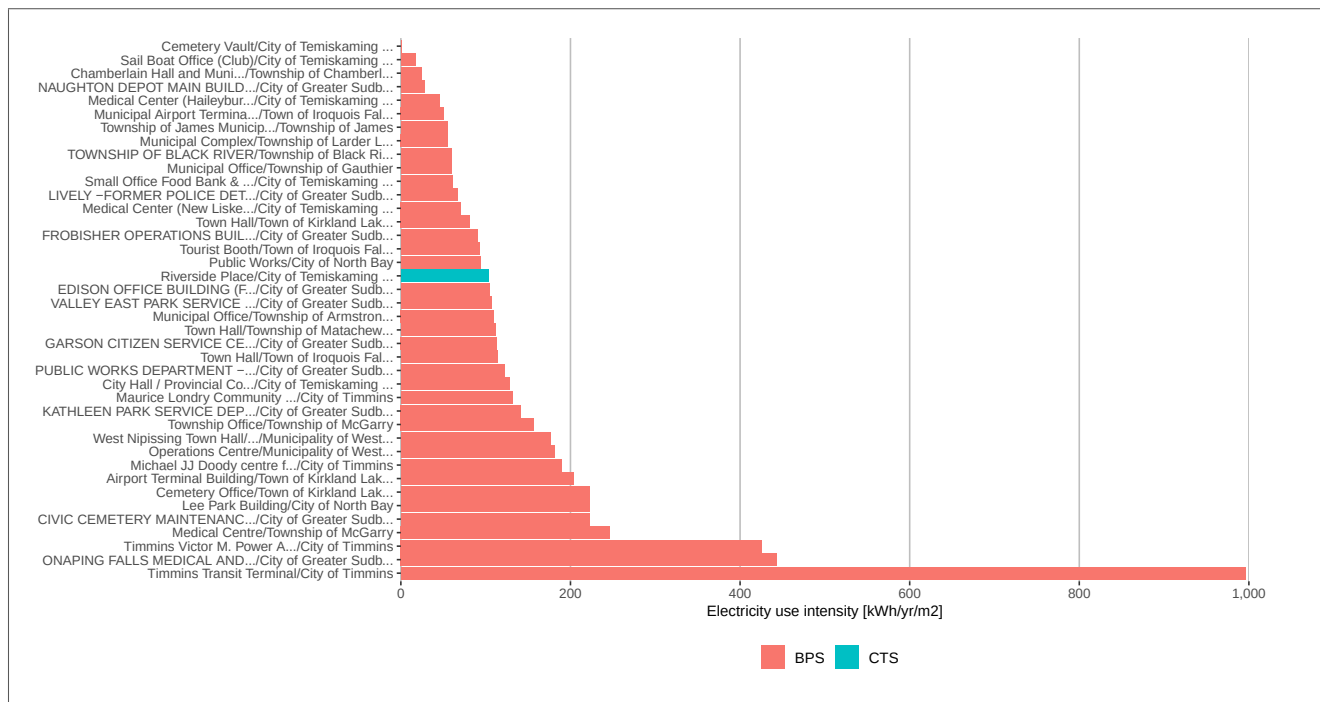


Figure 92: Electricity use intensity benchmarking analysis comparison

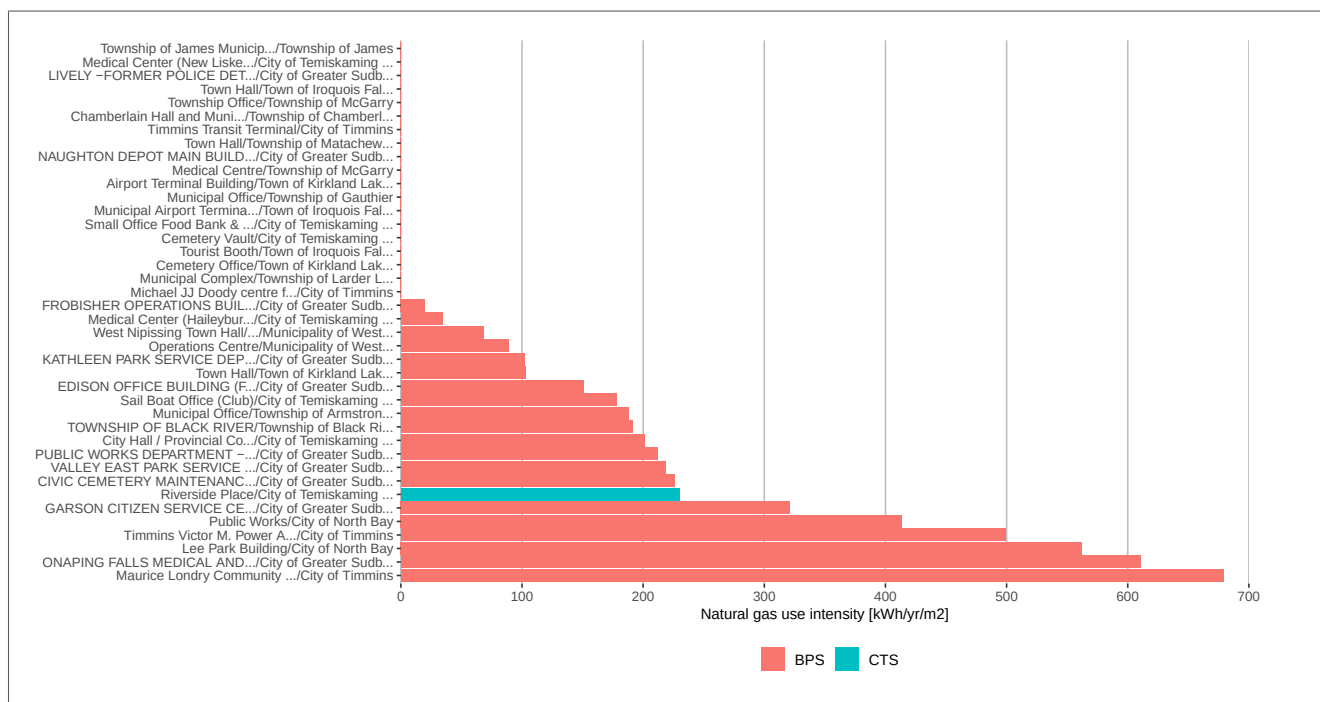


Figure 93: Natural gas use intensity benchmarking analysis comparison

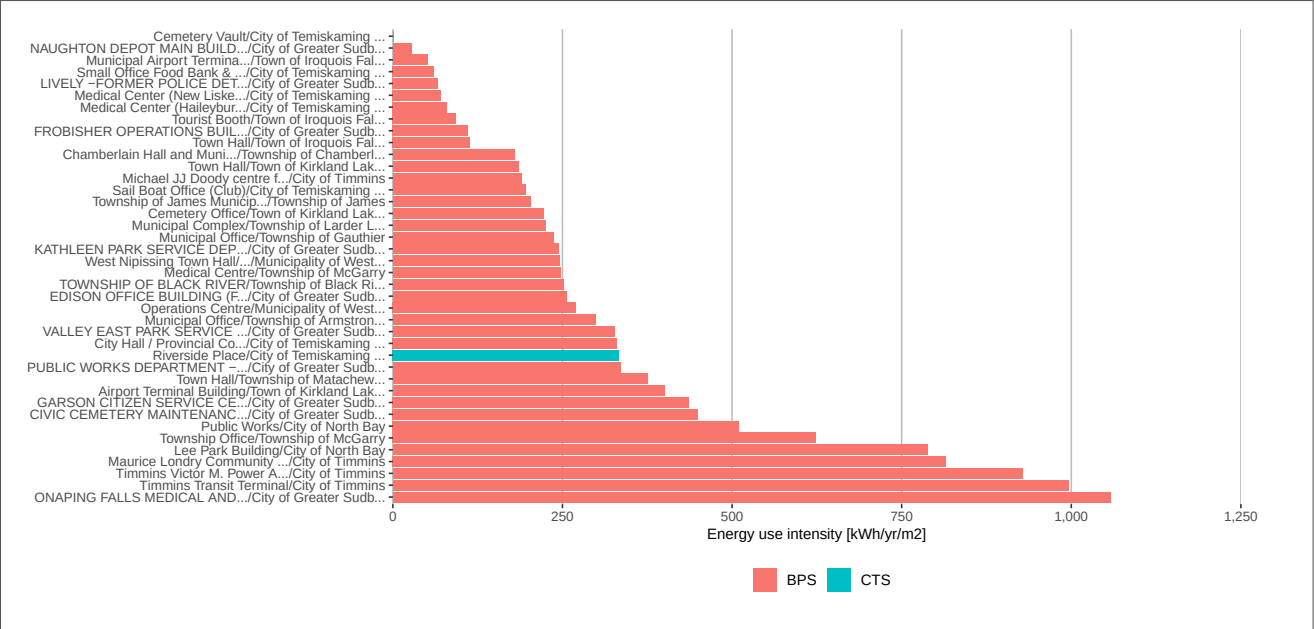


Figure 94: Total energy use intensity benchmarking analysis comparison

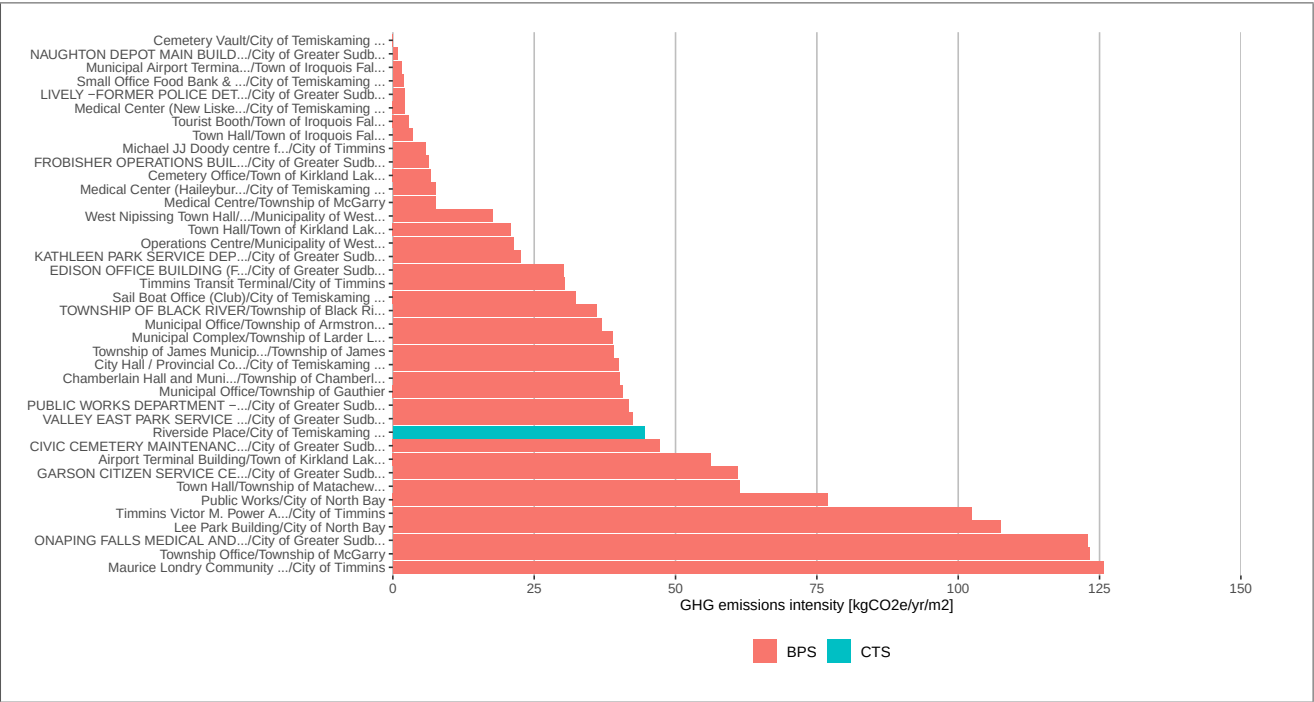


Figure 95: GHG emissions intensity benchmarking analysis comparison

3.7 ENERGY STAR Portfolio Manager benchmarking analysis

The scorecard is shown in Figure 96.

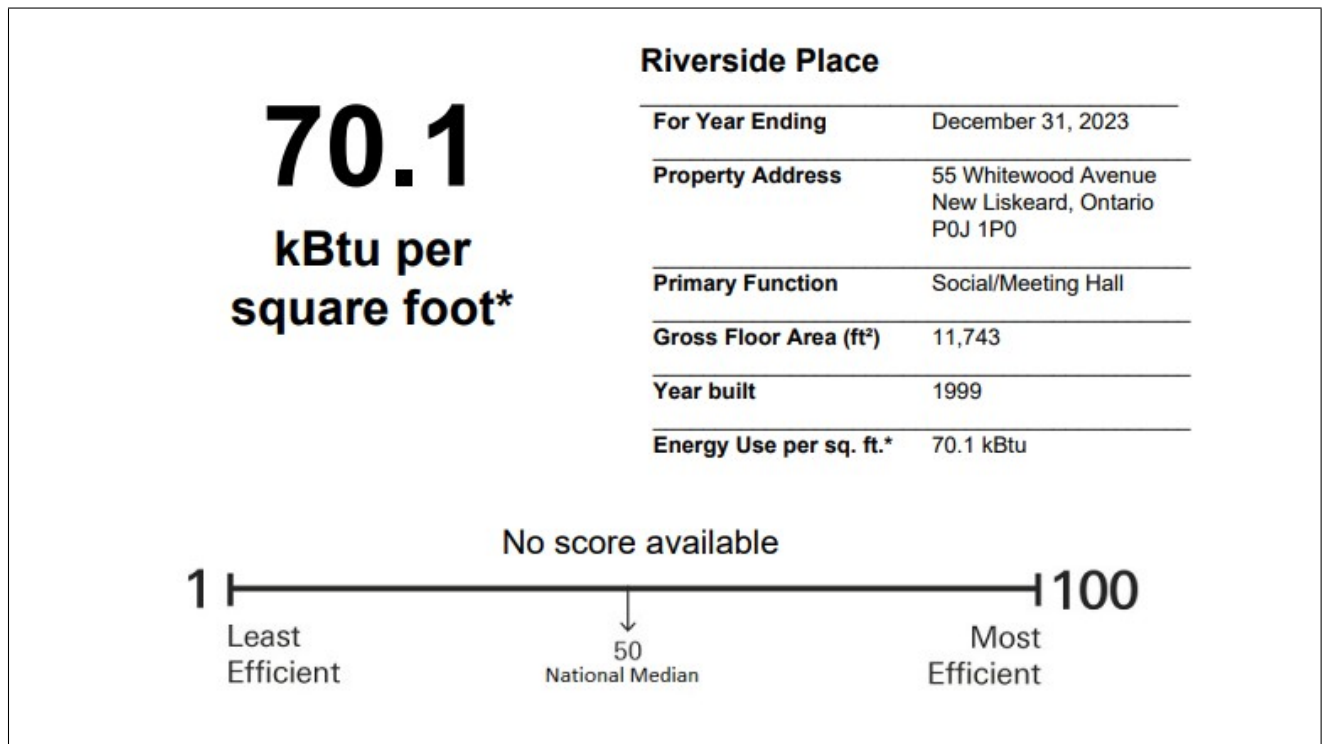


Figure 96: Energy Star energy performance scorecard.

3.8 Utility use analysis discussion

General

The following discussion seeks to explain utility use trends observed in the metered data, based on the understanding of the building systems and their operations presented in Section 2.

Electricity - Hourly

Hourly electricity consumption trends for the event hall are as follows (note that this does not include electricity consumption for the radio station):

- Hourly electricity consumption typically peaks during the summer and winter, most likely due to cooling and heating.
- Hourly consumption is typically under 20 kWh and above 2 kWh.
- A "W-shape" profile suggests heating in the winter and cooling in the summer.
- From late spring to early fall, there is a peak in electrical consumption on Saturdays from around 6 am to 12 pm. This would correspond to the farmer's market, which takes place from 8 am to 12 pm on Saturdays in the event hall.
- The consumption is otherwise fairly sporadic, but is often higher in the afternoons and evenings and likely corresponds to different events which take place at the event hall.

Electricity - Monthly

- Note that only data from September 2022 to December 2023 includes information from both the event hall and the radio station. Electricity use prior to September 2022 only captures the event hall consumption, and data after December 2023 only captures radio station electricity use.
- **2018:** The dataset provided started in November 2018 and did not allow for a full year of comparison, and only includes data from the event hall (with no data for the radio station).
- **2019:** Electricity consumption is considerably below the seasonal average until October. Electricity use peaks in November and December and stays at that level throughout most of the months after 2019, although it is unknown why.
- **2020:** Electricity use follows the typical annual trend, with relatively consistent electricity use throughout the year, and reduced use in the spring and fall. This is likely due to reduced heating and cooling demands during the shoulder seasons.
- **2021:** Throughout most of the year, electricity use falls below the seasonal average from May to July.
- **2022:** Electricity use follows seasonal trends. September 2022 is the first month in this data set where there is utility use information available for both the event hall and the radio station, and has a corresponding increase in magnitude.
- **2023:** Electricity use is fairly consistent, with lower consumption during the shoulder seasons where heating and cooling loads are reduced. Note that 2023 is the only complete year of data for both the event hall and the radio station.
- **2024:** Note that this data only includes data for the radio station. As such, consumption appears to be low for the seasonal average.

Natural gas

- Natural gas consumption has maintained a relatively consistent profile year over year. It is highest during the heating season and very low during the cooling season.
- Natural gas in this building is used for space heating, which is why there is next to no natural gas consumption during the summer months.

- In January and February 2023, the natural gas use is lower than in previous years, with no apparent cause. It is thought that this might be related to some of the windows being replaced.
- Of the sixty data points (thirty data points from each natural gas meter) available for monthly natural gas consumption, only 27 were actual readings, not estimates. This observation can lead to calibration issues, as the model may not pass ASHRAE Guideline 14.

4 ENERGY MODEL DEVELOPMENT

4.1 Energy model development methodology

The utility use profile was developed from an hourly analysis, spanning one year, of the following energy systems. The analysis reflects the existing conditions of the facility as documented in Section 2.

The energy model was created in eQUEST v3.65, build 7175, using the DOE2.3 engine. The inputs were established to match the existing conditions as closely as possible. The following sources were used as background information to inform energy model inputs:

- Observations from site survey and conversations with facility staff.
- Schedules and setpoints from the BAS. As-built drawings provided by the City of Temiskaming Shores.
- References from the Ontario Building Code (OBC) SB-12, ASHRAE90.1, and NECB where the above data was not available.

1. **Hourly utility use profiles.** An hourly utility use profile for each utility was developed according to the following methodology. Results were presented in Section 4.2.

- (a) *Utilities and end uses.* Hourly utility use profiles developed through this analysis were assigned to both utilities and end uses. The utilities and end uses that were modelled are summarized in Table 16.

Table 16: Utility and end use summary and definitions

Utility	End use	Definition of end use
Electricity	Cooling	Cooling energy use.
	DHW heat	Domestic hot water heating energy use.
	Equipment	Equipment energy use.
	Exterior lights	Exterior lighting energy use.
	Fans	Fan motor energy use.
	Lights	Lighting energy use.
	Other	Metered use less modelled use.
	Space heat	Space heating energy use.
Natural gas	Equipment	Equipment energy use.
	Space heat	Space heating energy use.

- (b) *Weather data.* Hourly weather data was obtained from the Earlton-Cimate weather station, ID 712130S.
- (c) *Facility spaces.* Facility spaces were grouped according to activities in the spaces and HVAC systems serving them. The thermal characteristics of the exterior building envelope components for each space were assumed based on findings documented in Section 2.7. Thermal loads within each space were calculated based on assumed space temperature and humidity setpoints, hourly weather data, and activities in the space that affect thermal conditions (e.g. lighting or equipment that generates heat).
- (d) *Primary systems.* Primary systems are defined as systems whose utility use can be predicted independent from other systems; examples include lighting, equipment (e.g. office and process equipment), pumps, etc. The hourly utility demand of primary systems was modelled based on assumed time-of-day operating schedules, peak power input and average loads relative to the peak power input. Peak power input was estimated from findings documented throughout Section 2, including lighting power or power density, nameplate horsepower of motors, etc.
- (e) *HVAC systems.* HVAC system energy use was modelled based on hourly weather data and space condition setpoints defined for the various spaces. The analysis also accounted for system-specific ventilation controls and activities and primary systems that have thermal influences on spaces (e.g. occupancy, lighting, equipment, processes that add heat to spaces). The analysis quantified hourly energy use of fans, heating (e.g. sensible, humidification, reheat) and cooling (e.g. sensible, dehumidification).

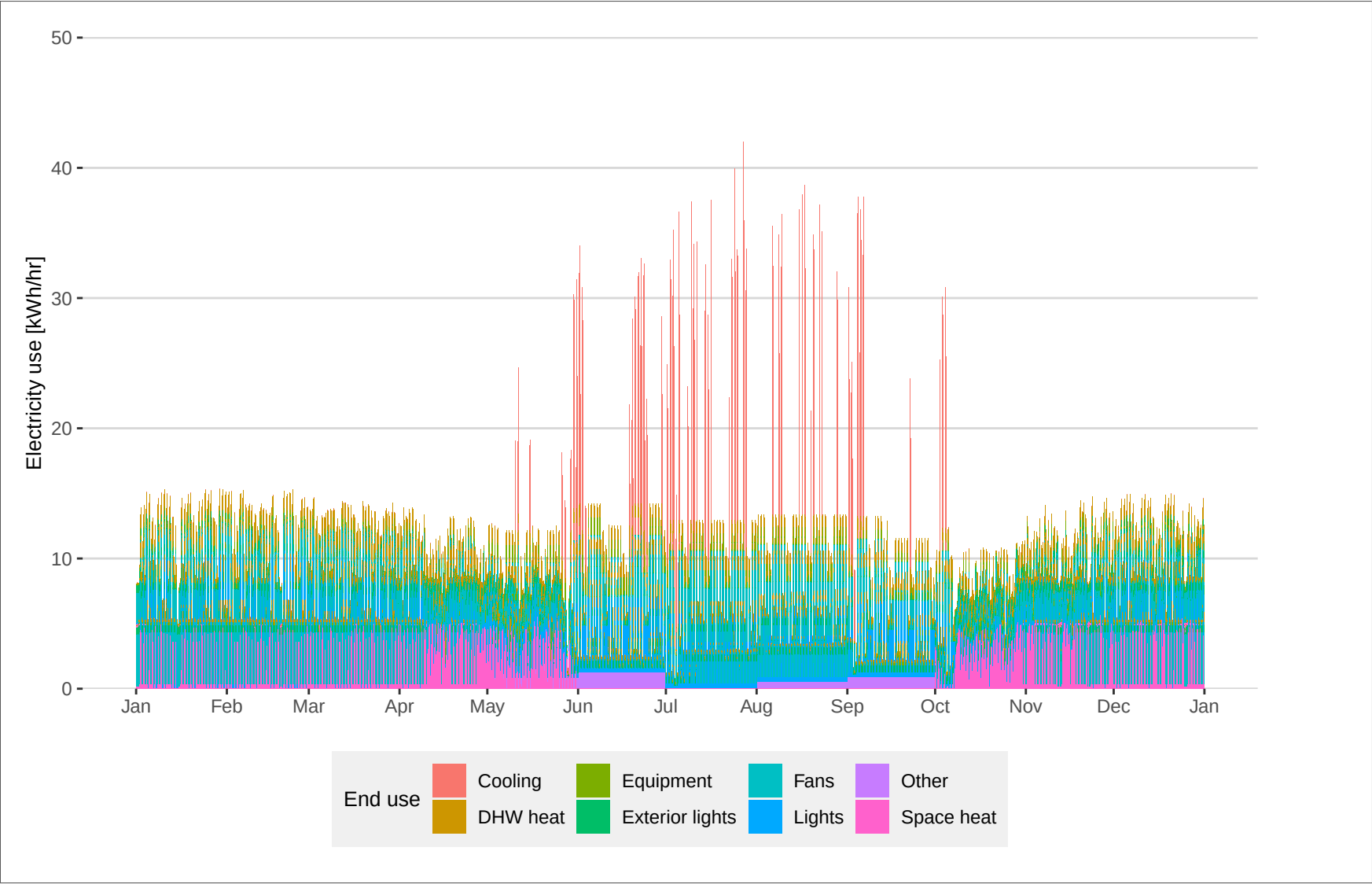
- (f) *Generators*. The utility use and generation of on-site systems that generate energy or utilities was modelled based on the assumed capacities and operations of those systems according to findings documented in Section 2; examples include solar PV, CHP, etc. Utilities generated on site were treated as negative utility consumption relative to utilities consumed on site so that the consumption, generation and the aggregate use of utilities could be tracked accordingly.
 - (g) *Other*. For each utility having valid metered utility use data available for the baseline year, the Other end use was modelled from the top down to reconcile results of the above utility-consuming systems that were modelled from the bottom up with metered utility use data for the baseline year. This end use was called Other.
2. **Monthly utility use profiles**. A monthly utility use profile for each utility was developed by grouping and summing up the hourly utility use profiles by end use and by month. Results were presented in Section 4.3.
 3. **Calibration analysis**. After explicitly modeling the above systems, the model was calibrated for each of the following utilities (utilities for which valid metered data for the baseline year was available) through the Other end use, which was calculated as the difference of metered and modeled utility use. The above modeling steps were iterated as required to achieve reasonable calibration.
 - Electricity
 - Natural gas
 4. **End use analysis**. An end use analysis of each utility was completed. Since the hourly utility use profiles already track the hourly utility use by each end use, the end use analysis involved summarizing data from the hourly utility use profiles to obtain yearly utility use by each end use. Results were presented in Section 4.5.

