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RESEARCH ARTICLE

Planning and Financing Strategy for Clustered Multi-Carrier Microgrids

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ABSTRACT This paper discusses the optimal deployment of a cluster consisting of connected AC-coupled, low voltage (48 V) multi-carrier microgrids within an integrated framework. The utilization of this integrated framework proves to be an effective approach for enhancing the reliability, resiliency, and operational quality of the clustered multi-carrier microgrids. Furthermore, it enables improved utilization of distributed energy resources in both grid-connected and stand-alone scenarios. In order to address local objectives, this paper presents a hybrid approach to determine the optimal integration and size of distributed energy resources in autonomous multi-carrier microgrids. Additionally, the proposed model identifies the ideal demand response intensity for each multi-carrier microgrid, which can result in energy savings and financial profits by modifying energy demands during peak hours. The primary objective is to minimize the development cost of clustered multi-carrier microgrids while ensuring a desired level of local reliability and online reserve. To address the planning problem of the proposed integrated parallel multi-carrier microgrid network, a mixed-integer programming model is formulated. Numerical results obtained from a three-microgrid system demonstrate the effectiveness of the proposed integrated planning model, validating the economic viability of the expansion project from various financial perspectives. Finally, a practical financing strategy is proposed to facilitate the successful implementation and deployment of parallel multi-carrier microgrids, thereby contributing to the achievement of sustainable development goals. The study examines the role of governments in facilitating capital investments for clustered multi-carrier microgrid projects, aligning with sustainable development goals. It proposes a feasible financing strategy through settled billing tax rates ranging from 4% to 26% for multi-carrier microgrid customers over ten years. This strategy can assist policymakers in formulating supportive policy programs to effectively implement and promote multi-carrier microgrids in diverse premises.

INDEX TERMS Load responsiveness, regulation, economic analysis, financing strategy, clustered multi-carrier microgrids, planning.

NOMENCLATURE

Indices:

boiler	Gas boiler.
chp	Cogeneration system.
d	Days.
ehp	Electric heat pump.
ess	Electric energy storage.
h	Hours.

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l	Carrier including {t: thermal, e: electrical}.
m, n	Microgrids.
pv	Photovoltaic system.
s	Seasons.
tss	Thermal storage device.
u	Distributed energy assets.
wt	Wind turbine.
y	Years.
$\sim$	Estimated parameters.

Sets:

G	Dispatchable assets.
S	Storage system asset.
W	Non-dispatchable assets (solar and wind).

Parameters:

A	Availability coefficient.
CC	Assets' capital cost.
$CCr(r)$	Assets' capital replacement cost.
CD	Enabling load responsiveness' capital cost.
CE	Capital cost of storages' energy ratings level.
$CEr(r)$	Capital replacement cost of storages' energy ratings level.
CIF	Capital investment budget.
CP	Capital cost of storages' power ratings.
$CPr(r)$	Capital replacement cost of storages' power ratings.
D	Load demand profile.
DOD	Storages assets' depth of discharge.
E^{cap}	Allowable installation energy capacity of storages.
EF	Carbon emission conversion coefficient.
EL	Assets' economic lifespan.
$\overline{ELF}$	Maximum acceptable value of equivalent loss factor.
G^{ing}	Solar radiation.
G^{stc}	Solar radiation in standard condition.
i	Interest rate.
$I^{Net,e}$	Islanding state
N	Total number.
P^{cap}	Assets' acceptable installation power capacity.
$\overline{P_{mn}^{line}}$	Flow limit between the integrated microgrids.
$\overline{P^{Net,e/g}}$	Power and gas flow limit between the utility grid and microgrid.
pp	Normalized generation forecast of non-dispatchable assets.
R	Desired amount of online reserve.
RM	Desired online reserve fraction.
Tr, Tc	Forecast and cell air temperatures.
Thr	storage assets' annual throughput.
v	Wind speed prediction.
$v^{ci/co/r}$	Wind turbine cut-in/out/rated speeds.
α^{ef}	Assets' efficiency.
α^{loss}	Energy loss factor.
α^{main}	Maintenance factor.
π^{em}	Carbon tax tariff.
π^{ens}	Energy not served cost.
$\pi^{MG,e}$	Local power exchange tariff.
$\pi^{Net,e}$	Electricity tariff.
$\pi^{Net,g}$	Gas tariff.
π^{peak}	Monthly peak demand tariff.
$\pi^{shifting}$	Energy demand shifting tariff.
κ	Maximum power temperature factor.
μ	Days per season value.
η	Months per season value.
ω	Present value coefficient.

Variables:

$D^{shup/shdo}$	Mutated up/down demand.
DC	Demand response enabling technology cost.
DPP	Discounted payback period.
E	Storages energy level.
$E^{\max}$	Deployed energy capacity of storages.
EC	Carbon cost of the system.
ELF	Equivalent loss factor value.
I^{inv}	Investment state of assets.
IC	Investment cost of assets.
$IS^{shup/shdo}$	Shifted up/down demand sign.
$LCOE$	Levelized cost of energy.
LPF	Load responsiveness rate.
MC	Maintenance and repair cost.
$MCPP$	Conventional power penetration within microgrid.
OC	Operation cost and/or benefit of the system.
OF	Objective function.
P	Distributed resources' power production.
$P^{dch/ch}$	Energy storage discharging/charging power.
P^{ens}	Loss of energy expectation.
$P^{EX,e}$	Local power exchange.
$P^{\max}$	Deployed power capacity of assets.
$P^{Net,e/g}$	Power exchange with the upstream grid.
PC	Annual peak demand charge.
PD	Electric heat pump energy consumption.
DPI	Discounted profitability index.
PP/SP	Purchase/sale probability.
RC	Asset's Replacement cost.
REP	Renewable energy penetration level.
SC	Cost/benefit of demand variation.
Thr^{annual}	Annual volume of storage throughput.
TIC	Overall investment value for each microgrid.
UC	Load shedding cost.
V	Commitment state of assets.
υ	Natural gas consumption.

Acronyms:

CHP	Combined Heat and Power.
CIF	Capital Investment Fund.
CMGCC	Clustered Microgrid Central Controller.
DERs	Distributed Energy Resources.
DG	Distributed Generation.
DPI	Discounted Profitability Index.
DPP	Discounted Payback Period.
DR	Demand Response.
DRP	Demand Response Program.
EHP	Electric Heat Pump.
ESS	Electrical Storage System.
LCOE	Levelized Cost of Energy.
MCMG	Multi-Carrier Microgrid.
MCPP	Microgrid Conventional Power Penetration.
MG	Microgrid.
MGCC	Microgrid Central Controller.
PP	Purchase Probability.
PV	Photovoltaic.
REP	Renewable Energy Penetration.
RERs	Renewable Energy Resources.
SP	Sale Probability.
TSS	Thermal Storage System.
VOLL	Value of Lost Load.
WT	Wind Turbine.

I. INTRODUCTION

The overarching objective of sustainable development is to fulfill the present generation's needs while safeguarding the capacity of future generations to fulfill their own needs. In this context, sustainable energy systems are designed to deliver dependable, cost-effective, and environmentally friendly energy services that foster long-term economic growth and enhance social well-being [1], [2], [3], [4].

On the other hand, the performance and reliability of the power system play a crucial role in the gross domestic product and socio-economic development of any nation. Accordingly, microgrids (MGs), which are small-scale power grids incorporating advanced technologies, serve as essential elements of intelligent power distribution grids. They provide smart, localized, and consistent control over supply- and demand-side assets [5], [6], [7].

The increasing penetration of MGs will result in the emergence of interconnected autonomous MG clusters, which could potentially offer substantial benefits for the power system. These advantages include: 1) reducing system-aggregated costs, 2) facilitating power delivery and minimizing load curtailments, 3) reducing power losses at the distribution level and enhancing energy efficiency, 4) sharing reserve resources to ensure uninterrupted power supply during unforeseen situations, 5) strengthening the resilience and reliability of the power system, and 6) providing ancillary services[1] [8], [9], [10], [11]. To fully harness the potential benefits of grid-connected clustered MGs, it is crucial to establish appropriate configurations and conduct comprehensive analytical investigations considering technical, economic, reliability, and environmental perspectives. By undertaking such analyses, a thorough understanding of the system can be gained, enabling the realization of the myriad advantages it can offer.

Clustered MGs are gaining recognition as a promising solution for fulfilling the energy requirements of communities and businesses, particularly in regions with limited access to conventional grid infrastructure. These MG systems involve the integration of diverse energy sources, such as solar, wind, and energy storage, to establish a robust and sustainable energy supply. The adoption of a multi-energy approach within clustered MGs is becoming increasingly prevalent due to several advantages it offers compared to traditional single-energy systems. These advantages encompass enhanced efficiency, reduced emissions, and improved grid reliability. The literature extensively discusses the optimal deployment of a single MG, often referred to as a multi-carrier MG (MCMG) system. A typical MCMG incorporates various distributed energy resources (DERs) to provide electricity, heating, and cooling services to end-users [12], [13], [14], [15], [16], [17], [18], [19], [20], [21], [22], [23], [24], [25], [26], [27], [28], [29], [30], [31], [32], [33], [34], [35], [36].

On the other hand, the current level of investment in MCMG projects integrated with RERs falls short of meeting sustainability goals [37]. These projects face several obstacles in accessing finance, including a lack of long-term financing, various risks, unsatisfactory rates of return, and limited capacity among market actors [38].

In order to enhance investments in RER-based MCMG projects and achieve sustainable development goals, the importance of green finance is emphasized in [39]. Pragmatic solutions for green financing include increasing the involvement of public and non-banking financial institutions such as pension funds and insurance companies in long-term investments, implementing spillover taxes to enhance the rate of return, establishing green credit guarantee schemes to reduce credit risks, establishing community-based trust funds, and addressing investment risks through financial and policy de-risking measures [40].

MG projects still require some form of incentive or financial support to initiate, such as cash grants or production-based subsidies, concessional loan rates, loan guarantees, or private investment. Financing for MGs can be obtained through private-sector equity or debt, either at the MG project level (project finance) or at the developer's level (corporate finance) [41].

[1] Ancillary services refer to a variety of specialized services that are necessary to maintain the stability and reliability of the electrical grid. These services include things such as frequency regulation, voltage support, and reactive power support.

