Applied Energy 384 (2025) 125418

Contents lists available at ScienceDirect

Applied Energy

journal homepage: www.elsevier.com/locate/apenergy

Addressing electricity transmission network congestions using battery energy storage systems – a case study of great Britain

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HIGHLIGHTS

- Examines the potential of BESS to mitigate transmission network congestion and support the integration of renewable energy sources.
- Applies the study to the entire transmission network of GB, offering practical insights.
- Utilises N-1 contingency analysis and hosting capacity assessments to identify bottlenecks in transmission lines and transformers.
- Uses the Flow Decomposition Technique (FDT) to determine optimal BESS locations and sizes for congestion relief.
- Uniquely combines large-scale application with both contingency analysis and hosting capacity assessment to address network bottlenecks.

ARTICLE INFO

Keywords:
Transmission expansion planning
Energy storage system
Net-zero
Hosting capacity
Contingency analysis

ABSTRACT

The UK has set an objective of achieving a clean power by 2030, with a specific commitment to deploying 50 GW of offshore wind capacity within the same timeframe. However, the current transmission network lacks the capacity to accommodate these ambitious goals, highlighting the urgent need for substantial reinforcement to support the increased generation and demand at the transmission level. This paper investigates the integration of Battery Energy Storage Systems (BESS) as a non-networked solution, offering a timely and less expensive alternative to traditional network upgrades to address transmission bottlenecks in Great Britain (GB). Using DIgSILENT PowerFactory 2024, the study models the GB transmission network for 2024 and 2030, focusing on peak winter and minimum summer demand scenarios. Contingency analysis and hosting capacity assessments have identified critical bottlenecks which pose significant risks to system reliability during peak periods. This study focuses on South Wales, examining how flow decomposition techniques can be applied to identify locations for BESS deployment to address these bottlenecks. The findings demonstrate that strategically placed BESS can effectively alleviate transmission system bottlenecks. For the specific case analysed, the equivalent annualised cost of the non-networked solution is significantly lower, ranging from 38 % to 63 % of the cost of line reinforcement. Additionally, this approach offers the advantages of faster implementation and enhanced facilitation of renewable energy integration, underscoring its potential as an efficient solution for addressing transmission network bottlenecks.

1. Introduction

The United Kingdom is making concerted efforts to decarbonise its power system. In 2023, zero-carbon power sources accounted for 51 % of electricity generation in Great Britain, exceeding the combined contribution of traditional fossil fuels, which comprised 32 % from natural gas and 1 % from coal, with the remainder supplied through imports and other sources [1]. By 2030, the UK aims to achieve clean power [2], incorporating renewable energy sources such as wind and solar farms, nuclear power plants, and abated fossil fuel generators, supported by energy storage solutions and interconnectors. Peak electricity demand is also expected to rise, from 58GW in 2023 to a range of 62-65GW by 2030, as the electrification of transport, heating, and industry advances [3]. To meet this demand, total generation capacity will need to expand from 100GW today to 190-220GW by 2030. Furthermore, the UK has established an objective to achieve the deployment of 50 GW of offshore wind capacity by the year 2030, with the potential for up to 5 GW to be derived from floating offshore wind technologies. Of

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https://doi.org/10.1016/j.apenergy.2025.125418
Received 2 November 2024; Received in revised form 6 January 2025; Accepted 20 January 2025
Available online 13 February 2025

this, 4.5 GW could be connected to the transmission network in South Wales. Additionally, 1 GW of offshore wind capacity is planned for integration into the network in South Wales [4]. The UK currently faces a network planning challenge comparable in scale to that encountered during the 1960s. However, these projections highlight the critical need for substantial reinforcement of the transmission network to accommodate this significant expansion in generation capacity. By 2035, the UK will need to construct five times the number of transmission overhead and underground lines than it has built in the past 30 years, as well as approximately four times the current capacity of subsea high-voltage cables installed along the British coast [5].

Currently, the connection queue presents a significant challenge for the transmission network. As of September 2023, a total of 549GW of projects held connection agreements across the system (143GW in distribution and 406GW in transmission), with 518GW allocated to generation and storage—more than double the capacity required by 2030 [6]. Over the past five years, the volume of transmission network connection applications has increased nearly tenfold, resulting in an average delay of over five years for projects seeking transmission connections. Approximately 64 % of generation and storage projects are unable to connect to the distribution network without transmission reinforcement [7]. Up until 8th October 2024, the entire Transmission Entry Capacity (TEC) register across all technologies in different stages is as shown in Fig. 1 [8].

Reforming of the connection process is essential to enable faster, more coordinated, and efficient integration of technologies in the connection queue with the GB electricity system in order to achieve net-zero targets. Ongoing collaboration between the government, the Office of Gas and Electricity Markets (Ofgem), and the energy industry remains crucial. The connection process must be future-proofed to allow for the prioritisation of projects that deliver benefits across the entire energy system and align with strategic network planning for net-zero [3]. Delays in transmission reinforcement are projected to lead to renewable energy curtailments of approximately 5 TWh by 2030 [9], which significantly hinders the UK's efforts to decarbonise its energy system, deploy low-carbon technologies, and attract investment. The Connections Action Plan (CAP) outlines collaborative efforts between the government, Ofgem, NGESO, and network companies to accelerate progress and significantly shorten connection timelines. The plan focuses on addressing critical bottlenecks, enhancing the efficiency of existing network infrastructure, and aligning connection processes with long-term strategic planning and market reforms [6]. In parallel, NGESO has introduced a set of initiatives aimed at reducing the connection queue and minimising transmission system connection timeframes. Together, these initiatives aim to streamline the connection process and support the transition to a more efficient and sustainable energy infrastructure [10].

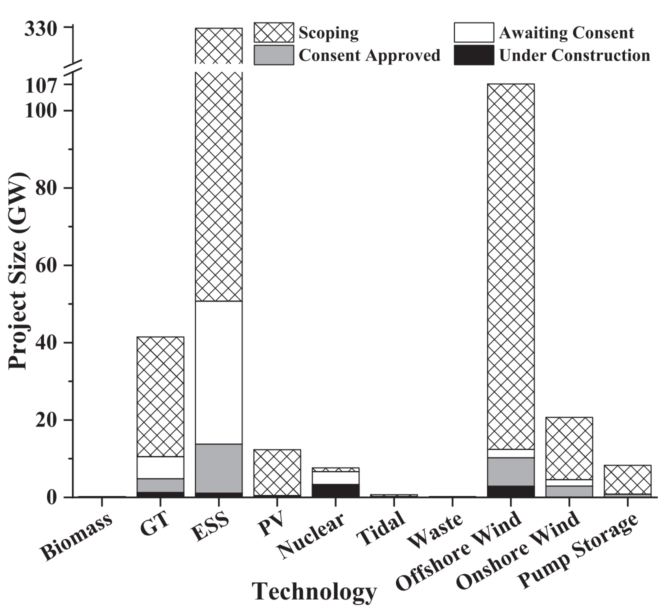

Fig. 1. Transmission entry capacity register across all technologies in different stages, GT: Gas turbine, PV: photovoltaic, ESS: energy storage system.

Managing transmission network bottlenecks can be approached through two main solutions: networked and non-networked options. In terms of networked solutions, strategies such as upgrading or constructing new transmission lines, enhancing or installing new transformers, and upgrading Flexible AC Transmission Systems (FACTS) devices and substation equipment are commonly employed. However, networked solutions are typically time-consuming and capital-intensive. In contrast, non-networked alternatives, such as market-based approaches, demand response programs, and the integration of BESS, offer a more expedient and cost-effective solution for managing transmission network congestion. While non-networked solutions such as BESS offer flexibility, they may lead to an increase in transmission losses. Furthermore, considering the characteristics of the problem, networked solutions could, in certain cases, provide a more effective approach compared to non-networked alternatives. For instance, if congestion occurs frequently on a transmission line or at a substation throughout the year, reinforcing the affected component might be a more sustainable and robust solution than relying on BESS or other non-networked solutions. However, if congestion arises intermittently, such as when a nearby wind farm operates at full capacity, the issue may not warrant infrastructure reinforcement. In such cases, BESS or other non-networked solutions could effectively address the problem. Conversely, if congestions occur frequently and sustain for long period, for instance when a new large load is connected to the network, or when a base-load generator is installed, networked solutions are likely to be more reliable and better suited for long-term mitigation.

2. Congestion management in the literature

Congestion management in transmission networks involves a range of strategies and actions aimed at alleviating and preventing the overloading of transmission lines and other essential infrastructure within the power grid. These measures are crucial for ensuring the stability, efficiency, and reliability of electricity transmission, particularly during periods of high demand. The literature is reviewed from the perspectives of networked and non-networked solutions as follows.

From the perspective of non-networked solutions, transmission switching, as introduced in [11], is applied in multi-area power system operations to mitigate congestion on both regional transmission lines and interconnecting tie lines, while accounting for credible contingencies. The methodology is based on a decentralised optimisation framework, allowing regional control centres to manage congestion within their local networks as well as across the tie lines that connect them to neighbouring regions. In [12], a predictive controller is proposed to directly address congestion. This controller integrates the stochastic nature of renewable energy into a feedback-driven decision-making process, focusing on preventing congestion by balancing operational constraints, strategic generation curtailment, and the use of energy storage. A key innovation is its ability to model disturbance trajectory scenarios, enhancing the system's capability to forecast and mitigate congestion, thereby improving grid reliability. A market-based approach to congestion management is also discussed in [13]. This study proposes a day-ahead market-clearing model that allows various distributed energy resources (DERs)—such as distributed storage, generation units, microgrids, and load aggregators—to participate in the electricity market. The model incorporates Volt/VAR control, network reconfiguration, and interactions with the wholesale market to optimise market clearing. One notable aspect of this approach is the use of locational marginal pricing (LMP) for both active and reactive power, decomposed into components related to active power, reactive power, congestion, voltage support, and losses. This decomposition provides clear price signals, encouraging DERs to contribute actively to congestion management and voltage support, ultimately promoting system stability and efficiency. A market-based approach is also employed in [14], focusing on unlocking flexibility from both small and large-scale energy resources. The proposed framework establishes a platform that allows system operators—both transmission system operators (TSOs) and distribution system operators (DSOs)—to access and utilise this flexibility for congestion management. By enabling a more dynamic and coordinated market participation, this model addresses two significant challenges: the issue of low market liquidity and the potential adverse effects associated with the activation of flexibility resources. Demand response is another key strategy for managing congestion in power systems. In [15], an optimal implementation strategy for demand response programs and distributed generation (DG) is presented, incorporating dynamic load flow and power transmission distribution factors. This model identifies the optimal timing for demand response activation and the most suitable locations for DG installations, particularly wind units, by accounting for their probabilistic impacts. The goal is to reduce congestion and enhance transfer capability by incentivising consumers to adjust electricity usage in response to price signals, thereby improving grid efficiency and stability.