4.2 Hourly utility use profiles

The hourly utility use profiles are presented graphically in this Section 4.2 in a format called a stacked bar plot. For each hour of the year, the utility use for all end uses active during that hour is presented in a single bar pertaining to that hour. The end uses are identified by colour, and all end uses are “stacked” on top of each other within each hour-specific bar such that the total height of each bar represents the total utility use of all end uses combined in that hour.

Electricity

The hourly electricity utility use profile by end use made by the energy model is plotted in Figure 97. See Table 16 for end use definitions.



Natural gas

The hourly natural gas utility use profile by end use made by the energy model is plotted in Figure 98. See Table 16 for end use definitions.

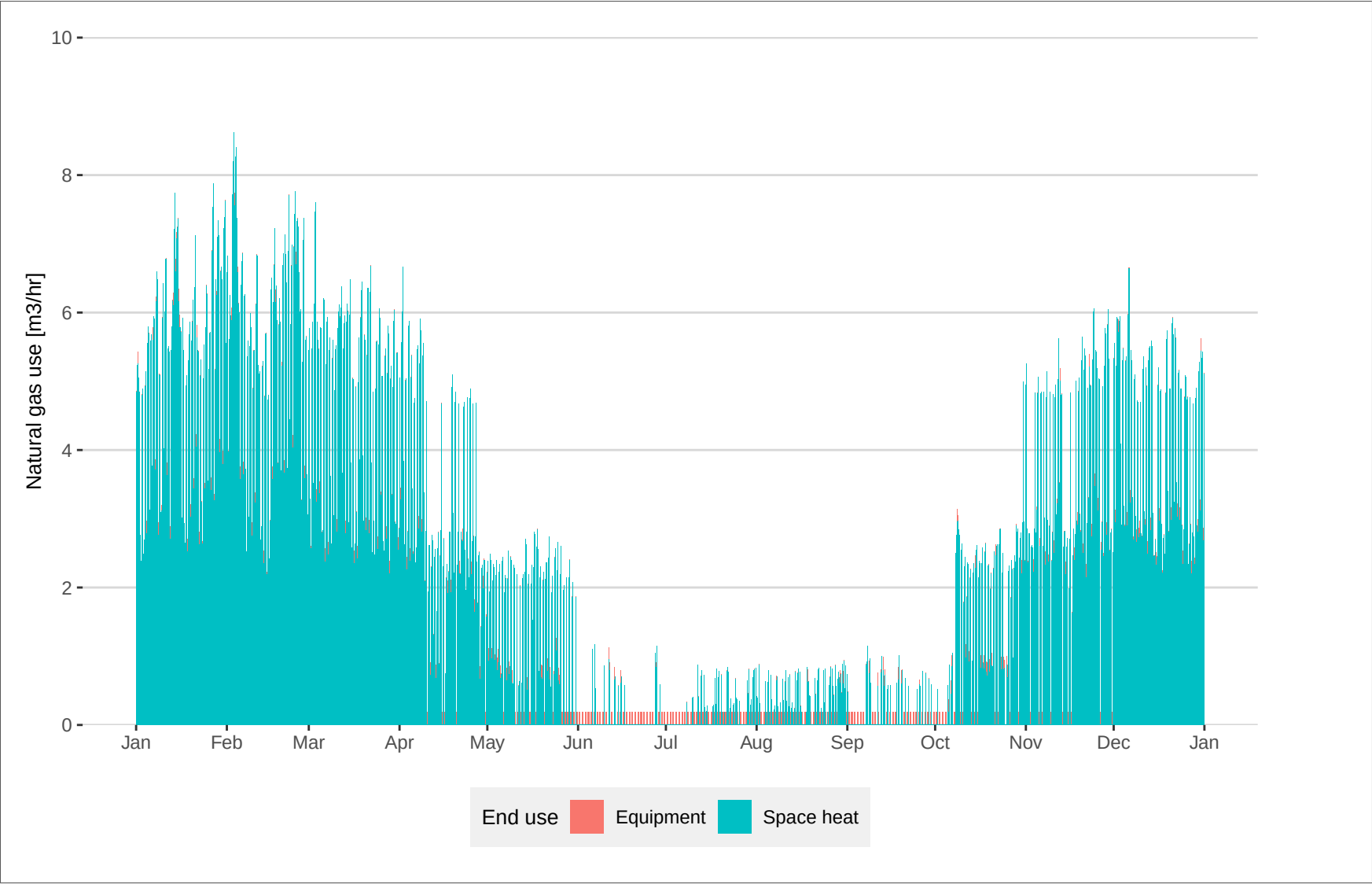


Figure 98: Hourly natural gas utility use by end use (made by calibrated energy model)

4.3 Monthly utility use profiles

Monthly utility use profiles for each modelled utility are presented in Figure 99.

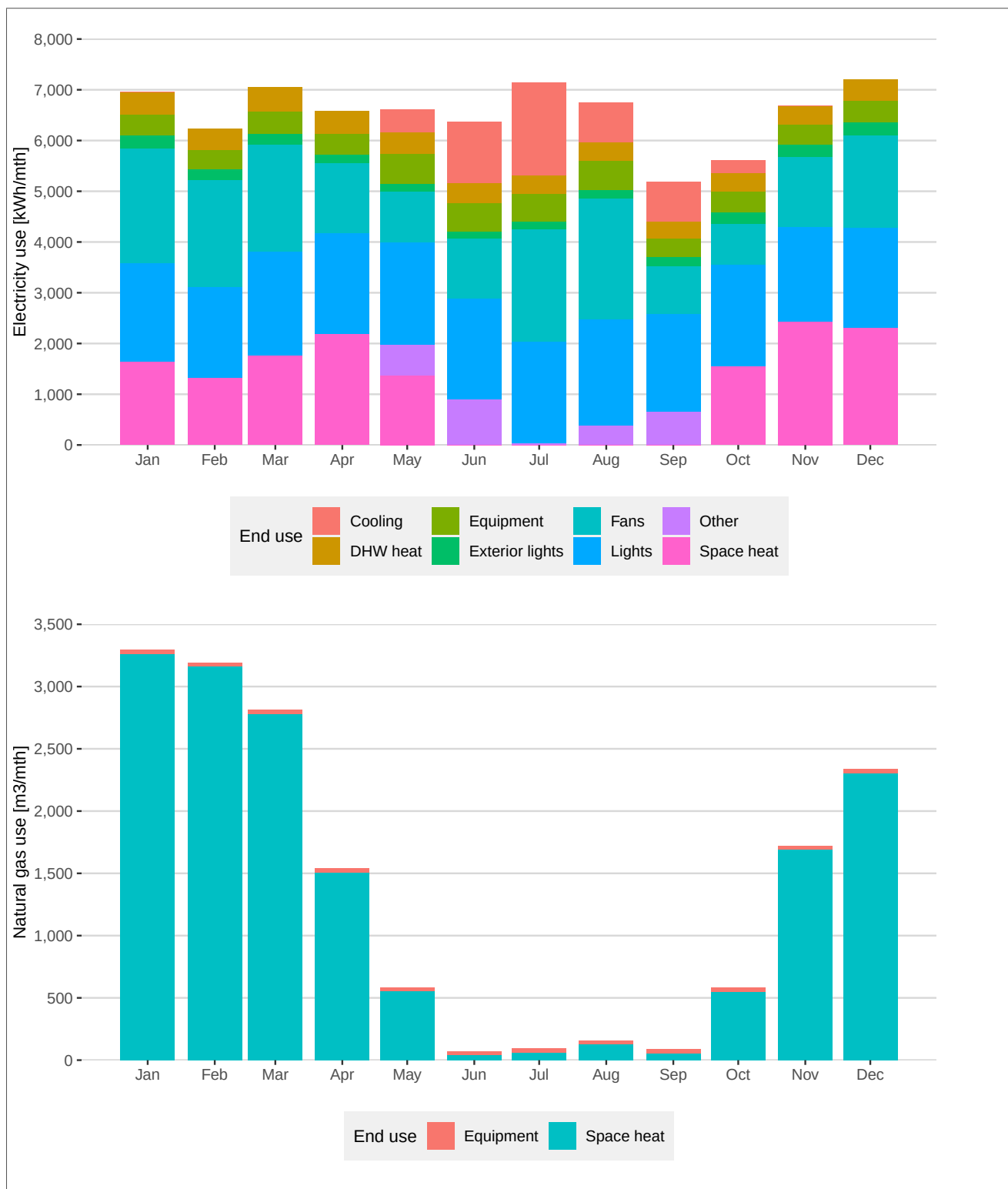


Figure 99: Monthly utility use profiles for each modelled utility

4.4 Calibration analysis

Electricity

Figure 100 compares the metered utility use with the modelled use to check how well the model is calibrated.

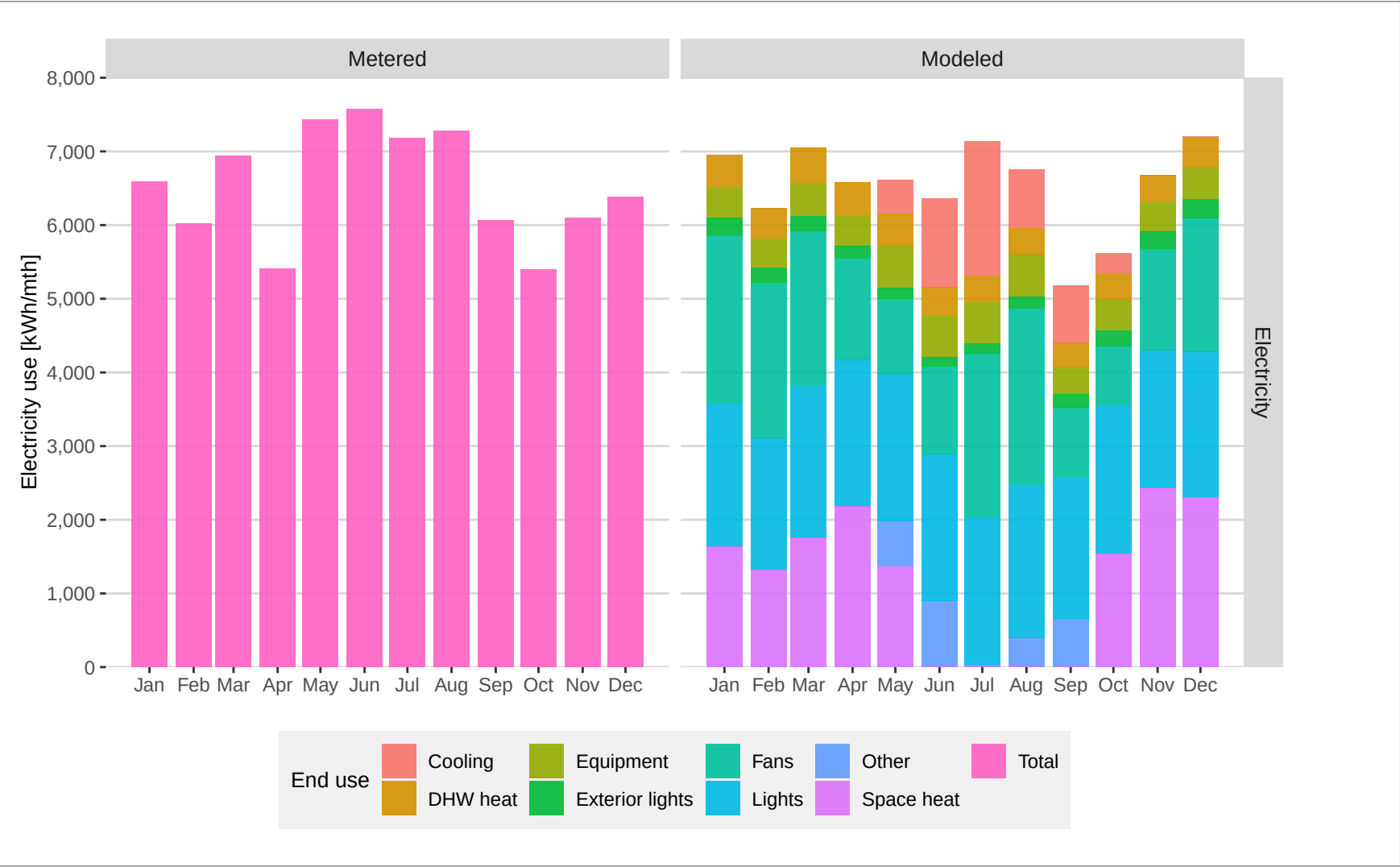


Figure 100: Electricity calibration analysis (metered vs modelled utility use)

Natural gas

Figure 101 compares the metered utility use with the modelled use to check how well the model is calibrated.

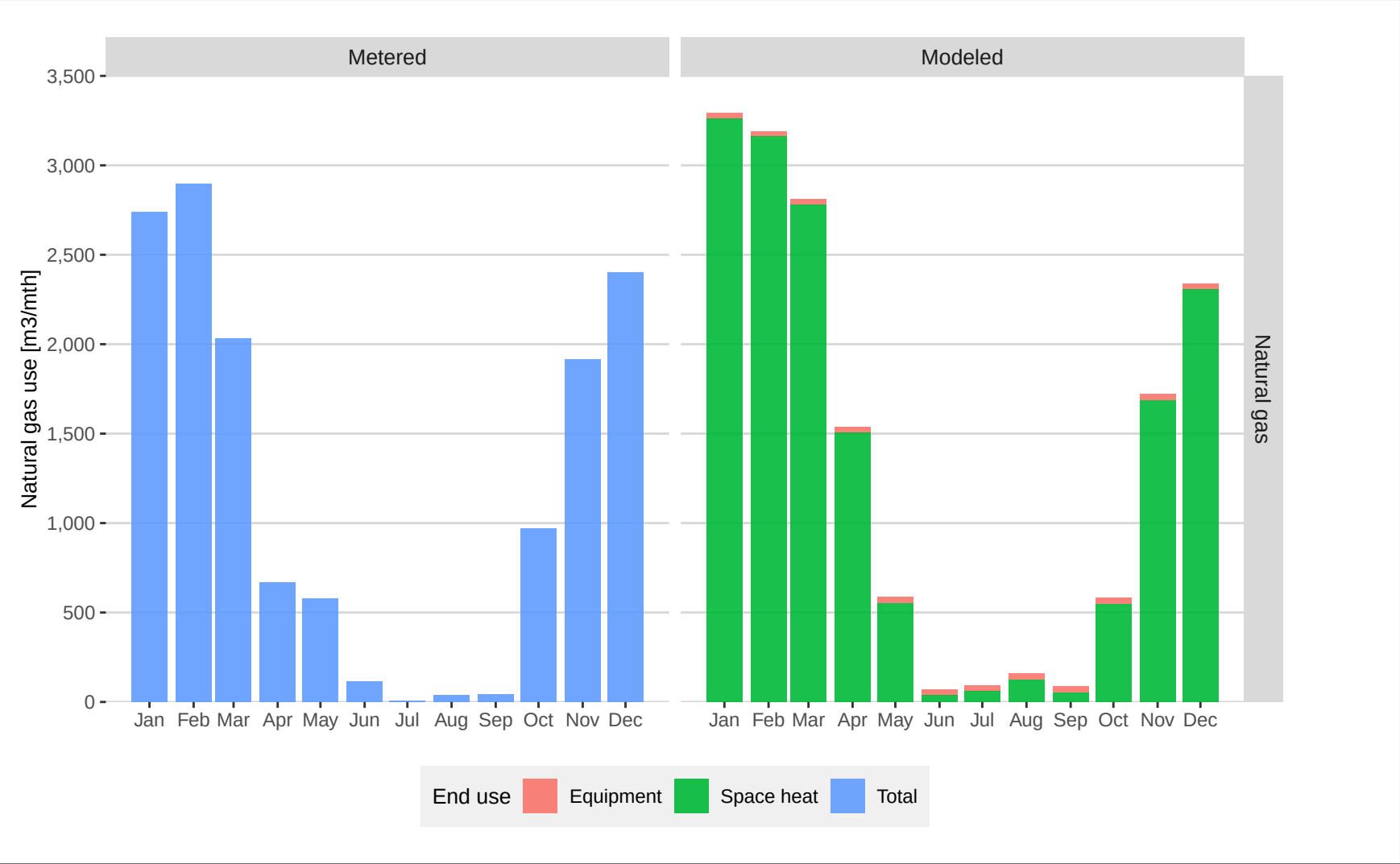


Figure 101: Natural gas calibration analysis (metered vs modelled utility use)

Statistical calibration analysis

ASHRAE Guideline 14 suggests maximum allowable values for the mean bias error, and the root mean bias error, which are defined as follows with respect to energy model calibration.

- **Mean bias error (MBE).** The average monthly error between modelled and metered utility use as a percentage of the mean monthly metered utility use. This metric indicates the ability of the model to accurately predict yearly utility use, despite month-to-month errors, by capturing the direction of all month-to-month errors.
- **Root mean square error (RMSE).** The square root of the sum of all squared monthly errors as a percentage of the mean monthly metered utility use. This metric indicates the ability of the model to accurately predict month-specific utility use.

Statistical calibration analysis results were calculated and are summarized in Table 17.

Table 17: Statistical calibration analysis summary

Utility	Description	Unit	ASHRAE 14	Model	Pass/Fail
Electricity	Mean bias error	[%]	< +/- 5	0.0	Pass
	Root mean square error	[%]	< 15	11.1	Pass
Natural gas	Mean bias error	[%]	< +/- 5	-15.7	Fail
	Root mean square error	[%]	< 15	35.4	Fail

It should be noted that the root mean square error test suggested by ASHRAE Guideline 14 places undue emphasis on months that have relatively little utility use (e.g. natural gas or steam use in the summer). This is because the root mean square error test is calculated based on relative errors between monthly metered and modelled utility use. Because of this, a small absolute error between metered and modelled utility use for a certain month may also be a large relative error, causing a significant increase in the root mean square error. Practically, though, the ability of the energy model to accurately quantify utility use overall has little dependence on its ability to quantify utility use in months with relatively little metered use, because overall utility use is more heavily influenced by those months with greater utility use. Therefore, it may not always be suitable for the model to pass the root mean square error test, provided that it reasonably captures utility use in the months of greater use.

A discussion of the energy model calibration analysis is as follows.

- Figures 100 and 101 both demonstrate a strong agreement between monthly trends observed in the metered utility use data and the monthly utility use predicted by the calibrated energy model.
- Electricity use was successfully calibrated according to the standards of ASHRAE Guideline 14. Note that the mean bias error is zero for electricity and natural gas because the Other end-use ensures that the yearly modelled utility use matches the yearly metered utility use. This process also maintains consistency between the baseline utility use derived from the metered utility data and all measure and scenario analyses.
- Natural gas consumption fails to follow Guideline 14 on the mean bias error and root mean square error. Some notable issues are that consumption is higher in the model from January to April. There is also a discrepancy in the summer months as well. Another note is that only 5 of 12 natural gas readings are actual readings. This issue makes it difficult to calibrate the model, especially against estimated data that the LDC typically underestimates.
- The successful energy model calibration is largely due to the methodology used in developing the calibrated energy model. Under this methodology, the major systems affecting utility use were studied in detail (see Section 2), including their operations and control sequences from analyzing the building automation system (BAS), so that these systems could be explicitly modelled one-to-one, precisely reflecting the unique operations associated with each system. Examples of such major systems include the air handling systems (AC1, AC2a, AC2b, and AC3). The methodology also integrates the Other end-use category, which reflects

the exact difference between metered and modelled utility use in a top-down calculation after all systems have been modelled from the bottom-up.

- Therefore, there can be confidence that the utility use impacts quantified in the various measure and scenario analyses under this report are reasonable.

Electricity

- Figure 100 indicates reasonable agreement between modelled and metered data.

Natural gas

- Figure 101 indicates good agreement between modelled and metered data.
- The annual amount of natural gas consumption in the model is close to the annual amount of the metered data. However, there are variances within several months. That being said, there are several estimated readings for this particular dataset.
- The largest discrepancies lie in January and February, where the model over-predicts the natural gas consumption. As noted in the utility use discussion, the modelled natural gas use in January and February 2023 was lower than it was in 2022, which might indicate a slight change in operations during these months which is not captured in the model.

4.5 End use analysis

Electricity

The yearly electricity end use breakdown calculated by the energy model is plotted in Figure 102. See Table 16 for end use definitions.

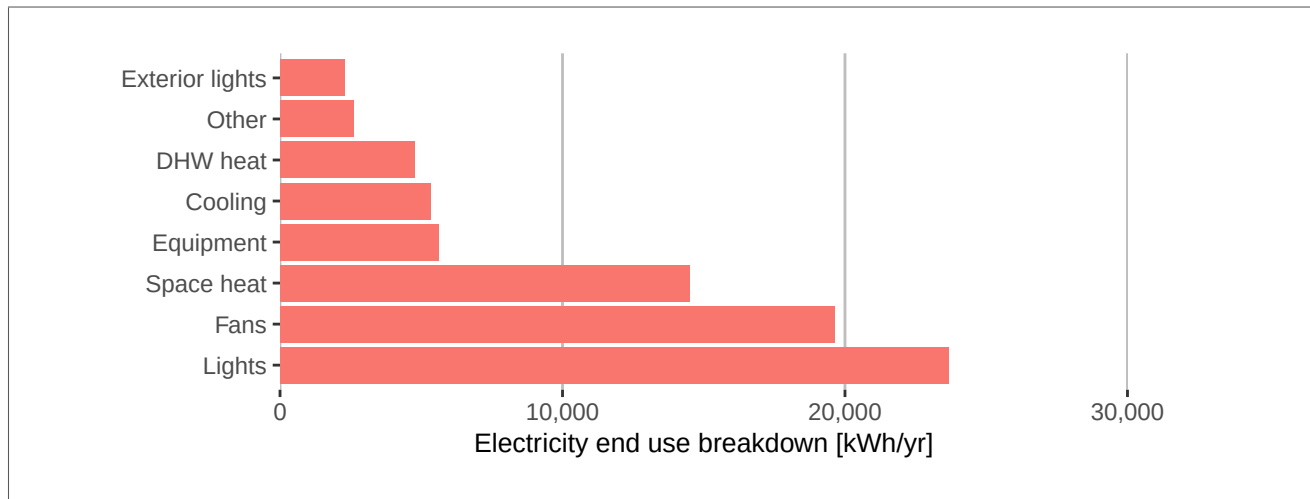


Figure 102: Electricity end use breakdown (calculated by calibrated energy model)

Natural gas

The yearly natural gas end use breakdown calculated by the energy model is plotted in Figure 103. See Table 16 for end use definitions.

