IEEE Access
Multidisciplinary ⋮ Rapid Review ⋮ Open Access Journal

Received March 3, 2022, accepted March 17, 2022, date of publication March 28, 2022, date of current version April 5, 2022.

Digital Object Identifier 10.1109/ACCESS.2022.3162587

Stacking Battery Energy Storage Revenues in Future Distribution Networks

AHMED A.RAOUF MOHAMED[1], (Graduate Student Member, IEEE), ROBERT J. BEST[1], (Member, IEEE), XUEQIN LIU[1], (Member, IEEE), D. JOHN MORROW[1], (Member, IEEE), JONATHAN POLLOCK[2], AND ANDREW CUPPLES[2]

[1]School of Electronics, Electrical Engineering and Computer Science, Queen's University Belfast, Belfast BT9 5BN, U.K.
[2]Northern Ireland Electricity Networks, Belfast BT9 5UB, U.K.

Corresponding author: Ahmed A.Raouf Mohamed (amohamed06@qub.ac.uk)

This work is part of the Storage Platform for the Integration of Renewable Energy (SPIRE 2) Project (Grant No: IVA5038) supported by the European Union's INTERREG VA Programme, managed by the Special EU Programmes Body (SEUPB).

ABSTRACT Distribution system operators are attracted to battery energy storage systems (BESS) as a smart option to support the distribution network. However, due to its high capital cost, BESS profitability is dependent on the participation in multiple services to stack revenues and rationalize their existence. Yet, revenue stacking is location-dependent based on the available services and regulations. In this paper, specific revenue stacking frameworks are proposed for BESS installed in modern distribution networks that consider the conflicts and synergies that may occur from the involvement in multiple services in practice. A simple yet effective sizing formulation is introduced to find the BESS system size based on the primary service which is to solve the distribution network violations. BESS scheduling is simulated in accordance with the proposed frameworks to maximize the stackable profits for a case study of Northern Ireland. The BESS profitability is investigated through cost-benefit analyses of different technologies for the sole and stacked services. The results show that revenue stacking can boost the annual revenues by 129% with a payback period of 8 years on average. The presented insights are useful for network operators and energy investors in understanding and assessing the profitability of different BESS technologies for various applications.

INDEX TERMS Battery energy storage systems, cost-benefit analysis, distribution network, optimization, revenue stacking.

I. INTRODUCTION

Battery energy storage systems (BESS) have been considered as one of the important innovative solutions due to their capabilities in providing different services to the network. These services are important in medium voltage (MV) distribution networks to mitigate the technical issues posed by the rapid deployment of low carbon technologies (LCT) such as solar photovoltaic (PV), electric vehicles (EV), and heat pumps [1]. Many distribution system operators (DSO) have adopted services from BESS for supporting the network and avoiding/deferring conventional reinforcements, especially to increase the renewable-based generation and reduce the emissions in accordance with the net-zero carbon targets. Several projects trialled the BESS as part of the UK low carbon network fund scheme [2], while in Europe, the Horizon 2020 project has supported many projects through the BRIDGE initiative [3]. In Northern Ireland, the DSO (NIE Networks) is introducing the Facilitation of Energy Storage Services (FESS) project to integrate customer-owned BESS to support the operation of distribution networks [4]. The main challenge with BESS deployment is its cost-effectiveness. Currently, BESS may struggle to achieve profitable revenues compared with the traditional distributed generation, especially through the participation in sole services. Hence, it is advisable for BESS to participate in multiple services in order to stack revenues and rationalize their existence.

The associate editor coordinating the review of this manuscript and approving it for publication was Alexander Micallef.

A. LITERATURE REVIEW AND CONTRIBUTIONS

In related literature, maximizing BESS energy arbitrage revenues from the participation in the integrated single electricity market (I-SEM) of the island of Ireland has been addressed in [5], [6]. The cost-benefit analysis (CBA) results of these studies show that the sole participation of BESS in the I-SEM is not viable as the BESS cannot pay back the investment expenditures. This also has been shown in [7], where CBAs have been performed to evaluate the economic feasibility of BESS participating in individual services in the MV networks of Northern Ireland. Study [7] concludes that the BESS can be profitable only with enhanced transmission services. Yet, admission into these ancillary services in the island of Ireland is not guaranteed, especially for medium/small-sized units [8]. Therefore, stacking BESS revenues is essential in order not only to maximize the revenues but also to reduce the risk of not being admitted to some of the services. In addition to mitigating the impact of potential reductions in payments due to the cap enforced on ancillary services payments by the regulator [9].

BESS revenues that can be stacked from participating in grid-scale services were quantified in [10]. The study quantified the BESS potential revenues in the Irish power system from the involvement in the enhanced transmission services through the DS3 programme [11], and energy arbitrage through the energy market [12]. The study used the data provided from an actual 5 MWh / 10 MW Li-Ion BESS located at the AES Kilroot Power Station, Northern Ireland. In [13], a cost-benefit analysis is conducted to quantify the benefits from Li-Ion BESS of 10 MWh / 6 MW, deployed at the Leighton Buzzard primary substation, UK. The study showed the potential BESS revenues from providing multiple services to the network including primary frequency response, energy arbitrage, network support, and carbon abatement. Another study in [14] addressed the BESS stacked revenues from the participation in energy arbitrage, frequency regulation, and distribution investment deferral for a 7.2 MWh / 1.2 MW NaS BESS located in West Virginia, US. Stacking revenues for different utility-scale BESS sizes vary from 1 MWh to 20 MWh for 10 years of operation have been addressed in [15]. The study aimed to maximize the revenues from the participation in energy arbitrage, network deferral, and improve network resilience.

