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THE IN-DEPTH INVESTIGATION AND
OPTIMISATION OF HYBRID OCEAN ENERGY
AND STORAGE SYSTEMS FOR SUPPORTING
ZERO-ENERGY BUILDINGS WITH NOVEL
OPERATIONS OF ONSHORE AND OFFSHORE
ENERGY STORAGES

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The In-Depth Investigation and Optimisation of
Hybrid Ocean Energy and Storage Systems for
Supporting Zero-Energy Buildings with Novel
Operations of Onshore and Offshore Energy
Storages

Luo Haojie

A thesis submitted in partial fulfilment of the
requirements for the degree of Doctor of
Philosophy

August 2025

CERTIFICATE OF ORIGINALITY

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Abstract

Rapid urbanisation drives economic growth and escalates energy demand and greenhouse gas emissions, underscoring the urgency of transitioning to renewable energy systems. This study investigates the feasibility of integrating wave energy converters and offshore wind turbines to support coastal zero-energy buildings, emphasising energy flexibility, resilience, and cost-effectiveness. A simulation framework in the TRNSYS 18 modelled building services, storage systems, and renewable energy units, evaluating performance through energy matching criteria, techno-economic analyses, and dynamic control strategies. This study first evaluated ocean thermal energy integration in heating and cooling systems, revealing that seawater-source heat exchangers with higher effectiveness over 0.85 improve chiller performance, though increased pump energy can offset gains. The immersed heat exchanger achieved superior system efficiency and reduced total energy use intensity by 10.9% compared to air-cooled systems. Replacing electric heaters with seawater-source heat pumps reduced heating electricity demand by 26%, demonstrating significant energy-saving potential. Hybrid wave-wind scenarios demonstrated enhanced energy matching, with a 62% wave and 38% wind ratio, achieving on-site electrical energy matching of 0.69. Integrating batteries further improved efficiencies by mitigating demand-generation mismatches. The hybrid wave-wind systems mitigated power shortages, achieving a 90% reduction in annual CO₂ emissions. Techno-economic evaluations confirmed project feasibility within a 20-year period, with a relative net present value highlighting cost-effectiveness.

Battery and wave energy storage controls were implemented to enhance energy flexibility. Battery systems demonstrated 100% peak-shaving capability, reducing operational costs by 1%, while novel wave energy converter reservoir controls improved energy matching by 10% and lowered costs to 83.99%, boosting net present value by 40%. Dynamic storage strategies, including real-time adjustments based on electricity tariffs and demand patterns, further optimise performance. For instance, varying reservoir discharge limits reduced operational costs by 4.5%, and integrating additional batteries enhanced peak shaving, cutting costs by 6.4–10.8%. Further, the system introduced the floating photovoltaic and electric vehicles system. The system's flexibility and resilience were tested under a demand response programme and power outages. Coordinating flexibility sources, wave energy storage, building batteries, and electric vehicles increased the flexibility index to 199.89% and reduced operational costs to 79.52%. During outages, resilience improved from 83% to over 99%, minimising reliance on diesel generators and CO₂ emissions. This study further investigates the impact of relative time series of outages and demand response events on resilience. Results indicate that a 100% outage response index significantly enhances resilience, with renewable energy and storage effectively meeting demand during outages, reducing reliance on diesel, and achieving cost savings. Integrating ocean renewable energy and adaptive storage controls offers a robust solution for coastal zero-energy buildings, harmonising energy flexibility, resilience, and cost savings. Significant fuel cost reductions and emissions savings justify the approach. This research advances dynamic control strategies for ocean energy systems, providing actionable insights for optimising grid interactions, mitigating outages, and accelerating the transition to sustainable urban energy infrastructures.

This study demonstrates novelty across multiple dimensions. It proposes a coastal zero-energy building supported by a hybrid ocean-renewable energy system, confirming the techno-economic feasibility of this

ocean-resourced integrated thermal and electrical design. Innovatively, this system incorporates control strategies with both the generation and storage sides' flexibility. Specifically, the wave energy converter's characteristic reservoir is utilised as a mechanical energy storage unit, thereby enhancing energy matching and reducing costs. The research highlights dynamic control based on a time-of-use electricity tariff to minimise operational costs. Its originality also lies in introducing hybrid storage coordination to achieve two goals: flexibility and resilience, along with efficient control strategies that address incentive maximisation and grid outage survivability. This research offers practical solutions for reducing reliance on fossil fuels and maintaining stable operations during grid disruptions. It is especially relevant for coastal urban regions with ocean energy potential and high electric vehicle adoption. Additionally, it offers a replicable framework for facilitating the transition to net-zero emissions.

Keywords: Energy management; Energy storage; Zero-energy buildings; Renewable energy; Hybrid energy systems.

Publications

[Publication I] H. Luo, S. Cao, and V. L. Lu, "The techno-economic feasibility of a coastal zero-energy hotel building supported by the hybrid wave-wind energy system," *Sustainable Energy, Grids and Networks*, vol. 30, p. 100650, 2022/06/01/ 2022, doi: <https://doi.org/10.1016/j.segan.2022.100650>.

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Nomenclature

AC	Air handling unit cooling
AHU	Air handling unit
CAPEX	Capital expenditure (HK\$)
CE_a	Annual carbon dioxide emissions ($\text{kg CO}_{2,eq}/\text{m}^2.\text{a}$)
CEF_{eq}	Equivalent carbon dioxide emission factor ($\text{kg CO}_{2,eq}/\text{kWh}_e$)
COP	Coefficient of performance
COP_{sys}	Coefficient of performance of the system
COP_{ch}	Coefficient of performance of the chiller
COP_{hp}	Coefficient of performance of the heat pump
DHW	Domestic hot water
DR	Demand response
$E_{exp,a}$	Annual exported energy to the electric grid ($\text{kWh}/\text{m}^2.\text{a}$)
$E_{imp,a}$	Annual imported energy from the electric grid ($\text{kWh}/\text{m}^2.\text{a}$)
EUI	Energy utilisation index
EV	Electric vehicle
FiT	Feed-in Tariff
FPV	Floating photovoltaic
FSOC	Fractional state of charge
FSOR	Fractional state of the reservoir
G_{elec}	Electricity generation (kWh)
H_s	Significant wave height (m)
HK\$	Hong Kong Dollar
HX	Heat exchanger
L_{elec}	Electricity load (kWh)
NPV_{rel}	Relative net present value (HK\$)
OEF _e	On-site electrical energy fraction
OEF_{eOP}	On-site electrical energy fraction during the on-peak period
OEF_{eOFP}	On-site electrical energy fraction during the off-peak period
OEM _e	On-site electrical energy matching
OEM_{eOP}	On-site electrical energy matching during the on-peak period
OEM_{eOFP}	On-site electrical energy matching during the off-peak period
OFF	Off-peak period
OP	On-peak period
OPEX	Operational expenditure
OWEC	Overtopping wave energy converter
PDM	Peak demand management
PSI_{OP}	Peak shaving indicator during the on-peak period
SC	Space cooling
SPP_{rel}	Relative simple payback period (year)
T_p	Ocean wave peak period (s)
V2B	Vehicle-to-building
VFI_{OFP}	Valley filling indicator during the off-peak period
WEC	Wave energy converter
WT	Wind turbine
ZEB	Zero-energy building

1 Introduction

1.1 Background

The accelerating pace of global urbanisation has amplified concerns over unsustainable fossil fuel dependency and its cascading environmental impacts, propelling carbon neutrality initiatives to the forefront of international discourse [1]. With climate change mitigation becoming an urgent priority, nations worldwide are mobilising collaborative efforts to achieve net-zero emissions through innovative energy transitions [2]. This major shift has driven progress in clean energy technologies and emission reduction strategies aimed at decoupling economic growth from non-renewable resource consumption [3, 4]. Among emerging trends, integrating variable renewable energy (RE) systems—particularly solar and wind power—has gained substantial momentum in modern power grids [5].

According to International Energy Agency reports, buildings constitute a critical focus area in energy transitions, accounting for approximately one-third of global final energy use and 40% of energy-related CO₂ emissions [6, 7]. Hong Kong SAR in China exemplifies this urban energy challenge, where buildings consume 68% of total energy (44% from commercial sectors and 24% from residential areas) [8]. Despite its dense population of 7.35 million and annual electricity demand reaching 1.61×10^5 TJ (2022), renewable sources contribute merely 0.8% to the energy mix. Current RE deployment remains skewed toward waste-to-energy (71.5%), underscoring the untapped potential for solar and wind adoption [9, 10]. Spatial constraints in this high-rise metropolis further complicate RE infrastructure implementation. A proposed land reclamation project named the Lantau Tomorrow Vision (17 km² artificial islands for 300,000 housing units) may enable marine energy exploitation [11]. The geographical location inherently offers a way to utilise ocean-related RE resources. While academic studies highlight promising wave and tidal energy potential in East/Southeast Asia [12], practical implementation of ocean energy converters remains nascent, with most technologies still in experimental or modelling phases.

The transition toward zero-energy buildings (ZEBs) has emerged as a strategic response to urban sustainability challenges, combining energy efficiency optimisation with on-site renewable generation [13, 14]. However, the intermittent nature of RE resources introduces grid stability concerns, necessitating advanced flexibility mechanisms to balance supply-demand dynamics [15, 16]. Research emphasises hybrid renewable systems coupled with energy storage as critical solutions for mitigating output fluctuations and preventing grid overloads [17-19]. Particularly for coastal regions, integrated marine energy portfolios combining offshore wind, wave, and tidal resources could enhance supply reliability while addressing spatial limitations [20-23]. Academic consensus underscores the importance of multi-technology integration and demand-side management strategies to improve system resilience against climate-induced disruptions and weather variability [24, 25].

Demand response (DR) programmes have been a popular and effective resort for regulating electric grid pressure. The process refers to electricity users proactively adjusting their electricity consumption patterns and behaviours based on external signals or incentive measures. The action is to assist in balancing supply and demand on the grid and optimising the grid operations. DR primarily operates through two key mechanisms: price-based programmes and incentive-based programmes. Price-based programmes leverage price signals and tariff structures to encourage consumers to adjust their consumption patterns in response to pricing variations.

Incentive-based programmes use direct payments to consumers who modify their demand behaviours as part of a demand-side response initiative. DR programmes target large consumers, primarily industries, to adjust consumption during grid imbalances. This facilitates grid stabilisation, mitigates the risk of blackouts, and enables participants to earn financial rewards through competitive auctions in established markets [26].

1.2 Literature Review

Review of Energy Efficiency Challenges and Solutions in the Coastal Building

The building sector plays a crucial role in urban areas, particularly regarding electricity consumption, and is increasingly recognised for its energy inefficiency. In Hong Kong, for example, commercial buildings alone account for 67% of total electricity usage and are generally regarded as energy inefficient [27]. Globally, policymakers have responded with ambitious building standards to address systemic inefficiencies. The UK's revised Energy Performance of Buildings Directive (2010) mandated that residential and commercial buildings should achieve nearly ZEB status by 2020 [28]. Similarly, in Japan, the government decided in 2009 to accelerate the development of ZEBs, mandating that all new public buildings meet ZEB standards by 2030 [29]. Achieving the ZEB target involves minimising energy demand, scaling on-site renewable generation, and optimising dynamic energy matching across building systems [30-33]. Similarly, the European Union's energy transition, driven by initiatives such as the European Green Deal and REPowerEU, relies on sustainable and digital energy reforms. Ambitious targets include installing solar panels on buildings, deploying 10 million heat pumps in five years, and replacing 30 million cars with zero-emission vehicles by 2030, all aimed at reducing emissions and achieving RE goals [34]. ZEBs serve as distributed energy resources that can enhance grid flexibility and reliability. The integration of RE sources allows ZEBs to produce energy that can meet their own demands and contribute surplus energy back to the grid. Academic research emphasises retrofitting strategies, where envelope optimisations, such as high-performance insulation and glazing, can reduce baseline energy demands, which is a critical step toward achieving the ZEB target. Moreover, combining these measures with RE generation systems is essential [28]. For instance, a study on low-rise residential buildings in Hong Kong demonstrated the feasibility of reducing energy demand through low-energy measures, such as the use of energy-efficient appliances and light fittings [35]. Kayo et al. proposed a community-based approach where buildings with varied energy demands share surplus energy through combined heat and power (CHP) systems, enhancing energy efficiency and matching [36].

In seashore cities, where resources like seawater are readily available, innovative strategies are being explored to enhance energy efficiency. Su et al. investigated the potential of using seawater heat pumps in coastal cities in northern China, highlighting the techno-economic and geographical advantages of this approach [37]. Beyond heat pumps, Luigi and Chiara's analysis of seawater-cooled chillers not only saves energy but also mitigates urban heat island effects when compared to air-source chillers [38]. Hotels, which are among the most energy-intensive buildings, have become a key focus of energy efficiency initiatives. In line with the European Union's energy policy, retrofitting existing hotels to achieve nearly zero energy standards by 2050 has been identified as a primary goal [39]. Hotels require a substantial amount of energy to meet the diverse needs for indoor comfort, leading to ongoing efforts to find innovative solutions to this challenge. For instance, Dinesh and Abba's techno-economic assessment of Mauritian coastal hotels showed that seawater air conditioning systems gained substantial

reductions in power consumption and a relatively short payback period, making this technology highly beneficial for tropical islands [40]. In Antalya, Türkiye, Tolga et al. studied a hotel where a seawater-sourced cooling system was implemented to replace the conventional air-cooled system, resulting in a significantly better coefficient of performance (COP) for the overall cooling system [41].

Review on Wave Energy Converter Technologies

Given the significant potential of ocean waves for RE extraction, WECs have become a critical focus for technological development. WECs harness the energy generated by the interaction between wind power and surface waves, which ultimately originates from solar energy [42]. Recent technological advancements have focused on optimising WEC configurations to maximise energy conversion efficiency. Doyle and Aggidis conducted a comparative analysis of oscillating water column WEC configurations, demonstrating that modular three-chamber arrays outperformed single-chamber units by generating triple the power output through integrated airflow collection [43]. This underscores the efficacy of modular architectures in enhancing operational performance. Similarly, oscillating body WECs with a single degree of freedom have been found to be less effective in power absorption. To address this limitation, Chen et al. introduced a WEC with a hemispherical geometry capable of operating with three degrees of freedom. Their research revealed that lowering the centre of gravity improved power absorption in pitch and roll motions. Additionally, they presented power matrices derived from various hemispherical scales under irregular wave conditions, providing valuable references for size design considerations [44]. Parallel innovations include Hong's circular ramp overtopping WEC (OWEC), which employs an annular reservoir and low-head hydro turbine system. Experimental studies by Liu et al. demonstrated that implementing guide vane arrays (0→12 vanes) significantly enhanced overtopping discharge. Furthermore, a milder ramp slope and the formation of splashes were found to optimise discharge efficiency [45].

OWEC operational principles analogous to conventional hydropower systems involve channelling wave surges into elevated reservoirs to drive turbines [46]. This technology finds synergistic applications in multifunctional overtopping breakwaters that combine coastal protection with energy generation. Palma et al. evaluated geometric parameters for such hybrid structures, identifying 45° parapet inclinations as optimal for balancing energy capture and structural integrity [47]. Di Lauro et al. advanced this concept through a vertical caisson design incorporating setback crown walls and ramp-integrated reservoirs. Their non-traditional configuration reduced wave reflection by 15–20% while improving hydraulic stability and energy yield under stochastic wave conditions [48]. Geometric optimisation studies by Martins et al. revealed context-dependent performance relationships: minimal ramp slopes maximised dimensionless power output in fixed-depth installations, whereas intermediate ramp dimensions proved superior in space-constrained scenarios [49]. These results highlight the importance of tailoring device geometry to specific wave conditions, as no single design can perfectly accommodate the variability of wave climates. Due to the intermittent nature of wave energy, a smooth and consistent power output is crucial for grid integration [50].

Review on the Role of Flexibility in Renewable Energy Integration

The Feed-in Tariff (FiT) policy in Hong Kong SAR during the 2010s marked a strategic economic intervention to incentivise distributed RE adoption and local generation capacity [51, 52]. Concurrently, academic investigations

have intensified around flexibility sources to address daily and seasonal weather-related fluctuations [53]. Defined as a power system's adaptive capacity to balance generation-consumption dynamics, flexibility has emerged as a critical enabler for scaling renewable penetration and achieving decarbonisation targets. Researchers have proposed various definitions and quantification methodologies for flexibility, evaluating solutions ranging from energy storage and RE deployment to demand-side management [54]. Key operational strategies include peak shaving, load shifting, and valley filling, with performance often measured through indicators like peak demand reduction and temporal load redistribution [55-57]. Advanced metrics such as the Flexibility Factor (-1 to +1 scale) quantify load adjustment capacities across tariff periods, while extensions incorporating cost and emission parameters broaden analytical perspectives [58-61]. Complementary indices like self-sufficiency (on-site generation coverage) and self-consumption (localised energy utilisation) provide additional insights into flexibility potential, with the Flexibility Index quantifying economic savings from optimised control strategies relative to inflexible operations [62, 63]. Recent conceptual expansions integrate cost-curve analyses into flexibility assessments, as demonstrated in utility rate optimisation studies [64, 65].

(1) Demand-side and generation-side flexibility

Residential load flexibility has been systematically investigated through appliance categorisation. D'hulst et al. identified domestic hot water (DHW) buffers and electric vehicles (EVs) as high-potential "buffered" devices due to their capacity for temporal energy redistribution without compromising user comfort, outperforming "postponed" appliances like dishwashers and washing machines [66]. Enhanced demand-side flexibility facilitates renewable integration and diminishes fossil fuel reliance through grid-responsive load management. Thermal and electrochemical storage integration has proven effective in harmonising building loads with grid requirements, as evidenced by studies demonstrating improved operational flexibility under dynamic pricing schemes [67-69]. Hewitt's analysis of hybrid heat pump-hot water storage systems stabilises RE systems and yields economic benefits under specific tariffs [70], while Hedegaard et al. demonstrated passive thermal storage's superiority over conventional tanks in reducing energy waste and operational costs [71]. Traditional power system flexibility, historically dependent on dispatchable generation and reserve margins, faces new challenges with rising RE penetration. Supply-side strategies now emphasise hybrid renewable portfolios (e.g., wind-solar complementarity) during surplus conditions [72, 73]. Curtailment, or the intentional reduction of RE output, has also been identified as a potential source of flexibility, especially during periods of high wind and solar generation [74]. Hydropower-rich regions exemplify large-scale flexibility through strategic generation modulation [75]. Key supply-side flexibility parameters encompass operational range, ramp rate capabilities, and sustained output duration, with combined heat and power (CHP) systems emerging as multi-functional flexible assets [76].

(2) Storage-side flexibility (electrical energy storage)

Energy storage systems, such as batteries and supercapacitors, have been integrated into renewable systems as backup power sources, providing a viable solution to absorb power fluctuations [77]. Zhang et al. employed model predictive control to demonstrate battery storage's capacity to satisfy 60-75% of building flexibility requirements when coupled with photovoltaic (PV) systems [78]. Integrated PV-vehicle-grid architectures developed by Zhou and Cao achieved cost minimisation through off-peak battery charging, effectively addressing grid congestion [79]. Comparative analyses by Niu et al. revealed synergistic benefits from combined battery-thermal storage

deployment, yielding 18-22% operational cost reductions through optimised load shifting [80]. Huang et al.'s cluster-level battery control strategy enhanced renewable self-consumption by 27% while reducing electricity expenditures [81]. Eseye et al. proposed a demand-side control strategy using batteries and EVs as dynamic energy storage systems. Their solution decreased RE curtailment, relieved peak power demand, and increased overall economic benefits [82]. At a larger scale, Narayanan studied the feasibility of a fully RE system for a city with 75,000 inhabitants, integrating WTs and PV panels supported by battery storage. However, the uncompetitive costs of RE-battery systems resulted in negative economic performance compared to traditional non-renewable systems [83].

(3) Storage-side flexibility (mechanical energy storage)

Mechanical storage alternatives offer distinct advantages in durability and environmental impact. Flywheel systems demonstrate promise for wind power stabilisation, with Yang et al.'s wave energy rectifier integration achieving 35% efficiency gains through variable-inertia flywheel optimisation [84-86]. Pumped hydro storage remains a cost-effective large-scale solution, as evidenced by Jordehi et al.'s microgrid study, which showed 15% cost reductions through strategic load shifting [87]. Ma et al.'s hybrid pumped hydro storage-battery configuration for Hong Kong's islands capitalised on coastal topography to achieve 12% greater cost-competitiveness versus standalone battery systems [88].

Review on Enhancing Grid Stability through Demand Response Programmes and Innovative Technologies

DR programmes have become crucial in managing electrical grids, enabling a balance between energy generation and demand, reducing peak consumption, and enhancing grid stability [89]. Various innovative approaches have been explored in the context of DR implementation in buildings. Wang et al. designed a super-high-rise building that achieved fast DR by restricting chiller loads while maintaining evenly raised temperatures across spaces during DR periods. This cooperative control method saved over 2,500 kWh, equivalent to approximately a 20% reduction in the building's initial energy consumption [90]. However, HVAC systems, which are commonly utilised in building energy management, are generally slow to respond to DR signals. To address this, prediction models have been employed to improve HVAC operations. Li et al., for instance, employed prediction methods to enhance solar energy forecasting for buildings, obtaining a 30% improvement in root mean square error and mean absolute error [91]. Similarly, Sehar et al. utilised end-use load management in smart buildings, optimising lighting and temperature settings to lower demand spikes without compromising occupant comfort. Building energy simulation tools were employed to develop models of dynamic plug loads [92]. Further innovations in DR technologies have been proposed for residential applications. Shadra et al. created an IoT-based approach using smart plugs to manage household appliances, which could save over 40% in costs with minimal disruption to users [93]. Rotger-Griful et al. introduced a multimodal building energy management system tested on a 12-storey residential building. Though the system demonstrated a relatively low DR potential of 7,400 kWh/year, it showed promise for improving residential DR and supporting RE integration [94]. Wang et al. extended the application of DR by incorporating it into a multi-objective optimisation model for building energy management systems. This model optimised system operation through the synergetic dispatch of source load storage and included controllable and deferrable loads under time-of-use price-based DR. The study highlighted DR's potential to improve energy efficiency and occupant comfort in building management [95].

ZEBs, through their active involvement in energy generation, consumption, and management, position themselves not just as energy-efficient buildings but as essential parts of the future energy ecosystem. Their ability to foster grid flexibility, enhance energy storage, and leverage EV integrations underscores their role in a renewable-dominant grid. ZEBs also play a vital role in DR programmes, as they can adjust their energy consumption patterns to align with grid conditions, contributing to power system stability. Naylor et al. performed an extensive review of studies on occupant-centred building management, emphasising the role of the building energy management system in reducing overall consumption. Additionally, ZEBs equipped with backup power systems can provide reliable electricity for essential loads. These buildings are also crucial for DR programmes, as they can modify their energy consumption patterns in response to grid conditions and help maintain power system stability. For instance, Nirbheram et al. optimised the size of battery energy storage systems in a solar-wind RE system, reducing energy costs by 25% when participating in DR [96]. Singh and Kumar further demonstrated the batteries' importance in DR, finding that the net present cost of a system could be reduced by 62% through their integration [97]. Guo et al. showcased the resilience of an off-grid ZEB in Tehran, which used solar and hydrogen energy storage to sustain four residents without power outages, as simulated using Trnsys software [98]. Kumar and Cao explored ZEB applications in zero-emission metro stations in Hong Kong. They demonstrated that integrating train batteries and swappable train batteries significantly improved the resilience factor during power outages, increasing it from 0.83 to 0.99 [99]. Distributed energy systems have also been identified as promising enablers for DR programmes, particularly in ZEBs that rely on intermittent solar or wind resources [100]. Zhu et al. concluded that integrating RE and energy storage in distributed systems can significantly enhance energy performance and reliability [101]. Wang et al. proposed a distributed generation method to address the uncertainty of solar and wind energy, reducing operational costs by 21% and achieving improvements in environmental sustainability and system reliability [102].

Review on EV Functioning as Mobile Flexibility Sources

Apart from stationary energy storage systems and electric appliances, EV functions as mobile energy storage units, offering another source of flexibility on the storage side. Beyond their primary function for daily transportation, numerous researchers have explored the potential of EVs to interact with buildings and contribute to efficient energy management [103]. This is especially relevant in regions like Hong Kong, where buildings account for approximately 60% of carbon emissions, and transportation contributes about 20% of the total emissions. Over the past decade, the EV market has expanded significantly, with global EV sales surging from 120,000 in 2012 to 6.6 million in 2021 [104]. Leading economies such as the Netherlands, Denmark, and Ireland have set ambitious goals to achieve 100% zero-emission vehicle sales in the next few decades. At the same time, Norway aims to reach this milestone by 2025. This rapid growth can be attributed to sustained policy support, ambitious electrification goals, and an increasing variety of EV models available to consumers [105]. To align with global trends, Hong Kong has announced plans to cease new registrations of fuel-powered private cars, including hybrids, by 2035 or earlier, facilitating a smooth transition to EVs [106]. The city's Transport Department has issued a Smart Mobility Roadmap (2019) that outlines key strategies for the next five years, focusing on Smart Transport Infrastructure, Data Sharing and Analytics, and Applications and Services. The roadmap explores the implementation of autonomous vehicles, vehicle-to-everything technology, big data platforms for traffic data

integration, and real-time smart parking systems [107]. The accelerated adoption of EVs has also stimulated advancements in everything-to-vehicle and vehicle-to-everything technologies, further establishing EVs as reliable sources of flexibility in energy systems [108].

As mobile energy storage units, EVs have been investigated for their ability to conduct efficient energy management among various end-users [109-111]. Tian and Talebizadehsardari, for instance, studied the charging behaviour of EVs to enhance the system resilience of combined commercial and residential buildings. They found that EVs with higher initial energy levels could provide critical support during grid blackouts and contribute to cost reductions [112]. Similarly, Bai et al. examined flexibility sources such as renewables, stationary batteries, EVs, and home appliances in response to DR events. Their study optimised EVs' travel parameters and charging/discharging behaviour, achieving operating cost reductions of 4% to 24% and peak power reductions of 15% to 96% [113]. The concept of vehicle-to-grid (V2G) has moved from theoretical studies to practical applications, with EVs increasingly being used as a backup power source during power outages [114]. With bidirectional charging, EVs can supply stored energy to support building demands during outages. For instance, when vehicles are connected, Einolander et al. proved that bidirectional EV charging could prevent over 95% of grid outages [115, 116]. An investigation of shared EV parking stations was proposed by Sridharan et al. to improve system resilience and reduce cost without requiring extra infrastructure [117]. Zhou et al. examined an interactive network of energy-sharing linking buildings and EVs, incorporating EV fleets into the system. These fleets increase flexibility by enabling energy transfer between the grid and renewable sources across various times [118]. To address PV generation fluctuations, Thomas et al. developed a mixed-integer linear programming model for collaborative energy management, highlighting EVs' role in bidirectional energy trading, particularly in office buildings with variable EV usage [119]. Employing vehicle-to-building (V2B), Ouammi proposed a predictive control strategy, further advancing the integration of EVs into energy systems. This strategy aimed to reduce peak loads by leveraging the operational flexibility of EVs. Simulations revealed that the framework effectively reduced peak loads through contributions, in which 75% from PV generation, 18% from EVs, and 7% from stationary energy storage systems [120].

Review on Ocean RE Supported Building

To overcome the limitations of conventional renewables, researchers have begun exploring alternative energy sources such as ocean energy. Ocean energy has shown vast potential due to its predictability, low variability, and minimal environmental impact [12]. Ocean energy technologies include mechanical systems like WECs and tidal stream generators that capture energy from currents, tides, and waves. They also encompass ocean-integrated systems such as floating photovoltaic (FPV) panels and offshore wind turbines, which save land space and offer high energy production potential. A novel modelling approach assessing how tidal and wave energy could be incorporated into Great Britain's 2030 power grid indicates that even adding as little as 1 GW of tidal stream or wave energy (less than 0.5% of total capacity) can cut dispatch costs by up to 1.1%, lower carbon emissions by up to 3.3%, and reduce fossil fuel dispatch by up to 3.2% [121]. Ocean energy converters, including WECs [122, 123], tidal stream generators [124], offshore WTs [122], and FPV panels [125], can collaborate with other RE resources to enhance supply-demand balance. For example, Peddakapu et al. developed a maritime microgrid integrating PV, WT, WEC, and storage systems, demonstrating the ability to reduce carbon emissions and ensure

a reliable energy generation [126]. Luo and Cao used the characteristic reservoir of OWEC to store incoming waves, releasing stored water to regulate electricity generation. This approach increased energy matching from around 60% to 70% and decreased costs to 83% of the initial value. [127, 128]. Zhou and Cao examined the economic advantages through DR programmes participation using a hybrid tidal stream generator and FPV system, where control via stationary batteries provided significant economic gains [129].

1.3 Scientific Gaps

The literature review identifies significant gaps in scientific research regarding RE integration in buildings, with a particular focus on ZEBs and flexible energy systems.

Firstly, there is a lack of studies focusing on the coastal ZEB thermal and electric system supported by ocean RE resources. Many studies have focused on specific regions or areas, often neglecting the broader scalability and adaptability of their proposed solutions. While certain research groups emphasise passive architectural designs, such as improving building envelopes for enhanced thermal insulation, these measures alone are insufficient to achieve low-energy or ZEBs. RE systems, which are critical for upgrading building performance, have yet to be fully integrated into such designs [130-132]. In dense urban environments like Hong Kong, the relative shortage of inland space poses significant challenges for implementing RE systems. Many existing studies do not address these spatial limitations, particularly concerning the installation of PV panels, WTs, or other space-intensive RE facilities. This limitation is especially critical for high-rise commercial buildings, where designing ZEBs remains a significant challenge due to the lack of viable space for such systems [133]. Hotels, as a type of commercial building, face unique challenges in energy management. While energy efficiency is essential, limiting power use in guest rooms is not advisable, as it could negatively impact customer experience and satisfaction [134]. As a result, designing ZEBs for hotels requires solutions that balance energy-saving measures with maintaining high standards of service. Although sea-sourced heat pumps and chillers are effective in reducing energy demand, relying solely on these solutions is not enough to attain a zero-energy target. These technologies, while beneficial, need to be complemented by other RE systems to meet the energy demands of coastal buildings.

Secondly, recent studies have not focused on WEC's application to the ZEBs and the hybrid ocean RE integration. The potential of ocean RE sources (wave, wind and tidal energy) remains underexplored and has yet to be fully incorporated into the design of coastal buildings. The ocean systems currently under discussion often concentrate on singular energy conversion technologies. Although advancements are being made, challenges remain due to variable resource availability, such as low wave heights for WECs [135, 136]. These factors not only hinder the overall performance of energy systems but also diminish economic benefits. Exploiting these technologies and leveraging them for on-site power production could offer a viable solution for achieving ZEBs in coastal cities, particularly for high-rise commercial buildings and hotels. However, further research is needed to assess the feasibility, efficiency, and scalability of these technologies for practical applications [137].

Thirdly, current research has primarily focused on single-sided flexibility control within (RE) systems, such as demand-side, storage-side, or generation-side strategies. However, a notable gap exists in efficient and sustainable strategies for multi-side flexibility control using RE generators. The lack of an appropriate indicator that

comprehensively assesses both technical and economic aspects through flexibility control represents a significant gap in the existing literature. While recent studies have explored various dimensions of flexibility control, including energy shifting, generation efficiency, and cost savings, there is a need for a more holistic approach that considers multiple qualifications simultaneously. Control strategies can be implemented through either thermal or electrical measures. However, in systems with limited thermal demand, leveraging electrical flexibility proves to be a more effective approach. [138]. The predominance of fossil fuels in global energy systems is attributed to their high levels of flexibility, running at nearly constant power. Although generation-side flexibility control mechanisms like curtailment, combined-cycle gas turbines, and CHP have been extensively studied, there is a notable neglect of flexibility control strategies for renewable generators [55]. The curtailment of RE, while seen as a potential source of flexibility, is not always economically or environmentally favourable. Wave energy technology shows promise for achieving zero-carbon cities in certain regions, but the unpredictable nature of wave conditions necessitates enhanced energy flexibility in building energy systems for effective management [139, 140]. Despite a number of studies investigating the viability of ocean RE technologies, the potential for flexibility in characteristic OWEC reservoirs remains relatively underexplored. Current research on OWEC primarily centres around maximising power output through the optimisation of geometric configurations, power take-off systems, and structural integrity. Integrating electric storage units enhances energy flexibility, although the high cost of electricity storage, primarily through batteries, poses challenges. Batteries experience ageing due to factors like cycle number, temperature, and user behaviour, necessitating replacement when capacity diminishes. While using batteries for flexibility control can reduce peak demands, it often results in increased capital and maintenance expenses. Excessive battery usage can further escalate costs, highlighting the importance of monitoring battery health to enhance reliability and decrease maintenance costs. Given the escalating costs associated with battery technologies, achieving an optimised trade-off between energy flexibility and economic viability necessitates comprehensive analysis and dialogue. From an economic perspective, flywheel energy storage systems emerge as a potentially superior alternative; however, their current deployment is largely constrained to megawatt-scale commercial installations focused on frequency regulation. While integrating pumped hydro storage with RE sources shows substantial potential, the lack of commercially available turbines designed for micro-RE systems utilising pumped storage represents a significant barrier to broader implementation in these applications.

Fourthly, research is scarce exploring the intersection of DR programmes and power outage resilience. The integration of several sources of flexibility, including mobile/stationary electrical/mechanical energy storage, remains relatively underexplored in current research. While DR participation offers valuable flexibility to the grid, challenges arise in altering residents' habits regarding daily appliance usage and integrating real-time occupant data into building control systems [141]. Adjusting indoor temperatures in ZEBs can help reduce grid energy consumption, but this approach's effectiveness depends on solar panel energy production, leading to variable energy savings [142]. One case can achieve a fast DR by regulating the load of the chillers, while the sacrifice in thermal comfort is not appreciated in most commercial service buildings. The technical/economic performance was heavily dependent on the energy consumption patterns of the occupants. Building systems may offer flexibility services, but differences in flexibility sources can limit resilience during unforeseen events like power outages. To address these challenges, an energy management system leveraging multiple flexibility sources is needed to respond effectively to both DR events and power outages.

Fifthly, the integration of various flexibility resources, such as mobile/stationary electrical/mechanical energy storage, is still relatively underexplored. Most current research primarily focuses on individual or combined electrical and thermal energy storage. While EV is recognised as mobile energy storage units capable of supporting demand through V2B and V2G interactions, their role in DR programmes has received less attention. Single EVs often lack sufficient capacity to make a significant impact on DR initiatives, and effective aggregator models generally rely on large fleets, which can increase costs and pose practical challenges for smaller operators. Although EVs can serve as mobile energy storage solutions, the necessary infrastructure for widespread integration is still lacking. Existing studies have primarily focused on electrical and thermal energy storage systems, neglecting the potential of mobile energy storage from EVs. Limited consideration has been given to the V2B and V2G (Vehicle-to-Grid) functions of EVs for DR support, especially in smaller fleet operations. While larger capacity EV aggregators are advantageous for ZEBs, the practicality of implementing these applications remains limited.

Sixthly, limited studies have explored utilising the flexibility of ocean energy systems to enhance DR flexibility and outage resilience. Previous studies examining the integration of ocean energy with building or community energy systems have predominantly centred on the analysis of annual energy matching efficacy, often neglecting the instantaneous supply-demand relationship. While hybrid renewable systems' resource proportions have been discussed for improved techno-economic performance, buildings have yet to prioritise flexibility services and resilience enhancement. The reliance on batteries as the main source of flexibility control in many studies, including those involving ZEBs with hybrid ocean energy systems, poses economic challenges due to high investment costs. The lack of investigation into generation-side flexibility in systems equipped with ocean-renewable facilities represents a notable gap, as this form of flexibility enables dynamic RE output adjustments, reduces grid imbalances, and supports DR programmes effectively. A study has demonstrated the efficiency of utilising characteristic reservoirs of OWEC for energy management [127]. However, existing research has primarily relied on electric batteries for flexibility control, overlooking the full potential of WEC reservoirs for enhancing energy flexibility. Control strategies for actively managing WEC reservoirs to improve flexibility and resilience have not been thoroughly explored. While batteries are actively managed to reduce peak loads and shift energy usage based on grid information, the lack of active control in maximising energy flexibility from WEC reservoirs indicates a need for enhanced control techniques. Building upon OWEC studies, researchers have yet to focus on active flexibility control directly on the OWEC itself, highlighting a gap in understanding and optimising the flexibility and resilience of wave energy generators.

1.4 Objectives

Having identified the key gaps, the research set a series of multi-objective studies outlining the actions to address those gaps, as illustrated in Figure 1-1.

(I) Based on several scientific gaps, this study aims to explore the potential for the utilisation of ocean RE to serve the coastal hotel buildings to reach the target of ZEB. The research first focuses on leveraging seawater to enhance the efficiency of a hybrid sea-sourced heat pump and chiller system, reducing energy demand. By integrating ocean renewable resources into the hotel building, the study evaluates different combinations of wave-

wind energy through on-site electrical energy matching (OEMe) and on-site electrical energy fraction (OEFe) analysis. Additionally, the impact of incorporating additional batteries on energy matching and carbon emissions is examined, alongside assessing the economic viability of the hybrid wave-wind energy system using relative net present value (NPV_{rel}) and relative simple payback period (SPP_{rel}) indicators.

(II) The hybrid RE system was employed after investigating the research about its techno-economic feasibility. This approach was tailored to an electricity billing structure that accounts for both the monthly maximum power demand and the overall energy consumption during the on-peak period (OP) and off-peak period (OFP). The study investigates enhancing energy flexibility in a ZEB by utilising OWEC reservoirs and electric storage within a hybrid wave-wind energy system. The research focuses on implementing flexibility controls to optimise energy usage based on electricity pricing schemes, particularly peak shaving and valley filling strategies. By utilising the OWEC's inherent reservoir characteristics, the study aims to improve seawater discharging control for enhanced power generation. The performance of the flexibility control was assessed using two newly proposed indicators: the OP peak shaving indicator (PSI_{OP}) and the OFP valley filling indicator (VFI_{OFP}). Additionally, energy matching indicators, OEMe and OEFe, were employed in this study to assess the degree of energy matching. Operational costs and NPV_{rel} were used to estimate economic performance.

(III) This chapter focuses on optimising cost efficiencies within current electricity tariff structures by leveraging flexible resources in a hybrid wave-wind RE system. Drawing inspiration from pumped hydro storage, the system deploys the characteristic built-in reservoir, stepping away from traditional battery systems to mitigate wave energy curtailment. The research aims to enhance system flexibility through advanced adaptive control strategies by integrating self-contained reservoirs for wave energy alongside electric batteries. Key objectives include the assessment of energy shifting, peak shaving, energy matching, and overall cost savings, with an emphasis on the development and real-time implementation of adaptive control systems that respond dynamically to fluctuations in energy demand. This approach aims to reduce operational costs while maintaining sufficient energy capacity.

(IV) Built upon the studied system that could dynamically regulate the response to RE production and energy demand, the research tested the system's capability by participating in the existing DR programme. Additional EV and FPV systems were introduced to harness the potential of flexibility sources. This study focuses on enhancing system resilience against power outages for a ZEB hotel by optimising the regulation of EVs, building batteries, and wave energy storage. The research aims to test the system's capability to participate in DR programmes, maximise profits, and evaluate resilience to power outages through adaptive control strategies utilising different flexibility sources.

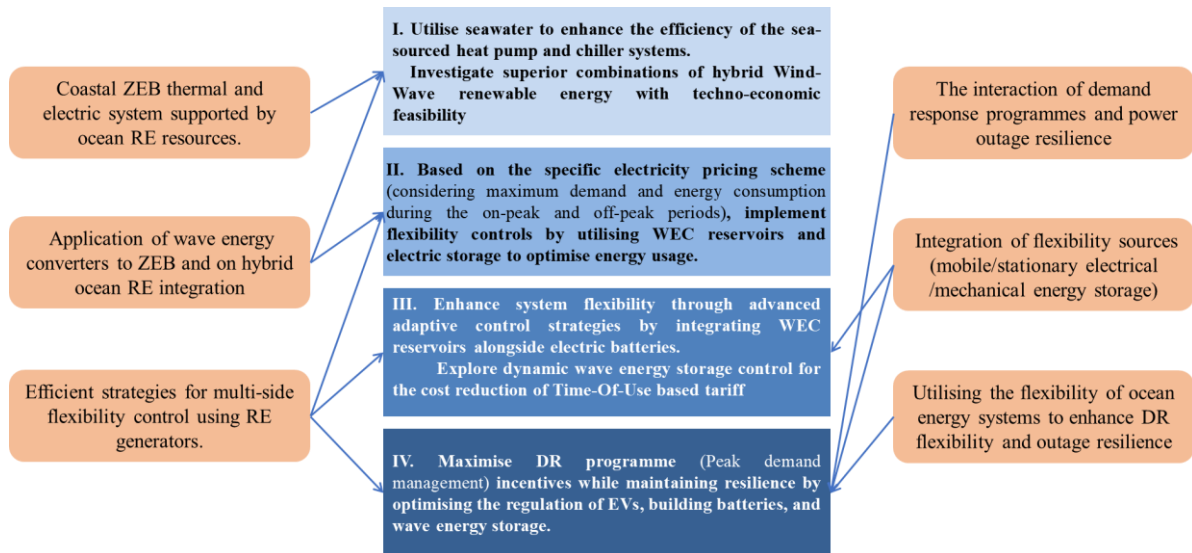


Figure 1-1. Correspondence of the objectives of each chapter against identified scientific gaps.

1.5 Thesis Organisation

The paper is structured into seven sections, each focusing on a specific aspect of the study. Below is an outline of the organisation. The paper begins with **Section 1 (Introduction)**. **Section 2 (Methodology)** introduces the overall research methodology employed in the study. **Section 3 (System Design and Modelling)** focuses on the design and modelling of the studied system and is further divided into three subsections: **3.1 (Weather, Coastal Building Demands, and Simulation Environment)**, **3.2 (Building Services and Ocean Energy System with Associated Flexibility Sources)**, and **3.3 (Utility Business Model)**. **Section 4 (Analysis Criteria)** defines the indicators that assess the control's performance, with two key subsections: **4.1 (Technical Indicators)** and **4.2 (Economic Indicators)**. **Section 5 (Results and Discussion)** presents the results of the study and discusses them in detail. It is divided into four distinct sub-studies. The final **Section 6 (Conclusions)** summarises the key findings of the study, highlighting major contributions, insights, and implications for coastal zero-energy building systems supported by hybrid ocean energy technologies.

2 Methodology

2.1 Research Flow

The study consisted of five interconnected and consecutive chapters. Its primary objective was to explore the use of ocean RE to achieve ZEB status in coastal hotels. The research investigated how to leverage seawater for efficiency in heat pump and chiller systems and assessed wave-wind energy combinations for on-site energy matching. The economic viability of these approaches was also evaluated. Focusing on the hybrid wind-wave RE system, the research examined energy flexibility in a ZEB using electric storage and OWEC reservoirs. It evaluated strategies such as peak shaving, valley filling, and associated economic performance indicators. The study further refined the control strategies of self-integrated WEC reservoirs to improve system flexibility and cost efficiency. Various controlled parameters for seawater discharge regulation were explored to enhance peak shaving and energy shift capabilities. Subsequently, the research introduced FPV and EV systems to broaden energy flexibility. By managing EVs, building batteries, and wave energy storage, the system aimed to maximise

benefits from DR events. When addressing potential outage issues, the study also emphasised maintaining system resilience against accidental grid disturbances.

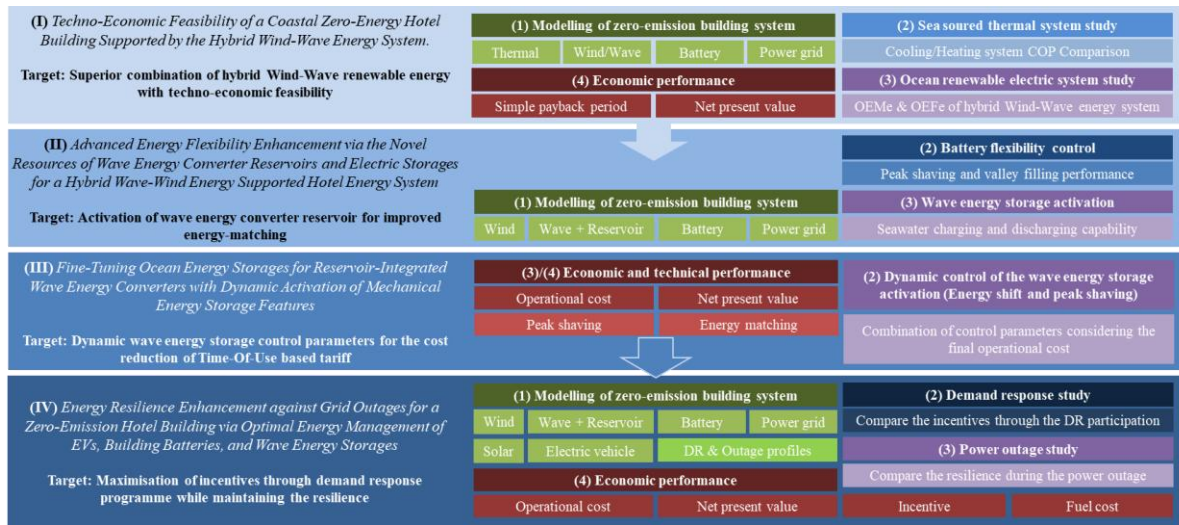


Figure 2-1. Methodology used for the study of the hybrid ocean ZEB system.

The first phase of the study involved modelling the ZEB within a simulation environment, as depicted in Figure 2-1. The hypothetical building was designed according to local building codes, with thermal and electrical systems adhering to established guidelines. The related devices, appliances, and EVs were based on commercially available products. The built RE system was created using both academic research and industry references. The study commenced with the initial building systems introduced in Chapter I, which included a RE system comprising offshore WT and OWEC. The system design and modelling details are described in Section 3. Chapters II and III focused on activating control strategies related to the WEC reservoir, while Chapter IV introduced FPV and EV systems. The study addressed grid events, including the DR programmes and power outages. The methodology's middle phases primarily involved simulation studies to achieve the stated objectives. Through a parametric study, the technical performance of various variables was compared. Chapter I mainly focused on the COP of the thermal system and the energy matching of the RE system. Chapter II examined the impact of flexibility control through electric storage and wave energy storage activation. Two indicators were evaluated in Chapter III: peak shaving and energy shifting through the fine-tuning of reservoir control. Chapter IV analysed the system's performance in reducing demand during DR events and evaluated its resilience against grid interruptions. The final phase of the study centred on economic assessment. Besides facility investment, technical performance was a key factor influencing economic outcomes, including cost savings, NPV_{rel} , and DR incentives. By balancing technical improvements with economic feasibility, the study addressed practical cases concerning (I) the superior combination of hybrid wave-wind RE with techno-economic feasibility, (II) activation of WEC reservoirs for enhanced energy matching, (III) dynamic control of wave energy storage parameters to reduce costs related to Time-of-Use tariffs, and (IV) maximisation of incentives through DR programme while maintaining resilience.

2.2 Data Sources and Input Parameters

The proposed simulation models were built based on data from several credible sources and commercial products. Building parameters, including thermal system setpoints, occupancy schedules, and specifications for lighting and ventilation, were defined in accordance with relevant local building guidelines and standards. Hourly weather data, including ambient temperature, humidity, solar radiation, and wind speed, were sourced from the Meteonorm dataset of the Hong Kong Observatory. For marine conditions, wave data recorded in the West Lamma Channel by the Civil Engineering and Development Department were employed to model wave energy converter output, while hourly seawater temperatures at 1 meter were obtained from measurements at Waglan Island. The performance characteristics of heating, cooling, RE facilities, energy storage systems, and electric vehicles were modelled based on specifications from existing commercial products or advanced prototypes. Economic inputs, including electricity tariffs, demand response programme incentives, feed-in tariff rates, and diesel fuel costs, were derived from local utility business models. Finally, financial parameters, including the interest rate, device capital investment costs, and corresponding operation and maintenance expenses, were based on prevailing local market conditions.