BESSs are defined by their rapid ramping, charging, and discharging capabilities, coupled with fast-acting control systems. As non-networked solutions, ESSs can alleviate the $N-1$ security criterion in transmission networks and enhance grid transfer capacity by providing real power reserves to quickly manage post-contingency currents in operational lines, as well as reactive power to increase voltage stability margins. Additionally, BESSs offer traditional storage services, such as energy arbitrage or load levelling, particularly during off-peak transfers through the grid [16]. Recently, BESS has been incorporated into TEP models alongside transmission lines, introducing a new dimension to the problem. BESS shifts electricity across time, complementing transmission lines that move electricity across space. Therefore, while BESS does not replace transmission lines, it acts as a complementary asset based on the characteristics of the power system, as demonstrated in [17]. A mixed-integer model focusing solely on BESS expansion in transmission systems is proposed in [18]. This model is solved in three stages: first, identifying optimal BESS locations; second, determining the ideal size of BESS installations at each location; and third, calculating the operational costs to assess the economic viability of the investment. A stochastic multistage TEP model that considers both BESS and transmission lines is presented in [19]. This model leverages BESS as both a long-term solution and a way to defer investments in transmission infrastructure under various renewable generation and load growth scenarios. In [20], a trilevel model is introduced where the upper-level problem optimises system operator investments in transmission lines and BESS, the middle-level focuses on merchant energy storage investment decisions, and the lower-level simulates the market clearing process for representative days. The study concludes that even with low-cost BESS, transmission lines are prioritised by system operators due to their greater longevity, and increases in social welfare are mainly driven by transmission line investments. Additionally, [21] proposes a mixed-integer linear programming (MILP) model for co-planning the transmission grid and Compressed Air Energy Storage (CAES) under the $N-1$ criterion. In [22], a three-level optimisation framework is presented to evaluate the resilience of ESSs against physical intentional attacks. Studies in [23] reveal that the optimal expansion of transmission lines and BESS can significantly improve grid reliability, and in [24,25], TEP is employed to enhance the reliability of large-scale transmission grids through optimal maintenance planning and the integration of wind farms.

The optimal allocation of BESS can significantly enhance network performance by reducing renewable energy curtailment, improving reliability, and increasing resilience. For example, [26] introduces a two-step framework, where the first step involves optimising the placement of BESS to maximise their accessibility to solar farms and load points, thereby minimising solar energy curtailment while considering network topology and power flow constraints. This process incorporates network connectivity constraints to ensure that the deployed BESS are directly connected to all buses within the network. The second step focuses on optimising the capacity distribution of the BESS identified in the initial stage. BESS are selected as the candidate energy storage technology due to their flexibility in deployment. The framework further addresses the identified gaps using a Genetic Algorithm (GA) integrated with Sequential Monte Carlo (SMC). This combined approach accounts for the time-series variability and intermittent nature of solar PV generation and BESS, as well as the stochastic behaviour of network conditions. Site selection analysis and capacity planning for DGs and BESSs based on various objective functions and optimisation methods are discussed in [27]. The site selection process identifies suitable installation locations through a vulnerability assessment, which considers factors such as voltage stability, line overload probability, and the likelihood of line faults under extreme weather conditions. This approach is demonstrated using the IEEE 33-node test system as a case study. A reliability assessment framework is proposed in [28], which evaluates the combined reliability impacts of a dynamic thermal rating system and BESS on a power network integrated with large-scale wind farms. This framework accounts for the numerous possible component states and the influence of chronological events, utilising the SMC method for analysis. Additionally, the study incorporates generation and transmission power constraints, which are critical elements in composite reliability assessments. The effectiveness of the proposed method is demonstrated using the Modified IEEE 24-bus Reliability Test Network (RTN). A network topology optimisation technique is presented in [29], which focuses on optimising line and busbar switching to alleviate network congestion and enhance network flexibility. The approach incorporates a dynamic thermal rating system to improve overhead line capacity and utilises a BESS to time-shift wind power usage, thereby preventing wind energy spillage. The study introduces an assessment framework that integrates these three methods into a unified model to evaluate their combined effects on wind integration and network reliability. The proposed framework is validated through case studies conducted on a modified IEEE 24-bus RTN. The authors in [30] explore the use of BESS as an alternative to conventional network assets, such as higher-capacity transmission lines, to enhance the security of supply for customers. The first key contribution of the paper is the development of a probabilistic evaluation method to analyse various combinations of BESS power ratings and energy capacities, assessing their impacts on transmission network reliability. This approach addresses the security of supply issue by utilising stored BESS charges to meet peak demands. The second contribution extends the analysis to evaluate the deployment of BESS in conjunction with Demand Response (DR) and Dynamic Thermal Rating (DTR) systems. Results indicate that the security of supply improves with optimised BESS sizing, achieving an enhancement of up to 37.2 %. Additionally, the study highlights that larger BESS units have a more significant impact on Expected Energy Not Supplied (EENS) during unavailability compared to smaller units. The analysis is conducted on the IEEE 24-bus RTN using DC power flow modelling. The optimal placement and sizing of BESS in distribution networks integrated with PV and Electric Vehicles (EVs) are investigated in [31]. The primary objective is to minimise system costs, including the installation, replacement, and operation and maintenance (O&M) costs of BESS. The replacement costs are evaluated over a 20-year period, while the O&M costs account for transmission line losses, voltage regulation, and peak demand management. To address this optimisation problem, three metaheuristic algorithms—Particle Swarm Optimisation (PSO), African Vultures Optimisation Algorithm (AVOA), and Salp Swarm Algorithm (SSA)—are utilised. The proposed approach is validated on the IEEE 33- and 69-bus distribution systems integrated with PV and EVs. And finally, the study in [32] examines the optimal sizing and placement of multiple

BESS in distribution systems integrated with DGs. To address the complexity of optimising multiple BESS units, a newly developed algorithm, the Crayfish Optimization Algorithm (COA), is employed. The results are compared with those obtained using PSO and SSA. The optimisation aims to minimise overall system costs while improving distribution system performance in three key areas: voltage regulation, peak demand reduction, and power loss reduction. The proposed method is validated using the IEEE 33- and 69-bus distribution systems integrated with DGs. Lastly, Power-to-hydrogen (P2H) technology is introduced in [33] as a strategy for enhancing the integration between the power grid and the hydrogen supply chain while also reducing renewable energy curtailment.

From the perspective of networked solutions, the Transmission Expansion Planning (TEP) problem is another way to address transmission system bottlenecks and is concerned with determining how a transmission system should evolve over time in the most cost-effective manner while maintaining an acceptable level of risk. This task is inherently complex, as it involves numerous variables with diverse characteristics and behaviours [34]. Additionally, TEP frequently involves uncertainty, given that future power system topologies and operating conditions are unknown. For example, [35] addresses TEP by considering uncertainty in demand forecasts. Due to the high complexity of such models, TEP problems are typically approached through the application of optimisation tools, such as heuristic methods [36], or mathematical decomposition techniques, such as the classical column-and-constraint generation method, can be employed to identify the optimal solution [37]. To ensure computational feasibility, many studies simplify power flow representations by using the DC model, which neglects voltage levels, power losses, and reactive power flows. In [38], a two-stage approach is employed to reduce the complexity of TEP by initially using a DC power flow model to generate a preliminary solution, which is then refined using an AC power flow model within a smaller, more manageable search space. Building on this, [39] introduces a more advanced four-stage methodology that efficiently addresses TEP for larger systems. In the first three stages of the proposed methodology, simplified models of the TEP problem are solved. Based on the results, a series of intelligent strategies are developed. These strategies are then applied in the final stage to address the multi-year, security-constrained AC Transmission Expansion Planning (ACTEP) problem, $N-1$ security criterion, with the objective of minimising overall investment costs. In contrast, [40] introduces a mathematical model that jointly considers both static and dynamic security in TEP with wind power integration. The uncertainty of wind power generation is addressed using selected scenarios, and the model is structured into a TEP master problem, accompanied by multiple sub-problems to assess static security and transient stability. Thus, TEP remains a crucial yet complex planning exercise, balancing economic efficiency with system reliability and risk management while accounting for future uncertainties.

3. Contributions of this paper

This paper examines the potential use of BESS to alleviate transmission network congestions and expedite the integration of new renewable generation sources. The study represents a real-world case, modelled on the entire transmission network of GB. In this work, transmission system bottlenecks, including both lines and transformers, identified through $N-1$ contingency analysis and hosting capacity assessments. The BESS is then sized and placed at the identified locations to address these bottlenecks using the Flow Decomposition Technique (FDT). Unlike previous studies, this research combines a large-scale real-world application with both contingency analysis and the hosting capacity method to identify transmission system bottlenecks. Additionally, the Equivalent Annualised Cost (EAC) method is employed as an index for comparing the lifecycle costs of various alternatives.

The structure of this paper is organised as follows: Section 4 delineates the methodological framework, encompassing hosting capacity analysis, contingency analysis, and the flow decomposition technique. Section 5 details the inputs and assumptions underpinning the study, while Section 6 presents the case studies conducted. Finally, Section 7 synthesises the key findings and provides the concluding remarks.

4. Methodological framework

This section provides a detailed explanation of the three main analyses used in this paper to identify transmission system bottlenecks. Following the explanation of these methods, the case study will be thoroughly examined. Before delving into the detailed analysis, Fig. 2 provides a high-level overview of the methodology employed in this study. The entire framework is structured into three key sections: model development, congestion analysis, and solution implementation. The proposed methodology can serve as a holistic procedural framework, guiding the process from the initial stages of network modelling to the identification of bottlenecks and, ultimately, the implementation of solutions to address those bottlenecks.

The model development phase which is described in the case study section outlines the foundational elements, including data input, which will describe the data sources used; assumptions incorporated into the model; debugging procedures; and finally, validation of the model against published documents from NGESO.

The congestion analysis phase, which is central to identifying transmission network bottlenecks, employs two critical methods: contingency analysis and hosting capacity analysis. These methods facilitate the identification of network limitations.

The final section addresses solution to the identified bottlenecks. Using the results from the congestion analysis and the model developed in the first phase, a FDT approach is applied. This technique identifies the locations and initial sizing of BESSs to alleviate congestions.