In [16], a revenue stacking model is introduced for the grid-scale BESS participating in reliability, energy arbitrage, and frequency management. The study prioritized reliability over the other contracted services. In [17], a dispatch optimization model is introduced for sole and stacked applications, different BESS capacities were simulated for five applications related to the energy market of California system operator. In [18], a short-term scheduling approach is introduced for BESS to stack revenues from participating in New York joint markets. Another BESS scheduling framework is introduced in [19] to stack revenues from providing multiple services in MV distribution networks. The framework consists of look-ahead scheduling and real-time control to mitigate the uncertainties in real-time. In [20], an optimization control framework is introduced to maximize the stacked revenues from the provision of multiple services represented in primary frequency control and peak shaving. In [21], the BESS operation for power shifting and ancillary services has been demonstrated for a unit installed in a 10 MW wind farm. In [7], the role of BESS to enhance the distribution network performance through flattening the grid power curve has been demonstrated, and the potential revenues were quantified.

Sizing BESS in the MV networks depends mainly on the technical and economic benefits. In [22], the optimal BESS locations and sizes were determined to solve distribution network congestion due to the integration of LCTs and renewable generation in Northern Ireland. The economic aspects were considered by finding the minimal BESS sizes to reduce the investment costs. The BESS sizing was introduced in [23] to find the optimal BESS size in the distribution network that maximizes the revenues from providing peak shaving and frequency regulation. In [24], an approach is introduced to determine the optimal locations and sizes of multiple BESS in radial networks that maximize the revenues while providing voltage support. A multiscale approach is introduced in [25] to find the planning decisions of BESS represented in sizes and replacements as well as the operational decisions represented in the market participation setpoints. However, these studies did not consider the reactive power control in sizing the BESS power conversion system (PCS), which is an important feature that needs to be considered to maximize the BESS utilization. The BESS allocation in PV-rich networks has been addressed in [26], where different sizes were simulated in order to evaluate the effectiveness of BESS in enhancing the network performance as well as driving profits to investors. The study emphasized the importance of reactive power control in maximizing profits which can support the economic viability of grid-scale BESS.

In evaluating the BESS economic feasibility through stacking revenues, previous studies focused mainly on BESS installed at higher network levels (>11 kV), only a few studies addressed the revenues that can be stacked from a unit located in the MV distribution networks [13], [19]. In addition, some studies stacked revenues by simply combining the profits from various services without considering the conflicts that may occur in practice between these services [10]. Several studies prioritized services over others [13], [14], [16]. While other studies optimized the BESS operation for multiple services [15], [17], yet, they did not consider the penalties that might be incurred if a contracted service is not provided when called upon. Furthermore, some studies did not consider the impact of their approaches on the network constraints as they did not consider a specific network model in evaluating their approaches [18]–[20].

Stacking BESS revenues depends mainly on country regulations, regulated services, and code. Hence, for each country, the stacked revenues framework may differ and can hardly be generalized for other locations. While co-optimizing multiple services together through BESS scheduling proved to maximize the profits as reported in the literature, it cannot be applied for all networks in practice. For instance, in Northern Ireland, the provision of the ancillary services to the transmission system operator (TSO) is usually granted to the high availability units that their availability is not connected to the energy market or any other services [8]. Additionally, if a unit is contracted with the TSO or the DSO for specific periods, it should be available to provide the service when called upon to avoid any penalties. Hence, detailed operation frameworks that prioritize all the services by specifying specific trading periods are essential to avoid overlapping in services or any penalties, which are addressed in this paper.

This paper complements the work presented in the literature by quantifying the revenues that can be gathered and stacked from BESS in MV distribution networks through benefiting the DSO, energy market and TSO, the contributions of this paper can be summarized as:

1) Introducing a sizing formulation aims to determine the optimal size of the BESS and its PCS to support the network operation against violations. The proposed formulation considers the BESS active/reactive power dispatch and seeks to find the minimal size of the BESS system to reduce the investment costs that solves the network violations for a pre-defined scenario of demand and generation according to the DSO's preference (i.e., generation and demand scenario by 2030 for a specific network) using optimal power flow (OPF). In order to avoid the complexity of OPF formulation, the proposed sizing approach formulates the network constraints as a feasibility problem in the form of a multi-objective function using black-box optimization, which reduces the computation complexity.
2) Proposing detailed scheduling frameworks that prioritize all the services by setting specific periods per day for each service to avoid any conflicts. These frameworks consider the practical rules and regulations of the available services.
3) Simulating the BESS operation according to the proposed frameworks considering the operational constraint and quantifying the expected gains.
4) Conducting cost-benefit analyses for three different BESS technologies to evaluate the BESS economic feasibility under the sole and stacked revenues.

The study is conducted for an actual 11 kV 53-node MV radial network located in Northern Ireland for 2030 demand and generation scenarios. While the proposed frameworks are developed for a specific case study, the procedures and formulations introduced in this paper are insightful to be considered in other cases in different geographical locations.

The paper is organized as follows: the proposed methodology is given in Section II. Section III presents the case study setup and the proposed operation frameworks for stackable revenues. The results are presented in Section IV. Finally, the conclusions and discussion are presented in Section V.

II. METHODOLOGY

The adopted methodology consists of the following steps: 1) Identifying potential applications for the BESS in the MV networks of Northern Ireland, 2) Performing time-series power flow calculations to investigate the potential congestion issues due to future projections of demand and generation 3) Sizing BESS to solve the DN violations, 4) Investigating the applicable frameworks for the BESS to stack multiple revenues simultaneously without any conflicts, 5) Simulate the scheduling frameworks to quantify the excepted annual payments and BESS lifetime, and 6) Conducting CBA to evaluate the BESS profitability for the sole and stacked services.

A. BESS APPLICATIONS IN MV DISTRIBUTION NETWORKS

BESS can provide different ancillary services to the electrical networks, these services are structured according to the network needs, regulations, and code. In Northern Ireland, the BESS has three possible sources of return which are explained as follows:

1) ENERGY ARBITRAGE

The BESS has the ability to achieve a profitable energy arbitrage by trading in the I-SEM according to the System Marginal Price (SMP) [12]. The I-SEM is operated by the Single Electricity Market Operator (SEMO) in the island of Ireland [12] and consists of several types of auctions including day-ahead and intraday. Few works have discussed and quantified the BESS revenues from the participation in the I-SEM [5], [6], [10].