The obtained building demands through the simulation process determined the system's scale. Given the annual energy consumption, the RE generation level is designed to achieve a zero-energy balance. Concurrently, the storage system was sized to balance technical and economic benefits and achieve an appropriate offset. The working curves and the control thresholds/logics of facilities were utilised based on reference product specifications. The specific prototypes are introduced in Section 3.2. The detailed simulation platform is introduced in Section 3.1.3, which presents the particular component types.

3 System Design and Modelling

3.1 Weather, Building Energy Demand, and Simulation Component

3.1.1 Weather Sources

The study examines a hotel, as a representative commercial building, in the coastal section of Hong Kong, China. The selected site is characterised by a subtropical climate, with its geographical position placing it adjacent to Guangdong Province to the north and facing the South China Sea to the south. The meteorological data used in this study come from the Hong Kong Observatory and are sourced from the Meteonorm database. Detailed hourly data on dry-bulb and wet-bulb temperatures, wind speed, and solar radiation levels are provided for analysis and reference [143, 144]. The annual average dry bulb temperature was 22.9 °C, and the wet bulb temperature was 19.9 °C. Figure 3-1 shows each month's total horizontal radiation levels as illustrated in orange bars. The highest radiation intensity occurred mainly between May and October, exceeding 120 kWh/m². The highest value recorded was 168 kWh/m² in July, closely followed by 158 kWh/m² in August. In contrast, February experienced the lowest intensity, with an approximate horizontal radiation of 64 kWh/m², and March was the second least intense month, recording 78 kWh/m². Furthermore, the figure illustrates both the monthly average wind speeds and the maximum wind speeds recorded, shown in graduated and patterned green bars, respectively. Wind speeds varied seasonally, with the lowest average of 3.6 m/s recorded in July, while higher velocities of approximately 5.7 m/s were observed during February, March, and April. Maximum wind velocities varied from 11.8 m/s in July

to 15.3 m/s in February and April. Figure 3-2 illustrates the annual probability distributions of wind speed and direction. The predominant wind directions were east and southeast, with wind speeds varying between 2 and 8 m/s. Instances of northerly winds throughout the year were exceptionally infrequent.

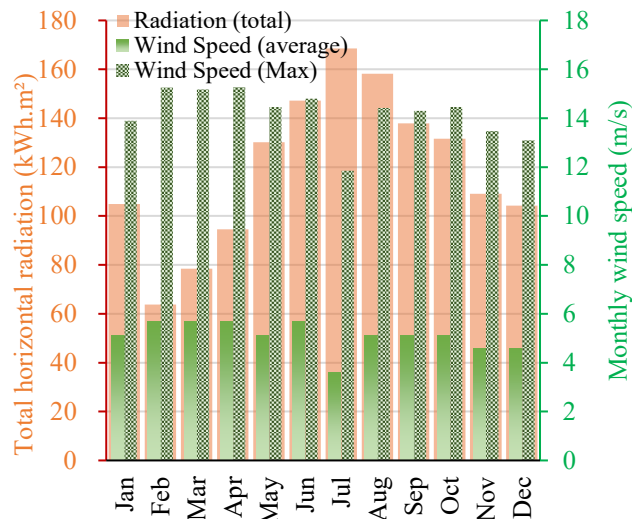


Figure 3-1. Monthly wind velocity and solar radiation [Publication IV].

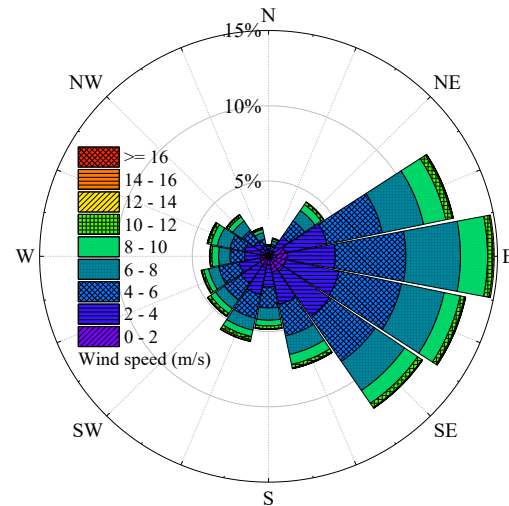


Figure 3-2. Annual wind rose diagram. [Publication I].

In addition to the Meteornorm data for Hong Kong, this investigation also utilised additional weather data sources. Sea surface temperature readings at a depth of one meter off Waglan Island were sourced from the Hong Kong Observatory, illustrated in Figure 3-3. The average seawater temperature ranged from 26.4 to 27.3 °C during the period of June to October, while it varied between 17.1 and 18.8 °C from January to March. The highest recorded temperature reached 29.5 °C in August, contrasting with the lowest temperature of 16.2 °C observed in December.

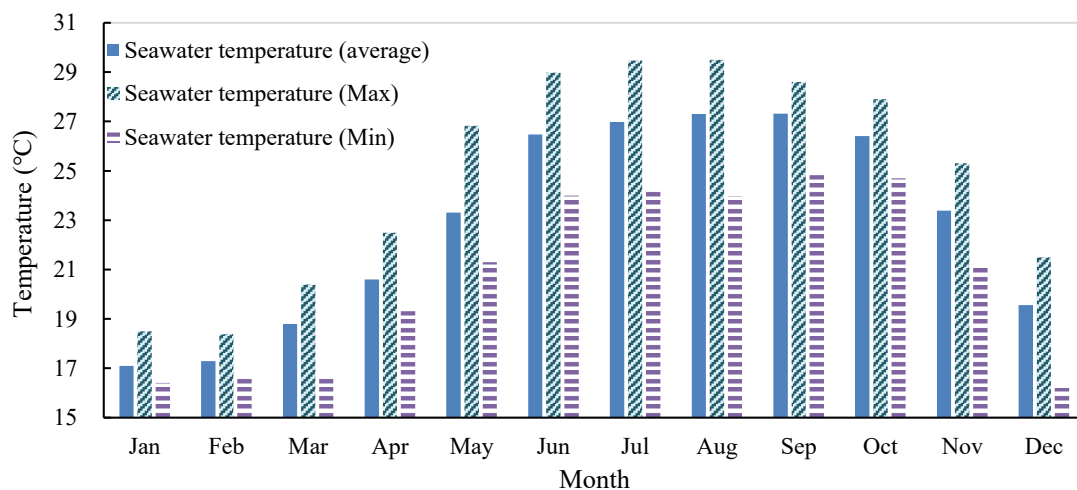


Figure 3-3. The monthly conditions of seawater temperature [Publication I].

In addition to the previously mentioned data sources, ocean wave characteristics were collected to aid in the WEC generation simulation. Figure 3-4 displays two essential parameters used to describe ocean wave conditions: peak period (T_p) and significant wave height (H_s). The H_s refers to the average height of the highest one-third of waves in a spectrum. The T_p is the time interval between successive wave crests/troughs of the highest waves, usually

measured in seconds. The figure presents monthly fluctuations of T_p , ranging from 4.9 s (February) to 8.8 s (November). The longest T_p , which indicates the maximum interval between wave crests within a month, varied between 8.3 s in June and 16.7 s in October. In terms of H_s , the value ranged from 0.25 m (March) to 0.46 m (August). The highest individual wave height recorded in a month, referred to as the maximum H_s , reached values between 0.48 m (February) and 0.94 m (July). Figure 3-5 presents a wave rose diagram that illustrates the annual distribution of wave directions along with their corresponding H_s , indicating that the prevailing waves primarily originated from the south and southeast directions. The annual wave climate, illustrated in Figure 3-6, is based on hourly wave data that includes H_s and T_p . The data shows that the most probable wave condition is represented by red colour in the graph (occurred at a H_s of approximately 0.3 m and a T_p of about 4 s). The isolines indicating wave power suggest that the wave climate at this location ranges from 0.1 to 0.9 kW/m.

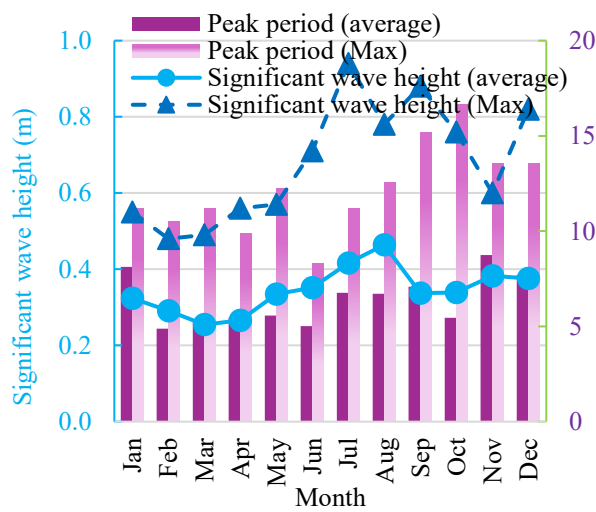


Figure 3-4. Monthly condition of the sea state [Publication I].

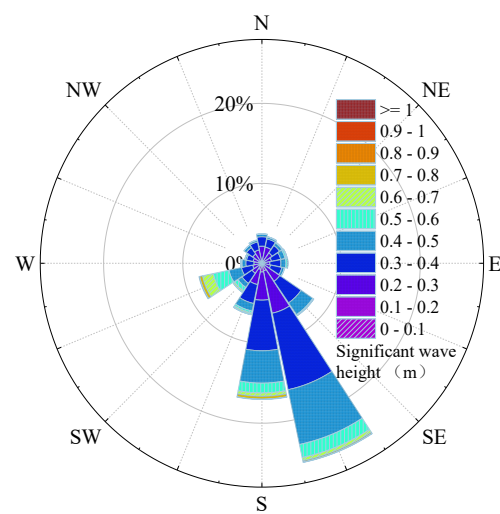


Figure 3-5. Annual wave rose diagram [Publication I].

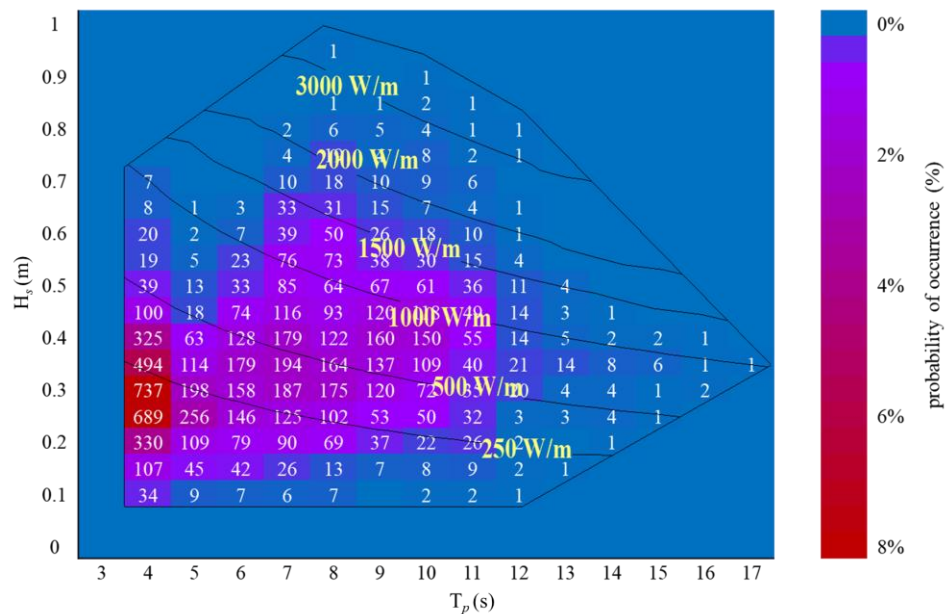


Figure 3-6. The annual hourly wave climate.

3.1.2 Coastal Building Demands

The hypothetical building has eight floors above ground, with each floor having a 480 m² floor area and a height of 3 m. The building design followed various guidelines, including the *Thermal Comfort: Analysis and Applications in Environmental Engineering* [145] and the *Performance-based Building Energy Code of Hong Kong* [146]. As shown in Table 3-1, on each floor, there were 19 occupants following the schedule, and the activity level of each occupant was 1.2 MET. The supply air temperature of the air handling unit (AHU) was directly proportional to the exhaust indoor air temperature. When the exhaust air temperature was 21 °C or lower, the supply air temperature was maintained at 21 °C. Conversely, when the exhaust air temperature was 24 °C or higher, the supply air temperature of 17 °C was triggered. The desired temperature for space cooling (SC) was 24 °C, and for space heating, it was 21 °C. The DHW was set to a temperature of 55 °C, with an estimated daily demand of 17.8 m³. The building's exterior envelope features U-values of 0.345 W/m²·K for the roof, 2.308 W/m²·K for external walls, and 2.78 W/m²·K for the window. The design of the exterior facade included a window-to-wall ratio of 0.32 to minimise solar heat gains. Internal gains from lighting and equipment followed established scheduling guidelines. Additionally, the building envelopes or roofs were not linked to external plants.

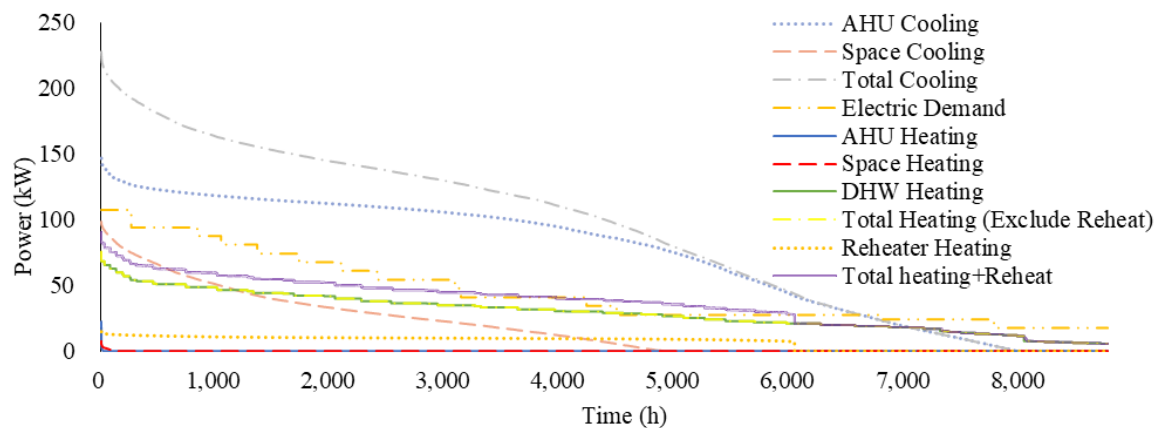


Figure 3-7. The annual duration curves of the hotel building's cooling, heating, and electric demands [Publication II].

Figure 3-7 shows the duration curves of the hotel building's cooling, heating, and electric demands. The total cooling demand comprises AHU cooling (AC) and SC demand. The heating demand includes AHU, space, and DHW heating, but does not include reheater heating. Electricity consumption beyond the thermal systems is based on lighting, ventilation fans, and equipment demands. Table 3-1 also presents the conditions of energy demand for building operations and EVs. The total cooling demand, with a combined peak load of 227.82 kW, amounted to 205.98 kWh/m²·a. This comprises AC (164.88 kWh/m²·a, 146.78 kW peak) and SC (41.10 kWh/m²·a, 98.49 kW peak). For heating, the DHW load constituted the dominant share (67.78 kWh/m²·a, 68.40 kW peak), while AHU heating (0.01 kWh/m²·a) and space heating (0.06 kWh/m²·a) were minimal. The total heating demand was 67.85 kWh/m²·a with a 75.70 kW peak. An additional reheater load (15.60 kWh/m²·a, 14.79 kW peak) is itemised separately, as it falls outside the AHU heating calculations. The electric demand consisted of appliances, ventilation fans, and lighting, and consumed 102.70 kWh/m²·a with a 100.94 kW peak, while the demand for EV charging accounted for 50.56 kWh/m². The introduction of EVs was applied in the studies of Chapter IV.

Table 3-1. Building model input parameters and annual energy demands [Publication IV].

Insulation (U-value, W/m².K)														
External roof				0.345				External wall				2.308		
Window glazing				2.78				Ground floor layer with soil layer				0.609		
Infiltration (h ⁻¹)														
According to <i>Performance-based Building Energy Code of Hong Kong</i> [147]: $\begin{cases} \text{If ventilation is on: infiltration} = 0 \text{ h}^{-1} \\ \text{If ventilation is off: infiltration} = 0.306 \text{ h}^{-1} \end{cases}$														
Occupants														
Number [147]				19 occupants/floor				Activity level MET [145]				1.2		
Schedule	0–6	6–7	7–8	8–9	9–11	11–13	13–15	15–16	16–17	17–18	18–19	19–21	21–22	22–24
Weekday	0.9	0.9	0.7	0.4	0.2	0.2	0.2	0.3	0.5	0.5	0.5	0.7	0.8	0.9
Saturday	0.9	0.7	0.5	0.5	0.3	0.3	0.3	0.3	0.3	0.5	0.6	0.6	0.7	0.7
Sunday	0.7	0.7	0.7	0.5	0.5	0.3	0.2	0.2	0.3	0.4	0.4	0.6	0.8	0.8
Electric Demand														
Unit								Annual Energy (kWh/m².a)				Peak Power (kW)		
Cooling				SC				41.10				98.49		
				AHU				164.88				146.78		
				Total				205.98				227.82		
Heating				DHW				67.78				68.40		
				Space				0.06				7.59		
				AHU				0.01				22.50		
				Total				67.85				75.70		
Reheater ^(a)								15.60				14.79		
Appliance ^(b)								102.70				100.94		
Electric vehicle ^(c) (Two shuttle buses, each with a 355-kWh battery)								50.56				59.26		

^(a) The reheater load is accounted for independently and is not included in the AHU heating load calculations.

^(b) The electric demand comprises appliance loads only, with HVAC systems and EV charging excluded.

^(c) The introduction of electric vehicles was applied in Chapter IV.

3.1.3 Simulation Environment

The research involved modelling and dynamic performance analysis of the designated building energy system through TRNSYS 18, an extensively validated simulation platform with four decades of continuous development. This modular software provides adaptive modelling capabilities through customisable component libraries, enabling detailed representation of energy systems [143]. The investigation implemented transient simulations incorporating HVAC infrastructure, mechanical services, thermal storage units, and RE integration.

For cooling applications, two chiller models (Type 666) coupled with stratified thermal storage (Type 534) delivered chilled fluid to air handling and space conditioning networks. During baseline operation, the cooling tower model (Type 126) provided heat rejection for water-cooled chillers. After introducing the ocean resources, an indirect seawater heat exchanger (HX) (Type 5) was employed to draw seawater, extracting sub-surface seawater (1m depth) for the condenser loop supplementation. The refrigeration plant maintained a 5 °C supply temperature for air treatment processes, with buffer storage ensuring 7 °C operational readiness through the controller (Type 2). Space conditioning networks implemented analogous control logic with elevated temperature thresholds – 13 °C supply water and 15 °C terminal delivery. Supplemental chillers are activated during peak demand intervals to maintain thermal stability. For heating applications, the system initially relied on an electric heater to meet the requirements for DHW and air handling requirements. System upgrades implemented a heat

pump with an indirect seawater HX utilising conditioning equipment component (Type 42) integrated with stratified thermal storage (Type 534). Within each tank, a controller (Type 2) was installed to monitor the water temperature. Temperature regulation was achieved based on signals from an on/off differential controller by detecting the temperature and adjusting the operational states of the components. DHW maintained 55 °C distribution temperatures, while air handling circuits operated at 40 °C thresholds. Auxiliary heating elements and blending valves ensured temperature maintenance during high-demand periods.

Energy flow analysis transformed thermal demand profiles into equivalent electrical consumption through component-level power modelling. The transient simulation framework enabled real-time evaluation of energy balance parameters, including storage capacity utilisation, RE generation matching, and demand-supply conditions. This approach facilitated a comprehensive assessment of system interactions across multiple energy domains and operational scenarios. The established components, like WT (Type 90), PV (Type 567), and battery (Type 47), were employed to build the energy system. In addition, the simulation incorporated unestablished models such as WEC, the electric grid, and EVs. Their behaviour and system interactions were defined using programmed equations within equation boxes. Furthermore, various predefined grid event profiles were input into the simulation through a data reader (Type 9). The TRNSYS software employed 15-minute simulation time steps to maintain tank stability and ensure the numerical convergence of the model.

3.2 Building Services, Renewable Energy System, and Associated Flexibility Sources

3.2.1 Basic components and control principle

Figure 3-8 illustrates the schematic of the zero-energy system supported by ocean energy. This hotel building had demands for cooling, heating, and electricity. Initially, cooling was provided by a cooling tower feeding a water-cooled chiller. The heating system, which served DHW, AHU, and space heating needs, relied on a direct electric heater. The electrical power for the hotel was sourced directly from the grid. Utilising its seaside location, the building employed water-cooled chillers; these chillers drew water after passing through an indirect seawater HX to facilitate the cooling process. The study demonstrated that the HX performed better than the air-cooled cooling tower in terms of thermal efficiency, primarily because of the relatively low seawater temperatures during the hot months. Additionally, the heating system was supplemented by a water-to-water heat pump, which was also connected to the indirect seawater HX, benefiting from the heat pump's higher efficiency compared to the direct heater. Several thermal storage tanks were installed to store thermal energy for both cooling and heating water.

The key improvement in the updated system was the inclusion of RE facilities. To harness ocean energy for electricity production, an additional source was needed to ensure consistent output, given the unpredictable nature of RE. The hybrid RE system incorporated offshore WT and OWEC to provide steady and dependable output. Additionally, to address fluctuations in energy production, a battery storage system was implemented to maintain an uninterrupted electricity supply and ensure consistent power delivery. In the analysis of Chapter IV, an additional floating PV system and two electric shuttle buses were integrated into the hybrid system. These newly introduced EVs were equipped with 355-kWh batteries. Primarily, the buses were used for daily transportation between the hotel and the airport. The updated hybrid RE system included three types of RE generators: floating PV, OWEC, and offshore WT. The annual energy generation met the building demand and EV charging needs.

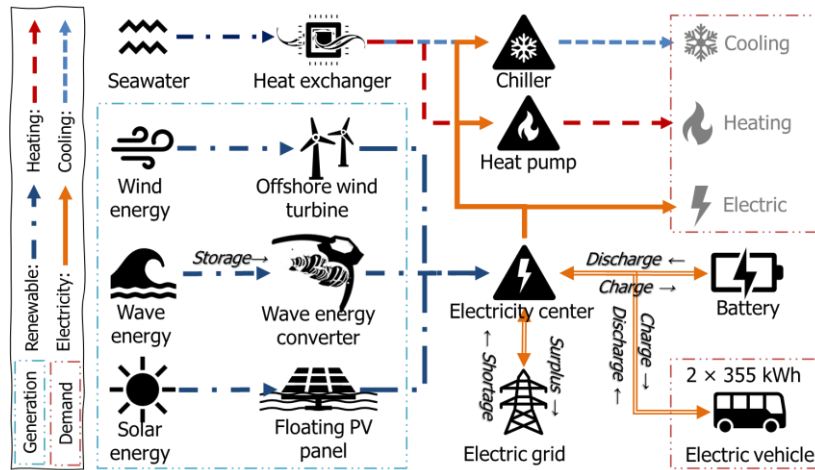


Figure 3-8. The brief schematic of the hybrid ocean energy-supported coastal building system.

RE was prioritised for powering the building and charging EVs. Any surplus energy was stored in a battery until it reached its maximum capacity. The feasibility of using an OWEC with a self-integrated reservoir for wave energy storage was investigated. Unlike options that required additional investments, the existing OWEC effectively stores hydropower generated from ocean waves, offering a financially viable solution to reduce energy fluctuations. The strategy for utilising this flexibility source is discussed further below. When RE was insufficient, the OWEC reservoir and the building's battery discharged to support the system. Additionally, after fulfilling transportation needs, EVs helped meet the building's energy demand. If multiple energy storage systems reached their lower discharge limits, the grid supplied the necessary power to compensate for the shortfall.

3.2.2 Thermal systems

The cooling tower, which relied on air for cooling, was replaced by a counter-flow HX. This new system used seawater as its cooling source, taking advantage of seawater's significantly higher specific heat capacity (approximately 4.2 kJ/kg·K) compared to air (approximately 1.0 kJ/kg·K). Seawater was drawn from 1.0 m below the seawater surface and served as the source side of the HX. This HX transferred cool temperatures to the cooling water on the load side, which was then delivered to the water-cooled chiller. The effectiveness of the HX varied, leading to different outlet temperatures for cooling water. This variation significantly impacted the chiller's coefficient of performance (COP_{ch}). The study in Chapter I outlined the relative effects of this factor in detail.

During cooling, water flows through the chiller, causing the condenser's heat transfer fluid to cool down. This fluid then absorbs heat from the incoming chilled water after it passes through the evaporator. A stratification method divided the water tank into five nodes, each with a different temperature. Fluid flow was controlled through separate ports, each having distinct inlet and outlet nodes. For AC, the chiller's outlet temperature was set at 5.00 °C. The chilled water was stored in a tank, with an end-user set point of 7.00 °C. The temperature at the 2nd node was monitored by a controller, which shut off the cooling equipment at 5.01 °C. Cooling resumed once the temperature exceeded 7.00 °C, ensuring adequate cooling for the lower nodes. Chilled water from Port 1 was sent to the 5th node of the storage tank and returned from the 1st node. Port 2 transported water from the 1st node to the 5th node for the end-user side, maintaining a set point of 7.00 °C. The SC system used a chiller outlet set

point of 13.00 °C and an end-user set point of 15.00 °C. The controller monitored the 2nd node, turning off the SC generation if it reached 13.01 °C and resuming when it rose to 15.00 °C. To address potential cooling shortages during peak usage periods, auxiliary chillers were available to provide additional cooling. COP_{ch} was employed to assess the effectiveness of these improvements.

The coefficient of performance of the heat pump (COP_{hp}) was used to assess the effectiveness of the water-to-water heat pump. This heat pump facilitated DHW production and heating for the AHU by raising the water to the desired temperature. Initially, a direct electric heater was employed in the reference system. The heat pump extracted heat from seawater via an indirect HX, which then flowed through the evaporator. This process heats the load-side water and delivers it to the 1st node of the hot water tank through port 3, while returning from the 5th node. A controller ensured that the temperature at the 2nd node remained between 52 °C and 55 °C, similar to a cooling system. The hot water output from the 1st node met the heating demands for both the AHU and domestic hot water. The DHW was then tempered or reheated to 55 °C while the AHU heating was maintained at 40 °C. The water used for the AHU heating system returned to the 4th node. The freshwater heated for DHW was supplied from the 5th node. A direct electric heater supports space heating due to the comparatively low energy usage.

3.2.3 Wave Energy System

The OWEC is an innovative technology that harnesses the energy from incident waves to generate potential energy above sea level. This stored potential energy is subsequently used to power low-head turbines for electricity production. A prominent floating OWEC design is the Wave Dragon system. It employs a central reservoir flanked by two winged reflectors with a front ramp that guides incoming waves over the crest and into the elevated reservoir, effectively capturing seawater with high potential energy. For this study, a 1:4.5 scale prototype of the Wave Dragon (rated at 20 kW) was selected. This prototype was deployed at Nisum Bredning, Denmark, a site characterised by a moderate wave power density of 300–600 W/m [148]. The power generation of WECs is influenced significantly by wave period and significant wave height, represented by variables T_p and H_s , respectively.

$$P_{overtopping} = R_c g \rho q = R_c g \rho \frac{\sqrt{g H_s^3 L}}{\sqrt{S_{op}/2\pi}} A e^{-B \frac{R_c}{H_s} \sqrt{S_{op}/2\pi}} \quad (1)$$

$$q = \frac{Q^* \sqrt{g H_s^3 L}}{\sqrt{S_{op}/2\pi}} = Q^* g H_s T_p \sqrt{L}$$

$$\sqrt{S_{op}/2\pi} = \sqrt{\frac{H_s}{L_{op}/2\pi}} = \sqrt{\frac{H_s}{\frac{g T_p^2}{2\pi}}} = \sqrt{\frac{H_s}{g T_p^2}} \quad (2)$$

$$Q^* = 0.025 \cdot e^{-40R^*} \quad (3)$$

$$P_{WEC} = P_{overtopping} \cdot \eta_{turb} \cdot \eta_{PMG} \cdot \eta_{fc} \cdot \eta_{disp} \quad (4)$$

The overtopping power, central to OWEC performance, is derived from the potential energy of the captured seawater as described by Equation (1). The seawater in this analysis, with a temperature of 25 °C and salinity of 35 g/kg, has a density (ρ) of 1023.6 kg/m³. The equation also includes the gravitational acceleration (g) and the crest freeboard height (R_c). [149]. The overtopping flow rate (q) in m³/s is determined by the ocean status and structure properties, as formulated by Equation (2). For the studied 20 kW prototype, empirical work by Hald and Frigaard established the parameters in this equation as $A = 0.025$ and $B = -40$, as shown in Equation (3) [150]. The power output of an OWEC is influenced by the power of the overtopping seawater, in conjunction with the efficiencies concerning the low-head turbine, permanent magnet generator, frequency converter, and dissipated power loss, which were determined to be $\eta_{turb} = 91\%$, $\eta_{PMG} = 94\%$, $\eta_{fc} = 98\%$, and $\eta_{disp} = 90\%$ respectively, as indicated in Equation (4).

Table 3-2. OWEC power matrix (power outputs based on the actual wave status are outlined) [Publication I].

Power matrix (kW)		Peak period, T_p (s)														
		3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Significant height, H_s (m)	1	1.9	3.8	6.2	8.8	11.6	14.5	17.5	20	20	20	20	20	20	20	20
		1.7	3.5	5.7	8.2	10.8	13.5	16.4	19.3	20	20	20	20	20	20	20
	0.9	1.5	3.2	5.3	7.6	10	12.6	15.3	18	20	20	20	20	20	20	20
		1.4	2.9	4.8	7	9.3	11.7	14.2	16.8	19.4	20	20	20	20	20	20
	0.8	1.2	2.6	4.4	6.4	8.5	10.8	13.1	15.5	18	20	20	20	20	20	20
		1.1	2.4	4	5.8	7.8	9.9	12	14.3	16.6	18.9	20	20	20	20	20
	0.7	0.9	2.1	3.5	5.2	7	9	11	13	15.2	17.3	19.5	20	20	20	20
		0.8	1.8	3.1	4.7	6.3	8.1	9.9	11.8	13.8	15.8	17.8	19.9	20	20	20
	0.6	0.7	1.6	2.8	4.1	5.6	7.2	8.9	10.6	12.4	14.3	16.1	18	19.9	20	20
		0.6	1.4	2.4	3.6	4.9	6.4	7.9	9.5	11.1	12.8	14.4	16.2	17.9	19.6	19.6
	0.5	0.5	1.1	2	3.1	4.3	5.6	6.9	8.3	9.8	11.3	12.8	14.3	15.9	17.5	17.5
		0.4	0.9	1.7	2.6	3.6	4.8	6	7.2	8.5	9.8	11.2	12.5	13.9	15.3	15.3
	0.4	0.3	0.7	1.4	2.1	3	4	5	6.1	7.2	8.4	9.6	10.8	12	13.3	13.3
		0.2	0.6	1.1	1.7	2.5	3.3	4.1	5.1	6	7	8	9.1	10.1	11.2	11.2
	0.3	0.1	0.4	0.8	1.3	1.9	2.6	3.3	4.1	4.9	5.7	6.5	7.4	8.3	9.2	9.2
		0.1	0.3	0.6	0.9	1.4	1.9	2.5	3.1	3.7	4.4	5.1	5.8	6.5	7.2	7.2
	0.2	0.1	0.2	0.4	0.6	0.9	1.3	1.7	2.2	2.7	3.2	3.7	4.3	4.8	5.4	5.4
		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0.1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

The annual data on ocean wave conditions includes T_p and H_s recorded hourly in the West Lamma Channel (114°4.76' E, 22°13.02' N), located in southern Hong Kong. This research utilised data from 2019 collected by the Civil Engineering and Development Department. Due to some missing data on certain days, gaps were filled using values from previous years. H_s ranged from approximately 0.10 to 1.00 m, while T_p typically fell between 4 and 11 s. A standard methodology for estimating on-site WEC power generation involves applying bivariate distributions of the characteristic wave parameters (T_p and H_s) to the device's operational power matrix. The resulting annual power matrix for the study site is presented in Table 3-2. In this table, power output levels are visually distinguished by a colour gradient, with purple indicating higher output and light blue indicating lower output. The ranges of T_p and H_s in the table are re defined by the underlying dataset. Cells outlined by the black lines indicate the operational power output corresponding to the recorded wave conditions.

3.2.4 Wind Energy System

Offshore wind turbines, a well-established technology, form part of the hybrid system. Given that commercially available offshore WTs predominantly comprise units rated above 300 kW, the project utilised a modified Type 90 model configured to represent a 300-kW benchmark. The configuration was based on the Bonus B31/300 turbine specifications: 31 m rotor diameter, 30 m hub height, 4.0 m/s cut-in speed, and a peak output of 304.5 kW at 14.0 m/s. All subsequent capacity scaling in the study referenced this standard unit to maintain comparability. The model was driven by Hong Kong's meteorological data, with wind speeds extrapolated from a 10 m measurement height using a 0.06 open-water shear exponent. The recorded data was collected at 10 m above sea level. The hourly variation from the dataset was utilised to simulate the behaviour of WTs. A WT catalogue file containing the power curve and key geometric parameters enabled the hourly performance simulation based on local wind and temperature variations.

3.2.5 Solar Energy System

Floating PV technology is emerging as a viable alternative to overcome land constraints, with additional potential benefits from water-induced panel cooling and reduced shading in open-water environments. The floating PV modelling was based on a previously published work investigating a floating PV system [125]. This study simulated floating PV performance using the TRNSYS Type 567 glazed solar collector component, a five-parameter model adapted from building-integrated photovoltaics. To capture the cooling effect of seawater, the model was modified to incorporate the panel's back-surface temperature. The panels were conceptually installed horizontally (0° slope) parallel to the water surface to eliminate performance variations from wind, waves, or shading. By making the necessary modifications, the Type 567 component was capable of accurately simulating the system's performance. The model was parameterised to represent a commercial FuturaSun FU-260P monocrystalline module. This panel has a rated power of 260 W and an efficiency of 15.92% at standard test conditions. Its physical dimensions are 1650 mm × 990 mm × 35 mm, and it utilises a 3.2 mm anti-reflective tempered glass cover.

3.2.6 Electric Vehicle Schedule

The study modelled electric shuttle buses based on the BYD K9, featuring a 355-kWh battery that supports 120 kW fast charging and consumes about 1 kWh/km. Two buses operated six daily round trips to the airport at 40 km/h, following staggered schedules illustrated in Figure 3-9. Bus A commenced service at 09:00, following a cycle of a 30-minute trip and a 15-minute break, concluding with a 45-minute rest upon return. Bus B followed an identical schedule with a one-hour delay, starting at 10:00. The bus charging strategy included mandatory overnight charging after each day's trips and intermittent security charging between trips, with charging facilities available exclusively at the targeted building.

The battery operated within defined limits, with an upper charging limit set at an FSOC of 0.95 and a lower discharging limit at an FSOC of 0.2. Overnight charging was conducted at a slow rate to reach an FSOC of 0.33, equivalent to the energy consumption of a single trip. Fast charging sessions aimed to boost the FSOC to 0.40 within 45 minutes, ensuring sufficient energy for the next trip. In scenarios where RE was abundant, surplus RE was utilised to charge the battery to its maximum capacity. Conversely, when RE was insufficient, the electric grid

supplemented the basic charging requirements. This comprehensive approach ensured efficient and reliable operations of the electric shuttle buses.

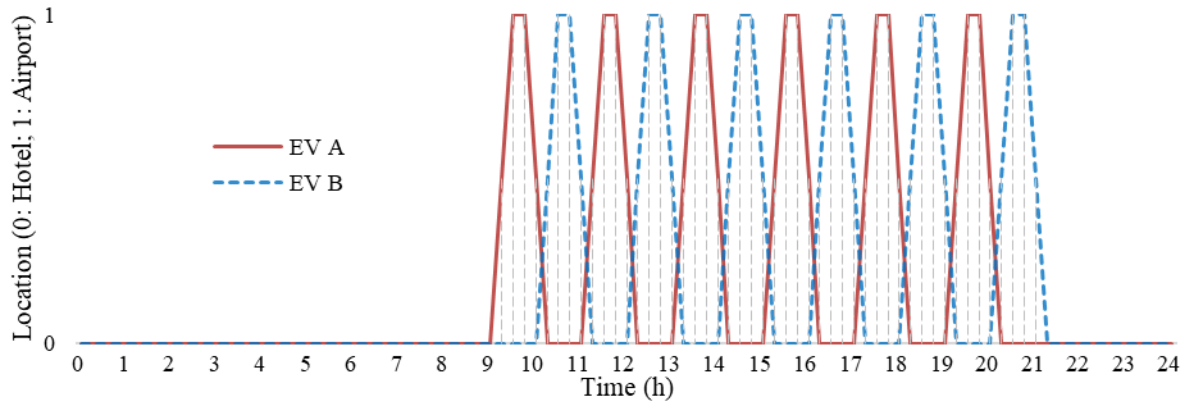


Figure 3-9. Daily transportation of the shuttle buses A and B [Publication IV].

3.3 Utility Business Model

3.3.1 Feed-in Tariff

FiTs are policy instruments aimed at encouraging the deployment of RE technologies by offering a guaranteed purchase price for the electrical energy generation. Typically, under a FiT arrangement, producers receive a rate that exceeds the current market price for electricity, creating a strong financial motivation for investing in RE projects. These schemes often involve contractual commitments spanning lengthy periods—usually between 15 and 20 years—providing project developers with stability and income certainty. Across many nations and regions, FiTs have been a central policy approach to accelerate the shift toward sustainable energy sources, reduce reliance on fossil fuels, and support the development of a low-carbon economy.

Hong Kong has actively pursued various initiatives to foster the adoption of RE and promote sustainable development. In the 2010s, Hong Kong implemented a Feed-in Tariff (FiT) programme to incentivise the growth of RE deployment. Under this scheme, rates determine payments to RE producers for each kilowatt-hour (kWh) they feed into the grid. Specifically, the FiT rates established by China Light & Power (CLP) Hong Kong Limited and Hong Kong Electric (Hong Kong's local utility providers) are linked to the capacity of the RE system. Since its implementation on April 27th, 2022, the scheme has offered the following rates: HK\$4 per kWh for systems up to 10 kW; HK\$3 per kWh for systems between 10 kW and 200 kW; and HK\$2.5 per kWh for capacities over 200 kW up to 1 MW [52, 151]. As the RE system considered in this research falls within the 200 kW to 1 MW range, the building has been compensated HK\$2.5 per kWh since April 27th, 2022. Before this date, the building received a rate of HK\$3.0 per kWh.

3.3.2 Electricity Tariff

Except for the study in Chapter I that employed an energy-based electricity tariff of HK\$1.22 per unit, other studies utilised the bulk tariff offered by CLP [152]. The tariff structure combined demand charges, energy rates, and fuel cost adjustments to accommodate high-consumption customers, and the pricing was tailored to both OP and OFP. This tariff was assessed through monthly meter readings and comprised several components. The electricity tariff structure outlined in Table 3-3 included a demand charge and an energy charge, varying rates

based on OP and OFP. During OP from 9:00 to 21:00 on regular days (excluding Sundays and public holidays), customers faced higher charges, starting at HK\$68.4 per kVA for the initial 650 kVA and decreasing to HK\$65.4 per kVA for any excess. The minimum billing demand during OP was set at 100 kVA. Conversely, in OFP, there was no charge for consumption up to the OP billing demand, but a rate of HK\$26.8 per kVA was applied to any excess. For the Energy Charge, during OP, the rate was HK\$0.782 per unit for the first 200,000 units and HK\$0.766 per unit for consumption exceeding this threshold. In contrast, the OFP saw a consistent rate of HK\$0.705 per unit. Moreover, a fuel cost adjustment was incorporated into the tariff structure based on projected fuel prices (from HK\$0.281 to HK\$0.620 was utilised in this manuscript). Monthly adjustments were made automatically to align with actual fuel expenses, and updates regarding these adjustments were available on the company's website. This time-based differentiation encouraged more efficient energy consumption practices and cost-effective electricity usage among consumers.

Table 3-3. The structure of the bulk tariff.

Component	Period	Rate (per unit/kVA)	Conditions
(a) Demand Charge	OP	HK\$68.4	≤ 650 kVA (Minimum billing demand: 100 kVA)
		HK\$65.4	> 650 kVA
	OFP	HK\$0	$\leq$ OP billing demand
		HK\$26.8	Section over OP billing demand
(b) Energy Charge	OP	HK\$0.782	First 200,000 units
		HK\$0.766	Section over 200,000 units
	OFP	HK\$0.705	
(c) Fuel Cost Adjustment		HK\$0.281~0.620	Based on projected fuel prices

3.3.3 Demand Response Programme

The annual profile of utility incentive events was designed based on the existing Peak Demand Management (PDM) programme operated by CLP [153]. This programme aims to enhance grid stability by incentivising customers to reduce electricity consumption during notified peak demand periods. Participants commit to a pre-agreed reduction target but incur no penalty for non-compliance. The incentive structure of the PDM programme is summarised in Table 3-4. Financial rewards are paid for each kWh of verified reduction, calculated as the difference between a participant's baseline consumption (the average of the three highest-demand days in the preceding ten non-event days) and actual usage during the event. Payouts are capped at 150% of the reduction target. The incentive rate is HK\$13/kWh for short-notice participation (4–24h notice) and HK\$8/kWh for standard notice (≥ 24 h). A fixed compensation of HK\$8/kWh is paid even for cancelled events. For a conservative estimate, this study applied the HK\$8/kWh rate throughout. Furthermore, building on established research [129, 154], three event frequencies were modelled: a high-frequency profile (1/2, one event every 2 days), a medium-frequency profile (1/4, one event every 4 days), and a low-frequency profile (1/6, one event every 6 days).

Table 3-4. The incentive structure of CLP Peak demand management programme.

Notification lead time	Condition	Incentive rate
≥ 24 hours	Executed	HK\$8/kWh
	Cancelled	HK\$8/kWh
< 24 hours & ≥ 4 hours	Executed	HK\$13/kWh
	Cancelled	HK\$8/kWh

3.3.4 Outage Issue

A power outage is defined as an unexpected disruption in electrical service. Such disruptions can originate from various causes, including severe weather (storms, lightning, heavy snowfall), equipment failure due to ageing or overload, scheduled or unplanned grid maintenance, and human error. For the analysis in Chapter IV, stochastic outage profiles with probabilities of 2%, 4%, 6%, 8%, and 10% were developed. Higher probabilities were built based on lower probabilities to establish relationships across different profile levels. The durations of outages varied widely, from as short as 15 minutes to several hours. Since unpredictable outages can happen at any time, there are different levels of uncertainty. The various outage levels and their features are summarised in Table 3-5. When an outage occurs, the grid cannot satisfy the system's electricity demand. In such situations, electricity needs are met by RE sources, backup diesel generators, and batteries. However, any excess RE generated during this time cannot be exported to the grid and must be wasted instead.

Table 3-5. Power outage occurrence levels [Publication IV].

Severity Level	Explanation
2% (Minimal)	Outages occur 2% of the time, representing the lowest risk.
4% (Modest)	Outages occur 4% of the time, representing a modest risk.
6% (Moderate)	Outages occur 6% of the time, representing a moderate risk.
8% (Significant)	Outages occur 8% of the time, representing a notable risk.
10% (Critical)	Outages occur 10% of the time, representing the highest risk.

4 Analysis Criteria

4.1 Technical Indicators

4.1.1 Coefficient of Performance

Since this ZEB addresses economic and technical outcomes, multiple indicators were used to examine the different systems in the study. From a thermal system perspective, the COP measures the system's efficiency in providing heating or cooling relative to the energy input required for its operation. In a heat pump or air conditioning system, COP is determined by the heating or cooling capacity ratio provided to the electrical power input needed. A higher COP signifies a more efficient system, meaning it generates more heating or cooling capacity for each unit of electricity consumed. In this study, the coefficient of performance of the system (COP_{sys}) calculation considered all related energy consumption, including the electric auxiliaries like the system's pumps. Meanwhile, the COP_{ch} or the COP_{hp} only accounts for the energy used by the chiller or heat pump.

4.1.2 Energy Matching

In a research article by Cao et al., two crucial indicators have been established to evaluate the balance of electricity inflow and outflow annually or monthly [155]. These indicators, known as OEMe and OEFe, are defined by Equations (5) and (6). OEMe represents the proportion of on-site electricity generation (G_{elec}) utilised within the electricity demand and battery storage instead of being exported (highlighted by the percentage of area III over the combined area of II and III as illustrated in Figure 4-1). Conversely, OEFe signifies the proportion of electricity load (L_{elec}) met by on-site electricity generation (depicted by the percentage of area III over the combined areas I and III).

$$\text{OEMe}_{(on/off)peak} = \frac{\int_{t_1}^{t_2} \text{Min} [G_{elec(on/off)}(t); L_{elec(on/off)}(t)] dt}{\int_{t_1}^{t_2} G_{elec(on/off)}(t) dt}, 0 \leq \text{OEMe} \leq 1 \quad (5)$$

$$\text{OEFe}_{(on/off)peak} = \frac{\int_{t_1}^{t_2} \text{Min} [G_{elec(on/off)}(t); L_{elec(on/off)}(t)] dt}{\int_{t_1}^{t_2} L_{elec(on/off)}(t) dt}, 0 \leq \text{OEFe} \leq 1 \quad (6)$$

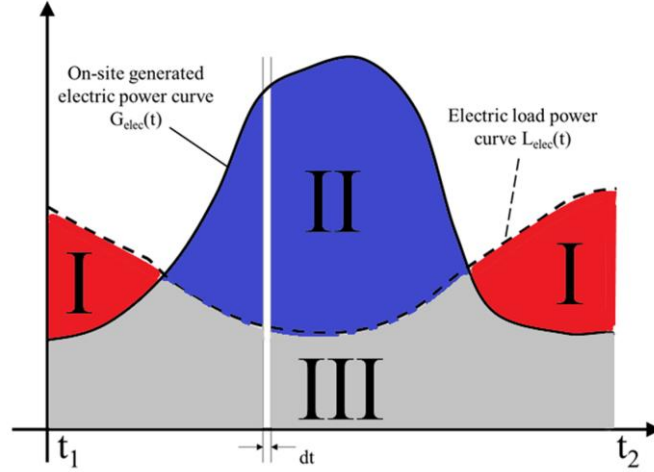


Figure 4-1. The illustration of energy matching indicators [155].

Due to the differential pricing in the bulk tariff, particularly the higher costs during OP, examining the implications of control related to OP and OFP is essential. This is especially important when considering the maximum monthly demand during OP. By leveraging the metrics OEMe and OEFe, this study segments these indicators based on OP and OFP durations. Consequently, four indicators—OEMe_{OP}, OEMe_{OFP}, OEFe_{OP}, and OEFe_{OFP}—are employed to evaluate the efficacy of flexibility control. The inclusion of OP/OFP in Equations (5) and (6) implies that these metrics can be applied to calculate performance during either OP or OFP.

