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Design and eco-technoeconomic analysis of a natural gas cogeneration energy management center (EMC) with short-term thermal storage

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ABSTRACT

This work proposes a non-islanded cogeneration energy management center (EMC) that can be used to displace grid-level natural gas turbine systems and natural gas combustion systems for heat. The design of the proposed EMC included a weighted multi-objective optimization aimed at minimizing: i) natural gas consumption; ii) capital costs; iii) utility costs; and iv) unmet thermal demand. The decision variables consisted of the existence and capacity of the equipment comprising the EMC, including: i) a natural gas boiler; ii) an internal combustion engine that generates heat and electricity; and iii) a hot water thermal storage system. Four resulting candidates EMC designs were then compared with the status-quo (SQ) in an eco-technoeconomic analysis; The SQ draws electricity from the grid and heating for dwellings come from natural gas boilers. Emissions at grid level change which alternative is favored. The findings showed that, for a system that serves 4–5 dense urban city blocks over a 20-year lifetime, the SQ system had cumulative levelized costs of 9.6 million USD for the final consumer, while the levelized costs of the EMC designs ranged from 12.9 to 15.1 million USD. In terms of emissions, the SQ emitted 959 tonnes of CO_{2eq} per year, while the EMC system produced around 500 tonnes of CO_{2eq} per year depending on the year, yielding a CCA varying between 364 and 653 USD/tonneCO_{2eq}

1. Introduction

According to the Independent Electricity System Operator (IESO), the government body responsible for electricity market operations in Ontario, Canada, nuclear power plants account for 34 % of Ontario's electrical installed capacity. For the period between June 2021 and December 2022, nuclear power plants are predicted to be responsible for 55 % of all electricity generated in Ontario (IESO 2021). To maintain the Ontario electrical grid's low carbon intensity of 34 gCO_2/kWh_{el} (TAF 2019), low-emission sources such as nuclear, hydro, wind, and solar are dispatched first. If these sources are unable to produce enough electricity to meet demand, gas turbines powered by natural gas (NG) are deployed due to their ability to quickly ramp-up production (Li et al., 2020).

Reducing the use of fossil fuel-based technologies would seem to be a natural step in responding to increasing pressure to reduce greenhouse gas emissions. However, the 3.1 GW Pickering Nuclear Generation Station is set to be fully decommissioned by the year 2028, removing a significant source of low-carbon energy (Ontario Power Generation (2) 2020). Although Ontario Power Generation plans to fully refurbish a different nuclear power plant (in Darlington) by the end of 2026 (Ontario Power Generation (1) 2020), this plan does not include expanding the plant's production capacity. Therefore, the loss in installed capacity from the closure of the Pickering generating station will need to be made up for using other technologies.

Wind and solar power would appear to be logical options for filling this gap, but they are unable to provide the same reliable and consistent large-scale baseload power source as nuclear. The scale, intermittency, storage, and transportation challenges associated with wind and solar, combined with Ontario's relatively low levels of solar irradiance (Sengupta et al., 2018), make it extremely unlikely that these technologies are suitable options for filling the large gap in power generation created

Abbreviations: ACCE, Aspen Capital Cost Estimator; CCA, Cost of carbon avoided; CEPCI, Chemical engineering plant cost index; CHP, Combined heat and power; EMC, Energy management center; eTEA, Eco-technoeconomic analysis; ICE, Internal combustion engine; IESO, Independent Electricity System Operator; MOPSO, Multi-objective particle swarm optimization; NG, Natural Gas; NMVOCs, Non-methane volatile organic compounds; NOx, Nitrous oxides; SQ, Status-quo; TCI, Total capital investment; TDC, Total direct cost; TOU, Time-of-use.

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by the closure of the Pickering station. Although hydroelectric power is a major contributor to the power grid with 25 % of its installed capacity (IESO 2021), its implementation is limited due to its large-scale effects on the surrounding environment and communities (Moran, et al. 2018). Coal power is also not an option for filling this gap, as legislation was passed in 2015 banning its use in the province (Government of Ontario 2015). Indeed, Ontario's lone remaining biomass power plant (Calstock) only operates occasionally and is predicted to contribute just 0.2 % of the total power generated in the province (IESO 2021). Furthermore, the construction of additional wood-burning power plants is unattractive at present due to supply challenges and the high prices of Canadian wood chips (on the order of 11 CAD per GJ_{LHV}, about 8–10 times that of coal), which is due to enormous and growing demand in Europe and Japan, as well as competition with non-industrial uses, construction, and other sectors (Ebadian, et al. 2021).

These limitations leave natural gas, which is especially attractive due to its low cost and flexibility, as the most viable replacement for the Pickering nuclear plant. However, natural gas is a fossil fuel, which means that its use will increase the electricity grid's carbon footprint. As such, natural gas should be implemented alongside technologies designed to minimize the resultant carbon footprint as much as possible, such as decentralized cogeneration systems that produce both heat and power. Although large, centralized cogeneration can work in some cases, Ontario's current energy infrastructure is more compatible with a distributed energy resource approach at the community scale (~10,000 people) to reduce additional transmission and distribution infrastructure. In addition, Ontario is in a period of rapid urban expansion and intensification, which has been accompanied by a construction boom on mostly undeveloped or agricultural land, with ready access to a robust natural gas grid. Ontario also contains many remote, isolated "fly-in" communities that are separated from the province's main urban areas by geographical barriers, which makes energy supply to these communities very difficult.

Distributed energy resource technologies have multiple benefits compared to centralized approaches, including: lower transmission losses due to being closer to the community they are servicing; the ability to be installed near remote communities; resiliency and the ability to be used as disaster relief if major disruptions occur in the main electrical grid (Akinnyele, et al. 2014) and better energy utilization. These benefits are amplified by the type of system proposed herein, which consists of a modular EMC built inside a shipping container to enhance portability. One major advantage of EMC cogeneration is that, in contrast to traditional gas turbine systems wherein low-grade waste heat from electricity production is simply exhausted, EMC systems utilize this low-grade waste heat (<100 °C) for heating purposes, thereby reducing heating-related fuel consumption. Some of the key challenges of decentralized energy systems are associated with lower economies of scale; for the same capacity, they have higher capital cost than bulk electric power production. Further, distributed energy resources have their own set of challenges that include the need for remote management and control.

In this work, we conducted an eco-technoeconomic analysis (eTEA) of decentralized energy management centers (EMCs) powered by NG. We compared the results with those for the status quo (SQ) that consists in grid level NG gas turbines and domestic boilers, all at a scale equivalent to four to five densely populated downtown blocks. This was used to identify the best design and operational decisions for EMCs and determine if they are advisable to use instead of the status quo (using the existing municipal grid for electricity with natural gas boilers for heat). This is the first such work to propose optimal non-islanded decentralized EMCs designs considering: 1 - thermal storage, internal fluid dynamics, and peak management; 2 - detailed EMC eTEAs considering in the context of Ontario; and 3 - prices paid by consumers in the community. This analysis sets a benchmark for future eTEAs, with results easily comparable with other cogeneration systems both in price and emissions. Although Ontario was used as a case study, the results are appropriate for any electric grid with a similar electricity generation mix, and the proposed methodology can be extended to any scenario.

1.1. System description

1.1.1. Energy management center and status-quo systems

Fig. 1 depicts a cogeneration EMC distribution scheme wherein heat is distributed using a large, one pipe, thermal loop that is supplemented by domestic boilers to guarantee demand is satisfied. The produced electricity is used to power the EMC itself, mainly its pump, with the remainder being delivered to the community according to its demands. Notably, this operational regimen ameliorates the issue of electricity curtailment.

While the above-described EMC system produce both heat and power, it is not be able to produce enough electricity to completely meet demand. Therefore, to guarantee that the community's electricity needs are met, both systems can draw electricity from the main grid if necessary.

The terms 'makeup' and 'backup' will be used in this work interchangeably to refer to the extra boilers necessary to meet heat demand or electricity imported from the main grid to meet electricity demand.

For comparison, the SQ system is shown in Fig. 2. The SQ system consists of the same community buildings and energy needs, but the energy needs are provided only through grid electricity and individual natural gas boilers.