Strategies for MG developers to mitigate risks, attract appropriate financiers, and scale up the industry are proposed by the authors in [42]. In [43], equipment lifetime financing and loan term financing are presented as two different approaches to drive efficient and secure MG development.

Despite the potential benefits of clustered MGs, there remain numerous challenges that must be overcome to effectively design and implement these systems. One primary challenge is the development of sophisticated control strategies capable of managing the complex interactions between multiple energy sources and loads. Another challenge is the integration of intermittent and unpredictable renewable energy sources into MGs while maintaining grid stability and reliability.

Additionally, the issue of islanding and reconnection, particularly in a cluster structure, poses a significant challenge for MGs [44]. Islanding occurs when a fault or disturbance in the main grid causes the MG to operate independently, while reconnection refers to the process of reconnecting the MG to the main grid once it becomes available again. In a cluster structure, the complexity of coordinating multiple MGs during both islanding and reconnection further exacerbates the challenge [45].

During islanding, it is crucial for the MGs within the cluster to operate independently while ensuring system stability and uninterrupted power supply to critical loads. Various control algorithms can be employed to achieve this objective, with one common approach being droop control. Droop control entails adjusting the frequency and voltage of the MGs based on their power output [46]. This method ensures load sharing and stable operation of the MGs during islanding.

Regarding reconnection, synchronization with the main grid is essential to prevent disturbances in the power system. Several control algorithms have been proposed to achieve this, including the virtual oscillator control method. This approach employs a virtual oscillator to synchronize the frequency and phase of the MGs during reconnection, facilitating a smooth transition back to grid-connected operation [47], [48].

In summary, the challenges associated with islanding and reconnection within a cluster structure are intricate and necessitate meticulous coordination between MGs. The selection of control algorithms depends on the specific characteristics of the MGs in the cluster, although droop control and virtual oscillator control have proven to be effective methods.

In recent years, clustered MGs have emerged as a promising solution for meeting the energy requirements of communities and businesses. Unlike traditional grid infrastructure, clustered MGs offer potential advantages such as improved energy efficiency, reduced greenhouse gas emissions, and enhanced grid resiliency. However, the design and implementation of clustered MGs present various challenges, particularly with respect to integrating multiple energy sources and optimizing energy dispatch [49], [50], [51], [52], [53].

One approach to addressing these challenges is the multi-energy approach, which involves the integration of multiple energy sources into the MG. This approach has gained increasing popularity due to its ability to provide a diverse and flexible energy supply. Notably, the integration of renewable energy sources, such as solar and wind power, can contribute to reducing greenhouse gas emissions and enhancing energy sustainability. Nevertheless, integrating renewable energy sources also poses challenges, including the management of energy imbalances and the assurance of grid stability [54].

To overcome these challenges, numerous control strategies have been proposed for clustered MGs. These strategies typically rely on predictive models and real-time data to optimize energy dispatch and ensure grid stability. For instance, some studies have proposed the use of predictive algorithms to anticipate energy demand and adjust energy supply accordingly [55], [56], [57]. Other studies have focused on developing sophisticated control strategies capable of managing the complex interactions between multiple energy sources and loads [58], [59], [60].

In addition to control strategies, there is a growing body of literature on financing models for MGs. The upfront investment required for microgrids can be a barrier to adoption for many communities and businesses [61], [62], [63]. Nonetheless, various financing models can help overcome these barriers, including public-private partnerships, community ownership structures, and innovative mechanisms like crowdfunding [64].

Table 1 presents a summary of related research works and our proposed model, focusing on the optimization problem, deployment of demand response (DR) programs, clustering or interconnecting of MCMGs, financial strategy considerations, and reliability criteria. According to the table, only a few researchers have addressed the optimal deployment of a cluster of parallel MCMGs to overcome the limitations of conventional power system structures.

Despite the numerous benefits of clustered MGs and the multi-energy approach, there are still several challenges that need to be addressed to effectively design and implement these systems. Advanced control strategies are required to manage the complex interactions between multiple energy sources and loads. Additionally, sophisticated financing models are needed to overcome the high upfront costs associated with these systems. The proposed study aims to tackle these challenges by presenting a planning and financing strategy for clustered multi-carrier MGs that integrates predictive control strategies and innovative financing models.

This study develops a holistic and integrated planning framework model that considers investment in clustered MCMGs from economic, environmental, technical, and reliability perspectives. The proposed model determines the optimal sizing of DERs power/energy ratings and the ideal intensity of DR within the clustered MCMG structure. A hybrid energy management system is introduced to address

TABLE 1. Taxonomy of the related research works.

References	Solution method	Optimization problem	DR programs	Multi-carrier energy	Interconnected MCMGs	Financial strategy	Reliability criteria
[13], [21]	HA	NLP	-	✓	-	-	✓
[14]	CS	MILP	-	✓	-	-	-
[15]–[17], [38], [40]–[43]	-	-	-	✓	-	✓	-
[18]	CS	MILP	✓	-	-	-	-
[20]	HA	NLP	✓	✓	✓	-	-
[22], [26]	BD	MILP	✓	✓	-	-	-
[23], [25]	CS	MILP	-	✓	-	-	-
[29]	HA	NLP	-	-	✓	-	✓
[29]–[31]	CS	MILP	-	-	✓	-	-
[32], [33]	HA	BLP	✓	-	✓	-	-
[34]–[36]	HA	NLP	-	-	✓	-	✓
This work	CS	MILP	✓	✓	✓	✓	✓

HA: heuristic algorithm, CS: commercial solver, BD: benders decomposition, NLP: non-linear programming, MILP: mixed-integer linear programming, and BLP: bi-level programming.

the drawbacks of conventional methods by prioritizing local energy requirements during islanding events.

Furthermore, an intelligent central controller facilitates power-sharing among geographically close and electrically connected MCMGs, minimizing capital-intensive DER underutilization and load curtailment during grid outages. The objective is to minimize the aggregated deployment cost of the clustered MCMG-based system, considering DERs investment and replacement costs, DR capacity costs, operation and maintenance costs, demand mutation benefit/cost, power peak demand charge, carbon tax, and the expected cost of curtailed load. The preferred levels of online reserve and reliability in each resulting MCMG are also ensured. The problem is formulated using a mixed-integer programming model. Lastly, a financing strategy is proposed to streamline the integration of DER-based MCMGs.

In summary, the key contributions and innovations of this work can be summarized as follows:

- Designing a cluster of interconnected MCMGs in an integrated manner to enhance the resilience, reliability, and economic performance of power systems.
- Determining the optimal technology mixture, power/energy ratings of DERs, and identifying the appropriate DR intensity within local premises to achieve cost-effective planning of the integrated MCMG structure.
- Minimizing the long-term development cost of clustered MCMGs while maintaining acceptable levels of local reliability and online reserve.
- Introducing a hybrid energy management framework to economically deploy assets in local areas and enable power trading between MCMGs for mutual benefits, thereby achieving optimal planning. It also ensures fair distribution of local investments considering both local and regional objectives.
- Quantifying the impact of deploying grid-connected customer MCMGs in an integrated framework on grid performance, while investigating the financial viability of MCMG-based systems from various economic and reliability perspectives.
- Proposing a pragmatic financing strategy to address the capital-intensive nature of the expansion project's budget.

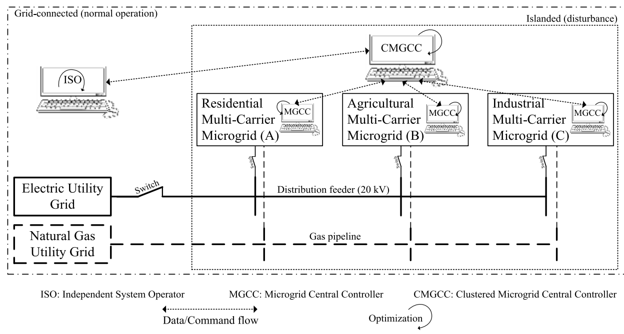


FIGURE 1. Deployment of autonomous parallel MCMGs on a single distribution feeder.

II. MODEL OUTLINE

One of the main drawbacks of deploying a single MCMG is its dependence on the number of islanding events, as the expansion of DERs may be inefficient if it is based solely on short and infrequent islanding hours throughout the year [65]. To overcome this limitation and promote the proliferation of renewable energy resources (RERs), networking multiple self-governed MCMGs during upstream electric grid outages can be considered a viable solution. This approach helps to prevent under- or over-installation of capital-intensive distributed generators (DGs) within parallel MCMGs and enhances the resiliency and reliability of power system networks by enabling power delivery through autonomous MCMGs.

Figure 1 illustrates the concept of parallel AC-coupled, low voltage (48 V) MCMGs installed simultaneously to meet the energy requirements of three zones, including residential, agricultural, and industrial customers, on a single distribution feeder. Each MCMG operates as an autonomous entity and is equipped with a local microgrid central controller (MGCC) to optimize local resources and achieve local objectives. The hybrid energy management approach, as described in [66] and [67], combines centralized and decentralized energy management systems. In this model, each MGCC optimizes local resources and communicates surplus/deficit power information to the clustered MGCC (CMGCC). The CMGCC acts as an intermediary between the independent system operator and MGCCs, facilitating the economic exchange of surplus/deficit power between MCMGs and the utility grid, considering the feeder's capacity in the grid-connected mode. Importantly, it enables trading between MCMGs through the distribution feeder, fostering mutual benefits in an integrated framework during electric utility grid disturbances.

The proposed integrated parallel MCMGs framework aims to minimize both the aggregated planning cost of the network and the planning cost of each autonomous MCMG. Through a transactive strategy with a negotiated price during islanding incidents, the framework not only promotes the penetration of RERs within distribution grids but also provides economic and reliability benefits for the local customers of each MCMG by leveraging the available flexibility offered by neighboring MCMGs. Since all MCMGs are connected to the same upstream substation, the market price for all MCMGs is uniform. It is important to note that there is no power exchange between customer MCMGs in the grid-connected phase, as it would reduce their individual economic benefits. In other words, the profit of one MCMG would result in an economic loss for another MCMG.