4.1.3 Carbon Dioxide Emissions

Electrical energy exchange between the building and the grid occurred based on the alignment of its energy consumption and surplus generation, enabling the calculation of annual imported energy from the grid ($E_{imp.a}$) and the exported energy back to the grid ($E_{exp.a}$). It was assumed that RE sources contributed negligible amounts of carbon dioxide emissions, with their carbon emission factors (CEF_{eq}) considered effectively zero [156]. The carbon intensity of grid electricity was derived from Hong Kong's local utility data. CLP's five-year average (2018–2022) CO₂ emission intensity was 0.43 kg of CO₂ equivalent per kilowatt-hour (kg CO_{2,eq}/kWh_e). In comparison, the previous five-year period (2016–2020) reported an average of 0.486 kg CO_{2,eq}/kWh_e [157]. A backup diesel generator was employed to supply power during grid outages when the grid could not meet the building's energy demand. The electricity generated by this diesel source was accounted for within $E_{imp.a}$. The associated carbon emissions were calculated based on the performance parameters of a modern diesel generator. Operating at a near-optimal load of 65–70%, the generator achieves a fuel conversion efficiency of approximately 30%, yielding at least 3 kWh of electricity per litre of diesel consumed [158]. With the combustion of one litre of diesel producing approximately 2.68 kg of CO₂, the resulting CO₂ emission factor for diesel-generated electricity

is approximately 0.893 kg CO_{2,eq}/kWh_e [159]. For this study, the analysed period spans one year. The total annual CO₂ emissions (CE_a) were subsequently calculated by Equation (7).

$$CE_a = CEF_{eq} \cdot (E_{imp.a} - E_{exp.a}) \quad (7)$$

The CO₂ emissions calculation in this study is centred entirely on the electrical energy flow between the building and the grid, and diesel for backup generation. This study does not include the life-cycle embodied carbon of RE equipment, storage systems, or building materials, nor does it include On-site generation's operational emissions.

4.1.4 Energy Flexibility

This study introduced two key flexibility indicators: the OP peak shaving indicator and the OFP valley filling indicator. PSI_{OP} quantifies that the demand above a specific demand level can be shaved during OP. VFI_{OFP} measures the capacity to fill energy below a specific demand level during OFP.

The indicator PSI_{OP} focuses on the system's capacity to reduce demand spikes during OP, reflecting a nuanced approach compared to traditional flexibility metrics that primarily consider energy consumption and charges. Figure 4-3 displays the duration curves of both the reference and controlled cases (P_{Case}) during OP, highlighting Area I where the reference demand exceeds the average power of the reference case. The time when these curves intersect is defined as t_p. As per the specified business tariff, peak shaving yields profitable outcomes, with reduced demand corresponding to Area II. Any demand exceeding the average OP power (P_{average (OP)}) before t_p falls under Area III, which is subtracted from Area II per Equation (8). PSI_{OP} provides insights into the percentage of high demand that is mitigated through flexibility control. A value of zero or below suggests minimal impact or negative effects, while a value of 100% or greater indicates successful removal of all peaks exceeding the average power reference, by constraining the comparison between P_{Case} and P_{average (OP)} through MAX(P_{Case}, P_{average (OP)}). The PSI_{OP} value is capped at 100% to ensure that Area II does not surpass Area I. Notably, variations in the average line, representing different baselines aligned with various pricing structures, can yield more meaningful outcomes.

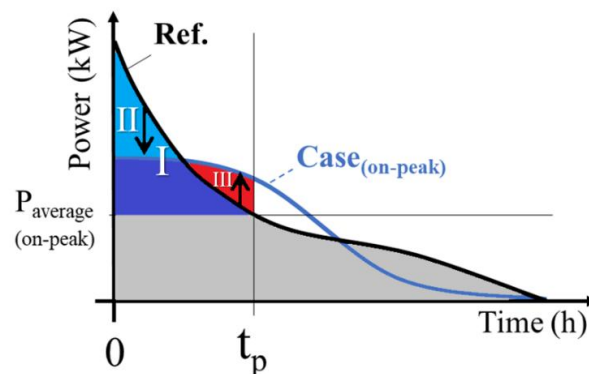


Figure 4-2. The illustration of OP PSI [Publication II].

$$PSI_{OP} = \frac{\int_0^{t_p} [P_{Ref} - \text{MAX}(P_{Case}, P_{average (on-peak)})] dt}{\int_0^{t_p} [P_{Ref} - P_{average (on-peak)}] dt} = \frac{\text{MIN}(\text{II}, \text{I}) - \text{III}}{\text{I}} \quad (8)$$

The VFI_{OFP} indicator evaluates the degree of power increase compared to a reference level within the valley below the reference average power during OFP for energy shifting purposes. In Figure 4-3, the time t_v marks where the reference duration curve intersects with the OFP average power line ($P_{average(OFP)}$). The area above the reference demand but below the average line after t_v is the target segment to be filled (Area I). During control strategies aimed at shifting energy consumption from high-cost periods to lower-cost ones, the OFP demand rises along with the duration curve of the new case. After t_v , the positive area above the reference curve but below the case curve is denoted as Area II. Conversely, suppose the demand in the new case is lower. In that case, the resulting Area III will not cover the targeted valley, indicating a negative effect as it relocates energy from a lower-priced period to a higher-priced one. The calculation for VFI_{OFP} is detailed in Equation (9), where a value of zero or below signifies ineffective control. In contrast, a higher VFI_{OFP} value indicates superior performance in filling the valley during OFP.

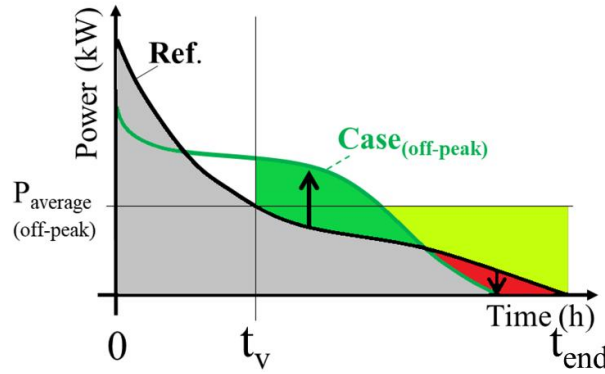


Figure 4-3. The illustration of OFP VFI [Publication II].

$$VFI_{OFP} = \frac{\int_{t_v}^{t_{end}} [P_{Case} - P_{Ref}] dt}{\int_{t_v}^{t_{end}} [P_{average(offpeak)} - P_{Ref}] dt} = \frac{II - III}{I} \quad (9)$$

4.1.5 Energy Resilience

Outage resilience assesses a system's capacity to endure and respond to unexpected power outages. Equation (10) demonstrates that by implementing specific controls and utilising diverse energy sources, the system improves its capacity to meet demand during an outage, thereby reducing its reliance on diesel backup generation. A resilience indicator of 100% signifies that the system can theoretically maintain operations during an outage without recourse to external fossil fuel-based energy. A higher resilience value corresponds to a more robust capability for sustaining demand fulfilment under outage conditions.

$$Outage\ resilience = \frac{\text{The satisfied demand during the outage}}{\text{The total demand during outage}} \quad (10)$$

4.2 Economic Indicators

Economic considerations are as vital as technical ones when assessing the practical viability of RE systems and associated control strategies. Economic evaluations involve factors such as capital expenditure (CAPEX),

operational expenditure (OPEX), equipment lifespan, and power generation metrics. In this study, the currency used was HK\$, with an exchange rate of approximately HK\$7.8 per US\$1.0, as provided by the International Monetary Fund [160]. CAPEX covers investments in renewable equipment, encompassing installation expenses and costs related to additional or replacement components like HXs, water pumps, heat pumps, and batteries, where applicable. OPEX includes operational and maintenance costs for renewable equipment, which typically constitute a portion of the CAPEX. Additionally, it involves expenses tied to battery replacements and imported electric energy, if relevant. The lifespan of equipment can vary based on the specific facility, ranging from 8 to over 20 years, influencing long-term financial planning and viability assessments. Revenue generated over the working period came from savings in electricity fees, FiT, and PDM incentives. The power generation output of the system is a critical factor in determining the annual benefits, which encompass savings and profits. These benefits are typically computed with respect to a reference group, a benchmark that varies based on the composition of the hybrid renewable system. Moreover, the investigations detailed in Chapter IV can potentially yield additional profits from PDM events, further enhancing the overall economic viability and advantages derived from the RE setup.

4.2.1 Payback Period

The SPP_{rel} serves as a crucial indicator in assessing the economic viability of an investment. This calculation involves comparing the CAPEX and OPEX to the revenue from the updated renewable systems without factoring in discounting. SPP_{rel} is used to assess the cost-effectiveness of an investment by calculating the time required for the cumulative benefits from the investment to match the CAPEX. Equation (11) outlines the formula for calculating the SPP_{rel} . As previously mentioned, CAPEX signifies incremental expenses compared to a reference scenario without renewable facilities. Benefits are calculated by deducting the OPEX from the savings obtained in the reference case or the profits derived from FiT. The SPP_{rel} offers an initial evaluation of investment feasibility. However, it is considered a basic and imprecise measure as it does not incorporate the time value of money, potentially leading to uncertainties in assessing the economic viability of the investment over time.

$$SPP_{rel} = \frac{\sum_n \Delta CAPEX_n}{\sum_n \Delta Revenue_n - \Delta OPEX_n} \quad (11)$$

n : the useful life of the project

4.2.2 Net Present Value

NPV_{rel} serves as a more robust assessment tool to evaluate the feasibility and viability of the researched RE systems, acting as a criterion for investment acceptance. NPV_{rel} calculates the disparity between the present value of costs and benefits over the service duration, factoring in an interest or discount rate to convert cash flows into a single current index. In this evaluation, benefits and CAPEX are gauged against respective reference cases in different chapters. NPV_{rel} , as determined by Equation (12), typically assumes zero benefits in the initial year. A positive NPV_{rel} suggests project viability, while a negative value indicates the opposite. For the studied system, NPV_{rel} is utilised over a 20-year operational period for the target building, facilitating feasibility assessments and enabling inter-case comparisons. Benefits encompass savings on electricity charges via flexibility control, FiT, and the battery's residual value at the 20th-year conclusion. Equation (12) is employed to compute NPV_{rel} , with j representing the operational period (typically commencing from 0) and i denoting the fixed interest rate.

$$NPV = \sum_{j=0}^n \frac{\text{Revenue}_j - \text{OPEX}_j}{(1+i)^j} - \text{CAPEX} \quad (12)$$

j : working period (from zero); i : interest rate (constant).

4.2.3 PDM Flexibility

The indicator of PDM flexibility is proposed to evaluate the control of the DR participation, defined in terms of the total reduced demand achieved during the PDM event, as expressed in Equation (16). Effective demand reduction is the difference between baseline consumption (the average of the three highest-demand days in the preceding ten non-event days) and actual usage during the event. These varying PDM frequency levels correspond to different incentives. The PDM flexibility indicator was proposed to evaluate the effectiveness of these controls on PDM incentives, expressed in Equation (13). The effects of these control strategies across different frequency levels can be compared by maintaining the same reference case. With a fixed denominator, more efficient strategies yield greater PDM demand reduction, leading to higher PDM flexibility and incentives.

$$\text{PDM flexibility} = \frac{\text{PDM demand reduction of studied case}}{\text{PDM demand reduction of reference case}} \quad (13)$$

4.2.4 Operational Cost

The relative operational cost evaluates cost-saving efficiencies across various scenarios, encompassing factors like electricity fees, PDM incentives, and diesel fuel costs. The bulk tariff is designed to incentivise increased electricity usage during OFP when costs are lower, as introduced in Section 3.3. PDM incentives denote the earnings from participating in PDM events, while fuel costs arise when resorting to diesel generators to meet demand during power outages. All scenarios are compared against a common reference case that achieved optimal PDM incentives without encountering power interruptions. The computation of the relative operational cost, outlined in Equation (14), juxtaposes total expenses (including incentives and costs) against the original electricity fee without flexibility controls. A value below 100% signifies an efficient control strategy, indicating cost savings. This indicator aids in assessing varying controls' impacts during specific events, facilitating clear comparisons among scenarios based on their operational costs.

$$\text{Relative operational cost} = \frac{\text{Operational cost of studied case}}{\text{Operational cost of reference case}} \quad (14)$$

(Operational cost = Electricity fee – PDM incentive + Fuel cost)

5 Results and Discussion

(I) Study on the Techno-Economic Feasibility of a Coastal Zero-Energy Hotel Building Supported by the Hybrid Wave-Wind Energy System

The research steps are visually depicted in Figure I-1, illustrating a structured flowchart of the study's progression. It began with a focus on the thermal system, analysing the cooling and heating systems separately. This analysis

involved a comparative evaluation of the COP_{ch} , COP_{hp} , and COP_{sys} using different cooling and heating sources to identify non-dominant outcomes.

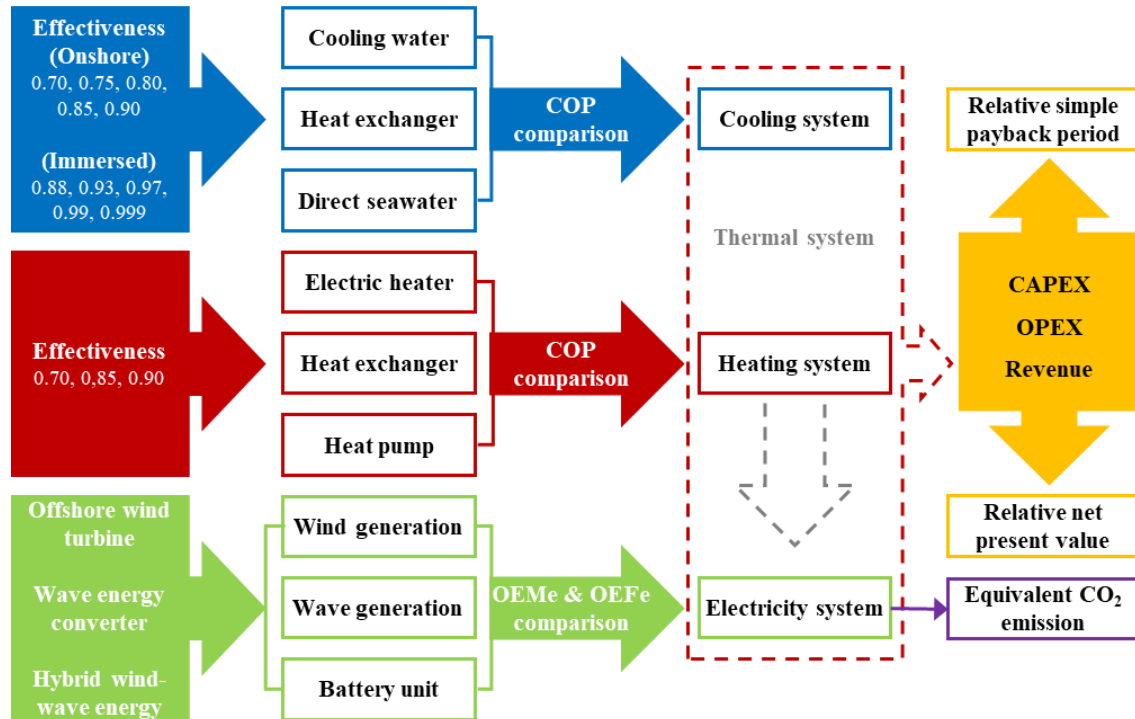


Figure I-1. The research steps of the study on the techno-economic feasibility of a coastal zero-energy hotel building supported by the hybrid wave-wind energy system [Publication I].

Subsequently, the study investigated varying wave-wind energy proportions on OEMe and OEFe. It also examined how increasing battery capacity within the renewable system affects its matching performance. By including data on electricity imports and exports, the research calculated the CE_d across various cases, enabling an evaluation of the environmental impact of each scenario. After conducting a technical comparison between traditional and sea-source systems, an economic analysis was performed. Two economic indicators— NPV_{rel} and SPP_{rel} —were used to assess the feasibility. The research progressed through these steps to comprehensively analyse the technical behaviour, environmental impact, and techno-economic aspects of the systems under investigation.

5.1 Technical Analysis of Seashore Thermal Energy System

This section aims to thoroughly examine how ocean thermal energy influences heating and cooling systems. A total of sixteen research scenarios were classified and detailed in Table I-1. These cases primarily focus on evaluating the performance of cooling and heating configurations separately. For the cooling system assessment, various scenarios were explored: the conventional approach using an air-cooled cooling tower, seawater-based systems that employed both onshore and submerged types of indirect seawater HX, and a direct seawater cooling method. Within the indirect seawater HX group, multiple cases with different effectiveness (ϵ) levels were analysed. The onshore variants exhibited ϵ values ranging from 0.70 to 0.90, whereas the submerged types showed higher efficiency, with ϵ values between 0.88 and 0.999. For the heating system evaluation, comparisons were made between an electric resistance heater and a seawater heat pump. Beyond the traditional electric heater setup, the study also examined configurations using water-to-water heat pumps equipped with corresponding indirect HX. These heat pumps were tested with three distinct effectiveness levels: 0.70, 0.85, and 0.90.

Table I-1. The effects of sea-sourced thermal system [Publication I].

Group	Cooling source	Effectiveness ε	Group	Heating source
Cooling tower	Air		Electric heater	Electricity
HX	Indirect seawater	Onshore: 0.70, 0.75, 0.80, 0.85, 0.90 Immersed: 0.88, 0.93, 0.97, 0.99, 0.999	Heat pump + HX	Indirect seawater (HX ε =0.70, 0.85, 0.90)
Direct seawater	Seawater	1.00		

(1) Cooling tower and sea-source HX

To compare the performance of sea-source HX with traditional air-cooled cooling towers, this study focused on cooling systems, specifically AC and SC, with different temperature requirements. The reference group utilised traditional cooling towers, while the study introduced HX with varying ε values of 70%, 75%, 80%, 85%, and 90%. The results, presented in the first half of Table I-2, showed that as the ε of the HX increased, the COP_{ch} for both AC and SC systems also improved. Notably, when the ε exceeded 85%, the sea-source HX exhibited a clear advantage in terms of chiller performance. However, it is essential to highlight that a higher ε does not necessarily increase the COP_{sys} , as the additional electricity consumption of water pumps due to the higher pressure head can offset the benefits. In the case of the AC system, the HX outperformed the cooling tower in terms of COP_{sys} . Conversely, for the SC system, the performance of the HX was similar to that of the cooling tower, but not superior unless the water pump consumed less power. Compared to the cooling tower case, the energy utilisation index (EUI) of the AC system decreased from 32.52 kWh/m² to 30.17 kWh/m² when employing a $\varepsilon = 0.70$ of onshore HX. For the SC system, the value increased from 7.46 kWh/m² to 7.51 kWh/m².

(2) Onshore HX, immersed HX in the sea, and direct seawater

The study examined the feasibility of immersing HX directly in seawater to achieve higher ε , as traditional HX designs with higher ε require more investment and space. Utilising the Number of Transfer Units (NTU) method, the research calculated new effectiveness values for the immersed HX, achieving ε levels of 88%, 93%, 97%, 99%, and 99.9%. These values were derived from the onshore HX's effectiveness of 70%, 75%, 80%, and 85%, as presented in the latter part of Table I-2.

As the ε value improved, the COP_{ch} improved, and the COP_{sys} for groups using the immersed-type HX exceeded that of the onshore-type groups. This improvement can be primarily credited to the enhanced efficiency of the immersed-type heat exchanger, which not only performs better but also contributes to lower energy usage by requiring fewer water pumps. Conversely, the direct seawater configuration, where seawater is directly circulated to the condenser of the water-cooled chiller, delivered the highest performance metrics, achieving an AC COP_{sys} of 5.89 and an SC COP_{sys} of 5.85. However, the maintenance costs related to the corrosive effects of seawater on the chiller components may make it less economical compared to the HX using indirect seawater as the cooling source. Within the immersed-type group, the scenario with an ε value of 88% achieved an AC COP_{sys} of 5.77 and an SC COP_{sys} of 5.82. Additionally, the energy use intensity (EUI) of the AC system was decreased to 28.57 kWh/m², while the SC system's EUI was reduced to 7.07 kWh/m². This resulted in a total EUI reduction from 39.98 kWh/m² (using a cooling tower) to 35.64 kWh/m² (using the immersed HX with $\varepsilon = 0.88$), demonstrating that the immersed-type HX is suitable for the cooling system of the seashore building analysed.

Table I-2. The comparison of COP_{ch} , COP_{sys} , and EUI between cooling tower and sea-source HX [Publication I].

Case	Onshore						Immersed					Direct seawater
Effectiveness (ϵ)	Cooling tower	70%	75%	80%	85%	90%	88%	93%	97%	99%	99.9%	
AC												
COP_{ch}	6.28	6.13	6.19	6.23	6.28	6.32	6.33	6.37	6.39	6.4	6.41	6.41
COP_{sys}	5.07	5.47	5.44	5.48	5.32	5.21	5.77	5.73	5.75	5.54	5.4	5.89
EUI (kWh/m ²)	32.52	30.17	30.29	30.08	31.00	31.64	28.57	28.79	28.69	29.74	30.52	28.02
SC												
COP_{ch}	7.54	7.39	7.44	7.49	7.53	7.57	7.59	7.62	7.65	7.66	7.66	7.66
COP_{sys}	5.51	5.47	5.5	5.43	5.45	5.32	5.82	5.84	5.74	5.74	5.58	5.85
EUI (kWh/m ²)	7.46	7.51	7.47	7.57	7.54	7.73	7.07	7.04	7.17	7.16	7.37	7.02
Total (AC + SC)												
EUI (kWh/m ²)	39.98	37.68	37.75	37.65	38.54	39.37	35.64	35.83	35.86	36.9	37.89	35.04
HX's ϵ (onshore and immersed type)												

(3) Electric heater and the sea-source heat pump

The study explored the transition from an electric heater to a seawater-source heat pump to enhance energy efficiency. Table I-3 compares the two systems, focusing on metrics such as COP_{sys} , COP_{hp} , and total EUI. The switch to the heat pump utilising the HX with ϵ values 0.70, 0.85, and 0.90, in which seawater was the heating source, achieved a COP_{hp} of 3.96~4.03 and COP_{sys} of 3.75~3.82. The transition to a heat pump using the HX with ϵ values 0.70, 0.85, and 0.90, where seawater served as the heating source, achieved a COP_{hp} of 3.96 to 4.03 and a COP_{sys} of 3.75 to 3.82. The update resulted in a notable reduction to 26% of the original electricity demand for the heating system. This significant decrease showcased the superior efficiency of the heat pump over the traditional electric heater, highlighting its potential for energy savings in heating applications.

Table I-3. The comparison of COP_{ch} , COP_{sys} and EUI between electric heater and heat pump with HX [Publication I].

Case	Electric heater	Heat pump + HX		
		$\epsilon = 70\%$	85%	90%
COP_{hp}		3.96	4.02	4.03
COP_{sys}		3.75	3.81	3.82
Total EUI (kWh/m ²)	85.51	22.45	22.15	22.06

5.2 Technical Analysis of Hybrid Wave-Wind RE System

(1) Energy generation of the wind-wave ratios

The hotel's total annual electricity consumption amounts to 6.18×10^5 kWh, translating to an EUI of 160.87 kWh/m². In the study, two distinct single renewable systems solely relying on 100% wind and 100% wave energy were evaluated, each producing 6.27×10^5 kWh annually, equivalent to 163.38 kWh/m². Figure I-2 illustrates the

monthly comparison between single wind/wave generation and the corresponding demand of the building. The wind energy side exhibited surplus energy production during the initial four months, followed by a notable energy deficit in July. In contrast, the wave energy side faced an energy shortfall from February to June but showcased an energy surplus in November and December.

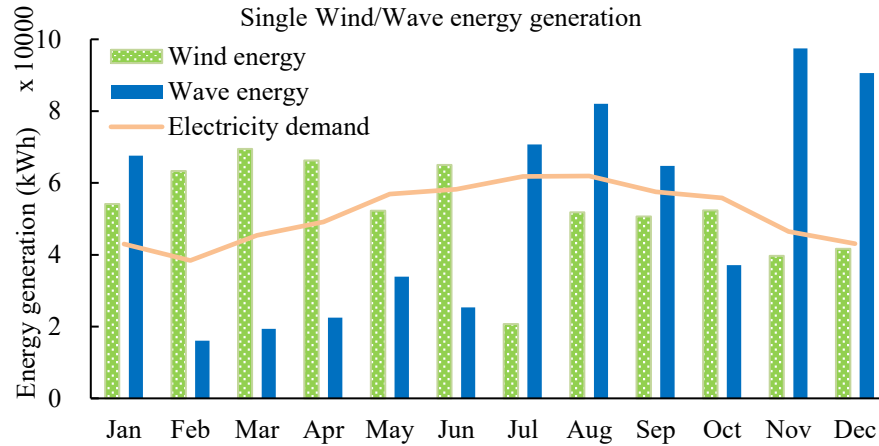


Figure I-2. Single wave/wind energy generation and demand of each month [Publication I].

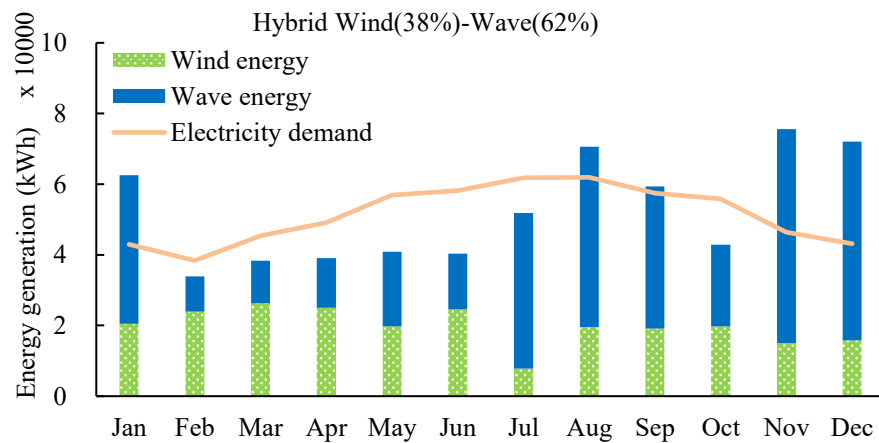


Figure I-3. Hybrid wave/wind energy generation and demand of each month [Publication I].

Figure I-4 compares offshore WT energy generation and electricity demand on a specific day in July. Wind energy production was poor on this particular day, resulting in an energy deficit. The electricity imported from the grid closely aligns with the energy demand, with limited surplus energy available. Figure I-5 depicts a day in February when the WEC performed poorly due to weak ocean wave conditions. As a result, the devices operated at lower power output levels. Only a small portion of the energy demand was fulfilled by wave energy, leading to a significant energy shortfall and minimal surplus energy availability.

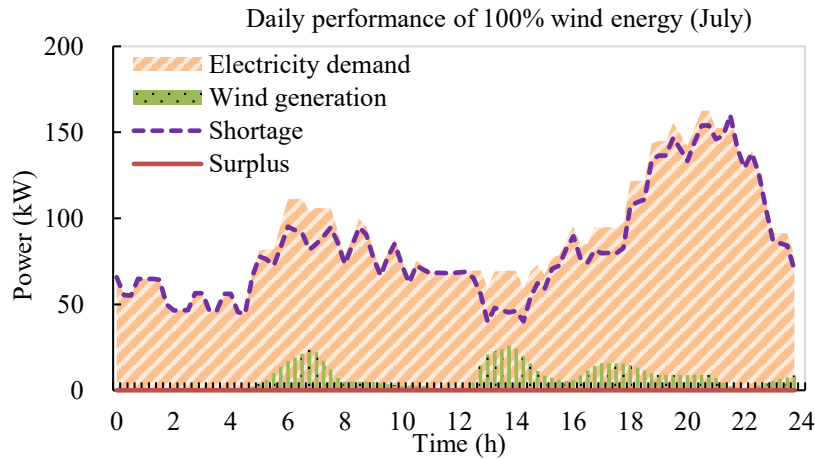


Figure I-4. 100% wind energy generation of one typical day in July [Publication I].

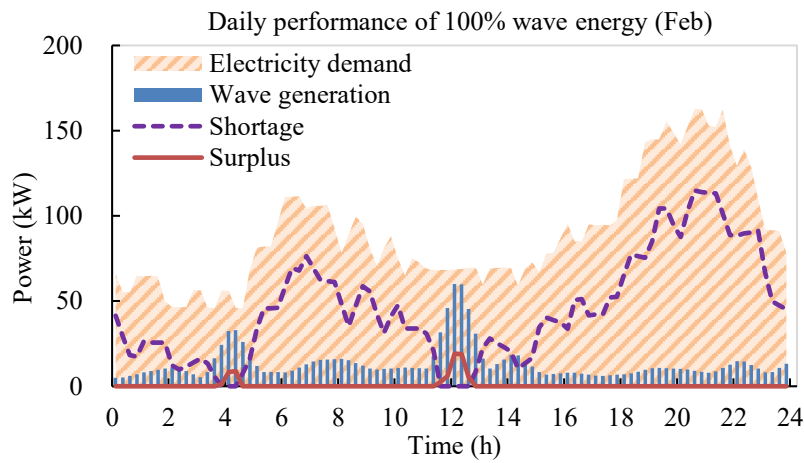


Figure I-5. Daily performance of 100% wave energy of one typical day in February [Publication I].

To address the energy demand-generation mismatch observed in the single renewable systems, nine hybrid renewable systems were explored, each designed to generate 6.27×10^5 kWh annually. These systems ranged from 100% wind energy support (case 1) to 100% wave energy support (case 9), incorporating varying proportions of WT and WEC capacities, as shown in Figure I-6. In these hybrids, to generate the same amount of energy in each case, the WEC supplemented the energy production of the reduced amounts of the WT. In Case 1, which represents a system powered entirely by wind energy with a WT capacity of 370 kW, the highest proportion of wind energy was employed. In contrast, Case 9, representing a system powered entirely by wave energy with a WEC capacity of 560 kW, utilised the highest proportion of wave energy. The performance metrics, OEMe and OEFe, for the two single renewable systems were compared. The 100% wind case (case 1) exhibited an OEMe of 0.52 and an OEFe of 0.47, while the 100% wave case (case 9) performed relatively better, with an OEMe of 0.59 and an OEFe of 0.55. Introducing hybrid renewable technologies demonstrated enhanced matching performance compared to single renewable systems. Notably, starting from case 3 (81% wind generation, 19% wave generation), the hybrid systems exhibited improved outcomes. Among the examined cases, case 6 (62% wave generation, 38% wind generation) stood out for its superior performance, boasting an OEMe of 0.69 and an OEFe of 0.65.

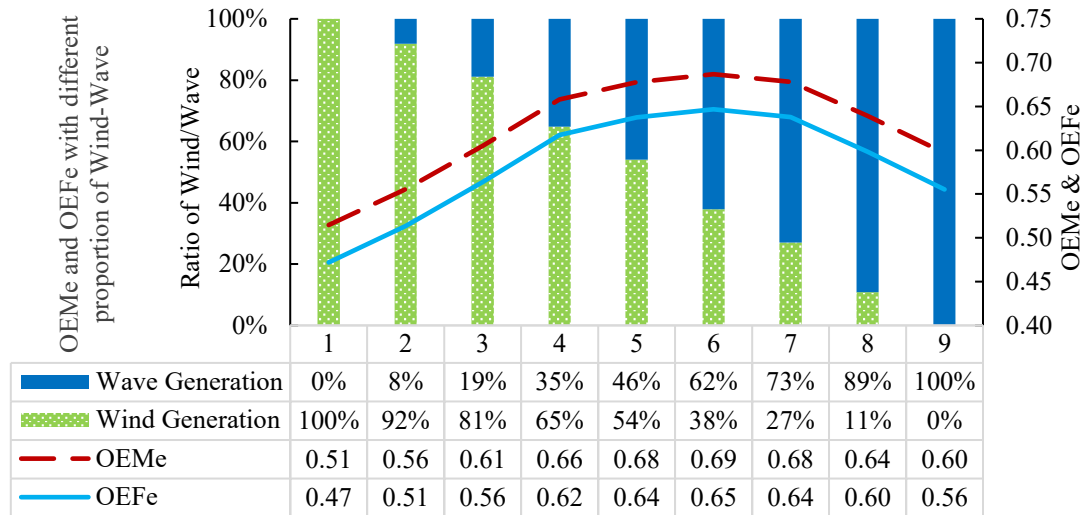


Figure I-6. OEMe and OEFc under different proportions of wind/wave with the same rated generation [Publication I].

Additionally, Figure I-3 demonstrates the monthly performance of Case 6. Its improved energy matching reduces the gap between energy generation and demand. In July, wave energy effectively compensated for the low wind energy production, as illustrated in Figure I-7. Similarly, in February, the offshore WT significantly addressed the energy shortage caused by weak wave energy production, as shown in Figure I-8. With the hybrid renewable system, any excess unused energy is exported to the electric grid, offering additional benefits and flexibility.

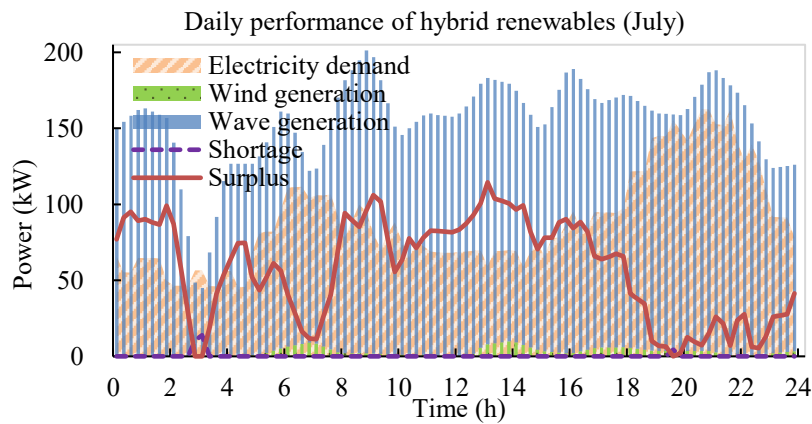


Figure I-7. Daily performance of hybrid renewables in July [Publication I].

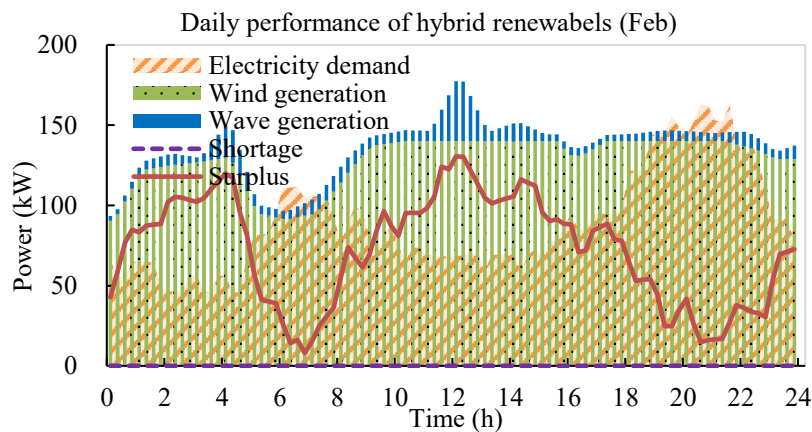


Figure I-8. Daily performance of hybrid renewables in February [Publication I].

(2) The solutions to enhance the matching capability of the hybrid wave-wind energy system

Following an assessment of various wave-wind ratios on matching performance, this study aimed to improve the matching capability of the hybrid wave-wind energy system by integrating electricity storage. The chosen commercial battery product for this study was the Tesla Inc. Powerpack, tailored to enhance the stability and consistency of renewable power output. Each Powerpack unit had a capacity of 232 kWh. The research incrementally introduced batteries to the system, ranging from 0 to 0.25, 0.5, 1, 1.5, 2, 3, 4, and 5 units. These additions were applied across both the nine cases of the rated generation group and the ten cases of the rated capacity group. The findings revealed a consistent impact and trend as the number of battery units increases, underscoring the efficacy of integrating storage solutions in enhancing system performance.

Figure I-9 provides insights into specific cases from single and hybrid wind/wave energy systems, encompassing case 1 featuring 100% wind energy, case 9 with 100% wave energy, and the superior case 6 with 62% wave generation and 38% wind generation. The figure illustrates that larger battery capacities contributed to enhanced matching performance, although the incremental improvement diminished with an increased number of battery units. In the 100% wind energy scenario (case 1), the OEMe steadily rose from 0.51 to 0.65 as the number of battery units was added from zero to five. Concurrently, the OEFe progressed from 0.47 to 0.59. In the 100% wave energy case (case 9), the OEMe advanced by 0.08, elevating from 0.60, while the OEFe increased by 0.06, moving from 0.56. The top-performing hybrid system, case 6, experiences an OEMe enhancement from 0.69 to 0.80, with the OEFe climbing from 0.65 to 0.75. Notably, after incorporating four battery units in case 6, the OEFe only marginally improved by 0.007 with the addition of the fifth unit. Nevertheless, the results underscored the continued benefit of expanding battery capacity. The study indicated that the overall advantages of scaling up the battery capacity warranted consideration due to the sustained enhancements in system performance.

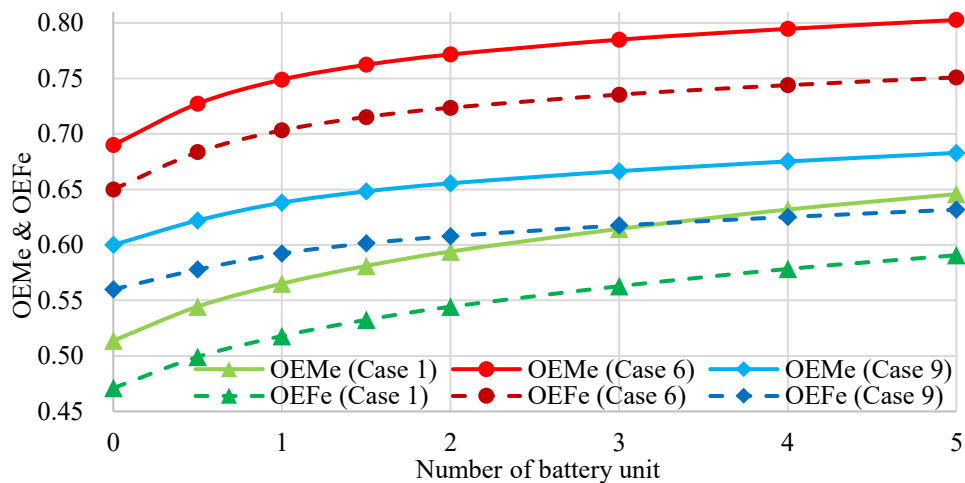


Figure I-9. Energy matching with different battery capacities for cases 1, 5, and 9.

(3) The impact of additional electric energy storage on the CO₂ emissions

Through studies on the impact of different proportions of wave-wind energy and the addition of batteries on matching performance, a series of annual equivalent CO₂ emissions was calculated. Figure I-10 presents CO₂ emissions (in kg CO_{2,eq}/m².a) across nine different cases, with varying battery configurations (from 0 to 5

batteries). The average CO₂ emission intensity of electricity used in these calculations is based on a value of 0.486 kg CO_{2,eq}/kWh, as provided by CLP Power Hong Kong for the period of 2016 to 2020. For the scenario with no battery, the CO₂ emission remains constant across all cases at 2.75 kg CO_{2,eq}/m².a. However, as the number of batteries increases, there is a noticeable rise in CO₂ emissions. With the addition of one battery, the CO₂ emissions range from 3.14 to 3.26 kg CO_{2,eq}/m².a, depending on the case. Similarly, for two batteries, emissions range between 3.31 and 3.48 kg CO_{2,eq}/m².a. As more batteries are added, the trend of increasing emissions continues, with three batteries showing values between 3.42 and 3.64 kg CO_{2,eq}/m².a, four batteries ranging from 3.52 to 3.77 kg CO_{2,eq}/m².a, and five batteries showing emissions between 3.61 and 3.88 kg CO_{2,eq}/m².a. The CE_a trends show a smooth increase with battery number, except for an inflexion observed when introducing the battery from zero. Among the cases with batteries, the improved energy matching came from more battery charging and discharging behaviours. Correspondingly, it incurred greater energy losses during the charging process. In contrast, the non-battery case does not have this factor to affect the CE_a. Therefore, a turning point occurs when the battery is added to the system. The electricity demand of the conventional building energy system was solely supported by the electricity grid without renewable generation. For comparison, the traditional system without renewable integration or storage shows an annual operational CE_a of 111.91 kg CO_{2,eq}/m².a, indicating the indirect emissions from grid electricity imports of the conventional building energy system. Across all cases, as the number of batteries increased, there was a consistent rise in CO₂ emissions. This suggests that while batteries can improve energy reliability, they may also contribute to increased emissions.

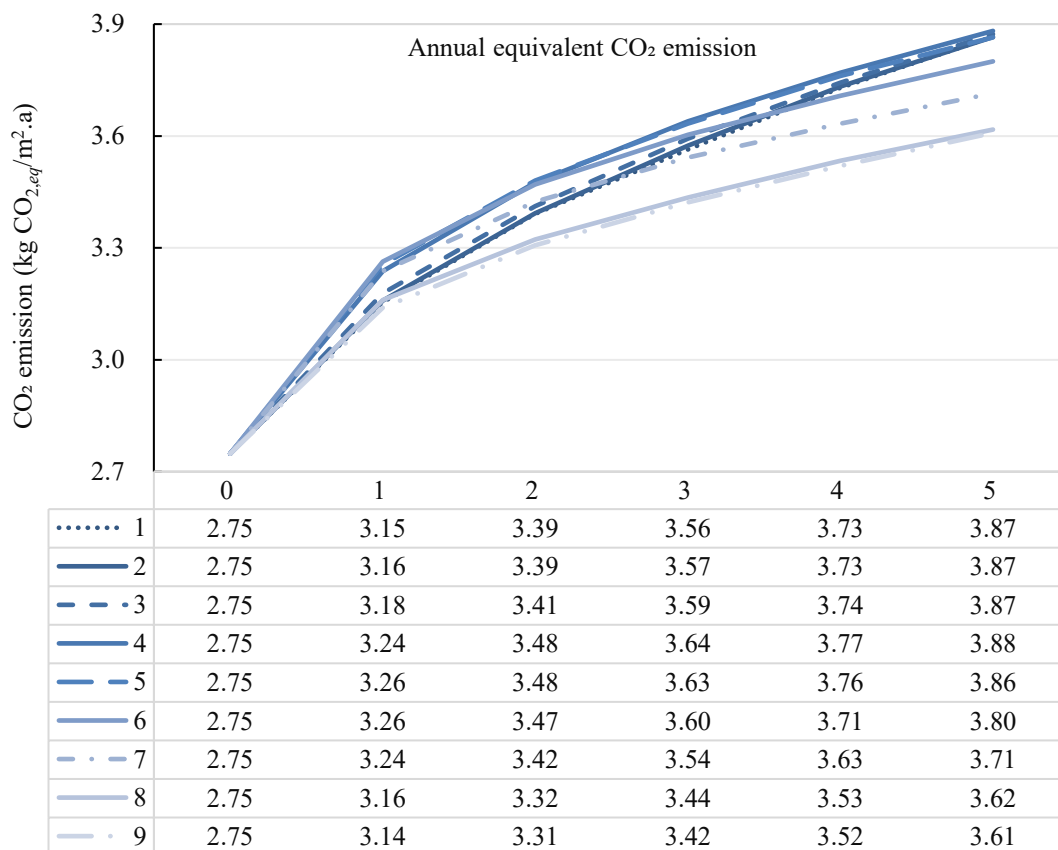


Figure I-10. Annual equivalent CO₂ emission with different battery capacities.

5.3 Techno-Economic Performance of the Hybrid Ocean Energy System

5.3.1 The techno-economic performance of the sea-source thermal system

(1) Comparison between cooling tower and sea-source chiller

A comparison of COP between the cooling systems in the reference group and the seashore group for both AC and SC systems led to the selection of an immersed-type HX with 88% effectiveness as a replacement for the cooling towers. The economic analysis used relative economic indicators, taking the original system without sea-source cooling/heating and RE integration as the baseline. Table I-4 provides the economic details of the newly added equipment for the cooling, heating, and electric systems. The costs of cooling towers sourced from Whaley Products Inc. for the AC and SC systems were HK\$100,932 and HK\$54,234, respectively. The initial investment for the HX in the AC system was HK\$21,546, while for SC, the cost was HK\$12,207. Furthermore, as the HX had a 10-year operational lifespan, an additional replacement cost of HK\$27,350 was included, calculated via the NPV_{rel} method. The initial investment for the sea-source cooling system was approximately 40% of the cost of the reference group's system. Besides, considering the significant energy savings observed in the study, replacing the cooling towers with the HX was recommended. This replacement not only lowered capital investment but also offered long-term reductions in energy consumption, contributing to both economic and environmental benefits.

Table I-4 The economic information on various facilities in cooling, heating, and electric systems.

System	Cooling				Heating			Electric
Seashore								
Item	HX (AC)	HX (SC)	Seawater pump (AC)	Seawater pump (SC)	Heat pump	HX	Seawater pump	Battery
Price (HK\$)	21,546	12,207	1,827	1,827	257,187	12,207	1,827	977,412
Model	Fin 95% effectiveness	Fin 96% effectiveness	50-125/03 Lowara	50-125/02 Lowara	50PSW360 Carrier	Counterflow	50-125/02 Lowara	Powerpack Tesla
Life cycle (year)	10	10	20	20	20	10	20	8
Traditional								
Item	Cooling tower (AC)		Cooling tower (SC)		Electric heater			
Price (HK\$)	100,932		53535		48174			
Model	WP1550-50, Whaley		WP850-25, Whaley		100 kW Industrial electric heater			
Life cycle (year)	20		20		20			
Interest rate: 2.139%								
Electricity tariff: 1.22 HK\$/unit								
Feed-in tariff: 3.00 HK\$/unit								

(2) Comparison between systems with and without a sea-source heat pump

The COP was also a key metric for evaluating the heating system's performance. A comparative analysis was conducted between the reference group, which used a direct electric heater, and the seashore group, which employed a water-to-water heat pump, with the heat source provided by the HX. The traditional system featured an industrial electric heater costing HK\$53,535, while the newly introduced heat pump, based on a product from Carrier Inc., had an investment cost of HK\$33,100. Additionally, the heat pump system required an HX costing HK\$12,206 to operate, with a replacement cost of HK\$9,868 incurred in the tenth year, also calculated using the NPV_{rel} method. Although the initial investment for the heat pump system was not significantly lower than that of the direct electric heater, the considerable energy savings (approximately 74%) from the heat pump's higher efficiency were highlighted. After considering the reduced electricity consumption, the system saved

approximately HK\$295,260 annually. This significant reduction in operational costs provided a strong financial incentive for adopting the sea-source heat pump system, making it a highly viable option despite the comparable upfront investment.

5.3.2 The techno-economic analysis of a hybrid RE system

(1) Revenue

Figure I-11 outlines the savings and profits associated with different cases of a RE system. These values were crucial for evaluating the financial benefits of such systems under the FiT scheme in Hong Kong, where power generated can be sold to HK Electric/CLP at a rate of HK\$3.00 per unit based on capacity [52, 151]. Under the FiT scheme and with a fixed electricity tariff of HK\$1.22 per unit, Figure I-11 demonstrates the saved tariffs for cases with different wave-wind energy ratios compared to the original group. After balancing the electricity fee, the profits represented the combination of the saved money and rewards from renewable power generation. Despite receiving equal FiT due to the same energy generation across cases, the savings ranged from HK\$680,760 for case 1 to HK\$812,521 for case 6. Consequently, the profits align with the technical performance, varying from HK\$2,070,810 for case 1 to HK\$2,334,332 for case 6.