1.1.2. Energy management center

The EMC used in this work is composed of an NG boiler, a combined heat and power system (CHP) comprised of an internal combustion engine (ICE) with integrated residual heat capture, a hot water sensible heat pit storage system, a cooling tower, and a plate heat exchanger, which were all connected to a header (Fig. 1). The EMC was installed inside an external enclosure made up of six refurbished ISO L5G1 standard shipping containers (12.5 m long, "45 ft. Standard High Cube")- with total footprint area of 340 m^2 (ISO 1995). The components were modelled using TRNSYS software, which features a robust library of built-in models and allows for in-house component modelling (Thermal Energy System Specialists, LLC 2019). The plate heat exchanger (type 626) had a fixed effectiveness of 65 % and a bypass in the source side to avoid heating the hot water distribution loop above 60 °C, which is acceptable for radiant floor heating, which accepts temperatures between 30 °C and 60 °C (Barron 2022). Both types operate following a first-principles model.

The other components had capacities that were determined via optimization algorithm, which are in detailed in Section Energy Management Center Design Optimization. The CHP model consisted of a linear regression model of the ICE and integrated heat exchanger that was trained using the proprietary data from the manufacturer's datasheet and implemented using the EQUATION tool in TRNSYS. Specifically, the model predicts the production of electricity, residual heat transferred to the heat loop, and fuel consumption as a function of the ratio between instantaneous demand and maximum capacity.

Based on commercially available data (Weil-McLain 2016) (HouseNeeds 2021), the boiler (type 659) was assumed to have 90 % efficiency without ambient heat loss. Similarly, no heat loss from the hot water pit storage (modeled as type 534) was considered due to sufficient thermal insulation and it was assumed to be fully mixed. Finally, the header between the equipment was modelled as a pipe (type 31) with a delay of one timestep (type 11), and ethylene glycol (mass: 33 %) was used as the working fluid in the EMC and hot water distribution loop. The models for all of these are based on first-principles.

The detailed control strategy used in the TRNSYS simulation can be found in Appendix I . It is important to highlight that the CHP is permitted only when NG is present in the grid in order to effectively displace centralized generation. This is because the emissions from CHP-generated electricity are higher than the average Ontario grid emissions

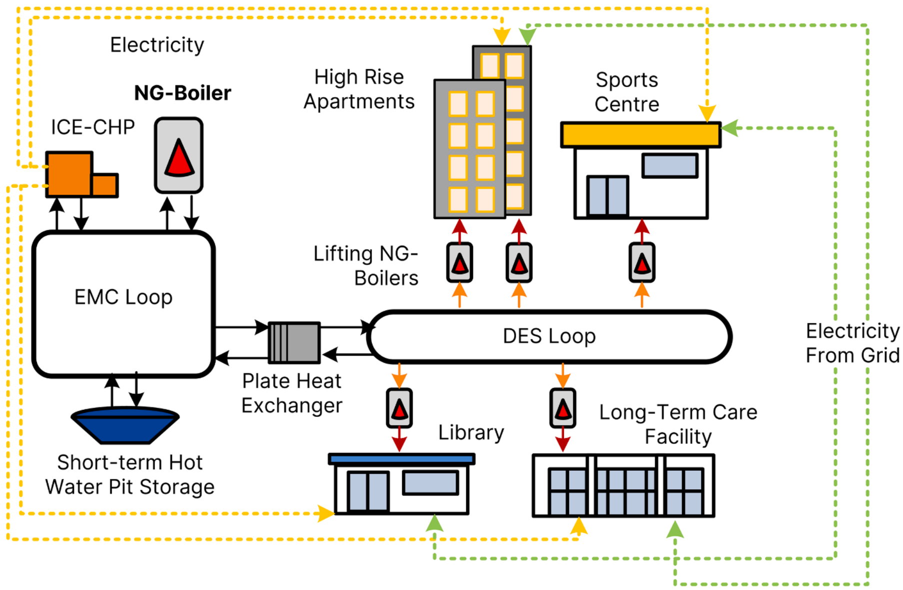

Fig. 1. - Energy distribution by the Energy Management Center system.

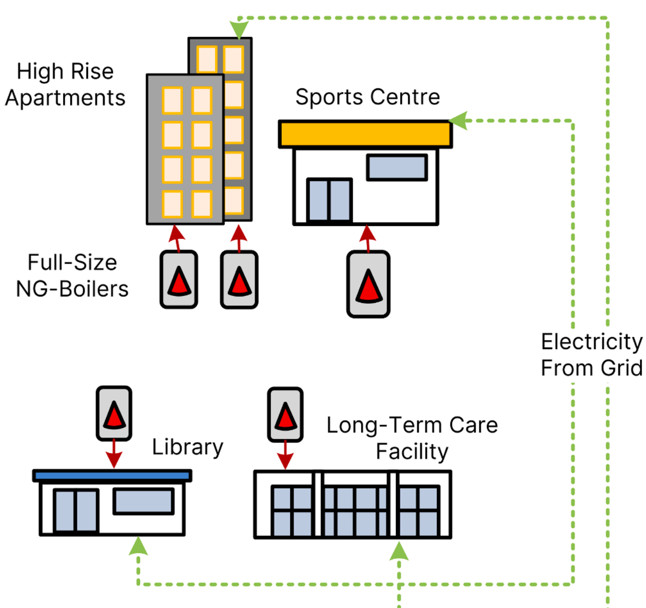

Fig. 2. - Energy distribution by the SQ system.

when natural gas power plants are not used, since the rest of Ontario's generation consists of nuclear, hydroelectric, solar, and wind.

1.1.3. *Demand profile*

The same lumped-demand approach was used to compare the SQ and EMC systems, as it aggregates all the demands of a community of buildings within the same time interval. The energy demand considered in this work is shown in Fig. 3. The hourly profile shown in Fig. 4 is representative of an aggregate of building archetypes created from proprietary data from the city of Burlington in Ontario, Canada. These archetypes replicate a downtown area equivalent to four to five blocks including two high rise towers, library, sports complex, and a long-term care facility, with any identifiable characteristics having been removed to respect the customer's privacy. As can be seen, the heating demand ranges from a minimum of 40 kWh during the summer to a maximum of 1329 kWh in the colder months. In contrast, electricity demand for non-cooling applications barely changes from season to season, varying from about 55 kWh to 814 kWh.

For this study, this demand was utilized as a benchmark. However, the methodology used herein can be applied to other communities, including mixed-use urban neighborhoods. Commercial and domestic dwellings may be included in this analysis.

1.1.4. *Ontario's electrical grid emission factor*

The use of NG as fuel for electricity generation is dependent on demand and the availability of low-emission sources. Because of that, there

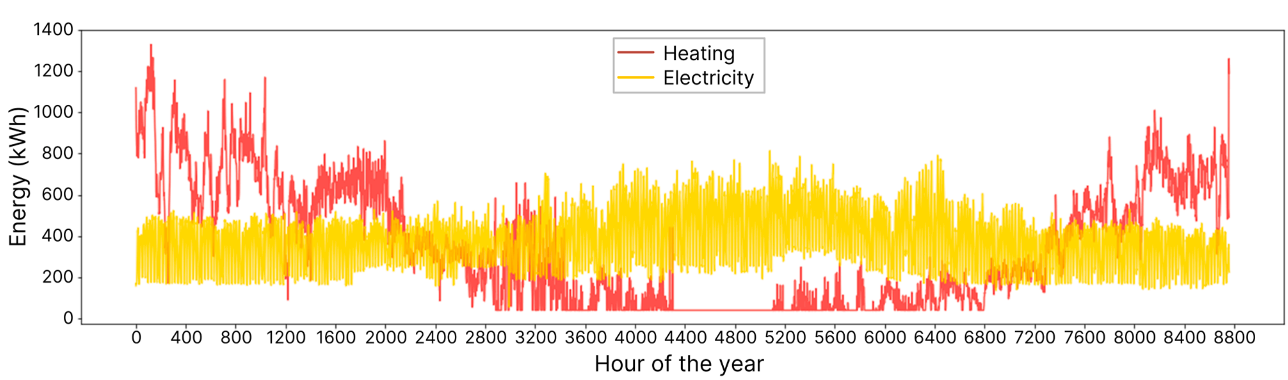

Fig. 3. - Hourly heat and electrical demand for the community.