In the residential MCMG, the composition typically includes various DERs such as solar photovoltaic (PV) panels, energy storage systems (ESSs), combined heat and power (CHP) units, electric heat pumps (EHPs), and thermal storage systems (TSSs). These resources work together to meet the electricity and thermal energy demands of residential buildings within the microgrid. Intermittent DERs generation, such as solar PV, is managed through energy storage systems, which store excess energy during periods of high generation and release it during periods of low generation.

The agricultural MCMG is designed to cater to the specific energy needs of agricultural facilities. It consists of a combination of DERs such as solar PV, wind turbines (WTs), and biomass systems. These resources provide electricity for various agricultural operations such as irrigation pumps, lighting, and equipment. Similar to the residential MCMG, intermittent generation from renewable sources is managed through energy storage systems to ensure a stable and reliable energy supply.

The industrial MCMG is tailored to the energy requirements of industrial complexes or manufacturing facilities. It typically incorporates a mix of DERs, including solar PV, WTs, and possibly cogeneration systems. The energy resources are utilized to power industrial processes, machinery, and equipment. In cases of intermittent DERs generation, the industrial MCMG relies on energy storage systems and grid connections to maintain a consistent energy supply and meet the demands of the industrial operations.

While the focus of the MCMGs is primarily on electricity and gas supply, it is possible to integrate other energy sources such as thermal (district heating) within the system. This would enable the MCMGs to provide not only electricity and gas but also thermal energy for space heating, water heating, or other heating applications. The inclusion of thermal energy can further enhance the overall energy efficiency and sustainability of the MCMGs, contributing to a more comprehensive and integrated energy solution.

III. PROBLEM STATEMENT

The aggregated multi-goal planning cost of the integrated parallel customer MCMGs is minimized, representing distinct terms associated with the venture capital and replacement costs of DERs, the cost of enabling DR capacity, operational profit/cost including fuel import and purchase/sales of electricity, maintenance cost, demand mutation benefit/cost, peak demand cost, carbon tax, and load shedding cost. The planning problem, defined in Equation (1a), aims to deploy decentralized autonomous MCMGs in parallel, minimizing the individual cost of each MCMG in grid-tied mode, while also minimizing the reliability cost of MCMGs with power deficit in islanded mode for mutual benefits.

$$OF = \sum_{m}\sum_{y}\omega_y \cdot \begin{pmatrix} IC_{my} + RC_{my} + DC_{my} + OC_{my} \\ +MC_{my} + SC_{my} + PC_{my} + EC_{my} + UC_{my} \end{pmatrix} \tag{1a}$$

The terms used in the objective function are thoroughly represented by Equations (1b) to (1j). Equations (1b) and (1c) capture the costs associated with the installation and replacement of DGs and storage systems, taking into account both power and energy ratings. The cost of enabling DR technology is modeled using Equation (1d), which is derived by multiplying the cost of advanced infrastructures by the DR ratio based on the maximum peak power demand. The operation cost is expressed in Equation (1e) and includes three components: the cost or benefit of power exchange with the natural gas and electricity upstream network, and the benefit or cost of power exchange with the integrated neighboring MCMGs in islanded mode. The maintenance cost of DGs is represented by Equation (1f). Equation (1g) captures the incentive or penalty payment for energy demand upshifting or downshifting by responsive users. The peak demand charge for large customers can be calculated using Equation (1h). The carbon dioxide equivalent (CO2e) emission tax is represented by Equation (1i). Lastly, the cost of unserved thermal and electrical energy demand is quantified by Equation (1j), which is determined by multiplying the value of lost load

(VOLL) by load curtailments.

$$IC_{my} = \sum_{u \in \{G,W\}} CC_u \cdot P_{mu}^{\max} + \sum_{u \in S} (CP_u \cdot P_{mu}^{\max} + CE_u \cdot E_{mu}^{\max}) \forall y = 1 \tag{1b}$$

$$RC_{my} = \sum_{u \in \{G,W\}} CCr_u(r_{uy}) \cdot P_{mu}^{\max} + \sum_{u \in S} \left(CPr_u(r_{uy}) \cdot P_{mu}^{\max} + CEr_u(r_{uy}) \cdot E_{mu}^{\max}\right) \tag{1c}$$

$$DC_{my} = CD \cdot LPF_m \cdot \max(D^e_{(y=Ny)sdh}) \quad \forall y = 1 \tag{1d}$$

$$OC_{my} = \sum_s \sum_d \mu_{sd} \cdot \sum_h \begin{pmatrix} +P_{mysdh}^{Net,e} \cdot \pi_{yh}^{Net,e} + P_{mysdh}^{Net,g} \cdot \pi_y^{Net,g} \\ + \sum_{n,n \neq m} P_{mnysdh}^{EX,e} \cdot \pi_{myh}^{MG,e} \end{pmatrix} \tag{1e}$$

$$MC_{my} = \sum_s \sum_d \mu_{sd} \cdot \sum_h \sum_{u \in \{G,W\}} P_{muysdh} \cdot \alpha_u^{main} \tag{1f}$$

$$SC_{my} = \sum_s \sum_d \mu_{sd} \cdot \sum_h \pi_{yh}^{shifting} \cdot \left(D_{mysdh}^{shup,e} - D_{mysdh}^{shdo,e}\right) \tag{1g}$$

$$PC_{my} = \sum_s \eta_s \cdot \pi_m^{peak} \cdot \max(P_{mysdh}^{Net,e,+}) \tag{1h}$$

$$EC_{my} = \sum_s \sum_d \mu_{sd} \cdot \sum_h \pi^{em} \cdot \left(P_{mysdh}^{Net,e} \cdot EF^{Net,e} + \sum_{u \in \{G,W\}} P_{muysdh} \cdot EF_u\right) \tag{1i}$$

$$UC_{my} = \sum_s \sum_d \mu_{sd} \cdot \sum_h \sum_{l \in \{e,t\}} P_{mysdh}^{ens,l} \cdot \pi_m^{ens,l} \tag{1j}$$

The present-worth value factor (2) is used to calculate the present value of the costs in the model.

$$\omega_y = 1/(1+i)^{y-1} \tag{2}$$

A. ENERGY BALANCE MODELLING

The power equilibrium equation (3a) ensures that the power generated by local DGs, the power exchanged with the utility grid, the power traded with neighboring MCMGs, the power charged/discharged by the ESS, and the expected electrical energy loss balance with the local electrical load. It also considers demand shifting and the energy consumed by the EHP asset to maintain energy balance across all assets.

Similarly, the thermal demand equilibrium equation (3b) ensures that the thermal generation from DERs, along with the expected thermal energy loss, meets or exceeds the local heat load. This equilibrium ensures that each MCMG can fulfill its thermal energy requirements without causing an energy imbalance.

Furthermore, Equation (3c) monitors and controls the natural gas consumption by gas-fired assets, ensuring it stays within predetermined limits while meeting the overall energy demands of the MCMG.

$$\sum_{u \in \{G,W\}} P_{muysdh}^e \pm \sum_{u \in ess} P_{muysdh}^{dch/ch} + P_{mysdh}^{ens,e} + P_{mysdh}^{Net,e} + \sum_{n,n \neq m} P_{mnysdh}^{EX,e} = D_{mysdh}^e + D_{mysdh}^{shup,e} - D_{mysdh}^{shdo,e} + \sum_{u \in ehp} PD_{muysdh}^e \tag{3a}$$

$$\sum_{u \in G} P_{muysdh}^t \pm \sum_{u \in tss} P_{muysdh}^{dch/ch} + P_{mysdh}^{ens,t} \geq D_{mysdh}^t \tag{3b}$$

$$P_{mysdh}^{Net,g} = \sum_{u \in \{chp,boiler\}} \upsilon_{muysdh} \tag{3c}$$

B. DISPATCHABLE AND NON-DISPATCHABLE GENERATION UNITS MODELLING

The power generated by dispatchable and non-dispatchable DGs is represented by Equations (4a) to (4e). The power output of non-dispatchable DGs (4c) to (4d) is determined based on site-specific meteorological conditions such as solar radiation, air temperature, and wind speed. The power output of DGs is subject to the generation capacity constraint (4e), which limits the maximum power that can be generated.

$$P_{muysdh}^l = \upsilon_{muysdh} \cdot \alpha_u^{ef,l} \cdot A_u \quad \forall u \in \{chp, boiler\}, \forall l \in \{e,t\} \tag{4a}$$

$$P_{muysdh}^t = PD_{muysdh}^e \cdot \alpha_{ush}^{ef} \cdot A_u \forall u \in ehp \tag{4b}$$

$$P_{muysdh} = \begin{pmatrix} P_{mu}^{\max} \cdot \alpha_{uy}^{ef} \cdot A_u \cdot \widetilde{pp}_{uh} \cdot \widetilde{G_s^{ing}} \cdot \\ (1 + \kappa \cdot (Tc - \widetilde{Tr}_s)) \end{pmatrix} / G^{stc} \quad \forall u \in pv \tag{4c}$$

$$P_{muysdh} = \begin{cases} 0 & 0 \leq \widetilde{v}_s \leq v^{ci} \ or \ \widetilde{v}_s \geq v^{co} \\ P_{mu}^{\max} \cdot \alpha_u^{ef} \cdot A_u \cdot \widetilde{pp}_{uh} \cdot \dfrac{\widetilde{v}_s^2 - v^{ci2}}{v^{r2} - v^{ci2}} & v^{ci} \leq \widetilde{v}_s \leq v^r \\ P_{mu}^{\max} \cdot \alpha_u^{ef} \cdot A_u \cdot \widetilde{pp}_{uh} & v^r \leq \widetilde{v}_s \leq v^{co} \end{cases} \tag{4d}$$

$$\forall u \in wt$$

$$0 \leq P_{muysdh} \leq P_{mu}^{\max} \cdot V_{muysdh} \forall u \in \{G,W\} \tag{4e}$$

C. STORAGE SYSTEMS MODELLING

The functional constraints of energy storages are defined in Equations (5a) to (5f). The state of charge of the storage asset at each hour is described by Equation (5a). It is assumed that there is no net charge or discharge of the storage asset at midnight (5b). The power and energy ratings of the energy storage assets are constrained by their determined capacities (5c) to (5d). The cost associated with cycling energy through the battery is considered in the model through Equations (5e) to (5f).