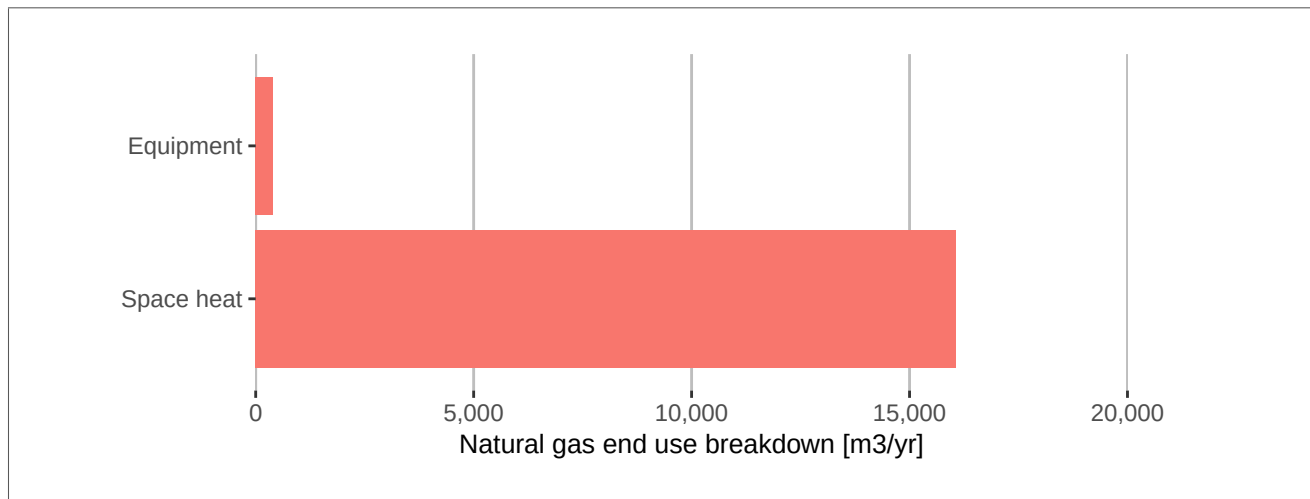


Figure 103: Natural gas end use breakdown (calculated by calibrated energy model)

5 MEASURE ANALYSIS

5.1 Measure analysis methodology

The measure analysis was completed according to the following methodology.

1. **Measure identification and triaging.** Measures that could be implemented to help achieve City of Temiskaming Shores's goals were identified based on the findings documented in Sections 2 and 3. Identified measures were triaged by labeling each one as either 'Analyzed' or 'Not analyzed'. The intent of triaging was to focus efforts on analyzing measures for which analysis was considered most valuable (typically for measures that are more complex or more impactful). Results are summarized in Section 5.3.
2. **Measure analysis.** For each 'Analyzed' measure, the analysis completed for that measure was summarized in a dedicated sub-section named after that measure (see Sections 5.4 through 5.14). In each sub-section, the following was documented.
 - *Measure description.* The relevant existing condition was summarized, an opportunity for improving the stated existing condition was described, and the intended utility-savings mechanism associated with the opportunity was described.
 - *Design description.* A conceptual design description was provided, including a written description of the proposed design concept and the associated project cost estimate.
 - *Utility analysis.* A utility analysis was completed using the energy model introduced in Section 4. Measure-specific assumptions applied in calculating the impacts on utility use were provided for each measure. For each measure, the expected GHG emissions, utility costs and financial incentives associated with implementing the measure were calculated based on utility use, using the assumptions outlined in Section 5.2. A life cycle cost analysis was completed, applying the assumptions summarized in Tables 14 and 20 according to the following methodology.
 - (a) The life cycle cost for each measure was calculated based on the assumed implementation year of 2026 for each measure. The life cycle cost for each measure was calculated as the sum of the following future financial cost expenditures, discounted back to present value using the discount rate from Table 20, over the evaluation period of present to 2050.
 - (b) Project costs: The future value of project costs was calculated based on the project cost estimate of each measure, inflated to future value associated with the assumed implementation year using the general inflation rate from Table 20. In the life cycle cost calculation, the project cost was amortized over the expected life of the measure such that the yearly present value is constant over every year of the expected life of the measure. This results in the net present value of the project cost being equal to what it would be if the owner was to pay for it via lump sum in the implementation year for that measure.
 - (c) Replacement costs: The future value of replacement costs was calculated assuming that a financial cost was incurred to replace equipment associated with each measure at the end of the expected life of that measure equal to 50% of the initial project cost, inflated to future value associated with the estimated time of replacement using the general inflation rate from Table 20. The same amortization approach as for project costs was used.
 - (d) Utility costs: The future value of yearly utility costs of the entire facility was accounted for in the life cycle cost calculation for each measure. The future value of yearly utility costs was calculated by applying the future utility cost rates from Table 18 to the utility use of the entire facility for that year as predicted by the calibrated energy model for each measure and scenario.
3. **Measure risk analysis.** A risk analysis of each individual measure was completed to test how the performance of that measure might be affected by changes to certain risk parameters. In this risk analysis, each of the risk parameters defined in Table 21 was tested under each risk case also defined in Table 21 for that risk parameter. For each risk case of each risk parameter, the expected performance of each measure was quantified, and the results were summarized using box and whisker plots indicating the range over

which performance might be expected to vary. Findings from the risk analysis were summarized in Section 5.15.

4. **Measure analysis summary.** Measure analysis results for all measures were summarized in table format in Section 5.16.

5.2 Measure analysis assumptions

Assumptions general to all measures are as follows.

- GHG emissions factor assumptions are summarized in Table 13, in Section 3.2.
- Utility cost rate assumptions applied to quantify yearly utility cost impacts relative to the baseline are summarized in Table 14, in Section 3.2. Utility cost rate future assumptions applied in the life cycle analysis for each measure are summarized in Table 18. Note that throughout this Pathway to Decarbonization Feasibility Study the Federal Carbon Charge is treated separately (if applicable) with respect to associated fuels (rather than being accounted for within the rates of the applicable fuels, the federal carbon charge line item is calculated separately based on the estimated yearly GHG emissions for that fuel). As such, all other utility cost rates exclude the federal carbon charge.

Table 18: Utility cost rate future assumptions

Year	Natural gas	Federal carbon charge	Carbon offsets	Class B HOEP	Class B GA	Class B regulatory
-	[\$/m3]	[\$/tCO2e]	[\$/tCO2e]	[\$/kWh]	[\$/kWh]	[\$/kWh]
2023	0.2652	65	30	0.0204	0.075	0.0058
2024	0.2705	80	30.6	0.0208	0.0765	0.0059
2025	0.2759	0	31.21	0.0212	0.078	0.006
2026	0.2814	0	31.84	0.0216	0.0796	0.0061
2027	0.287	0	32.47	0.022	0.0812	0.0062
2028	0.2927	0	33.12	0.0224	0.0828	0.0063
2029	0.2986	0	33.78	0.0228	0.0845	0.0064
2030	0.3046	0	34.46	0.0233	0.0862	0.0065
2031	0.3107	0	35.15	0.0238	0.0879	0.0066
2032	0.3169	0	35.85	0.0243	0.0897	0.0067
2033	0.3232	0	36.57	0.0248	0.0915	0.0068
2034	0.3297	0	37.3	0.0253	0.0933	0.0069
2035	0.3363	0	38.05	0.0258	0.0952	0.007
2036	0.343	0	38.81	0.0263	0.0971	0.0071
2037	0.3499	0	39.58	0.0268	0.099	0.0072
2038	0.3569	0	40.38	0.0273	0.101	0.0073
2039	0.364	0	41.18	0.0278	0.103	0.0074
2040	0.3713	0	42.01	0.0284	0.1051	0.0075
2041	0.3787	0	42.85	0.029	0.1072	0.0077
2042	0.3863	0	43.7	0.0296	0.1093	0.0079
2043	0.394	0	44.58	0.0302	0.1115	0.0081
2044	0.4019	0	45.47	0.0308	0.1137	0.0083
2045	0.4099	0	46.38	0.0314	0.116	0.0085
2046	0.4181	0	47.31	0.032	0.1183	0.0087
2047	0.4265	0	48.25	0.0326	0.1207	0.0089
2048	0.435	0	49.22	0.0333	0.1231	0.0091
2049	0.4437	0	50.2	0.034	0.1256	0.0093
2050	0.4526	0	51.21	0.0347	0.1281	0.0095

- Financial incentive assumptions are summarized in Table 19.

Table 19: Financial incentive assumptions

Incentive program	Incentive calculation rules
Enbridge custom	0.25 \$/m3/yr of natural gas reduction Up to a maximum of 50% of eligible project costs Up to a maximum of \$100,000
FCM CBR GHG reduction pathway grant	Up to 80% of project costs (grant + loan) Up to \$5 million (grant + loan) Up to 25% of funding can be grant

- Life cycle cost analysis assumptions are summarized in Table 20.

Table 20: Life cycle cost analysis assumptions

Description	Unit	Value
General cost inflation	[%]	2
Discount rate	[%]	5

- Risk analysis assumptions, including risk parameters and risk cases that were tested in the measure risk analysis are summarized in Table 21.

Table 21: Risk parameter and case definitions

Parameter	Description	Methodology	Case	X	Unit
Project cost	Project cost may differ from the estimated values.	The case project cost = x TIMES the initial project cost estimate.	Very low Low High Very high	0.75 0.9 1.1 1.25	[decimal]
Replacement cost	Replacement cost may differ from the estimated values.	The case replacement cost = x TIMES the initial replacement cost estimate.	Very low Low High Very high	0.75 0.9 1.1 1.25	[decimal]
Utility use change	Changes to utility use and thermal energy demand in a measure or scenario may differ from reality.	The case utility use profile is the baseline profile plus x TIMES the difference between the initial proposed profile and the baseline profile.	Very low Low High Very high	0.75 0.9 1.1 1.25	[decimal]
Electricity GHG factor	Future GHG factors for electricity may differ than those assumed.	For each year for which the GHG factor is projected, the case GHG factor for that year = the current year factor PLUS (x TIMES the difference between the initial value for that year, and the factor for the current year).	Very low Low High Very high	0.75 0.9 1.1 1.25	[decimal]
Incentive rates	Actual incentives may be different from estimated ones. While project cost and utility use affects incentive amounts, this risk parameter seeks to identify the risk in changes to the financial rates used in incentive amount calculations (e.g., if saveon energy provides incentives at 0.05 \$/kWh rather than 0.04 \$/kWh, etc).	For each financial rate used in incentive amount calculations, the case rate is x TIMES the initial rate.	Very low Low High Very high	0.75 0.9 1.1 1.25	[decimal]
Federal carbon charge	Future federal carbon charge rates may differ than those assumed.	The default federal carbon charge increases to 170 \$/tCO2e by 2030 and to 300 \$/tCO2e by 2050. The case federal carbon charge follows the default trend but limited to a maximum value of x.	Very low Low High Very high	0 100 240 300	[\$/tCO2e]
Utility cost inflation	Future utility cost rates may differ than what was assumed.	The case utility cost inflation rate for all utilities is x (as a decimal) compounded yearly.	Very low Low High Very high	0.01 0.015 0.025 0.03	[decimal]
General cost inflation	General cost inflation may differ from what was assumed. Note that general cost inflation is applied ONLY to project costs, replacement costs, and maintenance costs (future utility cost rates are handled separately).	The case general cost inflation rate is x.	Very low Low High Very high	0.01 0.015 0.025 0.03	[decimal]
Discount rate	It is worth testing the sensitivity of the discount rate on life cycle cost / net present value calculations.	The case discount rate is x.	Very low Low High Very high	0.05 0.06 0.08 0.09	[decimal]

- This building has not undergone a building condition assessment, and therefore, business as usual (BAU) measures were not available. WalterFedy utilized previous reports to gauge the potential costing of BAU renewal measures. These measures are provided for reference only and are not intended for use in budgetary

requirements. It's recommended that the City of Temiskaming Shores undertake a Building Condition Assessment of this building.

5.3 Measure identification

Results of the measure identification and triaging process are summarized in Table 22.

Table 22: Measure identification and triaging summary

Measure name	Triage for analysis
Baseline	
AC1 to ASHP with electric backup	Analyzed.
AC1 to ASHP with natural gas backup	Analyzed.
AC2a and AC2b to ASHP with electric backup	Analyzed.
AC2a and AC2b to ASHP with natural gas backup	Analyzed.
Carbon offsets 20	Analyzed.
Exterior LED lighting upgrade	Analyzed.
Interior LED lighting upgrade	Analyzed.
Roof upgrade to high performance	Analyzed.
Solar PV rooftop - community side	Analyzed.
Wall upgrade to high performance	Analyzed.
Windows and doors to high performance	Analyzed.
AC1 renewal	Business as usual.
AC2a and AC2b renewal	Business as usual.
Exterior lighting renewal	Business as usual.
Exterior walls renewal	Business as usual.
Interior lighting renewal	Business as usual.
Roof renewal	Business as usual.
Windows and doors renewal	Business as usual.
DHW heaters to ASHP	Not analyzed: already electric.
Solar PV canopy	Not analyzed: there is limited parking at this facility.

5.4 AC1 to ASHP with electric backup

Measure description

Existing condition

The facility's system includes three RTUs (AC1, AC2a, and AC2b). All three units have a natural gas-fired burner and DX cooling. AC1 serves the hall.



Opportunity

Replace the RTUs and use air-source heat pumps as the heating and cooling source with electric backup.

Utility-savings mechanism

The primary intent of this measure is to reduce GHG emissions by converting the fuel used for heating from natural gas to electricity due to electricity having a lower GHG intensity than natural gas. Reduced natural gas use and increased electricity use would be expected as a result.

Design description

Overview

This measure involves replacing the current rooftop units and furnace/AC units with a packaged air source heat pump (ASHP) model equipped with electric resistance heating for cold ambient conditions when the heat pump capacity would be insufficient for the entire heating load. For the initial selection of the unit, the heating and cooling capacities were selected to match the existing equipment. As an initial selection, a Daiken 10 ton rooftop unit similar to model DPS010A was considered for this application. It should be noted that other manufacturers also provide similar models.

The units are to be equipped with the following features:

- ECM variable speed supply fan motors

- Full economizer for free cooling
- Air source heat pump section
- Electric heating section
- Full controls

The unit will control the economizer and the heat pump to satisfy cooling requests based on the space temperature setpoints. For heating, the unit can be configured to provide heating from the air-sourced heat pump. Once the heat pump is operating at capacity, the electric resistance will be enabled as a second stage of heat. Note that heat pump heating and electric resistance heating can be on simultaneously, allowing the heat pump to always contribute as much as possible to the heating.

The capacity of heating from the heat pump is dependent on the ambient outdoor conditions.

The new rooftop unit can be installed in the same location as the existing unit and integrated into the existing ductwork distribution. The electrical distribution to the unit will have to be upgraded to account for the extra load imposed by the electric resistance heating (typically this is a separate feed to the electric resistance section).

The rooftop unit is provided with integral controls to efficiently control the heat pump, free cooling economizer, and electric heating. The space thermostat will be located within the facility in the same location as the current thermostat for the existing rooftop units. Thermostats and controls should be programmed to allow for scheduling, including temperature setpoint setbacks during unoccupied periods. The thermostat for the rooftop unit would be used to control the unit itself, while the existing thermostats within the individual zones would control the existing bypass dampers as required.

The following unit is noted for this project:

- AC-1 - 15T with 40kW backup

Electrical

The ASHP with the electric backup will add approximately 62.5 kW of power to the existing system, which will put the system at 90.25 kW, which is approximately 39% of the full load of the electrical capacity of the building.

Design Description

Project cost estimate

Table 23: Project cost estimate (AC1 to ASHP with electric backup)

Category	Line item	Unit	Value
Construction	Supply	[\$]	45,000
	Installation Cost	[\$]	20,000
	Electrical distribution to unit	[\$]	18,000
	General requirements (25%)	[\$]	20,800
Contingency	Subtotal after Construction	[\$]	103,800
	Design Contingency (25%)	[\$]	26,000
	Construction Contingency (10%)	[\$]	10,400
Design, Contractors, PM	Subtotal after Contingency	[\$]	140,200
	Engineering Design and Field Review (10%)	[\$]	14,000
	Contractor Fee (7%)	[\$]	9,800
Total	Total	[\$]	164,000

Utility analysis

Utility analysis methodology

The following assumptions were applied to the calibrated energy model to estimate utility use impacts.

- **Baseline:** The RTU provides space heating and cooling through natural gas-fired burners and DX, respectively. The existing heating efficiency is 80%, and the cooling COP is 4.
- **Proposed:** The RTU provides space heating and cooling through air-source heat pumps. The proposed average heating and cooling COPs are 3 and 4.1 (14 EER), respectively. Backup heating is provided through electric resistance when the outdoor air temperature is below -15 C.

Utility analysis results

Table 24: AC1 to ASHP with electric backup analysis results summary

Category	Description	Unit	Baseline	Proposed	Reduction	Reduction [%]
Utility use	Electricity use	[kWh/yr]	78,354	103,100	-24,746	-31.6
	Natural gas use	[m3/yr]	16,475	3,325	13,150	79.8
	Carbon offset use	[tCO2e/yr]	0	0	0	—
Equivalent energy use	Electricity energy	[kWh/yr]	78,354	103,100	-24,746	-31.6
	Natural gas energy	[kWh/yr]	173,920	35,099	138,821	79.8
	Total energy	[kWh/yr]	252,274	138,199	114,075	45.2
GHG emissions	Electricity GHGs	[tCO2e/yr]	1.9	2.5	-0.59	-31.6
	Natural gas GHGs	[tCO2e/yr]	31.8	6.4	25.4	79.8
	Carbon offsets GHGs	[tCO2e/yr]	0	0	0	—
	Total GHGs	[tCO2e/yr]	33.7	8.9	24.8	73.6
Utility cost	Electricity utility cost	[\$/yr]	7,773	10,228	-2,455	-31.6
	Natural gas utility cost	[\$/yr]	4,283	864	3,419	79.8
	Carbon offsets utility cost	[\$/yr]	0	0	0	—
	Federal carbon charge	[\$/yr]	1,592	321	1,271	79.8
	Total utility cost	[\$/yr]	13,648	11,413	2,235	16.4
Financial	Assumed life	[yrs]	15	18	—	—
	Project cost	[\$]	0	164,000	—	—
	Incentive amount	[\$]	0	32,800	—	—
	Incremental project cost	[\$]	0	131,200	—	—
	Life cycle cost	[\$]	336,004	482,715	—	—
	Net present value	[\$]	0	-146,711	—	—
	Project cost per GHG reduction	[\$/tCO2e]	—	5,286	—	—
	Simple payback period	[yr]	—	>20	—	—

5.5 AC1 to ASHP with natural gas backup

Measure description

Existing condition

The facility's system includes three RTUs (AC1, AC2a, and AC2b). All three units have a natural gas-fired burner and DX cooling. AC1 serves the hall.



Opportunity

Replace the RTUs and use air-source heat pumps as the heating and cooling source with natural gas backup.

Utility-savings mechanism

The primary intent of this measure is to reduce GHG emissions by converting the fuel used for heating from natural gas to electricity due to electricity having a lower GHG intensity than natural gas. Reduced natural gas use and increased electricity use would be expected as a result.

Design description

Overview

This measure involves replacing the current rooftop units with a packaged air source heat pump (ASHP) model equipped with natural gas heating for during cold ambient conditions when the heat pump capacity would be insufficient for the entire heating load. For the initial selection of the unit, the heating and cooling capacities were selected to match the existing equipment. As an initial selection, a Daiken 10 ton rooftop unit similar to model DPS010A was considered for this application. It should be noted that other manufacturers also provide similar models.

The unit is to be equipped with the following features:

- ECM variable speed supply fan motors

- Full economizer for free cooling
- Air source heat pump section
- Natural gas heating section
- Full controls

The unit will control the economizer and the heat pump to satisfy cooling requests based on the space temperature setpoints. For heating, the unit can be configured to provide heating from the air-sourced heat pump. Once the heat pump is operating at capacity, the natural gas heater will be enabled as a second stage of heat. Note that heat pump heating and the natural gas heating can be on simultaneously, allowing the heat pump to always contribute as much as possible to the heating.

The capacity of heating from the heat pump is dependent on the ambient outdoor conditions.

The new rooftop unit can be installed in the same location as the existing unit and integrated into the existing ductwork distribution.

The rooftop unit is provided with integral controls to efficiently control the heat pump, free cooling economizer, and natural gas heating. The space thermostat will be located within the facility in the same location as the current thermostat for the existing rooftop units. Thermostats and controls should be programmed to allow for scheduling, including temperature setpoint setbacks during unoccupied periods. The thermostat for the rooftop unit would be used to control the unit itself, while the existing thermostats within the individual zones would control the existing bypass dampers.

The following unit is noted for this project:

- AC-1 - 15T with 400MBH backup

Electrical

This measure is not expected to add much demand to the existing system, as the existing AC1 unit has 15T of cooling.

Design Description

Project cost estimate

Table 25: Project cost estimate (AC1 to ASHP with natural gas backup)

Category	Line item	Unit	Value
Construction	Supply	[\$]	46,500
	Installation Cost	[\$]	10,000
	Electrical distribution to unit	[\$]	6,000
	General requirements (25%)	[\$]	15,600
Contingency	Subtotal after Construction	[\$]	78,100
	Design Contingency (25%)	[\$]	19,500
	Construction Contingency (10%)	[\$]	7,800
Design, Contractors, PM	Subtotal after Contingency	[\$]	105,400
	Engineering Design and Field Review (10%)	[\$]	10,500
	Contractor Fee (7%)	[\$]	7,400
Total	Total	[\$]	123,300

Utility analysis

Utility analysis methodology

The following assumptions were applied to the calibrated energy model to estimate utility use impacts.

- **Baseline:** The RTUs provide space heating and cooling through natural gas-fired burners and DX, respectively. The existing heating efficiency is 80%, and the cooling COP is 4.
- **Proposed:** These furnaces provide space heating and cooling through air-source heat pumps. The proposed average heating and cooling COPs are 3 and 4.1 (14 EER), respectively. Backup heating is provided from the existing gas-fired furnace when the outdoor air temperature is below -15 C.

Utility analysis results

Table 26: AC1 to ASHP with natural gas backup analysis results summary

Category	Description	Unit	Baseline	Proposed	Reduction	Reduction [%]
Utility use	Electricity use	[kWh/yr]	78,354	94,664	-16,310	-20.8
	Natural gas use	[m3/yr]	16,475	4,623	11,852	71.9
	Carbon offset use	[tCO2e/yr]	0	0	0	—
Equivalent energy use	Electricity energy	[kWh/yr]	78,354	94,664	-16,310	-20.8
	Natural gas energy	[kWh/yr]	173,920	48,799	125,121	71.9
	Total energy	[kWh/yr]	252,274	143,463	108,811	43.1
GHG emissions	Electricity GHGs	[tCO2e/yr]	1.9	2.3	-0.39	-20.8
	Natural gas GHGs	[tCO2e/yr]	31.8	8.9	22.9	71.9
	Carbon offsets GHGs	[tCO2e/yr]	0	0	0	—
	Total GHGs	[tCO2e/yr]	33.7	11.2	22.5	66.8
Utility cost	Electricity utility cost	[\$/yr]	7,773	9,391	-1,618	-20.8
	Natural gas utility cost	[\$/yr]	4,283	1,202	3,082	71.9
	Carbon offsets utility cost	[\$/yr]	0	0	0	—
	Federal carbon charge	[\$/yr]	1,592	447	1,145	71.9
	Total utility cost	[\$/yr]	13,648	11,039	2,609	19.1
Financial	Assumed life	[yrs]	15	18	—	—
	Project cost	[\$]	0	123,300	—	—
	Incentive amount	[\$]	0	24,660	—	—
	Incremental project cost	[\$]	0	98,640	—	—
	Life cycle cost	[\$]	336,004	430,823	—	—
	Net present value	[\$]	0	-94,819	—	—
	Project cost per GHG reduction	[\$/tCO2e]	—	4,381	—	—
	Simple payback period	[yr]	—	>20	—	—

5.6 AC2a and AC2b to ASHP with electric backup

Measure description

Existing condition

The facility's system includes three RTUs (AC1, AC2a, and AC2b). All three units have a natural gas-fired burner and DX cooling. AC2a serves the north section of the radio station and AC2b serves the south section of the radio station.



Opportunity

Replace the RTUs and use air-source heat pumps as the heating and cooling source with electric backup.

Utility-savings mechanism

The primary intent of this measure is to reduce GHG emissions by converting the fuel used for heating from natural gas to electricity due to electricity having a lower GHG intensity than natural gas. Reduced natural gas use and increased electricity use would be expected as a result.