2) DISTRIBUTION NETWORK SUPPORT (DNS)

The DNS services should be paid by the DSO directly to the BESS owners or aggregators for network assists. These services include congestion management (e.g., peak shaving and voltage support), network upgrade deferral/avoid (e.g., feeders' replacement), renewable curtailment mitigation, power quality improvements (e.g., power factor, power losses, harmonics, and stability), and emission abatement. Payments for similar services are currently being trialled in Northern Ireland for providing flexibility services under the FLEX project [27]. Utilizing the BESS for DNS has been addressed previously in [7], [13], [15], [16], [28].

3) DS3 SERVICES

The DS3 programme, introduced by the TSO of Ireland and Northern Ireland (EirGrid/SONI), aims to support the secure operation of the electrical network on the island of Ireland through energy evolution [11]. The programme consists of 14 services to support the network with the required static and dynamic actions that maintain system stability and reliability. The BESS can provide most of these services, especially the services that require rapid response such as Fast Frequency Response (FFR). However, admission into DS3 for a unit installed at the MV level is not guaranteed and requires many assessments. The DS3 services and expected BESS profits are addressed in [6], [9], [10], [29].

B. BESS SIZING

The BESS sizing problem can be formulated in a way that maximizes the overall revenues that can be stacked from the participation in multiple services (i.e., energy market, DNS, and TSO schemes). However, this might yield an oversized BESS in case the BESS fails to be admitted to one of the aforementioned services. Therefore, in this paper, the BESS sizing is formulated based on the primary service which is guaranteed to be awarded. In the MV networks, the BESS will be mainly installed to provide DNS to the DSO as in the case of the FESS project [4]. Hence, the BESS objectives are to provide congestion management by solving the MV network stresses represented in line overloading and voltage violations. Yet, the BESS will still be capable to participate in other services when it is not being requested by the DSO. The MV network constraints are defined as:

1) *Node Voltage:* For N_n nodes, the node voltage ($V_{i,t}$) at each time-point t should be within the predefined thresholds.

$$V_i^{min} \leq V_{i,t} \leq V_i^{max}\,; \quad \forall\, i \in N_n\,;\ \forall\, t \in T \tag{1}$$

In the UK, the acceptable voltage limits for the 11 kV network as defined in ESQCR (No. 2665) are ±6 % of the nominal voltage [30]. Many network operators do, however, prefer to specify tighter voltage limits based on their working practice to mitigate voltage variations. Hence, in this paper, the voltage tolerance limits of ±5 % are used as per the US standard ANSI C84.1 [31]. Thus, the upper (V_i^{max}) and lower (V_i^{min}) limits are considered as:

$$V_i^{min} = 0.95\,pu\,; \quad V_i^{max} = 1.05\,pu \tag{2}$$

2) *Cables and Overhead Lines Loading:* The flow of current ($I_{br,t}$) in each branch (br) of branches (N_b) at any time should not exceed its ampacity (I_{br}^{max}).

$$\frac{|I_{br,t}|}{I_{br}^{max}} \times 100 \leq 100\%\,; \quad \forall\, br \in N_b\,;\ \forall\, t \in T \tag{3}$$

The proposed sizing optimization formulation aims to settle the optimal sizes of BESS and its PCS/Converter that solves the voltage and line violations. The optimal sizes are defined as the sizes required to preserve the network security with minimum investment costs (i.e., minimum BESS/PCS sizes). This is achieved by utilizing OPF to find the minimum active/reactive power injection/consumption from the BESS nodes at each congested time-point that solves the network violations over the simulation horizon. OPF is an NP-hard problem due to the nonconvexity associated with the equations and constraints which may result in convergence to a local point of infeasibility [32]. Different approaches have been introduced to tackle this problem through linearization, convex relaxation, or by converting the OPF constraints into soft constraints using penalty functions. In this paper, in order to reduce the OPF complexity and the optimization burden of using hard constraints, the proposed OPF problem is treated as unconstrained black-box optimization, where the constraints are formulated as a feasibility problem/constraint satisfaction problem in the form of a multi-objective function.

In this optimization problem, the decision variables (x) are represented in the BESS active/reactive power. The proposed objective function is formulated using the weighted sum method ($w_1 = w_2 = w_3$) and converted into a mono-objective function by normalization using the consequent upper-bound approach [33]:

$$min\left(\frac{w_1 F_1(x)}{F_1^{max}} + \frac{w_2 F_2(x)}{F_2^{max}} + \frac{w_3 F_3(x)}{F_3^{max}}\right) \tag{4}$$

$$F_1(x) = \sum_{i \in N_n} |V_{i,t} - V_i^{min}|[V_{i,t} < V_i^{min}]\,; \quad \forall\, t \in T \tag{5}$$

$$F_2\,(x) = \sum_{i \in N_n} |V_i^{max} - V_{i,t}|[V_{i,t} > V_i^{max}]\,; \quad \forall\, t \in T \tag{6}$$

$$F_3\,(x) = \sum_{br \in N_b} \left(\frac{|I_{br,t}|}{I_{br}^{max}} - 1\right)\left[\frac{|I_{br,t}|}{I_{br}^{max}} > 1\right]; \quad \forall\, t \in T \tag{7}$$

where [] denotes an Iverson bracket (the Iverson bracket is equal to 1 when the logical condition enclosed is true and 0 otherwise). The first term $F_1(x)$ focuses on the under-voltage events by minimizing the difference between the voltage of violated nodes and the acceptable lower limit (V_i^{min}). Conversely, the second term $F_2\,(x)$ aims to solve over-voltage events by pushing the voltage of violated nodes to the acceptable upper limit (V_i^{max}). The third term $F_3\,(x)$ aims to maintain the current flow in each branch within their ampacities. F_m^{max} represents the maximum value for objective-m for the normalization $m \in \{1, 2, 3\}$. Note that T is the simulation horizon.