4.1. Hosting capacity

Hosting capacity is commonly defined as the maximum amount of new generation or demand that can be accommodated by the grid without violating system constraints, such as maintaining power quality

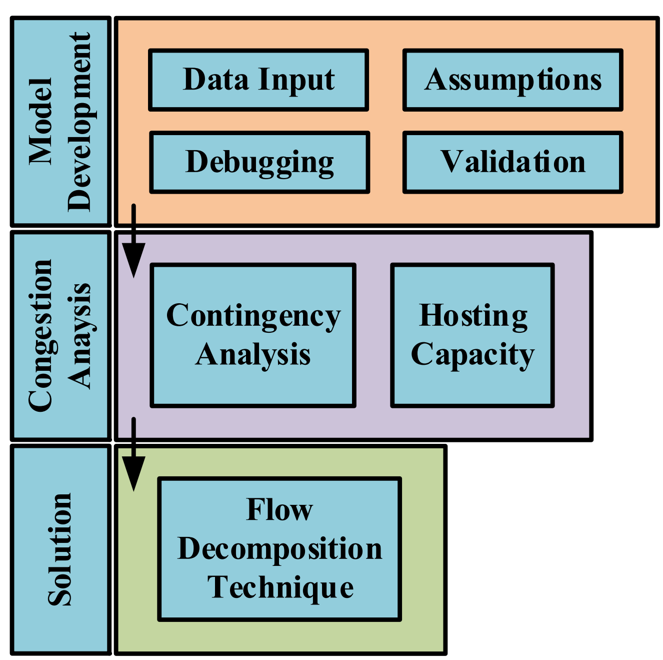

Fig. 2. Methodology overview

for customers, and without requiring network expansion. The calculation of hosting capacity provides valuable insight for assessing the effects of integrating additional generation or demand into a power system. The constraints that determine the permissible level of generation or demand can be quantified using a performance index which is associated with factors such as voltage violations, equipment overloads, and protection settings. The permissible levels of generation and demand are incrementally increased until the first constraint is violated. In the other words, hosting capacity can be described as the point at which the performance index reaches its threshold [41,42]. In this study, hosting capacity has been used to identify potential bottlenecks within the system. As demand and generation increase over time, the hosting capacity of each substation decreases, making it essential to pinpoint the critical components that limit this capacity. This approach allows for the proactive identification of constraints that could impact the system's ability to accommodate future growth.

The algorithm employed to determine the maximum hosting or spare demand capacity follows the binomial search method. The process begins with an initial active power value, which is incremented by a predefined step size. A load flow calculation is then performed, and the system is checked for any constraint violations. If no violations are detected, the algorithm proceeds by doubling the previous step size and repeating the checks. This process continues until a violation occurs, at which point the step size is halved. The procedure is repeated iteratively until the algorithm converges to an optimal solution without violations, or until the maximum number of iterations is reached [41].

4.2. Contingency analysis

Contingency analysis is a vital aspect of power system management, providing critical insights into the reliability and stability of electrical grids as they grow increasingly complex due to the integration of renewable energy sources, the electrification of transportation, and the rising demand for electricity. This analysis is essential for evaluating the behaviour of a power system under both normal and abnormal conditions. Specifically, contingency analysis refers to the assessment of system performance under abnormal conditions, allowing operators to evaluate the network's response to unplanned outages of individual components—such as transformers, busbars, or transmission lines—or groups of components. This process is crucial for determining power transfer margins and identifying vulnerabilities associated with varying demand conditions. By simulating the loss of key elements, contingency analysis helps operators understand the potential impacts on overall system performance, including voltage stability and power flow dynamics. This understanding enables the development of robust strategies to enhance system reliability, informing critical decisions related to infrastructure investments, maintenance practices, and operational procedures [43]. As power systems continue to evolve, the importance of contingency analysis in ensuring grid reliability and stability cannot be overstated.

4.3. Flow decomposition technique (FDT)

Power flows through a branch in a power system can be categorised based on the locations of the sources (e.g., generators) and sinks (e.g., loads) that drive these flows. Flow decomposition enables tracing the active power flow through a branch by analysing the contributing sources and sinks [44]. The branch element can be either internal to a specific area or a cross-border element connecting different zones, regions, or grids. Based on this classification and regional groupings (e.g., zones), several types of flows can be identified, as illustrated in Fig. 3 [41]:

Loop Flow: This occurs when the source and sink are within the same zone, but the branch element, or part of it, lies in another zone.

Transit Flow: In a transit flow, the source, sink, and branch element are all located in different zones. For example, an active power flow might originate from a source in zone A, flow through a line in zone B, and reach a sink in zone C.

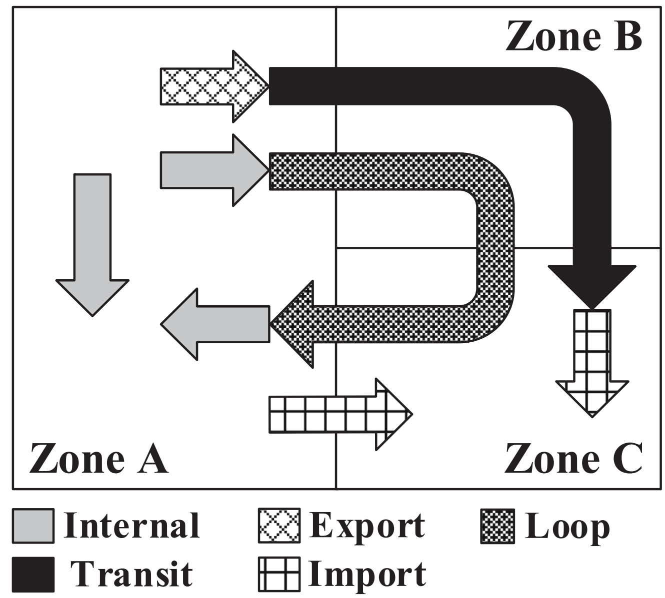

Fig. 3. Different flow types.

Export Flow: This refers to a flow where the branch element is located in the same zone as the source, while the sink is in another zone. Export flows are typically defined for internal elements.

Import Flow: An import flow occurs when the sink and part of the branch element are in the same zone, but the source is in a different zone. Flows on cross-border lines are always classified as import flows.

Internal Flow: An internal flow occurs when the source, sink, and branch element are all located within the same zone.

The FDT plays a critical role in network planning by ensuring that sufficient line capacity is available to accommodate market demands and by facilitating the analysis of potential measures to reduce unwanted phenomena, such as loop flows. Additionally, it is employed in the allocation of loop and transmission flows, serving as a key mechanism for cost-sharing agreements between different system operators.

Tracing electricity can be viewed as a transportation problem that seeks to determine how power injected by generators is distributed across the lines and loads of a meshed network. The objective is to trace electricity from a specific generator to a particular consumer. This process is carried out using the Full Line Decomposition (FLD) method, which is based on calculating a power exchange matrix, as described in detail by Bialek [44]. The main steps involved in the FLD method are as follows:

1. Perform a DC load flow calculation.
2. Obtain the nodal power transfer distribution factor (PTDF) matrix. This matrix describes the linear relationship between power injections from generators and the active power flows in the network elements.
3. Calculate the power exchange (PEX) matrix. The PEX matrix details the power exchanged between each generator node and each load node, where PEX_{ij} represents the power generated at node i and consumed at node j.
4. Calculate the power flow partitioning (PFP) matrix using the PTDF and PEX matrices.
5. Compute flow types by filtering and summing the elements of the PFP matrix.

This method enables a detailed analysis of how power flows within the network and helps trace the contributions of specific generators to particular loads.

Flow decomposition is primarily a diagnostic technique used to analyse and understand power flows within a network by breaking them down into components such as internal, loop, export, import, and transient flows. This method facilitates a detailed examination of power flow patterns, enabling the identification of issues like congestion, loss distribution, or the impact of renewable energy integration. For example, it can highlight how specific generators or load patterns contribute to transmission bottlenecks or energy losses. By leveraging methods based on linear algebra, sensitivity analysis, and graph theory—such as PTDF and FLD—flow decomposition provides interpretable, computationally efficient, and scalable insights for large networks [41,44].

In contrast, optimisation techniques focus on prescriptive decision-making, aiming to determine the best solutions for specific objectives, such as cost minimisation, system reliability enhancement, or emission reduction. These approaches employ various mathematical programming methods to solve complex, multi-variable problems under constraints. Optimisation is widely applied to tasks requiring actionable strategies to improve system performance. However, unlike flow decomposition, optimisation methods are computationally intensive, particularly for large-scale or nonlinear systems, and demand precise modelling of system parameters and constraints [26–32].

5. Inputs and assumptions

In this study, the GB's transmission network is modelled using DIgSILENT PowerFactory 2024 [45], utilising data for 2024 and 2030. Comprehensive specifications for all components—including lines, transformers, generators, substations, and FACTS devices—are sourced from [31]. The dataset encompasses 950 busbars across various voltage levels, 798 transmission lines, 362 transformers, 336 generators, 456 demand points, and 83 FACTS devices. Generators data is derived from the Transmission Entry Capacity provided by the NGESO [47,48], while demand data is obtained from relevant datasets [3,46]. AC power flow analysis is employed, and all relevant constraints, including active and reactive power limits, are incorporated into the modelling. Additionally, the operational limits for tap changers are considered. The Newton-Raphson algorithm is utilised for load flow calculations, with a maximum iteration limit set to 25.

The transmission network comprises four distinct voltage levels: 132 kV (exclusively in Scotland), 220 kV, 275 kV, and 400 kV. In the model, it is assumed that all generation resources connect to 33 kV busbars. Additionally, the power factor for demand is assumed to be 0.95, resulting in reactive power at each substation being approximately 33 % of its active power. Simulations are conducted for peak winter and minimum summer demand scenarios for both 2024 and 2030.

It is noteworthy that the peak demand recorded in 2024 reached 47,507 MW on January 18, referred to as the Transmission System Demand (TSD). The TSD represents the generation requirement of the transmission system and is equivalent to the initial transmission system outturn as well as the transmission system demand forecast reported in the Balancing Mechanism (BM) [49]. This peak likely represents the annual maximum, while the minimum summer demand was observed at 17,138 MW on May 11, 2024. According to the Future Energy Scenarios (FES) 2024, peak demand in 2030 is projected to increase by 7 % compared to 2023 in Holistic Transition (HC) scenario. A similar increase is anticipated for peak demand in 2030 relative to the peak in 2024, suggesting a peak of approximately 51 GW, with the minimum summer demand expected to be around 18,337 MW.

Table 1
Cost parameters of different system components.

	CAPEX (£)	OPEX (£)	Lifetime (Year)	Ref.
Line*	1.6 m/km	80 k/km	40	[50]
Substation	26,248/MVA	525/MVA	30	[51]
BESS	300/kWh	0	20	[52]

* 400 kV AC transmission line with a total capacity of 6380 MVA (2 × 3190 MVA).