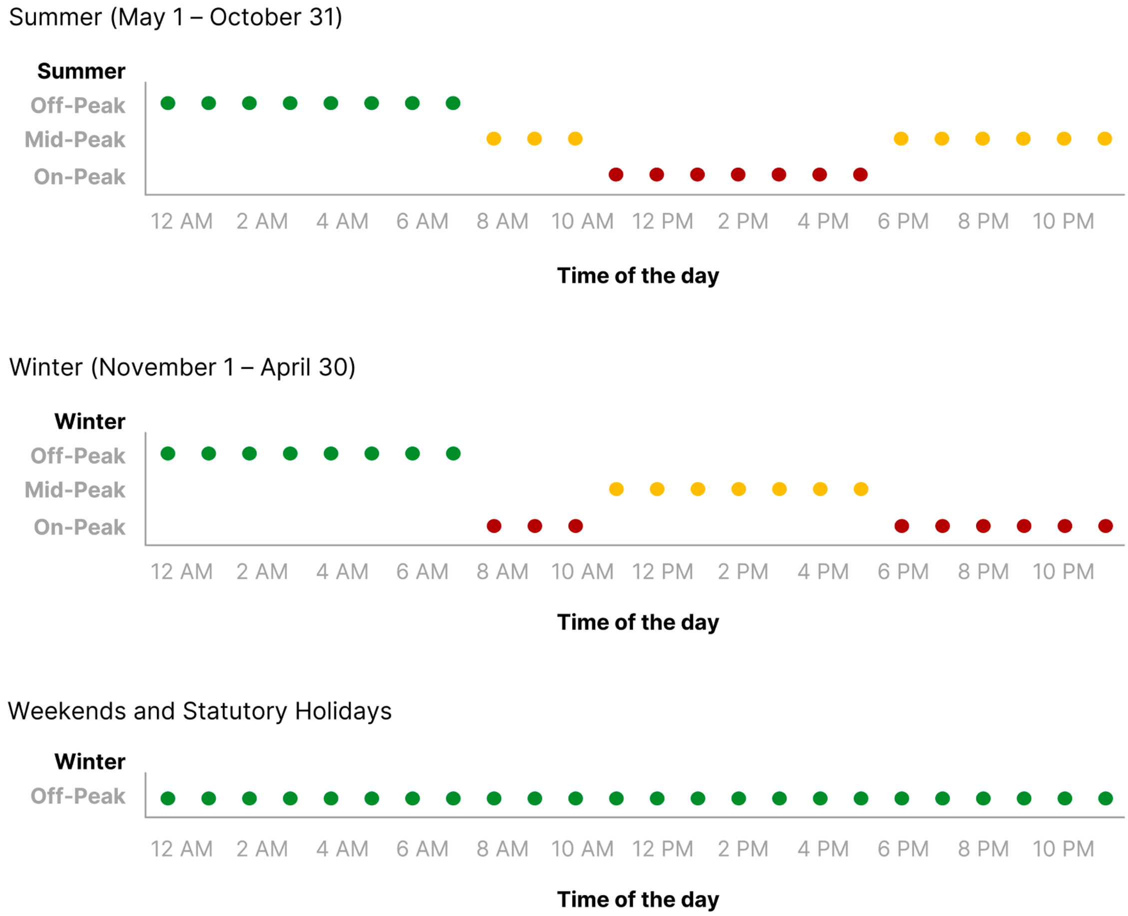

Fig. 4. - Ontario electricity time-of-use (TOU) periods using data from (Ontario Energy Board (1) 2021).

is a variability for each hour of emission factor per kWh of electricity production in the province. For this work, the historical hourly emission factor was estimated from production data from electricity generators between the years 2015 to 2021 (IESO 2022). Table 1 shows the range of cradle-to-gate emissions per kWh for each source. The table also shows the value used for the study herein, in which each was then proportioned according to its respective generator output in an hourly basis. This allows for an estimation of the gCO_2-eq emitted electricity production in the province.

1.1.5. Electricity time-of-use

In Ontario, smaller consumers pay for electricity according to time-of-use (TOU) (Ontario Energy Board 2022). The price of domestic electricity varies according to the peak phase of the day, with off-peak at 8.5 cents/kWh, mid-peak at 11.9 cents/kWh, and on-peak at 17.6 cents/kWh (Ontario Energy Board (1) 2021). TOU changes according to the season and day of week, as shown in Fig. 4.

Table 1
Emission factor cradle-to-gate per electricity generator. Data from (Milousi, et al. 2019).

Generator	Footprint range (gCO_2-eq/kWh)	Value for this work (gCO_2-eq/kWh)
Nuclear	4 – 110	47
Natural Gas	410 – 650	530
Hydroelectric	1 – 24	24
Wind	9 – 35	22
Solar	26 – 60	43

2. Material and methods

2.1. Energy management center design optimization

A multi-objective optimization procedure was used to select the capacities of the CHP, boiler, and water tank. For these tests, 2016 was used as the design year. The pseudo-formulation is described below and each component of the objective function is normalized between 0 and 1. More details about the constraints applied to the operation of the EMC can be found in Appendix I.

From modeFrontier:

$$\min_{C_i} \left(w_1\ NG\ consumed + w_2\ Equipment\ cost + w_3\ Utility\ cost + w_4\ Thermal\ demand\ unmet \right)$$

.

Constraints embedded in the TRNSYS simulation:

$$f(C_i, X, P) = 0$$

Calculated variables

$$X = \{NG_{cons}, Cost_{equip}, Th_{unmet}, El_{unmet}, T_{loop,t}, T_{header,t}, T_{tank,t}, P_{CHP,t}, Q_{CHP,t}, Q_{boiler,t}, Q_{del,EMC,t}, Q_{tank,t}, NG_{boiler,t}, NG_{CHP,t}\}.$$

Simulation parameters

$$
\begin{aligned}
P &= \{D_{electrical},\ D_{thermal}, eef_h\} \\
NG_{cons} &= \sum_{t=1}^{N} NG_{boiler,t} + \sum_{t=1}^{N} NG_{CHP,t} \\
Cost_{equip} &= \sum_{i} f_{FOB}(C_i) \\
Th_{unmet} &= \sum_{t=1}^{N} \left(D_{thermal,t} - Q_{del,EMC,t}\right) \\
El_{unmet} &= \sum_{t=1}^{N} \left(D_{electrical,t} - P_{CHP,t}\right) \\
C_{i,LB} &\leq C_i \leq C_{i,UB} \\
T_{loop,t} &\leq 45^{\circ}C \\
T_{loop,setpoint} &= 40^{\circ}C
\end{aligned}
$$

Where C_i is the capacity of each equipment $i \in \{CHP,\ boiler,\ water\ tank\}$ in varied units (kW_{el} for CHP, kW_{th} for boiler, and m^3 for the tank). The indexes, *LB* and *UB*, respectively refer to the lower bound and upper bound capacities for each piece of equipment. NG_{cons} is the total natural gas consumed by the EMC that is the sum of NG consumed by the boiler ($NG_{boiler,t}$) and the CHP ($NG_{CHP,t}$). The index for each timestep is *t*, with each timestep lasting 10 min until a full simulation period (seven years) is completed, thus the total timesteps $N = 8760\,\frac{hours}{year} \times 6\,\frac{timesteps}{hour} \times 7\ years = 367,920\ timesteps$. $Cost_{equip}$ is the sum of the free-on-board ($f_{FOB}(C_i)$) costs for each piece of equipment that composes the EMC based on their respective capacities. These calculations are further detailed in Appendix II. Th_{unmet} is the total thermal demand unmet (thus requiring backup boilers) and it is the sum of the differences of the thermal demand in each timestep ($D_{thermal,t}$) and the corresponding thermal energy delivered by the EMC ($Q_{del,EMC,t}$). El_{unmet} is the total electrical demand unmet and it is calculated by the difference of the electrical demand ($D_{Electrical,t}$) and the electricity delivered by the CHP ($P_{CHP,t}$). $T_{loop,t}$ is the temperature of the distribution loop at each timestep, while $T_{header,t}$ is the temperature of the header inside of the EMC. No lower bound for $T_{loop,t}$ was defined but based on the results it never dips lower than 35 °C. $T_{tank,t}$ is the temperature inside the tank at each *t*. $Q_{CHP,t}$ and $Q_{boiler,t}$ are respectively, thermal energy delivered by the CHP and by the boiler each *t*. eef_t is the hourly (subscript *h*) electricity emission factor of the electrical grid of Ontario during the years of 2015 to 2021, which were used for the designs.