$$E_{muysdh} = \begin{pmatrix} E_{muysd(h-1)} - E_{muysdh} \cdot \alpha_u^{\text{loss}} \\ +P_{muysdh}^{ch} - P_{muysdh}^{dch} / \alpha_u^{ef} \end{pmatrix} \cdot A_u \tag{5a}$$

$$\forall u \in S$$

$$\sum_{h} P^{ch}_{muysdh} - P^{dch}_{muysdh}/\alpha^{ef}_{u} = 0 \forall u \in S \tag{5b}$$

$$0 \leq P^{dch/ch}_{muysdh} \leq P^{\max}_{mu} \quad \forall u \in S \tag{5c}$$

$$E^{\max}_{mu} \cdot (1 - DOD_u) \leq E_{muysdh} \leq E^{\max}_{mu} \quad \forall u \in S \tag{5d}$$

$$Thr^{annual}_{muy} = \sum_{s} \sum_{d} \mu_{sd} \cdot$$

$$\sum_{h} \left(P^{ch}_{muysdh} + P^{dch}_{muysdh}/\alpha^{ef}_{u} + E_{muysdh} \cdot \alpha^{\text{loss}}_{u} \right) \tag{5e}$$

$$\forall u \in \text{ ess}$$

$$Thr^{anmual}_{muy} \leq E^{\max}_{mu} \cdot Thr_u/EL_u \quad \forall u \in \text{ ess} \tag{5f}$$

D. DERs RATED POWER AND ENERGY LIMITS MODELLING

$$\underline{P^{cap}_{u}} \cdot I^{inv}_{mu} \leq P^{\max}_{mu} \leq \overline{P^{cap}_{u}} \cdot I^{inv}_{mu} \quad \forall u \in \{G, W, S\} \tag{6a}$$

$$\underline{E^{cap}_{u}} \cdot I^{inv}_{mu} \leq E^{\max}_{mu} \leq \overline{E^{cap}_{u}} \cdot I^{inv}_{mu} \forall u \in S \tag{6b}$$

E. DR MODELLING

The associated demand response program (DRP) employs the demand adjustment strategy described in paper [68].

$$\sum_{h} D^{shup,e}_{mysdh} = \sum_{h} D^{shdo,e}_{mysdh} \tag{7a}$$

$$0 \leq D^{shup,e}_{mysdh} \leq D^{e}_{mysdh} \cdot LPF_m \cdot IS^{shup,e}_{mysdh} \tag{7b}$$

$$0 \leq D^{shdo,e}_{mysdh} \leq D^{e}_{mysdh} \cdot LPF_m \cdot IS^{shdo,e}_{mysdh} \tag{7c}$$

$$0 \leq IS^{shup,e}_{mysdh} + IS^{shdo,e}_{mysdh} \leq 1 \tag{7d}$$

F. UTILITY NETWORKS MODELLING

The total trade between parallel MCMGs and the electricity and natural gas grids must be limited by the capacity of the network, as indicated by Equations (8a) and (8b). The islanding state of the integrated parallel MCMGs, which occurs as a result of electric utility grid disturbances, is enforced by introducing a binary parameter in Equation (8a).

$$\left| \sum_{m} P^{Net,e}_{mysdh} \right| \leq \overline{P^{Net,e}} \cdot I^{Net,e}_{ysdh} \tag{8a}$$

$$0 \leq \sum_{m} P^{Net,g}_{mysdh} \leq \overline{P^{Net,g}} \tag{8b}$$

G. LOCAL POWER EXCHANGE MODELLING

During the isolated phase, the deployed MCMGs operate collectively by engaging in power trading through the distribution feeder, seeking mutual benefits within an integrated framework. However, the sharing of power with neighboring MCMGs in need is controlled by the MCMG experiencing power deficits, prioritizing the improvement of its own local reliability. This is because each MCMG acts as an autonomous entity driven by self-interest. The model representing the local power exchange can be found in Equation (9a). It is required that the sum of local power trades between integrated neighboring MCMGs is zero, indicating that the power offered by one MCMG is fully received by the adjacent MCMG in need (9b). Power losses through the distribution feeder are disregarded in the model due to the close proximity of the paralleled MCMGs.

$$- \overline{P^{line}_{mn}} \cdot (1 - I^{Net,e}_{ysdh}) + \overline{P^{line}_{mn}} \cdot (1 - I^{Net,e}_{ysdh}) \cdot sign(P^{ens,e}_{mysdh}) \leq P^{EX,e}_{mnysdh} \leq \overline{P^{line}_{mn}} \cdot (1 - I^{Net,e}_{ysdh}) \tag{9a}$$

$$P^{EX,e}_{mnysdh} + P^{EX,e}_{nmysdh} = 0 \quad \forall m, n \tag{9b}$$

H. RELIABILITY MODELLING

The thermal and electrical energy expectation loss within each MCMG is constrained not to exceed the demand (10a). Additionally, an annual limit is imposed on the equivalent loss factor, which serves as an indicator of the customer damage level within each MCMG (10b) [68], [69].

$$0 \leq P^{ens,l}_{mysdh} \leq (D^{l}_{mysdh} + D^{shup,l}_{mysdh} - D^{shdo,l}_{mysdh}) \ \forall l \in \{e, t\} \tag{10a}$$

$$ELF_{my} = \frac{\sum_{s} \sum_{d} \mu_{sd} \cdot \sum_{h} P^{ens,e}_{mysdh}/D^{e}_{mysdh}}{N_h \cdot \sum_{s} \sum_{d} \mu_{sd}} \leq \overline{ELF_{my}} \tag{10b}$$

I. MICROGRID ONLINE RESERVE MODELLING

The combination of dispatchable DGs, ESS, and demand shifting strategies of responsive customers can be employed collectively to meet the necessary online reserve and ensure reliable operation within each MCMG (11a to 11b).

$$\left(\sum_{u \in chp} (P^{\max}_{mu} \cdot A_u - P^{e}_{muysdh}) \right) + \left(\sum_{u \in ess} \alpha^{ef}_{u} \cdot \min{(E_{muysdh}/N_h, P^{\max}_{mu})} \right) + \left(D^{e}_{mysdh} \cdot LPF_m - D^{shup,e}_{mysdh} - D^{shdo,e}_{mysdh} \right) \geq R_{mysdh} \tag{11a}$$

$$R_{mysdh} = D^{e}_{mysdh} \cdot RM_m \tag{11b}$$

J. CAPITAL INVESTMENT FUND MODELLING

The expansion planning of the capital investment fund (CIF) for each MCMG is limited by its investors (12).

$$TIC_m = IC_{my} + DC_{my} \leq CIF_m \forall y = 1 \tag{12}$$

K. RELIABILITY AND ECONOMIC INDICES MODELLING

The reliability terms, including the renewable energy penetration (REP) and microgrid conventional power penetration (MCPP) criteria, as well as the purchase and sale probability metrics (PP and SP, respectively), are calculated according to Equations (13a) to (13d). Additionally, economic terms such as the levelized cost of energy (LCOE), discounted profitability index (DPI), and discounted payback period regarding savings (DPP), are used to assess the viability of the MCMGs project [70], [71]. It is important to note that savings can be determined by subtracting the non-microgrid operation cost from the microgrid planning cost.

$$REP_{my} = \frac{\sum_{s}\sum_{d}\mu_{sd} \cdot \sum_{h}\sum_{u\in W} P_{muysdh}}{\sum_{s}\sum_{d}\mu_{sd} \cdot \sum_{h} D^{e}_{mysdh} + D^{shup,e}_{mysdh} - D^{shdo,e}_{mysdh}} \tag{13a}$$

$$MCPP_{my} = \frac{\sum_{u\in G} P^{\max}_{mu}}{Average(D^{e}_{mysdh} + D^{t}_{mysdh})} \tag{13b}$$

$$PP_{my} = \frac{Sum\ of\ hours\ when\ MG\ purchase\ power}{Total\ annual\ hours\ of\ MG\ operation} \tag{13c}$$

$$SP_{my} = \frac{Sum\ of\ hours\ when\ MG\ sell\ power}{Total\ annual\ hours\ of\ MG\ operation} \tag{13d}$$

$$LCOE_{m} = \frac{Total\ planning\ cost\ of\ each\ microgrid}{Total\ served\ energy\ demand\ in\ each\ microgrid} \tag{13e}$$

$$\sum_{y=1}^{DPP_m} Savings\ in\ each\ microgrid = 0 \tag{13f}$$

$$PI_{m} = \frac{Savings\ in\ each\ microgrid}{Total\ investment\ cost\ in\ each\ microgrid} \tag{13g}$$

IV. NUMERICAL SIMULATIONS

Parallel customer MCMGs are proposed to be installed simultaneously to meet the energy demands of three zones. These zones are inhabited by residential customers located at coordinates 33°31'47.14" N, 50°19'20.40" E, agricultural customers located at coordinates 33°32'50.79" N, 50°18'41.80" E, and industrial customers located at coordinates 33°32'55.86" N, 50°18'02.12" E. The distribution feeder serves as the connection point for these MCMGs, as depicted in Figure 1.

The local load details for the initial year are provided in Table 2. The specifications of the DER assets are presented in Tables 3 and 4, which were obtained based on our previous study [72], upon which the current work is built. The allowable installation power/energy ratings of the available DERs are assumed to be 15 MW/MWh.

Table 5 presents the required data for the integrated system. The equivalent loss factor bound is set at 1% for the agricultural zone and 0.01% for the residential and industrial zones. The electricity market tariff is obtained from ISO-New England, and the gas tariff is acquired from the Henry Hub Natural Gas data sources [73], [74]. The planning horizon is set to 25 years, and all investments are made at the beginning of year one.

The power transactions with the electric utility grid and the local power transactions between integrated parallel MCMGs are subject to the capacity of the 5-MW distribution feeders. The negotiated price for power exchange between integrated parallel MCMGs is set to be the same as the upstream electricity market rate during islanding incidents. The model assumes twelve islanding incidents per year, each with a clearance time of two hours.

The planning problem is transformed into a mixed-integer linear programming formulation, which is then solved using the GAMS optimization software.

The following cases are investigated to explore the merits of power exchange in MCMGs planning:

Case 1: Independent deployment of MCMGs as a function of the capital investment budget.