Design description

Overview

This measure involves replacing the current rooftop units and furnace/AC units with a packaged air source heat pump (ASHP) model equipped with electric resistance heating for cold ambient conditions when the heat pump capacity would be insufficient for the entire heating load. For the initial selection of the unit, the heating and cooling capacities were selected to match the existing equipment. As an initial selection, a Daiken 10 ton rooftop unit similar to model DPS010A was considered for this application. It should be noted that other manufacturers also provide similar models.

The units are to be equipped with the following features:

- ECM variable speed supply fan motors
- Full economizer for free cooling
- Air source heat pump section
- Electric heating section
- Full controls

The unit will control the economizer and the heat pump to satisfy cooling requests based on the space temperature setpoints. For heating, the unit can be configured to provide heating from the air-sourced heat pump. Once the heat pump is operating at capacity, the electric resistance will be enabled as a second stage of heat. Note that heat pump heating and electric resistance heating can be on simultaneously, allowing the heat pump to always contribute as much as possible to the heating.

The capacity of heating from the heat pump is dependent on the ambient outdoor conditions.

The new rooftop units can be installed in the same location as the existing units and integrated into the existing ductwork distribution. The electrical distribution to the unit will have to be upgraded to account for the extra load imposed by the electric resistance heating (typically this is a separate feed to the electric resistance section).

The rooftop unit is provided with integral controls to efficiently control the heat pump, free cooling economizer, and electric heating. The space thermostat will be located within the facility in the same location as the current thermostat for the existing rooftop units. Thermostats and controls should be programmed to allow for scheduling, including temperature setpoint setbacks during unoccupied periods. The thermostat for the rooftop unit would be used to control the unit itself, while the existing thermostats within the individual zones would control the existing bypass dampers as required.

The following units are noted for this project:

- AC-2a - 4T with 10kW backup
- AC-2b - 4T with 10kW backup
- AC-3 - 2T with no backup

Electrical

The ASHP with the electric backup will add approximately 19 kW of power to the existing system, which will put the system at 46.75 kW, which is approximately 20% of the full load of the electrical capacity of the building.

Design Description

Project cost estimate

Table 27: Project cost estimate (AC2a and AC2b to ASHP with electric backup)

Category	Line item	Unit	Value
Construction	Supply	[\$]	36,000
	Installation Cost	[\$]	30,000
	Electrical distribution to unit	[\$]	15,000
	General requirements (25%)	[\$]	20,200
Contingency	Subtotal after Construction	[\$]	101,200
	Design Contingency (25%)	[\$]	25,300
	Construction Contingency (10%)	[\$]	10,100
Design, Contractors, PM	Subtotal after Contingency	[\$]	136,600
	Engineering Design and Field Review (10%)	[\$]	13,700
	Contractor Fee (7%)	[\$]	9,600
Total	Total	[\$]	159,900

Utility analysis

Utility analysis methodology

The following assumptions were applied to the calibrated energy model to estimate utility use impacts.

- **Baseline:** The RTUs provide space heating and cooling through natural gas-fired burners and DX, respectively. The existing heating efficiencies are 75%, and the cooling COPs are 3.5.
- **Proposed:** These furnaces provide space heating and cooling through air-source heat pumps. The proposed average heating and cooling COPs are 3 and 4.1 (14 EER), respectively. Backup heating is provided through electric resistance when the outdoor air temperature is below -15 C.

Utility analysis results

Table 28: AC2a and AC2b to ASHP with electric backup analysis results summary

Category	Description	Unit	Baseline	Proposed	Reduction	Reduction [%]
Utility use	Electricity use	[kWh/yr]	78,354	88,215	-9,860	-12.6
	Natural gas use	[m3/yr]	16,475	13,551	2,924	17.7
	Carbon offset use	[tCO2e/yr]	0	0	0	—
Equivalent energy use	Electricity energy	[kWh/yr]	78,354	88,215	-9,860	-12.6
	Natural gas energy	[kWh/yr]	173,920	143,049	30,871	17.7
	Total energy	[kWh/yr]	252,274	231,264	21,010	8.3
GHG emissions	Electricity GHGs	[tCO2e/yr]	1.9	2.1	-0.24	-12.6
	Natural gas GHGs	[tCO2e/yr]	31.8	26.2	5.7	17.7
	Carbon offsets GHGs	[tCO2e/yr]	0	0	0	—
	Total GHGs	[tCO2e/yr]	33.7	28.3	5.4	16.1
Utility cost	Electricity utility cost	[\$/yr]	7,773	8,751	-978	-12.6
	Natural gas utility cost	[\$/yr]	4,283	3,523	760	17.7
	Carbon offsets utility cost	[\$/yr]	0	0	0	—
	Federal carbon charge	[\$/yr]	1,592	1,309	283	17.7
	Total utility cost	[\$/yr]	13,648	13,583	64.7	0.47
Financial	Assumed life	[yrs]	15	18	—	—
	Project cost	[\$]	0	159,900	—	—
	Incentive amount	[\$]	0	31,980	—	—
	Incremental project cost	[\$]	0	127,920	—	—
	Life cycle cost	[\$]	336,004	489,739	—	—
	Net present value	[\$]	0	-153,735	—	—
	Project cost per GHG reduction	[\$/tCO2e]	—	23,623	—	—
	Simple payback period	[yr]	—	>20	—	—

5.7 AC2a and AC2b to ASHP with natural gas backup

Measure description

Existing condition

The facility's system includes three RTUs (AC1, AC2a, and AC2b). All three units have a natural gas-fired burner and DX cooling. AC2a serves the north section of the radio station and AC2b serves the south section of the radio station.



Opportunity

Replace the RTUs and use air-source heat pumps as the heating and cooling source with natural gas backup.

Utility-savings mechanism

The primary intent of this measure is to reduce GHG emissions by converting the fuel used for heating from natural gas to electricity due to electricity having a lower GHG intensity than natural gas. Reduced natural gas use and increased electricity use would be expected as a result.

Design description

Overview

This measure involves replacing the current rooftop units with a packaged air source heat pump (ASHP) model equipped with natural gas heating for during cold ambient conditions when the heat pump capacity would be insufficient for the entire heating load. For the initial selection of the unit, the heating and cooling capacities were selected to match the existing equipment. As an initial selection, a Daiken 10 ton rooftop unit similar to model DPS010A was considered for this application. It should be noted that other manufacturers also provide similar models.

The unit is to be equipped with the following features:

- ECM variable speed supply fan motors
- Full economizer for free cooling
- Air source heat pump section
- Natural gas heating section
- Full controls

The unit will control the economizer and the heat pump to satisfy cooling requests based on the space temperature setpoints. For heating, the unit can be configured to provide heating from the air-sourced heat pump. Once the heat pump is operating at capacity, the natural gas heater will be enabled as a second stage of heat. Note that heat pump heating and the natural gas heating can be on simultaneously, allowing the heat pump to always contribute as much as possible to the heating.

The capacity of heating from the heat pump is dependent on the ambient outdoor conditions.

The new rooftop units can be installed in the same location as the existing units and integrated into the existing ductwork distribution.

The rooftop unit is provided with integral controls to efficiently control the heat pump, free cooling economizer, and natural gas heating. The space thermostat will be located within the facility in the same location as the current thermostat for the existing rooftop units. Thermostats and controls should be programmed to allow for scheduling, including temperature setpoint setbacks during unoccupied periods. The thermostat for the rooftop unit would be used to control the unit itself, while the existing thermostats within the individual zones would control the existing bypass dampers.

The following units are noted for this project:

- AC-2a - 4T with 120MBH backup
- AC-2b - 4T with 120MBH backup
- AC-3 - 2T with no backup

Electrical

The ASHP with the natural gas backup will add approximately 9kW of power to the existing system, which will put the system at 36.75 kW, which is approximately 16% of the full load of the electrical capacity of the building.

Design Description

Project cost estimate

Table 29: Project cost estimate (AC2a and AC2b to ASHP with natural gas backup)

Category	Line item	Unit	Value
Construction	Supply	[\$]	38,000
	Installation Cost	[\$]	30,000
	Electrical distribution to unit	[\$]	8,000
	General requirements (25%)	[\$]	19,000
Contingency	Subtotal after Construction	[\$]	95,000
	Design Contingency (25%)	[\$]	23,800
	Construction Contingency (10%)	[\$]	9,500
Design, Contractors, PM	Subtotal after Contingency	[\$]	128,300
	Engineering Design and Field Review (10%)	[\$]	12,800
	Contractor Fee (7%)	[\$]	9,000
Total	Total	[\$]	150,100

Utility analysis

Utility analysis methodology

The following assumptions were applied to the calibrated energy model to estimate utility use impacts.

- **Baseline:** The RTUs provide space heating and cooling through natural gas-fired burners and DX, respectively. The existing heating efficiencies are 80% (for AC1) and 75% (for AC2), and the cooling COPs are 4 (for AC1) and 3.5 (for AC2).
- **Proposed:** These RTUs provide space heating and cooling through air-source heat pumps. The proposed average heating and cooling COPs are 3 and 4.1 (14 EER), respectively. Backup heating is provided from the existing gas-fired furnaces when the outdoor air temperature is below -15 C.

Utility analysis results

Table 30: AC2a and AC2b to ASHP with natural gas backup analysis results summary

Category	Description	Unit	Baseline	Proposed	Reduction	Reduction [%]
Utility use	Electricity use	[kWh/yr]	78,354	85,826	-7,472	-9.5
	Natural gas use	[m3/yr]	16,475	13,937	2,538	15.4
	Carbon offset use	[tCO2e/yr]	0	0	0	—
Equivalent energy use	Electricity energy	[kWh/yr]	78,354	85,826	-7,472	-9.5
	Natural gas energy	[kWh/yr]	173,920	147,126	26,794	15.4
	Total energy	[kWh/yr]	252,274	232,952	19,322	7.7
GHG emissions	Electricity GHGs	[tCO2e/yr]	1.9	2.1	-0.18	-9.5
	Natural gas GHGs	[tCO2e/yr]	31.8	26.9	4.9	15.4
	Carbon offsets GHGs	[tCO2e/yr]	0	0	0	—
	Total GHGs	[tCO2e/yr]	33.7	29.0	4.7	14.0
Utility cost	Electricity utility cost	[\$/yr]	7,773	8,514	-741	-9.5
	Natural gas utility cost	[\$/yr]	4,283	3,624	660	15.4
	Carbon offsets utility cost	[\$/yr]	0	0	0	—
	Federal carbon charge	[\$/yr]	1,592	1,347	245	15.4
	Total utility cost	[\$/yr]	13,648	13,484	164	1.2
Financial	Assumed life	[yrs]	15	18	—	—
	Project cost	[\$]	0	150,100	—	—
	Incentive amount	[\$]	0	30,020	—	—
	Incremental project cost	[\$]	0	120,080	—	—
	Life cycle cost	[\$]	336,004	476,670	—	—
	Net present value	[\$]	0	-140,666	—	—
	Project cost per GHG reduction	[\$/tCO2e]	—	25,409	—	—
	Simple payback period	[yr]	—	>20	—	—

5.8 Carbon offsets 20

Measure description

Existing condition

The facility is currently purchasing no carbon offsets.

Opportunity

After implementing other measures, purchase carbon offsets to offset 20% of the remaining GHG emissions.

Utility-savings mechanism

Energy use is not affected by purchasing carbon offsets. Yearly GHG emissions accounted against the facility will be reduced by the same quantity as those purchased for that year.

Design description

Net zero definition

The Canadian Green Building Council (CaGBC) defines net carbon emissions for a facility as in the following formula.

Net emissions = Embodied carbon + Operational carbon - Avoided emissions

The terms of this formula are defined as follows.

- **Embodied carbon.** GHG emissions associated with the construction, maintenance and final end-of-life disposal of the facility.
- **Operational carbon.** GHG emissions associated with the use of energy of the facility while in operation.
- **Avoided emissions.** GHG emissions avoided through activities such as exporting green power to local grids, or the purchase of carbon offsets.

Net Zero emissions as achieved when the Net emissions from this formula is zero or less.

This measure focuses on the on-going use of avoided emissions (as defined above) to offset operational carbon associated with ongoing energy use at the facility. Note that embodied carbon emissions tend to be a one-time event, in contrast to the on-going emissions associated with operations, which must also be accounted for through avoided emissions.

Renewable energy certificates

As defined above, emission avoidance activities recognized by the CaGBC definition of Net-Zero include exporting green power, or the purchase of carbon offsets. Green power exports include the exporting of on-site renewable energy, as well as the injection of renewable energy into local grids through off-site renewable energy generation facilities. The latter approach is typically accomplished through the purchase of Renewable Energy Certificates (RECs). RECs are utility-specific and are purchased by unit energy of the utility in question (e.g. kWh for electricity, or m³ for natural gas), and can only be used to offset GHG emissions associated with the specific utility in question. For example, electricity RECs can be purchased to offset up to 100% of electricity used by the building, but cannot be used to offset natural gas used by the building (and vice versa). RECs are typically considered best practise because they facilitate an immediate injection of renewable energy into grids. RECs can be purchased through REC providers such as Bullfrog Power.

Carbon offsets

The purchase of carbon offsets is the second approach for avoided emissions recognized by CaGBC. Carbon offsets are purchased per tonne of GHG emissions, and can be used to offset either direct (e.g. natural gas combustion on-site) or indirect (e.g. electricity use on-site, which is generated offsite) GHG emissions. Carbon offsets must be certified as stipulated within the CaGBCs Zero Carbon Building Standard, which is required to

uphold quality standards of the carbon offsets. Carbon offsets can be purchased through certified providers such as Less Emissions Inc.

Cost rates

Cost rates for RECs and carbon offsets are summarized as follows.

- Electricity REC cost rate (Bullfrog Power): 0.025 \$/kWh.
- Natural gas REC cost rate (Bullfrog Power): 0.186 \$/m3.
- Carbon offset cost rate (Less Emissions Inc.): 30 \$/mtCO₂e.

Utility analysis

Utility analysis methodology

Energy use is not affected by purchasing carbon offsets. Yearly GHG emissions accounted against the facility will be reduced by the same quantity as those purchased for that year.

Baseline. It is assumed that no carbon offsets are purchased.

Proposed. Carbon offsets are assumed to be purchased in the quantity equal to 20% of remaining GHG emissions. Note that as an individual measure, the analysis indicates the impact of offsetting baseline GHG emissions with carbon offsets. When considered as part of the scenario analyses in Section 6, this measure will cause 20% of remaining GHG emissions to be offset.

Utility analysis results

Table 31: Carbon offsets 20 analysis results summary

Category	Description	Unit	Baseline	Proposed	Reduction	Reduction [%]
Utility use	Electricity use	[kWh/yr]	78,354	78,354	0	0
	Natural gas use	[m3/yr]	16,475	16,475	0	0
	Carbon offset use	[tCO ₂ e/yr]	0	6.7	-6.7	—
Equivalent energy use	Electricity energy	[kWh/yr]	78,354	78,354	0	0
	Natural gas energy	[kWh/yr]	173,920	173,920	0	0
	Total energy	[kWh/yr]	252,274	252,274	0	0
GHG emissions	Electricity GHGs	[tCO ₂ e/yr]	1.9	1.9	0	0
	Natural gas GHGs	[tCO ₂ e/yr]	31.8	31.8	0	0
	Carbon offsets GHGs	[tCO ₂ e/yr]	0	-6.7	6.7	—
	Total GHGs	[tCO ₂ e/yr]	33.7	27.0	6.7	20
Utility cost	Electricity utility cost	[\$/yr]	7,773	7,773	0	0
	Natural gas utility cost	[\$/yr]	4,283	4,283	0	0
	Carbon offsets utility cost	[\$/yr]	0	202	-202	—
	Federal carbon charge	[\$/yr]	1,592	1,592	0	0
	Total utility cost	[\$/yr]	13,648	13,850	-202	-1.5
Financial	Assumed life	[yrs]	15	20	—	—
	Project cost	[\$]	0	—	—	—
	Incentive amount	[\$]	0	0	—	—
	Incremental project cost	[\$]	0	—	—	—
	Life cycle cost	[\$]	336,004	339,692	—	—
	Net present value	[\$]	0	-3,688	—	—
	Project cost per GHG reduction	[\$/tCO ₂ e]	—	—	—	—
	Simple payback period	[yr]	—	—	—	—

5.9 Exterior LED lighting upgrade

Measure description

Existing condition

The building exterior lighting utilizes LED and CFL lighting.



Opportunity

Replace all non-LED fixtures with LED equivalent fixtures.

Utility-savings mechanism

Reduced lighting energy use through more energy-efficient lamps. Given the fixtures are exterior to the building (i.e. unconditioned spaces), there are no effects on heating and cooling.

Design description

Overview

The lighting system shall be designed to meet the latest ASHRAE 90.1 energy codes, IESNA standards, the Riverside Place standards and other applicable regulations and standards.

The existing site has gone through some recent LED upgrades. It will be proposed that all the remaining fluorescent fixtures will be replaced with new LED fixtures.

LED luminaires shall be provided with an expected service life of over 50,000 hours, dark-sky compliant, and be listed on the Energy Star Qualified Commercial Lighting List or the Design Lights Consortium List (DLC) for incentive eligibility from the IESO's Save on Energy Program.

With the extended lifespan associated with LED fixtures, the likelihood of a complete fixture failure is significantly less likely than previous fixture types. Rather, the user would witness a slow degradation of the lighting output of

the fixtures. It would be recommended that an annual lighting review is conducted to measure the lighting levels after dusk or before dawn. At the 70% output level, the owner would expect a much quicker decline in the loss of lighting output in each fixture. As such, at the 70% lighting level, it would be recommended that the fixtures be replaced.

Type A1 and D fixtures should be replaced.

Project cost estimate

Table 32: Project cost estimate (Exterior LED lighting upgrade)

Category	Line item	Unit	Value
Materials and labour	Exterior LED lighting upgrade	[\$]	2,500
Contingency	Subtotal after Materials and labour	[\$]	2,500
	General Contingency (50%)	[\$]	1,200
Total	Total	[\$]	3,700

Utility analysis

Utility analysis methodology

The following assumptions were applied to the calibrated energy model to estimate utility use impacts.

- **Baseline:** Exterior lighting is assumed to consume 0.52 kW.
- **Proposed:** It is assumed that the exterior lighting is replaced with an LED equivalent which consumes 0.312 kW.

Utility analysis results

Table 33: Exterior LED lighting upgrade analysis results summary

Category	Description	Unit	Baseline	Proposed	Reduction	Reduction [%]
Utility use	Electricity use	[kWh/yr]	78,354	77,447	907	1.2
	Natural gas use	[m3/yr]	16,475	16,475	0	0
	Carbon offset use	[tCO2e/yr]	0	0	0	—
Equivalent energy use	Electricity energy	[kWh/yr]	78,354	77,447	907	1.2
	Natural gas energy	[kWh/yr]	173,920	173,920	0	0
	Total energy	[kWh/yr]	252,274	251,367	907	0.36
GHG emissions	Electricity GHGs	[tCO2e/yr]	1.9	1.9	0.02	1.2
	Natural gas GHGs	[tCO2e/yr]	31.8	31.8	0	0
	Carbon offsets GHGs	[tCO2e/yr]	0	0	0	—
	Total GHGs	[tCO2e/yr]	33.7	33.7	0.02	0.06
Utility cost	Electricity utility cost	[\$/yr]	7,773	7,683	90.0	1.2
	Natural gas utility cost	[\$/yr]	4,283	4,283	0	0
	Carbon offsets utility cost	[\$/yr]	0	0	0	—
	Federal carbon charge	[\$/yr]	1,592	1,592	0	0
	Total utility cost	[\$/yr]	13,648	13,558	90	0.66
Financial	Assumed life	[yrs]	15	20	—	—
	Project cost	[\$]	0	3,700	—	—
	Incentive amount	[\$]	0	0	—	—
	Incremental project cost	[\$]	0	3,700	—	—
	Life cycle cost	[\$]	336,004	337,486	—	—
	Net present value	[\$]	0	-1,482	—	—
	Project cost per GHG reduction	[\$/tCO2e]	—	170,633	—	—
	Simple payback period	[yr]	—	>20	—	—

5.10 Interior LED lighting upgrade

Measure description

Existing condition

Some areas of the building currently operate with LED fixtures (e.g. the hall). The remaining areas of the building primarily utilize CFL or incandescent lighting.



Opportunity

Replace remaining fixtures containing CFL and incandescent lamps with new LED fixtures.

Utility-savings mechanism

Reduced interior lighting energy use with higher efficiency LED fixtures. However, heating energy use will increase to offset the reduction in internal heat gain from the fixtures, while cooling energy use will decrease.

Design description

Overview

The lighting system shall be designed to meet the latest ASHRAE 90.1 energy codes, IESNA standards, the Riverside Place standards and other applicable regulations and standards.

The existing site has gone through some recent LED upgrades. It will be proposed that all the remaining fluorescent fixtures will be replaced with new LED fixtures.

LED luminaires shall be provided with an expected service life of over 50,000 hours and be listed on the Energy Star Qualified Commercial Lighting List or the Design Lights Consortium List (DLC) for incentive eligibility from the IESO's Save on Energy Program.

With the extended lifespan associated with LED fixtures, the likelihood of a complete fixture failure is significantly less likely than previous fixture types. Rather, the user would witness a slow degradation of the lighting output

of the fixtures. It would be recommended that an annual lighting review is conducted to measure the lighting levels within each space of the facility. At the 70% output level, the owner would expect a much quicker decline in the loss of lighting output in each fixture. As such, at the 70% lighting level, it would be recommended that the fixtures within that room be replaced.

Type E and E1 fixtures should be replaced.

Project cost estimate

Table 34: Project cost estimate (Interior LED lighting upgrade)

Category	Line item	Unit	Value
Materials and labour	Interior LED lighting upgrade	[\$]	17,500
Contingency	Subtotal after Materials and labour	[\$]	17,500
	General Contingency (50%)	[\$]	8,800
Total	Total	[\$]	26,300

Utility analysis

Utility analysis methodology

The following assumptions were applied to the calibrated energy model to estimate utility use impacts.

- **Baseline:** It is assumed that the hall has an average lpd of 8.2 W/m² (0.762 W/ft²), and that the radio station has an average lpd of 8.5 W/m² (0.790 W/ft²).
- **Proposed:** It is assumed that the hall lpd is reduced to 6.6 W/m² (0.609 W/ft²), and that the radio station lpd is reduced to 6.8 W/m² (0.632 W/ft²). Operation schedules are maintained.

Utility analysis results

Table 35: Interior LED lighting upgrade analysis results summary

Category	Description	Unit	Baseline	Proposed	Reduction	Reduction [%]
Utility use	Electricity use	[kWh/yr]	78,354	73,237	5,117	6.5
	Natural gas use	[m3/yr]	16,475	16,832	-357	-2.2
	Carbon offset use	[tCO ₂ e/yr]	0	0	0	—
Equivalent energy use	Electricity energy	[kWh/yr]	78,354	73,237	5,117	6.5
	Natural gas energy	[kWh/yr]	173,920	177,687	-3,767	-2.2
	Total energy	[kWh/yr]	252,274	250,924	1,350	0.54
GHG emissions	Electricity GHGs	[tCO ₂ e/yr]	1.9	1.8	0.12	6.5
	Natural gas GHGs	[tCO ₂ e/yr]	31.8	32.5	-0.69	-2.2
	Carbon offsets GHGs	[tCO ₂ e/yr]	0	0	0	—
	Total GHGs	[tCO ₂ e/yr]	33.7	34.3	-0.57	-1.7
Utility cost	Electricity utility cost	[\$/yr]	7,773	7,265	508	6.5
	Natural gas utility cost	[\$/yr]	4,283	4,376	-92.8	-2.2
	Carbon offsets utility cost	[\$/yr]	0	0	0	—
	Federal carbon charge	[\$/yr]	1,592	1,626	-34.5	-2.2
	Total utility cost	[\$/yr]	13,648	13,268	380	2.8
Financial	Assumed life	[yrs]	15	20	—	—
	Project cost	[\$]	0	26,300	—	—
	Incentive amount	[\$]	0	0	—	—
	Incremental project cost	[\$]	0	26,300	—	—
	Life cycle cost	[\$]	336,004	351,736	—	—
	Net present value	[\$]	0	-15,732	—	—
	Project cost per GHG reduction	[\$/tCO ₂ e]	—	-46,364	—	—
	Simple payback period	[yr]	—	>20	—	—

5.11 Roof upgrade to high performance

Measure description

Existing condition

There are four roof assemblies, with the exterior layers consisting of either asphalt shingles or 4-ply built up roof.



Opportunity

Upgrade upon the end of useful life or as required to meet scenario criteria.