Moreover, w_n, $n = \{1, 2, 3, 4\}$ is the weight attributed to each of the components of the objective function. These weights are attributed to each component of objective function normalized between 0 and 1, meaning that these values can be added together to calculate the overall objective function. This normalization is a result of the parameter space exploration given upper and lower bounds. The highest value obtained is assigned to be 1 while the lowest one becomes 0. All the other values can be found within this interval, meaning that there are infinite combinations to represent the Pareto front that formed by variation of these weights. Moreover, a 4D surface is not easy to represent or interpret. In the Results and Discussion section, we chose points from different zones from the Pareto front.

Because of the nature of TRNSYS, the model equations and sensitivities for the built-in unit operation models are not available to the user, and so for optimization purposes the software must be treated as a black-box. Therefore, the optimization algorithm must be suitable for black-box or derivative-free circumstances. We selected modeFrontier as the optimization framework, which can communicate with any modelling software that can accept an input file, run a simulation, and return an output file (ESTECO 2021), to evaluate an objective function. We chose the multi-objective particle swarm optimization (MOPSO) incorporated within modeFrontier that is applicable for derivative-free and discontinuous systems. While this algorithm is unable to guarantee global minima (Vikhar 2016), it still produces satisfactory results for this application.

The EMC is not meant to be a stand-alone system, therefore extra heating and electricity need to be fed from auxiliary systems to meet both demands at all times. These values are determined all together with the design optimization. In this case, electricity import comes from the main electrical grid considering TOU prices. For the heating, each community building has its own individually sized domestic boiler. Both auxiliary heat and electricity are considered a cost for the EMC system to better understand how much the consumer would pay for these systems.

3. Calculation

3.1. Cost

The system cost analyses presented herein estimate the total direct cost (TDC) required to commission each system. The TDC includes equipment costs, installation costs, and labor costs. In addition, it is also necessary to consider the operation and maintenance costs over the system's lifetime.

In this work, the TDC is calculated using the Aspen Capital Cost Estimator (ACCE) software (AspenTech 2021) wherever possible. ACCE cost estimations are quite rigorous and include factors such as materials of construction, concrete flooring, wiring, painting, scaffolding, control systems, and particulars about size and shape. To integrate this complex information into the analysis, cost estimate for each piece of equipment were calculated at different capacities in a range, and then the results were fit to a polynomial that computed TDC as a function of capacity. The resulting mathematical relations can be found in Table. 2. These relations were used in the optimization process, which is detailed in the Material and methods section.

C represents the equipment's capacities, C_{el} denotes that the considered capacity is electrical., and *V* refers to tank volume. Table 2 also includes the price of the metal and plastic tanks as these are the most common commercial materials to capture how the tank material impacts the TDC.

The direct costs listed in Table 2 and Table 3 are from the first quarter of 2019, and can be adjusted to 2021 prices using the chemical engineering plant cost index (CEPCI) (Vatavuk 2002). This adjustment is calculated using Eq. (4). The cost associated with the domestic boiler is already up to date (i.e., 2021).

$$f_{\$,2021} = f_{\$,2019}\frac{CEPCI_{2021}}{CEPCI_{2019}} \tag{4}$$

where $f_{\$}$ is the TDC, and *CEPCI* refers to the index values, with their corresponding years being indicated by the subscript, 2019 or 2021. For instance, $CEPCI_{2019}$ was 607.5 and $CEPCI_{2021}$ is 677.1 as of April 2021 (Chemical Engineering 2021).

The value of TDC can be used to estimate the total capital investment (TCI) necessary to build a plant. This is shown in detail in Appendix II. Unlike TCI, which occurs once, operation and maintenance costs occur every year the system is in operation. In this work, the operation cost

Table 2
Mathematical relations between the direct costs at variable equipment capacities.

Equipment	Considered Capacities	Direct Cost (USD)		Source
CHP	10 - 600 kW_{el}	$14,155 + 434.35\ C_{el}$	Eq. 1	ACCE
Pit water storage	0.5–3000 m^3	$V * 2494 * V^{-0.374}$	Eq. 2	(PlanEnergi and HFT Stuttgart 2019)
NG-boiler[1]	1 – 1000 kW_{th}	$-0.1835\ C^2 + 417\ C + 106,038$	Eq. 3	ACCE

[1] Industrial boiler.

Table 3
Direct costs of equipment with fixed capacity.

Equipment	Fixed Capacity	Direct Cost (USD)	Source
Heat exchanger	45 m^2	96,191	ACCE
Distribution loop	3 km	790,000	(Imran, et al. 2017)

Table 4
Utility and maintenance costs.

	Cost	Reference
Natural Gas[a,b]	13.64 ¢/stdm^3	(Ontario Energy Board (2) 2021)
Maintenance total	7 % TDC/year	(Seider, et al. 2008)

[a] Value converted from CAD to USD, Oct 4, 2021. [b] Includes transportation.

includes all utilities consumed, while the maintenance costs are based on a heuristic relationship. These values can be found in Table 4, and the electricity prices are listed in Table. 4.

The value of NG in Table 4 corresponds to the cost of NG alone. However, when consumer charges, federal carbon charges, and other factors included in Ontario's gas bills calculator (Ontario Utility BIlls 2021) are factored in, the effective cost for the consumer becomes around 42 ¢/stdm^3, which is the value used in this work. Prices for cooling water include reverse osmosis treatment.

These values are not adjusted for the inflation that would occur naturally throughout the course of a 20-year operation. For the scope of this work, the impact of inflation on operation costs is not relevant; rather, the comparison of the systems is much more salient in this context. It is important to note that the same amount of water was considered for all EMC designs, both for cooling tower and the internal EMC pipes.

3.2. Cost of carbon avoided

The cost of carbon avoided (CCA) compares two systems with respect to their emissions and total costs during their lifetimes and can be determined using Eq. (5).

$$CCA = \frac{C_{EMC} - C_{SQ}}{(Emissions_{SQ} \ - Emissions_{EMC})} \quad (5)$$

The term, C, corresponds to the system's levelized costs during its lifetime. The indexes represent the EMC and SQ. The economic parameters in Table 5 were used to perform a baseline evaluation of the system.

For this application, *Emissions* corresponds to the total direct emissions plus indirect emissions due to grid electricity consumption (in tonnes CO_2-eq) during the systems' operation lifetime. Direct CO_2 emissions occur from natural gas consumption for boilers in both cases and for the cogeneration system in the case of the EMC. The emissions are determined as follows:

$$Emissions_{SQ} = B_{SQ} + \sum_{t=1}^{367,920} D_{electrical,t} \times eef_t \, Emissions_{EMC} = NG_{cons} + B_{EMC} + \sum_{t=1}^{367,920} \left(D_{electrical,t} - \ P_{CHP,t}\right) \ \times eef_t \quad (6)$$

Table 5
Baseline parameters for economic analysis.

Project lifetime	20 years	(Colantoni, et al., 2021)
Loan on CAPEX	60 %	(Wimer 2008)
Loan interest/year	8 %	(Wimer 2008)
Discount Rate EMC/year	6 %	(Colantoni, et al. 2021)
Loan lifetime	10 years	(Wimer 2008)
Raw material inflation rate/year	3 %	(Wimer 2008)
Production cost inflation rate/year	4 %	(Wimer 2008)

B_{EMC} and B_{SQ} are determined by taking the value of the cumulative natural gas consumed by the backup boilers for the model year for each case as determined by the optimizer and assuming that all of the natural gas was completely combusted to CO_2, without consideration of NOx or NMVOCs. As noted previously, several different model years are explored in the analysis.