Case 2: Integrated deployment of MCMGs as a function of the capital investment budget.

Case 3: Investigation of the influence of the number of islanding hours on MCMGs deployment.

Case 4: Examination of the financing strategy for MCMGs deployment.

These cases aim to evaluate various aspects of MCMGs planning, including financial considerations, the impact of islanding hours, and the benefits of integrated deployment and power exchange.

To provide a clear representation of the decreasing capital investment funds across the defined cases, the x-axis values in the following figures are arranged such that the minimum value is positioned on the right-hand side. This ordering facilitates a visual understanding of the impact of decreasing capital investment funds on the analyzed parameters, with higher values on the left gradually decreasing towards the right. By adopting this arrangement, the figure highlights the diminishing capital investment as the cases progress, allowing readers to easily interpret the relationship between the defined cases and their corresponding capital investment funds.

- **Case 1**

In this case, the optimal structural design of autonomous MCMGs is determined independently, without any power exchange among MCMGs. The optimal sizing and mixture results of DER penetration within each MCMG are depicted in Figure 2. According to Figure 2(a), the combined heat and power (CHP) unit would typically be deployed as the principal supplier of electrical and heat demands in all scenarios. The CHP capacity would encompass about 21.7% to 100% of the aggregated DER capacity. Moreover, the aggregated capacity of heat suppliers, including the boiler and EHP units, represents only a small portion, up to 5.1% of the installed DER capacity in MCMG A. Additionally, 4.7% to 50.9% of the total installed DER capacity is penetrated by the PV unit in MCMG A for a capital investment budget (CIF) larger than \$2.41M. In this case, the PV unit holds the largest share of the aggregated installed capacity after the CHP unit in almost all scenarios. When the CIF exceeds \$3.01M, the planning solution incorporates TSSs in combination with thermal energy providers, with the energy rating ranging from 1.4% to 15.6% of the aggregated DER capacity. On the other hand, the planning solution prefers to install ESS only when significant investments are made in the MCMG project or when the project's viability is relatively low, with the power and

TABLE 2. Multi-carrier microgrids local demand details.

Zone	Energy (MWh)		Min/Max demand (MW)		VOLL ($/kWh)		Monthly peak demand charge ($/kW)
	electricity	heat	electricity	heat	electricity	heat	
Residential	18994.7	11755.4	1.18/3.20	0.65/2.44	5.94	0.174	0
Agricultural	5277.2	18693.4	0.33/0.89	1.14/3.86	3.3	0.097	6.192
Industrial	10854.5	29325.1	0.67/1.83	1.19/7.21	3.65	0.107	6.192

TABLE 3. Technical and cost parameters of non-dispatchable and dispatchable assets.

Assets	Capital investment / replacement costs ($/kW)	Maintenance factor ($/kWh)	Electrical/thermal efficiency (%)	Forced outage rate (%)	lifecycle (year)
PV	550/550	0.00310	-	4	25
WT	650/650	0.00600	90/0	4	25
CHP	300/300	0.01258	35/50	4	20
EHP	250/250	0.00300	97/0	2	15
Boiler	45/45	0.00870	0/90	3	10

TABLE 4. Technical and cost parameters of energy storage assets.

Assets	Capital investment / replacement costs		Efficiency (%)	Loss efficiency (%)	Depth of discharge level (%)	Forced outage rate (%)	lifecycle (year)
	Power ($/kW)	Energy ($/kWh)					
TSS	5/5	33/30	90	5	100	100	15
ESS	30/20	75/37	93	5	80	96	5

TABLE 5. MCMG plan required data.

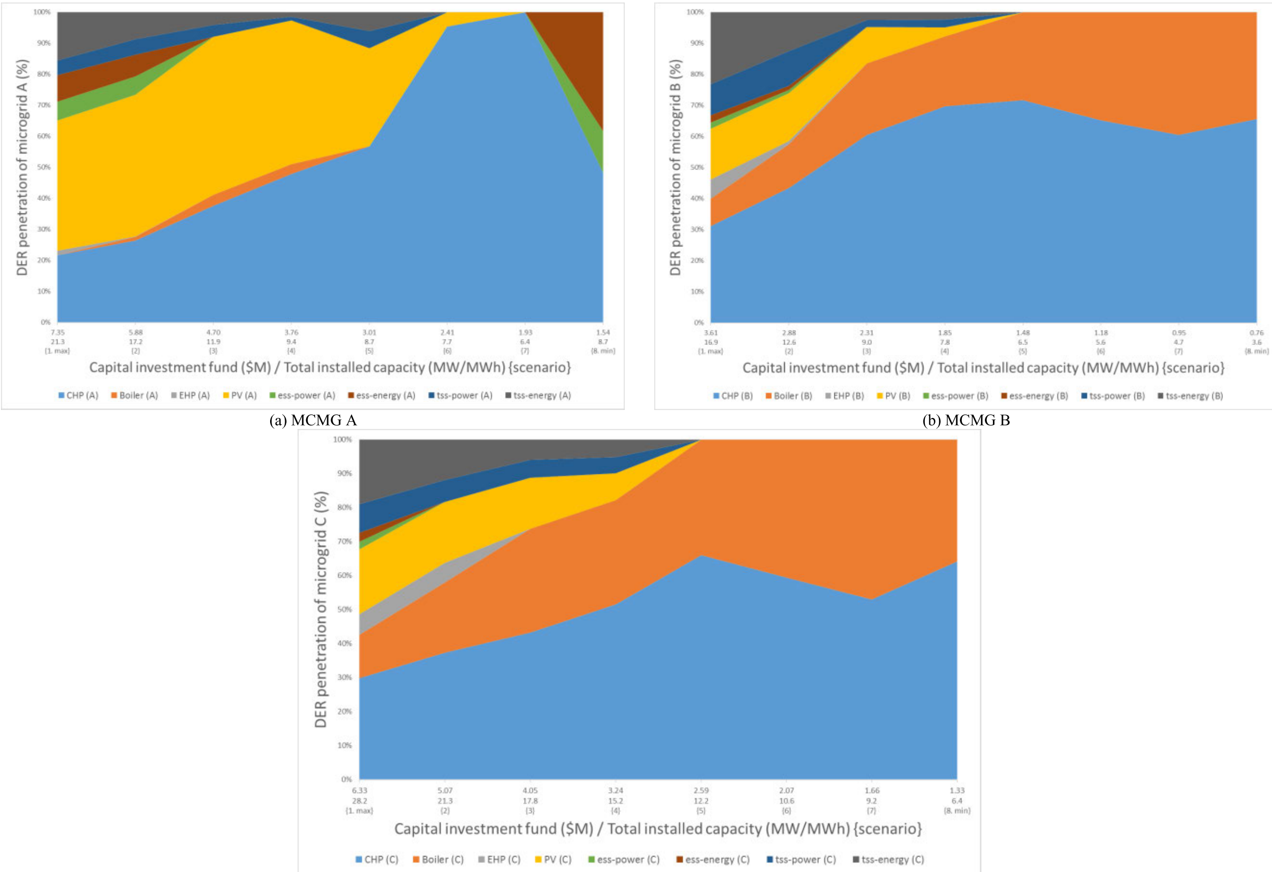
Interest rate (%)	5	CO2e tax tariff (kg/kWh)		0.0276
Expected load growth rate per year (%)	2.9	Pollution factor ($/kg.CO2e)	Utility	0.2556
Expected electricity price growth rate per year (%)	2.5		CHP	0.17606
Required reserve margin (%)	10			
Demand response capital cost ($/kW)	1200		Boiler	0.226

energy ratings of the ESS covering 5.9% to 13.4% and 7% to 38.3% of the aggregated DER capacity, respectively. Due to the absence of monthly peak demand charges for residential customers in MCMG A, the planning solution opts to install a large-scale nondispatchable PV unit in this zone. The power imbalance is then managed through power exchange with the network. Overall, MCMG A's DERs capacity ranges from 8.7 MW/h to 21.3 MW/h, taking into account the available CIF.

In MCMG B, as depicted in Fig. 2(b), the primary supply of electrical and thermal energy requirements would be fulfilled by CHP and boiler units, accounting for approximately 31.2%–71.7% and 8.7%–39.5% of the aggregated DERs capacity, respectively. Additionally, a small-sized EHP unit would be installed to meet the remaining thermal energy demand as a backup option in MCMG B. The planning solution also includes a PV unit, which makes up to 16.4% of the aggregated DERs capacity in MCMG B. To address the fluctuations in PV generation, an ESS with a relatively small capacity is implemented as a buffer. If the CIF exceeds $1.85M, the planning solution incorporates TSS units in conjunction with heat producers, with power and energy ratings ranging from 2.2%–11.2% and 2.4%–23.2% of the aggregated DERs capacity, respectively. Overall, MCMG B's DERs capacity ranges from 3.6 MW/h to 16.9 MW/h, considering the available CIF.

In the case of MCMG C, shown in Fig. 2(c), the configuration results are similar to MCMG B. However, there are some differences in the sizing of components. MCMG C features a smaller CHP unit, larger heat-only producers, and a relatively larger PV unit compared to MCMG B. The DERs capacity of MCMG C ranges from 6.4 MW/h to 28.2 MW/h, considering the least feasible and boundless CIF.