Utility-savings mechanism

Reduced heating energy use through improved thermal performance of the roof.

Design description

Overview

The portion of the roof resting on glulam beams has 64mm of rigid insulation and a vapour barrier on 38mm wood decking, with roofing felts and asphalt shingles as a finish. The roof has a thermal performance of around R12, which is considerably less than required by the current building code. The other roof assemblies have a thermal performance around R20. The performance could be significantly improved by adding another layer of rigid insulation onto what is existing, when the current shingled roofs are due for replacement. The roof would need to be R40 (for continuous insulation above a deck) to meet the current building code and R71 for insulation in an attic. This would mean adding another 400mm of batt insulation to the roof trusses or another 200mm of rigid insulation to the exhibition area roof or to the small flat roof. All of these measures (outside of the truss roof of the commercial wing) would entail removing and replacing the existing roof membrane and reworking the roof edge or parapet membrane flashing and metal caps.

Project cost estimate

Table 36: Project cost estimate (Roof upgrade to high performance)

Category	Line item	Unit	Value
Construction	Roof replacement	[\$]	272,000
	General requirements (25%)	[\$]	68,000
Contingency	Subtotal after Construction	[\$]	340,000
	Design Contingency (25%)	[\$]	85,000
	Construction Contingency (10%)	[\$]	34,000
Design, Contractors, PM	Subtotal after Contingency	[\$]	459,000
	Engineering Design and Field Review (10%)	[\$]	45,900
	Contractor Fee (7%)	[\$]	32,100
Total	Total	[\$]	537,000

Utility analysis

Utility analysis methodology

The following assumptions were applied to the calibrated energy model to estimate utility use impacts.

- **Baseline.** An average roof U-value of 0.050 BTU/hr.ft².F (R20) was assumed.
- **Proposed.** An average roof U-value of 0.025 BTU/hr.ft².F (R40) was assumed.

Utility analysis results

Table 37: Roof upgrade to high performance analysis results summary

Category	Description	Unit	Baseline	Proposed	Reduction	Reduction [%]
Utility use	Electricity use	[kWh/yr]	78,354	78,733	-379	-0.48
	Natural gas use	[m3/yr]	16,475	15,800	674	4.1
	Carbon offset use	[tCO ₂ e/yr]	0	0	0	—
Equivalent energy use	Electricity energy	[kWh/yr]	78,354	78,733	-379	-0.48
	Natural gas energy	[kWh/yr]	173,920	166,800	7,120	4.1
	Total energy	[kWh/yr]	252,274	245,533	6,741	2.7
GHG emissions	Electricity GHGs	[tCO ₂ e/yr]	1.9	1.9	-0.01	-0.48
	Natural gas GHGs	[tCO ₂ e/yr]	31.8	30.5	1.3	4.1
	Carbon offsets GHGs	[tCO ₂ e/yr]	0	0	0	—
	Total GHGs	[tCO ₂ e/yr]	33.7	32.4	1.3	3.8
Utility cost	Electricity utility cost	[\$/yr]	7,773	7,810	-37.6	-0.48
	Natural gas utility cost	[\$/yr]	4,283	4,108	175	4.1
	Carbon offsets utility cost	[\$/yr]	0	0	0	—
	Federal carbon charge	[\$/yr]	1,592	1,527	65.2	4.1
	Total utility cost	[\$/yr]	13,648	13,445	203	1.5
Financial	Assumed life	[yrs]	15	20	—	—
	Project cost	[\$]	0	537,000	—	—
	Incentive amount	[\$]	0	107,400	—	—
	Incremental project cost	[\$]	0	429,600	—	—
	Life cycle cost	[\$]	336,004	787,574	—	—
	Net present value	[\$]	0	-451,570	—	—
	Project cost per GHG reduction	[\$/tCO ₂ e]	—	331,926	—	—
	Simple payback period	[yr]	—	>20	—	—

5.12 Solar PV rooftop - community side

Measure description

Existing condition

There is no solar PV on the roof. Some rooftop space is available.

Opportunity

Install a solar PV system on the roof where feasible. A net-metering agreement is recommended so that the reduced GHG emissions associated with the electricity generated by the system can be retained by the City of Temiskaming Shores or exported to the grid if on-site electricity consumption is fulfilled.

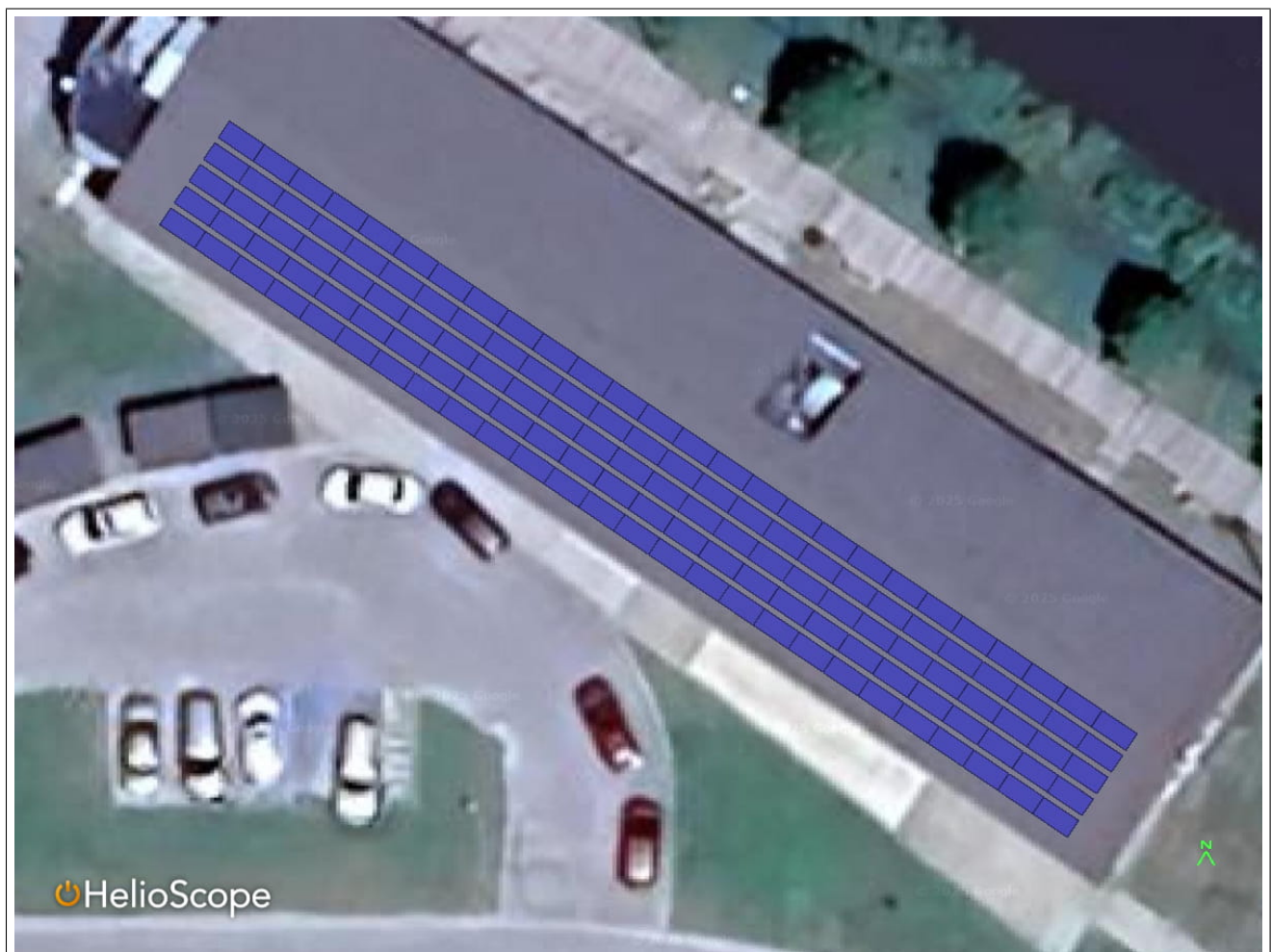
Utility-savings mechanism

The solar PV system will reduce the electricity use from the grid, GHG emissions, and utility costs.

Design description

Helioscope overview

Helioscope was used to determine a preliminary design concept for the proposed solar PV system. The Helioscope model is depicted in the following image.



Based on the results from the Helioscope model, the proposed solar PV system was assumed to have the following output capacity.

- Total system output capacity (DC) = 55 kW.

Proposed scope

Supply and install a rooftop solar PV electricity generation system, including the following.

- Solar PV modules.
- Racking system for mounting the solar panels onto.
- DC to AC inverters.
- Wiring, disconnects, meters, panels and transformers. The AC output from inverters is to be wired into a dedicated solar PV electrical panel before being connected to the main switchboard via a new breaker.
- Connection impact assessment, and other requirements to satisfy the utility provider for executing a Net Metering agreement.
- Installation of the above.

Electrical

With the existing system, the panel is rated high enough to accommodate the additional incoming load of the solar. No additional upgrades outside of the solar equipment will be required.

Project cost estimate

Table 38: Project cost estimate (Solar PV rooftop - community side)

Category	Line item	Unit	Value
Materials and labour	Solar PV electricity system installed (assuming 55 kW at 2000 \$/kW)	[\$]	110,000
	Electrical	[\$]	10,000
Contingency	Subtotal after Materials and labour	[\$]	120,000
	General Contingency (20%)	[\$]	24,000
	Design Contingency (10%)	[\$]	12,000
Total	Total	[\$]	156,000

Utility analysis

Utility analysis methodology

The following assumptions were applied to the calibrated energy model to estimate utility use impacts.

- **Baseline.** There is no solar PV present at this site.
- **Proposed.** The proposed solar PV electricity generation system described above was assumed to be implemented. Helioscope was used to model the hourly electricity output from the solar PV system. All electricity generated by the system was assumed to be used on-site, directly reducing grid electricity consumption, GHG emissions and utility costs.

Utility analysis results

Table 39: Solar PV rooftop - community side analysis results summary

Category	Description	Unit	Baseline	Proposed	Reduction	Reduction [%]
Utility use	Electricity use	[kWh/yr]	78,354	17,985	60,369	77.0
	Natural gas use	[m3/yr]	16,475	16,475	0	0
	Carbon offset use	[tCO2e/yr]	0	0	0	—
Equivalent energy use	Electricity energy	[kWh/yr]	78,354	17,985	60,369	77.0
	Natural gas energy	[kWh/yr]	173,920	173,920	0	0
	Total energy	[kWh/yr]	252,274	191,905	60,369	23.9
GHG emissions	Electricity GHGs	[tCO2e/yr]	1.9	0.43	1.4	77.0
	Natural gas GHGs	[tCO2e/yr]	31.8	31.8	0	0
	Carbon offsets GHGs	[tCO2e/yr]	0	0	0	—
	Total GHGs	[tCO2e/yr]	33.7	32.3	1.4	4.3
Utility cost	Electricity utility cost	[\$/yr]	7,773	1,784	5,989	77.0
	Natural gas utility cost	[\$/yr]	4,283	4,283	0	0
	Carbon offsets utility cost	[\$/yr]	0	0	0	—
	Federal carbon charge	[\$/yr]	1,592	1,592	0	0
	Total utility cost	[\$/yr]	13,648	7,659	5,989	43.9
Financial	Assumed life	[yrs]	15	30	—	—
	Project cost	[\$]	0	156,000	—	—
	Incentive amount	[\$]	0	31,200	—	—
	Incremental project cost	[\$]	0	124,800	—	—
	Life cycle cost	[\$]	336,004	279,776	—	—
	Net present value	[\$]	0	56,228	—	—
	Project cost per GHG reduction	[\$/tCO2e]	—	86,497	—	—
	Simple payback period	[yr]	—	>20	—	—

5.13 Wall upgrade to high performance

Measure description

Existing condition

There are 16 exterior wall assembly types. The main exterior walls tend to have a minimum of 140mm of batt insulation with wood studs. The notable exterior layers include brick, cedar siding, and split face concrete block.



Opportunity

Upgrade upon the end of useful life or as required to meet scenario criteria.

Utility-savings mechanism

Reduced heating energy use through improved thermal performance of exterior walls.

Design description

Overview

The performance of the wall could be improved to just over R30 by adding a 75mm EIFS system to the exterior, but this would greatly change the appearance of the building. EIFS systems can be purchased with a masonry veneer finish, but the existing brick ties would need to be assessed to see if they could support the extra weight. EIFS systems with an acrylic stucco finish have been successfully applied at 150mm thick over existing cavity wall brick buildings across Canada, so the 75mm system is almost certainly well within the tolerances of the supporting structure.

Project cost estimate

Table 40: Project cost estimate (Wall upgrade to high performance)

Category	Line item	Unit	Value
Construction	Wall upgrade	[\$]	217,000
	General requirements (25%)	[\$]	54,200
Contingency	Subtotal after Construction	[\$]	271,200
	Design Contingency (25%)	[\$]	67,800
	Construction Contingency (10%)	[\$]	27,100
Design, Contractors, PM	Subtotal after Contingency	[\$]	366,100
	Engineering Design and Field Review (10%)	[\$]	36,600
	Contractor Fee (7%)	[\$]	25,600
Total	Total	[\$]	428,300

Utility analysis

Utility analysis methodology

The following assumptions were applied to the calibrated energy model to estimate utility use impacts.

- **Baseline.** An average wall U-value of 0.04 BTU/hr.ft².F (R25) was assumed.
- **Proposed.** An average wall U-value of 0.0333 BTU/hr.ft².F (R30) was assumed. Infiltration flow was assumed to be reduced by 10% in total relative to the Baseline for affected spaces.

Utility analysis results

Table 41: Wall upgrade to high performance analysis results summary

Category	Description	Unit	Baseline	Proposed	Reduction	Reduction [%]
Utility use	Electricity use	[kWh/yr]	78,354	78,834	-480	-0.61
	Natural gas use	[m3/yr]	16,475	15,652	823	5.0
	Carbon offset use	[tCO ₂ e/yr]	0	0	0	—
Equivalent energy use	Electricity energy	[kWh/yr]	78,354	78,834	-480	-0.61
	Natural gas energy	[kWh/yr]	173,920	165,229	8,690	5.0
	Total energy	[kWh/yr]	252,274	244,064	8,210	3.3
GHG emissions	Electricity GHGs	[tCO ₂ e/yr]	1.9	1.9	-0.01	-0.61
	Natural gas GHGs	[tCO ₂ e/yr]	31.8	30.2	1.6	5.0
	Carbon offsets GHGs	[tCO ₂ e/yr]	0	0	0	—
	Total GHGs	[tCO ₂ e/yr]	33.7	32.1	1.6	4.7
Utility cost	Electricity utility cost	[\$/yr]	7,773	7,820	-47.6	-0.61
	Natural gas utility cost	[\$/yr]	4,283	4,069	214	5.0
	Carbon offsets utility cost	[\$/yr]	0	0	0	—
	Federal carbon charge	[\$/yr]	1,592	1,512	79.5	5.0
	Total utility cost	[\$/yr]	13,648	13,402	246	1.8
Financial	Assumed life	[yrs]	15	75	—	—
	Project cost	[\$]	0	428,300	—	—
	Incentive amount	[\$]	0	85,660	—	—
	Incremental project cost	[\$]	0	342,640	—	—
	Life cycle cost	[\$]	336,004	444,224	—	—
	Net present value	[\$]	0	-108,220	—	—
	Project cost per GHG reduction	[\$/tCO ₂ e]	—	216,958	—	—
	Simple payback period	[yr]	—	>20	—	—

5.14 Windows and doors to high performance

Measure description

Existing condition

The facility has nine different window types, as per the drawings. Windows are typically insulated aluminum-framed, double-pane operable windows. The drawings indicate some vinyl windows, which were replaced. The facility has swing doors with glazing, sliding doors with glazing, hollow metal, and overhead doors with glazing.



Opportunity

Upgrade upon the end of useful life or as required to meet scenario criteria.

Utility-savings mechanism

Reduced heating energy use through improved thermal performance of windows and doors.

Design description

Windows

We recommend replacing all windows with Passive House Certified Triple-glazed, thermally broken windows. These could be framed in aluminum, vinyl or fiberglass.

Doors

Doors are a significant source of heat loss and air infiltration. To minimize their impact, we recommend the following measures:

- **Hollow Metal Doors:** Replace existing hollow metal doors with insulated doors in thermally broken frames.
- **Glazed Entry Doors:** Should be triple-glazed and thermally broken as part of the curtain wall/window improvements.

Project cost estimate

Table 42: Project cost estimate (Windows and doors to high performance)

Category	Line item	Unit	Value
Construction	Window and door replacement	[\$]	319,000
	General requirements (25%)	[\$]	79,800
Contingency	Subtotal after Construction	[\$]	398,800
	Design Contingency (25%)	[\$]	99,700
	Construction Contingency (10%)	[\$]	39,900
Design, Contractors, PM	Subtotal after Contingency	[\$]	538,400
	Engineering Design and Field Review (10%)	[\$]	53,800
	Contractor Fee (7%)	[\$]	37,700
Total	Total	[\$]	629,900

Utility analysis

Utility analysis methodology

The following assumptions were applied to the calibrated energy model to estimate utility use impacts.

- **Baseline.** The average U-value of all windows and doors was assumed to be 0.625 and 0.8806 BTU/hr.ft².F, respectively.
- **Proposed.** The average U-value of all windows and doors was assumed to be 0.125 BTU/hr.ft².F (R8). Infiltration flow was assumed to be reduced by 10% in total relative to the Baseline for affected spaces.

Utility analysis results

Table 43: Windows and doors to high performance analysis results summary

Category	Description	Unit	Baseline	Proposed	Reduction	Reduction [%]
Utility use	Electricity use	[kWh/yr]	78,354	77,976	378	0.48
	Natural gas use	[m3/yr]	16,475	15,148	1,327	8.1
	Carbon offset use	[tCO ₂ e/yr]	0	0	0	—
Equivalent energy use	Electricity energy	[kWh/yr]	78,354	77,976	378	0.48
	Natural gas energy	[kWh/yr]	173,920	159,911	14,009	8.1
	Total energy	[kWh/yr]	252,274	237,887	14,387	5.7
GHG emissions	Electricity GHGs	[tCO ₂ e/yr]	1.9	1.9	0.01	0.48
	Natural gas GHGs	[tCO ₂ e/yr]	31.8	29.3	2.6	8.1
	Carbon offsets GHGs	[tCO ₂ e/yr]	0	0	0	—
	Total GHGs	[tCO ₂ e/yr]	33.7	31.1	2.6	7.6
Utility cost	Electricity utility cost	[\$/yr]	7,773	7,735	37.5	0.48
	Natural gas utility cost	[\$/yr]	4,283	3,938	345	8.1
	Carbon offsets utility cost	[\$/yr]	0	0	0	—
	Federal carbon charge	[\$/yr]	1,592	1,464	128	8.1
	Total utility cost	[\$/yr]	13,648	13,137	511	3.7
Financial	Assumed life	[yrs]	15	40	—	—
	Project cost	[\$]	0	629,900	—	—
	Incentive amount	[\$]	0	125,980	—	—
	Incremental project cost	[\$]	0	503,920	—	—
	Life cycle cost	[\$]	336,004	634,554	—	—
	Net present value	[\$]	0	-298,550	—	—
	Project cost per GHG reduction	[\$/tCO ₂ e]	—	195,820	—	—
	Simple payback period	[yr]	—	>20	—	—

5.15 Measure risk analysis

Utility use sensitivity

Figure 104 indicates how sensitive cumulative electricity and natural gas use are to variations in each risk parameter.

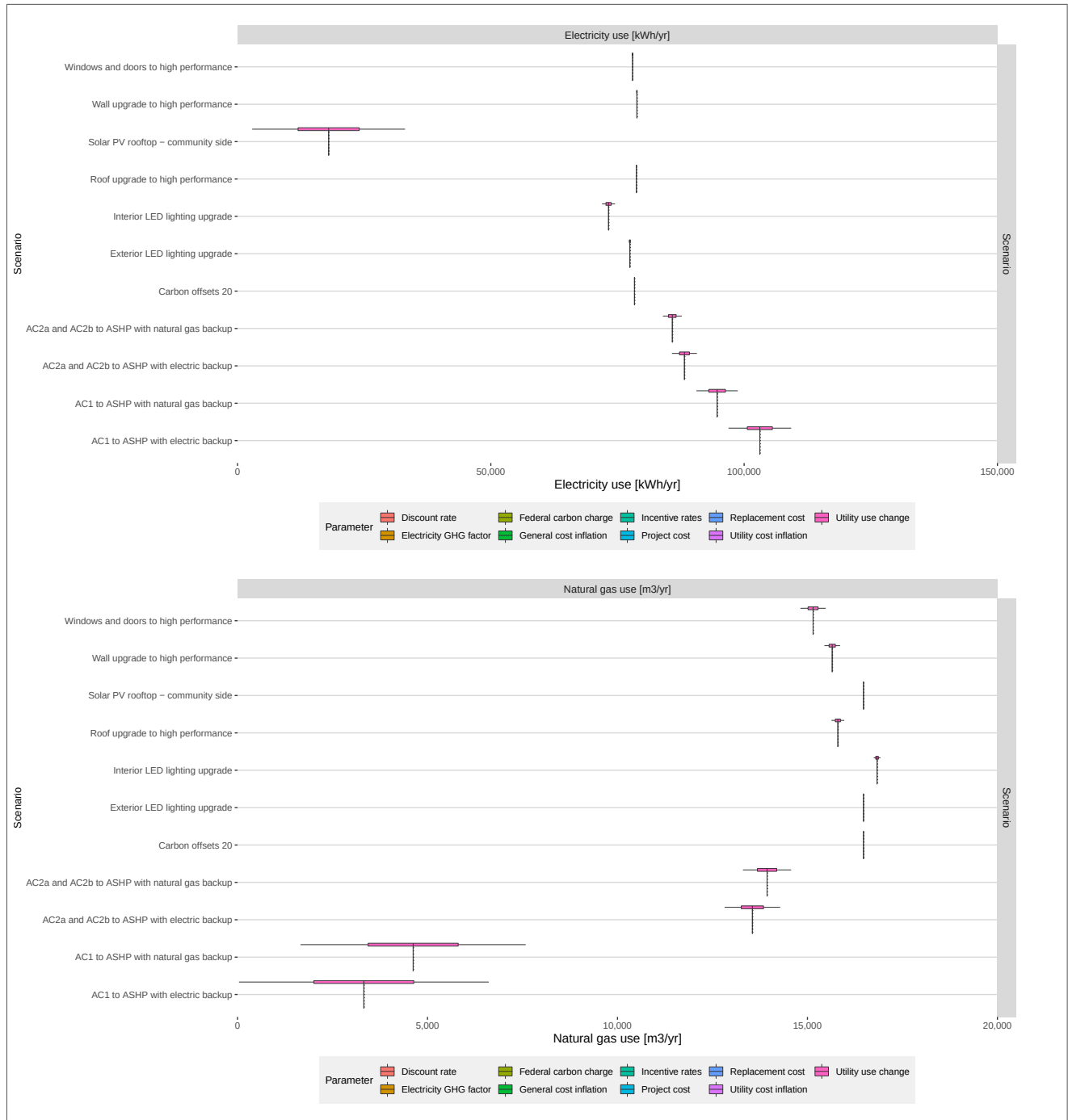


Figure 104: Utility cumulative use sensitivity analysis

GHG emissions and life cycle cost sensitivity

Figure 105 indicates how sensitive cumulative GHG emissions and life cycle costs are to variations in each risk parameter.