The decision variables are represented as active power ($x_1, \ldots, x_k$) and reactive power ($x_{k+1}, \ldots, x_{2k}$), where k is the number of BESS. At each congested time-point (that has voltage or line flow violation), the optimization solver initializes two decision variables for each BESS node and evaluates the objective function Eq.(4) as a black-box using power flow calculations. Note that in the power flow calculations, the BESS decision variables at each BESS node are treated as a negative load during the discharging mode and as a positive load during the charging mode. The decision variables are updated in each iteration according to the evaluated objective function until convergence. The outputs are the minimum active/reactive power setpoints for each BESS node that push the violations to their limits. Afterwards, the active power setpoints are modified to consider the BESS system efficiency, which can be mathematically expressed for BESS s installed on node j as:

$$P_{s,t} = \frac{|x_{s,j,t}|}{\eta_s}\,; \quad \forall\, x_{s,j,t} < 0\,;\ \forall s \in k\,;\ \forall\, t \in T_{cg} \tag{8}$$

$$P_{s,t} = \eta_s\, x_{s,j,t}\,; \quad \forall\, x_{s,j,t} > 0\,;\ \forall s \in k\,;\ \forall\, t \in T_{cg} \tag{9}$$

where $x_{s,j,t} < 0$ represents discharging, $x_{s,j,t} > 0$ represents charging, and T_{cg} is the congested time points. η_s is the BESS system efficiency that considers the input/output efficiencies of the BESS (η_s^{bt}) and PCS (η_s^{pcs}):

$$\eta_s = \eta_s^{bt}\,\eta_s^{pcs} \tag{10}$$

The modified active power values are then analysed to determine the consecutive discharging and charging periods in each day. The consecutive period with the highest discharged/charged energy (T_{cg}^{che}) is used to calculate the BESS usable capacity (E_s^{us}) $\forall s \in k$ as:

$$E_s^{us} = \sum_{t \in T_{cg}^{che}} P_{s,t}\tau\,; \quad T_{cg}^{che} \in T_{cg}\,; \; \tau = \frac{dm}{60} \tag{11}$$

where dm is data resolution in minute (e.g., 60 for an hour) used to calculate the time interval τ. The BESS nameplate capacity (E_s^{nc}) considering the maximum depth of discharge (DoD_s^{max}) is then calculated as:

$$E_s^{nc} = \frac{E_s^{us}}{DoD_s^{max}}\,; \quad \forall\, s \in k \tag{12}$$

The BESS rating $\forall s \in k$ is determined based on the maximum active power injected/consumed within all the congested time points, and the PCS rating is determined based on the maximum MVA power handled by the PCS within all the congested time-points.

$$P_s^{max} = max(x_{s,j,t})\,; \quad \forall\, t \in T_{cg} \tag{13}$$

$$S_s^{max} = max\left(\sqrt{x_{s,j,t}^2 + x_{s+k,j,t}^2}\right)\,; \quad \forall\, t \in T_{cg} \tag{14}$$

where x_{s+k} represents the reactive power decision variable for each BESS. The previous optimization formulation settles only the sizes. To consider the BESS locations, the previous formulation can be modified to accommodate integer decision variables ($x_{2k+1}, \ldots, x_{3k}$) for each BESS as in [22]. However, it has not been considered in this paper as it is assumed that the BESS locations are pre-defined with the aid of our previous work [22]. The proposed sizing methodology flowchart is illustrated in Figure 1.

A graphical illustration of the proposed BESS sizing methodology is given in Figure 2 for a single BESS. Two consecutive winter days with peak demand are shown in Figure 2. To shave the evening peak and solve network violations, the power dispatch from the BESS node that is being determined by the proposed methodology is shown for both days (red dot-dash line in Figure 2). To consider the BESS system efficiency, the power dispatch has been increased using Eq.(8) as shown in the black dot-dash line in Figure 2. Afterwards, the discharging periods in each day are being analysed. The needed energy to shave the peak of the first day is 2.5 MWh and 2.8 MWh for the second day. Therefore, the results of the second day will be used to calculate the BESS size (i.e., usable capacity of 2.8 MWh) as this is the consecutive period with the highest discharged energy amongst the simulated days. The nameplate capacity can be then calculated using Eq.(12). The BESS rating can be determined based on the maximum discharge power amongst the results using Eq.(13). In case of reactive power injections, the PCS rating is calculated using Eq.(14), otherwise, the PCS rating will be the same as the BESS.

It should be noted that the results in Figure 2 represent the needed discharge power during a day to solve the violations.

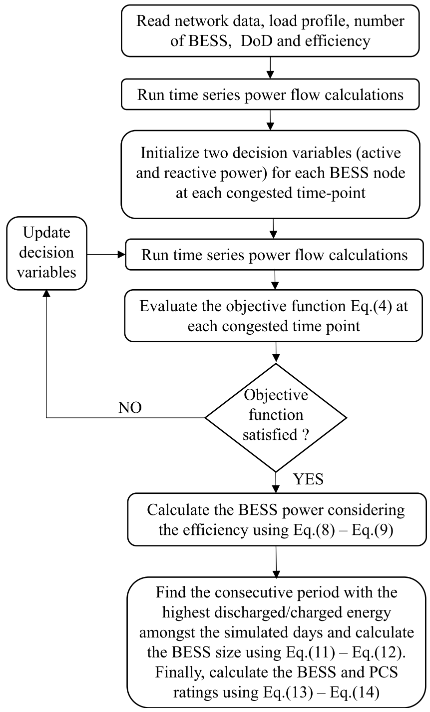

FIGURE 1. Proposed BESS sizing methodology.

However, in reality, the BESS will have to charge before discharging. This can be done during the low-rate period (i.e., from 01:00 hr to 08:00 hr) which will be considered when scheduling the BESS. The previous example shows winter days with peak demand; however, the proposed methodology follows the same process in summer days with high reverse power flow from PV units by considering the charging power needed to solve the violations. Based on the number of days being simulated, the proposed methodology determines the BESS size according to the highest usable capacity obtained amongst all the simulated days.