CCA is expressed in USD/tonneCO_2-eq, which can be directly compared to the carbon tax. In Canada, the federal floor for carbon tax will reach 50 CAD/tonneCO_2-eq in 2022 (about 40 USD/tonneCO_2-eq), which a steep rise of 15 CAD per tonneCO_2-eq per year from 2022, reaching 170 CAD/tonneCO_2-eq by 2030 (about 136 USD/tonneCO_2-eq) (Environment and Climate Change Canada 2021). If the CCAs is below the amount of the tax, it is generally more economical to install the EMC, and if not, it is generally more economical from the perspective of the consumer to use the SQ system and just pay the tax.

4. Results and discussion

4.1. Energy management center

The MOPSO optimization was programmed to perform 400 iterative evaluations of the objective functions, from which the Pareto points are selected from these designs. However, a four-dimensional problem produces a Pareto front that is hard to interpret. Fig. 5 demonstrates all four dimensions using a 2D plot, color gradient, and marker size. The size of the circle is proportional to the yearly cost of utility, color blue (best) to red (worst) represent how well the EMC met thermal demand, the y-axis shows capital cost for a system with plastic tank, and the x-axis shows the emission reduction from the status-quo

For preliminary analysis, we chose the selected designs shown in Fig. 5 (labeled 93 and 174) due to their position on the Pareto distribution. Table 6 shows design details of the designs shown in the figure.

We chose pit thermal energy storage due to its low cost per cubic meter and the possibility that they offer a large volume capacity (PlanEnergi and HFT Stuttgart 2019). Moreover, this type of thermal storage has been successfully implemented in district heating applications since 1994 (IEA-DHC 2018). The costs of the heat exchanger are included for the TDC functions as shown in Table 3. Besides capital costs, operational costs also significantly impact the overall financial requirements of each design.

Cases 2 and 3 are the only one that have lift boilers, albeit the optimization allowed for that for all cases. These cases also do not include a boiler at all in the EMC. Further, Cases 1 and 4 have considerably large tank capacities which are reflected in their costs.

Table 7 shows that electricity is the most expensive utility for all cases, amounting around to 83 % of the utility price for the final consumer. It is to be noted that this study focuses on domestic consumers, therefore reduced electricity tariffs granted to industries are not applicable. All designs assure that the minimum temperature is delivered to the heating system.

Fig. 6 shows the EMC performance before its makeup system, it shows the impact of varying equipment size, in which Case 4 notable produces less electricity and heat. A representative week was chosen for clarity. Note that in both cases, the electricity delivered never exceeds demand; when it does not meet demand, electricity must be imported from the grid at that time instant. Also in the figure, the heat delivered refers to the heat delivered to the heating loop, not to the customer. Heat delivery can therefore exceed demand because surplus heat is stored in the loop in the form of higher circulating fluid temperature. Similarly, all of a customer's heating demand might be met at a time step even though the heat delivered to the loop might be lower than the demand at that timestep because the customer can draw additional stored heat from the loop, thus reducing the loop temperature. Any remaining portion of customer heat demand that cannot be met through heat transfer from the loop (perhaps because the loop temperature is too low)

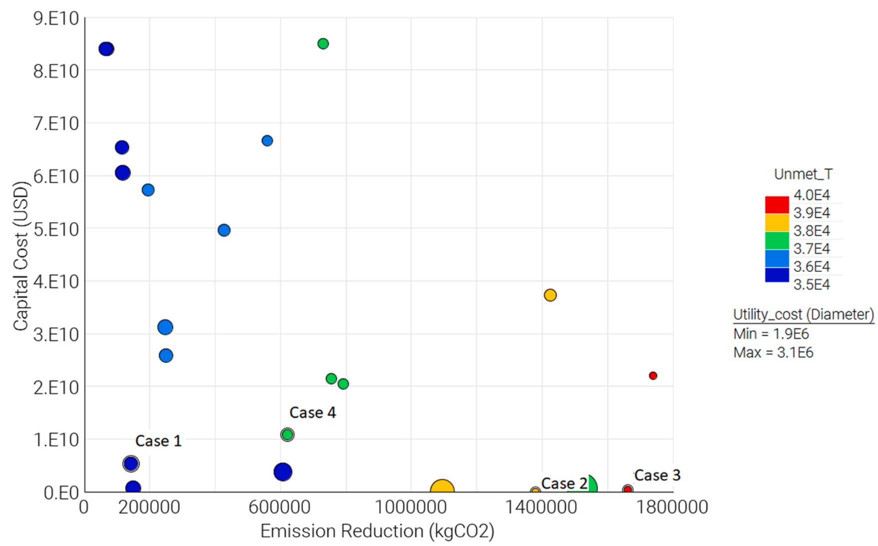

Fig. 5. - Representation of resulting designs from the Pareto front. The size of the circle represents the yearly cost of utility, the color blue (best) to red (worst) represent how well the EMC met thermal demand, y-axis shows capital cost, and x-axis shows the emission reduction from the status-quo.

Table 6
Objective function results for EMC design cases.

	#92 - Case 1	#232 - Case 2	#237 – Case 3	#386 – Case 4
CHP capacity (kW_{el})	501	378	482	365
Pit volume (m^3)	1258	91	335	1803
Boiler capacity (kW_{th})	286	–	–	126
$Boiler_{TDC}$ ($1000 USD)	168	–	–	125
CHP_{TDC} ($1000 USD)	185	144	179	138
Pit $storage_{TDC}$ ($1000 USD)	221	43	97	277
Heat exchanger ($1000 USD)*	96.2	96	96	96
Distribution loop ($1000 USD)*	790	790	790	790
TDC ($1000 USD)	1460	1073	1162	1426

is met through use of the backup boilers in the individual customer buildings at that particular timestep.

An important point is that despite the setpoint being 40 °C, the loop temperature is left to vary between 30 °C and 60 °C, which is used in radiant floor heating (Barron 2022). The fluid in the loop itself functions as an energy storage device, and so the EMC does not need to be able to generate the maximum instantaneous heat demand from the community because the system can draw from stored thermal energy in the loop

Table 7
Detailed description of design Case 1 to 4, including utility consumption by the EMC designs, makeup utility costs, and total utility costs for the final consumers in thousands of USD.

	#92 - Case 1	#232 - Case 2	#237 - Case 3	#386 - Case 4
EMC				
CHP capacity (kW_{el})	501	378	482	365
Pit volume (m^3)	1258	91	335	1803
Boiler capacity (kW_{th})	286	–	–	126
$Boiler_{TDC}$ ($1000 USD)	168	–	–	125
CHP_{TDC} ($1000 USD)	185	144	179	138
Pit $storage_{TDC}$ ($1000 USD)	221	43	97	277
Fuel Boiler (GJ_{HHV}/year)	7700	5604	6063	8066
Fuel CHP (GJ_{HHV}/year)	29	–	–	31
Total NG consumption (GJ_{HHV}/year)	7729	5604	6063	8097
NG cost ($1000 USD/year)*	47.0 - 69.3	47.7 - 50.3	47.1 - 54.4	47.8 - 72.6
TDC ($1000 USD)	574	187	276	540
Makeup system				
Lift boiler capacity (kW_{th})	–	117	53	–
Lift boiler NG cost ($1000 USD/year)*	–	7.7	3.5	–
Electricity import (MWh/year)	2693	2734	2720	2687
Electricity cost ($1000 USD/year)*	230.4 - 266.8	256.9 - 269.5	249.5 - 267.6	231.3 - 269.8
Utility cost ($1000 USD/year)*	230.4 - 266.8	264.5 – 277.1	252.9 – 271.1	231.3 - 269.8
TDC ($1000 USD)	–	385	342	
Overall				
Total TDC ($1000 USD)	1461	1458	1504	1426
Total utility cost ($1000 USD/year)*	299.7 - 314.3	314.8 – 325.5	307.3 - 318.2	303.9 - 317.9

* Fixed cost from Table 3 **Changes according to the calendar year, respecting peak and off-peak hours. The ranges show the minimum and the maximum values found by considering this variation.