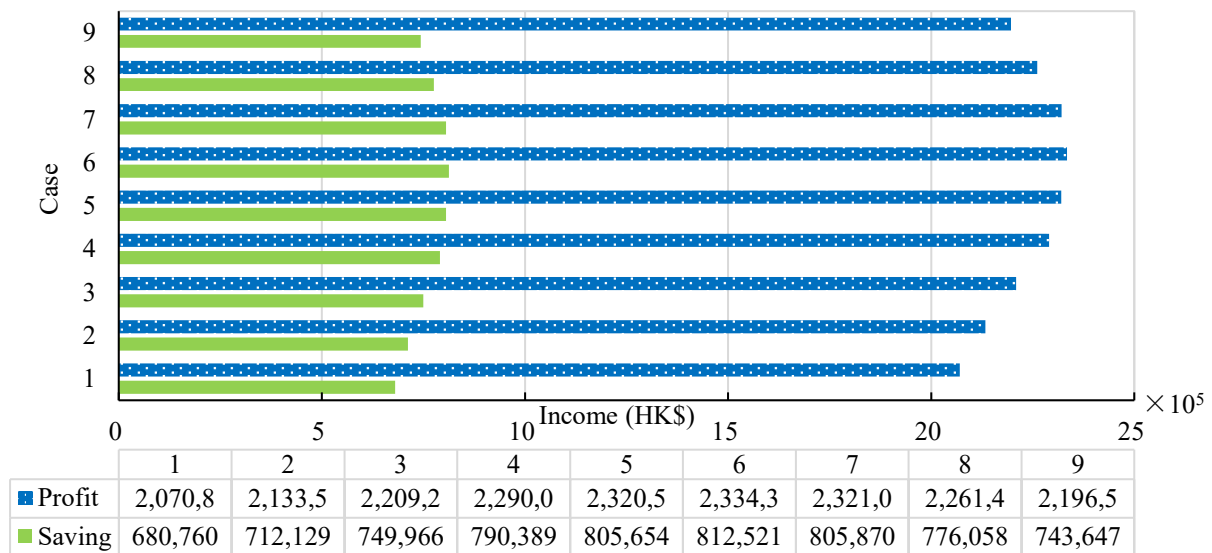


Figure I-11. The saved imported energy fees and profits of various wave-wind energy combinations.

(2) Relative simple payback period (with or without FiT)

In analysing the total costs for the seashore group, CAPEX related to the RE system was significant. To explore this further, a sensitivity analysis was conducted involving four scenarios, each considering different price levels for energy converters. Table I-5 presents four scenarios. For the OWEC, the higher price was over HK\$45,000 per kW, accompanied by an OPEX of 4.80%. In contrast, the lower price was HK\$28,300 per kW, with the same OPEX [161]. For the offshore WT, the higher price was nearly HK\$40,000 per kW with an OPEX of 0.80% [162], while the lower price was HK\$29,500 per kW and an OPEX of 0.92% [163]. The expected operational lifespan of the entire system was assumed to be 20 years. The interest rate used for the economic analysis was 2.139%, reflecting the average rate in Hong Kong over the past five years [164]. Additionally, the study included the Tesla

Powerpack battery, which costs HK\$977,412 [165], with an assumed lifespan of eight years, necessitating two replacements within the 20-year operational period.

Table I-5. Four scenarios with various price level combinations for energy converters.

Energy converter		CAPEX(HK\$/kW)	OPEX	1	2	3	4
OWEC	1.5 MW	45,455	4.80%	✓		✓	
	7 MW	28,329	4.80%		✓		✓
Offshore WT	NREL	39,837	0.80%	✓	✓		
	IRENA	29,526	0.92%			✓	✓

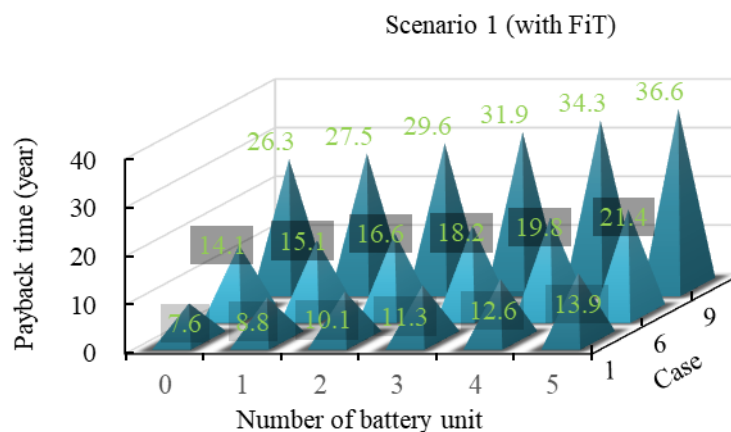


Figure I-12. SPP_{rel} under scenario 1 (with FiT).

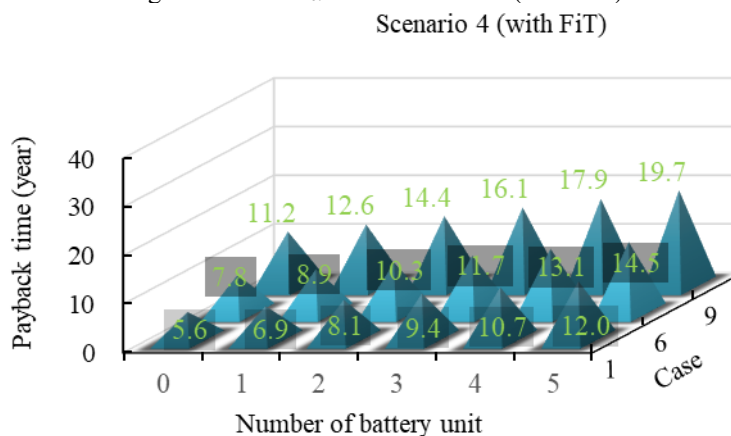


Figure I-13. SPP_{rel} under scenario 4 (with FiT).

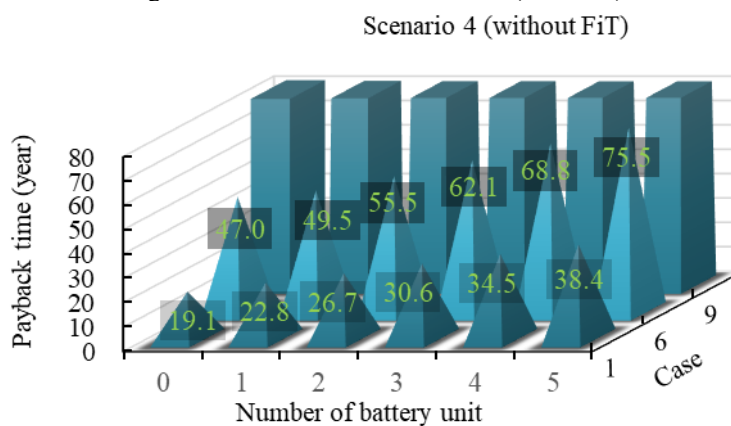


Figure I-14. SPP_{rel} under scenario 4 (without FiT).

Figure I-12 presents SPP_{rel} with FiT under scenario 1, which utilised higher price levels for both energy converters. The figure highlights three cases: Case 1 (100% wind energy), Case 9 (100% wave energy), and Case 6 (62% wave and 38% wind energy). As battery capacities increased, the SPP_{rel} gradually lengthened. When accounting for the FiT, most cases with 100% wind energy showed a payback period ranging from 7.6 to 13.9 years, while selected hybrid cases varied from 14.1 to 21.4 years. All cases, regardless of higher energy converter prices, would likely recoup the initial investment within 20 years. In contrast, the 100% wave energy case had a payback period of 26.3 years with no batteries, exceeding the anticipated 20 years. This period extended to 36.6 years when five batteries were added. Under Scenario 4, where prices for both WT and WEC were lower, the SPP_{rel} with FiT is displayed in Figure I-13. The 100% wave energy case showed a payback period of 12.2 years with zero batteries and 19.7 years with five batteries, meeting the 20-year expectation. Other cases with a lower proportion of wave energy required less SPP_{rel} : Case 6 ranged from 7.8 to 14.5 years with increased battery capacity, while Case 1 ranged from 5.6 to 12.0 years. However, when the FiT was not considered, as depicted in Figure I-14, the situation significantly deteriorated. The shortest payback period in this group was 19.1 years for Case 1 with zero batteries, nearing the 20-year limit, while other cases had even longer periods. Increased penetration of WEC led to a more unsustainable SPP_{rel} .

(3) Relative net present value

Another critical economic indicator employed was the NPV_{rel} in the assessment of the economic feasibility of the study. Initially, an analysis was conducted under scenarios 1-4, where cases with different ratios of wave-wind energy were examined without including a battery storage system. The results in Figure I-15 indicated that all the scenarios exhibited lower NPV_{rel} values as the proportion of wave energy increased. Notably, only scenario 2 showed a consistent alignment between the NPV_{rel} and technical performance of energy matching, as depicted in Figure I-16. The SPP_{rel} for scenarios 1 and 2 was also detailed in Figure I-17, implying that the better performance concerning the energy matching from wave energy was not attractive unless the investment in WEC decreased.

Except for the cases in which over 70% of wave energy employed higher prices of WEC, the four scenarios that received incentives through the FiT generally gained positive NPV_{rel} values over a 20-year period, indicating the economic acceptability of most projects. Conversely, scenario 4, which lacked FiT incentives, approached zero but remained negative, highlighting the necessity of FiT within the system. Furthermore, the relationship between battery capacity and NPV_{rel} was analysed, as shown in Figure I-16. As the number of battery units increased from zero to four, the NPV_{rel} decreased significantly, negatively impacting economic behaviour. Besides, the gaps between cases were gradually enlarged because the improved technical performance cannot offset the disadvantage of relatively high investment. This finding underscored the importance of carefully considering the influence of battery storage capacity on the economic performance of RE systems.

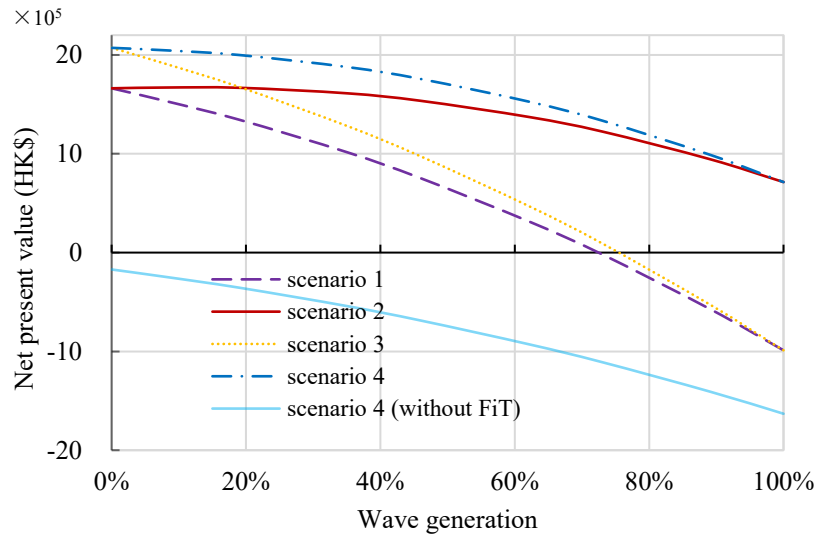


Figure I-15. NPV_{rel} under scenarios 1-4 [Publication I].

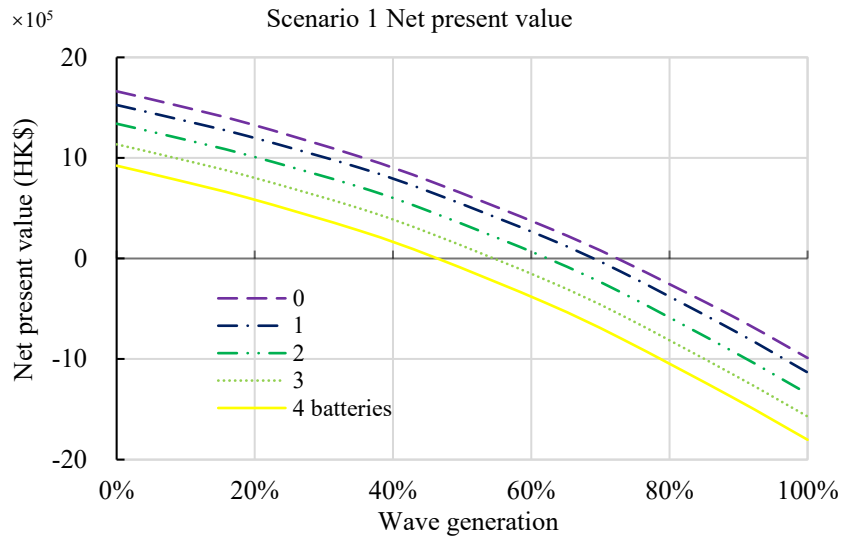


Figure I-16. NPV_{rel} with batteries under scenario 1 [Publication I].

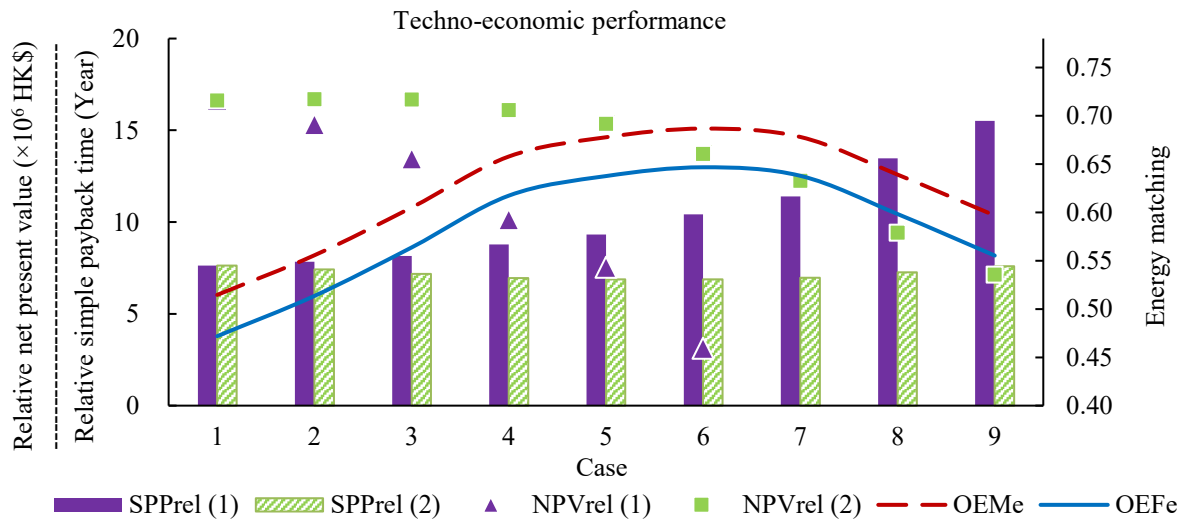


Figure I-17. Techno-economic performance under scenarios 1 and 2 [Publication I].

(II) Study on Advanced Energy Flexibility Enhancement via the Novel Resources of Wave Energy Converter Reservoirs and Electric Storages for a Hybrid Wave-Wind Energy Supported Hotel Energy System

Following the techno-economic feasibility investigation, the hybrid RE system was selected based on the results obtained earlier, which demonstrated its feasibility and superior performance. This study implemented a renewable setup combining 360 kW OWEC with 140 kW offshore WT. The influence of different flexibility control strategies, using flexibility sources such as batteries and the characteristic reservoir of the OWEC, was comprehensively investigated. Four groups were systematically classified in Table II-1. The table presented different flexibility sources and battery charge combinations under specific energy pricing schemes, considering scenarios with and without a 100 kVA demand limitation. The first group represented a traditional system without RE, where the battery was utilised as the only flexibility source. Group 2 comprised hybrid RE generators, specifically offshore WT and WEC. Building upon Group 1, which solely imported energy from the grid, hybrid RE generation primarily supported the demand. In instances where RE was inadequate during power shortages, the control strategy aimed to address this additional demand. This was achieved by charging the battery solely with surplus RE, if available. Group 3 introduced an additional flexibility source: the reservoir within the OWEC, which was managed to control seawater discharge behaviour. This regulation helped modulate power generation and provided an extra layer of operational flexibility. All three groups operated under the existing Bulk Tariff, which included a minimum demand charge of 100 kVA. To evaluate the effect of this demand limit, Group 4 employed a new tariff scheme, assuming the absence of a 100 kVA line. This allowed for a comparison with Group 3 and evaluated the effects of the new tariff scheme on technical performance.

Table II-1. Activated flexibility sources of research groups.

Group	(1) All grid	(2) Renewable	(3) Reservoir (100 kVA)	(4) Reservoir (No 100 kVA)
Renewables	N ^(a)	Y ^(b)	Y	Y
Flexibility source	Battery	Battery	Reservoir + Battery	Reservoir + Battery
Battery charge	Grid	Renewable	Renewable + Grid	Renewable + Grid
100 kVA	Y	Y	Y	N

^(a) "N": not employed; ^(b) "Y": employed.

The flow chart in Figure II-1 illustrates the controls implemented by different flexibility sources. The process began with the "all grid" Group 1, which represented the original demand (Demand 1st). In this scenario, efforts were made to manage flexibility primarily to lower peak demand, given that demand charges constituted a major portion of operational expenses. The analysis included determining the optimal capacity for an additional battery, as well as defining the control strategies for charging and discharging it. When renewable facilities were introduced into the system, the demand was initially met by RE sources. The resulting lowered demand (Demand 2nd) obtained from this coverage was then subject to similar control strategies employed by Group 2. However, the battery capacity required for Group 2 was much smaller, and the battery in this group utilised surplus RE for charging. Additionally, Group 3 stored seawater inside the reservoir of the WEC instead of immediately discharging it to generate power. This occurred when there was sufficient wind energy to support the initial demand. The reservoir was discharged during power shortages, and the corresponding demand was recognised as Demand 3rd. Group 4 utilised the OWEC as a flexibility source and investigated flexibility control using the battery, similar to Group 3, but under different price schemes. Each group's demand profile and control approach

influenced the incentive line, resulting in varied impacts across scenarios. Four distinct groups were established based on the combination of flexibility source and tariff, as illustrated in Figure II-1. To assess the effectiveness of flexibility control, several indicators were analysed from different perspectives. For example, the NPV_{rel} assessed the economic viability, while $OEMe_{OP/OPF}$ and $OEFe_{OP/OPF}$ measured the degree of energy matching during operational and peak periods. The PSI_{OP} indicated the effectiveness of demand reduction above specific thresholds during operational periods, and the VFI_{OPF} quantified how much energy was filled during low-demand periods below a certain threshold. These indicators provided insights into the effectiveness of flexibility control in managing peak demand and maximising energy usage.

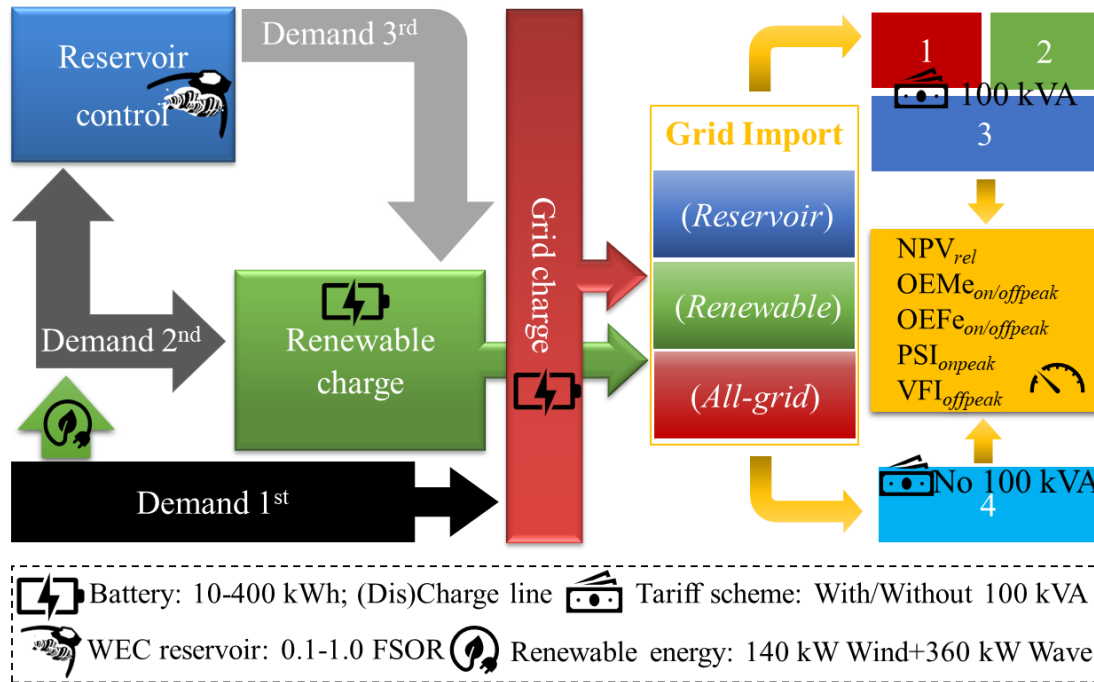


Figure II-1. Flow chart of the investigation on flexibility control through different sources [Publication II].

5.4 Investigation of Flexibility Source Relating to All-Grid Group

(1) Demand profiles of the traditional system:

The provided data offers an overview of how electricity demand varies across different times of the year before applying flexibility control measures. This is illustrated through four figures—Figure II-2a to Figure II-2d—that display the average electricity usage across various systems for each quarter. In each chart, a yellow line outlines the combined demand from the electric, cooling, and heating systems. A consistent pattern emerges throughout the year, characterised by two daily peak loads around 7:00 and 21:00, reflecting times of increased electricity use. The blue-shaded area indicates the load from the cooling system, encompassing both SC and AC loads. During the first quarter (Q1: January to March), cooling demand was at its lowest, whereas in the third quarter (Q3: July to September), it was roughly five times higher. This significant seasonal variation is primarily due to the hot summer months, which cause a surge in cooling requirements, thereby influencing the overall demand profile across seasons. The central red segment corresponds to the heating system's electricity demand, which showed similar usage patterns across different seasons but contributed only a small portion to the total energy consumption. The top section, highlighted in yellow, encompasses lighting, ventilation, and other electrical devices, accounting for the largest share of energy use among the three categories. Given these observations, the

study mainly concentrated on exploring flexibility options within the electrical system, since it represents the major component of total energy demand.

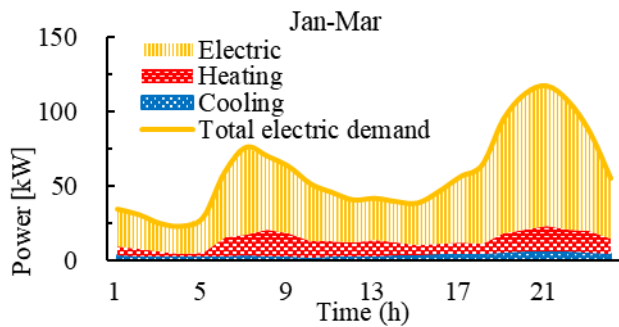


Figure II-2a. Component of electric demand in Q1 [Publication II].

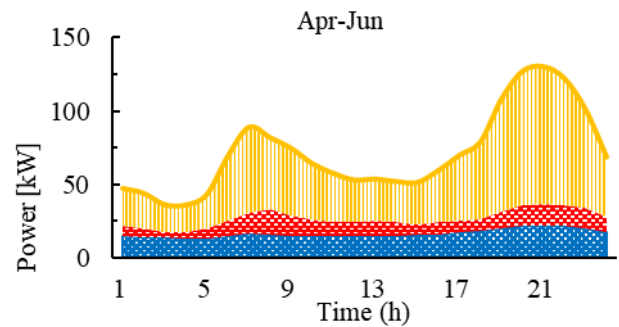


Figure II-2b. Component of electric demand in Q2 [Publication II].

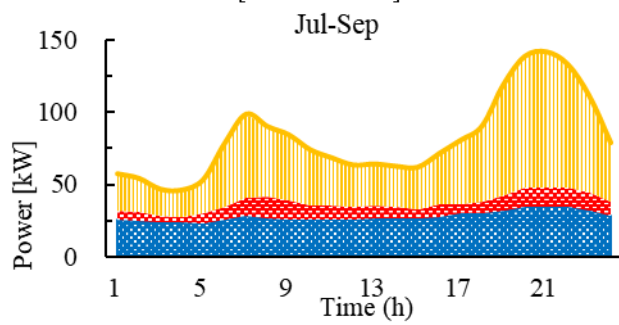


Figure II-2c. Component of electric demand in Q3 [Publication II].

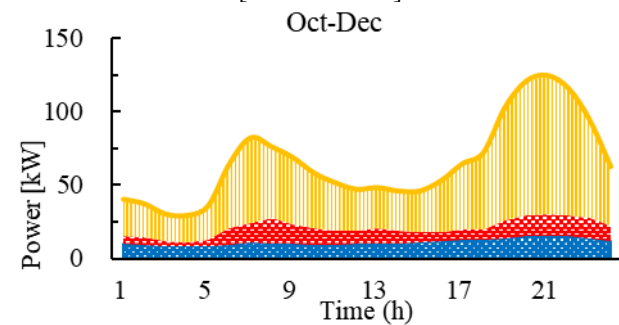


Figure II-2d. Component of electric demand in Q4 [Publication II].

To address the significant differences observed between the first and third seasons in the average charts, detailed energy demand profiles are provided in Figure II-3a (representing a selected day in January) and Figure II-3b (representing a selected day in July). Each figure displayed energy demand in 0.25-hour intervals, with Figure II-3a averaging around 60 kW and Figure II-3b averaging around 90 kW. Upon comparison with the average seasonal charts, it became apparent that the shape of the energy demand in Figure II-3a and Figure II-3b was more fluctuating. The actual demand recorded in these profiles was approximately 20 kW higher than the average value. Notably, as the monthly maximum power increased, the associated operational costs also rose. To mitigate these spikes above the average line and take advantage of periods with lower demand, the concept of using electricity storage was introduced in Figure II-4a and Figure II-4b. The idea was to charge the battery whenever the load fell below the red average power line (indicated by the blue section) and to discharge it during periods when the power exceeded the average power (indicated by the green section). By implementing this strategy, energy demand peaks could be smoothed out by storing excess energy during low-demand periods and utilising it during high-demand periods. This approach aimed to improve energy usage and reduce operational costs associated with high-demand periods.

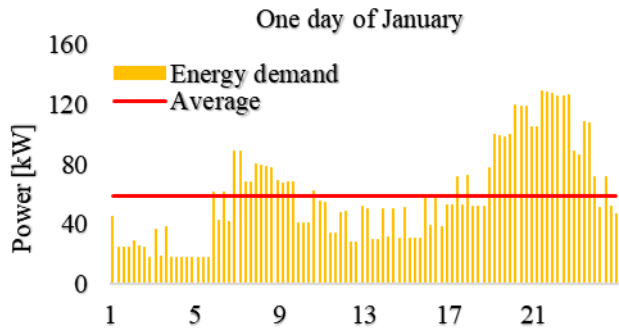


Figure II-3a. Dynamic electric demand of one day in January [Publication II].

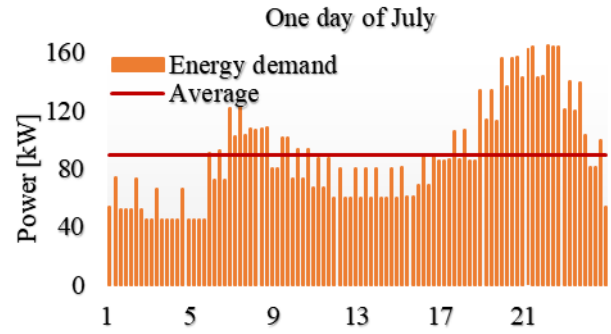


Figure II-3b. Dynamic electric demand of one day in July [Publication II].

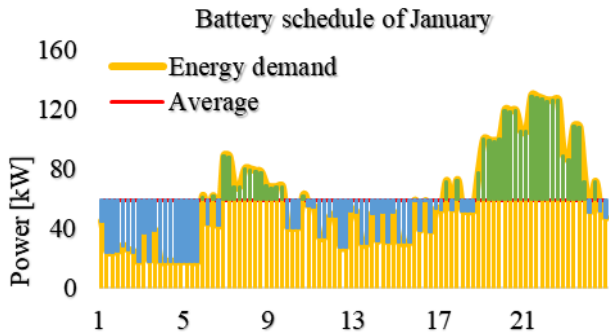


Figure II-4a. Ideal battery charging/discharging in January [Publication II].

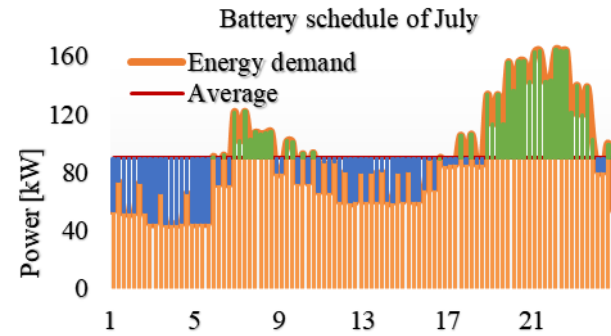


Figure II-4b. Ideal battery charging/discharging in July [Publication II].

(2) The designed control scenarios:

The performance of battery control on costs was examined by integrating designed scenarios with the Bulk Tariff that was introduced in Section 3.3.2. Figure II-5 illustrates the composition of the electricity cost of the original case. Figure II-5 shows (a) demand charge, (b) energy charge, and (c) fuel cost adjustment. Based on the demand profiles discussed earlier, it was observed that months in hotter seasons, such as July and August, consumed more energy and required higher power in both OP (from 9:00 to 21:00) and OFP (from 21:00 to +9:00). The demand charge for the OFP was relatively low for most months, as the demand during those periods did not significantly exceed the OP. Interestingly, the OFP energy charge was higher than the OP, even though the former was associated with cheaper pricing. This indicated that there was more energy consumption during the OFP.

Table II-2 presents additional conditions that were studied, including the average, 100 kVA, OFP cases, and the original case. The original case represented the average monthly electricity cost exceeding HK\$60,000. The Average case assumed a constant demand of 71 kW in each time step, resulting in a consistent energy consumption of 25,739 kWh, as depicted in Figure II-6. In contrast, the OFP case supposed that the grid import occurred exclusively during the OFP, with demand present only during that time. Figure II-6 and Table II-2 highlight the unique characteristics of the 100 kVA case. Due to the electricity tariff including a minimum demand charge of 100 kVA OP, this case reached a maximum demand of 100 kW during the OP, while the demand during the OFP did not exceed this value. Figure II-6 illustrates the extreme condition of the 100 kVA case, with OP demand consistently at 100 kW and OFP demand at 41 kW. By adjusting the demand conditions from the original case, the corresponding monthly electricity tariffs were examined in Figure II-5 and Table II-2. The OFP case incurred the lowest OP demand charge, even if there was no energy consumption during that period. Additionally, the

excess power cost during the OFP was also considered. In the 100 kVA case, the maximum power during the OP remained at 100 kW, while the OFP's power was significantly lower at 40 kW. Therefore, there was no need to pay the OFP demand charge. In the average case, the power was maintained at 71 kW, resulting in equal energy consumption during both the OP and OFP. Due to the lower price plan during the OFP, the energy charge was lower than that of the OP despite the same electricity usage. As these cases were developed from the original case, their overall energy use remained the same, resulting in identical fuel costs. Table II-2 displays the total monthly tariffs for each case. Compared to the original case, the total tariff for the OFP case was 93%, the 100 kVA case was 96%, and the Average case was 95%.

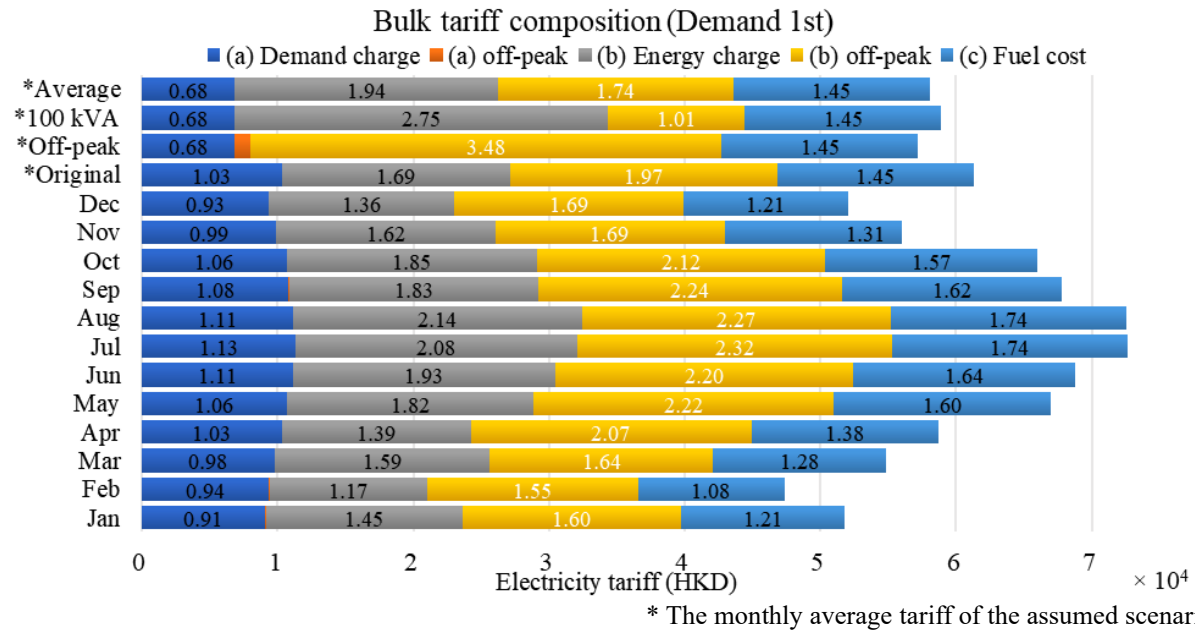


Figure II-5. Component of electricity tariff in the reference case (Demand 1st) [Publication II].

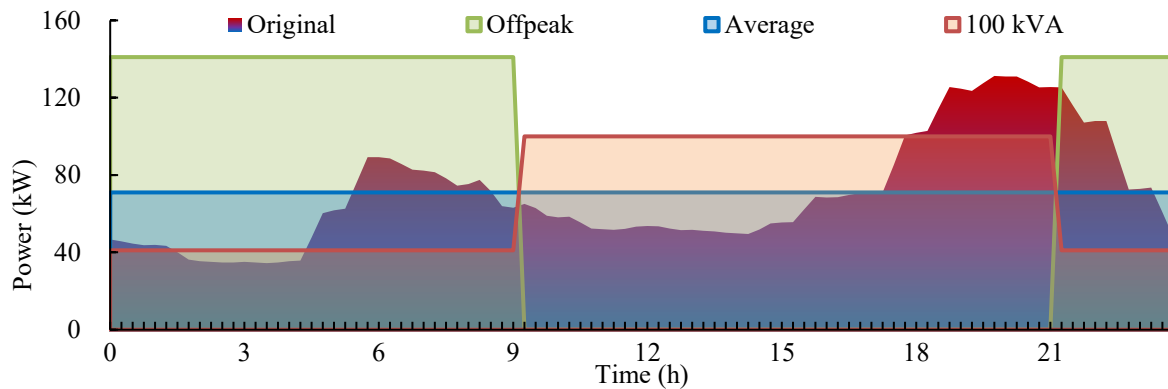


Figure II-6. Demand profiles of designed scenarios [Publication II].

Table II-2. Performance of designed scenarios [Publication II].

	Import (kWh)		Max demand (kW)		(a) Demand charge		(b) Energy charge		(c) Fuel cost	Total tariff (HK\$)	
	OP	OFP	OP	OFP	OP	OFP	OP	OFP			
Average	25,739	25,739	71	71	6,840	0	19,381	17,399	14,465	58,085	95%
100 kVA	36,500	14,977	100	41	6,840	0	27,485	10,125		58,915	96%
OFP	0	51,477	0	141	6,840	1,100	0	34,799		57,204	93%
Original	22,385	29,092	150	151	10,278	26	16,856	19,666		61,291	100%

While the OFP case offered significant potential for reducing operational costs by shifting energy consumption from the OP to the OFP, it required a large-capacity electricity storage system and incurred energy losses, making it an expensive investment. Similarly, the average case demonstrated favourable results for cost reduction. However, the 100 kVA case required additional analysis since it came close to 96% of the original cost under the most extreme conditions. In the 100 kVA case, if the control strategy restricted both operational periods to a maximum of 100 kW, no extra demand charge was applied because the OFP demand did not exceed the OP demand. Furthermore, imposing this limit ensured that the demand during the OP was not consistently at a high level. This implied that more energy consumption could be shifted from the high-price OP to the lower-priced OFP, resulting in additional savings in electricity fees. Considering these factors, the 100 kVA case proved to be a compelling choice as it substantially reduced operational costs. By implementing control measures that restricted the maximum power for both periods, the case offered the potential for cost savings without incurring additional demand charges. This strategy enabled efficient energy consumption during the lower-priced OFP, maximising the benefits of energy shifting and generating further savings in electricity fees.

(3) Battery's flexibility control:

Upon analysing the all-grid case's demand profiles and exploring the potential of control strategies using an additional battery, this study considered a battery cost of 200 USD/kWh and assumed a replacement after a ten-year period [166]. To minimise battery usage and avoid excessive investment in electricity storage, the battery's primary purpose was to smooth out demand spikes rather than shift energy consumption. Group 1 (all-grid group) was proposed, consisting of batteries with varying capacities ranging from 200 kWh to 400 kWh, as presented in Table II-2. In this group, the charging and discharging actions were compared to a demand level of 100 kW. The selection of the trigger line at 100 kW was determined through a preliminary analysis that assessed the impact of different trigger lines ranging from 80 to 120 kW. Among the cases evaluated, the 100 kW case demonstrated the desired outcome. When the demand fell below 100 kW, the battery was charged from the grid while ensuring that the charging power did not exceed the 100 kW threshold. On the other hand, when the demand exceeded 100 kW, the battery supported the system to ensure that the grid-imported power did not surpass the threshold. This approach helped to minimise the demand charge. Additionally, since the second busiest period occurred around 21 o'clock and power demand was predominantly above 100 kW during this time, the battery was programmed to avoid grid charging during these hours. Figure II-7 illustrates the demand profile of the original scenario. The gradient purple area shows the average demand, the blue solid line indicates the average grid import, the red line marks the 100-kW threshold, and the yellow dot represents the annual maximum demand recorded at each step. The purpose of the flexibility control was to keep these maximum demand points (yellow dots) below 100 kW, especially during OP. Consequently, the shape of the blue curve varied accordingly, deviating from the original demand profile.

Table II-3 outlines five different scenarios with different battery capacities (200, 250, 300, 350, and 400 kWh), in comparison to the baseline case without a battery. The table includes key metrics such as maximum OP/OFP power, which represents the highest demand recorded in any month over the year, and maximum (OFP-OP) power, indicating the maximum OFP demand exceeding the OP within a month. In all controlled cases, the maximum OP power was capped at 1,200 kW, whereas the original case without control reached 1,803 kW. This demonstrates

effective peak shaving, ensuring that the demand never surpasses 100 kW. However, the 200 kWh and 250 kWh battery scenarios experienced excess maximum OFP power, resulting in additional OFP demand charges. In contrast, the cases (300, 350, and 400 kWh) maintained a total maximum OFP demand of 1,200 kW across the year, indicating that larger batteries can better prevent excess OFP demand. Additionally, larger battery capacities allowed for fewer cycles and longer working periods. Comparing the monthly operational costs, the original case amounted to HK\$736,590, while the controlled cases ranged around 95% of the original cost. Notably, the 350 kWh battery case achieved its peak shaving target, indicating limited additional savings with larger battery sizes. While larger batteries could facilitate energy shifting from higher-priced to lower-priced periods, the associated investment and energy loss needed to be considered. Figure II-8 illustrates the impact of the 350 kWh battery case. Throughout the year, the maximum power demand remained below 100 kW, effectively achieving peak shaving. The blue curve representing grid-imported energy demonstrated the shift of consumption from high-demand periods to relaxed periods.

Table II-3. Economic performance using the control of group 1 [Publication II].

Battery capacity (kWh)	0	200	250	300	350	400
Max OP power (kW)	1803	1200	1200	1200	1200	1200
Max OFP power	1812	1491	1339	1200	1200	1200
Max (off - on) power	12	291	139	0	0	0
Operational cost (HK\$)	736,590	706,098	702,447	698,153	698,011	698,064
	100.00%	95.86%	95.36%	94.78%	94.76%	94.77%
Initial battery (HK\$)	/	310,800	388,500	466,200	543,900	621,600
Battery replacement (HK\$)	/	235,649	294,561	353,473	412,385	471,297
Saving (HK\$)	0	30,493	34,143	38,437	38,579	38,526
Relative NPV (HK\$)	0	-28,317	-102,894	-166,545	-300,748	-438,259

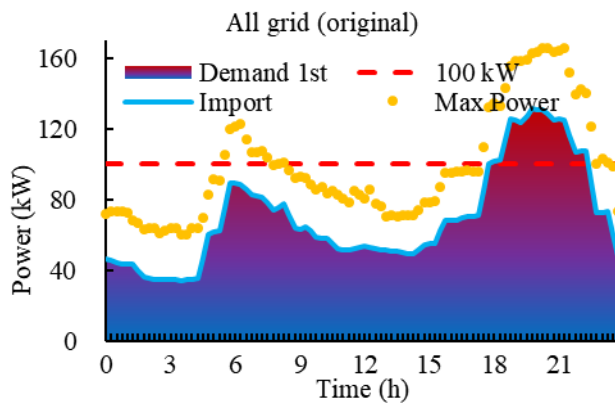


Figure II-7. Demand profile of the original case [Publication II].

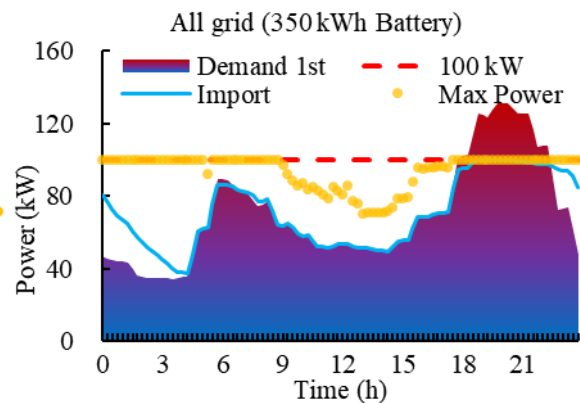


Figure II-8. Demand profile with battery control [Publication II].

(4) Relative net present value:

The NPV_{rel} for the all-grid group was calculated relative to the original case, accounting for the additional investment in the primary battery and the replacement expenses. The profit was determined by the savings in electricity tariffs resulting from the control strategies and the battery's salvage value, which was not fully utilised. The electricity fee was considered an annual price escalation rate of 1.315%, reflecting the price variation over the past twenty years. The battery replacement was evaluated using an interest rate of 2.807%, representing the average interest rate over the past five years [167, 168]. Since the battery had a lifespan of ten years, it was

replaced with a new one at the end of this period. Table II-3 presents the NPV_{rel} results for each case, comparing them to the original case. The table demonstrates that all battery-controlled cases underperformed relative to the original. The 200 kWh battery case had the lowest NPV_{rel} at HK\$-28,317. This case achieved greater cost savings than those with larger batteries, thanks to its lower battery investment.

(5) The Peak shaving indicator and Valley filling indicator:

The effectiveness of the control strategy was quantified using two indicators: the PSI_{OP} and VFI_{OFP} . These indicators were based on the specific tariff and utilised an incentive line set at 100 kW rather than the average demand. The impact of the control strategy was evaluated by comparing the annual duration curves of cases with the battery to a reference case within the group. The PSI_{OP} was calculated using the annual duration curve during the OP, while the VFI_{OFP} utilised the annual duration curve during the OFP. These indicators provided insights into the extent of peak shaving and valley filling achieved by the control strategy. The results for cases with different battery capacities are presented in Table II-4. Additionally, Figure II-9 and Figure II-10 depict the results of one specific case, showcasing the original demand covered by the imported energy from the grid (coloured section) in contrast to the original demand (grey section). The findings indicated that all cases achieved a PSI_{OP} of 100%, indicating that successful peak shaving targets were met. Moreover, cases with larger battery capacities exhibited higher VFI_{OFP} values. This suggested that more energy could be shifted from the OP to the OFP as the battery volume increased. It was important to strike a balance between the benefits of energy shifting and the energy loss associated with battery usage, since the battery was designed to facilitate peak shaving and subsequent energy shifting.

Table II-4. The PSI_{OP} and VFI_{OFP} of group 1 [Publication II].

Battery (kWh)	200	250	300	350	400
PSI_{OP}	100%	100%	100%	100%	100%
VFI_{OFP}	22.45%	24.21%	24.59%	24.62%	24.65%

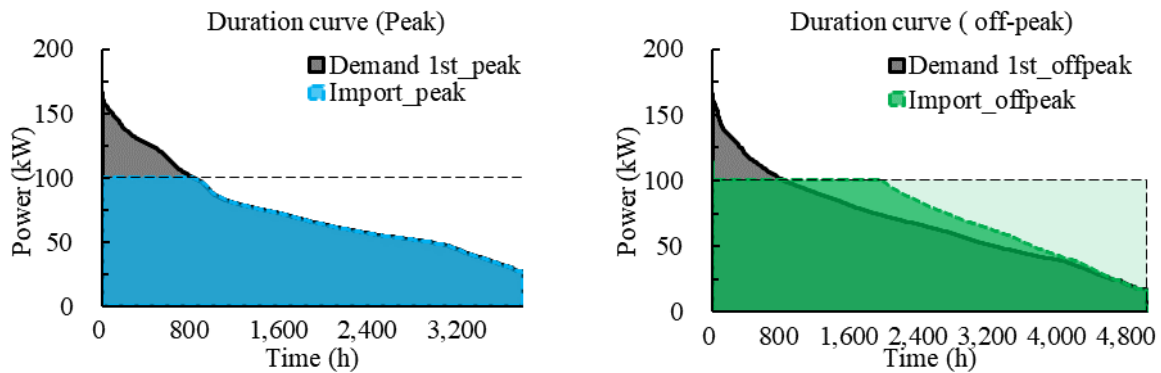


Figure II-9. The PSI_{OP} of All-grid case [Publication II]. Figure II-10. The VFI_{OFP} of All-grid case [Publication II].

5.5 Investigation of Flexibility Sources Relating to The Energy Management System of Hybrid Wave-Wind Generators

(1) The demand profiles of the renewable system:

With the integration of offshore WT and OWEC, the RE system primarily supported the overall energy demand. Figure II-11a to Figure II-11d illustrate the quarterly average conditions of the system load and generation alongside the corresponding new demand patterns. These figures provided insights into the average generation

output and the resulting energy requirements. After assessing various proportions of renewable generation, a combination of a 140-kW WT and a 360-kW WEC was selected, as this configuration offered a relatively stable power output. Nonetheless, it is essential to note that renewable sources alone may not fully meet the energy requirements, resulting in power shortages during periods of intense demand. Consequently, the new demand (depicted by the blue curve) exhibited a similar shape to the original demand (represented by the yellow area) but at a lower power level. For the zero-energy building and renewable groups, flexibility control strategies were based on this new demand profile (Demand 2nd).

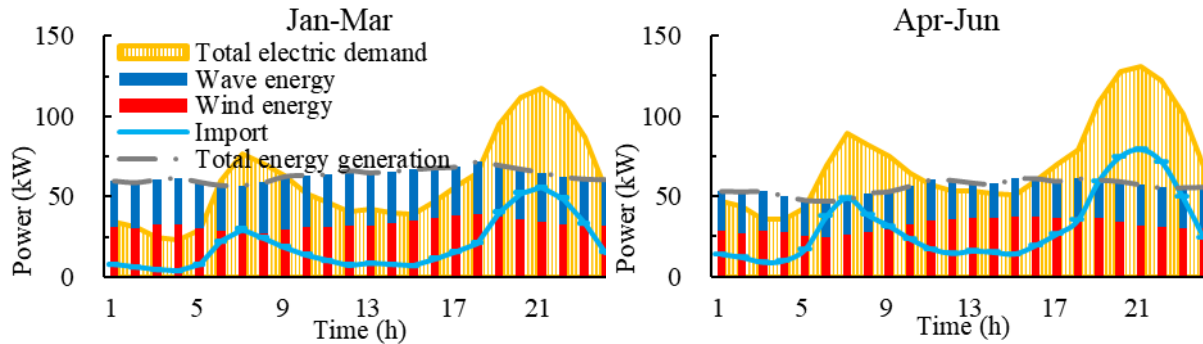


Figure II-11a. Average generation and demand in Q1 [Publication II].