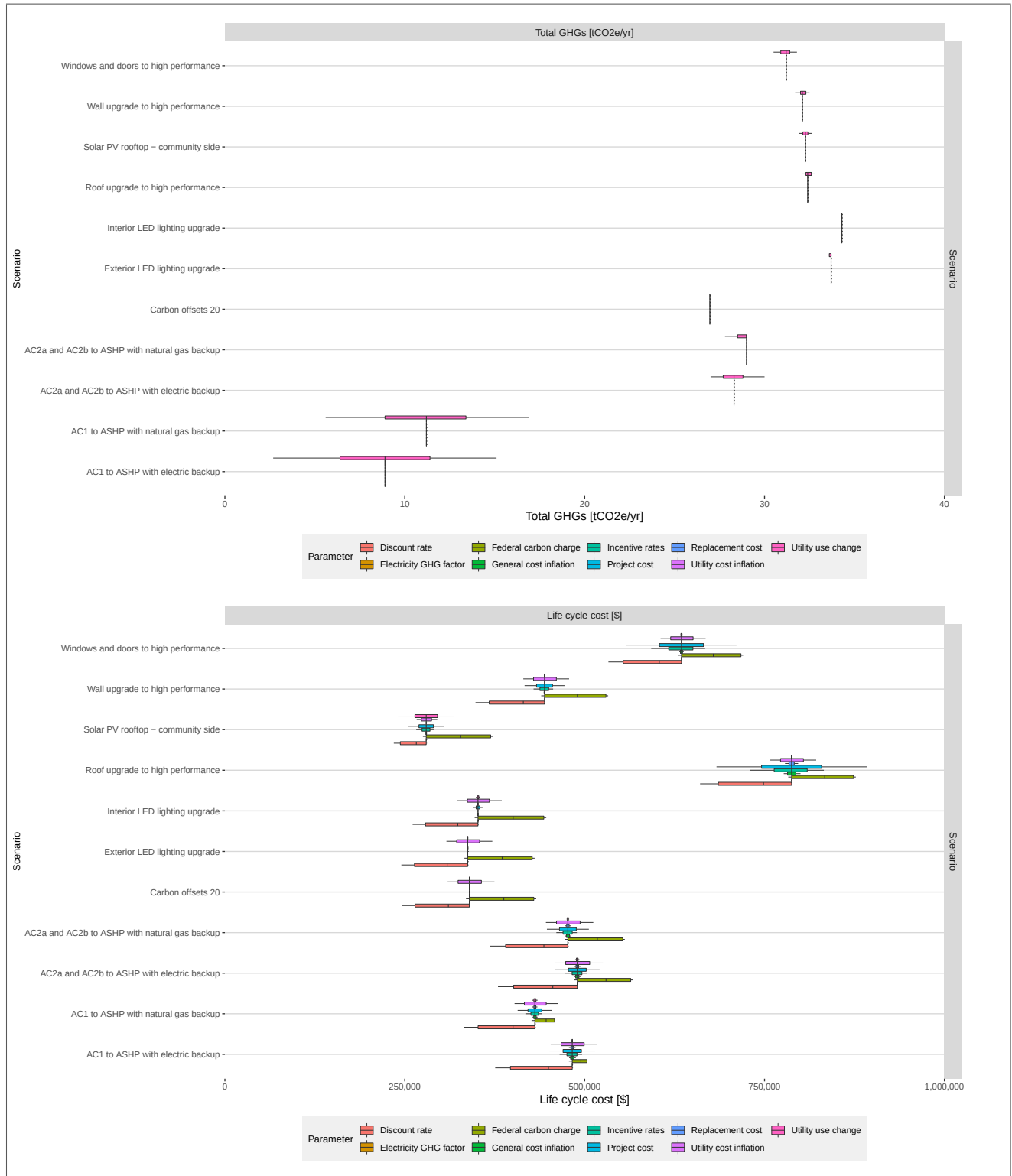


Figure 105: GHG cumulative emissions and life cycle cost sensitivity analysis

5.16 Measure analysis summary

For each analyzed measure, the analysis results are summarized in Table 44.

Table 44: Measure analysis summary

Measure ID	Utility use				Equivalent energy use		GHG emissions		Utility cost		Financial							
	Electricity use reduction	Electricity use reduction	Natural gas use reduction	Natural gas use reduction	Total energy reduction	Total energy reduction	Total GHG reduction	Total GHG reduction	Utility cost reduction	Utility cost reduction	Assumed life	Project cost	Incentive amount	Incremental project cost	Life cycle cost	Net present value	Project cost per GHG reduction	Simple payback period
-	[kWh/yr]	[%]	[m3/yr]	[%]	[kWh/yr]	[%]	[tCO2e/yr]	[%]	[\$/yr]	[%]	[yrs]	[\$]	[\$]	[\$]	[\$]	[\$]	[\$/tCO2e]	[yr]
Baseline	78,354	100.0	16,475	100.0	252,274	100.0	34	100.0	13,648	100.0	15	0	0	0	336,004	0	-	-
AC1 to ASHP with electric backup	-24,746	-31.6	13,150	79.8	114,075	45.2	25	73.6	2,235	16.4	18	164,000	32,800	131,200	482,715	-146,711	5,286	59
AC1 to ASHP with natural gas backup	-16,310	-20.8	11,852	71.9	108,811	43.1	23	66.8	2,609	19.1	18	123,300	24,660	98,640	430,823	-94,819	4,381	38
AC2a and AC2b to ASHP with electric backup	-9,860	-12.6	2,924	17.7	21,010	8.3	5	16.1	65	0.5	18	159,900	31,980	127,920	489,739	-153,735	23,623	1,977
AC2a and AC2b to ASHP with natural gas backup	-7,472	-9.5	2,538	15.4	19,322	7.7	5	14.0	164	1.2	18	150,100	30,020	120,080	476,670	-140,666	25,409	733
Carbon offsets 20	0	0.0	0	0.0	0	0.0	7	20.0	-202	-1.5	20	-	0	-	339,692	-3,688	-	-
Exterior LED lighting upgrade	907	1.2	0	0.0	907	0.4	0	0.1	90	0.7	20	3,700	0	3,700	337,486	-1,482	170,633	41
Interior LED lighting upgrade	5,117	6.5	-357	-2.2	1,350	0.5	-1	-1.7	380	2.8	20	26,300	0	26,300	351,736	-15,732	-46,364	69
Roof upgrade to high performance	-379	-0.5	674	4.1	6,741	2.7	1	3.8	203	1.5	20	537,000	107,400	429,600	787,574	-451,570	331,926	2,117
Solar PV rooftop - community side	60,369	77.0	0	0.0	60,369	23.9	1	4.3	5,989	43.9	30	156,000	31,200	124,800	279,776	56,228	86,497	21
Wall upgrade to high performance	-480	-0.6	823	5.0	8,211	3.3	2	4.7	246	1.8	75	428,300	85,660	342,640	444,224	-108,220	216,958	1,393
Windows and doors to high performance	378	0.5	1,327	8.1	14,387	5.7	3	7.6	511	3.7	40	629,900	125,980	503,920	634,554	-298,550	195,820	987
Total project cost	-	-	-	-	-	-	-	-	-	-	-	2,378,500	-	-	-	-	-	-
AC1 renewal	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	18	77,000	0	77,000	419,435	-83,432	-	-
AC2a and AC2b renewal	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	18	144,000	0	144,000	492,032	-156,028	-	-
Exterior lighting renewal	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	20	1,000	0	1,000	337,043	-1,039	-	-
Exterior walls renewal	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	75	4,000	0	4,000	337,299	-1,295	-	-
Interior lighting renewal	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	20	11,000	0	11,000	347,438	-11,434	-	-
Roof renewal	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	20	248,000	0	248,000	593,783	-257,779	-	-
Windows and doors renewal	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	40	108,000	0	108,000	401,575	-65,571	-	-
BAU measure totals	-	-	-	-	-	-	-	-	-	-	-	593,000	-	-	-	-	-	-

6 SCENARIO ANALYSIS

6.1 Cluster scenario analysis methodology

A scenario analysis was completed to estimate the costs and benefits expected from implementing various combinations (i.e. scenarios) of the measures that were individually analyzed in Section 5. Whereas in Section 5, each measure was individually analyzed as though implemented by itself, in Section 6, scenarios of multiple measures being implemented together were analyzed, and the interactive effects between measures within each scenario were accounted for. The scenario analysis was completed according to the following methodology.

1. **Cluster scenario objectives.** All scenarios that were analyzed and their objectives were defined as summarized in Table 45.
2. **Cluster scenario composition.** Each scenario was composed by iteratively assigning measures to that scenario to achieve the objectives of that scenario as closely as possible. Results are presented in Section 6.3.
3. **Cluster scenario performance analysis.** Each scenario was analyzed using the energy model to estimate the overall performance that implementing all measures in that scenario would have on utility use, equivalent energy use, GHG emissions, utility costs and several financial performance metrics. Results are presented in Section 6.4.
4. **Cluster scenario analysis discussion.** Results of the scenario analysis were discussed in Section 6.4.

6.2 Cluster scenario objectives

The cluster scenarios that were analyzed and their objectives are summarized in Table 45.

Table 45: Scenario objectives

Scenario	Objectives
Control optimization	To estimate the impact of all control optimization measures combined.
Envelope upgrades	To estimate the impact of all envelope upgrade measures combined.
Load minimization	To estimate the impact of all controls optimization, envelope upgrades, and other measures intended to reduce the thermal and electrical load of the facility, which would ideally reduce the capacity requirements of new equipment.
Comprehensive cluster	To understand the limit of GHG reductions possible by implementing all measures that have the greatest reduction on GHG emissions.

6.3 Cluster scenario composition

In the scenario composition exercise, individual measures were assigned to each scenario in an iterative process to achieve the objectives of that scenario as closely as possible. Figure 106 and Table 46 present the results of this exercise, indicating which measures were assigned to which scenario.

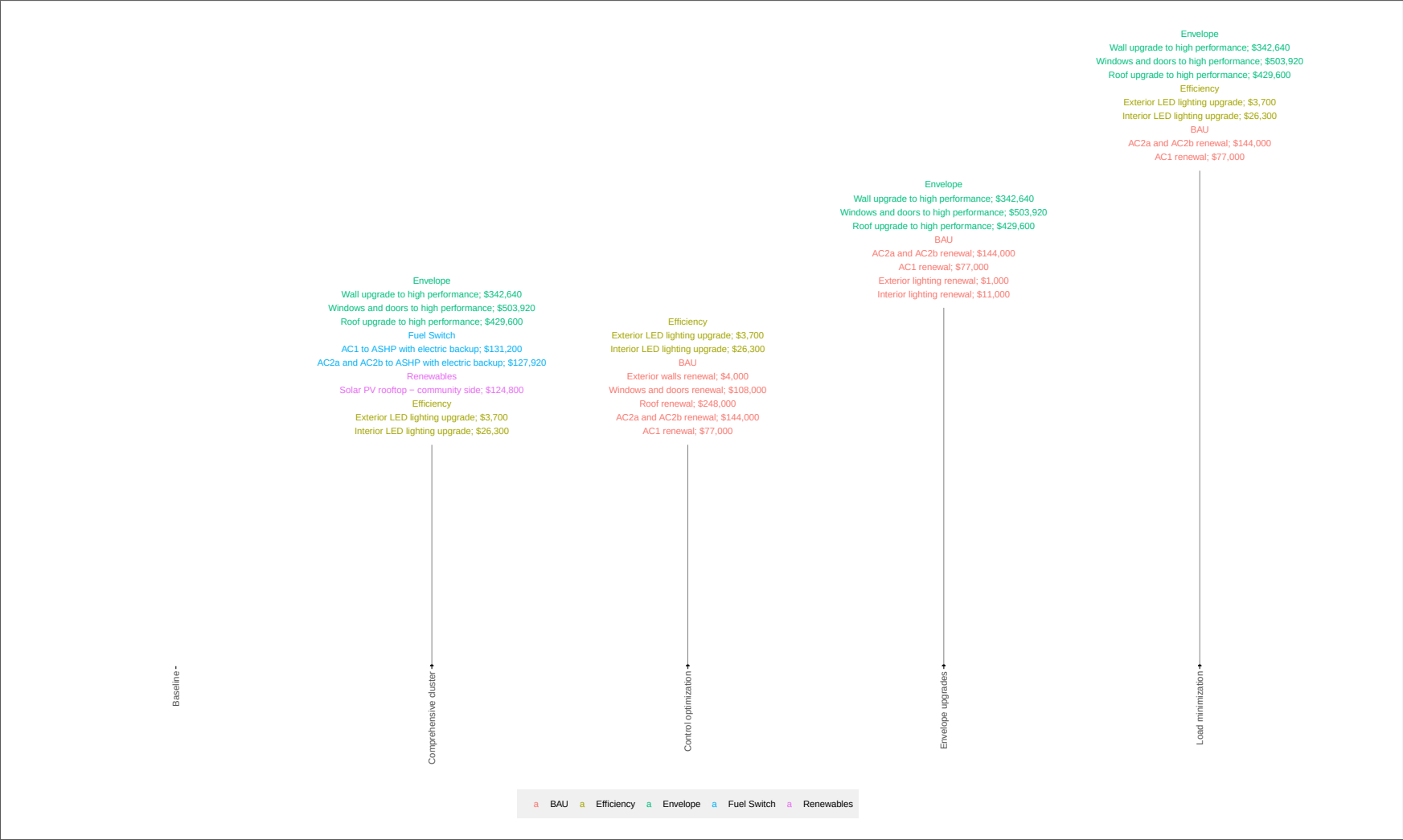


Figure 106: Scenario composition

Table 46: Cluster composition

Measure	Control optimization	Envelope upgrades	Load minimization	Comprehensive cluster
AC1 to ASHP with electric backup	✗	✗	✗	✓
AC1 to ASHP with natural gas backup	✗	✗	✗	✗
AC2a and AC2b to ASHP with electric backup	✗	✗	✗	✓
AC2a and AC2b to ASHP with natural gas backup	✗	✗	✗	✗
Carbon offsets 20	✗	✗	✗	✗
Exterior LED lighting upgrade	✓	✗	✓	✓
Interior LED lighting upgrade	✓	✗	✓	✓
Roof upgrade to high performance	✗	✓	✓	✓
Solar PV rooftop - community side	✗	✗	✗	✓
Wall upgrade to high performance	✗	✓	✓	✓
Windows and doors to high performance	✗	✓	✓	✓
AC1 renewal	✓	✓	✓	✗
AC2a and AC2b renewal	✓	✓	✓	✗
Exterior lighting renewal	✗	✓	✗	✗
Exterior walls renewal	✓	✗	✗	✗
Interior lighting renewal	✗	✓	✗	✗
Roof renewal	✓	✗	✗	✗
Windows and doors renewal	✓	✗	✗	✗

6.4 Cluster scenario performance analysis

The scenario performance analysis was completed by using the energy model (see Section 4) to determine the expected performance of implementing all measures in each scenario. Results are presented throughout Section 6.4.

Cluster scenario performance analysis summary

Results of the scenario analysis are summarized in Table 47, which indicates all individual measures that were considered to be implemented under each scenario, the measure-specific impacts that each measure was estimated to have if implemented by itself, and the combined impacts that implementing all measures in each scenario is expected to have, accounting for the interactive effects between measures within each scenario.

Table 47: Scenario analysis summary

Measure ID	Utility use					Equivalent energy use		GHG emissions		Utility cost		Financial									
Scenario	Measure name	Electricity use reduction	Electricity use reduction	Natural gas use reduction	Natural gas use reduction	Total energy reduction	Total energy reduction	Total GHG reduction	Total GHG reduction	Utility cost reduction	Utility cost reduction	Assumed life	Project cost	Incentive amount	Incremental project cost	Life cycle cost	Net present value	Project cost per GHG reduction	Simple payback period		
-	-	[kWh/yr]	[%]	[m3/yr]	[%]	[kWh/yr]	[%]	[tCO2e/yr]	[%]	[\$/yr]	[%]	[yrs]	[\$]	[\$]	[\$]	[\$]	[\$]	[\$/yr/tCO2e]	[yr]		
Comprehensive cluster	Combined	38,004	48.5	16,072		97.6		207,668	82.3	94.8	9,501	69.6	-	2,105,100	415,020	1,690,080	1,390,531	-1,054,527	52,874	178	
Comprehensive cluster	Wall upgrade to high performance	-480	-0.6	823		5.0		8,211	3.3	2	4.7	246	1.8	75	428,300	85,660	342,640	444,224	-108,220	216,958	1,393
Comprehensive cluster	Windows and doors to high performance	378	0.5	1,327		8.1		14,387	5.7	3	7.6	511	3.7	40	629,900	125,980	503,920	634,554	-298,550	195,820	987
Comprehensive cluster	Roof upgrade to high performance	-379	-0.5	674		4.1		6,741	2.7	1	3.8	203	1.5	20	537,000	107,400	429,600	787,574	-451,570	331,926	2,117
Comprehensive cluster	AC1 to ASHP with electric backup	-24,746	-31.6	13,150		79.8		114,075	45.2	25	73.6	2,235	16.4	18	164,000	32,800	131,200	482,715	-146,711	5,286	59
Comprehensive cluster	Solar PV rooftop - community side	60,369	77.0	0		0.0		60,369	23.9	1	4.3	5,989	43.9	30	156,000	31,200	124,800	279,776	-56,228	86,497	21
Comprehensive cluster	Exterior LED lighting upgrade	907	1.2	0		0.0		907	0.4	0	0.1	90	0.7	20	3,700	0	3,700	337,486	-1,482	170,633	41
Comprehensive cluster	Interior LED lighting upgrade	5,117	6.5	-357		-2.2		1,350	0.5	-1	-1.7	380	2.8	20	26,300	0	26,300	351,736	-15,732	-46,364	69
Comprehensive cluster	AC2a and AC2b to ASHP with electric backup	-9,860	-12.6	2,924		17.7		21,010	8.3	5	16.1	65	0.5	18	159,900	31,980	127,920	489,739	-153,735	23,623	1,977
Control optimization	Combined	6,025	7.7	-357		-2.2		2,258	0.9	-1	-1.6	470	3.4	-	611,000	0	611,000	891,381	-555,377	-1,119,934	1,299
Control optimization	Exterior LED lighting upgrade	907	1.2	0		0.0		907	0.4	0	0.1	90	0.7	20	3,700	0	3,700	337,486	-1,482	170,633	41
Control optimization	Interior LED lighting upgrade	5,117	6.5	-357		-2.2		1,350	0.5	-1	-1.7	380	2.8	20	26,300	0	26,300	351,736	-15,732	-46,364	69
Control optimization	Exterior walls renewal	0	0.0	0		0.0		0	0.0	0	0.0	0	0.0	75	4,000	0	4,000	337,299	-1,295	-	-
Control optimization	Windows and doors renewal	0	0.0	0		0.0		0	0.0	0	0.0	0	0.0	40	108,000	0	108,000	401,575	-65,571	-	-
Control optimization	Roof renewal	0	0.0	0		0.0		0	0.0	0	0.0	0	0.0	20	248,000	0	248,000	593,783	-257,779	-	-
Control optimization	AC2a and AC2b renewal	0	0.0	0		0.0		0	0.0	0	0.0	0	0.0	18	144,000	0	144,000	492,032	-156,028	-	-
Control optimization	AC1 renewal	0	0.0	0		0.0		0	0.0	0	0.0	0	0.0	18	77,000	0	77,000	419,435	-83,432	-	-
Envelope upgrades	Combined	-1,015	-1.3	2,422		14.7		24,549	9.7	5	13.8	763	5.6	-	1,828,200	319,040	1,509,160	1,391,152	-1,055,148	324,199	1,978
Envelope upgrades	Wall upgrade to high performance	-480	-0.6	823		5.0		8,211	3.3	2	4.7	246	1.8	75	428,300	85,660	342,640	444,224	-108,220	216,958	1,393
Envelope upgrades	Windows and doors to high performance	378	0.5	1,327		8.1		14,387	5.7	3	7.6	511	3.7	40	629,900	125,980	503,920	634,554	-298,550	195,820	987
Envelope upgrades	Roof upgrade to high performance	-379	-0.5	674		4.1		6,741	2.7	1	3.8	203	1.5	20	537,000	107,400	429,600	787,574	-451,570	331,926	2,117
Envelope upgrades	AC2a and AC2b renewal	0	0.0	0		0.0		0	0.0	0	0.0	0	0.0	18	144,000	0	144,000	492,032	-156,028	-	-
Envelope upgrades	AC1 renewal	0	0.0	0		0.0		0	0.0	0	0.0	0	0.0	18	77,000	0	77,000	419,435	-83,432	-	-
Envelope upgrades	Exterior lighting renewal	0	0.0	0		0.0		0	0.0	0	0.0	0	0.0	20	1,000	0	1,000	337,043	-1,039	-	-
Envelope upgrades	Interior lighting renewal	0	0.0	0		0.0		0	0.0	0	0.0	0	0.0	20	11,000	0	11,000	347,438	-11,434	-	-
Load minimization	Combined	6,154	7.9	2,224		13.5		29,629	11.7	4	13.2	1,403	10.3	-	1,846,200	319,040	1,527,160	1,392,354	-1,056,350	343,639	1,088
Load minimization	Wall upgrade to high performance	-480	-0.6	823		5.0		8,211	3.3	2	4.7	246	1.8	75	428,300	85,660	342,640	444,224	-108,220	216,958	1,393
Load minimization	Windows and doors to high performance	378	0.5	1,327		8.1		14,387	5.7	3	7.6	511	3.7	40	629,900	125,980	503,920	634,554	-298,550	195,820	987
Load minimization	Roof upgrade to high performance	-379	-0.5	674		4.1		6,741	2.7	1	3.8	203	1.5	20	537,000	107,400	429,600	787,574	-451,570	331,926	2,117
Load minimization	Exterior LED lighting upgrade	907	1.2	0		0.0		907	0.4	0	0.1	90	0.7	20	3,700	0	3,700	337,486	-1,482	170,633	41
Load minimization	Interior LED lighting upgrade	5,117	6.5	-357		-2.2		1,350	0.5	-1	-1.7	380	2.8	20	26,300	0	26,300	351,736	-15,732	-46,364	69
Load minimization	AC2a and AC2b renewal	0	0.0	0		0.0		0	0.0	0	0.0	0	0.0	18	144,000	0	144,000	492,032	-156,028	-	-
Load minimization	AC1 renewal	0	0.0	0		0.0		0	0.0	0	0.0	0	0.0	18	77,000	0	77,000	419,435	-83,432	-	-

Utility use comparison

The following figures compare the total expected yearly utility use by end use between each scenario.