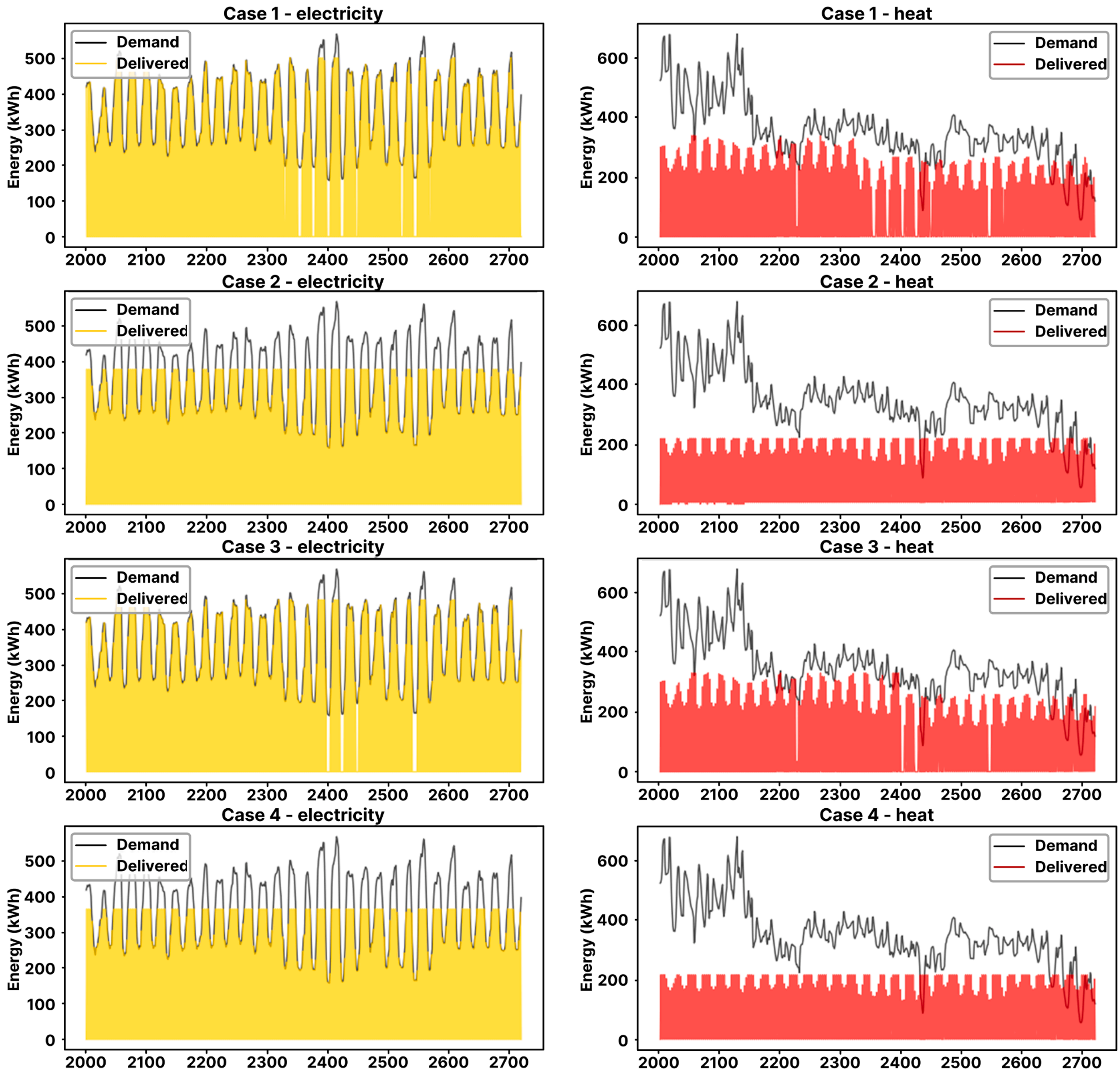

Fig. 6. - Electricity demand and optimal electricity delivered for the optimal designs of Case 1 to 4. The rows show the results for each case. Left-hand plots show the electricity delivered by the EMC compared to the demand, while the right-hand side plots show thermal energy delivered to the thermal loop (not necessarily to the customer) compared to its demand. All plots show the systems' performance in one representative week.

Table 8
Yearly emissions for each EMC design.

	#92 - Case 1	#232 - Case 2	#237 – Case 3	#386 – Case 4
EMC				
Emissions by EMC (tonne CO_2/year)	271.5 - 400.5	275.3 - 290.4	272.2 - 314.1	276.2 - 419.5
Emissions by electricity import (tonne CO_2/year)	167.2 - 233.3	168.3 - 248.3	167.1 - 243.1	168.5 - 222.2
Emissions by lift boiler (tonne CO_2/year)	–	44.0 – 44.3	20.1 – 20.2	–
Total emissions (tonne CO_2/year)	438.9 - 626	487.8 - 582.7	461.5 - 577.3	446.7 - 641.8

Table 9
Utility consumption by the SQ for the final consumers in thousands of USD and associated emissions.

SQ	Amount (MWh)	Infrastructure cost (Thousand USD)	Cost for consumer (Thousand USD)	Emissions (tonne CO_2-eq/year)
Electricity	3342[a]	N/A[c]	316 - 327	305
Domestic boilers	2,981[b]	980	113	654
Total	–	980	429 - 440	959

[a] MWh_{el} [b]MWh_{th} [c]No cost of infrastructure for electricity was included because there is the assumption that it is already in place.

Table 10
Levelized cost and emissions during a 20 year lifetime for each evaluated EMC designs and the SQ.

Design	Levelized Cost (thousand USD)	Emissions (tonneCO_2-eq)	CCA (USD/tonneCO_2-eq)
Case 1	$14,992	10,006	$ 584
Case 2	$15,147	10,740	$ 653
Case 3	$13,347	10,220	$ 414
Case 4	$12,893	10,246	$ 364
SQ	$9636	19,180	–

fluid itself. The water flowrate in the loop is 15 kg/s according to the master thesis in preparation by Van Ryn (2022) and the setpoint temperature was chosen to be based on practical suggestions for this scale and application (Yang, Li and Svendsen 2016). The cost of each operation includes the heating load necessary to heat the distribution loop.

Table 8 shows the yearly emissions for each EMC design, assuming electricity emissions of 58 gCO_2/kWh_{el} and natural gas emissions of 1.95 $kgCO_2/m^3$ (Wills and Brubacher 2007).

As shown in Table 8, the emissions from the NG consumption and electricity imports are of the same order of magnitude, varying from year to year. Because of the advantages both in emissions and cost of Case 2 and 3 - which are smaller in terms of equipment sizes for the container portion of it – the next step is to verify how status-quo fare compared to this design.

4.2. Status quo

As previously discussed in the Energy Management Center and Status-quo systems section, the SQ demands are met considering only electricity from the grid and heating from domestic boilers. As result, the only values that change with different years are the cost of imported electricity due to different holidays and peak occurrences as shown in Table 9. This variance is very small, keeping the contribution of electricity for the final utility bill around 74 % for all years. In terms of emissions, we can see a more even contribution from heating (59 %) and electricity (41 %) out of a yearly output of 959 tonnes of CO_{2eq} per year.

4.3. Economic analysis

Table 10 shows the levelized cost of constructing and operating all of the designs evaluated in the Results section according to the parameters in Table 5. Table 10 also includes the system's lifetime emissions. Both columns include the makeup systems: extra electricity from the main grid and domestic boilers. The levelized cost of the status quo only includes operation cost for the community.

The EMC designs always produced lower emissions, even when makeup utilities are considered. The main reason for this result is that the EMC design's utilization of the waste heat and the presence of the tank help to reduce steep peaks in thermal consumption. Table 10 also shows that the EMC is more expensive, which is expected because of extra infrastructure necessary when comparing to the SQ. In this work, the optimizer had the option to use backup boilers as extra domestic heating if necessary. This can be switched for a heat pump, which works using electricity to reduce or increase temperature depending on the needs. In the Conclusion, we expand on this, but the opportunity to draw heat from one building and deliver to another one further decreases domestic heating demand from EMC, further reducing its emissions.

The emission reduction is considerable compared to SQ, roughly halving it. The CCA of the designs vary drastically, some are significatively above the carbon tax expected for 2030 which is 170 CAD/tonneCO_2-eq (136 USD/tonneCO_2-eq), while CCA for case 3 is comparable. Some important aspects of the EMC, such as the proximity to the final consumer reduce transport losses, were not account for in this study, but could further favor the EMC option.