Figure II-11b. Average generation and demand in Q2 [Publication II].

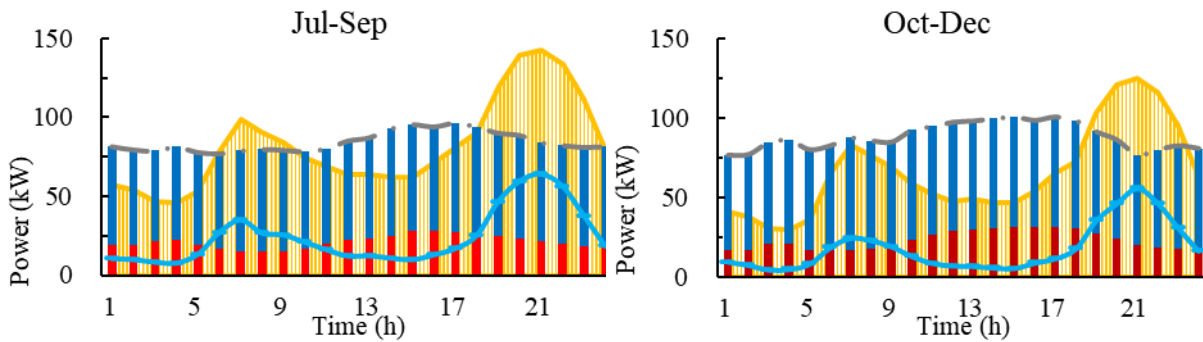


Figure II-11c. Average generation and demand in Q3 [Publication II].

Figure II-11d. Average generation and demand in Q4 [Publication II].

(2) The flexibility control through the battery:

Despite the average Demand 2nd being significantly lower than the original case (Figure II-7), Figure II-12 reveals that the maximum demand did not decrease substantially. Without batteries, the yellow dots represented the maximum demand at each time step throughout the year, which consistently remained well above the average level. This suggested that while RE could reduce the reliance on grid-imported energy, it was challenging to lower the peak power demand during critical periods, particularly during OP around 7:00 and 21:00. Consequently, the proportion of the demand charge in the overall electricity tariff became more significant, as depicted in Figure II-13, highlighting the need for peak shaving measures. In contrast to the All-grid group, the group under consideration employed smaller battery sizes ranging from 10 to 50 kWh. The building's demand characteristics exhibited two periods with intensive but short-lived power loads, with surplus RE generation occurring between these periods. Thus, discharging the battery at each time step to meet the demand allowed for the utilisation of surplus energy and created room to absorb the subsequent surplus energy. Previous studies indicated that shifting demand from OP to OFP by limiting battery discharging led to energy loss, as surplus energy extraction was

missed, and reliance on grid-imported energy increased. Therefore, this group had the potential to reduce operational costs by implementing peak-shaving techniques using reserved battery power during OP.

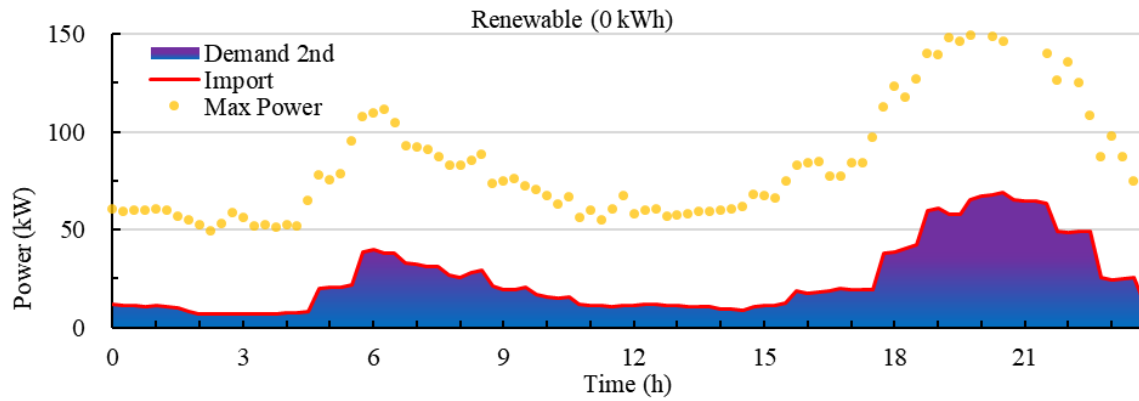


Figure II-12. Average annual demand profile of the renewable group [Publication II].

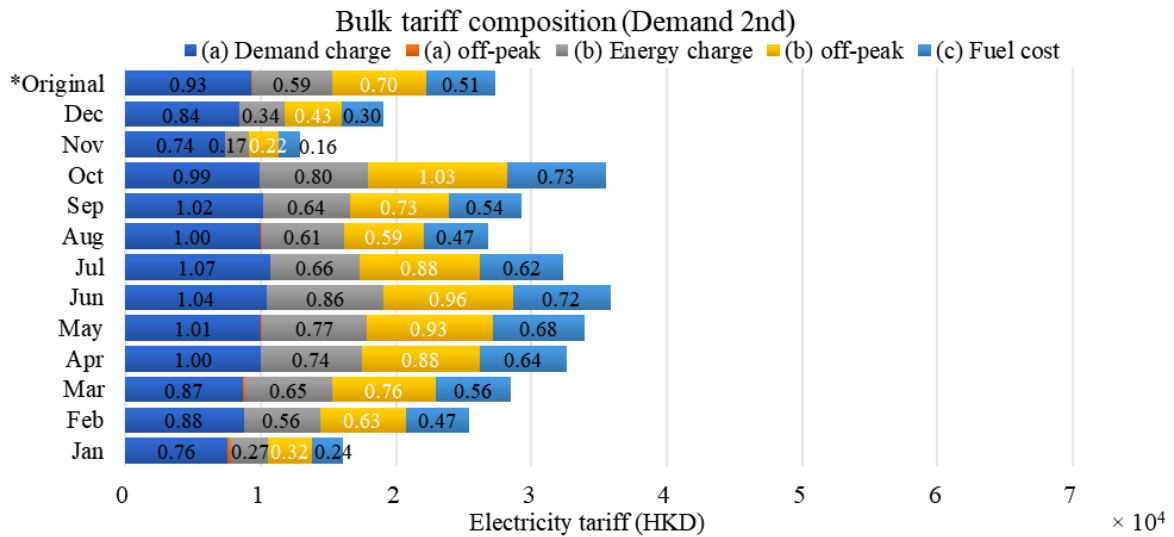


Figure II-13. Component of electricity tariff in the reference case (Demand 2nd) [Publication II].

Table II-5. Operational cost using various discharging FSOC limitations and battery capacities [Publication II].

FSOC (Discharge)	10 kWh	20 kWh	30 kWh	40 kWh	50 kWh	60 kWh	70 kWh	80 kWh	90 kWh	100 kWh
Ref	323,994	320,432	317,382	314,684	312,244	310,018	307,971	306,069	304,303	302,692
0.4	323,766	320,046	316,906	314,120	311,608	309,375	307,328	305,422	303,646	302,010
0.5	323,520	319,773	316,713	314,045	311,623	309,402	307,345	305,428	303,644	301,996
0.6	323,410	319,664	316,592	313,930	311,586	309,461	307,488	305,643	303,923	302,328
0.7	323,312	319,547	316,668	314,145	311,853	309,762	307,833	306,039	304,356	303,304
0.8	323,439	319,727	316,898	314,419	312,159	310,106	308,223	306,464	304,823	303,304

Table II-5 demonstrates that smaller battery sizes can yield greater benefits in cost-saving ratios within the same battery capacity. Based on this observation, the group consists of five cases, each with a different battery capacity ranging from 10 to 50 kWh. Table II-7 and Table II-8 present the group's results implementing the original control strategy. This strategy involved charging the battery with surplus RE and discharging it when RE generation was insufficient to meet the demand. On the other hand, Table II-7 and Table II-9 showcase the results of Group 2, which employed a flexibility control strategy.

The controls for Group 1 and Group 2 are outlined in Figure II-14 and Figure II-15, respectively. These flowcharts illustrate each group's actions taken to manage their energy systems. In Group 2, the initial demand (Demand 1st) was met by the generation from wave and wind energy sources (Supply 1). No grid charging was available. If surplus energy were available, the battery would be charged (Surp 1). Instead, there was only a discharging line that varied across different months. This discharging line was determined based on an investigation into the demand charge limitations within the electricity tariff. When renewable generation was insufficient to meet the demand, the battery was discharged during the OFP to fulfil the energy requirements, targeting a fractional state of charge (FSOC) of 0.2 (Short 1.1). During the OP, the battery's discharging FSOC was limited based on the specific battery size, as indicated in Table II-5. For example, if a 20 kWh battery had the lowest operational cost at a discharging FSOC of 0.7, it would only discharge to maintain a reserve for high-demand periods, provided the demand did not exceed the discharging limit. Once demand reached this set discharging threshold, the battery could discharge down to an FSOC of 0.2, which helped lower the maximum power demand (Short 1.1). If the energy shortfall persisted, the grid supplied additional power support (Short 1.2).

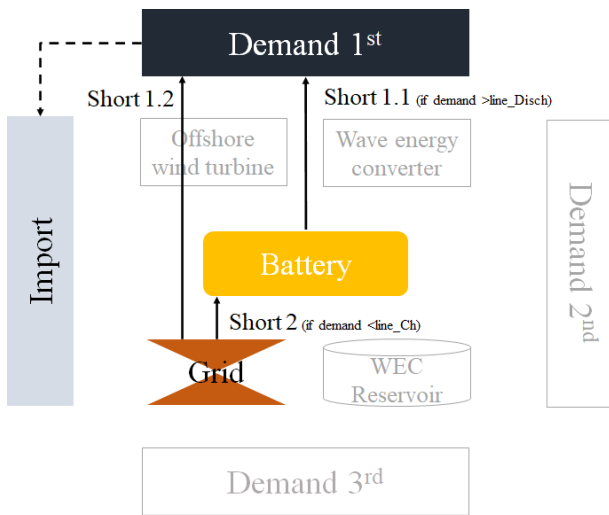


Figure II-14. Flow chart of Group 1 [Publication II].

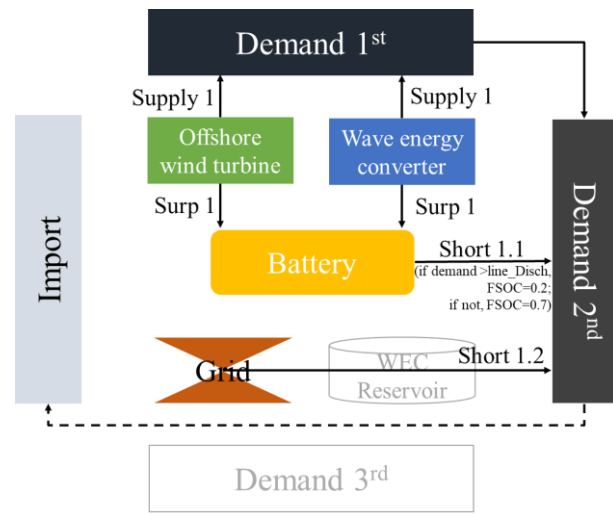


Figure II-15. Flow chart of Group 2 [Publication II].

(3) The charging and discharging line:

To determine appropriate charging and discharging setpoints for different months, the study conducted an investigation considering the influence of monthly variations in the demand profile. The process involved finding a suitable line as the trigger point for flexibility control. The following steps were followed: Using the 0-kW case from Table II-6 (combination 1) as a reference, which represents that the current month was not controlled. Creating 24 cases, where each case involved changing the power by ± 10 kW for one specific month while keeping the other months at 100 kW (combinations 2 to 25 in Table II-6). Identify profitable changes for different months and combine them into combination 26 in Table II-6. Further refining the control by adjusting the incentive line's power until each month reached its optimal setpoint, resulting in additional cases labelled as combination N in Table II-6). By following these steps and evaluating the various cases, the study identified the best combination of charging and discharging setpoints for different months. As a result, Group 2 consists of five cases utilising battery sizes ranging from 10 kWh to 50 kWh. This approach allowed for a systematic exploration of different combinations and selecting optimal setpoints based on operational costs and profitability.

Table II-6. Monthly adjustment of discharging lines combination [Publication II].

Month	1	2	3	4	5	6	7	...	26	27	28	...	N
1	0	90	110	100	100	100	100	...	100	110	100	...	100
2		100	100	90	110		...	110		...	100		
3				100	100		90	110		...	100	...	105
4						100	100	...	0	0	0	...	0
5								...				...	0
6								...				...	0
7								...				...	0
8								...				...	0
9								...				...	0
10								...				...	0
11						...	100	100	100	...	100		
12						...	0	0	0	...	0		
Cost (HK\$)	320,432	...	...	...	...	...	...	...	...	...	...	319,112	

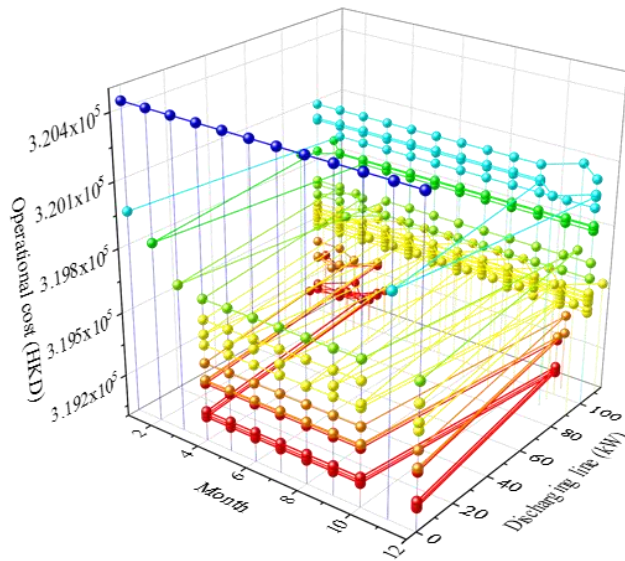


Figure II-16. Comparison of the combinations of various monthly discharging lines [Publication II].

(4) Operational cost saving:

Table II-7 provides a comparison between the flexibility control strategy and the absence of flexibility control, highlighting the improvements achieved in operational cost savings. By utilising a combination of N, representing the control approach applied in January, February, March, and November, the table illustrates the notable reductions in maximum OP power during these months. In January, the maximum OP power was reduced from 110.5 kW to 100.5 kW. In February, it decreased from 128.1 kW to 121.8 kW; in March, it decreased from 127.7 kW to 121.8 kW. Furthermore, in December, the maximum OP power was reduced to 99.3 kW from 107.7 kW. These reductions in maximum OP power indicated reduced demand charges and contributed to cost savings. Additionally, there were small improvements in reducing OFP maximum power in certain months. This could be attributed to the surplus reserve energy stored in the battery during the OP that was subsequently utilised during the OFP. Hence, the operational cost savings were not only limited to the OP but also extended to the OFP. Furthermore, flexibility cases show lower import energy around 22:00 according to the red line, as shown in Figure II-17a-d, aligning with the observations in the corresponding table. This supported the explanation provided in the table, highlighting the positive impact of the flexibility control strategy on reducing imported energy from the grid.

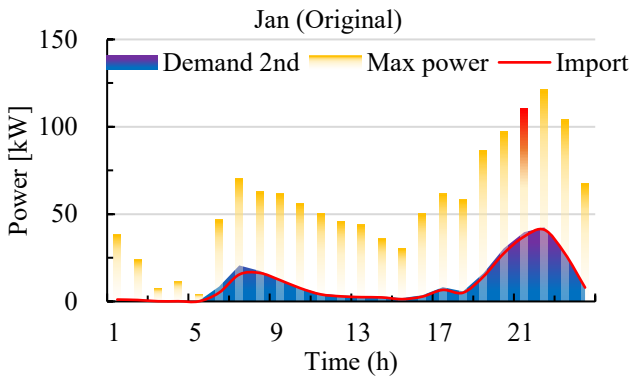


Figure II-17a. Average demand before control in January [Publication II].

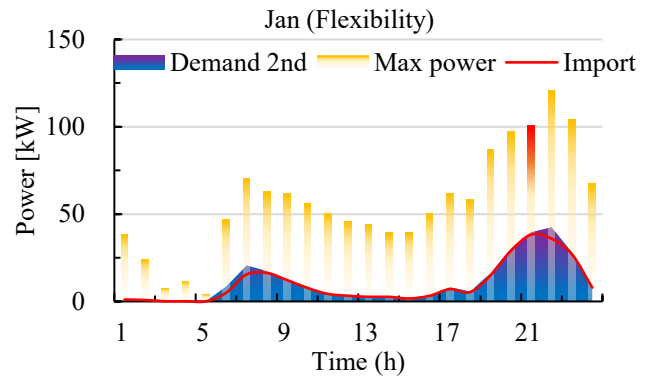


Figure II-17b. Average demand after control in January [Publication II].

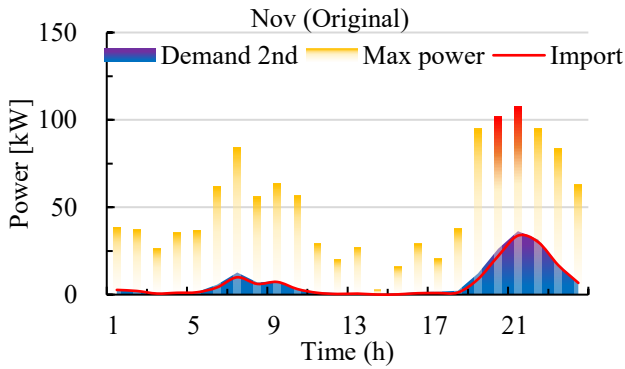


Figure II-17c. Average demand before control in November [Publication II].

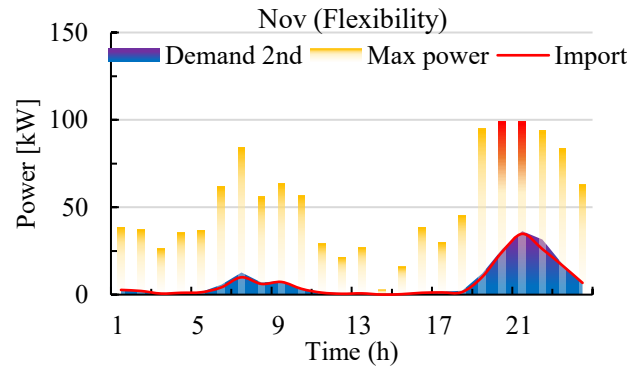


Figure II-17d. Average demand after control in November [Publication II].

Table II-7. OP/OFP maximum power and corresponding cost (group 2) [Publication II].

Month		1	2	3	4	5	6	7	8	9	10	11	12
OP Max P (kW)	Original	110.5	128.1	127.7	146.4	147.0	152.7	156.1	146.3	149.3	145.2	107.7	122.6
	Flexibility	100.5	121.8	122.3	146.4	147.0	152.7	156.1	146.3	149.3	145.2	99.3	122.6
OFP Max P (kW)	Original	121.2	125.7	132.1	146.2	149.6	154.7	157.9	148.8	146.4	145.7	95.3	121.9
	Flexibility	120.5	125.7	132.0	146.2	149.6	154.7	157.9	148.8	146.4	145.7	95.1	121.9
OP Cost (HK\$)	Original	10,889	16,217	17,305	19,972	20,279	22,065	19,441	17,954	18,759	20,429	9,367	12,738
	Flexibility	10,406	15,926	17,122	19,972	20,279	22,065	19,441	17,954	18,759	20,429	9,037	12,738
OFP Cost (HK\$)	Original	4,379	8,632	10,530	12,132	12,893	13,327	12,223	8,107	9,956	14,302	2,793	5,743
	Flexibility	4,461	8,628	10,541	12,132	12,893	13,327	12,223	8,107	9,956	14,302	2,672	5,743

(5) Relative net present value:

The upper portion of Table II-8 and Table II-9 provides an insight into the technical performance and operational cost control achieved by the battery. Table II-8 represents the group that applies the original charging and discharging control based on surplus and shortage logic without considering peak-shaving or energy shifting. Conversely, Table II-9 incorporates the monthly discharge line, as previously mentioned, alongside various battery capacities. With a 10 kWh battery, the maximum OP demand was reduced to 1620 kW from the original 1640 kW. Additionally, the operational cost amounted to 98.40% of the case without a battery. By increasing the battery capacity from 10 kWh to 50 kWh, the total maximum OFP demand could be further reduced to 1610 kW, resulting in an operational cost reduction of 5.26%. The NPV_{rel} of this group, as well as subsequent groups, was compared to the original all-grid case, which did not incorporate a battery. It was important to consider not only the expenses associated with the initial battery and alternative batteries but also the investments in renewable technologies, along with their OPEX. For the hybrid renewable system considered in this study, the installation cost was

HK\$21,940,770, and the OPEX cost amounted to HK\$830,071. Assuming proper maintenance over the 20-year project lifespan, there was no need for alternative investments during this period. Furthermore, considering the FiT policy in Hong Kong, which rewarded renewable generation based on the power generation scale, the study became eligible for a subsidy of HK\$3 per kWh, equivalent to HK\$1,908,675 per year [52]. In the last row of the table, the bluer bars represented higher NPV_{rel} values achieved by the cases with 50 kWh and 40 kWh battery capacities. Among the cases with a battery, all NPV_{rel} values in Group 2 outperformed the reference cases of the all-grid group and the cases without flexibility control. Moreover, the results indicated a preference for larger battery capacities, showcasing both technical and economic advantages.

Table II-8. Economic performance of original cases without flexibility control [Publication II].

Battery capacity (kWh)	0	10	20	30	40	50
Max OP power (kW)	1,640	1,640	1,640	1,640	1,640	1,639
Max OFP power	1,646	1,646	1,645	1,645	1,645	1,645
Max Off-On power	25	25	25	25	25	25
OP cost (HK\$)	209,338	207,190	205,415	203,889	202,540	201,297
OFP cost (HK\$)	118,973	116,804	115,017	113,493	112,145	110,947
Operational cost (HK\$)	328,311	323,994	320,432	317,382	314,684	312,244
	100.00%	98.69%	97.60%	96.67%	95.85%	95.11%
Initial battery (HK\$)	/	15,540	31,080	46,620	62,160	77,700
Alternative battery (HK\$)	/	11,782	23,565	35,347	47,130	58,912
Profit (HK\$)	1,486,884	1,491,201	1,494,763	1,497,812	1,500,510	1,502,951
Relative NPV (HK\$)	2,261,647	2,307,677	2,340,883	2,365,376	2,383,898	2,398,045

Table II-9. Economic performance using the control of group 2 [Publication II].

Battery capacity (kWh)	0	10	20	30	40	50
Max OP power (kW)	1,640	1,620	1,610	1,612	1,610	1,610
Max OFP power	1,646	1,645	1,644	1,645	1,645	1,644
Max Off-On power	25	37	43	43	43	43
OP cost (HK\$)	209,338	206,217	204,140	202,793	201,559	200,526
OFP cost (HK\$)	118,973	116,851	114,973	113,367	111,860	110,505
Operational cost (HK\$)	328,311	323,069	319,113	316,160	313,418	311,031
	100.00%	98.40%	97.20%	96.30%	95.46%	94.74%
Profit (HK\$)	1,486,884	1,492,126	1,496,082	1,499,034	1,501,776	1,504,163
Relative NPV (HK\$)	2,261,647	2,323,401	2,363,294	2,386,139	2,405,413	2,418,650

(6) The Peak shaving indicator:

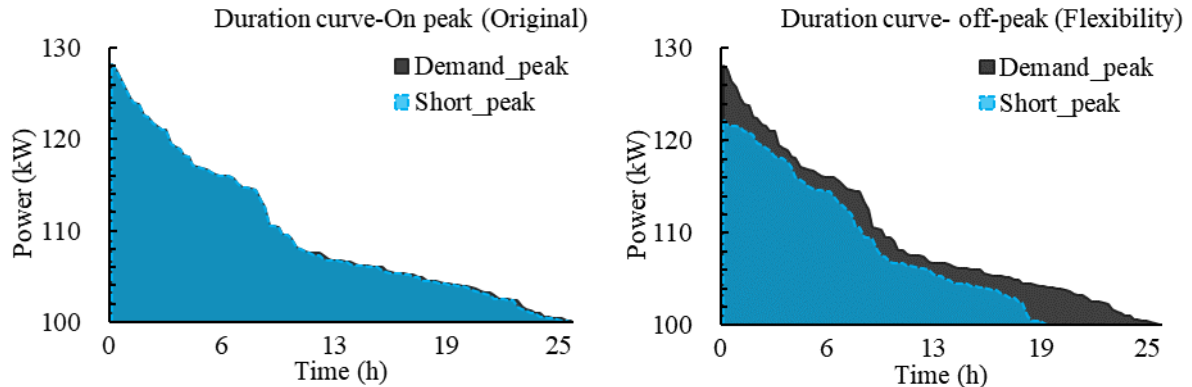
Table II-10 presents the PSI_{OP} results for Group 2, allowing for the quantification of the flexibility control. It is essential to note that the PSI_{OP} calculations for each group were based on the demand of their respective reference, making direct comparisons with other groups inappropriate. The PSI_{OP} values within Group 2 exhibited more pronounced variations from 10 kWh to 50 kWh when compared to the original case. The original cases, which were primarily concerned about power shortages, exhibited PSI_{OP} values ranging from 0.048% to 0.082%. In contrast, Group 2, which employed flexibility control and focused on peak demand reduction, exhibited PSI_{OP} values ranging from 1.167% to 2.023%. These contrasting results could be attributed to the different operational objectives of the two groups. The OP duration curves are depicted in Figure II-18a and Figure II-18b, which employed original control and flexibility control, respectively. In these figures, the blue sections represented the grid-imported energy, which corresponded to January, February, March, and November. A visual inspection showed that the original scenario had little effect on peak shaving since the blue area nearly completely enveloped

the demand area. In contrast, the flexibility cases exhibited a peak-shaving impact for several months. However, their capacity was limited by the small-scale battery, which mainly functioned to reduce power spikes instead of enabling energy shifting. Additionally, a deeper battery utilisation may have resulted in unnecessary charging and discharging operations, leading to increased energy loss and costs.

Table II-10. PSI_{OP} with varied battery capacities (group 2) [Publication II].

kWh	10	2	30	40	50
Original	0.048%	0.073%	0.075%	0.078%	0.082%
Flexibility	1.167%	2.023%	1.840%	1.840%	2.017%

* Combined performance of specific months



5.6 Investigation of Flexibility Source of Wave Energy Converter Built-in Reservoir under the Original Tariff

(1) The flexibility of the OWEC built-in reservoir:

A generation-side flexibility control strategy was introduced to overcome battery limitations in smoothing energy demand, while also addressing economic efficiency. This method involves adjusting the power output of the OWEC. Through this control, power fluctuations are minimised compared to direct wave energy transfer without seawater discharge control. The strategy enables the OWEC to handle excess energy and regulate power production effectively, utilising natural wave resources without extra component costs. The OWEC features an integrated seawater reservoir, inspired by small hydraulic power plants found in hydroelectric stations. This setup allows the OWEC to manage seawater discharge based on user needs and weather conditions. When other renewables supply sufficient energy, seawater is stored; during power deficits, seawater is released to generate electricity, optimising wave energy utilisation for power support. To visualise this integration, Figure II-19 illustrates the energy flow and control logic. It demonstrates how the proposed generation-side flexibility integrates into the existing system and highlights the associated energy management mechanisms.

The offshore WT mainly meets the initial demand, called Demand 1st (Supply 1.1). When wind energy surpasses this demand, the excess energy charges the battery, and the seawater reservoir in the OWEC stores the surplus as seawater (Surp 1.1). Once the reservoir reaches capacity, the OWEC releases seawater to generate electricity, which then recharges the battery (Surp 1.2). If wind generation cannot fully meet demand, the OWEC's storage is used first to support power needs (Supply 1.2). Any remaining unmet demand then triggers seawater discharge

from the OWEC to operate turbines and generate power for Demand 2 (Supply 2). If seawater discharge still falls short, the battery provides additional support based on a control strategy similar to that in Group 2. The battery discharges only up to a set fraction of its FSOC, maintaining reserve capacity for high load periods. When demand hits the predefined discharging limit, the battery can be discharged to 0.2 FSOC for maximum power reduction (Short 1.1). If demand surpasses this level, the system can draw electricity directly from the grid (Short 1.2).

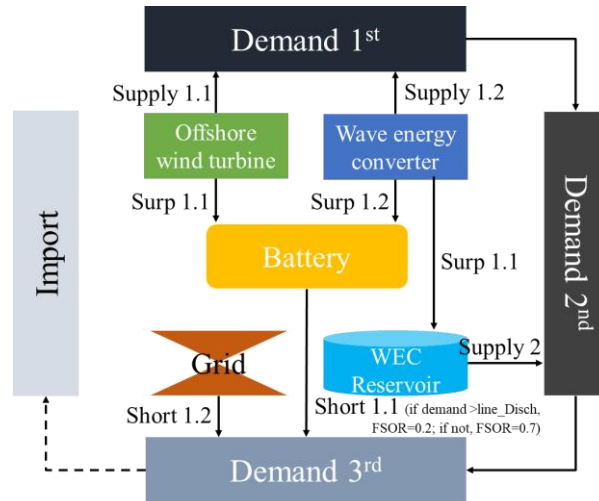


Figure II-19. The flow chart of the Reservoir group [Publication II].

(2) The limitation of the built-in reservoir of the OWEC:

The power output of the OWEC is influenced by the potential energy of incoming waves. As a result, the amount of energy generated from discharging stored seawater varies depending on the reservoir's Fractional State of Reservoir (FSOR).

Table II-11. Energy loss of varied available reservoir volumes [Publication II].

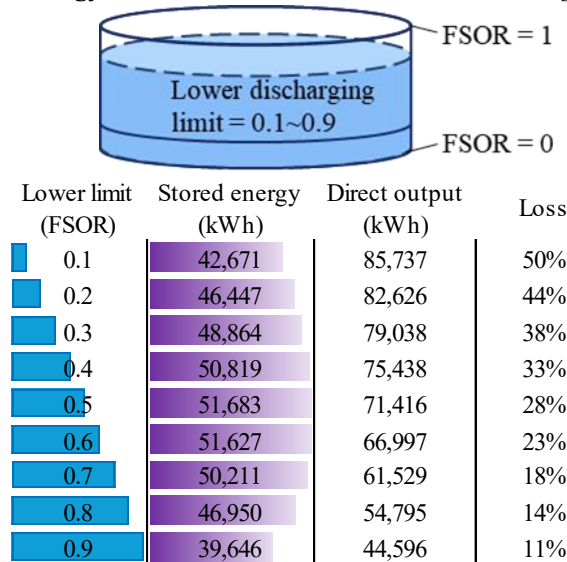


Table II-11 illustrates the FSOR values, where FSOR=1 indicates a full seawater tank, and FSOR=0 signifies an empty reservoir. A key limitation relates to the available volume of the reservoir. The upper charging limit corresponds to the maximum seawater fraction that can be stored, while the lower discharging limit indicates the

minimum seawater level that can be drained. By fixing the FSOR=1, the study examined how different lower discharging limits impact energy loss. The discharging limits ranged from 0.10 to 0.90. Intuitively, a larger reservoir volume (higher FSOR upper limit) can produce and store more energy when wave energy is directly converted. However, when controlling discharging based on demand, the stored energy's effective availability is affected by potential energy losses. The findings revealed that a medium discharging limit yielded the highest energy output, balancing storage capacity and loss. Based on the analysis in Table II-11, a lower discharging limit of 0.5 was selected because it maximised stored energy capacity, despite incurring approximately 28% energy loss.

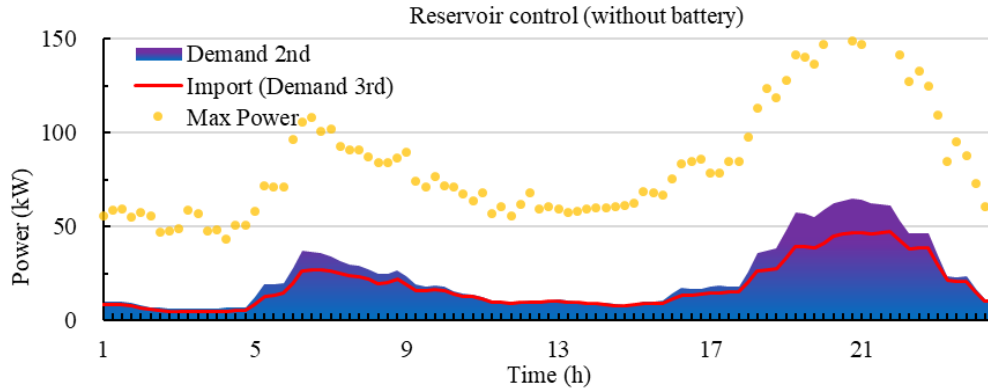


Figure II-20. Annual average demand profile using reservoir control [Publication II].

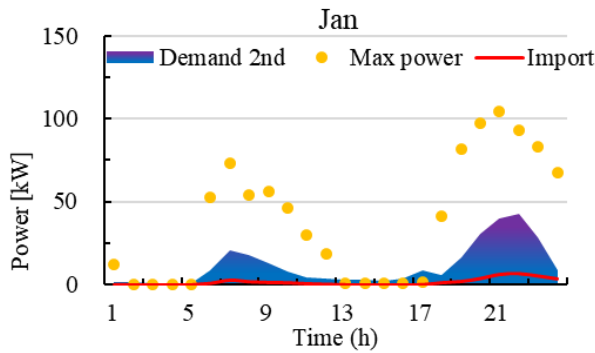


Figure II-21a. Demand with reservoir control in January [Publication II].

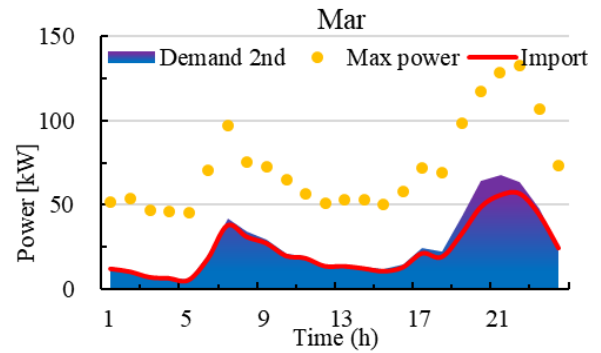


Figure II-21b. Demand with reservoir control in March [Publication II].

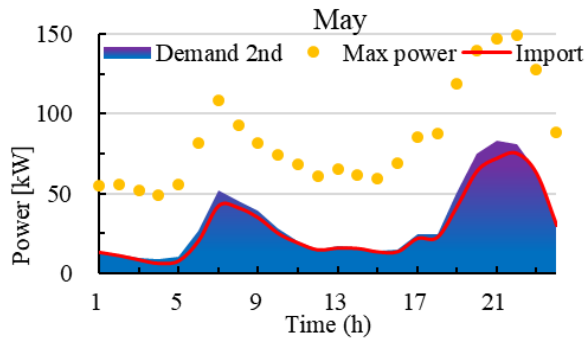


Figure II-21c. Demand with reservoir control in May [Publication II].

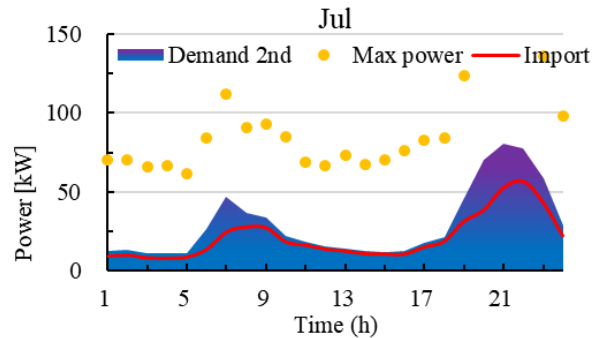


Figure II-21d. Demand with reservoir control in July [Publication II].

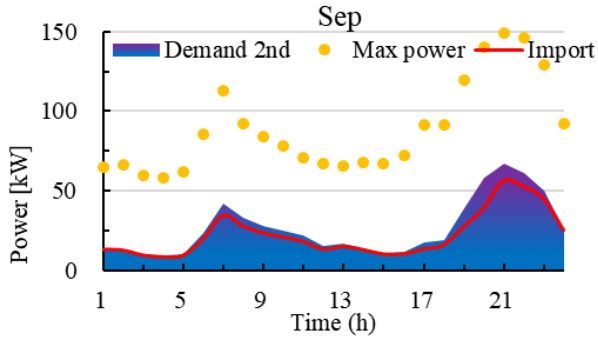


Figure II-21e. Demand with reservoir control in September [Publication II].

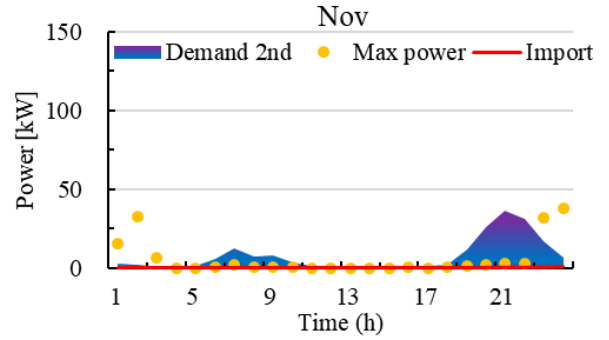


Figure II-21f. Demand with reservoir control in November [Publication II].

Figure II-20 shows the demand profile after implementing the reservoir's flexibility control with fixed settings. The control strategy effectively reduced grid energy import, especially during peak demand periods, lowering power requirements from about 70 kW to 50 kW. However, the yellow dots indicate that the maximum power demand still occasionally exceeded 100 kW, highlighting some residual peaks. Further insights were gained by analysing specific months, as shown in Figure II-21a to Figure II-21e. Six months were selected to examine the demand profiles and the effectiveness of reservoir control. The red line represents the residual demand that was not fully met by renewable generation and reservoir support. Months such as March and May showed relatively high demand, probably due to weaker wave energy resources, as discussed in Section 3.1.1. Hot months, such as July and September, experienced increased cooling needs that RE sources alone could not easily meet. Conversely, in January and November, demand levels during the OP period were nearly zero, indicating that reservoir management effectively supplied most of the demand when wave energy was plentiful. During November, the peak power demand was almost zero during OP, greatly enhancing system resilience and decreasing grid dependence.

(3) The flexibility of the electric batteries:

Despite the relatively low level of Demand 3rd, the issue of high maximum power persisted, except for November. The earlier investigation revealed that the small-sized battery (10-50 kWh) employed in this study effectively mitigated sporadic spikes in demand, as observed in January and February. However, peak shaving was not feasible during periods of extended high demand, such as in the hot season. The same control logic used in Group 2 was applied to address this, and the strategy was implemented in January, February, and March (excluding November due to its low maximum demand). The battery control focused on Demand 3rd, which indicates the imported energy after reservoir control, as shown by the red curve in Figure II-21. The demand profiles for January and February were specifically chosen to assess peak shaving performance, with results presented in Table II-12 and Figure II-22. Table II-12 demonstrated a reduction in the OP maximum power across these three months. Notably, January exhibited a significant reduction in both OP and OFP. Specifically, the OP maximum power decreased from 101.86 kW to 87.91 kW, while the OFP maximum power decreased from 92.41 kW to 86.83 kW. As a result of controlling the maximum OP power, these three months experienced cost savings during OP operational periods and a slight profit during OFP. This indicated the effectiveness of the battery control strategy in reducing peak power demands and operational costs.

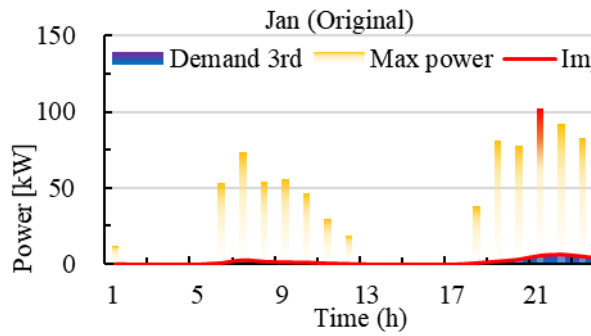


Figure II-22a. Demand before peak shaving (Jan) [Publication II].

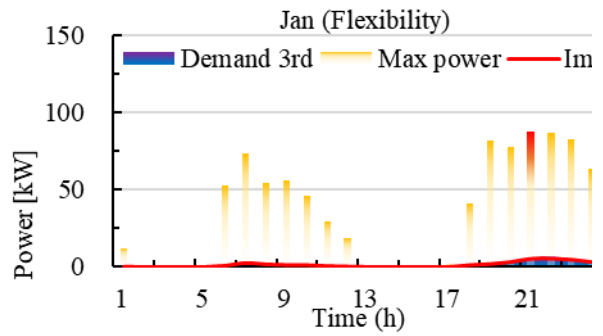


Figure II-22b. Demand after peak shaving (Jan) [Publication II].

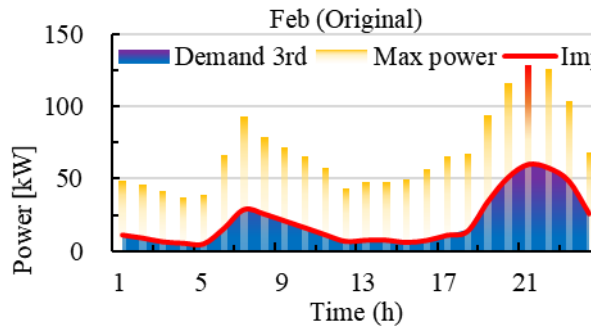


Figure II-22c. Demand before peak shaving (Feb) [Publication II].

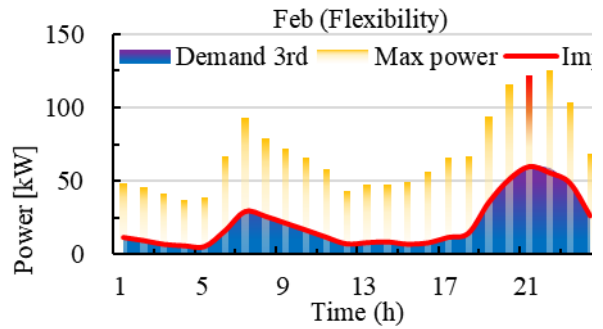


Figure II-22d. Demand after peak shaving (Feb) [Publication II].

Table II-12. OP/OFP maximum power and corresponding cost (group 3) [Publication II].

Reservoir Case		Jan	Feb	Mar
OP Max Power (kW)	Original	101.86	128.15	127.66
	Flexibility	87.91	122.06	123.51
OFP Max Power (kW)	Original	92.41	125.67	132.12
	Flexibility	86.83	125.67	132.09
OP Cost (HK\$)	Original	7,387	14,990	16,039
	Flexibility	7,276	14,637	15,909
OFP Cost (HK\$)	Original	615	7,466	9,274
	Flexibility	599	7,503	9,268

(4) Relative net present value:

According to Table II-13, the flexibility control implemented solely through the reservoir resulted in operational costs around 83.99% of those in the renewable energy group without control strategies. This demonstrates a notable cost reduction achieved by controlling the discharge behaviour of the OWEC's built-in reservoir, without adding extra component costs. To further evaluate the impact of introducing additional batteries ranging from 10 kWh to 50 kWh, the effects on operational costs and NPV_{rel} were analysed. By determining the optimal monthly discharging profiles for each battery capacity, the cases demonstrated a reduction in operational costs from 83.99% to 82.5% when incorporating the flexibility control strategy. However, increasing battery size yielded marginal benefits in cost savings. This suggested that larger battery sizes slightly enhance cost-saving benefits, while introducing them incurred additional initial costs, as indicated in the last row of Table II-13, thereby negatively affecting net present value. Comparing the NPV_{rel} of the cases with the reference case in the renewable group (which amounted to HK\$2,261,647), all cases achieved significantly higher values. The NPV_{rel} ranged from HK\$3,101,190 for the 50 kWh case to HK\$3,154,655 for the case without a battery. While battery-equipped cases demonstrated improvements in technical performance, their economic advantages were less pronounced due to

higher energy costs associated with battery investments. Moreover, even without including a battery, the case that solely employed reservoir control already achieved considerable profits through tariff savings and attained an exceptional 30% approximately increase in NPV_{rel} compared to the reference case in Group 2.

Table II-13. Economic performance using the control of group 3 [Publication II].

Battery capacity (kWh)	0	10	20	30	40	50
Max OP Power (kW)	1628	1617	1611	1611	1611	1611
Max OFP Power	1560	1560	1550	1550	1554	1559
Max Off-On Power	14	21	22	22	22	22
Operational cost (HK\$)	275,756	274,149	272,938	272,202	271,514	270,863
	83.99%	83.50%	83.13%	82.91%	82.70%	82.50%
Initial Battery (HK\$)	/	15,540	31,080	46,620	62,160	77,700
Alternative battery (HK\$)	/	11,782	23,565	35,347	47,130	58,912
Profit (HK\$)	1,539,438	1,541,045	1,542,256	1,542,992	1,543,681	1,544,332
Relative NPV (HK\$)	3,154,655	3,154,637	3,147,894	3,133,076	3,117,450	3,101,190

(5) On-site electrical energy matching and on-site electrical energy fraction:

The study further investigated the energy-matching capability under different conditions using two quantification indicators. Table II-14 presents the OEMe and OEFe to assess the net electricity inflow and outflow annually during OP and OFP, respectively. In the absence of a battery, the renewable case achieved 66.3% of OEFe during OP, 57.5% of OEMe during OP, 54.4% of OEFe during OFP, and 66.8% of OEMe during OFP. When batteries and control strategies were introduced into the system, the OEFe during OP improved by 1.3%, while the OEFe during OFP improved by 3.5%. This indicated that higher OEFe values corresponded to lower imported electricity from the grid and, consequently, reduced operational costs. Additionally, the OEMe during OFP increased to 69.2%, indicating a higher self-consumption of RE generation during OFP. However, exporting surplus energy to the grid did not yield significant benefits in this study. The last row in Table II-14 represents the scenario where a battery is employed alongside reservoir control. The addition of electric storage led to marginal improvements of about 1% or less in OEFe during OP and OFP, as well as OEMe during OFP. This indicated better energy matching during OFP and reduced reliance on imported energy from the grid. Overall, although the battery provided limited improvements, reservoir control alone demonstrated strong performance in optimising energy matching, consistent with the results from other indicators.

Table II-14. OP/OFP energy matching comparison [Publication II].

Case (kWh)		OEFe_{OP}	OEMe_{OP}	OEFe_{OFP}	OEMe_{OFP}
Renewable	0	66.3%	57.5%	54.4%	66.8%
	50	68.6%	57.5%	57.9%	69.2%
Reservoir	0	74.9%	67.0%	64.6%	78.4%
	50	75.4%	67.0%	65.6%	79.0%

5.7 Investigation of Flexibility Sources of The Self-Integrated Reservoirs of the Wave Energy Converters under the Assumed Tariff

(1) The flexibility of the electric batteries:

Based on the quantification results mentioned earlier, it is evident that further peak shaving, particularly under a specific tariff, did not yield economic benefits. However, exploring a more suitable pricing scheme could reveal the benefits of reducing maximum power demand below 100 kW. Without the 100 kVA demand restriction,

different battery control strategies were tested, including various incentive schemes for charging and discharging, as well as different battery sizes. The goal was to identify the optimal combination of charging and discharging patterns to minimise electricity costs. Initially, the focus was on selecting a profile that would achieve the lowest operational costs over the year. However, it was observed that the cost differences between profiles under the new tariff were minimal. As a result, the same profile used by Group 3 was chosen, since it had nearly the lowest costs. For instance, with a 40 kWh battery, Figure II-23 displays the breakdown of the electricity tariff. The month marked with an asterisk indicates when the new tariff took effect. Under the old pricing structure, the primary operational cost in January and November was the OP demand charge. Even with low energy imports in November, the minimum demand charge was HK\$6,840 for a demand of 100 kVA. As shown in Table II-12, energy charges in November were only HK\$2 during OP and HK\$41 during OFP. The study also examined whether further reductions in peak OP demand from 102 kW to 88 kW in January would be advantageous. It was determined that lowering demand beyond this level did not provide additional benefits.