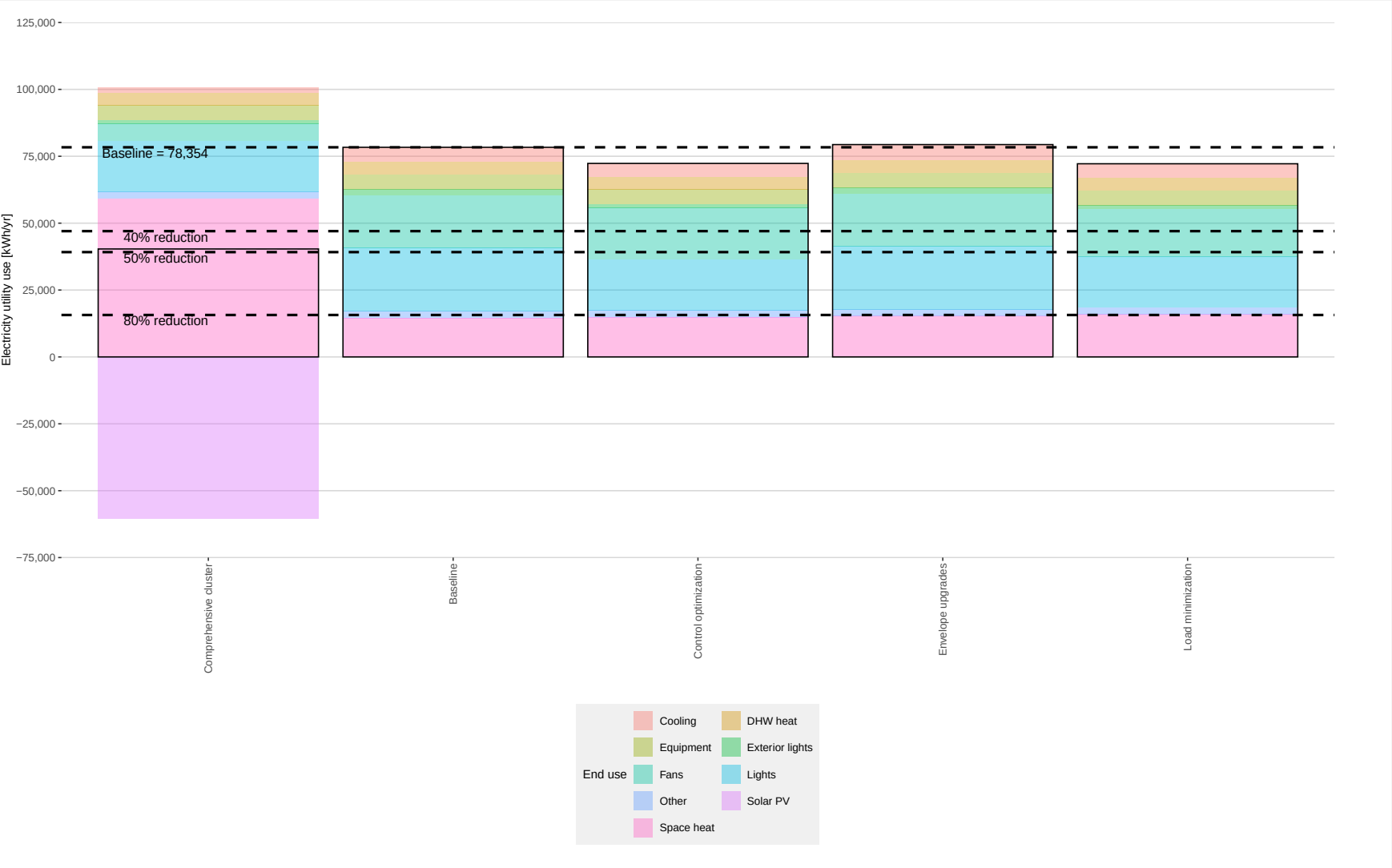


Figure 107: Electricity utility use expected yearly for each scenario by end use

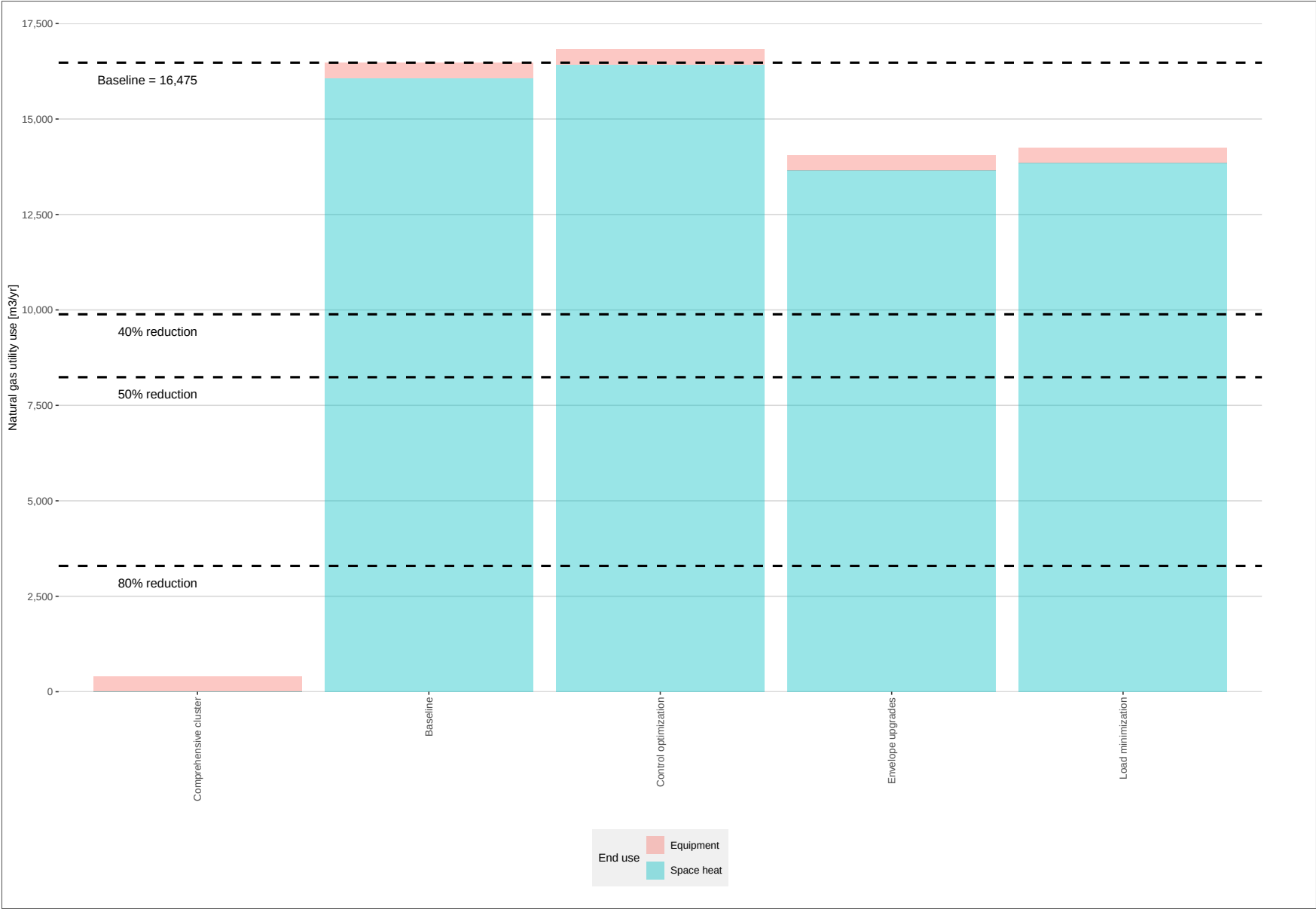


Figure 108: Natural gas utility use expected yearly for each scenario by end use

Energy, GHG and utility cost comparison

The following figures compare the total expected yearly equivalent energy use, GHG emissions and utility costs between each scenario.

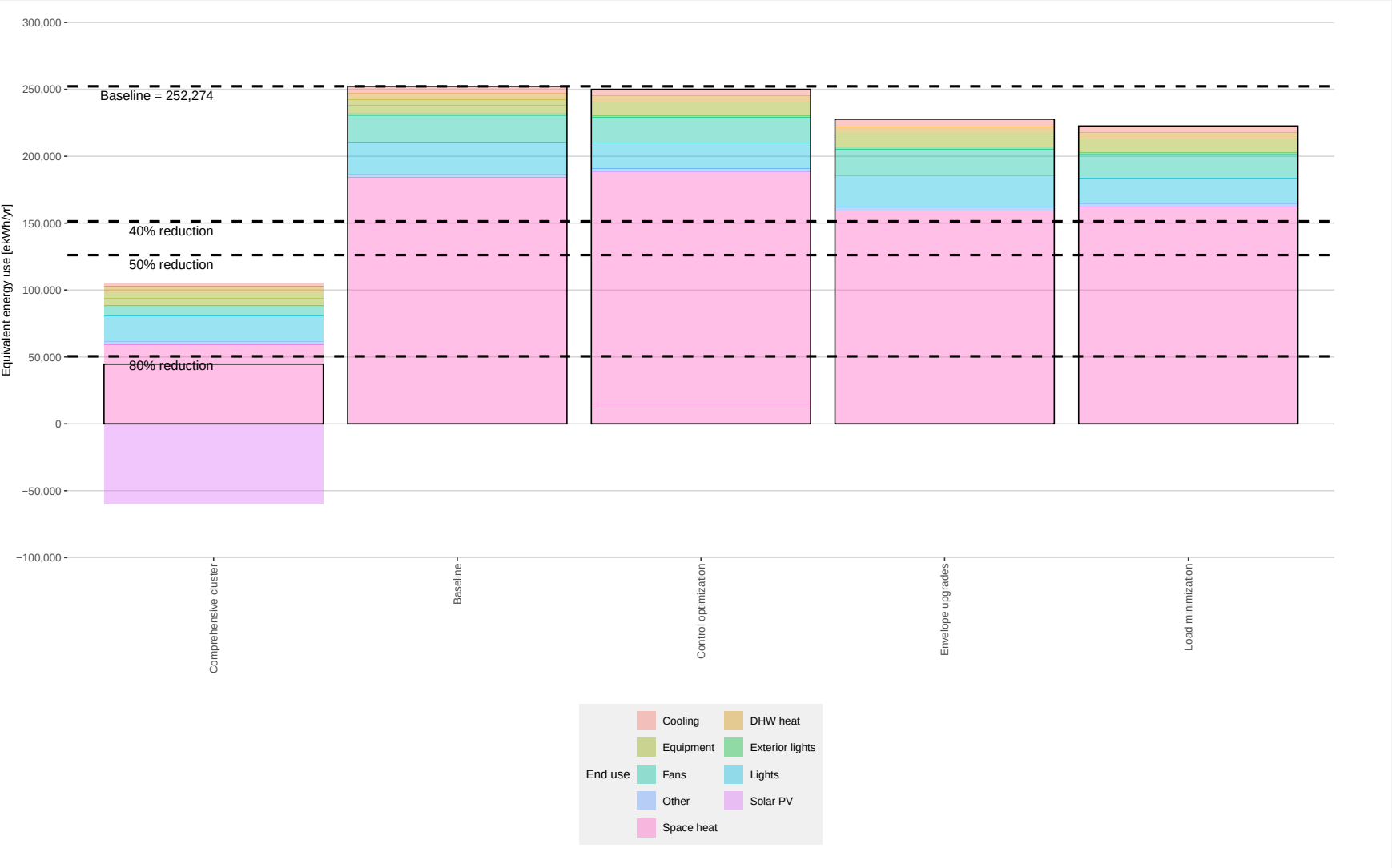


Figure 109: Equivalent energy use expected yearly for each scenario by end use



Figure 110: GHG emissions expected yearly for each scenario by end use

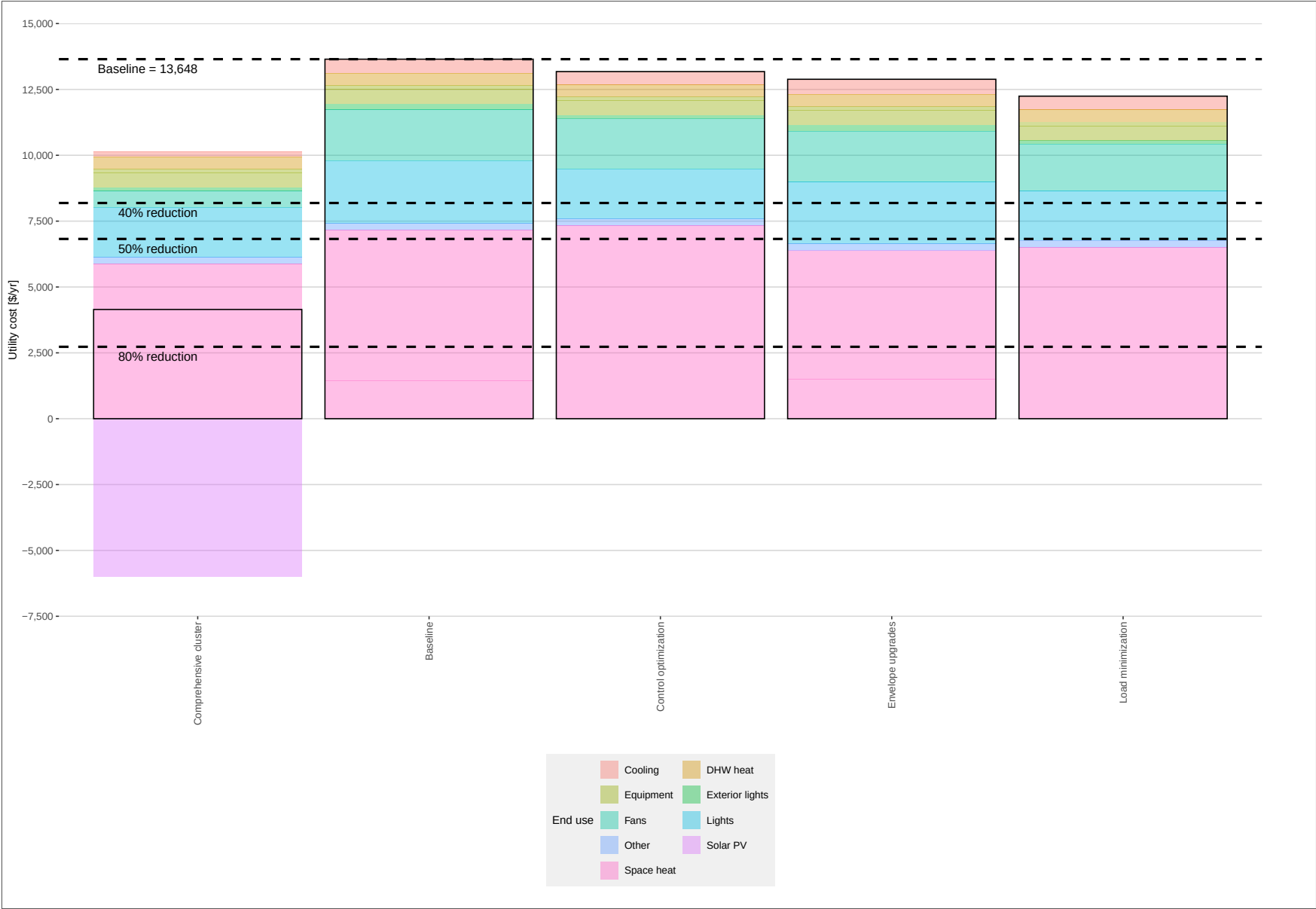


Figure 111: Utility costs expected yearly for each scenario by end use

Financial performance comparison

The following figures compare the financial performance between each scenario.

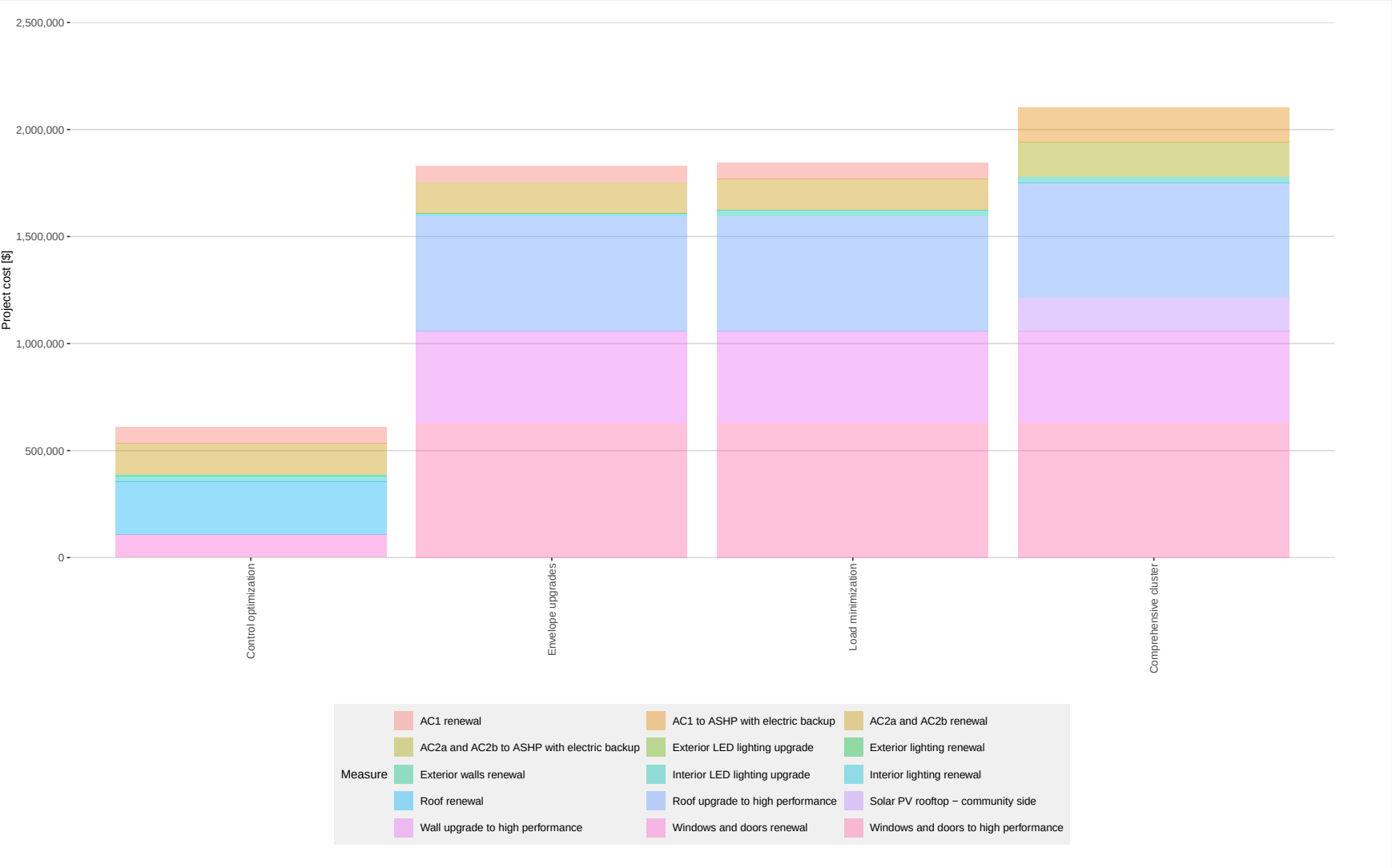


Figure 112: Project cost expected for each scenario by measure

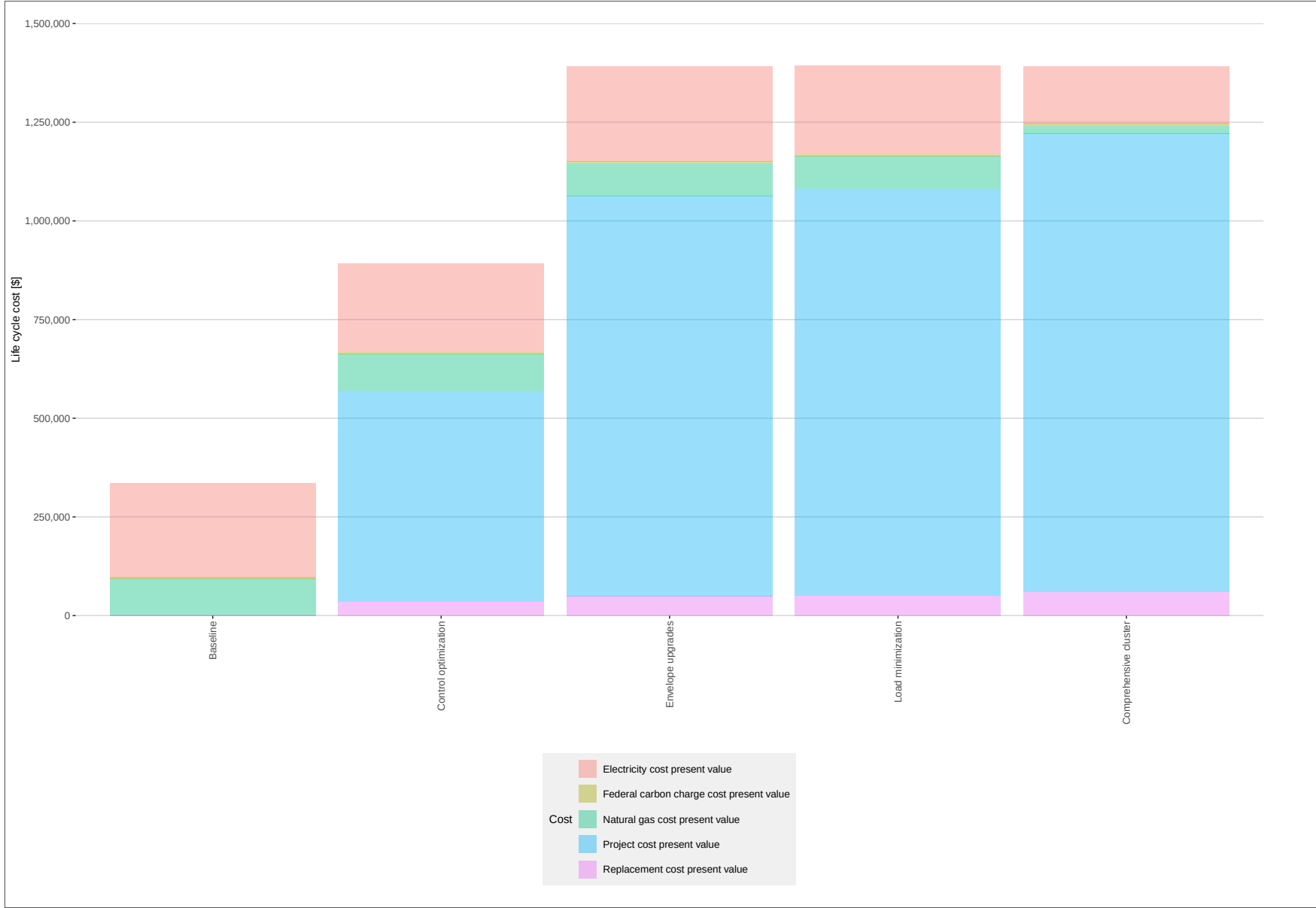


Figure 113: Life cycle cost expected for each scenario by cost item

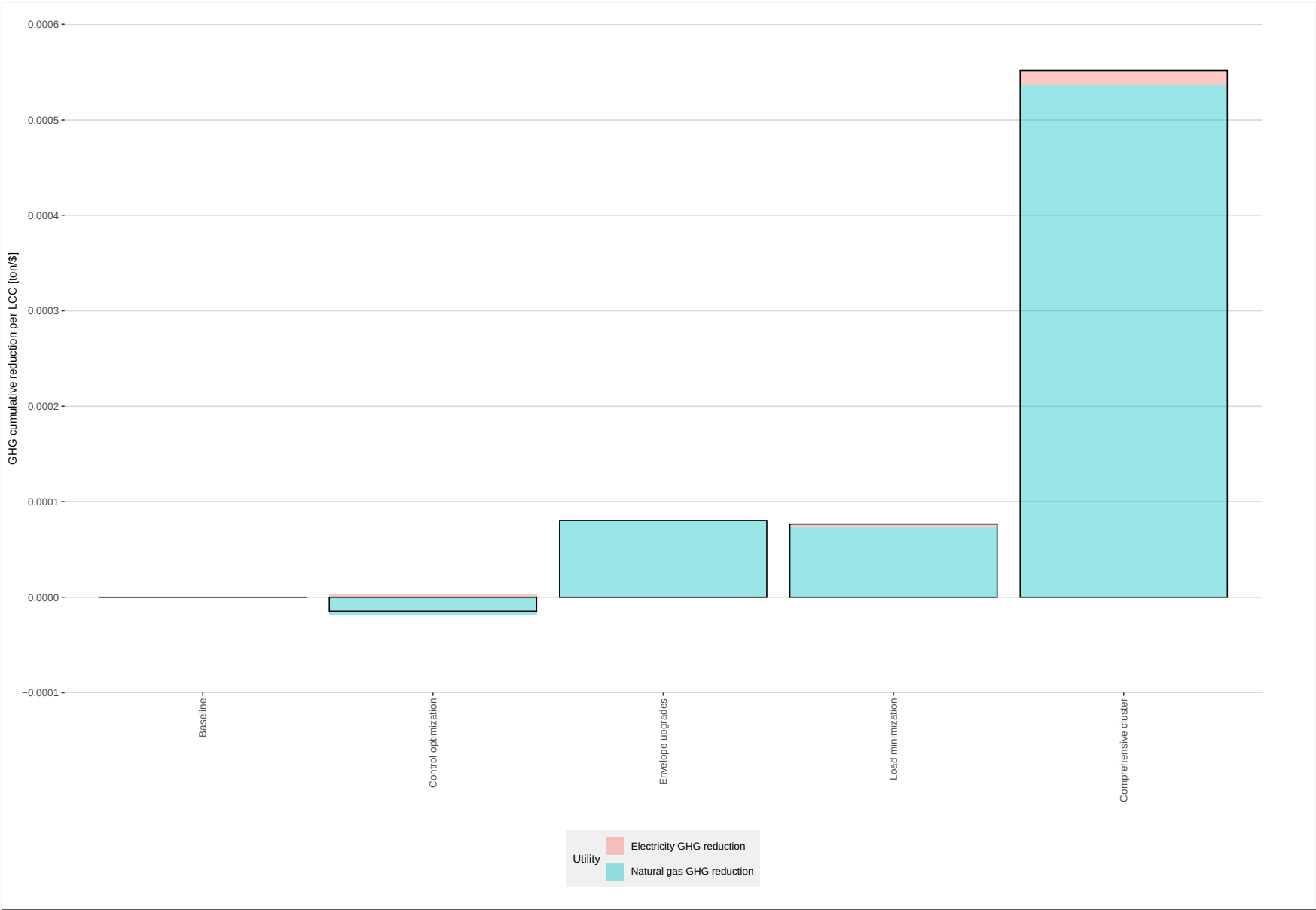


Figure 114: GHG cumulative reduction per life cycle cost (LCC) dollar expected for each scenario by utility

6.5 Plan scenario development

Plan scenario identification and objectives

The plan scenarios that were analyzed and their objectives are summarized in Table 48.