There are opportunities for better economic markers for the EMC. One option is the capacity to sell electricity back to the grid during peak hours if CHP is allowed to operate above demand. Another option is government grants to incentivize its implementation until economy of scale lowers capital costs. A grant valued at $185,000 USD is sufficient to reduce the costs of Case 3 to yield a CCA that matches the carbon tax cost of 2030. That is the environmental break-even point at which the cost of using the technology (to the end user) becomes the same as just paying tax and using the business-as-usual services. If the carbon tax is ignored completely, a grant of $700,000 USD would bring the cost of Case 3 equal to the business-as-usual case for the end user. In other words, policies which provide funding or incentives above this amount would incentive the construction of design 3 from a purely economic standpoint.

4.3.1. Sensitivity analysis

To ensure the robustness of our economic evaluation, a sensitivity analysis was conducted to determine how various economic parameters influenced the levelized cost of the EMC designs. As shown in Table 11, a variance of −50 % and +50 % from the base case was used in this analysis, with the resultant effects being illustrated in Fig. 7 and 8.

The tornado plots in Fig. 7 and Fig. 8 show that discount rate had the greatest impact on the final levelized cost, with costs increasing by 10 % when the discount rate is 4.5 % (−25 % variation) and upwards of 24 % when discount rate is 3 % (−50 % variation). Conversely, the loan interest had the lowest impact on the levelized cost, only affecting it by plus or minus around 1.5 % for variation of 25 % and plus or minus 3 % for 50 % variation in inflation rate. Therefore, the cost of the EMC is mainly affected by the discount rate, which tracks the time value of the capital invested on it and it is impacted by financing institutions.

5. Conclusion

In this work, we proposed an energy management center as an alternative technology to displace the use of grid electricity and domestic heat. Specifically, the proposed EMC is a cogeneration system that increases fuel utilization by harnessing waste heat and enabling short-term thermal storage. The findings of this work demonstrate that the EMC proposed reduces emissions when compared to the status-quo in Ontario.

Because Ontario's electricity grid has a baseload with very low carbon intensity (mostly hydroelectric and nuclear) and achieves peaking capability with much more carbon intensive natural gas plants, the carbon intensity and energy mixture of the grid changes rapidly within hours, with daytime emissions generally being much higher than at night. This means that the behavior of the EMC is influenced greatly by the grid intensity of the moment. The EMC would behave much differently on other grids where the carbon intensity is either more constant throughout the day, or also if the carbon intensity is higher at night than

Table 11
Sensitivity analysis parameters for the levelized costs of the EMC designs.

.	−50 %	−25 %	Base case	25 %	50 %
Loan interest/year	4 %	6 %	8 %	10 %	12 %
Discount Rate EMC/year	3 %	4.5 %	6 %	7.5 %	9 %
Raw material inflation rate/year	2 %	2.25 %	3 %	3.75 %	5 %
Production inflation rate/year	2 %	3 %	4 %	5 %	6 %

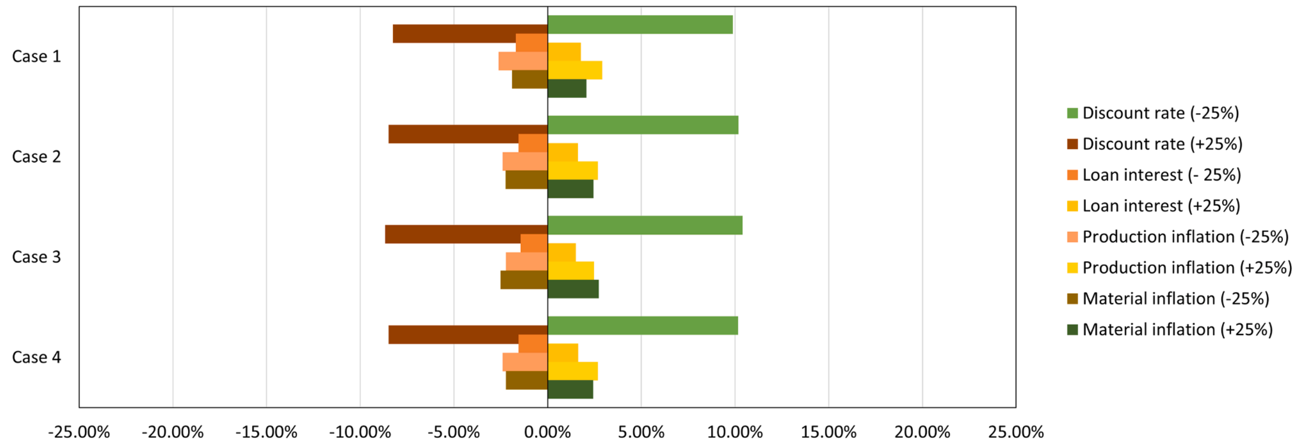

Fig. 7. - Tornado plot for the sensitivity analysis of the levelized cost of EMC designs for a +/- variation of 25 %.

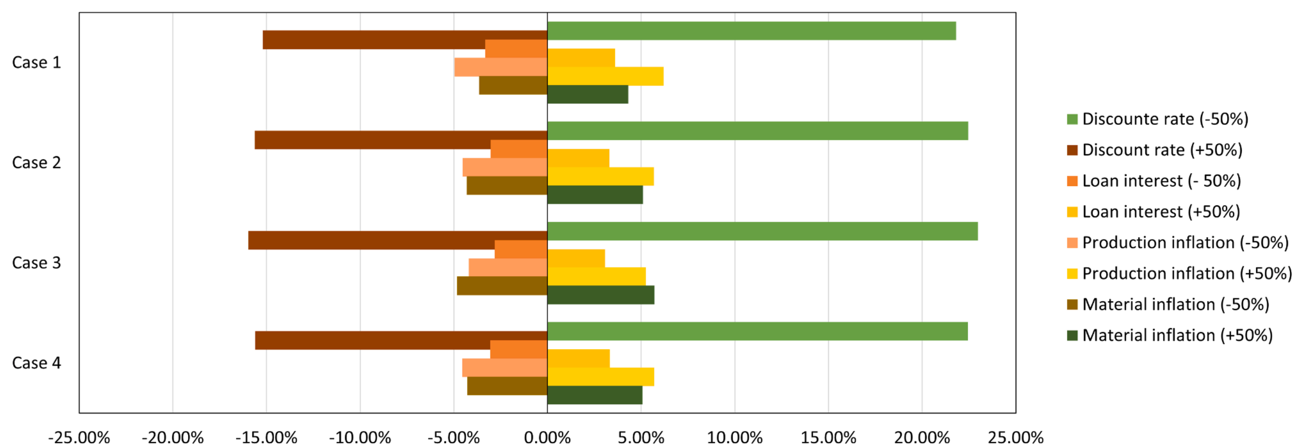

Fig. 8. - Tornado plot for the sensitivity analysis of the levelized cost of EMC designs for a +/- variation of 50 %.

during the day, such as for grids with coal-fired power generation for baseload capacity and natural gas for peaking. The EMC should have even lower CCA in those cases, but this needs to be explored in future work.

Further to this, one of the key reasons that the amount of CO_2 emissions avoided by the EMC may be smaller in the Ontario case compared to cases in which the municipal grids have a much greater dependence on fossil fuels is that the CHP generally only runs during times when grid emissions are high. Specifically, this is usually during daytime hours and more often in the summer and winter when electric demands tend to be higher. During the summer portion, the heat demand is also low, and so there is often a mismatch between electricity and heat demand such that when the CHP is most likely to be turned on, the waste heat it generates is not much in demand. For the Ontario case, more emissions could be avoided by including seasonal energy storage, such as geothermal borehole storage. In this way, the heat generated from the CHP during times of low heating demand could be used at other times of high heat demand when the CHP is off, leading to a further reduction of net emissions. This is a study for future work.