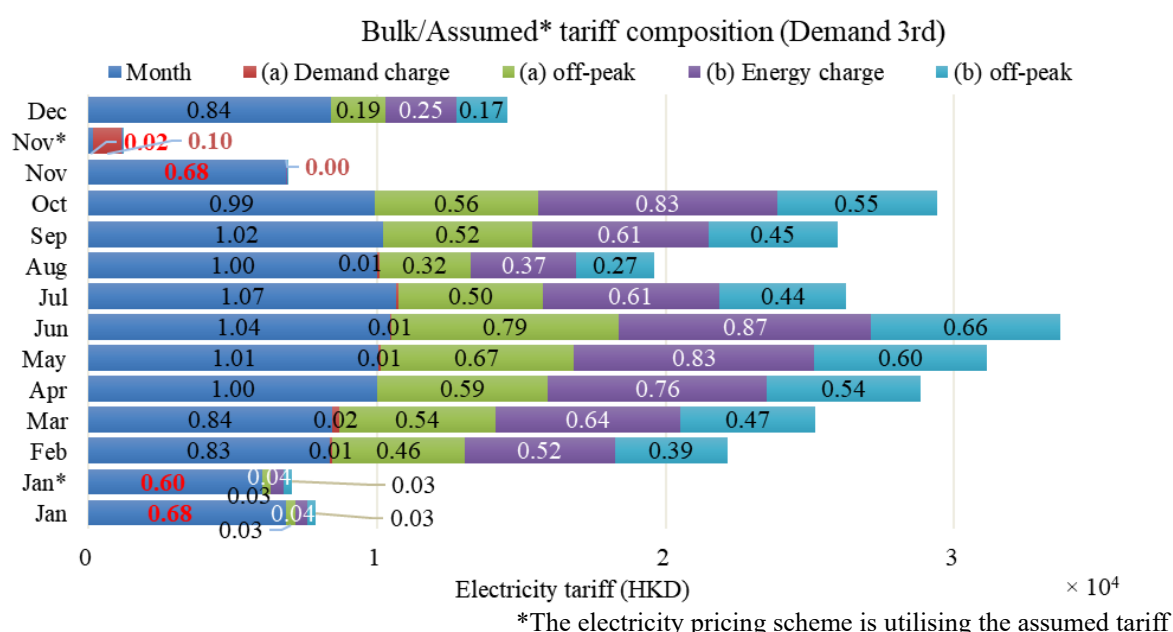


Figure II-23. Component of electricity tariff in the reference case (Demand 3rd) [Publication II].

Table II-15. OP/OFP operational cost comparison (groups 3 and 4) [Publication II].

Month	(a) Demand charge		(b) Energy charge		(c) Fuel cost	Total (HK\$)
	OP	OFP	OP	OFP		
Original Tariff						
Jan	6,840	0	318	423	295	7,876
...	...	...	...	...	...	...
Nov	6,840	0	2	41	18	6,900
...	...	...	...	...	...	...
Total	110,209	578	51,712	63,374	45,641	271,514
Assumed Tariff						
Jan	6,013	0	318	423	295	7,048
...	...	...	...	...	...	...
Nov	177	954	2	41	18	1,190
...	...	...	...	...	...	...
Total	102,718	1,532	51,712	63,374	45,641	264,977

Subsequently, an alternative tariff was proposed, removing the minimum OP billing demand charge, while retaining the original pricing scheme for OFP charges, which apply to power exceeding the OP maximum. With this new scheme, reducing power demand during OP directly lowered costs, as shown in Figure II-23 (highlighted in red). The OP demand charge decreased significantly from HK\$6,840 to HK\$6,013 in January and HK\$177 in November (Table II-15). Although there was a cost associated with the OFP demand charge for excess power, this charge was much lower than the OP demand charge. Therefore, high demand during OFP had a limited impact on total costs. Overall, by implementing peak-shaving adjustments over two months under the new tariff, the annual operational cost could be reduced by approximately HK\$6,537 compared to the original tariff scheme.

(2) Relative net present value:

Table II-16. Economic performance using the assumed tariff of group 4 [Publication II].

Battery capacity (kWh)	0	10	20	30	40	50
Max OP Power (kW)	1,528	1,519	1,509	1,503	1,502	1,501
Max OFP Power	1,560	1,560	1,559	1,553	1,554	1,552
Max Off-On Power	49	56	58	57	57	57
Operational cost (HK\$)	270,048	268,441	266,969	265,764	264,977	264,328
	82.25%	81.76%	81.32%	80.95%	80.71%	80.51%
Initial Battery (HK\$)	/	15,540	31,080	46,620	62,160	77,700
Alternative battery (HK\$)	/	11,782	23,565	35,347	47,130	58,912
Profit (HK\$)	1,545,147	1,546,754	1,548,225	1,549,431	1,550,217	1,550,867
Relative NPV (HK\$)	3,251,652	3,251,641	3,249,320	3,242,482	3,228,525	3,212,233

Results from Group 4 in Table II-15 demonstrated that further operational cost savings are achievable under the new billing model. Table II-16 shows that increasing battery capacity from 0 kWh to 50 kWh steadily reduced operational costs from 82.25% to 80.51%. Accounting for the 10-year battery lifespan and interest rates, corresponding replacement costs were included for each case. The last row of Table II-16 presents the NPV_{rel} relative to a baseline case with no control and no RE. These results indicate that, with additional savings on electricity bills, the benefits of battery-based flexibility control become more significant. Specifically, the NPV_{rel} increased by approximately HK\$100,000 compared to the cases in Group 3. However, it's important to note that smaller batteries or even no batteries tended to yield higher NPV_{rel} values, as illustrated by the blue cube in the figure. This suggests that, given the high investment costs associated with larger batteries, reservoir control combined with a smaller battery would be more economically advantageous.

(III) Study on Fine-Tuning Ocean Energy Storages for Reservoir-integrated Wave Energy Converters with Dynamic Activation of Mechanical Energy Storage Features

In this research, multiple groups were formed to explore the OWEC's built-in reservoir capacity for flexibility management, concentrating on energy shifting and peak shaving through manipulation of seawater storage and wave energy release. The potential advantages of these methods were forecasted based on the electricity pricing detailed in Section 3.3.2. Control variables for each group were outlined in Table III-1. The first group focused on shifting energy consumption from OP to OFP by developing a seawater discharge schedule based on peak/OFP and the FSOR to regulate water release and RE production. The second group aimed to decrease operational costs

by importing energy during lower-cost periods, utilising various FSOR measurements linked to a monthly schedule as control variables. Group 3 worked on peak shaving by adjusting seawater discharge based on current electricity demand, ensuring demand was met at a set point, and modifying the FSOR according to a schedule along with a monthly discharge threshold. The fourth group added battery support to manage remaining demand spikes, with discharge trigger levels tailored monthly and daily.

Table III-1. Variables employed in different groups [Publication III].

Variable Group	Schedule	Volume	Extent	Battery
1	Y ^(a)	N ^(b)	N	N
2	Y	Y	N	N
3	Y	Y	Y	N
4	Y	Y	Y	Y

(a) “Y”: employed; (b) “N”: not employed

OWEC incorporated a self-contained seawater reservoir, positioning it as a potential miniature hydropower facility, drawing inspiration from traditional hydroelectric plants. This research investigated the capabilities of OWEC functioning as a storage mechanism for wave energy by assessing various sources of flexibility to facilitate generation-side control strategies. The control methodologies evaluated encompassed (1) the scheduling of the reservoir's charging and discharging processes, (2) the storage capacity available for discharge purposes, (3) the extent of seawater that could be released, and (4) the incorporation of auxiliary battery systems. A flowchart in Figure III-1 presents the research methodologies and the interactions among different groups. Groups 1 and 2 concentrated on load transfer from OP to OFP, whereas Groups 3 and 4 were dedicated to strategies aimed at peak shaving. The specific pathways associated with each group are delineated in red on the left side of Figure III-1. Group 1 restricted OWEC generation (Supply 1.2), based on the existing FSOR framework. It determined whether to generate electricity or store incoming wave energy by monitoring FSOR signals alongside OP/OFP signals. Group 2 and Group 3 adjusted discharging behaviour for energy shifting and peak shaving (Short 1), respectively. Group 2 introduced a dynamic FSOR lower limit that adapts based on operational conditions and monthly energy demands, establishing a more profitable threshold. Conversely, Group 3 focused on peak shaving during OP, setting a monthly discharge threshold activated by the scheduling signal, which enabled effective management of the seawater discharge volume. Additionally, Group 4 advanced a proposal for integrating a supplementary battery system to bolster peak shaving efficacy, an objective not fulfilled by Group 3. The revised control methodologies incorporated insights from Group 3's findings through the “Short 1” section and established a “Short 2” framework for battery discharge operations. Battery discharge control was informed by the FSOR lower limit and the triggering line, while charging operations were facilitated through surplus RE. Comprehensive discussions on the specific control logic and parameters pertinent to each group are elaborated in the subsequent sections. The study quantitatively evaluated performance by analysing various technical and economic indicators. Further detailed discussions on the control logic and parameters for each group are included in subsequent sections, along with evaluations of performance using various technical and economic indicators.

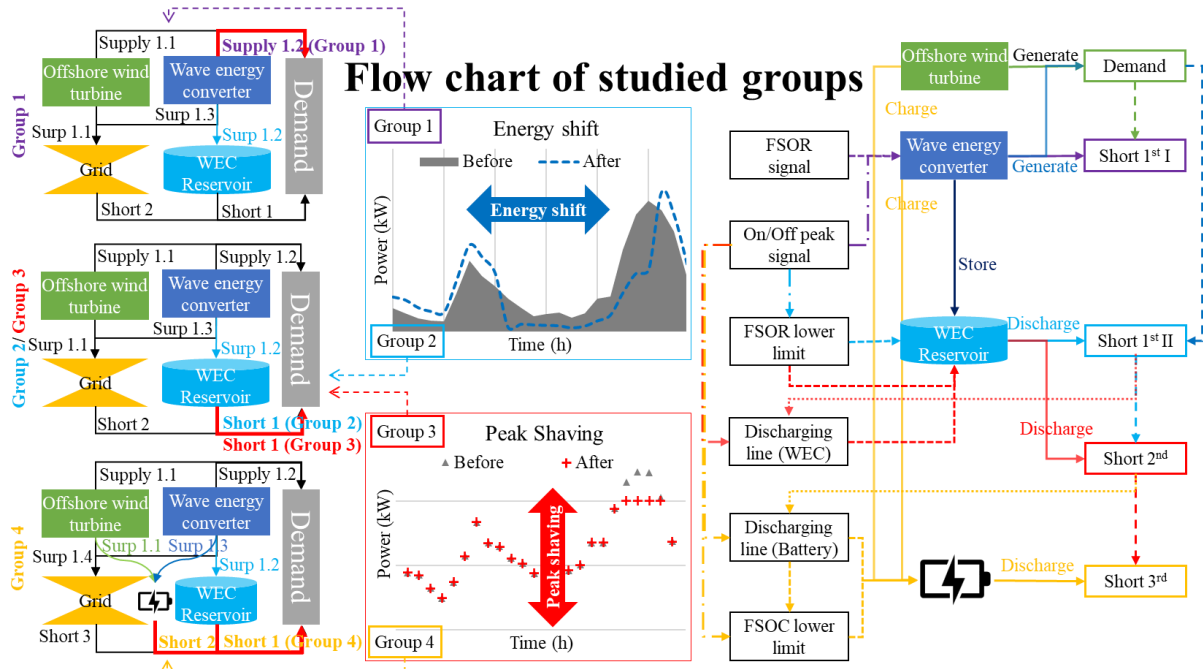


Figure III-1. Flow chart of studied groups [Publication III].

5.8 Scheduled Generation and Storage Behaviours of Wave Energy Converter

Group 1 implemented an adaptive control strategy for the WEC system by prioritising wave energy retention in the containment structure over immediate discharge. Figure III-1 details the operational hierarchy through a decision-making schematic. The offshore WT served as the primary energy source for baseline demand fulfilment (Supply 1.1). During periods of insufficient wind generation, wave-derived electricity production activated proportionally to real-time resource availability (Supply 1.2). When wind output exceeded system requirements, WEC operation deferred to accumulate hydraulic potential within the reservoir (Surplus 1.2) while diverting surplus wind generation to external grids (Surplus 1.1). The reservoir would initiate seawater release exclusively under dual-failure conditions where neither wind nor wave resources could satisfy consumption needs (Shortage 1). Conversely, the WEC retained seawater within the tank unless it reached capacity (when the full state of the reservoir, $FSOR = 1$), with excess wave energy beyond containment limits being directly converted for grid export (Surplus 1.3). Furthermore, any power shortages were compensated for by the grid (Short 2).

As illustrated in Table II-11 in Section 6.3(2), the utilisation of a larger volume for seawater storage in the reservoir was associated with increased energy losses. The energy stored within the system reflects the actual energy output generated through the discharge of the reservoir, whereas the direct energy metric signifies the output produced by the WEC in the absence of any storage capacity. This research primarily focused on control mechanisms initiated from a lower threshold, which was intentionally set at a reduced level, acknowledging the subsequent rise in energy losses. It is important to note that the increased volume available for seawater storage provided greater flexibility in implementing control strategies. The benefits derived from these flexible control measures, therefore, mitigated the impact of energy losses, resulting in a net gain. Consequently, this investigation began with a lower limit established at 0.1.

For the annual evaluation, the team formulated specific regulations to outline the protocols and limitations associated with the management of seawater storage and discharge. During OP, the release behaviour was consistent. In contrast, during OFP, it was necessary to elevate the FSOR adequately to maintain the stored seawater at the desired level prior to its release. The discharging FSOR set-points were examined, ranging from 0.1 to 0.9 (refer to Table III-2). The 0.1 set-point indicates an unconstrained scenario, representing the baseline FSOR for discharge operations. As the FSOR increased from 0.2 to 0.9, there was a corresponding decline in total operational expenses. Notably, operational costs during OP showed a decrease, while costs during OFP experienced an increase. This trend can be attributed to the elevated FSOR set-point facilitating enhanced discharging during OFP. Nonetheless, even with this increased discharging, OFP operational costs remained 5% higher compared to the scenario without discharge constraints, suggesting that the OP savings were insufficient to completely balance the OFP losses.

Table III-2. Economic effect of various discharging limits (annual) [Publication III].

FSOR	OP (HK\$)	OFP (HK\$)	Total (HK\$)	
0.9	145,019	153,163	298,182	105%
0.8	149,656	148,353	298,009	105%
0.7	154,987	143,958	298,945	105%
0.6	158,912	140,828	299,740	105%
0.5	163,003	137,989	300,992	106%
0.4	166,968	135,317	302,284	106%
0.3	171,719	132,033	303,752	107%
0.2	178,381	126,709	305,090	107%
0.1	188,252	96,211	284,463	100%

Table III-3. Economic effect of fixed discharging limit [Publication III].

(HK\$)	OP	OFP	Total	-	OP	OFP	Total	=	OP	OFP	Total
Jan	7,010	293	7,302	FSOR = 0.9	6,876	4,750	11,626	Comparison	134	-4,457	-4,324
Feb	15,680	8,046	23,725		11,453	10,879	22,332		4,226	-2,833	1,393
Mar	17,083	9,958	27,041		15,348	13,095	28,443		1,735	-3,137	-1,402
Apr	18,750	11,249	29,999		14,966	15,120	30,086		3,784	-3,871	-86
May	20,032	12,766	32,797		12,895	19,649	32,544		7,136	-6,883	253
Jun	22,010	13,031	35,041		16,772	19,070	35,842		5,238	-6,039	-801
Jul	17,980	9,974	27,954		12,087	17,464	29,552		5,892	-7,490	-1,598
Aug	15,177	5,516	20,693		11,043	11,899	22,941		4,134	-6,383	-2,248
Sep	17,849	8,664	26,513		14,541	13,875	28,416		3,308	-5,211	-1,903
Oct	18,728	13,110	31,838		13,325	18,547	31,872		5,403	-5,437	-35
Nov	6,952	284	7,236		6,862	2,729	9,591		91	-2,445	-2,355
Dec	11,002	3,321	14,323		8,851	6,085	14,936		2,151	-2,765	-613
Annual	188,252	96,211	284,463		145,019	153,163	298,182		43,233	-56,951	-13,719

Table III-4. Annual operational costs with and without discharge control (Group 1) [Publication III].

(HK\$)	OP	OFP	Total	
Original	188,252	96,211	284,463	100%
With control	176,561	106,616	283,178	99.50%

To evaluate the control effects on a monthly basis, Table III-3 presents a comparison of monthly operational costs for scenarios using and not using discharge set points. The left section of the table details the baseline case without a set point, whereas the middle section corresponds to a discharge FSOR of 0.9. The right section facilitates a direct comparison between these two scenarios. The data indicate a consistent reduction in costs during OP; however, there was a notable increase in costs during OFP, which exceeded the savings achieved during OP. These

findings validate the control strategy's objective of redistributing energy consumption from OP to OFP, effectively shifting expenses from higher to lower cost windows. Overall, the monthly cost analysis revealed considerable variability, with all months exhibiting changes except for February and May. Notably, only February and May demonstrated profitability, while the remaining months resulted in financial losses.

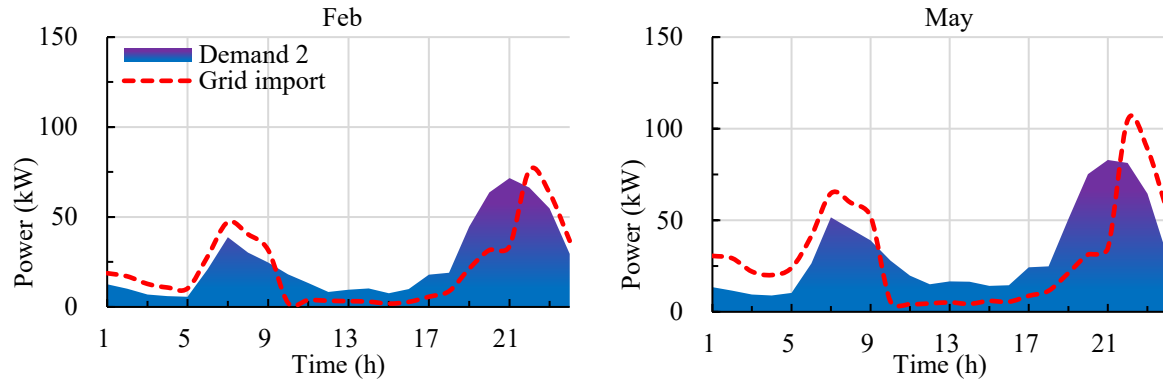


Figure III-2. Demand profiles of February and May with the new control (Group 1) [Publication III].

The data presented in Table III-3 indicates that the original control group achieved positive outcomes over several months, with February and May standing out as the only months where the control measures provided a significant advantage. The effects of the control implemented exclusively during these months are summarised in Table III-3, while Figure III-2 illustrates the associated demand profile. In this figure, the blue shaded area signifies Demand 2nd, reflecting unmet demand post-RE support in the absence of control interventions. The dashed red line represents the grid energy imports when control measures are enacted, highlighting a strategic shift in energy consumption patterns from OP to OFP. Furthermore, as evidenced in Table III-4, the annual costs associated with this control mechanism reflect a marginal reduction of 0.5% when compared to the preceding scenario.

5.9 Dynamic Available Volume of Wave Energy Converter Reservoir

Group 2 prioritised balance management between wave energy harvesting and consumption rather than maximising discharging behaviours. This strategy employed monthly-adjusted wave energy storage parameters, with the reservoir's operational capacity range normalised between FSOR = 0 (empty) and FSOR = 1 (full). A control mechanism was implemented for Demand 2nd: during renewable supply gaps where combined WT output and direct wave energy conversion proved inadequate, the system activated seawater release for power generation to bridge energy deficits. The control maintained a fixed maximum WEC reservoir charging threshold (FSOR = 1) while implementing dynamic discharge levels – adjustable from 0.1 to 0.9 based on load profiles, irrespective of temporal demand variations (OP/OFP). As detailed in Figure III-1, this group's operational logic was different from Group 1 by eliminating time-of-use considerations during wave energy extraction. Under wind generation shortfalls, the WEC initiated immediate power production regardless of demand periodicity (Supply 1.2). Reservoir discharge was triggered only when concurrent WT/WEC underperformance occurred (Short 1), with seawater release modulated to predefined storage thresholds rather than full depletion.

Table III-5. Cost comparison across various discharging limits [Publication III].

Lower limit	0.10	0.20	0.30	0.40	0.50	0.60	0.70	0.80	0.90
Jan	7,302	7,396	7,499	7,657	8,296	9,237	10,050	10,663	11,688
Feb	23,725	23,457	23,212	22,985	22,867	22,855	22,853	22,875	23,120
Mar	27,041	26,669	26,318	26,023	26,031	26,066	26,129	26,211	26,435
Apr	29,999	29,812	29,642	29,498	29,392	29,607	29,871	30,158	30,500
May	32,797	32,445	32,099	31,752	31,402	31,063	30,726	30,528	30,689
Jun	35,041	34,793	34,552	34,314	34,086	33,857	33,629	33,679	34,082
Jul	27,954	27,508	27,103	26,731	26,373	26,043	26,134	26,532	27,681
Aug	20,693	20,360	20,044	19,862	19,762	19,845	20,240	20,943	22,317
Sep	26,513	26,415	26,332	26,273	26,238	26,228	26,252	26,304	26,380
Oct	31,838	30,377	29,991	29,729	29,784	29,934	30,312	30,754	31,644
Nov	7,236	7,110	7,053	7,000	6,949	6,899	6,896	7,271	8,445
Dec	14,323	14,364	14,434	14,498	14,576	14,665	14,887	15,220	15,682

Table III-6. Economic effect of varied discharging limit [Publication III].

(HK\$)	OP	OFP	Total	-	OP	OFP	Total	=	OP	OFP	Total
Jan	7,010	293	7,302	Monthly FSOR	7,010	293	7,302	Comparison	0	0	0
Feb	15,680	8,046	23,725		15,545	7,880	23,424		135	166	301
Mar	17,083	9,958	27,041		16,121	9,384	25,504		962	575	1,537
Apr	18,750	11,249	29,999		18,315	11,077	29,392		435	172	608
May	20,032	12,766	32,797		19,437	11,803	31,240		595	962	1,557
Jun	22,010	13,031	35,041		21,141	12,261	33,402		870	769	1,639
Jul	17,980	9,974	27,954		17,329	8,415	25,744		650	1,559	2,209
Aug	15,177	5,516	20,693		14,453	5,144	19,597		725	371	1,096
Sep	17,849	8,664	26,513		17,326	8,902	26,228		523	-238	285
Oct	18,728	13,110	31,838		17,349	11,966	29,315		1,378	1,144	2,522
Nov	6,952	284	7,236		6,931	210	7,142		21	74	95
Dec	11,002	3,321	14,323		11,002	3,321	14,323		0	0	0
Annual	188,252	96,211	284,463		181,957	90,656	272,614		6,295	5,555	11,849

Table III-7. Economic effect of varied discharging limit considering OP/OFP distinction [Publication III].

	Original cost (HK\$)	FSOR		Operational cost (HK\$)		FSOR		Operational cost (HK\$)		OP	OFP
Jan	7,302	0.1	Monthly FSOR	7,302	100.0%	0.1	Monthly FSOR (on/OFP)	7,302	100.0%	0.1	0.1
Feb	23,725			23,424	98.7%	0.7		23,424	98.7%	0.7	0.7
Mar	27,041			25,504	94.3%	0.4		25,414	94.0%	0.4	0.7
Apr	29,999			29,392	98.0%	0.5		29,266	97.6%	0.5	0.9
May	32,797			31,240	95.3%	0.8		31,123	94.9%	0.8	0.9
Jun	35,041			33,402	95.3%	0.7		33,251	94.9%	0.7	0.9
Jul	27,954			25,744	92.1%	0.6		25,390	90.8%	0.6	0.8
Aug	20,693			19,597	94.7%	0.5		19,597	94.7%	0.5	0.5
Sep	26,513			26,228	98.9%	0.6		26,189	98.8%	0.6	0.9
Oct	31,838			29,315	92.1%	0.4		29,249	91.9%	0.4	0.6
Nov	7,236			7,142	98.7%	0.5		7,099	98.1%	0.5	0.6
Dec	14,323			14,323	100.0%	0.1		14,256	99.5%	0.1	0.5
Annual	284,463			272,614	95.8%			271,560	95.5%		

The results are summarised in Table III-5. Each column corresponded to a scenario with a distinct lower limit, while each row represented a different month. A darker shaded cell denoted more significant advantages under each lower limit. For instance, January exhibited superior performance under lower limits of 0.1, 0.2, and 0.3, while February excelled at around 0.7. Table III-6 compares the FSOR set-point lower limits for each month. Previous findings indicated profitability during both OP and OFP. The cost for the whole year has decreased to

95.8% of the original amount, as outlined in Table III-7. Moreover, the impact of varying lower discharge limits during OP and OFP was examined. Notably, specific months from March to May reached higher limits during OFP. This distinction further lowered operational costs during OP, bringing the annual cost down to 95.5%.

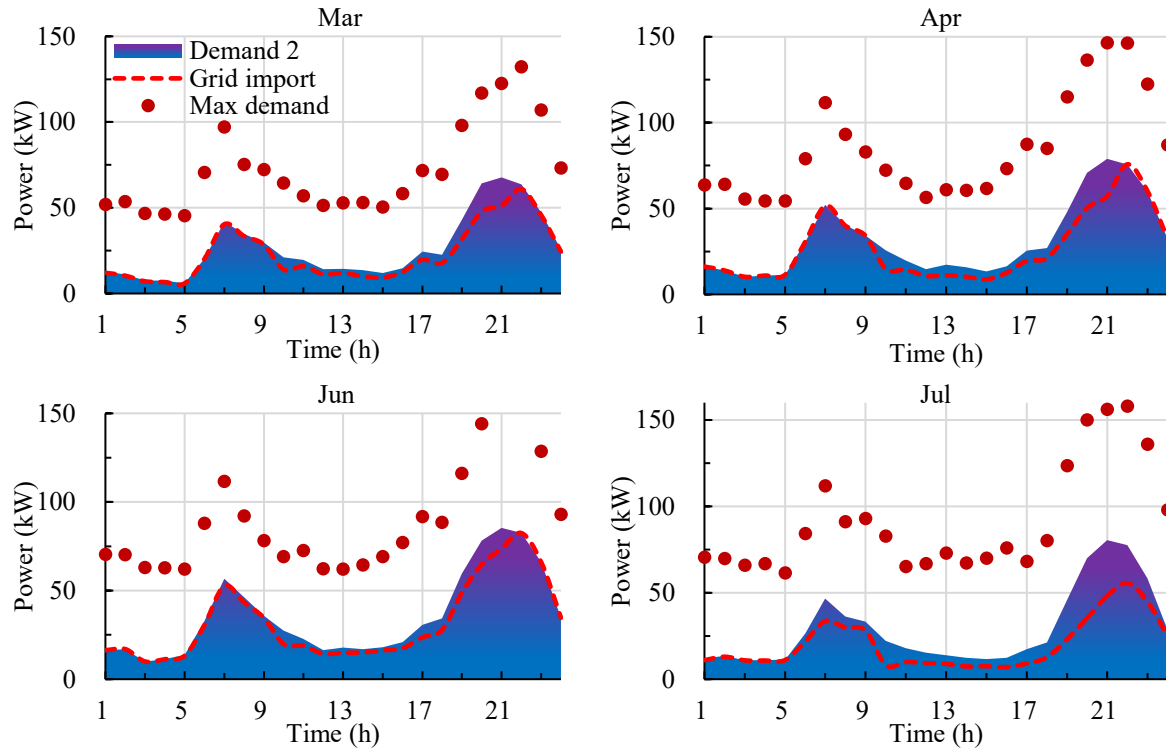


Figure III-3. Demand profile (March, April, June, and July) of Group 2 [Publication III].

Figure III-3 illustrates the demand profiles for four months (March, April, June, and July), showcasing significant energy shifting influenced by grid interactions. The red curve indicates increased grid energy import during OFP. Additionally, Group 2 did not retain the lowest value ($FSOR = 0.1$) as the discharging lower limit, which previously led to substantial power loss. Energy loss was reduced by adjusting the lower limit to values between 0.4 and 0.7 based on cost-saving strategies (refer to Table II-11). The enhancement of energy matching could be measured through $OEMe_{OP/OFP}$ and $OEFe_{OP/OFP}$, the evaluation of which concentrated on the two periods. Control measures were implemented monthly; hence, Figure III-4 displayed the monthly performance of the four indicators before applying the controls. Figure III-5 presents the results following the dynamic FOSR control. Prior to the control, there was no notable difference between $OEFe$ and $OEMe$ during both OP and OFP. The performance of $OEFe$ in the four months (January, August, November, and December) was superior compared to other months, whereas $OEMe$ demonstrated inferior performance during the same period. A higher $OEFe$ indicated reduced grid energy import, leading to lower operational costs in those months (refer to Table III-7). The $OEFe$ values for January and November, both recorded at 0.99, suggest a negligible requirement for grid energy import.

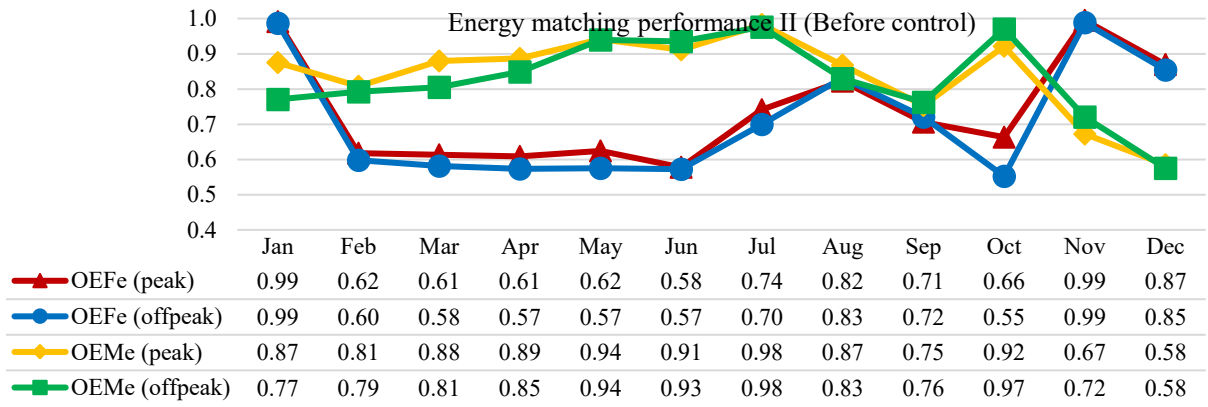


Figure III-4. Energy-matching (original) [Publication III].

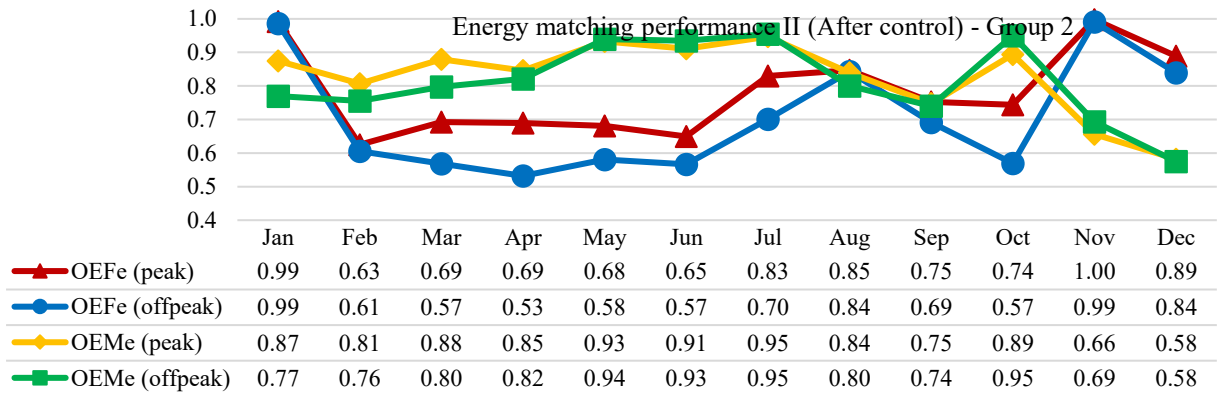


Figure III-5. Energy-matching (Group 2) [Publication III].

Adjusting the FSOR monthly and varying it between OP and OFP revealed apparent differences between OEF_{eOP} and OEF_{eOFP} due to energy shifting. Performance during OP improved, while OFP performance declined. OP typically incur higher energy charges. Hence, a better OEF_{eOP} implied reduced grid energy import during this period. Compared to the previous scenario, OEM_e exhibited minor fluctuations, with slight decreases in both OP and OFP. This was attributed to the higher set-points of the discharging limit than the original FSOR = 0.1. The reduction in power losses and improved control yielded promising enhancements in operational cost reduction.

The persistent high maximum demand highlighted the need for peak shaving, as indicated by the red points in Figure III-3. Figure III-6 presents the duration curves of each month with and without implementing volume control for the reservoir to evaluate demand spikes. The green section depicted the condition incorporating the direct power output of the hybrid system with no control measures. In contrast, the blue section represented the condition employing the reservoir's controls, complemented by wind and wave energy. Furthermore, Table III-8 details the monthly performance for PSI_{OP} during OP demand periods.

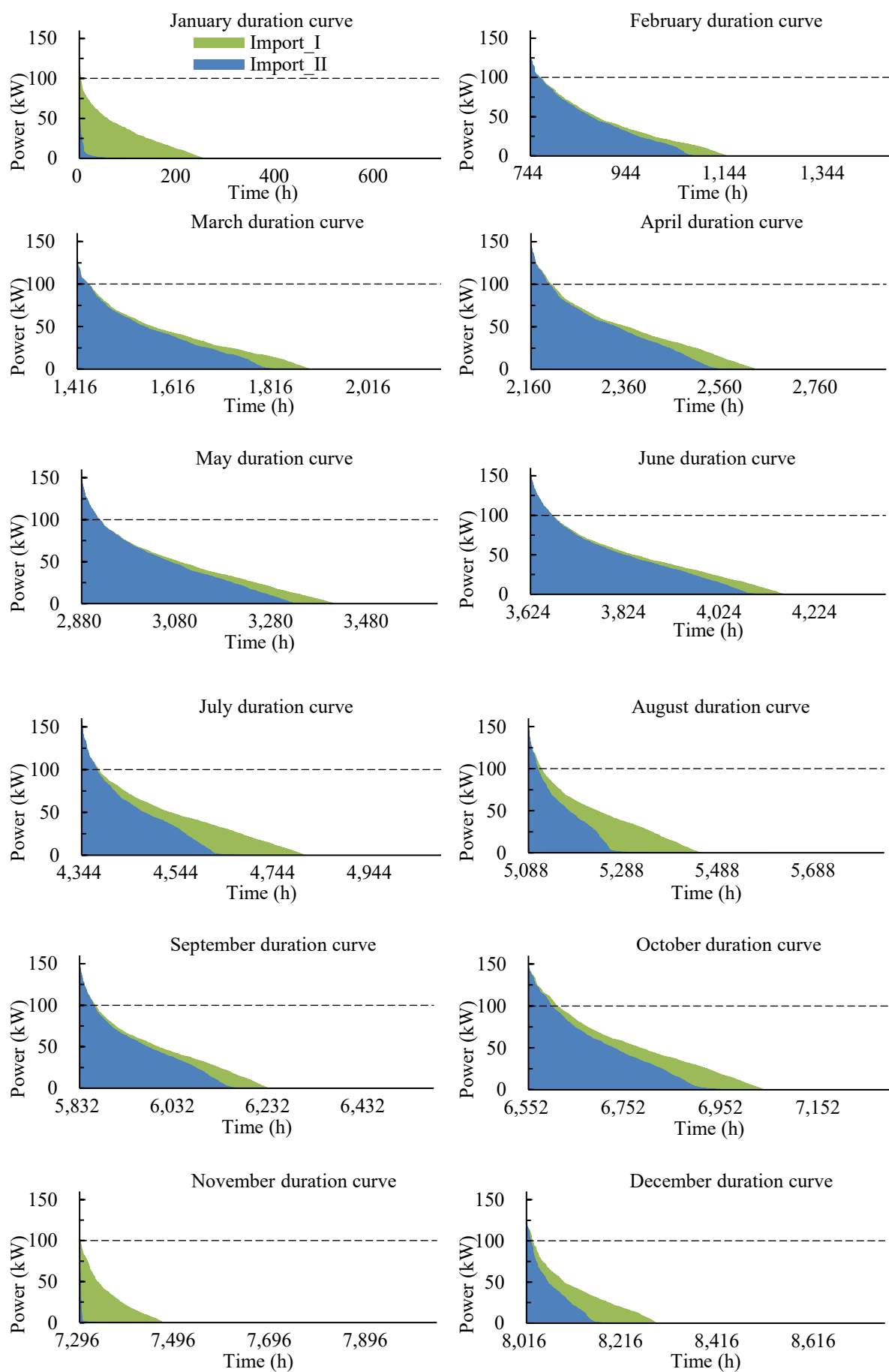


Figure III-6. Monthly duration curves with and without the volume control [Publication III].

Table III-8. Comparison of monthly PSI_{OP} with and without the volume control [Publication III].

	Area I	Area II	PSI_{OP}
Jan	24	0	100%
Feb	468	452	4%
Mar	470	355	25%
Apr	1,660	1,351	19%
May	1,527	1,522	0%
Jun	1,944	1,908	2%
Jul	1,466	1,388	5%
Aug	1,165	917	21%
Sep	1,277	1,139	11%
Oct	2,415	1,840	24%
Nov	33	0	100%
Dec	357	213	40%

A significant reduction in grid-imported energy was observed primarily due to enhancements in energy matching, aiding in lowering demand during persistent high-demand periods. This disparity arose from the weakness of wave energy resources during peak demand intervals. While employing a reservoir for wave energy storage offered some flexibility, there was still a shortfall in power to meet requirements during high-demand times. With a target of 100 kW, only January and November attained a PSI_{OP} of 100%. The Area I depicted scenarios where the demand exceeded 100 kW for cases not utilising control, relying solely on the RE system's direct power output. Area II showcased the situation using varied FSOR controls. During periods when power demands were less than or equal to 100 kW, the PSI_{OP} reached 100%. The initial demand of January and November was relatively low, as observed in Area I. In the remaining months, the peak-shaving impact was below 40%. Consequently, while energy costs decreased, demand charges persisted at high levels.

5.10 Discharging Level of Wave Energy Converter Reservoir

Methods for peak shaving were investigated to enhance the reduction of demand charges, as depicted in Figure III-1. Group 3 developed the control as an extension of the original case, with a minimum discharge limit set at 0.1. In scenarios where wind energy partially met the demand but still fell short, the WEC transformed incoming waves into power generation to fulfil the demand (Supply 1.2). If both wave and wind resources were inadequate for peak shaving, the reservoir supported the system based on the discharging line. The WEC reservoir remained inactive if it was not needed for support (Short 1).

The study focused on cases where the fixed discharging line for the OWEC reservoir ranged from 10 to 120 kW, as detailed in Table III-9. At a lower limit of 0.1, the 70 kW and 80 kW annual lines exhibited cost advantages. Table III-10 presents the case using a 70 kW annual discharging line, showcasing a monthly comparison of peak demand and operational costs. Apart from January and June, the majority of months experienced significant declines in the maximum demand, decreasing from above 120 kW to around 70 kW. In January, there was a demand increase from the lower 70 kW level, while in June, there was no successful reduction in its peak demand, remaining above 150 kW. Notably, even though there were decreased demand charges, some months showed an operational cost deficit. This suggested that excessive peak shaving control should be avoided. Consequently, the objective was to establish a suitable combination of reservoir discharges for each month.

Table III-9 Operational cost using varied discharging lines [Publication III].

Discharging line (kW)	0	10	20	30	40	50	60	70	80	90	100	110	120
Cost (HK\$)	284,463	287,421	291,323	294,606	296,474	294,268	290,503	278,363	281,439	287,424	291,836	302,567	311,352
	100%	101%	102%	104%	104%	103%	102%	98%	99%	101%	103%	106%	109%

Table III-10. OP/OFP Maximum demand and corresponding cost with a fixed discharging line [Publication III].

(HK\$)	OP	OFP	Cost	-	OP	OFP	Cost	=	Cost
Jan	46	56	7,302	Discharging line = 70 kW	70	70	14,801	Comparison	-7,499
Feb	128	126	23,725		71	71	21,906		1,819
Mar	128	132	27,041		71	71	24,815		2,226
Apr	146	146	29,999		73	73	26,602		3,397
May	147	150	32,797		72	72	27,898		4,899
Jun	153	155	35,041		153	155	34,141		900
Jul	156	158	27,954		72	72	25,849		2,105
Aug	146	149	20,693		71	72	21,613		-920
Sep	149	146	26,513		71	71	23,621		2,892
Oct	145	146	31,838		73	90	28,442		3,396
Nov	88	82	7,236		70	70	12,059		-4,823
Dec	123	122	14,323		70	71	16,616		-2,293
Annual	1,556	1,568	284,463		937	957	278,363		6,100

Table III-11. Operational cost of each month using varied discharging lines [Publication III].

(HK\$)	0	10	20	30	40	50	60	70	80	90	100	110	120
Jan	0	-1,888	-3,684	-5,044	-6,055	-6,749	-7,208	-7,498	-7,668	-7,745	-7,790	-8,495	-8,790
Feb	0	696	1,264	1,491	1,409	3,864	2,718	1,819	1,164	696	403	-404	-1,149
Mar	0	57	-105	-447	-683	-764	443	2,227	1,571	1,108	787	-46	-794
Apr	0	4	19	-10	0	8	51	3,397	2,481	1,815	1,279	258	-651
May	0	17	44	104	178	225	305	4,899	3,989	3,323	2,839	1,854	980
Jun	0	28	53	89	121	126	172	900	5,066	4,314	3,735	2,679	1,752
Jul	0	-208	-429	-539	44	-204	3,201	2,105	1,228	603	147	-817	-1,671
Aug	0	-546	-1,086	-1,583	-2,139	-2,081	-2,870	-920	-1,572	-2,046	-2,396	-3,296	-4,126
Sep	0	-129	-124	-175	-210	882	3,474	2,892	2,145	1,600	1,186	240	-609
Oct	0	898	643	429	742	315	83	3,395	2,236	1,302	576	-614	-1,638
Nov	0	-1,362	-2,431	-3,220	-3,846	-4,285	-4,597	-4,823	-4,986	-5,067	-5,103	-5,640	-5,640
Dec	0	-525	-1,024	-1,238	-1,571	-1,141	-1,813	-2,293	-2,631	-2,865	-3,035	-3,822	-4,552
Annual	0	-2,958	-6,860	-10,143	-12,011	-9,805	-6,040	6,099	3,024	-2,962	-7,373	-18,104	-26,889

Monthly operational costs associated with varied discharging lines were outlined in Table III-11. Blue bars indicated higher profits due to electricity fee reductions, while red bars represented lower profits. Most months displayed optimal benefits with a 70 kW discharging line, followed by the 80 kW line. This implies benefits from utilising varying annual discharging lines. The optimal discharging line for each month was selected based on data from Table III-11. For instance, January favoured no control (column 0), while February preferred a 50 kW discharging line. After compiling the chosen monthly discharging lines from Table III-11, a comparison of operational costs for each month was conducted, as shown in Table III-12. Compared to the scenario in Table III-10 (with a consistent discharging line for each month), changing the limit of each month led to increased cost savings and fewer deficit months. However, March and October showed less favourable outcomes with this control. Overall, annual operational costs decreased from 97.9% to 93.6% relative to the original case by implementing monthly control.

Additionally, various discharging lower limits (0.3, 0.5, 0.7, and 0.9) were explored. The same methodology was used to determine the most adequate combination of discharging lines. As shown in Table III-13, employing the

annual lower limit (FSOR=0.3) resulted in the lowest cost. Results from the last group indicated that using different lower limits for each month further reduced electricity fees. Therefore, a parametric study identified the best combination of monthly lower limits. Table III-14 presents the control parameters and summarises the operational cost comparison. Every month, the tariff reported either a profit or breaking even, leading to a decrease in annual operational costs from HK\$261,501 to HK\$259,660.

Table III-12. Operational cost using varied monthly lines (FSOR = 0.1) [Publication III].

(HK\$)	Cost	Monthly line	Cost		Cost
Jan	7,302	0	7,302	Comparison	0
Feb	23,725	50	22,364		1,361
Mar	27,041	70	27,851		-810
Apr	29,999	70	26,602		3,397
May	32,797	70	27,925		4,872
Jun	35,041	80	29,982		5,059
Jul	27,954	60	26,038		1,916
Aug	20,693	0	19,735		958
Sep	26,513	60	24,927		1,586
Oct	31,838	70	32,311		-473
Nov	7,236	70	6,891		345
Dec	14,323	71	14,323		0
Annual	284,463	(kW)	266,251		18,212

Table III-13. Operational cost using varied discharging limits [Publication III].

FSOR	0.1	0.3	0.5	0.7	0.9
Cost	266,251	261,501	269,865	274,275	285,918
(HK\$)	93.60%	91.90%	94.90%	96.40%	100.50%

Table III-14. Operational cost employing monthly lines and mixed FSOR [Publication III].

(HK\$)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Cost	7,302	23,725	27,041	29,999	32,797	35,041	27,954	20,693	26,513	31,838	7,236	14,323	284,463
Discharging line	0	50	0	70	70	80	70	0	70	80	0	0	(kW)
Lower limit	0.1	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.1	
OP	46	122	128	73	87	82	72	146	71	81	2	123	(kW)
OFP	56	126	132	73	83	83	72	149	71	82	2	122	(kW)
Cost	7,302	22,364	26,318	26,602	27,925	29,982	25,848	18,880	23,621	29,606	6,889	14,323	259,660
Comparison													
Cost	0	1,361	724	3,397	4,872	5,059	2,106	1,813	2,892	2,231	348	0	24,803

Table III-15. Setting of mixed discharging lines and limits [Publication III].

	Period	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Discharging line (kW)	OP	0	90	20	70	70	80	60	0	70	70	0	0
	OFP		50	0				70					
Lower limit	OP	0.1	0.2	0.3	0.3	0.3	0.3	0.3	0.4	0.3	0.3	0.3	0.1
	OFP		0.9						0.9				0.5

As depicted in Table III-14, February, March, August, and December experienced significant demand spikes. To tackle the challenge, specific controls were implemented, blending lower limit establishment and discharging line adjustments during these months. Through extensive simulations, the study identified a more effective set of mixed controls that mitigated the spike and reduced cost, as illustrated in Table III-15. In February, the discharge line parameters were delineated into OP and OFP segments, configured to operate at 90 kW and 50 kW, respectively. Moreover, the lower limit was set at FSOR = 0.2 when demand exceeded the discharging line during the OP; otherwise, it was fixed at FSOR = 0.9. For March, the OP discharging line was raised to 20 kW while

maintaining the OFP line at zero. In August, the variation in discharging limits across two periods was adjusted to FSOR = 0.4 if demand surpassed the line during the OP; if not, it remained FSOR = 0.9. The December settings were reverted to Group 2, utilising OP/OFP lower limits, as the previous strategy was not advantageous for effective peak-shaving control. In July and October, operational costs failed to meet expectations under the prior control configuration. As a response, the control strategy segmented the discharge line into distinct intervals for these months. Specifically, the discharging lines were decreased by 10 kW during the OP.