C. BESS SCHEDULING

After settling the BESS/PCS sizes, the BESS scheduling should be determined according to the designated application. For the DNS, the BESS will be utilized to support the network against network violations. Hence, the same objective function Eq.(4) is being adopted as a black-box when the BESS is scheduled to support the network by controlling the BESS active/reactive power considering the BESS constraints (modelled as hard constraints). In this paper, the following equations describe the BESS operational constraints:

1) BESS Power Rating: The discharged power ($P_{s,t}^{dis}$) or charged power ($P_{s,t}^{chr}$) cannot exceed the BESS s rating.

$$P_{s,t}^{dis}, P_{s,t}^{chr} \leq P_s^{max}\,; \quad \forall\, s \in k\,; \; \forall\, t \in T \tag{15}$$

2) System efficiency: The power imported ($P_{s,t}^{ch}$) or exported ($P_{s,t}^{di}$) from/to the network by the BESS is

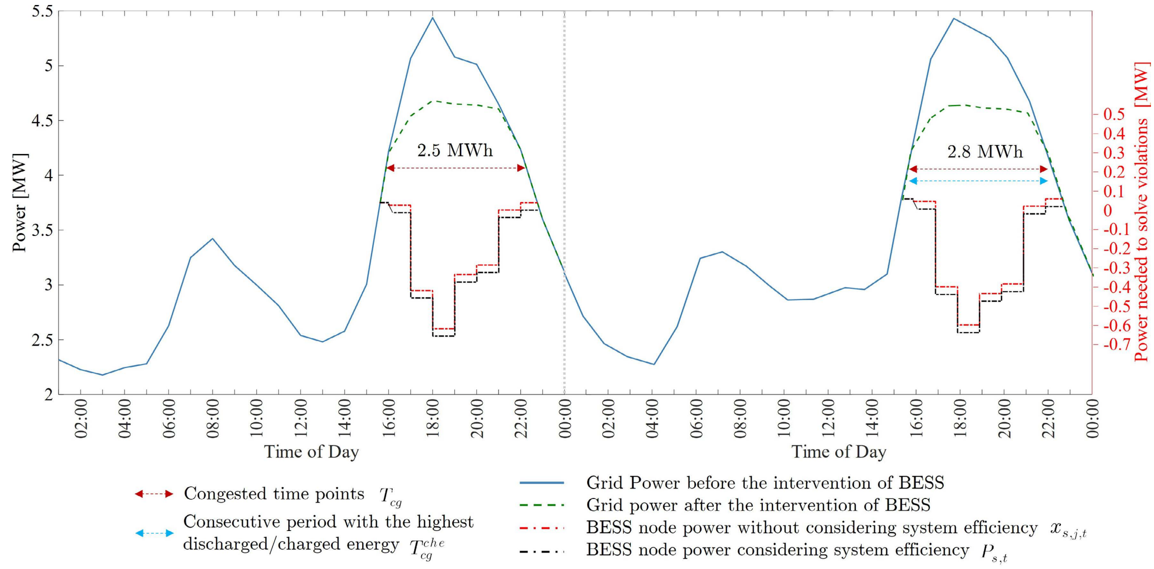

FIGURE 2. **Graphical example for the BESS sizing methodology.**

constrained by the BESS system efficiency $\forall s \in k$.

$$P^{di}_{s,t} = P^{dis}_{s,t}\eta_s\,; \quad P^{ch}_{s,t} = \frac{P^{chr}_{s,t}}{\eta_s}\,; \;\forall t \in T \tag{16}$$

3) State of Charge (SoC): SoC is the percentage measurement that indicates the available capacity still in the BESS. The $SoC\ \forall s \in k$ must be maintained within the pre-defined limits.

$$SoC^{min}_s \leq SoC_{s,t} \leq SoC^{max}_s\,; \quad \forall t \in T \tag{17}$$

$$SoC_{s,t} = SoC_{s,t-1} + \frac{P^{ch}_{s,t}\eta_s\tau}{E^{nc}_s} - \frac{P^{di}_{s,t}\tau}{E^{nc}_s\eta_s}\,; \quad \forall t \in T \tag{18}$$

4) PCS Rating: The power handled by the PCS (inverter/charger) must not exceed its rating.

$$S_{s,t} \leq S^{max}_s\,; \quad \forall s \in k\,; \;\forall t \in T \tag{19}$$

For the energy market, the BESS will have to achieve energy arbitrage by buying (charging) electricity during low SMP and selling (discharging) electricity during high SMP periods to maximize revenues while considering the BESS and market constraints. The energy arbitrage maximization framework introduced in our previous paper [5] is being used to determine the BESS schedule that maximises the I-SEM revenues. The model in [5] aims to maximise the revenues obtained from the participation in the I-SEM ex-ante markets (i.e., day-ahead and intraday auctions). This model considers all the BESS operation model Eq.(15) – Eq.(19) as well as the I-SEM rules. Note that, during the I-SEM scheduling, power flow calculations are performed to analyse the impact of BESS power on network constraints. In case of violation, the BESS power is adjusted to avoid violating the constraints. For the DS3 services, it is assumed that the BESS is operated according to a signal from the TSO based on the grid needs and the expected revenues are estimated. However, a detailed BESS scheduling methodology for DS3 services is not considered in this paper.