In Ontario, because the baseload emissions are so low, it may seem like electrification of heating may be a better alternative than an EMC for reducing emissions from the community heating sector. However, this is only true in the event that the additional demand created by electrical heating is provided from further low-carbon sources. For Ontario, this would only make sense if the existing nuclear, wind, and solar capacity is expanded in significantly, including the necessary storage systems or other energy management systems required for successful wind/solar expansion. Realistically, any immediate electrification of community heat would require corresponding increased use of natural gas peaking in the Ontario grid (since that capacity already exists) for probably at least a decade, and if so, this means the EMC becomes the better choice.

While this work was conducted considering Ontario grid and pricing, this methodology can be expanded to other regions to verify if NG-based EMCs can help lower emissions. The province of Quebec generates over 90 % of its electricity from hydro, contributing to an exceptionally low impact grid (Canada Energy Regulator 2021). In this case, a NG-based EMC would increase the environmental impact of electricity produced. However, heat management is of extreme importance and cannot be disregarded. Measures such as heat electrification and seasonal storage have the potential to reduce Quebec's emissions even further. For provinces that rely heavily on fossil fuels, such as Alberta and Saskatchewan, the designs proposed herein can be operated more frequently and theoretically would reduce their emissions even further than in the Ontario case.

This EMC design requires some degree of scale and density. There has to be a minimum number of buildings of sufficient scale in order to have enough waste heat supply and demand for this to make economic or environmental sense. Furthermore, the buildings must also be sufficiently close to each other. If buildings are spaced too far apart, then the heat loop not only costs more per utility delivered, it also suffers from increased heat losses and increased pump costs. The EMC designs discussed in this paper could work even in lower-density Provinces as long as they are located in neighborhoods of sufficient urban density (e.g. Iqaluit, Nunavut; Yellowknife, NT, etc.). The methods in this paper could be used on any such application to determine if the EMC is still economically and environmentally favorable on a case-by-case basis. Although not in the scope of this work, it is unlikely that this EMC design makes sense in a strictly rural or low-density application. The feasibility "cut-off" point between urban and rural has not yet been determined.

Further work will expand on the EMC by switching the domestic boilers for reversible heat pumps, which extract heat from buildings that need cooling, rejecting it to the heat loop. During winter, it would increase loop temperature to meet setpoints. This equipment uses electricity to work, which alters the community demand for electricity, needing further study and modelling. Moreover, future work will assess these factors by conducting a detailed cradle-to-grave lifecycle assessment.

CRediT authorship contribution statement

Nina Monteiro: Writing – review & editing, Writing – original draft, Validation, Methodology, Investigation, Formal analysis. **Thomas A. Adams:** Writing – review & editing, Supervision, Methodology, Conceptualization. **James Cotton:** Supervision, Project administration, Funding acquisition.

Declaration of competing interest

The authors declare the following financial interests/personal relationships which may be considered as potential competing interests:

James Cotton reports financial support was provided by Natural Sciences and Engineering Research Council of Canada. James Cotton reports financial support was provided by Ontario Centre of Excellence.

Data availability

Data will be made available on request.

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Appendix I

Control strategy

The EMC system obeys the logic and structure shown in Appendix Table 1. The logic regulates whether certain units turn on or off, or if setpoints are changed, depending on whether certain criteria are met. For example, the boiler turns on or off depending on the loop temperature and other criteria. The CHP turns on only when there is natural gas-based power production being used on the Ontario grid at that moment and other criteria are also met; when the CHP is on, it chooses fuel consumption and other operational parameters in an attempt to produce electric power that matches the electrical demand at the moment (as opposed to the thermal demand).

Appendix Table 1
Control strategy used in the EMC TRNSYS simulation file.

Equipment	Control operation
Boiler	$(condition\ i)\ T_{loop,\ HXout}(t) \leq 39.5^{\circ}C$ $(condition\ ii) T_{header,\ HXreturn}(t) \leq T_{header,critical}(t) - 1^{\circ}C$ $Signal_{boiler}(t) = \begin{cases} 1, & \text{when } (i)\ \&\ (ii) \\ 0 \end{cases}$ $T_{boiler,setpoint}(t) = T_{CT,trigger}(t) - 1^{\circ}C$
CHP	$(condition\ iii)\ NG_{grid}(t) = 1$ $(condition\ iv) T_{header,\ HXreturn}(t) \leq T_{header,critical}(t)$ $Signal_{CHP}(t) = \begin{cases} 1, & \text{when } (iii)\ \&\ (iv) \\ 0 \end{cases}$ $CHP_{mode}:\ Electrical\ following$
Tank valve	$(condition\ v)\ T_{tank}(t) < T_{tank,inlet}(\mathrm{t})$ $(condition\ vi)\ T_{tank}(t) \geq T_{tank,inlet}(\mathrm{t})(condition\ vii)\ T_{loop,\ HXout}(t) < T_{loop,\ setpoint}(t)$ $(condition\ viii)\ Signal_{boiler}(t) = 0$ $Signal_{tank}(t) = \begin{cases} 1, & (v)\ \&\ (vv) \\ -1, & (vii)\ \&\ (viii) \\ 0 \end{cases}$

With reference to Appendix Table 1, note:

1) If the CHP is turned ON ($Signal_{CHP} = 1$), it must remain ON for at least two hours to reach steady-state operation. Conversely, if it is turned OFF, it must remain OFF for at least one hour (Arndt, et al. 2007).
2) The tank can be in either charging ($Signal_{tank}(t) = 1$), discharging ($Signal_{tank}(t) = -1$), or inactive ($Signal_{tank}(t) = 0$) modes.
3) The minimum load ratio of the NG-GT is 25 % (Wang, et al. 2018), (Holoch, et al. 2010), (Pavri and Moore n.d.).

Model components in TRNSYS

Tank model: Built-in thermal energy system specialists (TESS) model type 534. Solves dynamic mass and energy balances. For this work, only one node was considered, which represents a fully mixed tank. Assumed perfect insulation, constant liquid volume, and no heat exchanger inside the tank.

$f(Q_{in,tank,t}, T_{tank,t-1}, V_{tank}) \rightarrow [T_{tank,t}]$

CHP model: Empirical model regressed from manufacturer data.

$f(D_{electrical,t}, C_{CHP}) \rightarrow [NG_{CHP,t},\ Q_{CHP,t}, P_{CHP,t}]$

Boiler model: Built-in TESS model type 659 using a pseudo-steady first-principles model.

$f(T_{header,t}, C_{boiler}) \rightarrow [NG_{boiler,t}, Q_{boiler,t}]$

Heat exchanger model: Built-in TESS model type 626 using a pseudo-steady first-principles model. This model considers logic that will divert the hot fluid away when necessary to keep the cold side at below or equal maximum temperature.

$f(T_{header_{inlet},t}, T_{loop_{inlet},t},\ HX_{eff}) \rightarrow [T_{header_{outlet},t}, T_{loop_{outlet},t}, Q_{del,EMC}]$

Pipe model: Built-in Solar Energy Laboratory model type 31 using pseudo-steady plug-flow first-principles model. This model is used for both the headers inside the EMC and the external distribution loop.

$f(T_{inlet,t}, \dot{m}_{inlet,t}, L_{pipe}) \rightarrow [T_{outlet,t}]$

Appendix II

According to (Seider, et al. 2008), the TCI can be estimated from the TDC values obtained from Aspen Capital Cost Estimator as demonstrated in the table below.

Appendix table 2

Appendix Table 2
Mathematical relationships to estimate total capital investment from total direct costs.

Total Direct Costs	TDC	
f.o.b. costs	C_{fob}	0.427*TDC
shipping (including insurance and taxes)	C_{ship}	0.08* C_{fob}
construction overhead	C_{over}	0.517* C_{fob}
contractor engineering	C_{eng}	0.296* C_{fob}
contingencies	C_{slop}	0.15 to 0.35 * C_{fob}
Total Indirect Costs	C_{TIC}	$C_{TIC} = C_{ship} + C_{over} + C_{eng} + C_{slop}$
Total Depreciable Capital	C_{dep}	$C_{dep} = TDC + C_{TIC}$
Total Working Capital	C_{WC}	0.7 to 0.89 *($C_{fob} + C_{ship}$)
Total Capital Investment	C_{TCI}	$C_{TCI} = C_{WC}$

Usually, C_{TCI} is the sum of C_{WC} with the fixed capital investment, which includes real estate, royalties and startup costs. This were not considered in this work.

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