Table 1 presents the input parameters for capital costs (CAPEX) and operating and maintenance costs (OPEX) of the various system components. The Discount rate is supposed to be 3.5 % [50].

The transmission network features nine interconnections with neighbouring countries, as illustrated in Fig. 4. This figure provides an overview of the entire GB transmission network under peak winter and minimum summer demand conditions for both 2024 and 2030. Ownership of the network is attributed to Scottish Hydro Electric (SHE) Transmission, Scottish Power (SP) Transmission, and National Grid, with the system segmented into 36 distinct zones [53].

6. Case study

This section examines three case studies. The first considers the normal operating conditions of the entire GB network in 2024 and 2030. The subsequent scenarios focus on the South Wales transmission network, analysing conditions both with and without the integration of floating offshore wind.

6.1. Normal operating condition of the entire system

Fig. 4 presents the power flow across GB and its interconnections for both 2024 and 2030. This figure represents the initial output of the model under peak winter and minimum summer demand conditions. It demonstrates that power predominantly flows from the north to the south of the country due to the concentration of wind resources in the north. Additionally, the primary electricity demand is located in England, rather than Scotland or Wales, contributing to this flow direction. The figure further highlights that GB exports electricity to interconnections with Northern Ireland and the Republic of Ireland, while importing electricity from other interconnections. A closer examination of the zones reveals that South Wales (zone 4) consistently transfers electricity to zone 14 in England. This is due to the abundance of both renewable and non-renewable energy resources in South Wales. Notably, by 2030, South Wales is projected to send significantly more electricity to zone 14 compared to 2024, largely due to the expected integration of new wind power plants in the region by 2030. As previously mentioned, there are plans to connect 1 GW of offshore wind capacity in South Wales. Additionally, a proposal exists to connect 4.5 GW of floating offshore wind capacity [54]. South Wales currently accommodates several pollutant-based generation resources, creating a need to examine how the integration of new renewable generation sources will impact the transmission network and the overall system reliability. Thus, South Wales has been selected as the case study, with two subsections providing a closer analysis.

6.2. South Wales transmission network analysis excluding floating offshore wind

Fig. 5 illustrates the projected configuration of the South Wales and West England transmission network for 2030. This configuration largely mirrors the current network, with the notable exception of a newly planned wind power facility in Pembroke, excluding the consideration of floating offshore wind developments. This figure offers a more detailed view of zone 4 and some other zones from the previous figure. According to the government's strategic plan, by 2030, the region will see the establishment of two 300 MW wind farms and one 400 MW wind farm in southern Wales, specifically in Pembroke [55]. Additionally, the network integrates five other power plants connected to the transmission grid at Pembroke, Swansea North, Upper Boat, Rhigos, and Uskmouth. As shown, the South Wales transmission network is connected to the broader GB transmission network via 400 kV lines running from the Walham and Melksham substations. It is important to note that some lines within the network, such as Swansea North-Cilfynydd, are double-circuit, while others, like Pembroke-Swansea North, are triple-

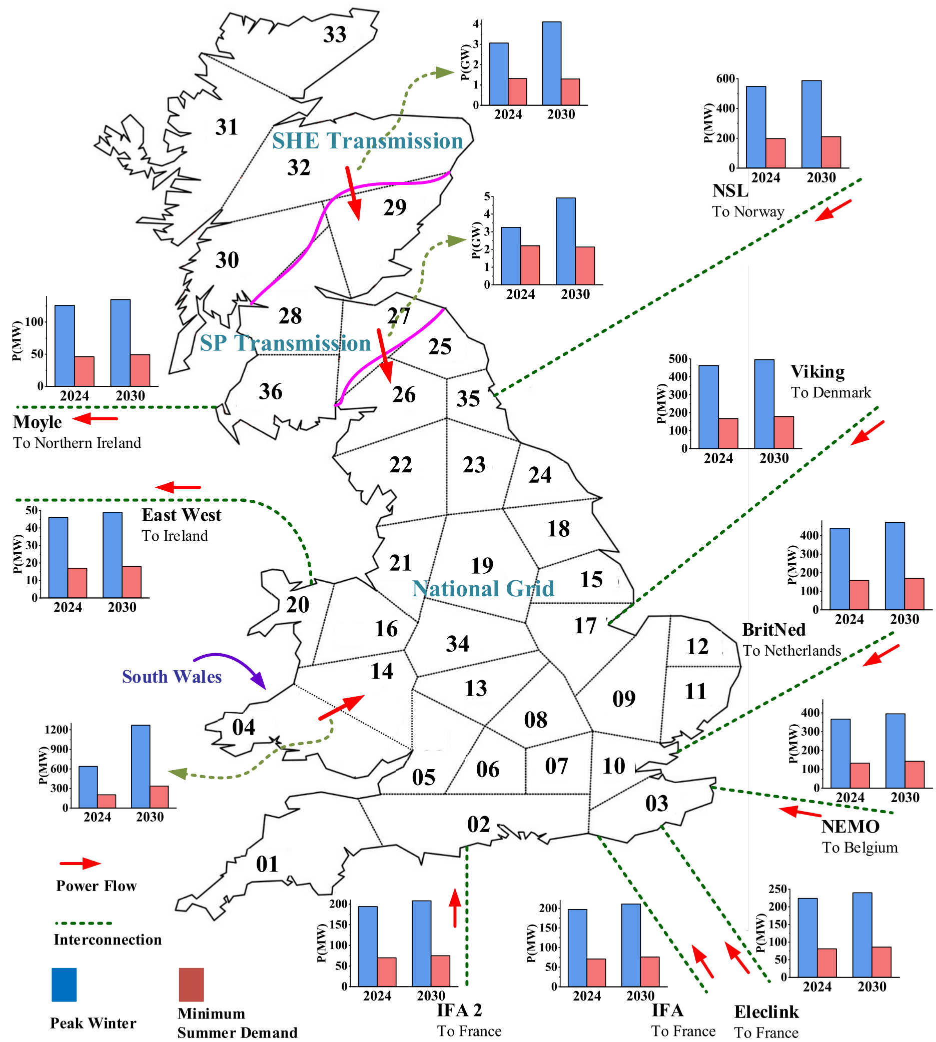

Fig. 4. Power flow dynamics across GB and interconnections under peak winter and minimum summer demand conditions for 2024 and 2030

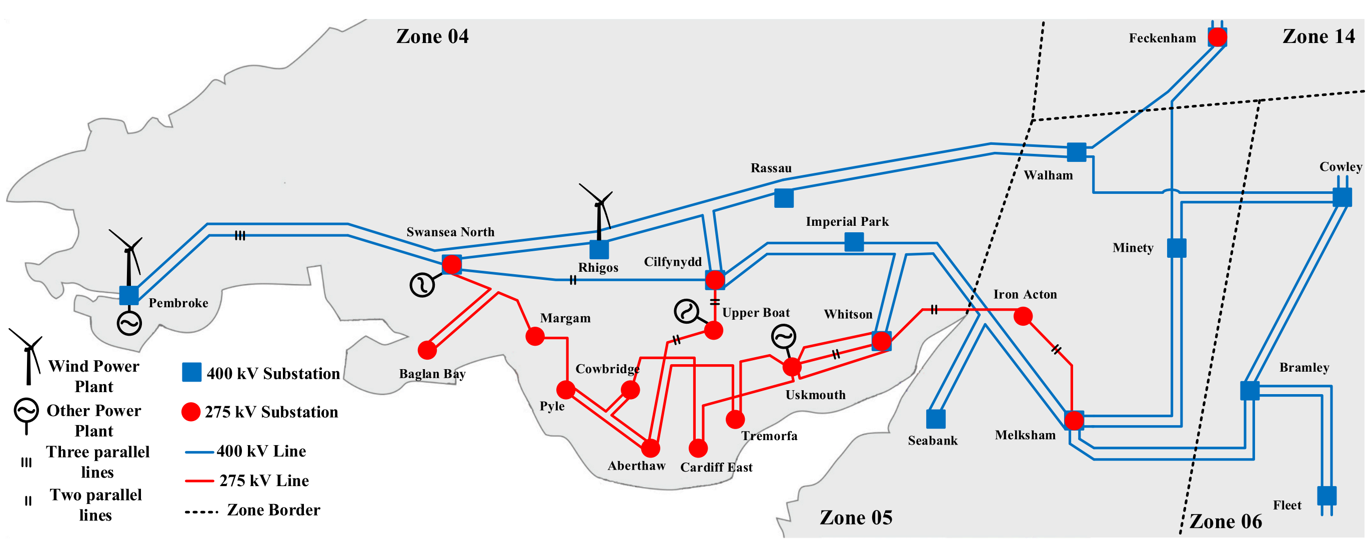

Fig. 5. Configuration of the south Wales and west England transmission network in 2030. This figure was produced using data from [46–48].

circuit configurations [46].

As previously noted, two case studies will be examined: one focused on the projected demand for 2030, and the other on the conditions in 2024. Both studies will analyse peak winter and minimum summer demand scenarios to ensure the transmission system operates effectively under the worst-case scenarios. Initially, the system's performance under normal conditions will be assessed. Subsequently, contingency analysis and hosting capacity will be employed to pinpoint the critical bottlenecks in the transmission network. Finally, a BESS-based non-network solution will be explored as a potential measure to alleviate these constraints.

We now turn our attention to South Wales to identify potential system bottlenecks in this region. South Wales is employed as a case study to illustrate the functionality of the model, while the entire GB transmission network is simulated. Table 2 presents the voltage magnitudes for multiple busbars in the area under two different normal operating conditions. In all scenarios, the voltage magnitudes remain within the acceptable range (0.95–1.05 pu). The table reveals that voltage magnitudes increase during periods of minimum summer demand compared to peak winter conditions. This rise in voltage during low demand is primarily due to the reduced current flowing through transmission lines, which leads to a smaller voltage drop across the network. Additionally, the reduced demand can alter the balance between inductive and capacitive effects in the system, further contributing to the increase in voltage. These combined factors explain the higher voltage observed during periods of reduced demand.

Fig. 6 depicts the loading of select lines (LN) and transformers (TR) during peak winter conditions in 2024 and 2030, representing the worst-case scenario under normal operating conditions in the area. The figure indicates an increase in loading from 2024 to 2030, which aligns with expectations due to the projected rise in demand over this period. This increase in demand naturally results in higher loading on both the lines and transformers within the network.

6.2.1. Contingency analysis of the system

The output presented in Table 2 and Fig. 6 indicate that, under normal operating conditions during peak winter of 2030, system performance remains stable. Both the loading levels and voltage magnitudes are within the acceptable limits, demonstrating no abnormalities.