In Case 1, Fig. 3 provides insights into the costs associated with the establishment of each MCMG. According to Fig. 3(a), MCMG A's DERs investment cost consistently decreases as the budget is constrained. Similarly, the same trend can be observed in assets replacement cost, although it fluctuates due to the installation of ESS for lower fund extents ($3.01M). The results indicate that a DR intensity of 8.9% is achieved for a boundless fund extent in order to mitigate price fluctuations. However, the cost of DR enabling

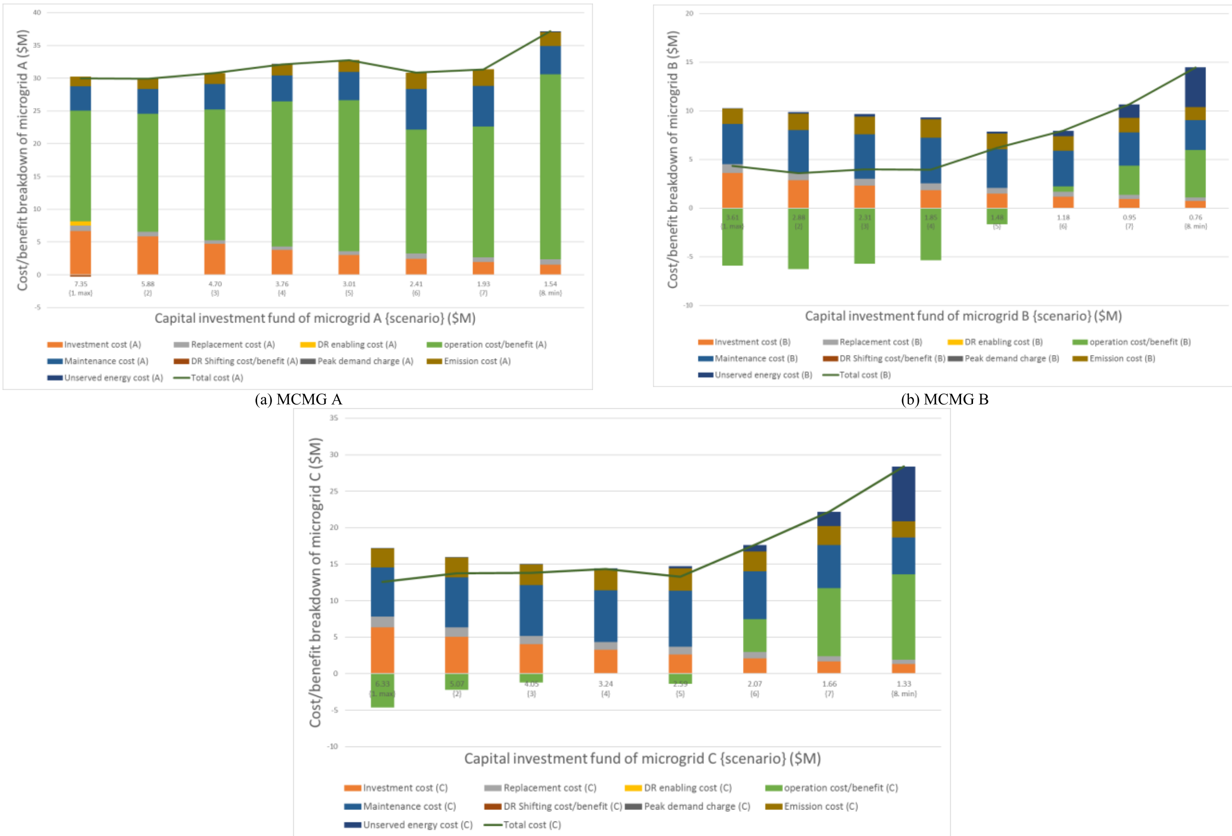


(a) MCMG A
(b) MCMG B
(c) MCMG C

FIGURE 2. Installed der penetration as a function of capital investment budget in Case 1.

technology amounts to 9.3% of the available CIF. Additionally, 44% of the financed DR technology cost is recovered through DR shifting programs over the planning horizon. As can be inferred from the figure, it can be observed that decreasing CIF leads to an initial increase followed by a sharp reduction in MCMG A's operation cost. However, it steeply increases again due to significant power exchange with the utility grid. On the other hand, maintenance and emission costs in MCMG A gradually increase until the CIF drops to \$3.01M, after which the costs fluctuate abruptly due to changes in DERs configuration, particularly CHP unit sizing. In this case, the unserved energy cost ranges from \$0.01M to \$1.846M by limiting the CIF, with the cost of \$0.14M occurring only for the least feasible budget. The aggregated electrical and low-prioritized thermal demand curtailments in MCMG A amount to 6.6 MWh and 2181.9 MWh, respectively. Overall, the turning points of MCMG A's total cost occur at \$3.01M and \$1.93M fund extents, where it initially rises monotonically, followed by a moderate decrease and a drastic upsurge in cost.

In Fig. 3(b), it is evident that the DERs investment and replacement costs of MCMG B consistently decrease as the CIF is limited. In this case, MCMG B's accumulated net cash flow is negative when the CIF is between \$3.61M and \$1.48M, indicating that the revenue streams compensate for the fuel costs. However, cash outflows start to exceed cash inflows as the CIF is further reduced. Moreover, reducing the CIF from \$3.61M to \$1.85M results in a relatively small increase in emission and maintenance costs for MCMG B. However, beyond that point, these costs decrease significantly due to a substantial decrease in CHP sizing. Additionally, a significant peak demand charge is imposed only for the least feasible CIF, resulting from purchasing power from the utility grid exclusively during peak periods of the last five years. By reducing the CIF from \$3.61M to \$1.18M, the unserved energy cost increases from \$0.48M to \$0.55M, primarily due to clipping low-prioritized thermal demands. Importantly, improper sizing of the CHP unit for a lower fund extent exacerbates the unserved energy cost, as it comprises a significant portion of the deployment cost resulting from clipping critical electrical demands. In this case, MCMG B experiences total electrical and thermal load curtailments ranging from 0 MWh to 126.1 MWh and from 1561 MWh to 89230 MWh, respectively. Overall, MCMG B's total cost remains relatively stable until the CIF drops to \$1.85M, after which it escalates significantly due to a substantial increase in operation and unserved energy costs.



(a) MCMG A

(b) MCMG B

(c) MCMG C

FIGURE 3. Cost breakdown as a function of capital investment budget in Case 1.

According to Fig. 3(c), the DERs investment and replacement costs in MCMG C consistently decrease as the CIF is limited. It can be observed that MCMG C's accrued net cash flow is negative for budgets beyond \$2.59M, indicating that the profits exceed the fuel expenses. However, as the budget is progressively constrained, the cash outflows start to surpass the cash inflows significantly. The maintenance and emission costs in MCMG C increase steadily, followed by a sharp decline in costs when the CIF drops below \$2.59M. In this case, peak demand charges are applied in the last two scenarios to avoid load shedding by purchasing power from the upstream network as much as possible. The unserved energy cost increases from \$0.07M to \$7.5M as the budget decreases. The total electrical and thermal demand curtailments in MCMG C range from 0 MWh to 9.1 MWh and from 1951.7 MWh to 149564 MWh over the planning horizon, respectively. Overall, MCMG C's total cost remains relatively stable until the CIF drops to \$2.59M, after which it sharply increases due to a significant surge in operation and unserved energy costs.

In Fig. 4, the LCOE trend in each MCMG-based system is depicted as a function of the capital investment budget. The results highlight that the most optimal LCOE is achieved in MCMG B's model, which has the lowest energy requirements and the lowest load sensitivity among the neighboring MCMGs. However, the economic viability of all deployed MCMGs is confirmed as the specified LCOEs are significantly below the medium retail tariff of \$0.086/kWh. In summary, the lower load curtailments in MCMG A can be attributed to higher VOLLs, resulting in over-installation of DERs within the premises. The importance of enabling

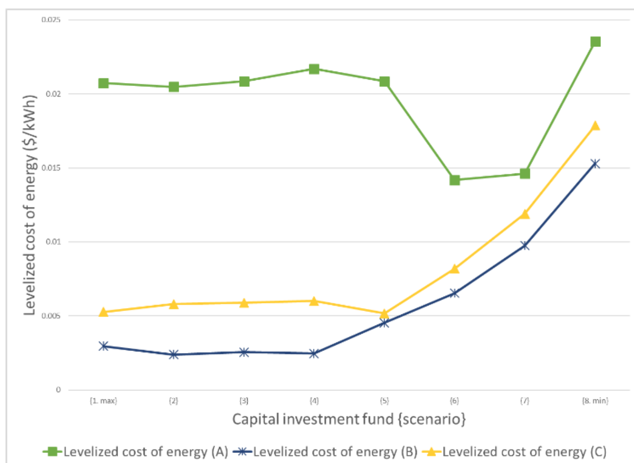
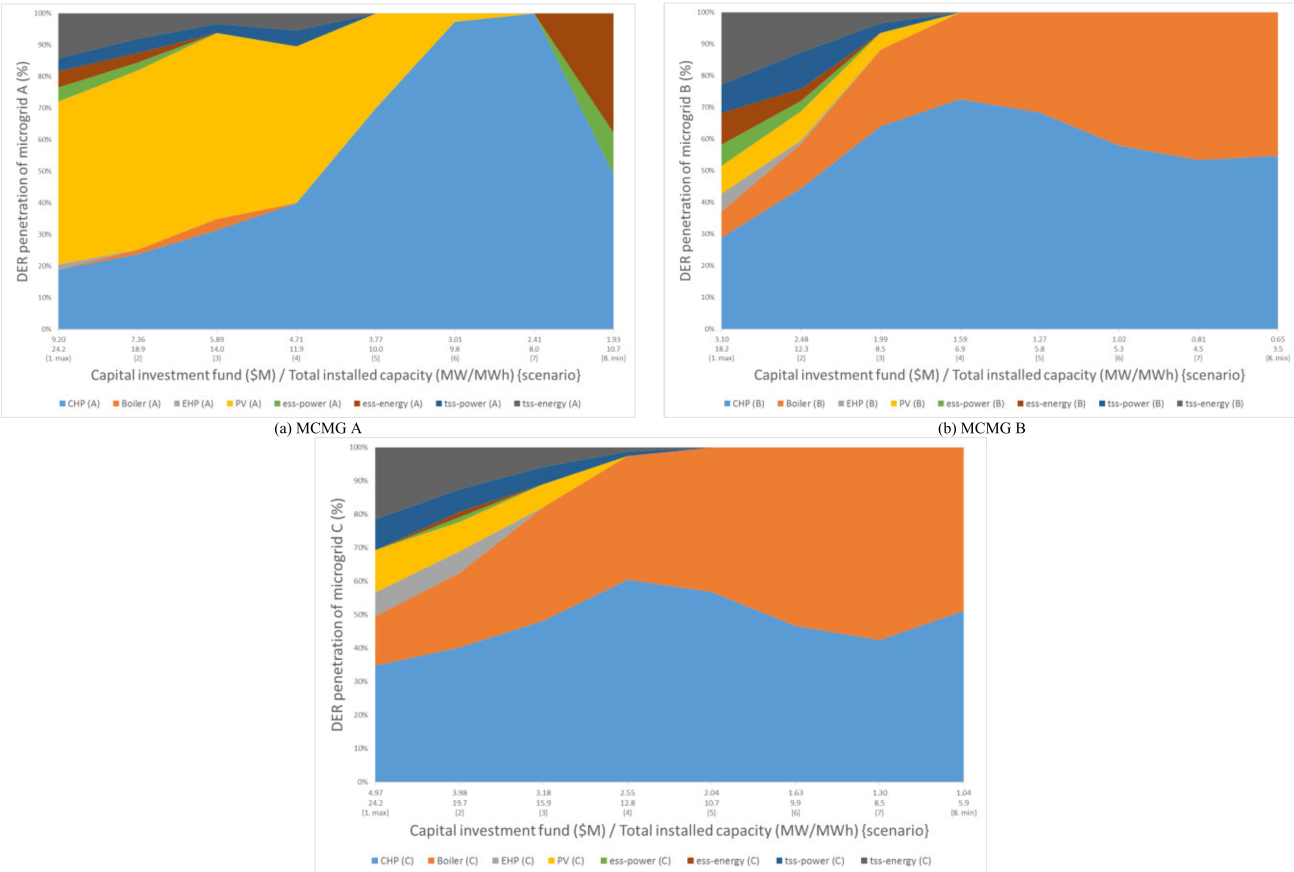


FIGURE 4. Effect of CIF variations on MCMGs' levelized cost of energy in Case 1.