To assess the impact of the proposed control method, which combined varied discharging limits and lines, Table III-16 presents relevant results concerning maximum demand during OP and OFP, along with operational costs. December had no additional controls to enhance performance, thus maintaining the unchanged results. Although the maximum demand in August was not reduced, the associated energy charges related to energy shifting decreased. Figure III-7 and Figure III-8 showcase the demand profiles with and without implementing the mixed control. Peak demand was reduced during OP in February (from 122 kW to 91 kW) and March (from 128 kW to 122 kW). Furthermore, Peak demands during the OFP in February were reduced from 126 kW to 54 kW. Despite July and October already showing reduced peaks, there were still opportunities to optimise demand further through the variations in both OP and OFP discharging lines.

Table III-16. Maximum demand and profit before and after using mixed control [Publication III].

(HK\$)	Feb	Mar	July	Aug	Oct	Dec	Annual
Before mixed control							
OP	122	128	72	146	81	123	(kW)
OFP	126	132	72	149	82	122	(kW)
Cost	22,364	26,318	25,848	18,880	29,606	14,323	259,660
After mixed control							
OP	91	122	62	146	72	123	(kW)
OFP	54	132	72	149	83	122	(kW)
Cost	21,367	25,611	25,331	18,856	29,115	14,256	256,857
Profit	997	707	517	63	491	67	1,834

A more detailed figure illustrating the relationship between energy demand and production was required to understand why certain spikes were eliminated or remained. Figure III-9 for February displays this comparison between adopting and not adopting mixed controls. These figures showed the profiles of RE production from WEC and offshore WT, building electricity demand, and grid-imported energy at a 0.25-hour time step. In February, there had been a plentiful supply of wave energy from the start, but energy levels weakened during the ~600–800 timestep, leading to spikes exceeding 100 kW. The control system elevated the discharging capacity during peak periods from 50 kW to 90 kW, reserving wave energy to address the following energy shortages. Additionally, the available discharging volume was adjusted to maintain an adequate seawater storage level, successfully achieving peak shaving during both periods.

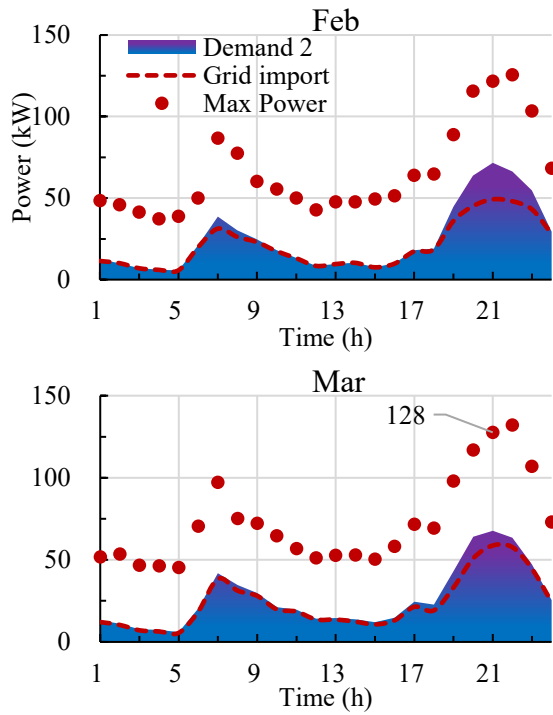


Figure III-7. Demand profile without mixed control [Publication III].

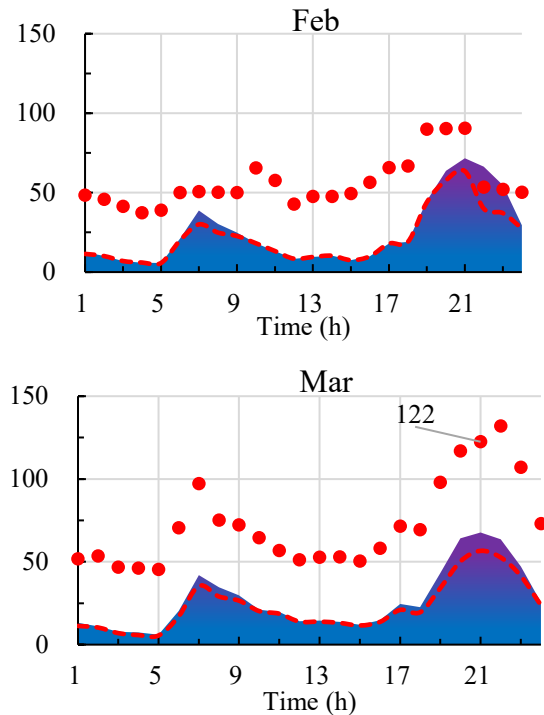


Figure III-8. Demand profile with mixed control [Publication III].

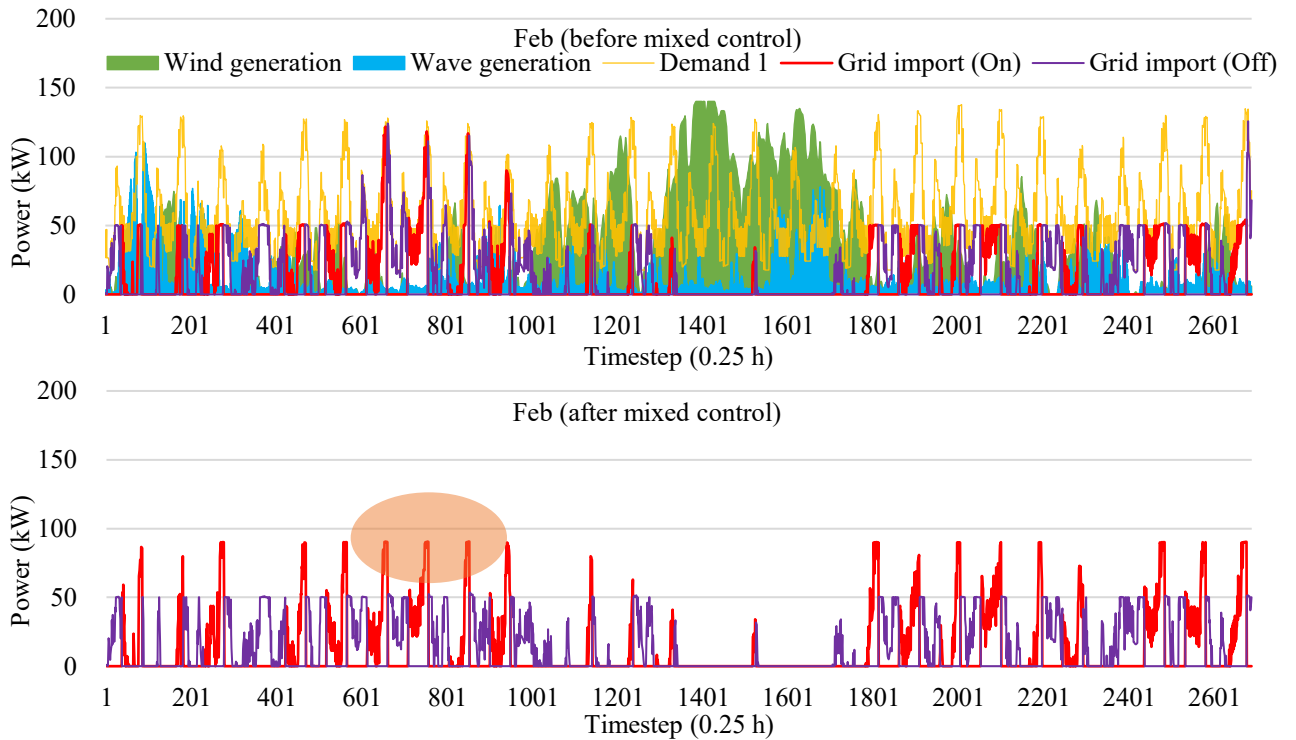


Figure III-9. Detailed profiles of energy generation and demand before and after mixed controls (February) [Publication III].

Three cases (original case, Group 2, and Group 3) were compared in Table III-17, providing a comparative analysis of operational costs. Group 2 implemented dynamic monthly discharge limits, taking into account both OP and OFP. In contrast, Group 3 adopted a strategy with variable monthly reservoir discharge parameters, also considering the distinctions between OP and OFP. Furthermore, Group 3 leveraged discharging limit controls

similar to those used in Group 2. Group 2's approach effectively reduced OP costs by strategically transferring imported energy from high-rate to low-rate periods, resulting in diminished annual operational costs during OP, although OFP costs rose relative to the original case. Conversely, Group 3's demand-centric control strategy not only achieved reductions in energy charges but also minimised demand charges across both OP and OFP, contributing to overall cost reductions in both scenarios. In summary, Group 2 decreased the operational cost reduction to 95.5%, while Group 3 realised an even more significant decrease, bringing costs down to 90.3%.

Table III-17. Comparison of operational cost among various groups [Publication III].

(HK\$)		OP	OFP	Total		OP	OFP	Total		OP	OFP	Total
Jan	Original (100%)	7,010	293	7,302	Group 2 (95.5%)	7,010	293	7,302	Group 3 (90.3%)	7,010	293	7,302
Feb		15,680	8,046	23,725		15,545	7,880	23,424		14,318	7,049	21,367
Mar		17,083	9,958	27,041		15,009	10,405	25,414		16,206	9,405	25,611
Apr		18,750	11,249	29,999		16,940	12,326	29,266		15,620	10,982	26,602
May		20,032	12,766	32,797		18,532	12,591	31,123		16,106	11,819	27,925
Jun		22,010	13,031	35,041		20,054	13,197	33,251		17,504	12,478	29,982
Jul		17,980	9,974	27,954		15,486	9,904	25,390		14,132	11,199	25,331
Aug		15,177	5,516	20,693		14,453	5,144	19,597		13,815	5,041	18,856
Sep		17,849	8,664	26,513		16,636	9,553	26,189		14,459	9,162	23,621
Oct		18,728	13,110	31,838		16,630	12,619	29,249		15,905	13,210	29,115
Nov		6,952	284	7,236		6,881	218	7,099		6,861	27	6,889
Dec		11,002	3,321	14,323		10,611	3,645	14,256		10,611	3,645	14,256
Annual		188,252	96,211	284,463		173,787	97,773	271,560		162,548	94,309	256,857

The comparison of monthly duration curves with and without peak-shaving control is depicted in Figure III-10, which shows the changes in the duration curves through implementing peak-shaving control. Table III-18 compares monthly PSI_{OP} with and without peak-shaving control. Notably, March, August, and December failed to meet the 100% PSI_{OP} , which was the target reached in all other months. Compared to Group 2, the duration curves for most months under Group 3 exhibited a different shape. For instance, Group 3 achieved a 100% peak shaving performance in May, whereas Group 2 recorded a PSI_{OP} of zero for that month. The target area was delineated as the difference between the strategies of the two groups: Group 2's strategy involved energy shifting without regard to demand levels, while Group 3 explicitly focused on peak demand intervals. Consequently, for most months, as shown in Figure 7-6, the duration curves indicated a reduction in demand during later time steps compared to Group 2's control. On the other hand, Group 3's control effectively reduced demand during earlier time steps for most months (as illustrated in Figure III-10), alleviating periods of peak demand.

Table III-18. Comparison of monthly PSI_{OP} with and without peak-shaving control [Publication III].

	Area I	Area II	PSI_{OP}
Jan	24	0	100%
Feb	468	0	100%
Mar	470	355	25%
Apr	1,660	0	100%
May	1,527	0	100%
Jun	1,944	0	100%
Jul	1,466	0	100%
Aug	1,165	676	42%
Sep	1,277	0	100%
Oct	2,415	0	100%
Nov	33	0	100%
Dec	357	213	40%

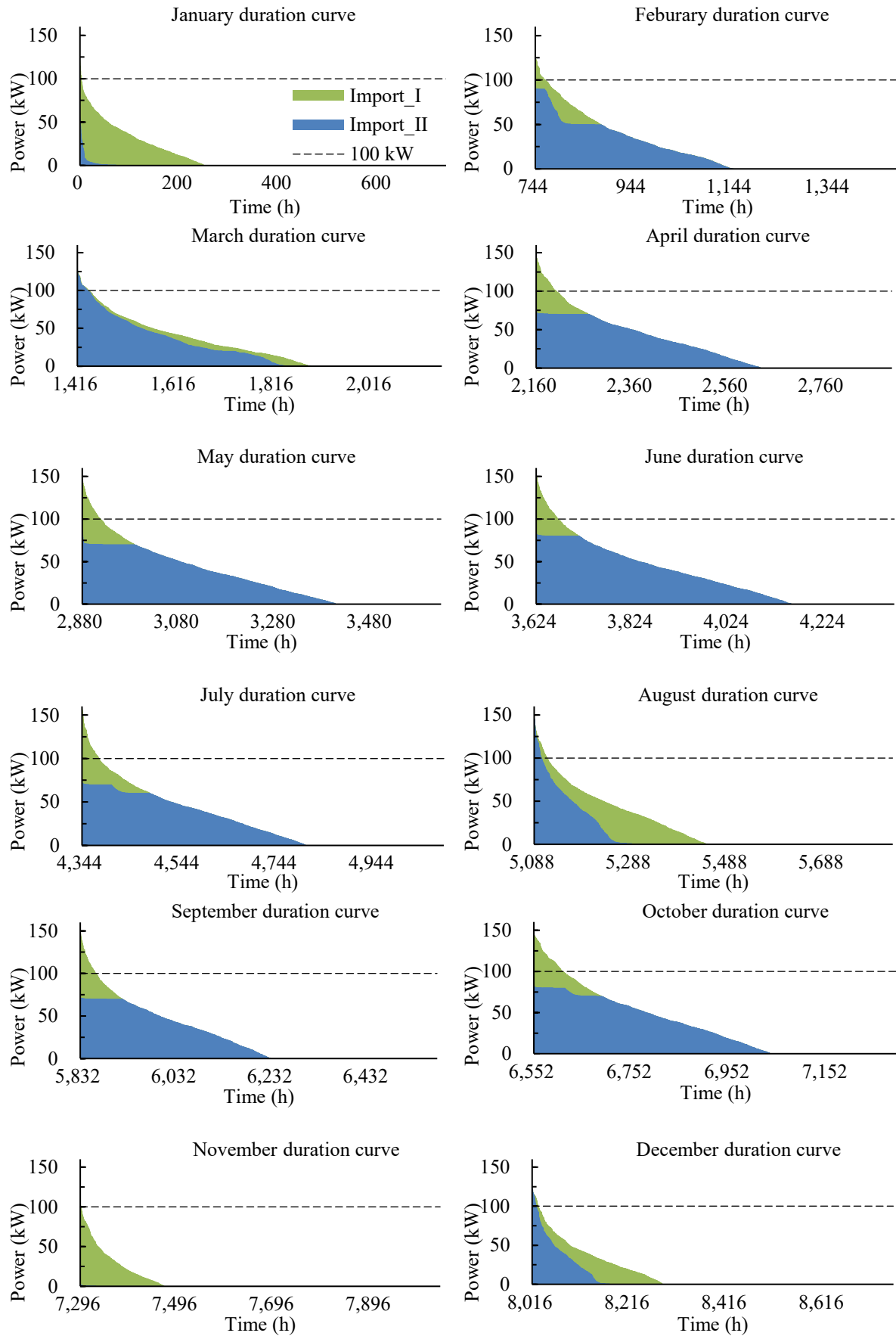


Figure III-10. Monthly duration curves with and without peak shaving control [Publication III].

The implications of peak shaving were further elucidated in Figure III-10. Under Group 3's control for specific months, the duration curve exhibited flat segments in the early stage, a result of trigger lines aimed at reservoir release during OP and OFP. The two flat lines, in instances like February, July, and October, were generated by peak-shaving control and corresponded to varying discharging limits for OP and OFP, serving as an efficient constraint for the discharge function. Both demand and energy charges were taken into account to elaborate on the benefits. Months with a single flat line indicated a consistent incentive line throughout the period. In contrast, months that either failed to implement peak-shaving control or did not necessitate it displayed a shape similar to that of Group 2.

Figure III-11 illustrates the performance measured through $OEMe_{OP/OFP}$ and $OEFe_{OP/OFP}$ following the mixed control implementation. Despite significant improvements in operational costs and peak demand reductions in this group, the energy-matching performance did not show enhancement. When comparing the results to previous groups (as shown in Figure III-4 and Figure III-5), minor fluctuations were observed at specific points with the energy shifting and peak shaving control strategies. The general trend and monthly values exhibited similar characteristics to those observed in previous cases. This similarity stems from the original case's effective performance utilising an OWEC inherent reservoir for storing wave energy, as detailed in prior research, rather than solely relying on the WEC's direct output.

The findings suggest that Group 3 leveraged stored wave energy more effectively with the designed methods from an economic standpoint. In scenarios with fluctuating wave energy resources and limited reservoir capacity, Group 2 redirected surplus energy from OFP to OP, generating the energy pricing differentials. Additionally, Group 3 evaluated the present demand status to determine the most profitable energy supply quantity. Consequently, there was no necessity to discharge excess energy from the reservoir when the additional release was not economically viable. This approach effectively prevented missing the chance to mitigate impending demand spikes, which holds a higher value.

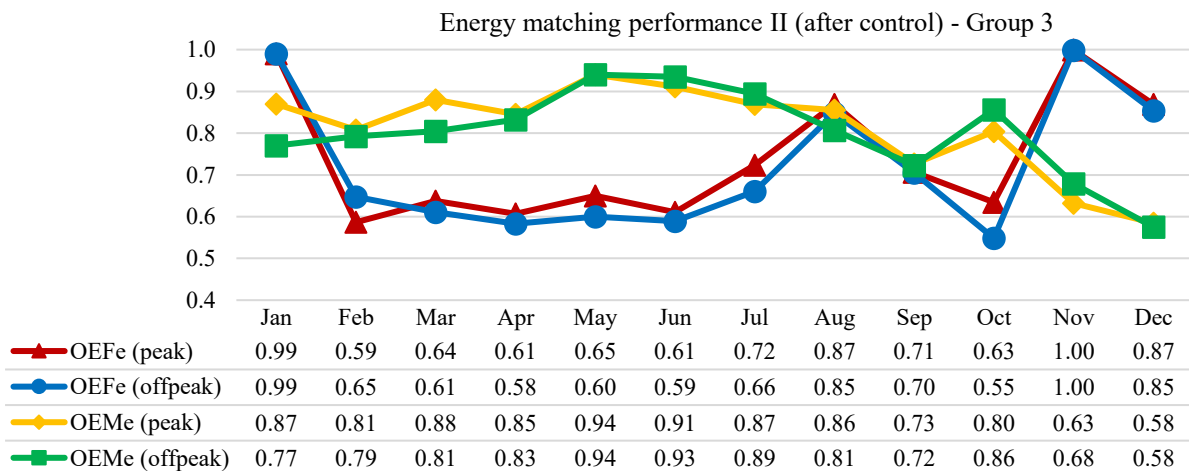


Figure III-11. Energy-matching (Group 3) [Publication III].

5.11 Supplementary Battery Control

According to the data in Table III-16, a need remained to address the maximum demand exceeding 100 kW observed in the months of March, August, and December. Group 4 added the battery as a supplementary flexibility source for peak shaving enhancement. The flowchart depicting Group 4's operations is presented in Figure III-1. Excess energy generated by wind energy charges the battery to its capacity. When the battery was full, any excess energy was transferred from the WEC to the battery. This new battery was specifically employed for peak shaving and discharging if RE, including the WEC reservoir, failed to satisfy system requirements. Discharge occurred only when demand surpassed the designated trigger line; otherwise, grid support was utilised.

Further peak shaving was only necessary for three months, with the battery discharging based on present demand without extra control. The discharging line was initially established for March, August, and December to assess potential enhancements. Various battery capacities ranging from 10 to 150 kWh were explored to determine the optimal monthly discharge incentive line through extensive simulations, considering operational costs. Table III-19 contrasts the annual performance of the groups before and after peak shaving control through the battery, showcasing different combinations based on varying battery capacities. Group 3 exhibited the most significant cost reduction without using a battery (0 kWh), forming the basis for calculating cost percentages.

In March, the absence of added benefits from adopting battery controls led to the removal of the incentive line for that month. In August, only beneficial when the battery capacity exceeds 100 kWh. December did not yield financial gain with low battery capacities (10 and 20 kWh) with control. However, operational cost reductions were observed when the battery capacity reached 30 kWh compared to the scenario without control. The table's right-side details both OP and OFP's maximum power for each month. The cost reduction in December was attributed to peak shaving for battery capacities with 20-100 kWh. In August, additional peak shaving benefits were evident for cases with 110-150 kWh battery capacities. Ultimately, the group achieved the desired line with a capacity of 140 kWh.

Table III-19. Effect of battery capacities on operational cost.

Battery	0	10	20	30	40	50	60	70	80	90	100	110	120	130	140	150	
Operational cost (HK\$)																	
Without control	256,857	255,105	253,745	252,570	251,527	250,591	249,731	248,956	248,250	247,615	247,014	246,439	245,903	245,417	244,960	244,522	
	100%	89.7%	89.2%	88.8%	88.4%	88.1%	87.8%	87.5%	87.3%	87.1%	86.8%	86.6%	86.4%	86.3%	86.1%	86.0%	
With control	/	255,133	253,757	252,510	251,330	250,374	249,452	248,668	247,961	247,325	246,716	244,684	244,093	243,108	242,363	241,770	
	/	89.7%	89.2%	88.8%	88.4%	88.0%	87.7%	87.4%	87.2%	86.9%	86.7%	86.0%	85.8%	85.5%	85.2%	85.0%	
Discharging line (kW)																	
March	/	0															
August	/	0											120				
December	/	100															
Maximum demand (kW)																	
August	On	146											120				
	Off	149											133				
December	On	122	122	121	117	117	117	117	117	117	117	114	112	101	100	100	
	Off	122	122	122	122	121	119	118	118	118	118	118	118	117	107	100	

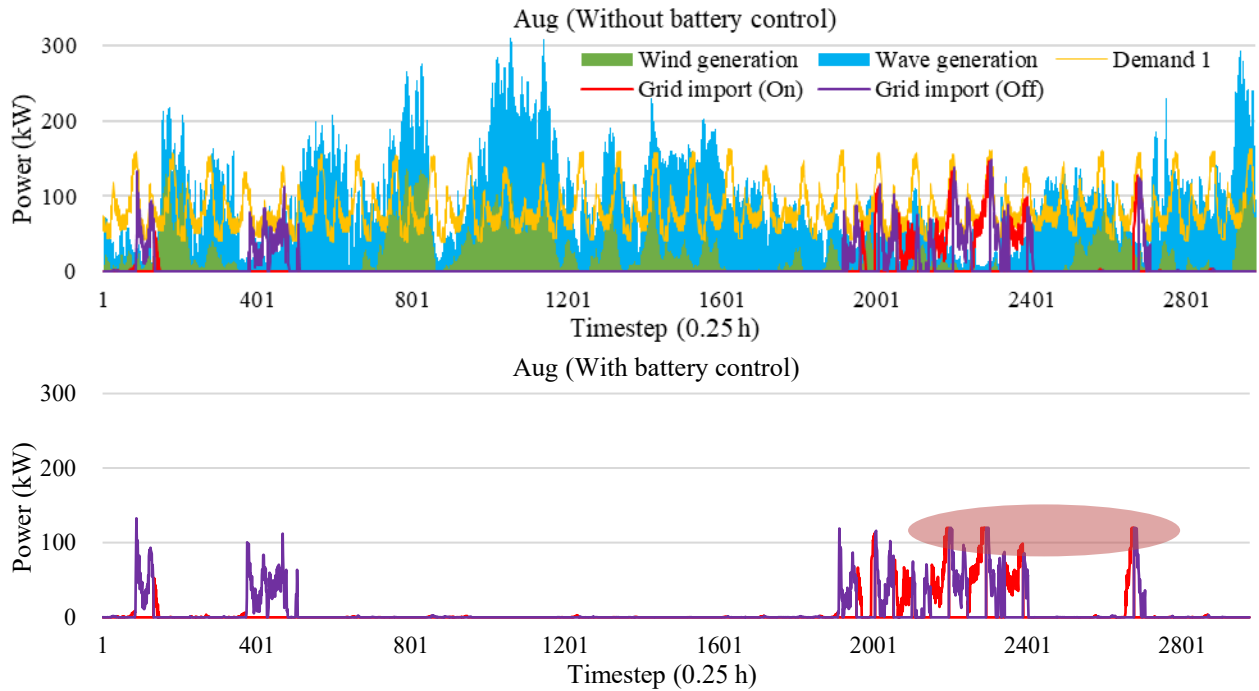


Figure III-12. Energy demand and generation profile before and after battery control in August [Publication III].

Figure III-12 visually presents the impact of battery control on peak shaving. The figure compares energy demand and generation profile before and after battery control in August, specifically focusing on scenarios utilising a 150 kWh battery. While no profitable method was found to mitigate the spikes observed in March, the situation in August was quite different, with abundant renewable resources, especially wave energy. When the proposed battery system was active, there was no need to import energy from the grid during this period. Several demand spikes were noted during the ~2000-2400 timestep period. With battery control, the maximum power was maintained at 120 kW during the OP. However, this approach limited the ability to fulfil the requirement when it dropped below 120 kW in order to reserve energy. As a result, many demand spikes were clustered at the lower levels in this scenario.

Table III-20. Economic impacts with/without control under varied battery capacities [Publication III].

Battery (kWh)	Operational cost (HK\$)		NPV (HK\$)	Operational cost (HK\$)		NPV (HK\$)
Original	284,463	100.00%	0			
0	256,857	90.30%	469,082			
10	255,105	89.68%	471,526	255,133	89.69%	471,059
20	253,745	89.20%	467,314	253,757	89.21%	467,114
30	252,570	88.79%	459,961	252,510	88.77%	460,969
40	251,527	88.42%	450,362	251,330	88.35%	453,710
50	250,591	88.09%	438,942	250,374	88.02%	442,635
60	249,731	87.79%	426,228	249,452	87.69%	430,969
70	248,956	87.52%	412,073	248,668	87.42%	416,968
80	248,250	87.27%	396,750	247,961	87.17%	401,654
90	247,615	87.05%	380,217	247,325	86.94%	385,147
100	247,014	86.84%	363,111	246,716	86.73%	368,173
110	246,439	86.63%	345,552	244,684	86.02%	375,376
120	245,903	86.44%	327,342	244,093	85.81%	358,097
130	245,417	86.27%	308,278	243,108	85.46%	347,511
140	244,960	86.11%	288,721	242,363	85.20%	332,842
150	244,522	85.96%	268,839	241,770	84.99%	315,597

The analysis indicates the ability of the battery to provide flexibility. Table III-20 presents the Economic impacts with/without control under varied battery capacities. Except for the original case, the best scenario was chosen from Group 3 as the “0 kWh” case in the table. The relative operational cost was evaluated in comparison to the original case, with the NPV_{rel} being set to zero. The table compares the battery capacities ranging from 10 to 150 kWh. The left part illustrates the standard surplus and shortage logic based on energy generation and demand. The right part demonstrates the implementation of peak shaving through the battery during August and December.

NPV_{rel} was obtained based on the operational cost savings, while the battery cost is considered an outflow. The system's working period was set at 20 years, incorporating an annual price escalation of the general electricity fee at 1.315%, which was estimated based on tariff variations over the past two decades [167]. Currently, the battery cost is assumed to be US\$200 per kWh, with a lifespan of ten years [166]. The replacement cost of the battery was based on an interest rate (2.807%), reflecting the average level over five years [168]. Different levels of investment and replacement costs were applied for various scenarios.

In the no-battery case, an operational cost of HK\$469,082 was achieved after implementing several control measures involving the variable wave energy storage release trigger line and dynamic discharge set point. Since no batteries were utilised, the outflow was assumed to be zero. The control mechanism was built with a self-contained reservoir, avoiding extra component costs. Costs related to system modifications were not considered in this analysis. Since no batteries were utilised, no outflow was assumed. The control mechanism was designed around an OWEC built-in reservoir without incurring extra costs; potential investment costs related to the system's modifications were not included in this analysis.

Table III-20 displayed that the NPV_{rel} of various cases was all positive. Operational costs gradually reduced as the battery capacity increased from 10 to 150 kWh. However, the cases involving 10 kWh and 20 kWh batteries proved to be less cost-effective when factoring in battery expenses, resulting in worse NPV_{rel} compared to scenarios without employing battery control. On the other hand, the larger battery capacities demonstrated a clear advantage, which was reflected in both operational costs and NPV_{rel} results. Notably, only the case of 10 kWh showed a superior NPV_{rel} compared to the no-battery scenario. In this instance, the system reduced the maximum demand from 123 kW to 122 kW, but it limited the discharging at low-demand times, as indicated in Table III-21. The decrease in demand charges was overshadowed by the rise in energy charges across both periods. In the controlled scenario, there were many small demand instances left. Additionally, the performance of the smaller battery in peak shaving was subpar, leading to the overall poor performance of the control group.

On the other hand, the 150 kWh case presented several advantages associated with the control strategy. As outlined in Table III-21, the scenario initially delivered advantages in terms of demand charges during the OP, primarily due to peak shaving, which reduced consumption from 123 kW to 100 kW. While the highest power of OFP also decreased. As the maximum demand for the OFP did not exceed that of the OP, the billing structure did not impose OFP demand charges. However, restricting OP energy usage impacted potential economic savings. The shift of energy from OFP led to increased operational costs. Nevertheless, the overall cost reduction outweighed this increase. It is important to note that the NPV_{rel} decreased as battery size increased, indicating that the cost savings

were insufficient to offset the investment in larger batteries. Throughout the study, the battery had a minor impact, with less than 2,000 cycles of usage. The battery was intended for replacement after a 10-year utilisation, which also strained the economic advantage due to additional costs. Additionally, the newly proposed battery control strategy was only implemented for two months annually, resulting in limited benefits. Therefore, the investment was not completely regained due to the comparatively high costs, except in the 10 kWh battery case.

Table III-21. Comparison between with and without control using a 10 kWh/150 kWh battery [Publication III].

Item	OP/OF period	10 kWh		150 kWh	
		Non-control	Control	Non-control	Control
Maximum demand (kW)	On	123	122	123	100
	Off	122	122	122	100
Energy (kWh)	On	2133	2147	2129	2096
	Off	3774	3800	3661	3751
Demand charge (HK\$)	On	8389	8377	8389	6840
	Off	0	0	0	0
Energy charge (HK\$)	On	1606	1617	1603	1578
	Off	2551	2569	2475	2536

(IV) Study on Energy Resilience Enhancement against Grid Outages for a Zero-Emission Hotel Building via Optimal Energy Management of EVs, Building Batteries and Wave Energy Storages

This study extensively explored the sources of flexibility for grid events (PDM and outage) [154]. Four categories were identified, as illustrated in Figure IV-1, comprising both single- and hybrid-activation studies for enhancing flexibility and resilience. To analyse PDM flexibility, three PDM frequencies were established. In scenarios employing a single activation, each source reacted independently to PDM events, with other sources remaining inactive. In contrast, the hybrid group involved sources responding sequentially according to a predefined priority. Incentives are paid for each kWh of verified reduction, calculated as the difference between a participant's baseline consumption (the average of the three highest-demand days in the preceding ten non-event days) and actual usage during the event.

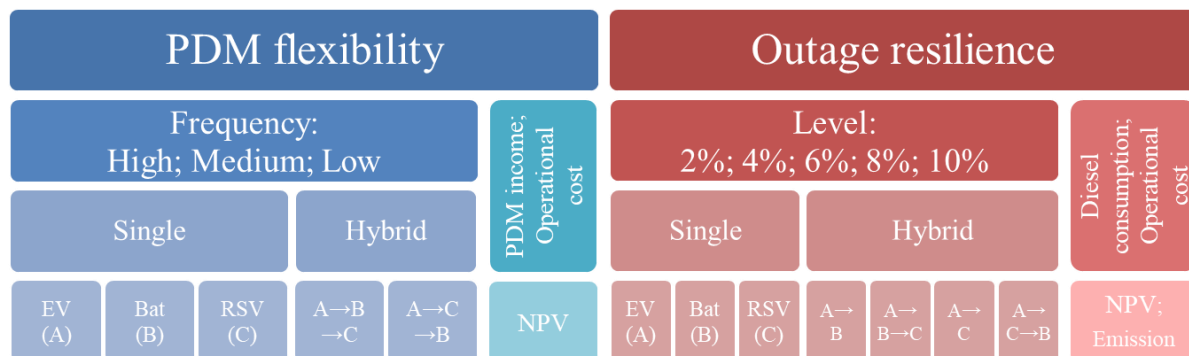


Figure IV-1. Research steps for PDM flexibility and outage resilience enhancement [Publication IV].

The evaluation focused on three key indicators: relative flexibility, operational cost, and NPV_{rel} . A case characterised by non-dominance under medium PDM frequency was selected to assess system resilience against outages. Both groups, single- and hybrid-activation, were evaluated across five outage levels (2%, 4%, 6%, 8%, and 10%). Additionally, the hybrid scenario analysed the simultaneous control of two sources. The performance

of these groups was assessed based on metrics such as diesel consumption, operational cost, NPV_{rel} , and emissions. Finally, sensitivity analyses were performed to examine the effect of different key parameters on both economic and technical performance.

5.12 Source Activation for Demand Response Programmes

This study focused on enhancing techno-economic performance by utilising flexibility sources from EV batteries, OWEC reservoirs, and building batteries during PDM events. The analysis began with the activation of a single flexibility source for each type, starting with the medium-frequency PDM condition. Subsequently, the system was tested under low- and high-frequency PDM to assess performance. The potential for enhancement through the coordination of different flexibility sources was assessed using optimal parameters derived from the simulation results of each source.

5.12.1 Single Flexibility Activation

(1) Electric Vehicle Battery

The study analyses the regulation of the EVs' charging and discharging modes when they park at the building. Each shuttle bus has a 355-kWh battery, with operational schedules outlined in Section 3.2.6. When a notification of an upcoming PDM event is received within 24 hours, buses are required to charge from the end of their last trip until 9:00 the next day. The charging target was adjusted from the original value, which is $FSOC = 0.33$, to a new value, referred to as “a” (where $0.33 \leq a \leq 0.95$), as depicted in Figure IV-2. Furthermore, the V2B was limited to save energy for the event, and the minimum discharge limit has been updated from the previous $FSOC$ value of 0.4 to a new value, referred to as “b” ($0.33 \leq b \leq 0.95$).

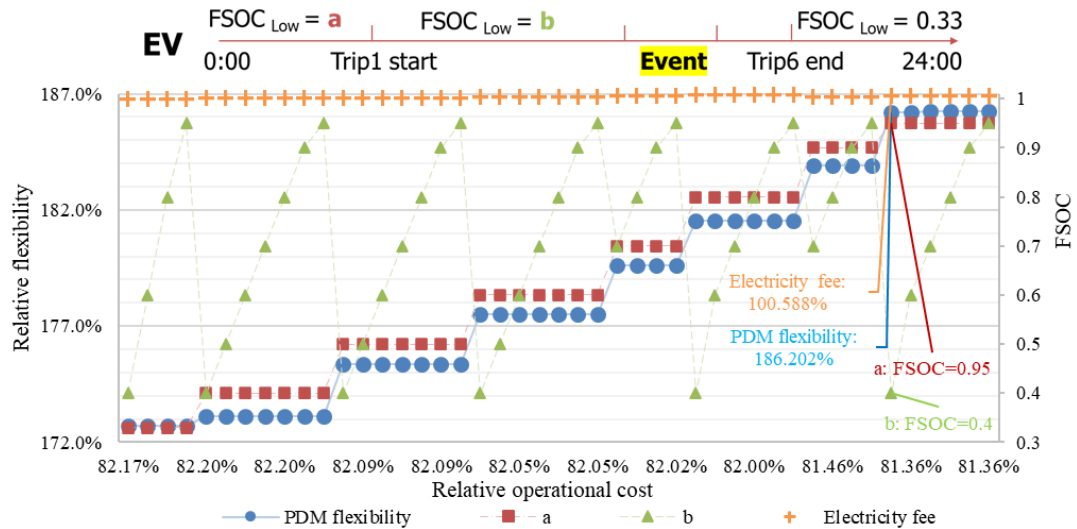


Figure IV-2. Techno-economic performance of different EV parameter combinations with the medium PDM [Publication IV].

Figure IV-2 illustrates results from various combinations of “a” and “b”, emphasising their influence on electricity costs, PDM flexibility, and operational expenses, all expressed as percentages of baseline scenarios. The relative electricity fee is calculated using an original value, while PDM flexibility reflects total demand reduction during PDM at the specified frequency. Operational costs are derived by subtracting incentives from PDM participation

from electricity fees. The X-axis represents operational costs; the left Y-axis shows flexibility (blue dots), and the right Y-axis displays FSOC parameter settings, with “a” marked by red squares and “b” by green triangles. The results indicate that higher charging targets for “a” generally led to increased electricity fees but also improved PDM flexibility, with “b” having minimal impact. Stricter discharge limits before the event further enhanced overall performance.

(2) Wave Energy Converter Reservoir (RSV)

The second source of flexibility considered was the built-in reservoir of the WEC, which captured waves that overtopped the system. This reservoir functioned similarly to pumped hydroelectric storage, as it could store wave energy for later use. Incoming waves were collected in a tank positioned above sea level. When electricity is required, stored seawater in a tank above sea level is released to the turbines when needed, converting potential energy into electricity. The reservoir's state of charge (FSOR, range 0–1) directly influences power output, with a lower FSOR indicating less stored energy. Prior studies set the discharge limit at FSOR = 0.5 [127].

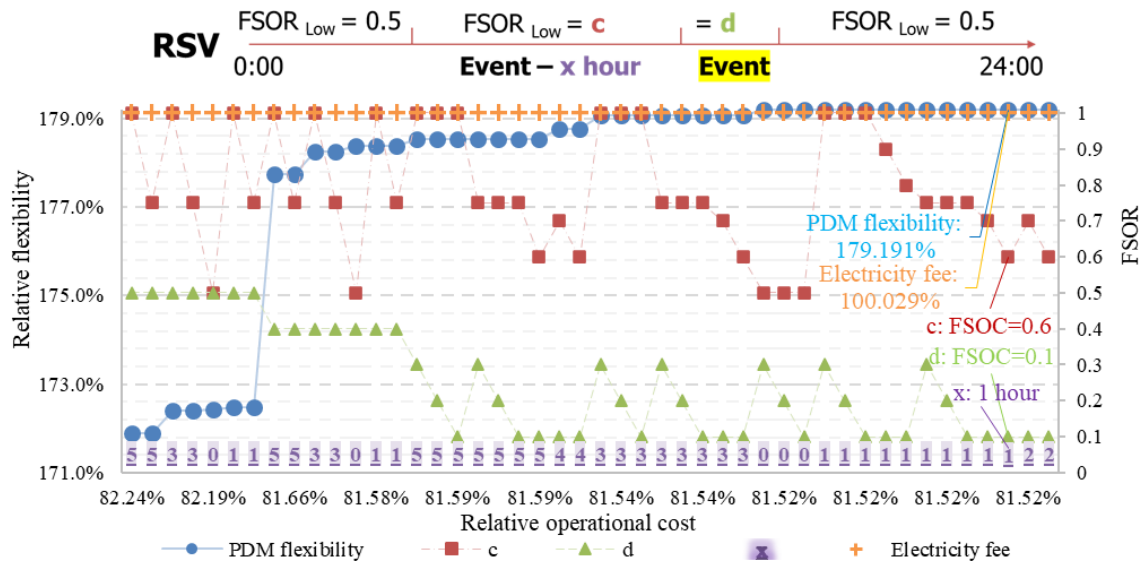


Figure IV-3. Techno-economic performance of different RSV parameter combinations with the medium PDM [Publication IV].

As illustrated in Figure IV-3, three variables were assessed by activating the flexibility of the WEC reservoir. Parameter “c” ($0.5 \leq c \leq 1$) served as the setpoint for the discharging restriction before an event. Parameter “x” represented the advance notice time for scheduling seawater reservation, while parameter “d” ($0.1 \leq d \leq 0.5$) set the minimum allowable seawater discharge from the WEC during the event. In the initial configuration, with “c” at 0.5 and FSOR at 0.5, lowering the “d” led to higher electricity costs, although it enhanced PDM flexibility, as depicted in the figure. The “d” demonstrated minor sensitivity when it fell below 0.3. Raising the “c” resulted in reduced electricity costs without sacrificing flexibility. Furthermore, extending the reservation period for seawater (increasing “x”) also reduced electricity costs, yet extending “x” negatively impacted flexibility. The examination of final operational costs indicated a preference for smaller values of “d” and “x.” Ideally, keep “d” at or below 0.3, while setting “x” to 1 or 2. Furthermore, the value of “c” could be increased beyond the initial 0.5, with 0.6 being adequate, as larger values offered no additional advantages.

(3) Building Battery (Bat)

The building's static 600-kWh battery serves as the other source of flexibility. Typically, the battery was charged using RE to the maximum FSOC limit of 0.95. When both RE and EV batteries fell short of meeting demand, the building battery provided support, operating with a minimal FSOC threshold of 0.2. Upon notification of a following PDM event, the system switched the relevant control variables into a preparatory state. As illustrated in Figure IV-4, the flexibility control of the building battery was activated to investigate these variables. Variable “e” ($0.2 \leq “e” \leq 0.95$) represented the setpoint for maintaining energy levels prior to the event. The “x” represents the preparation time needed to schedule a reservation. During this reservation period, parameter “f” ($0.2 \leq “f” \leq 0.95$) determined the battery's discharging limit.

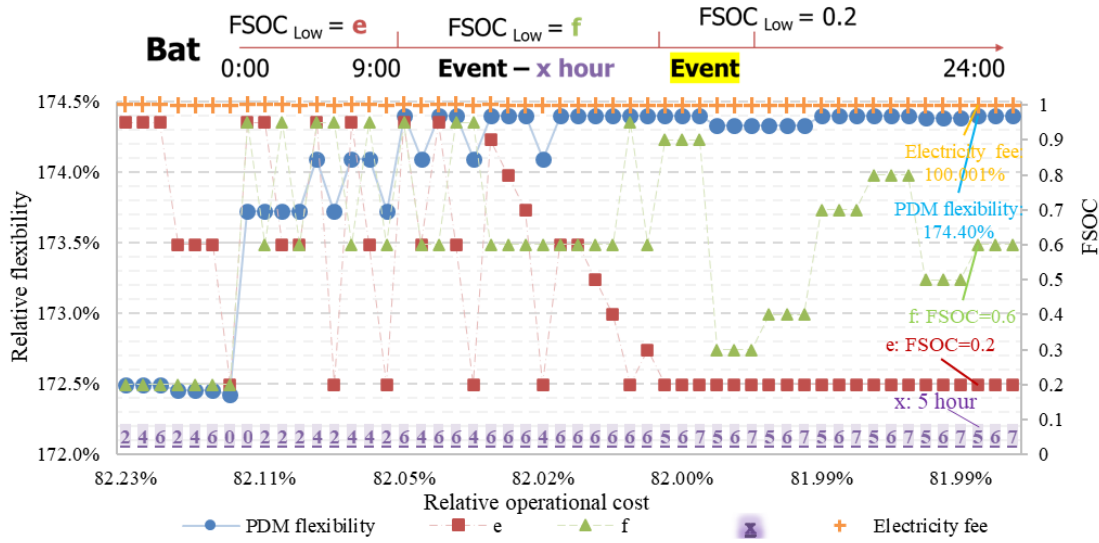


Figure IV-4. Techno-economic performance of different battery parameter combinations with the medium PDM [Publication IV].

The analysis showed that selecting a higher value for “e”, which is in anticipation of daytime events scheduled at midnight, increased overall electricity costs. Parameters “f” and “x” demonstrated a similar trend, with minimal impact on overall costs. In contrast, the relative flexibility for PDM was primarily influenced by parameter f. When the parameter “e” was set to a low value (FSOC = 0.2), combined with higher “f” and “x” values, it enhanced the system’s responsiveness. To mitigate negative impacts on operational costs, parameter “f” was maintained at a moderate level of FSOC = 0.6, while parameter “x” was set to 5 h.

By evaluating the performance of each flexibility resource, an optimal set of parameters was determined to improve system responsiveness to annual PDM events. To facilitate comparison of the parametric analysis outcomes, Figure IV-5 integrates the results from all three groups. In this figure, the vertical axis indicates the relative PDM flexibility, whereas the horizontal axis depicts the relative operational costs. Points positioned near the top of the Y-axis and toward the left side of the X-axis indicated better performance. As illustrated in Figure IV-5, the EV control group demonstrated the most favourable overall results, followed by the RSV group. The battery-based approach showed limited improvements, primarily due to the existing energy flow architecture within the building system introduced in Section 3.2.1. Regardless of whether a PDM event occurred, EVs parked at the hotel prioritised meeting demand when RE was insufficient. The reservoir released stored seawater to help

address any energy shortfall, while the building's battery served as a last backup during energy deficiencies. This inherent priority structure meant that even if primary sources did not respond directly to PDM signals, the system's default demand reduction sequence continued to support PDM objectives. From these findings, it is evident that individual EV control achieved the greatest operational cost reduction, lowering expenses to approximately 81.36% of the uncontrolled scenario, while delivering the highest PDM flexibility at 186.24%. The RSV control strategy also provided significant benefits, with a flexibility of about 179.19% and costs reduced to roughly 81.52%. The best performance among the battery-based options resulted in a flexibility of approximately 174.40%, with costs decreased to about 81.99%. Consequently, the inherent sequence of energy flow constrained the potential for enhancing the flexibility of the source in the postposition.

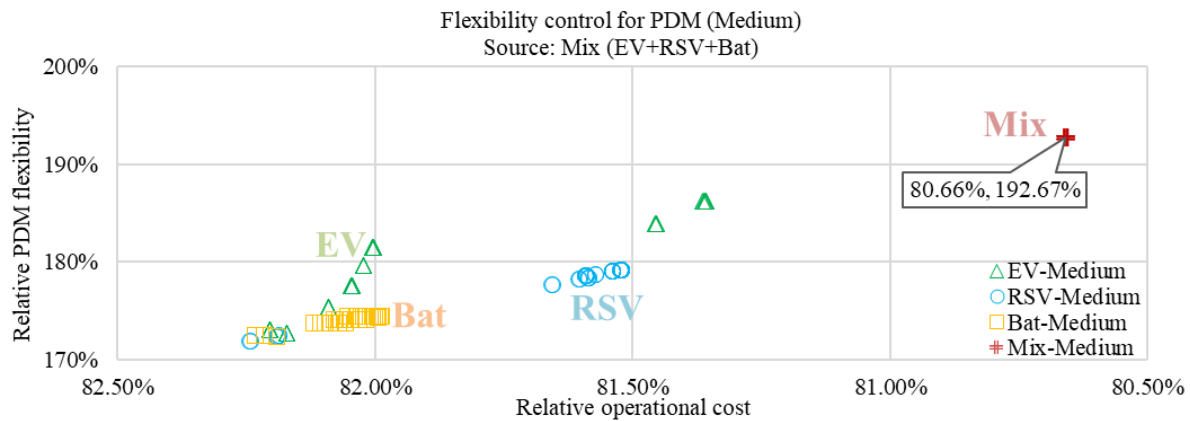


Figure IV-5. Techno-economic performance of different sources (medium PDM scenario) [Publication IV].