The system's normal operation in 2030 reveals no bottlenecks under standard conditions. However, as previously mentioned, two analyses were used to identify potential system bottlenecks: contingency and hosting capacity analyses. In this context, an N-1 contingency analysis was conducted for South Wales (Zone 4) during the peak winter day of 2030. The results are shown in Fig. 7.

The simulation outputs reveal that in the event of an outage on the Pembroke-Swansea North line, the loading on the Pembroke-Walham line would increase significantly from 21 % to 88 %. This occurs because, with the Pembroke-Swansea North line out of service, all power from Pembroke to eastern Wales and western England must be rerouted through the Pembroke-Walham line, leading to the increased loading. Similarly, if the Swansea North transformer fails, the loading on the Cilfynydd transformer would rise from 51 % to a critical 94 %. Furthermore, an outage of the Uskmouth transformer would result in the loading on the Whitson transformer increasing from 50 % to 84 %. Lastly, an outage on the Whitson-Iron Acton line would cause the loading on the Melksham transformer to surge from 61 % to 110 %, a critically high level. This is because the Iron Acton and downstream substations rely on power from both the Melksham and Whitson substations. When the Whitson-Iron Acton line is out of service, the entire demand must be handled by the Melksham transformer, leading to severe overloading.

These results highlight the presence of a bottleneck in the Melksham transformer and potential bottlenecks in the Pembroke-Walham line, Cilfynydd transformer, and Uskmouth transformer. Addressing these areas should be prioritised in the system reinforcement process.

As previously discussed, hosting capacity analysis is another method used to identify system bottlenecks, particularly as the system expands. This analysis assesses the system's ability to accommodate increased generation and demand at each substation, as well as the components that impose limitations. By identifying these limiting components, it is possible to determine which elements of the system may constrain future demand growth.

Table 3 provides the hosting capacity for both generation and demand across all substations in South Wales (Zone 4) for 2030, along with their corresponding limiting components. The data indicate that the Melksham and Swansea North transformers are critical bottlenecks, restricting demand capacity in a wide range of substations, including some that are geographically distant. For example, the Melksham transformer is identified as the limiting factor for five different substations, underscoring its crucial role in power transmission within the region.

In most cases, the primary constraint on generation hosting capacity at substations is the transmission line connecting the substation to another. This result is anticipated, as these lines are engineered according to existing generation capacity, with a built-in allowance for future growth.

To provide a more detailed analysis of Melksham transformer role in the region, Fig. 8 and Table 4 present a portion of the power exchange analysis based on FDT for this component. Flow numbers in Fig. 8 explain in Table 4. The table outlines the sending and receiving power, transferred through the Melksham transformer, along with the corresponding zones involved. Additionally, it categorises the type of power flow. According to the data, the Melksham transformer plays a critical role in power transfer between Zones 4 and 5. For example, 120 MW of power flows from Pembroke to Iron Acton via the Melksham transformer, indicating an import flow for this transformer, as depicted in Fig. 8. A similar situation is observed for the Swansea North transformer.

This section has identified several bottlenecks within the transmission network, particularly in South Wales. One critical case—the Melksham transformer—has been selected for further analysis and the implementation of proposed solutions to address this bottleneck.

6.2.2. BESS as a solution to address system bottlenecks

For addressing system bottlenecks such as those discussed in the previous section, there are two available approaches: networked and non-networked solutions. Networked solutions involve physical upgrades to the infrastructure, such as reinforcing transmission lines, transformers, and making necessary enhancements at substations. However, these solutions tend to be expensive and time-consuming, potentially delaying the achievement of system objectives.

Unlike traditional networked solutions, non-networked approaches offer faster implementation and lower costs. We have developed a non-networked solution that utilises BESS to manage system bottlenecks, particularly during critical periods when equipment loading reaches critical levels. For example, during peak hours, an outage on the Whitson-Iron Acton line pushes the loading of the Melksham transformer into a critical range. This issue occurs only for a limited number

Table 2
Voltage magnitude [pu] in normal operating condition.

Busbar	2024		2030	
	PW	MSD	PW	MSD
Pembroke	1.04	1.05	1.03	1
Swansea North	0.96	1.01	0.95	1.03
Cilfynydd	0.97	1.04	0.96	1.03
Whitson	0.97	1.02	0.97	1.04
Melksham	0.95	1.01	0.95	1.02
Baglan Bay	0.97	0.99	0.96	0.97
Margam	0.98	1	0.97	0.98
Pyle	0.98	1.01	0.97	0.99
Cowbridge	0.98	1.02	0.97	1.01
Aberthaw	1	1.02	0.99	1.01
Upper Boat	0.98	1.04	0.97	1.01
Cardiff East	0.98	1.02	0.97	1.03
Tremorfa	0.98	1.02	0.98	1.04
Uskmouth	0.98	1.02	0.97	1.05
Iron Acton	0.95	1.01	0.95	1.02

PW: Peak Winter, **MSD:** Minimum Summer demand.

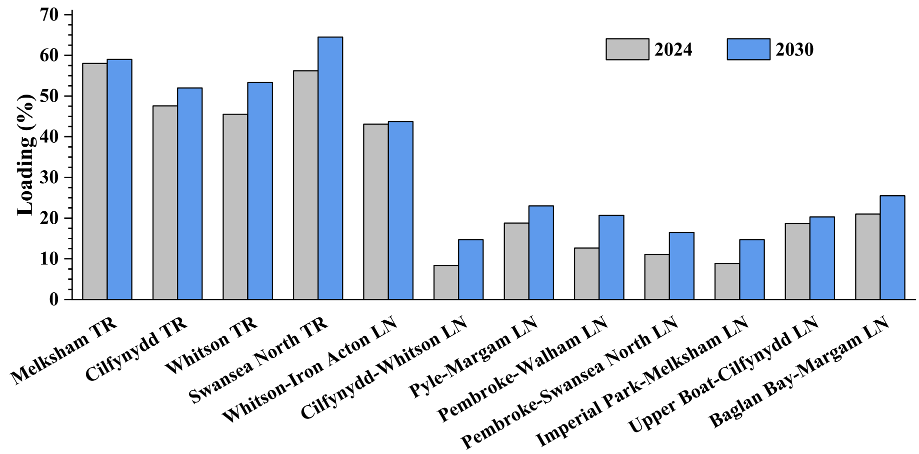

Fig. 6. Loading characteristics of selected lines and transformers in south Wales during peak hour.

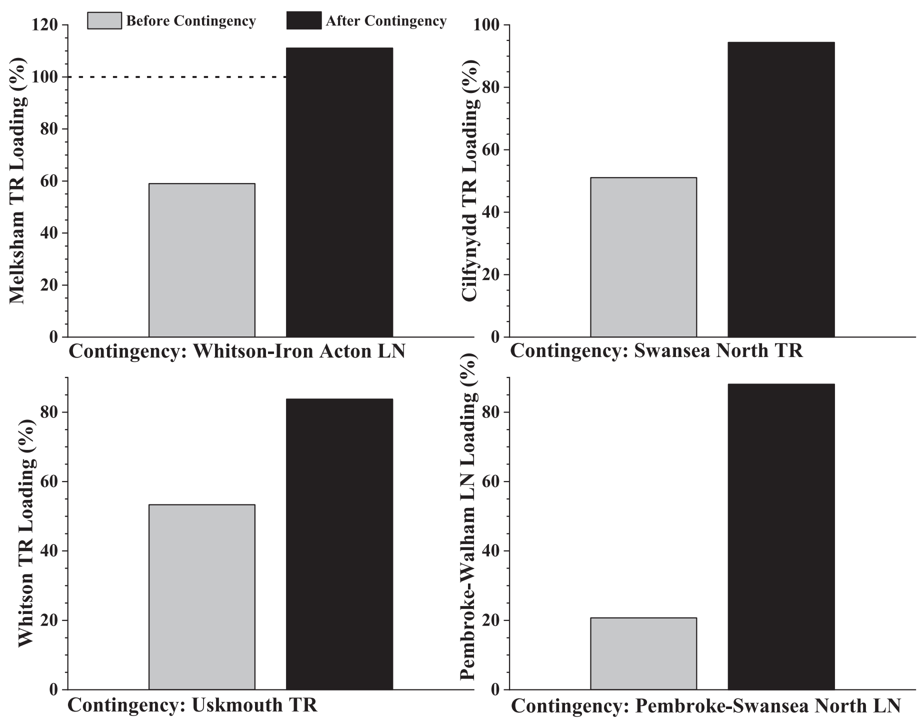

Fig. 7. Results of N-1 contingency analysis in south Wales during peak hour.

of hours during the peak time, typically less than 5–6 h over 20 days per year. To address this, we designed a BESS-based method to manage equipment loading during these specific periods. The BESS would be placed at the locations on the receiving side of the transformer or transmission line as the biggest sink. It would charge during off-peak hours, or when the system is operating under normal conditions, and discharge during critical hours to prevent excessive power flow that pushes the system into critical conditions. This ensures that the loading on the line or transformer remains within safe operating limits, while avoiding unsupplied demand.

The primary challenge lies in determining the appropriate BESS size, for which we have developed a methodology based on FDT. The method's flowchart is presented in Fig. 9. It was demonstrated that the network operates without any issues under normal operating conditions (Table 2 and Fig. 6). The critical hours are assumed to be continuous and begin at t_0 and conclude at T, with time steps denoted by t' (which are 30-min intervals in this study). Initially, a contingency analysis is performed to assess the loading of the congested components. Additionally, a hosting capacity analysis is conducted to identify the components most constrained as demand and generation increase. However, it does not directly influence the calculation of BESS sizing. At this stage, all bottlenecks in the system will be identified and represented as $bk_t = 1, 2, \ldots, BK_t$. Then according to the FDT, the initial battery size ($BC_{bk_t} = C0_{bk_t}$) and its location are determined, where BC_{bk_t} represents Battery Capacity (in MWh) required to address the bottleneck bk at time t. The parameter $C0_{bk_t}$ can be appropriately selected based on the output of the FDT for the substation under study, as considered in this paper. This is done by assuming a depth of discharge of 10 % for the BESS. If the capacity is sufficient for the remaining critical time slots, the algorithm terminates. Otherwise, the battery capacity is incremented in steps of C'_{bk_t} to ensure the BESS can meet the requirements for all critical hours throughout the day. C'_{bk_t} is supposed to be 3 MWh. The power rating capacity of the BESS (measured in MW) is defined as the maximum power required during the critical hours. It is important to note that if multiple time slots (t_0 to T) occur on different occasions within the same day, the BESS can be sized

Table 3
Hosting capacity analysis results in south Wales during peak hour.