(a) MCMG A (b) MCMG B (c) MCMG C

FIGURE 5. Installed der penetration as a function of capital investment budget in Case 2.

active customers in an MCMG that engages in substantial power exchange with the utility grid is emphasized to handle price oscillations. The results also indicate that MCMG A's net cash flows have never become negative, as the developer prefers to install DERs that are sufficient to meet the local energy requirements and procure unsupplied power from the upstream network during peaks (without incurring any peak demand charge). For example, the lowest MCPP is achieved in MCMG A's planning model compared to the other deployed MCMGs. On the other hand, MCMG A generates the largest REP by offering inexpensive power to local consumers. In conclusion, the most optimal configuration for meeting local electrical and thermal demands is achieved by the joint installation of CHP and PV units within grid-connected MCMGs.

- **Case 2**

Fig. 5 illustrates the DERs penetration level within each MCMG in Case 2, considering local power exchange during upstream outages. The configuration results of MCMGs in Case 2 are similar to Case 1, but with some differences. In MCMG A, the average PV capacity is increased by 13% compared to Case 1. However, the average sizing of CHP, boiler, EHP, ESS, and TSS units is decreased by 1%, 37%, 6%, 18%, and 16%, respectively. In MCMG B, the average sizing of the boiler and ESS power/energy ratings is increased by 17% and 231%/279%, respectively, while the capacity of CHP, EHP, PV, and TSS units is decreased by 5%, 7%, 50%, and 7%, respectively. In MCMG C, the average sizing of the boiler and EHP is increased by 23% and 14%, respectively, while the capacity of CHP, PV, ESS, and TSS units is decreased by 6%, 53%, 38%, and 6%, respectively. These differences in DERs sizing are due to the electrical interconnectivity between neighboring MCMGs.

Fig. 6 shows the REP and MCPP trends of the initial year with respect to CIF in Case 2. Compared to the previous case, the system's purchase probability is notably decreased by 16% on average, while the sale probability is increased by approximately 3%. This indicates that in an integrated framework, the reliance of electrically connected MCMGs on the utility grid is reduced. Additionally, in Case 2, 7.9% of MCMG A's customers are equipped with smart appliances, which is 1% lower than in Case 1. The lower realization of potential responsive customers in Case 2 is mainly due to minor power trade with the utility grid, resulting in increased cost-efficiency of the system.

Fig. 7 provides the following important insights into the total deployment cost and its breakdown for the MCMGs in Case 2:

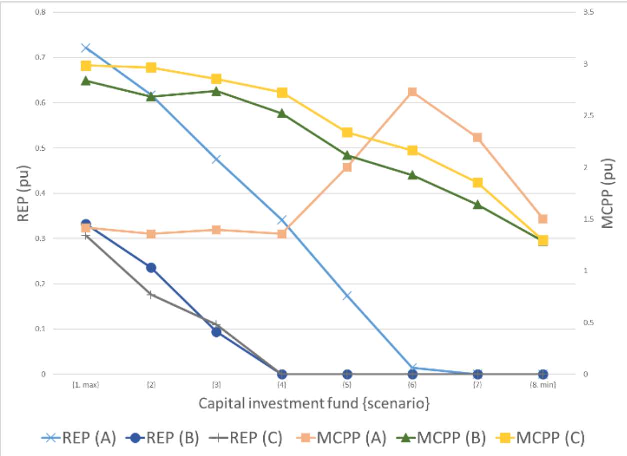


FIGURE 6. Assets' power penetration of the integrated MCMGs as a function of capital investment budget in Case 2.

1. MCMG A's investment cost for DERs increases by an average of 26% compared to Case 1. On the other hand, MCMGs B and C experience reductions of 13.9% and 21.5% in their investment costs, respectively. The trend in replacement costs follows a similar pattern.
2. MCMG A sees a 16.2% increase in maintenance costs and a 10.1% increase in emission costs compared to Case 1. MCMGs B and C, however, experience slight decreases in these costs.
3. The DR enabling technology cost for MCMG A decreases by 11.6% in Case 2 due to lower participation in DR shifting programs. As a result, the incentive payments for participating in such programs also decrease.
4. MCMGs A and B benefit from notable reductions in operation costs by 23% and 83.2% respectively, in Case 2. On the contrary, MCMG C experiences a significant increase of 215.4% in its average operation cost compared to the previous case. These variations are attributed to larger-scale installations of PV and ESS units in MCMGs A and B, respectively.
5. MCMG A achieves a substantial decrease of 90.1% in its unserved energy cost, which includes more sensitive electrical and thermal loads, in Case 2. However, MCMGs B and C face increases of 14% and 28.3% in their unserved energy costs for partially curtailed low-prioritized thermal demands, respectively.
6. MCMGs B and C experience significant increases in peak demand charges due to higher energy purchases from the utility grid during peak periods.

The results indicate that the total integrated planning cost of the entire system ranges from \$46.9M to \$86.2M, depending on the chosen CIF. The integrated planning solution requires a slightly lower budget (0.06% lower) compared to independent planning. Surprisingly, the total cost of the whole system decreases by 0.03% in the integrated framework.

The economic metrics are summarized in Table 6, revealing that MCMG B's customers, with the lowest energy requirements and load sensitivity among neighboring MCMGs, achieve the most profitable business case based on various economic measures.

Even the least economically favorable model, which belongs to MCMG A's customers, remains financially attractive with a discounted profitability index well above 1. Overall, the economic viability of the deployed MCMGs is justified as their LCOEs are significantly lower than the medium tariff rate of \$0.086/kWh.

Fig. 8 illustrates the power exchange among the connected MCMGs during the planning horizon in Case 2. The exchanged power among the integrated MCMGs ranges from 6587 MWh to 7703 MWh during islanding events. The results demonstrate that power is exchanged among the MCMGs to avoid the underutilization of capital-intensive DERs, even when neighboring MCMGs have surplus or deficient generation.

MCMG A's customers emerge as the largest buyers and sellers of power from and to the neighboring MCMGs due to the installation of large-scale non-dispatchable units alongside medium-scale dispatchable units. Specifically, MCMG A's stakeholders compensate MCMGs B and C's stakeholders with \$0.045M and \$0.022M, respectively, for their services during upstream power outage events.

In summary, the integrated framework not only enhances economic benefits for the selling MCMG by leveraging its unused power but also improves reliability for the buying MCMG while preventing the underutilization of capital-intensive DERs.