5.12.2 Hybrid Flexibility Resources

(1) Coordinated Flexibility Sources

To improve incentives for PDM participation, the study examined the influence of strategies that combined flexibility sources into the control. By harnessing the optimal combination of variables from different sources, the updated method enables simultaneous participation in PDM events. As shown in Figure IV-5, marked by the red cross, this integrated approach resulted in a substantial increase in operational flexibility, raising the relative PDM flexibility to 192.67%. Simultaneously, the overall costs decreased to 80.66% of the baseline, demonstrating that combining multiple flexibility sources can enhance both operational efficiency and economic performance. This study also applied the same methodology to explore two further PDM scenarios: low-frequency and high-frequency, each starting with the best single-source parameter configurations and then employing coordinated control among all sources to gain further improvements. Figure IV-6 depicts the performance across these scenarios, with the high-frequency case on one end of the spectrum, the medium frequency in the middle, and the low-frequency scenario on the opposite end. The high-frequency scenario demonstrated notable improvements in both flexibility and cost efficiency, with more differences among control strategies. The mixed control scenario showed even greater improvements. Furthermore, the flexibility benefits within the RSV group increased as PDM frequency rose. The chart's distribution indicated a positive trend for the system's engagement in events. Under high-frequency conditions, the maximum PDM flexibility reached 331.19%, tripling that of the low-frequency scenario. Economically, costs decreased by approximately 22%, dropping from 89.10% in the low-frequency case to 67.07% when operating at high frequency.

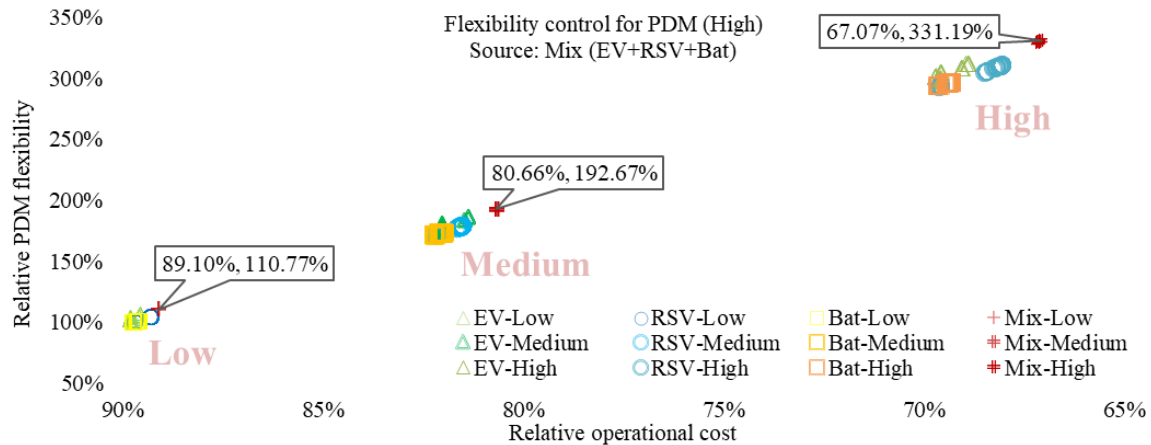


Figure IV-6. Techno-economic performance with different PDM scenarios [Publication IV].

Table IV-1. Economic performance and battery usage in different PDM scenarios [Publication IV].

Scenario	0 (All-grid)	0 (ZEB)	Low	Medium	High
Electricity fee (HK\$)	1,250,334 381.50%	327,738 100.00%	329,501 100.54%	329,572 100.56%	331,922 101.28%
Building battery capacity	600 kWh				
Annual cycle	40				
Alternative (year)	10				
EV Battery capacity	355 kWh				
Annual cycle A/B	195 195	262 229	261 233	262 237	261 242
Renewal A/B (year)	10 10	7 8	7 8	7 8	7 8
Operational cost (HK\$)	A1				
	292,004				
	89.10%				
Relative NPV (HK\$)	0	-2,106,110	-1,496,614	-1,024,940	-265,245
Operational cost (HK\$)	A2				
	166,349				
	50.76%				
Relative NPV (HK\$)	0	-2,106,110	646,600	2,377,321	6,984,944

Table IV-1 provides detailed conditions for each scenario. The first two columns present cases that did not participate in PDM. The all-grid case represents a system supported solely by energy imported from the electric grid, serving as the primary case where the NPV was zero. In this scenario, there was no backup battery in the building, nor was there a V2B function for the EVs. The ZEB case introduced RE facilities in the building along with a 600-kWh battery, with the V2B function of EVs activated. This study used the parameters from the ZEB case as default values, with all subsequent control strategies in different scenarios based on these values under modifications. Therefore, the impacts of various variables at low, medium, and high frequencies were compared against the ZEB as a reference.

The battery was intended to be replaced after 2,000 cycles or every 10 years. Increased attendance at events led to a corresponding rise in the usage of both EV and building batteries, resulting in more charge and discharge cycles. The annual cycle difference between Batteries A and B in the EVs stemmed from the need to prioritise discharging EV A to meet demand before considering EV B. With increased usage, the lifespan of the batteries

decreased. Consequently, batteries A and B required replacement every seven and eight years, respectively. Over a 20-year operational span, both batteries were projected to be replaced twice. If the last battery still had cycles left after 20 years, its salvage value would be factored in. However, due to the minimal use of the building battery, in all scenarios, it expired before hitting its cycle limit after ten years, resulting in no salvage value.

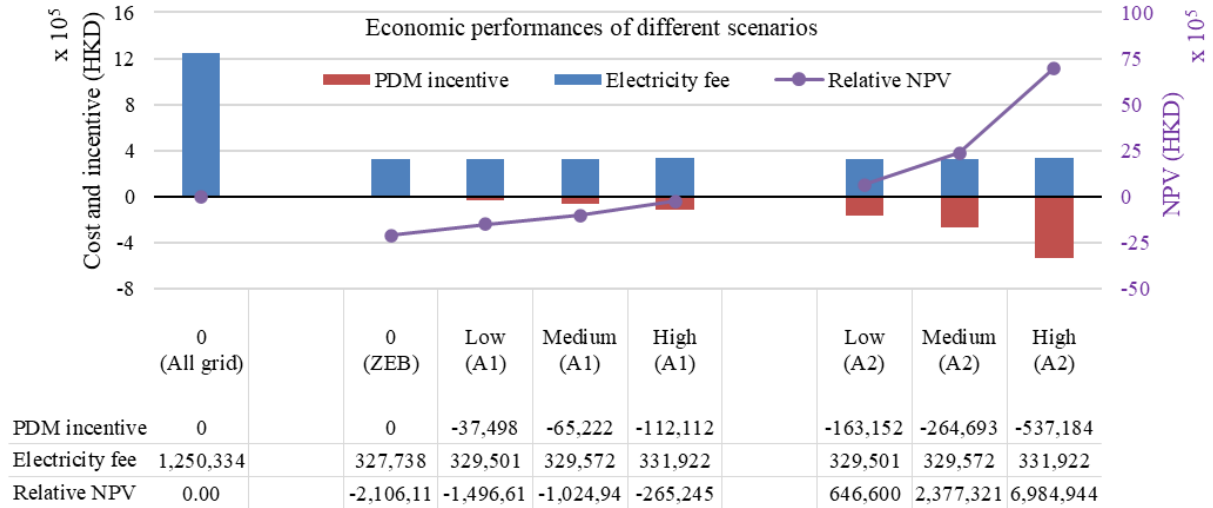


Figure IV-7. Economic performance with different controls based on A1/A2 standards [Publication IV].

Compared to the baseline scenario (0 ZEB), where the relative electricity cost was standardised at 100%, the cases that responded to PDM events experienced a marginal increase in operational expenses. Table IV-1 illustrates the final operational costs and electricity fees, accounting for the PDM incentives received through demand reductions during these events. To determine these incentives, two normalised baseline profiles (A1 and A2) were employed. As described in Section 3.3.3, the utility company calculated demand reductions by subtracting the actual electricity consumption during a PDM event from the corresponding baseline demand. Baseline A1 was established by averaging the three highest daily electricity demands from ten non-event days prior to each PDM event. The results previously discussed were based on this A1 baseline. To promote the integration of RE sources within building systems, an alternative baseline, A2, was proposed. This baseline used the building's original demand profile before RE supplementation, encouraging stakeholders to adopt RE sources. The advantages of incorporating renewables became evident, as the relative operational cost dropped from 89.10% under the A1 baseline to just 50.76% under the A2 baseline in low-frequency scenarios. In high-frequency scenarios where the incentives considerably exceeded the costs, the building system did not incur fees but instead received financial rewards.

In Figure IV-7, the red bars represent the PDM rewards, whereas the blue bars show the electricity fee costs. The blue bars displayed little variation across cases with RE support, regardless of the presence of control strategies. In contrast, the red bars indicate a notable revenue generated from events, especially for cases using the A2 baseline. The successful implementation of control strategies resulted in increased economic advantages, as shown by the significant rise in NPV_{rel} , depicted by the purple dots. However, even though the high-frequency case did not achieve a positive NPV_{rel} over 20 years when utilising the A1 baseline. In comparison, all cases using the A2 baseline yielded favourable results, with low-frequency cases achieving an NPV_{rel} of HK\$646,600, medium-frequency cases reaching HK\$2,377,321, and high-frequency cases obtaining HK\$6,984,944.

(2) Priorities for Activating Flexibility Sources

Improvements in flexibility performance were noted through the coordinated control of three flexibility sources. The original energy flow limited the flexibility enhancement for lower-priority sources. As a result, labelling these sources as having poor progress under control strategies was viewed as inequitable. The focus of this study was to explore how prioritisation in activating these sources could enhance system flexibility. Initially, when RE generation fell short of demand, the discharge sequence prioritised EV batteries first, followed by the built-in reservoir, and finally, the building's battery. During a PDM event, the EV responded first, then the reservoir, and finally the building battery. Since EVs had fixed trip schedules between their destination and the studied building, EV batteries were prioritised and utilised as soon as they arrived. It was important to determine whether the reservoir should be the second source or if the building battery should take that role. The original sequence was EV → RSV → Bat, where the reservoir was the second source activated during energy shortages and PDM events. An alternative proposed sequence was EV → Bat → RSV, which prioritised the building battery over the reservoir for managing energy shortages and PDM situations. In this configuration, the building battery would provide energy when EV batteries fell short, while the reservoir would maintain its stored seawater if the building battery met the demand; otherwise, it would discharge to cover any remaining energy needs. This study followed a similar methodology to compare the impacts of PDM incentives and costs and identify the best parameter combination for various flexibility sources.

Table IV-2. Economic effect of activation priorities [Publication IV].

Priority	EV → RSV → Bat		EV → Bat → RSV	
Scenario	0	3	0	3
Electricity fee (HK\$)	327,738	329,572	326,723	328,267
	100.00%	100.56%	99.69%	100.16%
PDM flexibility (HK\$)		65,222		67,665
		192.67%		199.89%
Operational cost (HK\$)		264,349		260,602
		80.66%		79.52%

Table IV-2 highlights the activation priorities with medium PDM frequency. A designation of zero sources indicated no sources responded to an event, while a value of three signified full coordination among all sources. The table presents data on electricity fees, PDM flexibility, and operational costs under two scenarios (EV → RSV → Bat and EV → Bat → RSV). Comparing the two scenarios, the latter scenario required less grid-imported energy. Due to the nature of potential energy, more frequent discharges from the reservoir led to higher energy losses. In contrast, energy stored in the battery exhibited a slight variation after changes in the coordination of flexibility sources. Therefore, prioritising the building battery as the second source reduced wave energy losses and resulted in more seawater being conserved in the reservoir. Compared to the original scenario, the EV → Bat → RSV configuration retained more seawater in the reservoir, enhancing PDM flexibility and increasing profits. The relative PDM flexibility improved from 192.67% to 199.89%. Due to the combined benefits of improved PDM incentives and lower electricity fees, operational costs decreased from 80.66% to 79.52%.

5.13 Source Activation for Demand Response Programme and Power Outage

This section examines the resilience of the energy system to unexpected, unannounced power outages. During

such events, the grid was unable to satisfy the building's demand, necessitating the activation of a backup diesel generator when RE sources and batteries fell short. Additionally, excess RE that could not be exported to the grid was wasted, leading to increased CO₂ emissions. Section 3.3.4 provided outage profiles modelled as stochastic events, which evaluated the likelihood of power outages happening within specific timeframes. These profiles were assigned probabilities at 2%, 4%, 6%, 8%, and 10%, carefully built to avoid overlapping with the existing PDM events. Higher-probability outage profiles were associated with lower probabilities at different profile levels. Outages could last from a minimum of one 15-minute interval to several hours.

5.13.1 Single Flexibility Activation for Outage

The study categorised the outage scenarios into five levels based on their probabilities to assess how effectively each flexibility source could enhance system resilience. The control strategies employed were based on the optimal configuration identified earlier (EV → Battery → RSV), which demonstrated superior techno-economic performance under medium-frequency PDM events. During an outage, the primary goal was to maintain normal operation within the building. To achieve this, all flexibility sources were permitted to discharge energy down to their lowest operational limits, even if these limits exceeded the thresholds set for PDM events. The responses from each energy source were evaluated based on this criterion:

- (A) EV Battery: During an outage, the EV batteries discharged at an FSOC of 0.4, while adhering to the vehicle's travel schedule. After all trips were completed, the discharge limit was reduced to 0.33. The discharged energy was limited to prevent compromising the EVs' mobility. Under normal conditions (excluding transportation), the discharge FSOC was set higher. Different FSOC levels ranging from 0.4 to 0.95 were tested to assess their impact.
- (B) Building Battery: During outages, the building battery discharged at an FSOC of 0.2. Outside of outage issues, the discharge limit was set higher to ensure readiness for unpredictable outages, with FSOC levels explored from 0.3 to 0.95. The battery was designed to reserve several hours of energy for oncoming events, following a lower discharge limit during outage conditions.
- (C) WEC Reservoir: The minimum discharge limit was adjusted to an FSOR of 0.1 during outages, allowing the reservoir to contribute to energy support. Outside of outage issues, the reservoir followed the settings for the PDM event preparation.

Figure IV-8 depicts the resilience performance of each individual source. A distinct trend was observed: higher discharge limits during normal operations enabled greater energy storage for use during outages. All scenarios were evaluated against a baseline with no control, indicated by the blue columns across various outage levels. Among the energy sources, the building battery (B) achieved the most substantial decrease in energy shortages, reducing them from 13,902 kWh in the no-control scenario to 3,027 kWh at the 10% outage level. The reservoir (C) cut shortages down to 6,711 kWh, while the EV battery (A) led to shortages of 9,589 kWh.

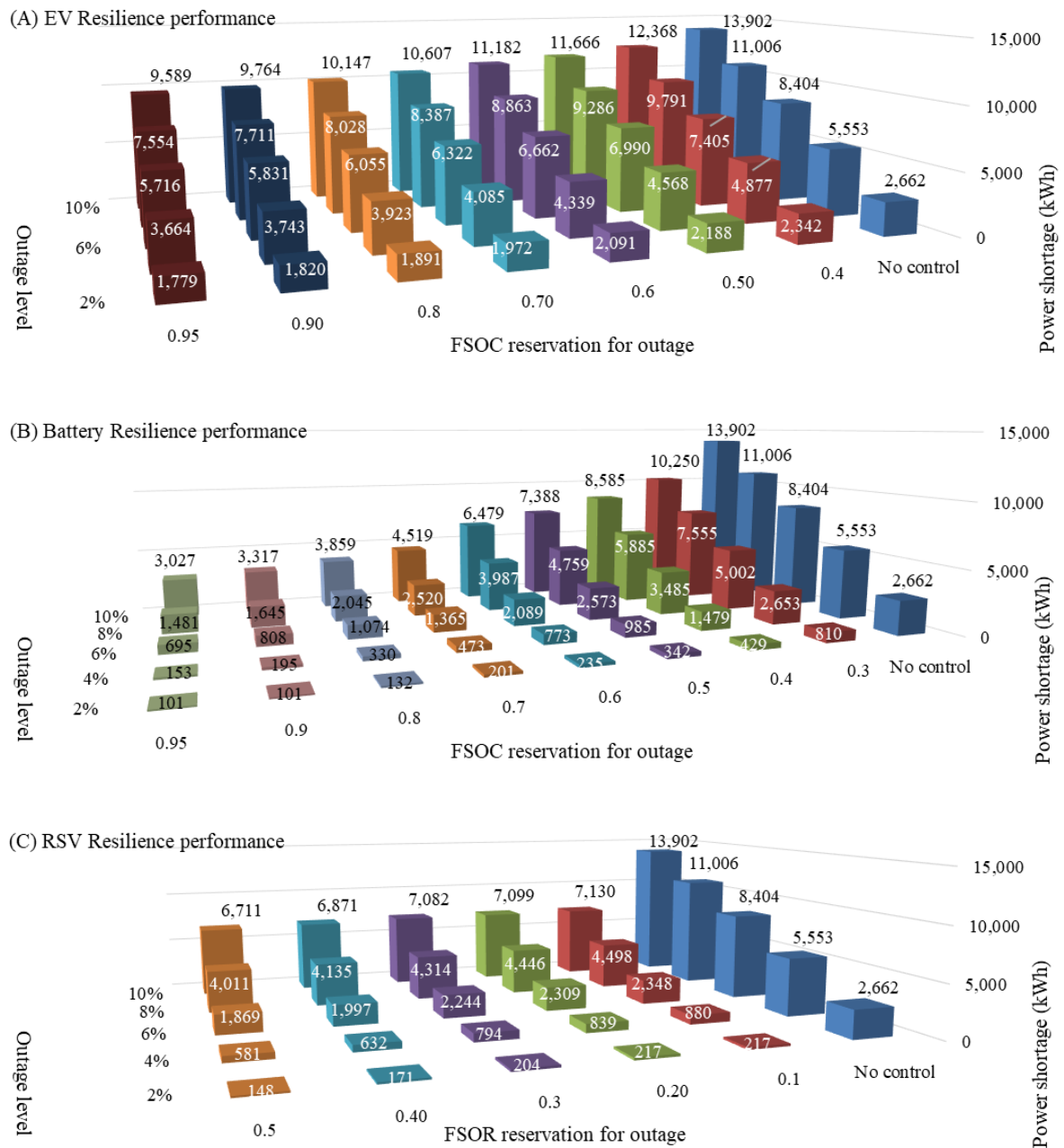


Figure IV-8. Unsatisfied energy during the outage (single activation) [Publication IV].

Given the variability in power outage events, with differing levels of severity, direct comparisons across outage levels are inherently complex. To assess the effectiveness of control strategies under these conditions, the study utilised the indicator “outage resilience” outlined in Section 4.1.5. This metric assesses the system's ability to support energy shortages during outages, taking into account the performance of various flexibility sources and varying outage intensities. Table IV-3 summarises the optimal control strategies through (A), (B), and (C) by presenting the power shortage's corresponding outage resilience across five outage levels, from 2% to 10%. The outage resilience percentage reflects the proportion of the maximum demand that the system can support during a power outage. In the baseline scenario labelled as “No control, ” where no specific measures were taken, the system demonstrated a relatively stable performance. The outage resilience percentages were approximately 83.85%, 83.33%, 83.19%, 83.46%, and 83.31% for outage levels of 2%, 4%, 6%, 8%, and 10%, respectively.

(A) EV: Applying a targeted control strategy resulted in higher resilience, with percentages ranging from 89.20% at 2% outage down to 88.49% at 10% outage, demonstrating notable improvements over the no-control case.

(B) Building Battery: This approach yielded even greater resilience, with percentages decreasing from 99.39% at a 2% outage to 96.37% at a 10% outage. The system's capacity to support demand remained close to full capacity, even at higher outage levels.

(C) WEC Reservoir: This strategy produced the highest resilience percentages among the three, ranging from 99.10% at 2% outage to 91.94% at 10% outage. Despite some decline at higher outage levels, the system consistently maintained a high level of support capability.

Table IV-3. Outage resilience of various scenarios and levels [Publication IV].

Scenario	2%	4%	6%	8%	10%
No control	83.85%	83.33%	83.19%	83.46%	83.31%
EV (A)	89.20%	89.00%	88.57%	88.65%	88.49%
Battery (B)	99.39%	99.54%	98.61%	97.77%	96.37%
RSV (C)	99.10%	98.26%	96.26%	93.97%	91.94%

5.13.2 Hybrid Flexibility Activation for Outage

The previous analysis indicated that controlling the system using a single flexibility source could achieve outage resilience levels up to 99.54% in specific scenarios. However, as illustrated in Figure IV-9, group (A) still had potential for further improvement, as the resilience remained relatively stable at around 89%. The enhancement was limited for groups (B) and (C), where higher outage levels posed greater management challenges. To tackle this issue, a hybrid strategy utilising various flexibility sources was suggested to enhance responsiveness during outages. Key considerations included determining the optimal number of sources for coordination and establishing control priority sequences. Since EVs follow predetermined schedules for trips to and from the building, it was essential to engage EV batteries as soon as they become available to maximise their usage. Next, it was essential to assess whether the reservoir or the building battery should function as the secondary source. Four distinct coordination scenarios were devised:

A → B: The secondary source is the building battery, activated only if EV batteries are insufficient.

A → C: The reservoir acts as the secondary source, activated only when EV batteries are inadequate.

A → B → C: The reservoir activates only if the second source (building battery) cannot meet demand.

A → C → B: A variation where the building battery (C) is prioritised as the secondary, with the reservoir (B) as the tertiary, activated only if needed.

Control group “A → B” and “A → C” employed two sources, activating the second only when EV batteries were unavailable or insufficient. The three-source configurations (“A → B → C” and “A → C → B”) are built upon these, engaging the third source only if the second failed to satisfy demand during outages. After parametric testing, the most promising solutions across various outage levels were depicted in Figure IV-9. The results demonstrated that hybrid coordination further improved outage resilience, especially at higher outage levels, by reducing delays in response. Notably, the “A → B” configuration, which prioritised the building battery as the secondary source, consistently achieved 99% outage resilience across all tested levels. The performance difference between the three-source groups (“A → B → C” and “A → C → B”) was minimal, with a slight edge to group “A → B → C”. At outage levels of 2% and 4%, this configuration effectively prevented power shortfalls, though some shortfalls emerged as outage severity increased.

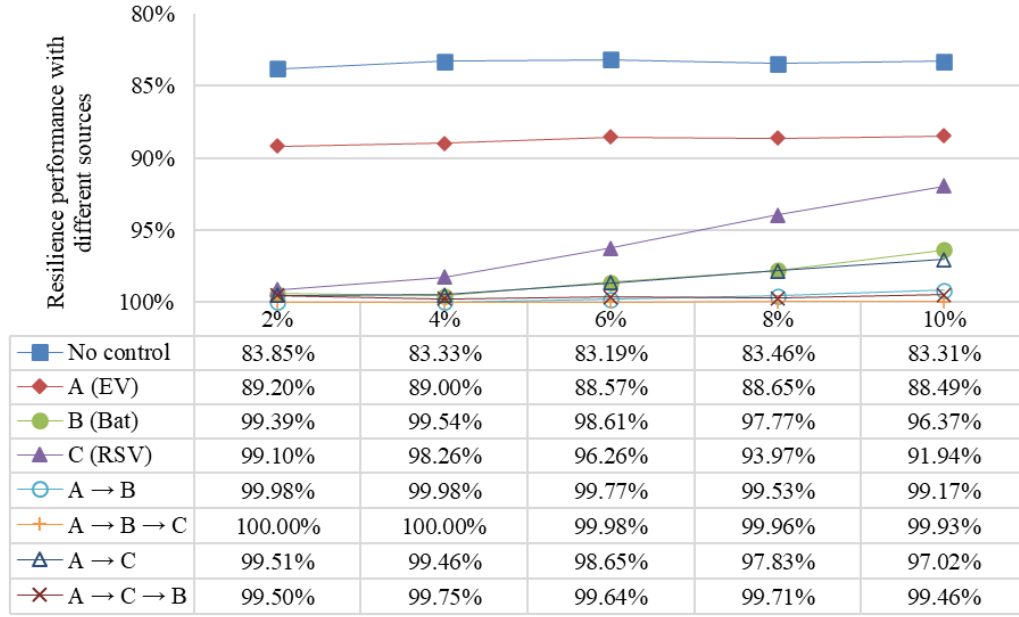


Figure IV-9. Outage resilience through single/hybrid sources [Publication IV].

Figure IV-10 depicts the environmental and economic impacts between the uncontrolled baseline (denoted as “×”) and the coordinated control strategy (“A → B → C”, denoted as “√”). The total emissions, represented by CE_a , include CO_2 emissions from grid-imported energy “ CO_2 (Grid)” and from diesel generators “ CO_2 (Diesel)”. The costs of operation incorporate electricity tariffs, PDM income, and diesel fuel expenses—calculated at HK\$21 per litre, as per the Hong Kong Consumer Council [169]. From an emissions standpoint, implementing outage control increased grid energy imports, raising CE_a from 1.724 kg $CO_{2,eq}/m^2$ at a 2% outage to 3.077 kg $CO_{2,eq}/m^2$ at 10%, as presented by the blue columns in Figure IV-10. However, due to effective control strategies, diesel emissions were negligible in the controlled scenarios. Conversely, the uncontrolled cases showed much higher CE_a , ranging from 0.619 to 3.233 kg $CO_{2,eq}/m^2$. Concerning operational expenses, a significant turning point arose at the 6% outage level; past this point, the controlled approach yielded lower costs compared to the uncontrolled scenario. This suggests that, even with increased dependence on grid energy, the control strategy enhances resilience while providing both environmental and economic benefits, reducing the need for investment in backup diesel generators and improving overall system sustainability during outages.

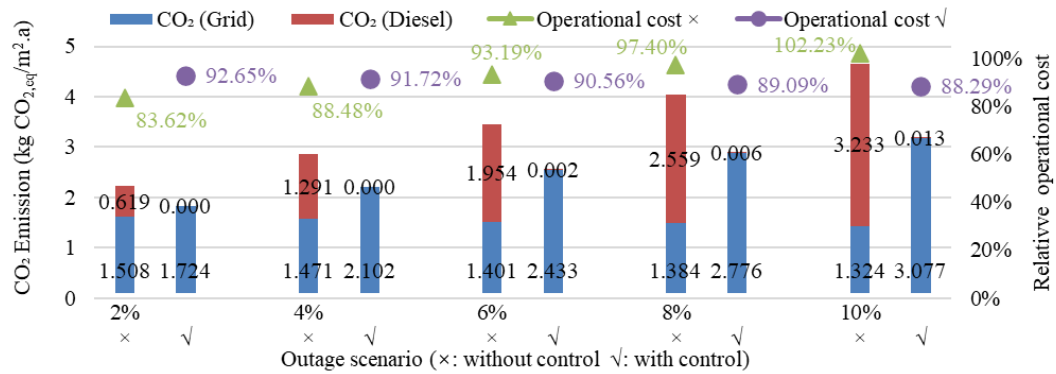


Figure IV-10. The effects of outage level on CO_2 emission and relative operational cost [Publication IV].

5.14 Sensitivity analysis

5.14.1 Sensitivity analysis for the key technical parameters

In exploring control strategies aimed at optimising both technical performance and economic outcomes, several critical parameters were tested. These included the discharging limits, the charging targets, and schedules. The adaptability of the control strategies under varying PDM frequency conditions was evaluated. To ensure consistency, the investigation kept an outage level of 2% throughout. The previously described control strategy, utilising a hybrid control approach in Group “A → B → C” at a medium PDM level, was evaluated under other conditions: low- and high-frequency. Figure IV-11 presents the performance across these three conditions, contrasting scenarios that use or do not use control. The findings indicate that the impacts of emission reduction and cost increases were comparable, regardless of PDM frequency. Notably, at high PDM frequencies, costs escalated under the 2% outage constraint, primarily due to the increased frequency of PDM events that negatively impacted energy storage efficiency. Crucially, in every scenario, the hybrid control strategy effectively kept the outage level at 2% without engaging backup diesel engines, thus preventing diesel emissions. As a result, the overall annual emissions were reduced compared to uncontrolled situations, demonstrating the control method's effectiveness and resilience.

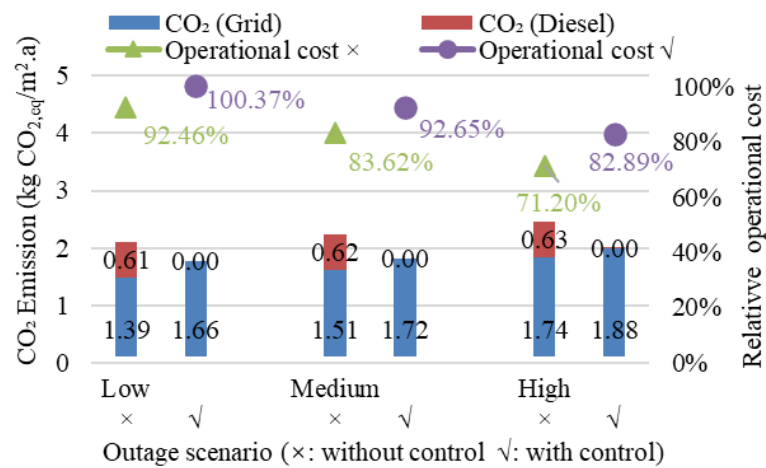


Figure IV-11. Annual environmental performance and economic results with different PDM frequencies.

5.14.2 Sensitivity analysis for the key economic parameters

(1) FiT adjustment and renewable penetration

Besides assessing the technical performance, the sensitivity analysis concerning the system's economic viability was carried out. A key economic parameter examined was the FiT, which directly influenced annual revenue. The original FiT was set at HK\$2.5 per kWh for renewable generation, provided by CLP [52]. Figure IV-12 illustrates the results when the FiT varied between HK\$3 and HK\$0.5 per kWh. As indicated by the purple bars on the left side of the figure, the NPV_{rel} gradually decreased from HK\$0.5 × 10⁷ to HK\$−2.6 × 10⁷. The neutral NPV_{rel} was recorded at HK\$2.6 and HK\$2.5 per kWh of FiT. With the FiT currently established by CLP at HK\$2.5, the NPV_{rel} for the system stood at HK\$−0.1 × 10⁷.

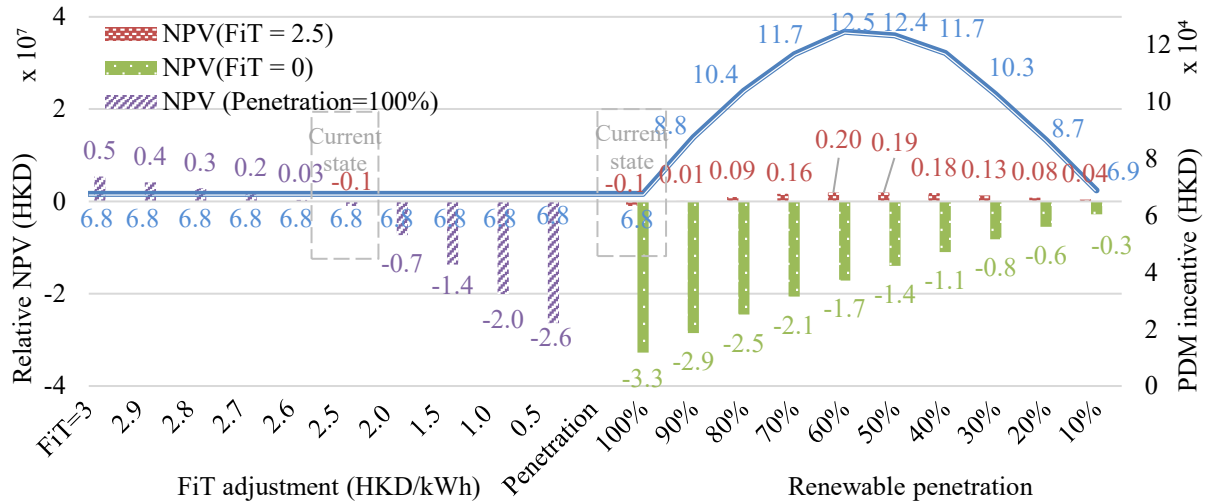


Figure IV-12. Effects of FiT and renewable penetration on NPV.

On the right side of the figure, the effects of different RE penetration levels are displayed. The current penetration level is 100%, supporting the studied ZEB. Keeping the ratios of wind, solar, and wave energy generation constant, the total RE penetration is reduced from 100% down to 10%. The NPV_{rel} for a FiT of HK\$2.5 per kWh and a zero FiT is represented by red and green bars, respectively. The NPV_{rel} increases as renewable penetration decreases, highlighting the significant impact of investment in renewable facilities. For the case with a FiT of HK\$2.5 per kWh, the NPV_{rel} increased from HK\$ -0.1×10^7 at 100% penetration to HK\$ 0.20×10^7 at 60% penetration. At a 90% penetration rate, the NPV_{rel} achieved a positive value of HK\$ 0.01×10^7 . In the absence of the FiT subsidy, all scenarios resulted in negative NPV_{rel} ranging from HK\$ -3.3×10^7 to HK\$ -0.3×10^7 . As the match between RE generation and demand varied with penetration levels, the PDM baseline increased at lower RE penetration. The blue curve indicates that annual PDM incentives peaked at HK\$125,000 under 60% renewable penetration, more than double the original HK\$68,000. However, further reductions in RE penetration have not enhanced PDM incomes, as the available flexible resources diminished accordingly.

(2) Incentive magnitude adjustment

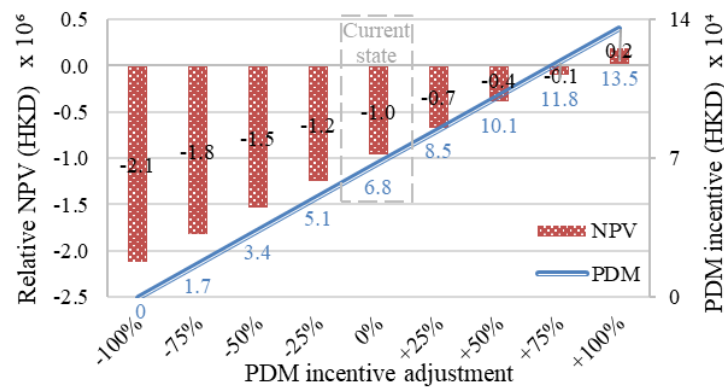


Figure IV-13. Effect of PDM incentive on NPV.

The PDM incentive also had a significant impact on the economic performance. Figure IV-13 illustrates the link between the NPV_{rel} and the income across different incentive levels. A 0% baseline reflects the current PDM rate of HK\$8/kWh. The incentive levels range from -100% (no PDM incentives) to 100% (HK\$16/kWh). As the incentive magnitude increases linearly, the annual PDM incentive rises from HK\$0 to HK\$135,000, compared to the original PDM earning of HK\$68,000. Consequently, the NPV_{rel} increases from HK\$ -2.1×10^6 to HK\$ $0.2 \times$

10^6 . Notably, a positive NPV_{rel} is reached when the PDM incentive surpasses a 75% increase.

(3) Interest rate and electricity fee escalation ratio adjustment

Figure IV-14 illustrates two curves that represent how the NPV_{rel} varies based on different interest rates and electricity fee escalation rates. The current interest rate is set at 2.96%, based on the average interest rate over the past five years [168]. In contrast, the escalation rate for electricity fees was determined by comparing the current year's fees with those from 20 years ago, resulting in an annual escalation rate of 1.525% [167]. This escalation rate reflects the average increase in electricity fees over that period. In the graph, the blue dots represent interest rates ranging from 1% to 8%. The NPV_{rel} at a 1% interest rate is HK\$ 5.0×10^6 , while it decreases to HK\$ -10.9×10^6 at an 8% interest rate. Notably, when the interest rate exceeds 2.5%, the NPV_{rel} turns negative. This is because, although annual cash flows are positive, an increasing interest rate reduces the overall NPV_{rel} . Conversely, the red dots represent scenarios with escalation rates that range from 0% to 8%. In these cases, the NPV_{rel} increases from HK\$ -3.1×10^6 to HK\$ 13.6×10^6 . A positive NPV_{rel} is achieved when the escalation rate is increased to 2%. Compared to the current situation, which yields an NPV_{rel} of HK\$ -1.0×10^6 , both a higher escalation rate and a lower interest rate contribute to an improvement in the NPV_{rel} .

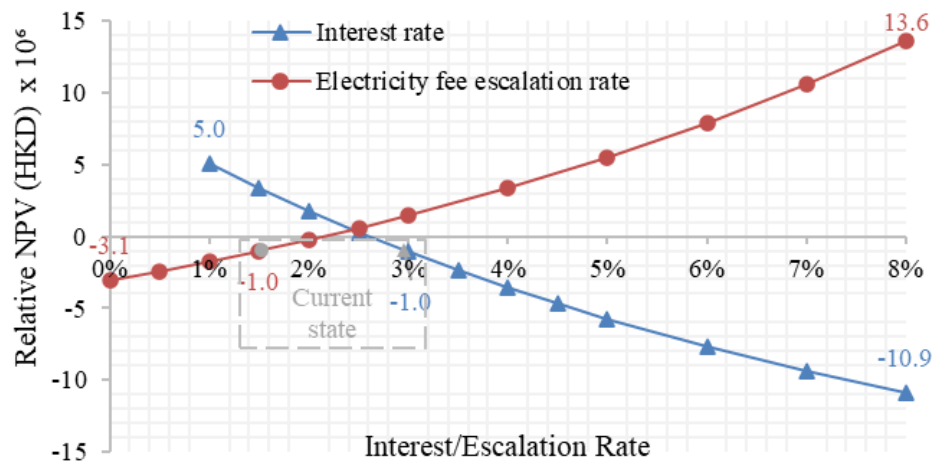


Figure IV-14. Relative NPV variation with interest and escalation rate adjustment.

6 Conclusions

6.1 Research outcomes

The transition toward coastal ZEB necessitates innovative solutions integrating RE systems with advanced storage and energy management. This research systematically explored the potential of hybrid ocean RE systems through four key dimensions: techno-economic feasibility, exploration of flexibility sources, dynamic wave energy storage controls, and energy flexibility resilience enhancement. This study provides a comprehensive framework for modifying RE integration in coastal environments by combining theoretical modelling, simulation-based assessments, and economic analyses. The findings demonstrate that while technical and economic challenges persist, strategic system design and intelligent energy management can unlock significant environmental and operational benefits. This multi-chapter research systematically investigates the integration of ocean-related technologies to advance coastal ZEB, emphasising techno-economic feasibility, energy flexibility, resilience, and sustainability.

The first study established the technical and economic viability of a coastal zero-energy hotel building supported by a hybrid wave-wind energy system. It aimed at utilising advanced ocean energy technologies to promote coastal zero-energy buildings. The research addressed multiple objectives through systematic investigation and analysis, emphasising energy matching, economic growth, and environmental improvement. Simulation studies based on the analysed data assessed the system's performance. A comparison of effectiveness showed that the COP_{ch} improved from 70% to 90% with greater heat exchanger effectiveness. To address space and cost concerns, a solution involving immersion of the heat exchanger in seawater was explored, resulting in the best COP_{sys} at 88% effectiveness. Replacing the electric heater with a heat pump reduced electricity demand by 26%, enhancing overall thermal system performance. The technical performance of the RE system was evaluated using wave-wind ratios based on OEM_e and OEF_e . Both hybrid renewable scenarios showed improved energy matching, with 62% wave and 38% wind achieving OEM_e of 0.69 and OEF_e of 0.65. Adding batteries improved these efficiencies further by alleviating the demand-generation mismatch. The system interactions with the electric grid led to significant reductions in annual equivalent CO_2 emissions, from 111.91 kg $CO_{2,eq}/m^2.a$ in original cases to near-zero levels in the renewable cases. As the number of batteries increased, emissions rose due to the losses incurred during charging. Replacing the cooling tower with an immersed heat exchanger improved the chiller and cooling system's performance. The analysis showed favourable NPV_{rel} and an expected SPP_{rel} within 20 years, particularly benefiting from higher wind energy proportions. However, the economic viability of batteries was hindered by their high costs, meaning that the best technical performance did not always translate to the best economic returns. Despite high initial investments, the long-term benefits could be significant, making it a profitable and environmentally friendly option.

The subsequent study explored advanced energy flexibility enhancement via novel resources of WEC reservoir and electric storage for this hybrid wave-wind energy system. This investigation is based on the findings presented in Chapter I. The emphasis was on battery management for peak shaving across various scenarios, along with innovative regulation of the built-in reservoir of OWEC. In Group 1, which solely used the electric grid, a battery with a capacity of 200 to 400 kWh was added. The 300-kWh case showed excellent performance in peak shaving and achieved over a 5% reduction in annual operational costs with demand charging. However, its NPV_{rel} remained negative due to high initial investment costs over 20 years, though it became more attractive with decreasing battery prices. Group 2 utilised smaller batteries (10 to 50 kWh), effectively reducing operational costs through peak shaving compared to the original method. As battery size increased, NPV_{rel} improved and showed positive results, highlighting the benefits of flexibility control. In Group 3, the self-integrated reservoir functioned as “wave energy storage,” reducing grid energy imports and saving 16% in operational costs. The control strategy significantly improved energy matching and increased NPV_{rel} for the 0-kWh case by 30% over group 2, although larger batteries showed decreased NPV_{rel} . A new electricity pricing scheme was introduced for Group 4, incentivising consumers to lower the maximum power demand and facilitating additional peak shaving while easing grid pressure.

Building upon prior work in Chapter II that utilised the reservoir as a wave energy storage unit, further refinements to wave energy storage control strategies were conducted, fine-tuning the dynamic regulation of OWEC reservoir

features. The implemented controls leveraged the OWEC's flexibility for energy shifting and peak shaving, operating in response to real-time electricity tariffs. Strategies were designed by adjusting lower discharging limits and activation thresholds to optimise cost savings and energy consumption patterns across on-peak and off-peak periods, accounting for monthly variations. Different control strategies resulted in varying enhancement levels. The first control group aimed to shift energy usage from peak to off-peak periods, scheduling the WEC's discharging to meet on-peak demand. This resulted in only a 0.5% savings in electricity fees due to limited off-peak energy matching. To improve upon this, the second group lowered the minimum FSOR for discharging, enhancing on-peak energy efficiency but compromising off-peak performance, reducing the operational cost to 95.5% of the reference case. The third group focused on peak shaving, controlling WEC output to balance energy needs while preserving reservoir capacity for future demand. This strategy maintained a 100% on-peak constraint in most months and reduced operational costs to 90.3% of the original. The fourth group added a battery system to address performance issues from the third group (10 to 150 kWh). While the NPV_{rel} was less favourable due to high investment costs, the 10-kWh case performed better. Integrating batteries with flexible controls resulted in annual savings between 4.5% and 6.8% through energy shifting, with peak shaving controls significantly cutting maximum demand and yielding cost reductions of 6.4% to 10.8%. This was facilitated by efficient ocean energy storage for quick and flexible charge and discharge.

After that, the research considered DR incentive maximisation and system outage resilience improvement through several flexibility sources (EV, building battery, and wave energy storage). The study additionally introduced EVs and DR programmes into the analysed energy system. It compared the control parameters for building battery, EV battery, and WEC reservoir to improve energy flexibility in buildings during planned PDM events. The research focused on activating individual flexibility sources and their coordination. The performance of different flexibility sources in building power systems was evaluated, revealing that EV control provided the best results for PDM flexibility (186.24%) and cost reduction (81.36%), followed by reservoir control and battery systems. Combining multiple sources in a mixed-control strategy enhanced PDM flexibility to 192.67% and reduced costs to 80.66%. Higher frequency scenarios improved flexibility and economic efficiency, with a peak PDM flexibility of 331.19% at high frequencies. Different baseline calculations indicated that A2 offered greater financial benefits. The research also assessed building resilience during power outages. Group B (building battery) showed notably higher resilience (96.37% to 99.39%), while Group C (self-integrated reservoir) ranged from 91.94% to 99.10%. Prioritising the building battery achieved 99% resilience in outages, demonstrating that hybrid flexibility sources enhance overall resilience and reduce latency during outages. While controlled strategies increased grid energy imports, they minimised diesel use and emissions, making them more cost-effective at higher outage levels. Sensitivity analyses highlighted the economic impact of factors like FiT and RE penetration on NPV_{rel} , with lower FiT correlating with reduced NPV_{rel} . The study also found a linear relationship between PDM incentives and annual revenue, emphasising the significance of investing in RE for improved economic outcomes. It also explored the effects of interest rates and electricity fee escalation rates on NPV_{rel} , demonstrating that a higher escalation rate combined with lower interest rates improved NPV_{rel} .

In summary, this research makes several contributions to sustainable coastal energy systems: The study first confirmed the techno-economic viability of a coastal zero-energy hotel powered by a hybrid wave-wind system,

showing a positive NPV_{rel} and SPP_{rel} within 20 years, despite high initial investments. Next, the integration of a novel wave energy storage mechanism through a WEC reservoir was explored, reducing grid energy costs by 16% and increasing the system's NPV_{rel} by 30%. Further optimisation of the WEC control strategy enabled effective peak shaving while maintaining on-peak constraints in most months, thereby reducing operational costs to 90.3% of the original. The research also assessed DR event participation and resilience improvement during grid outages through coordinated control of EVs, building batteries, and WEC reservoirs. Although these strategies increased grid imports under normal conditions, they significantly reduced diesel dependency and emissions during outages, making them more cost-effective in extended outage scenarios. Overall, this work highlights the potential of ocean-based hybrid systems to achieve ZEB goals by strategically integrating renewables and dynamic storage control, providing a sustainable and resilient pathway for coastal energy systems.

6.2 Potential adaptations

This research investigated the enhancement of energy flexibility and resilience through a hybrid renewable energy-storage system. By leveraging the favourable coastal geography, the system effectively harnesses marine renewable resources. The hybrid RE system design is also suitable for comparable coastal situations. Under different ocean and climate conditions, it is appropriate to investigate the beneficial renewable combination for the hybrid energy system, as this study did, concerning techno-economic benefits. The system design follows the local guidelines of commercial hotel buildings. The building types with similar patterns and lower thermal comfort requirements provide the feasibility for method transferability. Furthermore, the methodology developed for coordinating diverse flexibility sources presents a transferable framework. Its principles can be adapted to various energy systems, including those in non-coastal regions, thereby extending the relevance of this work beyond the immediate case study. For any system, identifying key resilience points and vulnerabilities remains critical for optimising responses to grid disturbances.

7 Future work

Building upon prior research that highlighted the potential of ocean energy systems in ZEB objectives, through a balance of technical performance, economic feasibility, and environmental sustainability, future work will focus on advancing the resilience and adaptability of coastal energy systems. Integrating RE sources, dynamic storage control mechanisms, and DR programmes has already demonstrated promise in creating sustainable and robust energy infrastructures. However, significant challenges remain in optimising costs and ensuring interoperability within existing grid networks.

The proposed future research will examine the temporal dynamics and interdependencies between power outage events and DR programmes. Specifically, it aims to assess the system's resilience under various outage scenarios—categorised as fixed, stochastic, beforehand, and afterwards—within the current energy system configuration. By simulating diverse outage conditions and evaluating the system's response to scheduled and unscheduled DR events, this study intends to identify optimal strategies for enhancing system robustness and responsiveness. A central objective of the future investigation is to optimise utility incentive earnings derived from activated flexibility resources, while simultaneously ensuring reliability in meeting energy demand. To achieve this, the study will implement a comprehensive scenario-based analysis, incorporating various levels of outage response

indices and outage durations. The framework will consider three primary scenario groups: (1) a full outage response index, (2) partial outage response indices, and (3) outage durations spanning several hours. The proposed system's performance will be evaluated in terms of energy flexibility, resilience, and cost-effectiveness. Control strategies will leverage three flexibility sources: EV batteries, the built-in reservoir of the WEC, and stationary building-integrated battery storage systems. These sources will be strategically coordinated to respond to DR signals and outage events to maintain system stability and service continuity.

Ultimately, this research seeks to develop a robust framework for strategically deploying flexibility resources in ocean-integrated ZEB systems, contributing to the larger goal of resilient, sustainable, and economically viable coastal energy solutions in the face of increasing grid uncertainties and climate-related disruptions.

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