Substation	Type	Maximum Extra Active Power (MW)	Limiting Component
Whitson	Demand	1095	Melksham TR
	Generation	2169	Whitson-Iron Acton LN
Uskmouth	Demand	1107	Melksham TR
	Generation	2217	Whitson-Iron Acton LN
Upper Boat	Demand	236	Upper Boat TR
	Generation	2177	Cilfynydd TR
Tremorfa	Demand	868	Uskmouth-Tremorfa LN
	Generation	1014	Uskmouth-Tremorfa LN
Swansea North	Demand	1814	Swansea North TR
	Generation	3841	Swansea North TR
Rhigos	Demand	1049	Swansea North TR
	Generation	3745	Rhigos-Cilfynydd LN
Rassau	Demand	3474	Braintree-Bramford LN
	Generation	4617	Cilfynydd-Rassau LN
Pyle	Demand	1863	Melksham TR
	Generation	2585	Cowbridge-Pyle LN
Pembroke	Demand	4832	Braintree-Bramford LN
	Generation	2621	Pembroke TR
Margam	Demand	1715	Baglan Bay-Margam LN
	Generation	1829	Pyle-Margam LN
Imperial Park	Demand	3902	Imperial Park-Melksham LN
	Generation	3177	Imperial Park-Melksham LN
Cowbridge	Demand	1628	Melksham TR
	Generation	2057	Cowbridge-Aberthaw LN
Cilfynydd	Demand	525	Cilfynydd TR
	Generation	5225	Whitson-Seabank LN
Cardiff East	Demand	787	Cardiff East-Uskmouth LN
	Generation	1313	Cardiff East-Uskmouth LN
Baglan Bay	Demand	1638	Baglan Bay-Swansea North LN
	Generation	2241	Baglan Bay-Margam LN
Aberthaw	Demand	1420	Melksham TR
	Generation	3065	Tremorfa-Aberthaw LN

for each time slot individually, with the largest required battery size being selected.

The Melksham transformer is the candidates for the implementation of the abovementioned approach. Fig. 10 illustrates the loading and the problematic MW of the Melksham transformer under N-1 contingency (Whitson-Iron Acton) on a peak winter day. According to the figure, during an outage of the Whiston-Iron Acton line, the transformer experiences critical overloading, exceeding 100 % capacity during specific hours—namely from 9:00 to 10:00 and 15:30 to 19:30. This critical loading must be mitigated.

The FDT analysis identifies the source and sink for each megawatt of power flowing through the lines and transformers. As shown in Table 4, the majority of the power passing through the Melksham transformer is directed towards meeting demand at the Iron Acton and Melksham substations. Therefore, placing a BESS with sufficient capacity at either of these substations would alleviate the critical loading.

The key question, however, is determining the appropriate energy capacity for the BESS. Fig. 10 quantifies the amount of power (referred to as "problematic MW") that needs to be reduced or curtailed during these time periods to bring the transformer's loading below 100 %. This problematic MW represents the amount of power the BESS would need to inject into the system. The highest problematic MW occurs at 17:00, requiring 104 MW, while the lowest occurs at 9:00, with only 15 MW needed. The BESS's power rating capacity is equal to the highest Problematic MW that it needs to inject to the system.

To accurately size the BESS, it is essential to calculate the highest continuous MWh requirement during peak days and use the maximum value as the reference for sizing. This is necessary because, during critical periods, the BESS can only discharge power; it cannot recharge. Therefore, the BESS must have sufficient capacity to supply energy throughout the entire duration of critical conditions. However, for subsequent days, there is ample time for recharging, so the worst-case scenario—a peak day—should be used as the basis for calculating BESS capacity.

For example, when sizing the BESS for the Melksham transformer, the problematic MW during the hours of 9:00 and 10:00 can be excluded because there is sufficient time between 10:00 and 15:30 for the BESS to recharge before the next critical period. The focus should be on the continuous critical hours from 15:30 to 19:30, which require 318 MWh. Taking into account a 10 % depth of discharge for the ESS, the required capacity would be 354 MWh. This means that installing a BESS with this capacity on the secondary side of the Melksham transformer would mitigate any issues during the most severe contingency scenarios, without needing to reinforce the transformer. The execution time for this

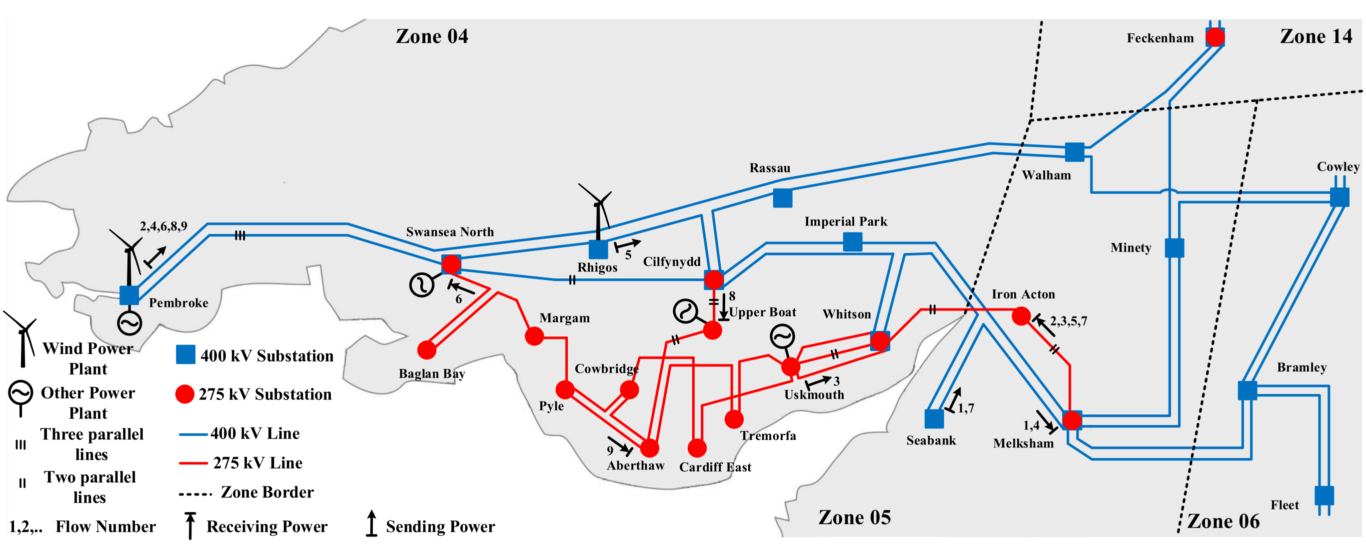

Fig. 8. Power exchange results for Melksham transformer based on FDT during peak hour in south Wales, and west of England.

Table 4
Power exchange results for Melksham transformer based on FDT during peak hour.

Sending Substation	Flow Number	Sending Zone	Receiving Substation	Receiving Zone	Flow Type	Flow (MW)
Seabank	1	5	Melksham	5	Internal	128
Pembroke	2	4	Iron Acton	5	Import	120
Uskmouth	3	4	Iron Acton	5	Import	75
Pembroke	4	4	Melksham	5	Import	47
Rhigos	5	4	Iron Acton	5	Import	41
Pembroke	6	4	Swansea North	4	Loop	31
Seabank	7	5	Iron Acton	5	Internal	26
Pembroke	8	4	Upper Boat	4	Loop	23
Pembroke	9	4	Aberthaw	4	Loop	20

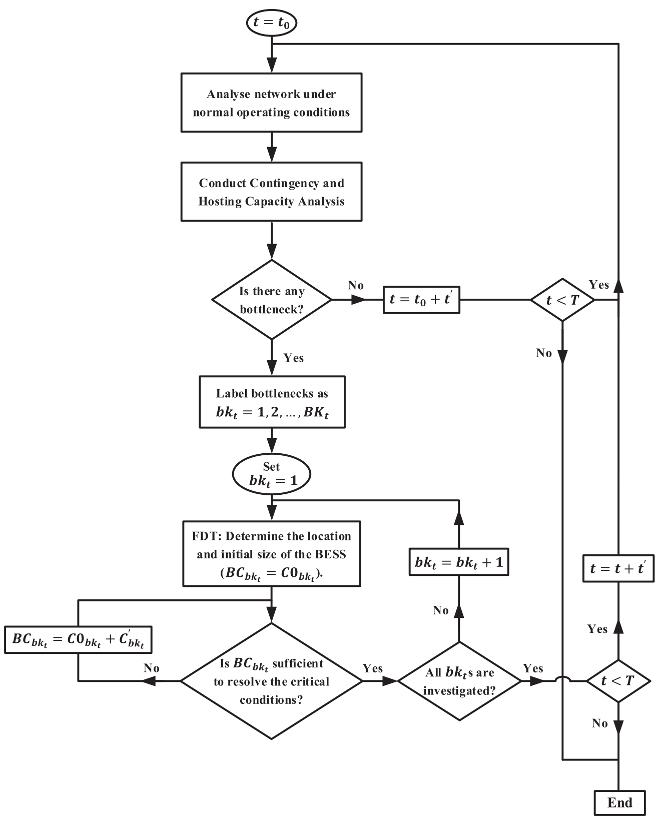

Fig. 9. Flowchart for determining size and location of BESSs to address the network bottlenecks.

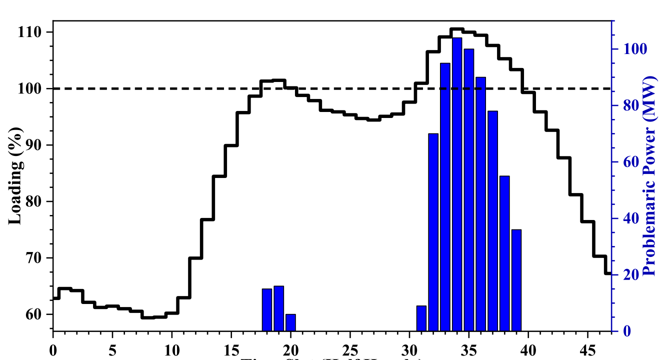

Fig. 10. Loading and problematic power of the Melksham transformer under N-1 contingency on peak winter 2030.

case study is recorded as 73.96 s, demonstrating the computational efficiency of the proposed approach.

6.2.3. The EAC for the networked and non-networked solutions

The EAC represents the annualised cost of constructing, operating, and maintaining an asset over its entire lifespan and is expressed by Eq.1 [56].

$$EAC = CAPEX \times CRF + OPEX \tag{1}$$

The Capital Recovery Factor (CRF) is employed to convert the capital cost of each project into an annualised cost, spread over the system's expected service life, and is expressed by Eq. 2 [56]:

$$CRF = \frac{R(1+R)^T}{(1+R)^T - 1} \tag{2}$$

where T denotes the operational lifetime of the technology and R represents the discount rate [43,44].