D. COST-BENEFIT ANALYSIS

In this paper, CBAs are conducted for the BESS lifetime (LT_s) to assess the investment feasibility by calculating the total savings (TS), net present value (NPV), annual return on investment (AROI) and the discounted payback period (PP) based on the sum of annual expected payments (p^a_r) for each service r that belongs to a set of services z, annual charging costs (c^a_s), and revenues increase/decrease rate (α) $\forall s \in k$:

$$NPV_s = TS_s - CE_s \tag{20}$$

$$AROI_s = \frac{NPV_s}{LT_s \times CE_s} \tag{21}$$

$$TS_s = \sum_{\substack{n=1\\ \forall r \in z}}^{LT_s} \frac{(1+\alpha)\left(p^a_{r,s} - c^a_s\right)(1-(n \times L)) - OE_s}{(1+ir)^{n-1}} \tag{22}$$

$$CE_s = \rho^{bt}_s E^{nc}_s + \rho^{pcs}_s S^{max}_s \tag{23}$$

CE is the capital expenditures, OE is the operational expenditures, ρ^{bt}_s is the BESS cost [£/kWh], and ρ^{pcs}_s is the PCS cost [£/kVA]. The total savings are calculated considering the annual percentage loss in BESS capacity (L) and the interest rate (ir). The discounted payback period is calculated by solving Eq.(20) for zero NPV.

III. CASE STUDY SETUP

In this paper, the case study is based on Northern Ireland, UK. The 2030 scenario is adopted by investigating the potential increase in renewable-based generation and demand by 2030.

A. TEST FEEDER

An actual 11 kV 53-node 16.5 km suburban radial feeder (Figure 3) located in Northern Ireland representing a typical distribution network in the UK is adopted for the analysis. The network model is developed on NEPLAN power system software. Half-hourly substation current measurements for this feeder were provided by the DSO of Northern Ireland (NIE Networks) covering different periods across the year of 2019. The winter peak demand varies between 17:00 to 23:00 hr with a peak demand of 2.7 MW. To tackle climate change, the generation from renewables in Northern Ireland is planned to reach 70% by 2030 [34]. Hence, two wind DGs are assumed to be placed at nodes 13, and 29, and two PV DGs are placed at nodes 49, and 53. Node 13 has been selected as there is an aggregated DG placed currently at node 13. While the other nodes were selected randomly based on the sensitive locations to violations obtained previously in [22].

One year measurements for the period 2019/2020 was obtained from the TSO of Northern Ireland, SONI [35] providing quarter-hourly demand and was scaled on the test feeder. By 2030, energy consumption is expected to increase by 20% due to the anticipated growth in demand caused by new connections and the increase in the population [34]. Regarding the 2030 LCTs uptake, the winter peak demand is anticipated to increase by 60% due to the rapid deployment of EVs, and heat pumps [36]. This is modelled on the network load profile to simulate the impact of LCTs on the network by 2030 through increasing the peak demand (from 17:00 to 23:00 hr) by 60% for the winter and 30% for the summer, as the heat-pump demand is lower in the summer.

For PV deployment, the installed capacity was 389.5 MW by the end of 2019 in Northern Ireland [37]. By 2030, the total PV solar capacity is projected to be 667 MW [38]. According to recent data provided by NIE Networks for 2019/2020, the total PV units with microgeneration connections (G83/G98) is 83.5 MW. Hence, by 2030, this capacity is projected to reach 143 MW. For the test network, the base annual consumption is 13,405.5 MWh, compared to the total annual consumption in Northern Ireland of 7,895,444 MWh [35]. Hence, a total PV capacity of 243 kW (microgeneration) is projected for the test network by 2030.

For the DGs, each DG is assumed to have a size of 1 MW calculated based on the projected demand of 2030. Their generation profiles were obtained from the aggregated PV/wind generation profiles in 15-minute resolution [35].

B. POWER FLOW CALCULATIONS

One-year time-series power flow analysis has been conducted for the base case (2020) and 2030 scenario. The results are then analysed by evaluating the node voltages, and line flows at each time-point of the year as shown in Figure 4. The power flow results show the potential violations that may occur due to the future projections of demand and LCTs. The major violations occurred during the winter with a high drop in node voltage and line overloading. The line rating violations are concentrated mainly on the branches between nodes 10 and 30 and the node violations were observed over the remote nodes starting from nodes 33 to 53. The severest line violations occurred for Line 16 (120.2 %) that connects node 10 to 17 and the worst voltage violations were observed for node 53 (0.930 pu) and node 49 (1.057 pu) due to their far locations from the substation. As given in the previous results, the voltage violation occurs for longer periods w.r.t line overloading. Nodes 53 and 49 had severe violations due to their distant location from the substation, and the nature of the loading in the radial network. Line 16 had the severest overloading, and all the other violated lines are branched from it.

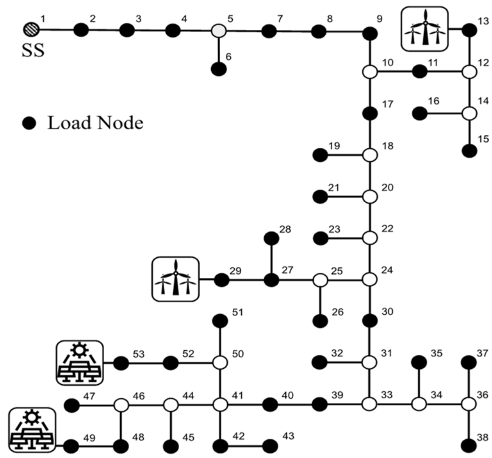

FIGURE 3. Test feeder schematic with the DG locations and types.

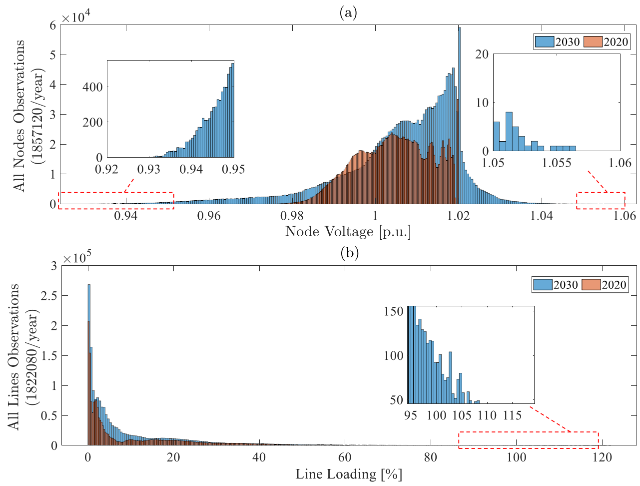

FIGURE 4. The probability distribution over the year for 2020 and 2030 scenarios: (a) Nodal Voltage, (b) Line loading.