Table 48: Plan scenario identification and objectives

Plan scenario	Objectives
Minimum performance scenario	To achieve a 50% reduction in operational GHG emissions within 10 years and 80% within 20 years. This scenario addresses the minimum performance scenario of FCM's CBR program.
Aggressive deep retrofit	Implement the same measures as in the minimum performance scenario but achieve an 80% reduction in GHG emissions within five years. This scenario addresses the additional scenario requirement of FCM's CBR program.
Comprehensive	To understand the limit of GHG reductions possible by implementing all mutually exclusive measures that have the greatest reduction on GHG emissions and excluding the use of carbon offsets.
Organizational goal alignment	To reduce emissions by 40% GHG emissions from 2019 levels by 2033 and 80% reduction by 2050 of on-site emissions. The remaining 20% is to be addressed through carbon offsets, as noted in the City's Corporate Greenhouse Gas Reduction Plan (GHGRP).
Business as usual	To follow the existing capital renewal plan and replace equipment at the end of its life with like-for-like equipment, meeting minimum energy-efficiency requirements of ASHRAE 90.1.

Plan scenario composition

The plan scenarios were composed with the intent of achieving the objective of each plan scenario, as outlined in Table 48. Results of the plan scenario composition are presented in Figure 115, which is a measure implementation timeline plot indicating which measures were assumed to be implemented in which plan scenarios and when, and the estimated project cost of each measure. The measures are also colour-coded according to measure group. The same information is included in plan performance analysis results figures in Section 6.6 for ease of reference. The plan scenario composition is also presented in Tables 49 to 54.

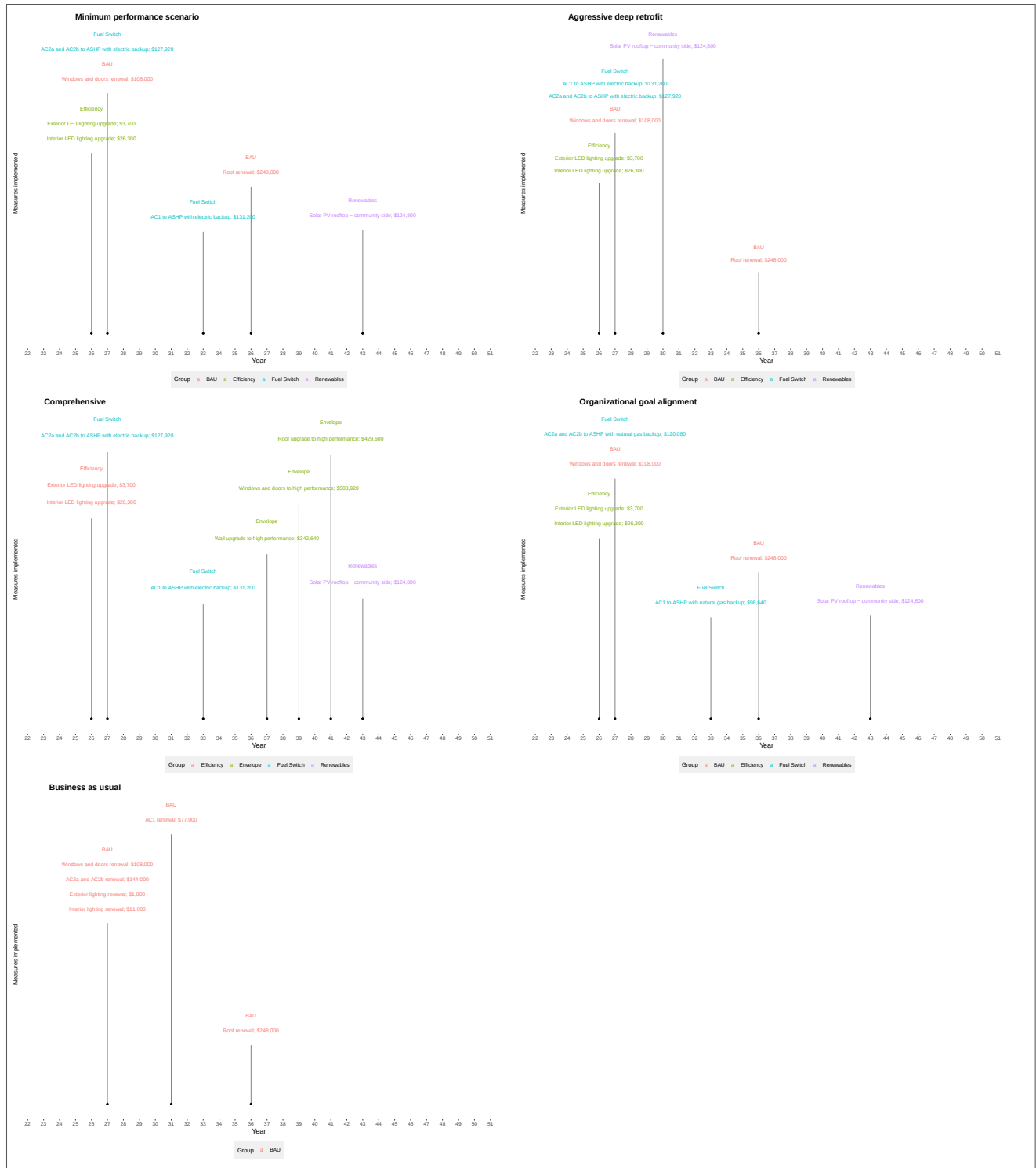


Figure 115: Plan scenario composition, indicating which measures are implemented when and at what cost in each plan scenario

Table 49: Scenario composition summary

Measure	Minimum performance scenario	Aggressive deep retrofit	Comprehensive	Organizational goal alignment
AC1 to ASHP with electric backup	✓	✓	✓	✗
AC1 to ASHP with natural gas backup	✗	✗	✗	✓
AC2a and AC2b to ASHP with electric backup	✓	✓	✓	✗
AC2a and AC2b to ASHP with natural gas backup	✗	✗	✗	✓
Carbon offsets 20	✗	✗	✗	✗
Exterior LED lighting upgrade	✓	✓	✓	✓
Interior LED lighting upgrade	✓	✓	✓	✓
Roof upgrade to high performance	✗	✗	✓	✗
Solar PV rooftop - community side	✓	✓	✓	✓
Wall upgrade to high performance	✗	✗	✓	✗
Windows and doors to high performance	✗	✗	✓	✗
AC1 renewal	✗	✗	✗	✗
AC2a and AC2b renewal	✗	✗	✗	✗
Exterior lighting renewal	✗	✗	✗	✗
Exterior walls renewal	✓	✓	✗	✓
Interior lighting renewal	✗	✗	✗	✗
Roof renewal	✓	✓	✗	✓
Windows and doors renewal	✓	✓	✗	✓

Table 50: Minimum performance scenario measure implementation timeline

Measure	Year
Exterior LED lighting upgrade	2026
Interior LED lighting upgrade	2026
AC2a and AC2b to ASHP with electric backup	2027
Windows and doors renewal	2027
AC1 to ASHP with electric backup	2033
Roof renewal	2036
Solar PV rooftop - community side	2043
Exterior walls renewal	2062

Table 51: Aggressive deep retrofit measure implementation timeline

Measure	Year
Exterior LED lighting upgrade	2026
Interior LED lighting upgrade	2026
AC1 to ASHP with electric backup	2027
AC2a and AC2b to ASHP with electric backup	2027
Windows and doors renewal	2027
Solar PV rooftop - community side	2030
Roof renewal	2036
Exterior walls renewal	2062

Table 52: Comprehensive measure implementation timeline

Measure	Year
Exterior LED lighting upgrade	2026
Interior LED lighting upgrade	2026
AC2a and AC2b to ASHP with electric backup	2027
AC1 to ASHP with electric backup	2033
Wall upgrade to high performance	2037
Windows and doors to high performance	2039
Roof upgrade to high performance	2041
Solar PV rooftop - community side	2043

Table 53: Organizational goal alignment measure implementation timeline

Measure	Year
Exterior LED lighting upgrade	2026
Interior LED lighting upgrade	2026
AC2a and AC2b to ASHP with natural gas backup	2027
Windows and doors renewal	2027
AC1 to ASHP with natural gas backup	2033
Roof renewal	2036
Solar PV rooftop - community side	2043
Exterior walls renewal	2062

Table 54: Business as usual measure implementation timeline

Measure	Year
AC2a and AC2b renewal	2027
Exterior lighting renewal	2027
Interior lighting renewal	2027
Windows and doors renewal	2027
AC1 renewal	2031
Roof renewal	2036
Exterior walls renewal	2062

6.6 Plan performance analysis

Figures 116 through 119 present the projected yearly electricity use, natural gas use, GHG emissions and life cycle costs associated with each plan scenario.

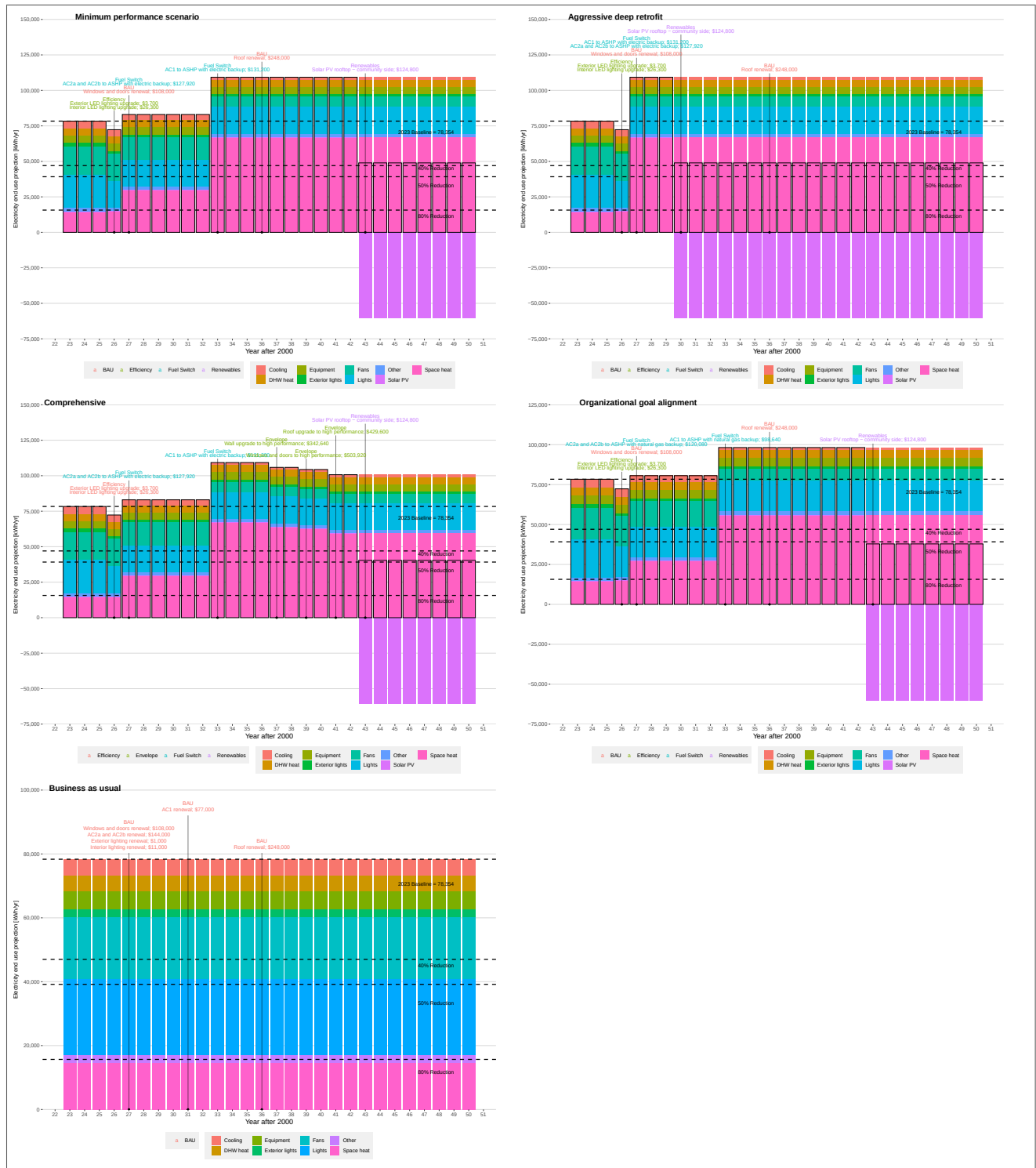


Figure 116: Electricity yearly utility use projection for each scenario



Figure 117: Natural gas yearly utility use projection for each scenario

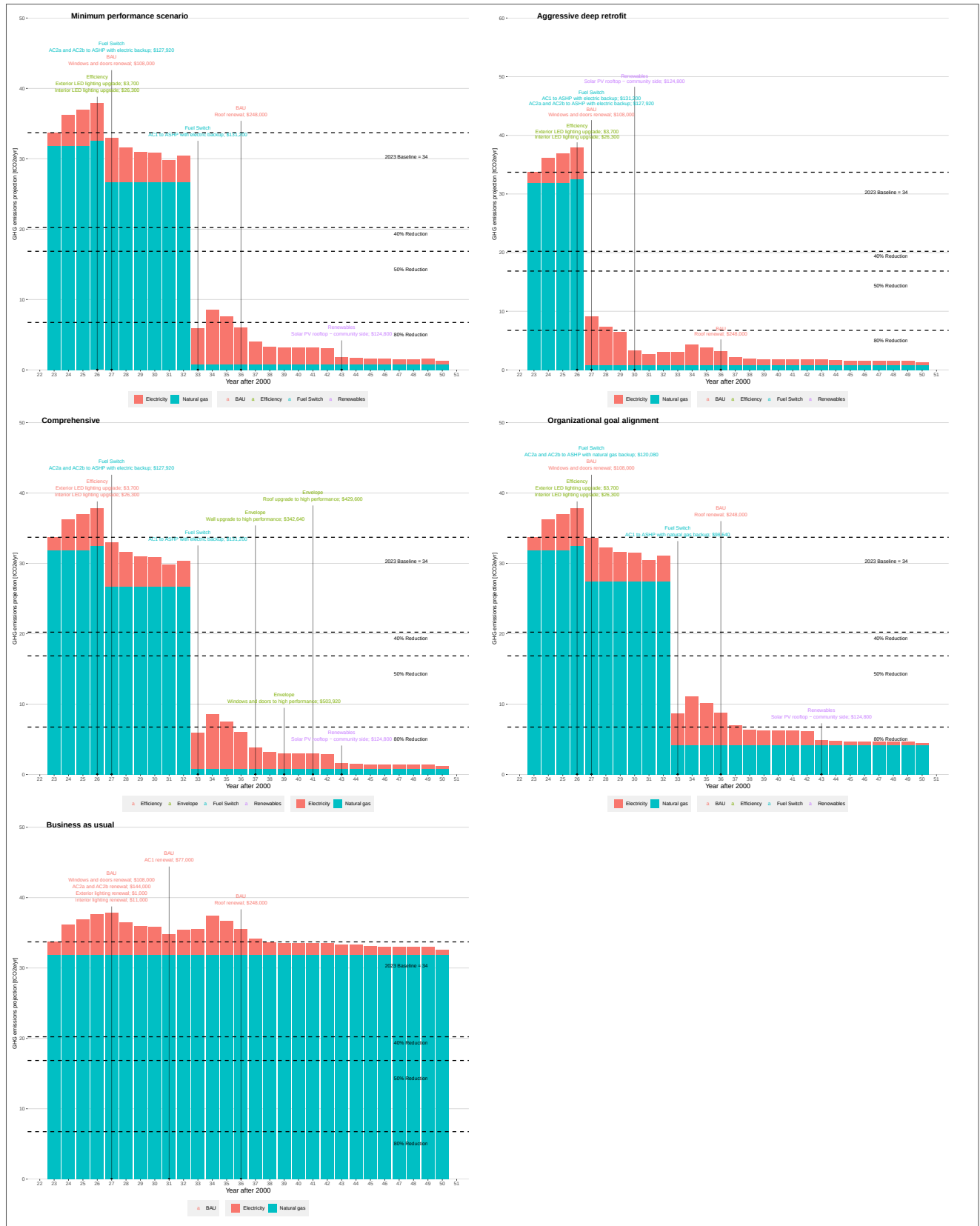


Figure 118: GHG yearly emissions projection for each scenario

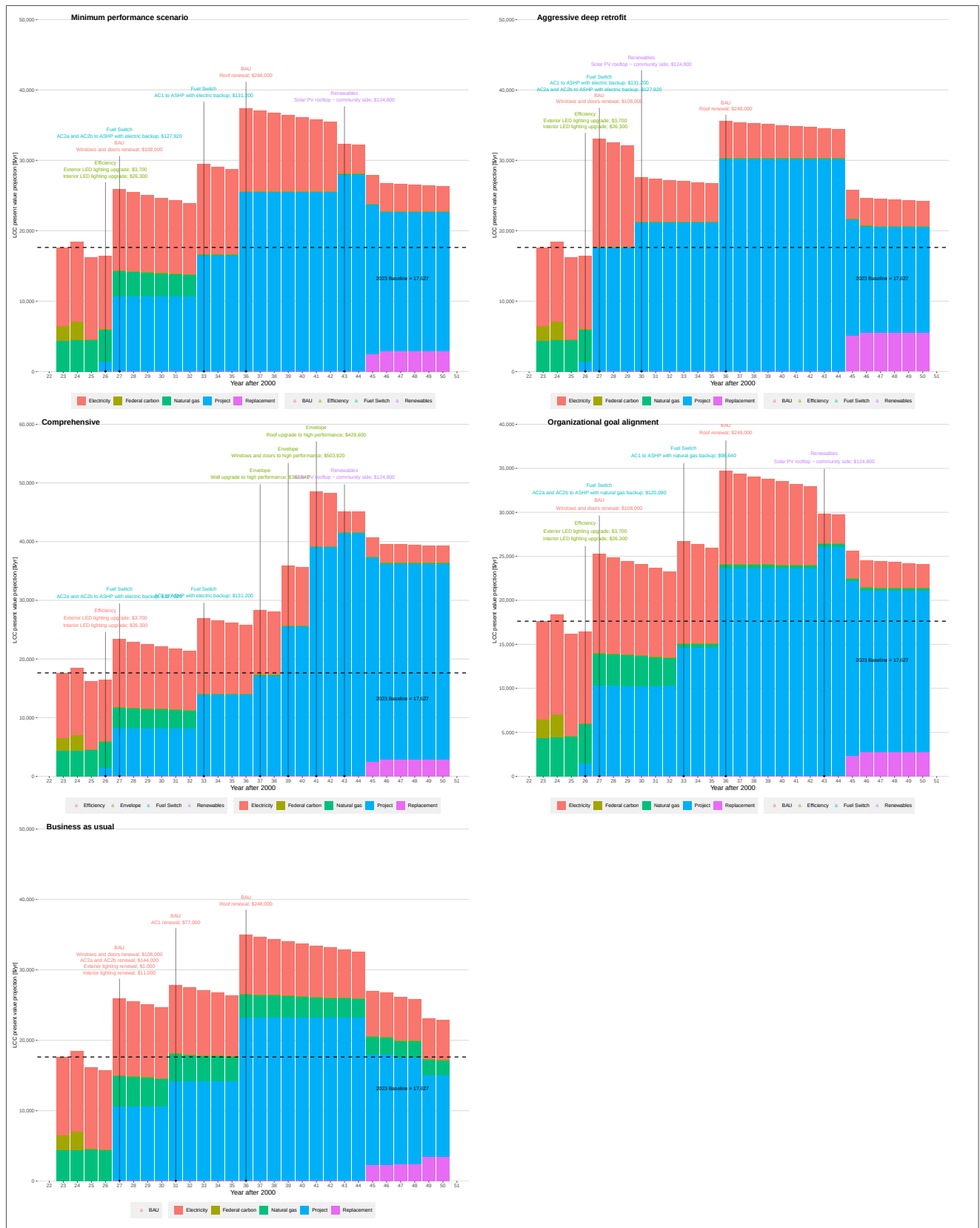


Figure 119: Life cycle yearly cost (after discounting to present value) projection for each scenario

6.7 Plan performance summary

Plan performance summary

Table 55 summarizes the performance of each plan scenario with respect to utility use, GHG emissions, utility cost, and financial metrics. The first half of Table 55 represents the estimated performance in the final year (2050) of the evaluation period. The second half of Table 55 represents the estimated cumulative performance across the entire evaluation period (present to 2050). All final year dollar values are in the value of today's currency. All cumulative dollar values presented in Table 55 are calculated as the simple sum of expenditures over the evaluation period, except for the life cycle cost, which is discounted to present value (as illustrated in Figure 119).

Table 55: Plan performance summary

Section	Description	Unit	Minimum performance scenario	Aggressive deep retrofit	Comprehensive	Organizational goal alignment	Business as usual
Utility use final	Electricity use	[kWh/yr]	48,912	48,912	40,351	37,849	78,354
	Electricity monthly peak (av)	[kW]	30.6	30.6	28.9	21.6	25.3
	Electricity yearly peak (max)	[kW]	62.5	62.5	59.4	34.2	42.0
	Natural gas use	[m3/yr]	403	403	403	2,130	16,475
GHG emissions final	Electricity GHGs	[tCO2e/yr]	0.46	0.46	0.38	0.36	0.74
	Natural gas GHGs	[tCO2e/yr]	0.8	0.8	0.8	4.1	31.8
	Carbon offsets GHGs	[tCO2e/yr]	0.00	0.00	0.00	0.00	0.00
	Total GHGs	[tCO2e/yr]	1.2	1.2	1.2	4.5	32.6
Utility cost final	Electricity utility cost	[\$/yr]	11,925	11,925	9,838	9,228	19,103
	Natural gas utility cost	[\$/yr]	182	182	182	964	7,456
	Carbon offsets utility cost	[\$/yr]	0.00	0.00	0.00	0.00	0.00
	Federal carbon charge	[\$/yr]	0.00	0.00	0.00	0.00	0.00
	Total utility cost	[\$/yr]	12,107	12,107	10,020	10,192	26,559
Utility use cumulative	Electricity use	[kWh]	2,289,602	1,662,393	2,187,376	2,075,850	2,193,919
	Natural gas use	[m3]	156,276	75,930	156,276	189,735	461,295
GHG emissions cumulative	Electricity GHGs	[tCO2e]	89.1	67.5	87.3	82.9	80.4
	Natural gas GHGs	[tCO2e]	302	147	302	367	891
	Carbon offsets GHGs	[tCO2e]	0.00	0.00	0.00	0.00	0.00
	Total GHGs	[tCO2e]	391	214	389	450	972
Utility cost cumulative	Electricity utility cost	[\$]	423,653	303,849	401,292	380,031	414,682
	Natural gas utility cost	[\$]	45,871	21,627	45,871	58,540	161,857
	Carbon offsets utility cost	[\$]	0.00	0.00	0.00	0.00	0.00
	Federal carbon charge	[\$]	4,616	4,616	4,616	4,616	4,616
	Total utility cost	[\$]	474,141	330,092	451,779	443,187	581,155
Financial cumulative	Project cost	[\$]	1,032,639	960,542	2,723,432	974,756	669,737
	Replacement cost	[\$]	141,537	263,384	141,537	134,255	178,189
	Life cycle cost	[\$]	785,235	791,942	861,161	736,592	760,501

6.8 Scenario analysis discussion

Baseline

- This scenario reflects existing conditions.

Minimum performance scenario

- To meet the FCM minimum performance scenario, significant capital retrofits would be required. Heating system electrification to heat pump would be required.

Aggressive deep retrofit

- For the aggressive deep retrofit, the same measures as the minimum performance scenario need to be implemented, but on a shorter timeframe.

Organizational goal alignment

- To achieve the organizational goal alignment of 80% reduction in GHG emissions without carbon offsets, all measures must be implemented, with the exception of envelope upgrades. Heating system electrification is required, although natural gas backup can be used.

Comprehensive

- The comprehensive scenario demonstrates the upper limit of energy-efficiency that the Riverside Place could achieve, based on the measures that were analyzed under this Pathway to Decarbonization Feasibility Study.

7 END