This metric serves as a valuable index for comparing the costs of various alternatives. Table 5 shows the results of EAC for this case study. As the details are described in Table 5, reinforcing the Melksham substation to address the issue results in an EAC of £291.4 thousand—a substantial cost advantage in favour of substation reinforcement. It is important to note that when reinforcing a substation, the maximum problematic MW must be considered as the critical design parameter. In this case, the peak problematic MW is 104 MW. To account for the reactive power component, a power factor of 0.72 is assumed for the substation. Accordingly, the required capacity is calculated in MVA and rounded up to 150 MVA to ensure sufficient capacity for reliable operation. For the BESS implementation, the EAC is calculated at £7.4 million, nevertheless, anticipated advancements in BESS technology are expected to drive capital cost reductions of 16–49 % by 2030 and 28–67 % by 2050 [52]. As a result, by 2030, the EAC for the BESS is projected to range between £3.8 million and £6.2 million. It is important to note that while this paper focuses on the benefits of BESS in congestion management, BESS also offers a wide range of additional advantages. These include reducing line losses, improving voltage profiles, peak shaving, providing frequency response, and numerous other benefits.

6.3. South Wales transmission network analysis including floating offshore wind

This scenario considers the integration of three 1.5 GW floating

Table 5
Cost parameters for various options.

	CAPEX (£)	OPEX (£)	CRF	Lifetime (Year)	EAC (£/year)
Melksham Substation Reinforcement	3.937 m	78.8 k	0.054	30	291.4 k
BESS for Melksham Substation in 2024	106.2 m	0	0.070	20	7.4 m
BESS for Melksham Substation in 2030	54.2 m–89.2 m	0	0.070	20	3.8 m–6.2 m

offshore wind farms, connected to Pembroke, Baglan Bay, and Pyle, along with an additional 1 GW offshore wind farm connected to Pembroke. Consistent with the previous case study, contingency analysis and hosting capacity assessments are employed to identify transmission network bottlenecks in the region. Additionally, the FDT is utilised to determine the location and sizing of the BESS to mitigate these issues. The contingency analysis reveals two critical bottlenecks in the region: the Pembroke-Walham line and the Melksham transformer. Fig. 11 illustrates the loading of these components under an N-1 contingency scenario during peak winter conditions in 2030. As shown, the loading of both components exceeds 100 % in certain time intervals, highlighting a critical issue that requires resolution. The contingency leading to overloading of the Pembroke-Walham line is the outage of the Pembroke-Swansea North line, while the overloading of the Melksham transformer results from the outage of the Whitson-Iron Acton line.

Before determining the problematic MW for the Pembroke-Walham line and Melksham transformer, it is useful to first review the power exchange results based on the FDT analysis during peak hours, as shown in Tables 6 and 7. According to Table 6 for Pembroke-Walham line, the highest power flow, 197 MW, originates from Pembroke and is directed towards Walham to meet the demand there. This suggests that installing a BESS at Walham could effectively resolve the issue. In Table 6 for Melksham transformer, the same approach there shows that Melksham could be the best place for installing the BESS. In other words, the FDT analysis, by identifying the source and sink of each megawatt flowing through the lines, indicates the location for placing the BESS to mitigate bottlenecks.

Figs. 12 and 13 illustrate the different flow types for the Pembroke-Walham line and the Melksham transformer, respectively. Flow numbers in these figures explain in Tables 7 and 8. For instance, for the Pembroke-Walham line, the power flow from Pembroke to Walham is classified as an import flow, as it transfers power from Zone 4 to Zone 5. The flow from Pembroke to Bramley is considered a transit flow, as it passes through Zone 5 from Zone 4 to Zone 6. Meanwhile, the flow from Pembroke to Imperial Park is categorised as a loop flow, as it moves from Zone 4 to Zone 5 and then returns to Zone 4. In the case of the Melksham transformer, the power flow from Pembroke to Melksham is considered an import flow, while the flow from Seabank to Melksham is categorised as an internal flow.

Fig. 14 illustrates the MW values for each time slot that, if curtailed or reduced, would bring the loading of the Pembroke-Walham line and the Melksham transformer below 100 % (problematic MW). For the Pembroke-Walham line, the highest problematic MW occurs during the peak hour at 17:00, reaching 780 MW, while the lowest is 210 MW at 16:00. In contrast, for the Melksham transformer, the highest problematic MW is observed at 17:00, reaching 104 MW, and the lowest is 6.9 MW at 15:30.

Following the methodology applied to the Melksham transformer in the previous case study, the total problematic MWh for the Pembroke-Walham line between 16:00 and 18:00 amounts to 1290 MWh. With a

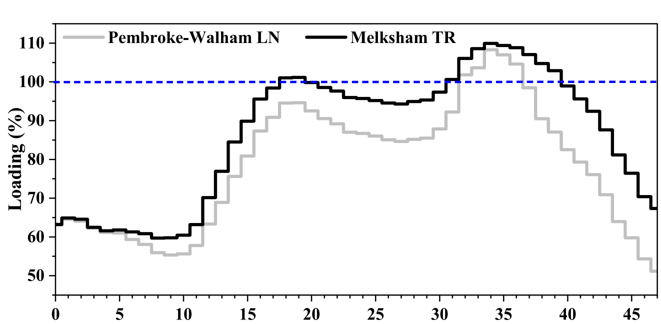

Fig. 11. Loading of the Pembroke-Walham line and Melksham transformer under N-1 contingency on peak winter 2030.

Table 6
Hosting capacity analysis results in south Wales during peak hour.

Substation	Type	Maximum Extra Active Power (MW)	Limiting Component
Whitson	Demand	1719	Melksham TR
	Generation	1607	Whitson-Iron Acton LN
Uskmouth	Demand	1758	Melksham TR
	Generation	1041	Whitson-Iron Acton LN
Upper Boat	Demand	236	Upper Boat TR
	Generation	1495	Cilfynydd TR
Tremorfa	Demand	1289	Uskmouth-Tremorfa LN
	Generation	577	Uskmouth-Tremorfa LN
Swansea North	Demand	3055	Swansea North TR
	Generation	2865	Whitson-Seabank LN
Rhigos	Demand	1049	Swansea North TR
	Generation	2801	Whitson-Seabank LN
Rassau	Demand	3908	Braintree-Bramford LN
	Generation	3441	Whitson-Seabank LN
Pyle	Demand	2102	Melksham TR
	Generation	861	Cowbridge-Pyle LN
Pembroke	Demand	7555	Braintree-Bramford LN
	Generation	1621	Baglan Bay-Swansea North LN
Margam	Demand	1846	Baglan Bay-Margam LN
	Generation	959	Pyle-Cowbridge LN
Imperial Park	Demand	3464	Imperial Park-Melksham LN
	Generation	1957	Imperial Park-Melksham LN
Cowbridge	Demand	963	Melksham TR
	Generation	850	Cowbridge-Cardiff East LN
Cilfynydd	Demand	1049	Cilfynydd TR
	Generation	2769	Whitson-Seabank LN
Cardiff East	Demand	662	Cardiff East-Uskmouth LN
	Generation	686	Cardiff East-Uskmouth LN
Baglan Bay	Demand	2621	Baglan Bay-Swansea North LN
	Generation	1247	Pyle-Cowbridge LN
Aberthaw	Demand	2314	Melksham TR
	Generation	1201	Cardiff East-Cowbridge LN

10 % depth of discharge considered for the BESS, the required BESS capacity is calculated to be 1419 MWh. It is important to note that the highest problematic MW indicates the power rating of the BESS, which, in the case of the Pembroke-Walham line, is 780 MW. Applying the same procedure to the Melksham transformer reveals that a BESS capacity of 336 MWh with a power rating of 104 MW is required. This BESS installation would effectively address the bottlenecks on both the Pembroke-Walham line and the Melksham transformer, thereby eliminating the need for costly and time-consuming infrastructure upgrades.

The above calculations determine the size of the BESS when considered independently. However, the capacity requirements change when another BESS is already present in the network. If the Melksham BESS is installed, the required size for the Walham BESS decreases to 1218 MWh/690 MW, compared to 1419 MWh/780 MW without it. Similarly, if the Walham BESS is already in place, the required size for the Melksham BESS reduces to 333 MWh/102 MW, instead of 336 MWh/104 MW. The execution time for this case study is recorded as 198.64 s.

Fig. 15 presents the range of voltages during peak day for several substations in South Wales, taking into account the operation of the BESSs. As illustrated in this figure, all voltage levels remain within the

Table 7
Power exchange results for Pembroke-Walham line based on FDT during peak hour.

Sending Substation	Flow Number	Sending Zone	Receiving Substation	Receiving Zone	Flow Type	Flow (MW)
Pembroke	1	4	Walham	5	Import	197
Pembroke	2	4	Bramley	6	Transit	103
Pembroke	3	4	Cowley	6	Transit	88
Pembroke	4	4	Fleet	6	Transit	63
Pembroke	5	4	Melksham	5	Import	63
Pembroke	6	4	Minety	5	Import	47
Pembroke	7	4	Seabank	5	Import	44
Pembroke	8	4	Iron Acton	5	Import	31
Pembroke	9	4	Swansea North	4	Loop	26
Pembroke	10	4	Feckenham	14	Transit	25
Pembroke	11	4	Imperial Park	4	Loop	22

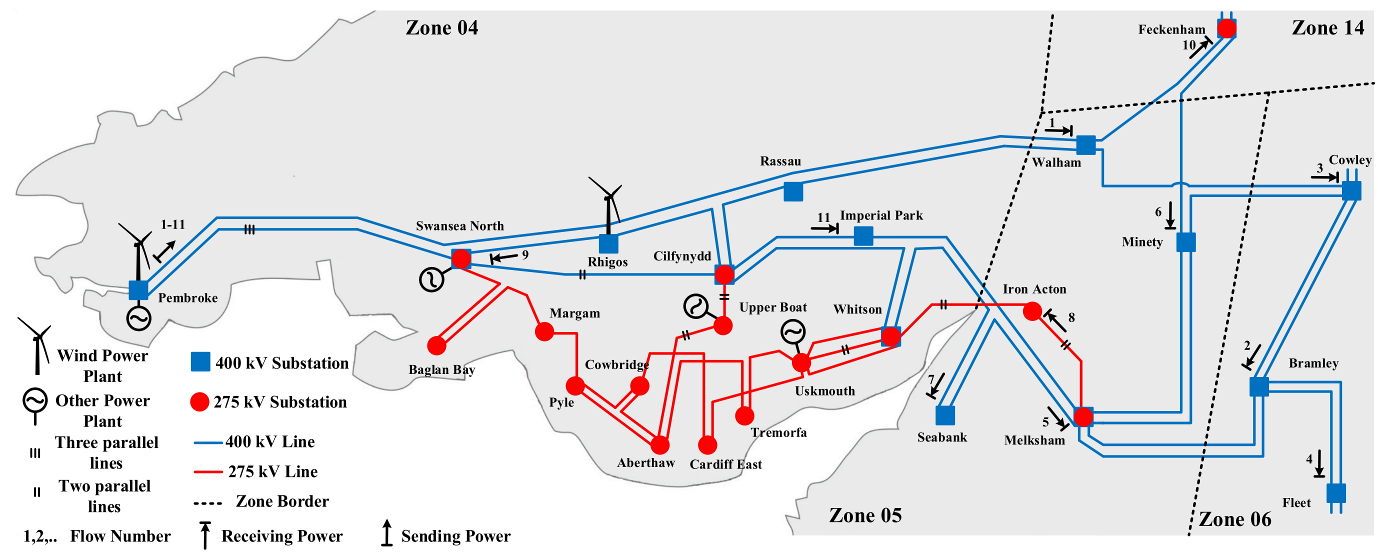

Fig. 12. Power exchange results for Pembroke-Walham line based on FDT during peak hour in South Wales, and west of England.