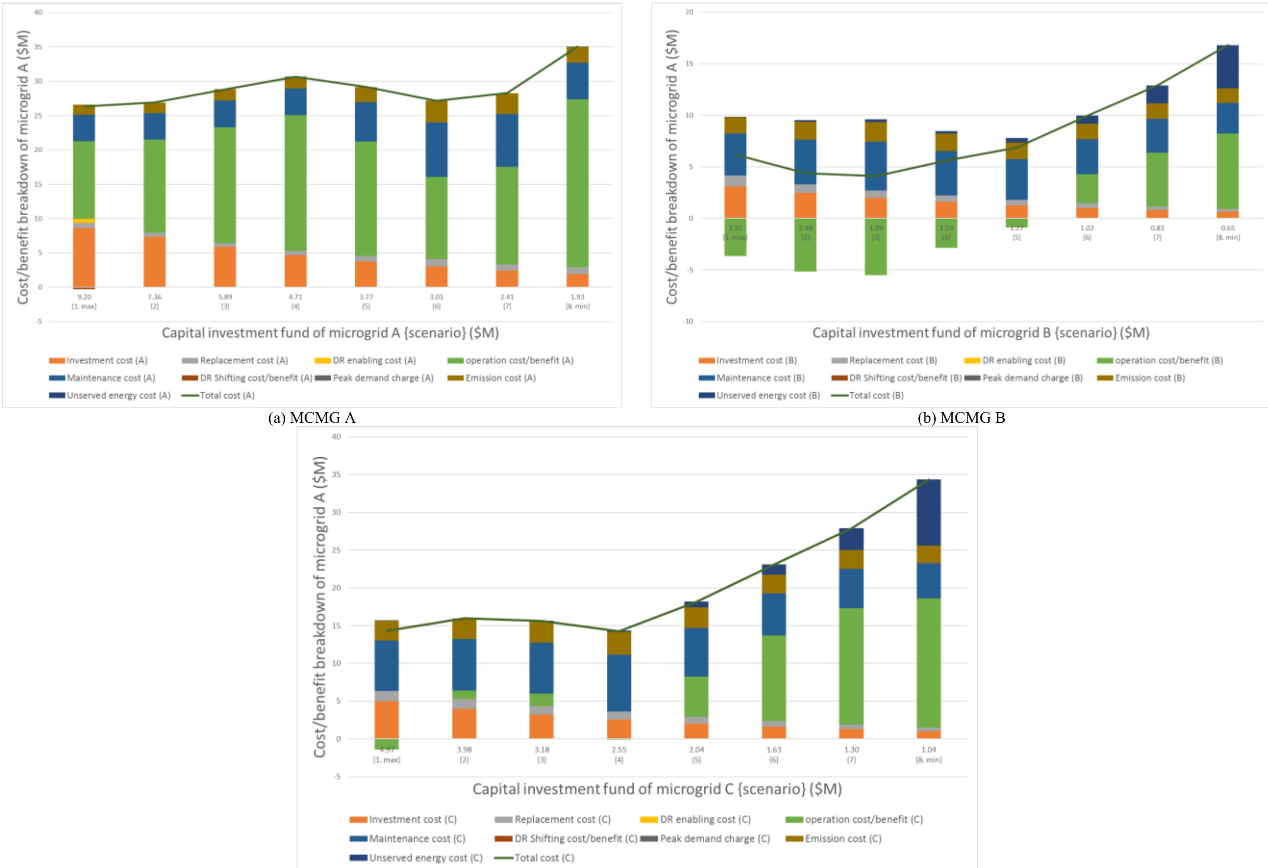
- **Case 3**

In Case 3, the sensitivity of planning solutions is analyzed in relation to changes in the number of multi-period islanding events. Four scenarios are considered, where the duration of outages is extended from 12 to 48 hours, with clearance times ranging from 1 to 4 hours. The results indicate that as the number of outages increases, the system's total cost moderately rises by approximately 5% to 20%. Additionally, the system's REP and MCPP in the initial year decrease by 59.4% and 4.8%, respectively, when the annual islanding hours increase from 12 to 48.

Contrary to previous findings [65], which suggested that an integrated framework could lead to lower REP and higher MCPP, the proposed integrated MCMG project demonstrates a 12% higher REP and a 5.1% lower MCPP in the face of extended upstream grid outages.

This indicates that the economic viability of the integrated framework is less dependent on the number of multi-period islanding events compared to earlier research. The total cost deviation is reduced by approximately 48% due to the extension of grid outages, further supporting the robustness of the integrated MCMG project's economic viability.

Indeed, despite the increase in the system's LCOE by up to 20% as a result of extending the number of multi-period islanding hours, the project remains economically viable. The LCOE of the integrated MCMG project is still lower than the retail rate, indicating that the project is financially attractive.



(a) MCMG A
(b) MCMG B
(c) MCMG C

FIGURE 7. Cost breakdown as a function of capital investment budget in Case 2.

TABLE 6. MCMGs economic analysis considering CIF variations in case 2.

MCMG	LCOE ($/kWh)			DPP (year)			DPI (pu)		
	lowest	highest	average	lowest	highest	average	lowest	highest	average
A	0.00973	0.02057	0.01605	3.00	5.73	4.21	4.5	16.8	10.1
B	0.00254	0.01925	0.00750	1.00	2	1.28	64.0	288.9	155.4
C	0.00570	0.02490	0.01125	2.13	3.99	2.85	38.8	166.0	91.6

This suggests that even with the additional costs incurred due to longer islanding events, the overall economics of the project are favorable, and the benefits of local DER deployment outweigh the expenses.

- **Case 4**

Table 7 presents the effective billings tax rate for a ten-year expansion of MCMG business cases. The proposed financing strategy involves levying a settled tax on a zone's electricity and gas bills to gather the required CIF for deploying MCMGs. The customers of a community agree to pay an additional amount beyond their bills as a financing activity for the installation of DERs in a targeted year.

The stakeholders of the MCMG-based systems are the local customers who contribute to the tax payments. The utility company acts as a consultant, providing guidance and supervision to MCMG investors in order to optimize the deployment of assets. The objective is to minimize both the planning cost of autonomous MCMGs and the system-aggregated cost, considering the future perspective of the distribution grid.

The effective billings tax rate is calculated for a ten-year expansion of MCMG business cases. The specific values and details of the tax rates can be found in Table 7, which is not provided in the given information. This table would outline the tax rates applicable to customers over the ten-year period, indicating the additional amount they need to pay beyond their regular electricity and gas bills.

The proposed financing solution aims to address the challenge of obtaining a large capital budget for MCMG deployment, which may be impractical for individual customers or even the utility company alone. By involving the

TABLE 7. Calculated billings tax rates as a financing strategy for customer MCMG deployments.

	MCMG	Scenario							
		1	2	3	4	5	6	7	8
Budget allocation ($M)	A	9.20	7.36	5.89	4.71	3.77	3.01	2.41	1.93
	B	3.10	2.48	1.99	1.59	1.27	1.02	0.81	0.65
	C	4.97	3.98	3.18	2.55	2.04	1.63	1.30	1.04
Billings tax rate (%)	A	26	22	18	15	12	10	8	7
	B	21	17	14	12	10	8	6	5
	C	17	14	12	9	8	6	5	4

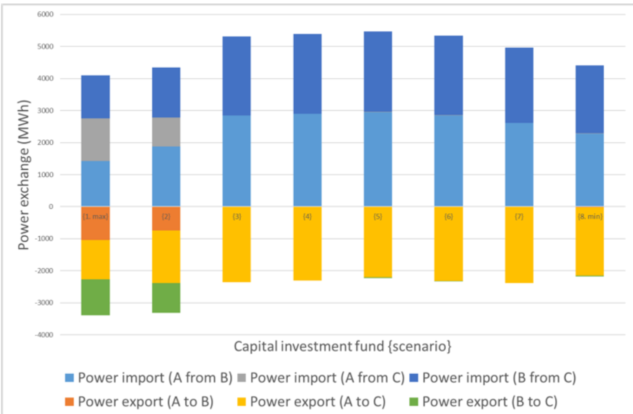


FIGURE 8. Power exchange among MCMGs in Case 2.

community and implementing a tax-based financing strategy, the necessary funds can be collected to support the installation of MCMGs and the development of a sustainable energy infrastructure.

The proposed approach suggests that the representatives of each zone (CMGCC developers) and the utility company can negotiate and agree upon a ten-year billings tax rate for local DERs deployment. This tax rate is determined by dividing the MCMG investment cost by the sum of the MCMG investment cost and the non-microgrid operational cost of the zone over the ten-year period.

By reaching a compromise on the desired tax rate, the stakeholders can ensure that the financing for MCMG deployment is feasible and economically viable in the long run. This approach benefits not only the stakeholders of MCMGs but also the utility company. It provides a solution to address reliability and environmental concerns by integrating local DERs, which can improve power system operational efficiency.

The integration of local DERs brings several advantages, such as reduced reliance on the central grid, enhanced resilience, and potential cost savings. By deploying MCMGs and leveraging local DERs, communities can have more control over their energy supply, reduce greenhouse gas emissions, and contribute to a more sustainable energy future.

V. DISCUSSIONS

The optimal deployment of parallel MCMGs in an integrated framework offers several key features and provides insights into MCMGs planning decisions:

- Economic Viability: The proposed model ensures the economic viability of the integrated parallel MCMGs. The results demonstrate that deploying parallel MCMGs in an integrated fashion is economically feasible. The planning cost of the system is significantly lower compared to supplying loads without MCMGs development, and the LCOE is much lower than the average retail rate.
- Integrated Framework Benefits: The integration of neighboring MCMGs in an islanded mode brings substantial economic and reliability improvements. Integrated planning for a cluster of neighboring MCMGs helps avoid under- or over-installation of DERs and reduces the dependence on the utility grid. This, in turn, minimizes the need for reinforcements in distribution and transmission networks.
- Role of Islanding Hours: While islanding capability is a crucial feature of MCMGs during upstream grid outages, the attractiveness of RER penetration within MCMGs decreases as the duration of islanding hours increases. However, the proposed integrated planning demonstrates a lower reliance of RER penetration levels on the number of islanding incidents compared to independent planning. The model ensures that the influence of islanding extents on RER penetration levels is relatively low. Nonetheless, renewable energy incentives are still necessary to support investments in non-dispatchable units by private financers with limited budgets.
- Control Unit: The article introduces a CMGCC unit that acts as an intermediary between the independent system operator and MGCCs. This control unit enables the design and operation of parallel autonomous MCMGs, taking into account both local and regional objectives. A hybrid energy management system is proposed, allowing for trading between connected MCMGs.
- Financing Strategy: The direct beneficiaries of MCMG expansions are the local customers at a premise. Therefore, MCMG stakeholders must establish a business budget for deploying the MCMG-based system. This

work proposes the imposition of settled taxes on customers' energy utility bills to generate the necessary business budget in a targeted year. This approach is not only practical for creating a substantial budget but also feasible and advantageous for MCMG customers in the long term.

VI. CONCLUSION

This paper has presented a systematic approach for deploying a clustered multi-carrier microgrids business case, aiming to advance intelligent and sustainable integrated power systems. The study has explored the financial feasibility of multi-carrier microgrids by optimizing the technology mix to meet local energy requirements in both grid-connected and islanded scenarios.

By minimizing the overall planning cost of clustered multi-carrier microgrids, considering local and regional objectives, the research provides a solution to the planning problem. The integrated planning framework was applied to various cases, demonstrating its economic merit. Additionally, the proposed framework highlights significant potential benefits, including asset utilization efficiency, cost savings in operations, and improvements in reliability and resiliency. These findings emphasize the framework's practicality and performance.

The study has also discussed the role of governments in facilitating capital investments for the development of clustered multi-carrier microgrid projects, aligning with sustainable development goals. Moreover, a feasible financing strategy is suggested, proposing settled billing tax rates ranging from 4% to 26% for multi-carrier microgrid customers over a ten-year period. This strategy can aid policymakers in formulating policy programs that support the successful implementation and proliferation of multi-carrier microgrids within various premises.

Overall, this study contributes to the advancement of intelligent and sustainable power systems by providing a comprehensive analysis of the financial feasibility, planning optimization, and policy considerations for clustered multi-carrier microgrid projects.

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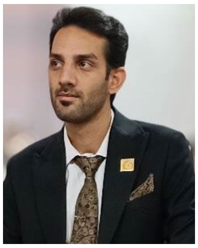

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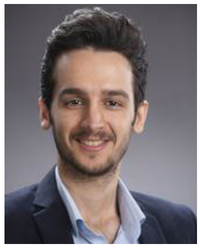

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