Traditional reinforcement such as upgrading the congested lines and adding reactive power compensators can be used to alleviate the network stresses, however, they have high costs, significant implementation time and can result in power interruptions during the upgrading process. In addition, overvoltage issues can be solved by curtailing the excess generation of DGs which is not preferable. In this paper, the BESS is adopted to support the network, motivated by their wide applications and impact on reducing emissions.

C. STACKING BESS REVENUES FRAMEWORKS

This part aims to investigate the applicable BESS operation frameworks in the distribution networks of Northern Ireland to stack the revenues from multiple services. As observed from the power flow results, the BESS may not be needed continuously by the DSO as most of the time there are no violations in the network. Hence, the BESS can involve in other services such as I-SEM and DS3 services. However, the involvement in multiple services should consider avoiding any overlapping or conflicts that might incur penalties if a contracted service is not provided when called upon. For this case study, the BESS will be more likely to be eligible in the DNS scheme and I-SEM. For the DNS, the BESS is needed more in winter than summer as the violations occurring in the winter are higher and more severe than those in the summer according to the power flow results. Thus, the DSO requires BESS full capacity support during the following periods:

1) The BESS is required to be available for discharging from 17:00 to 22:00 hr in the winter/autumn (from October to March) to alleviate the peak demand.
2) The BESS is required to be available for charging from 10:00 to 15:00 hr in the summer/spring (from April to September) to mitigate the high reverse power flow.

At all other times of the year, the BESS is not needed by the DSO, hence, the BESS shall participate in the I-SEM. Generally, the BESS should buy electricity at lower SMP periods (late night to early morning) and sell electricity during the peak demand periods. These conditions can be applied theoretically, however, in practice, they may not be valid. According to the DNS periods defined previously, in the summer, the BESS should be empty from 10:00 to 15:00 hr, and hence, it cannot be charged during the low-rate periods unless it sells back the electricity before the DNS period. In addition, the BESS in the winter should be fully available from 17:00 to 22:00 hr, and hence, it cannot sell electricity to the energy market during the most lucrative periods of the day (evening peak). Therefore, different operation frameworks can be settled for I-SEM participation. For instance, in the summer the BESS can trade in the period between 01:00 to 10:00 hr and 15:00 to 01:00 hr. While in the winter, the BESS can trade in the period between 22:00 to 01:00 hr and 01:00 to 17:00 hr. Furthermore, the BESS should be fully empty before the DNS period of the summer and be fully charged before the DNS period of the winter. Yet, the selection of a proper framework should consider the BESS degradation w.r.t to the returned gains. For instance, the profits obtained from participation in the I-SEM market is not significant [5], [6]. Hence, it is not advised to cycle the BESS frequently through the I-SEM energy arbitrage.

Note that according to the I-SEM rules [12], the orders and auctions should be booked in a period ahead. The bidders can adjust their physical positions ordered in the

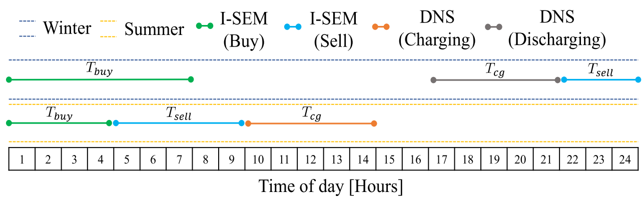

FIGURE 5. Proposed BESS operation framework for stacked services (DNS + I SEM).

day-ahead market through the intraday markets, and the balancing market operates to balance the generation with the demand. In this paper, it is assumed that the BESS buys and sells the electricity through the day-ahead and intraday markets by placing orders with the quantity of BESS capacity at each buying/selling period (see Figure 5), the ordered quantity may be changed according to the use of the BESS with DNS, this change will be handled by the SEMO through the balancing market. The participation of the BESS in the I-SEM while supporting the DSO without any conflicts can be summarized in the following points (see Figure 5):

1) In the winter, the BESS can buy electricity for charging in the period between 01:00 to 08:00 hr to be fully charged before the DNS period, after the DNS period ends, the BESS will sell back the available capacity (residual capacity after the DNS period) to the I-SEM from 22:00 to 01:00 hr.
2) In the summer, the BESS can buy electricity for charging in the period between 01:00 to 05:00 hr and then fully sell the electricity in the period between 05:00 to 10:00 hr to be ready for the DNS period.

According to the previous framework, the BESS may complete more than one cycle per day according to its utilization from the DSO which may impact its effective lifetime. Note that, in each of the operation periods illustrated in Figure 5, the BESS only operates in a single mode; charging or discharging, this is assumed to preserve the BESS lifespan by reducing the number of transitions between charging and discharging which affects the degradation. The BESS is dispatched according to each period in Figure 5 as explained in Section II.C.

As mentioned previously, admission into DS3 services is not straightforward. However, in this work, the additional streams from stacking some of the DS3 services with the previous framework are quantified. The DS3 programme consists of two procurement processes [8]; Volume Capped (VC), and Volume Uncapped (VU). Generally, the VC procurement is awarded to the high availability units that their availability is not connected to the energy market or any other services [8]. This means that if a BESS is contracted with the DSO to provide DNS or with the I-SEM for trading will not be admitted to the VC procurement. Hence, in this work, it is assumed that the BESS can participate in the DS3 system services through the VU procurement. The proposed operation framework illustrated in Figure 5 can be then adjusted to the one shown in Figure 6 to consider the participation in DS3 services.