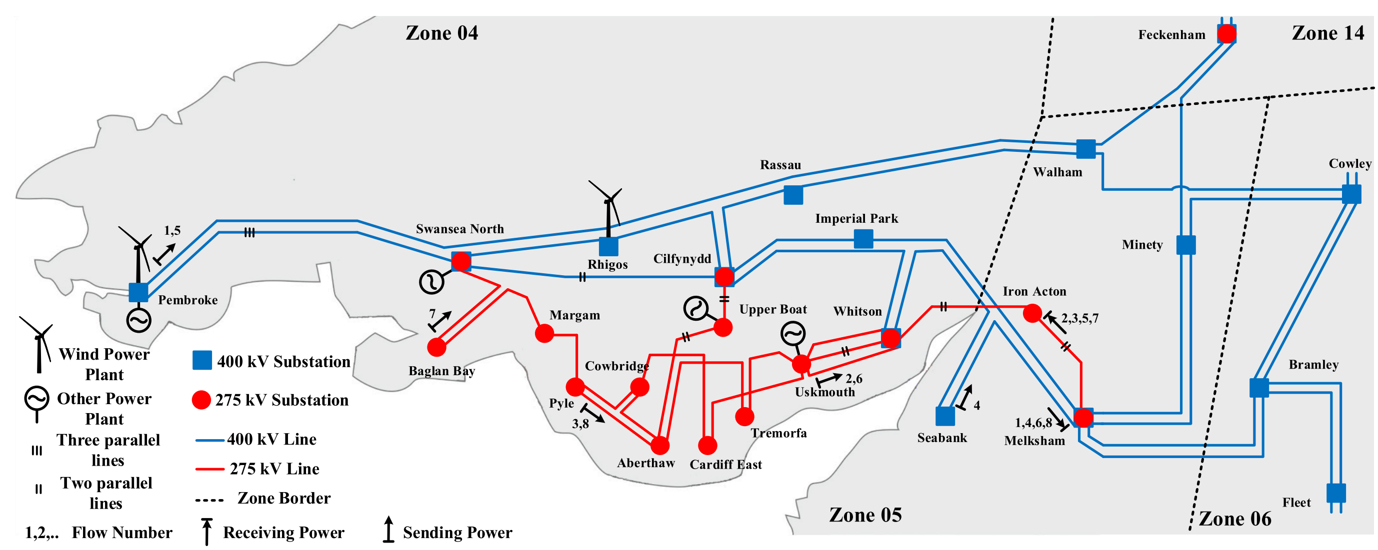

Fig. 13. Power exchange results for Melksham transformer based on FDT during peak hour in South Wales, and west of England.

normal operating range, indicating that the operation of the BESSs does not negatively impact system performance.

6.3.1. The EAC for the networked and non-networked solutions

Using the same EAC method, as the Table 9 shows, the EAC for implementing the BESS is £7 million, compared to £291.4 thousand for reinforcing the Melksham substation to resolve the issue. For the Pembroke-Walham line, the EAC for implementing the BESS is £25.5 million, whereas reinforcing the line would cost £34.14 million. By 2030, the EAC for the BESS at the Melksham transformer and Pembroke-Walham line is projected to be in the range of £3.6–£5.9 million and £13–£21.4 million, respectively, demonstrating that BESS, compared to

Table 8
Power exchange results for Melksham transformer based on FDT during peak hour.

Sending Substation	Flow Number	Sending Zone	Receiving Substation	Receiving Zone	Flow Type	Flow (MW)
Pembroke	1	4	Melksham	5	Import	113
Uskmouth	2	4	Iron Acton	5	Import	99
Pyle	3	4	Iron Acton	5	Import	61
Seabank	4	5	Melksham	5	Internal	57
Pembroke	5	4	Iron Acton	5	Import	54
Uskmouth	6	4	Melksham	5	Import	37
Baglan Bay	7	4	Iron Acton	5	Import	23
Pyle	8	4	Melksham	5	Import	22

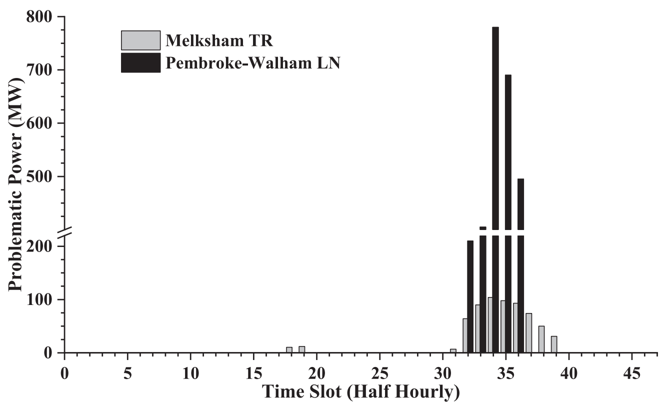

Fig. 14. Problematic power for Pembroke-Walham line and Melksham transformer.

Table 9
Cost parameters for various options.

	CAPEX (£)	OPEX (£)	CRF	Lifetime (Year)	EAC (£/year)
Melksham Substation Reinforcement	3.937 m	78.8 k	0.054	30	291.4 k
BESS for Melksham Substation in 2024	99.9 m	0	0.070	20	7 m
BESS for Melksham Substation in 2030	50.9 m–83.9 m	0	0.070	20	3.6 m–5.9 m
Pembroke-Walham line Reinforcement	352 m	17.6 m	0.047	40	34.14 m
BESS for Pembroke-Walham line in 2024	365.4 m	0	0.070	20	25.5 m
BESS for Pembroke-Walham line in 2030	186.4 m–307 m	0	0.070	20	13 m–21.4 m

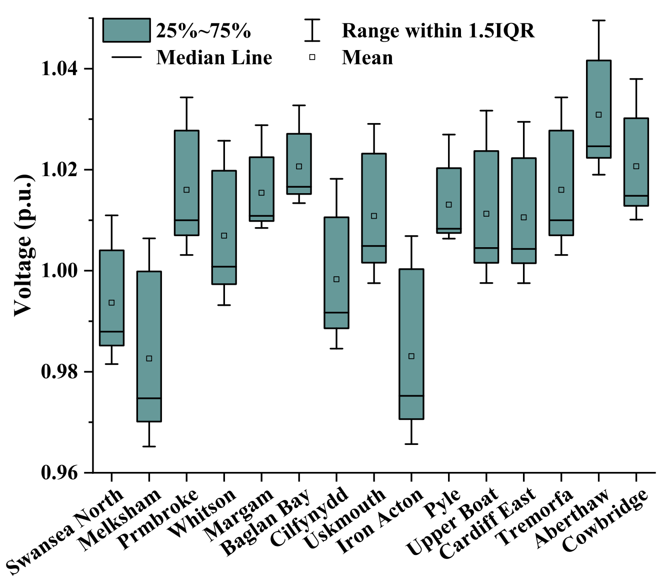

Fig. 15. Voltage range in peak winter day.

line reinforcement, offers a cost-effective and rapidly implementable solution.

7. Conclusion

The UK aims to achieve clean power by 2030, with a significant emphasis on the expansion of offshore wind capacity. These ambitious objectives highlight the urgent necessity for substantial enhancements to the transmission network to accommodate increased generation and transmission demands. This paper explores the integration of BESS as a non-networked solution to mitigate transmission bottlenecks in GB. This study models the GB transmission network for the years 2024 and 2030, concentrating on peak winter and minimum summer demand scenarios. Contingency analyses and hosting capacity assessments identify critical bottlenecks, particularly along the Pembroke-Walham line and the Melksham transformer, which pose risks to system reliability during peak demand periods. By applying FDT, the study identifies the locations for BESS deployment. The findings indicate that BESS positioned at these locations can effectively mitigate transmission system bottlenecks. Specifically, the results show that a 1419 MWh BESS can replace the need for reinforcing a 220 km, 400 kV transmission line (Pembroke-Walham), offering a faster solution. Additionally, the study reveals that deploying two BESS units simultaneously within the system can reduce the required capacity for each. For instance, when the Melksham BESS is considered, the required capacity of the Walham BESS decreases by 14 %. The study ultimately revealed that the EAC for BESS is significantly lower than that of reinforcing the Pembroke-Walham line.

In this study, the sizing of the BESS has been conducted using a fixed-step approach, as described in the methodology. However, future research could explore the application of metaheuristic optimisation algorithms to enhance the efficiency and precision of the sizing process. From a cost-benefit perspective, this work employs a simplified model focused on a representative peak day. To gain deeper insights into the problem's characteristics, future studies should consider a more detailed analysis over an extended timeframe. This would facilitate a comprehensive comparison between networked and non-networked solutions, providing a more holistic understanding of their relative advantages.

CRediT authorship contribution statement

Morteza Shafiekhani: Writing – original draft, Visualization, Validation, Software, Methodology, Investigation, Formal analysis, Conceptualization. **Meysam Qadrdan:** Writing – review & editing, Validation, Supervision, Project administration, Investigation.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Acknowledgment

The authors would like to acknowledge the UK Research and Innovation (UKRI) for providing funding through the Hydrogen Integration for ACcelerated energy Transitions (HI-ACT) program (Grant number EP/X038823/2), which supported this research.

Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.apenergy.2025.125418.

Data availability

All the data for this study is provided in the link below.
http://doi/org/10.17035/cardiff.28152161

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