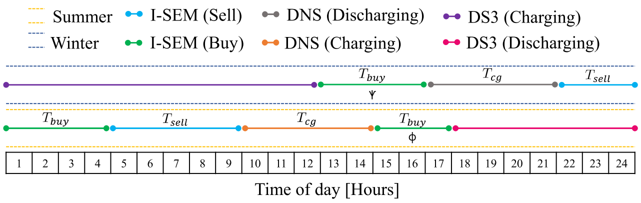

FIGURE 6. **Proposed BESS operation framework for stacked services (DNS + I SEM + DS3).**

As shown in Figure 6, the BESS can participate in the DS3 services through (dis)charging or controlling the reactive power according to a signal from the TSO in the period between 01:00 to 13:00 hr in the winter and between 18:00 to 01:00 hr in the summer. However, the BESS may need to recharge its capacity to be ready for the DNS in the winter between 13:00 to 17:00 hr (ψ) if it has not been used fully by the TSO. While, in the summer, the BESS will have to buy electricity from 15:00 to 18:00 hr (ϕ) if it has not been used fully during the DNS period to be ready for the DS3 period. Furthermore, the operation of the BESS in DS3 services will increase the number of undergone cycles as well as the charging costs as the BESS may have to buy electricity to be ready for the DS3 service in the summer or if it has not been charged completely during the DS3 period in the winter. This increase depends on the utilization of the BESS for the DS3 services which is uncertain as it depends on the sudden events in which the BESS will have to incorporate to support the network. However, by 2030, SONI is targeting to reach 95% of the system non-synchronous penetration (SNSP) [34], which means that the need for the DS3 services will be essential, hence, it is assumed that the BESS will be utilized by 50% throughout the year for DS3 services.

D. BESS COSTS AND EXPECTED PAYMENTS

In this paper, the BESS costs and specifications are quantified for the 2030 central scenario using the tool and report provided by IRENA [39]. Three possible technologies are used due to their capabilities in providing the mentioned services [39], their specifications are given in Table 1.

TABLE 1. **BESS technologies and specifications [39].**

BESS Technology	System Efficiency [%]	Depth of discharge [%]	Number of Cycles [Cycles]	Calendric Lifetime [Years]	Capacity Loss [%/year]
Li-Ion (LFP)	89	90	4,800	13	1.4
Sodium Sulfur (NaS)	81	100	7,300	20	0.96
Vanadium Redox Flow (VRF)	75	100	7,000	19	1.04

The number of effective cycles and calendric lifetime is calculated by averaging the expected BESS lifetime for each application (e.g., energy arbitrage, network support, and frequency services) of the IRENA tool [39], assuming that the BESS completes one cycle per day. These numbers represent the BESS end of life when the BESS loses 20% of its usable capacity. Note that, the BESS lifetime will vary according to the scheduling framework as the BESS may complete more than one cycle per day. The BESS capital costs are given as £164/kWh for the Li-Ion, £119/kWh for the NaS, and £87/kWh for the VRF. The PCS price is given as £38/kVA. These costs are estimated according to the 2030 IRENA projections [39]. The operation expenditures include the BESS/PCS maintenance, self-discharge, efficiency losses, and other charges associated with the transmission and distribution networks which are given in Section IV.

For the BESS payments, market data obtained from SEMO for one year for 2019/2020, was used to quantify the buying/selling payments from participating in the I-SEM. The DNS payments for BESS owners differ between networks according to the type and occurrence of the violations. Generally, these payments have two rates according to the availability (£/MW/h) and the utilization (£/MWh) [27]. For the case study presented in this paper, the BESS apparent power is being used to support the network, hence, the payments are constructed based on the MVA availability and utilization. These payments are obtained from the expected payments for the FLEX project of Northern Ireland [27]; £300/MVAh for utilization and £8/MVA/h for the availability. Note that during the utilization, the BESS owner receives both payments.

Quantifying the expected gains from the participation in DS3 services through the pre-explained framework is difficult as it depends on many scalars based on the unit's location, performance/response, and the SNSP level. Hence, a rough estimate of £72,712/year per MW of available volume is considered based on the average annual payment of four VU dynamic frequency response services; FFR, Primary, Secondary, and Primary Operating Reserve from [29]. Yet, the payment given in [29] is estimated for a BESS that is fully available for the DS3 services only. Hence, this payment is scaled according to the proposed framework in Figure 6, as the BESS is available for only 12 hours/day during winter and 7 hours/day during summer.

E. ADOPTED OPTIMIZATION SOLVERS

As the BESS sizing and DNS scheduling are formulated as black-box optimization, hence, derivative-free solvers are preferred. Different solvers were tested, the selection of the best solver for each problem was assessed based on the execution time and the output results. The Surrogate optimization algorithm from the MATLAB optimization toolbox obtained the best results for the BESS sizing and the NOMAD solver was adopted for the BESS DNS scheduling. NOMAD solver [41] was implemented through OPTI Toolbox [42]. For the I-SEM scheduling, the model in [5] is being utilized which adopts the WORHP solver [43]. Comparison between different optimizers for the adopted optimization problems is given in Appendix.

IV. CASE STUDY RESULTS

A single BESS is assumed to be installed at node 53, this location was determined from [22]. The results obtained from the BESS sizing considering each technology specifications are tabulated in Table 2, along with the capital expenditures (CE) and operation expenditures (OE) [39].

TABLE 2. Sizing results and BESS CE/OE.

BESS Technology	Nameplate size / Rating / PCS [MWh / MW / MVA]	CE [£]	OE [£/year]
Li-Ion	1.55 / 0.75 / 0.8	295,000	8,500
NaS	1.55 / 0.8 / 0.9	230,000	9,500
VRF	1.7 / 0.9 / 0.95	197,000	19,500

The simulation results for scheduling the BESS under the DNS through the frameworks (Figure 5 and Figure 6), show that the BESS was utilized for 158.5 hours with a total capacity of 70 MVAh and was available for 1,666.5 hours. The results obtained for the violations of node voltages and line overloads throughout the year with/without the BESS utilization are shown in Figure 7.

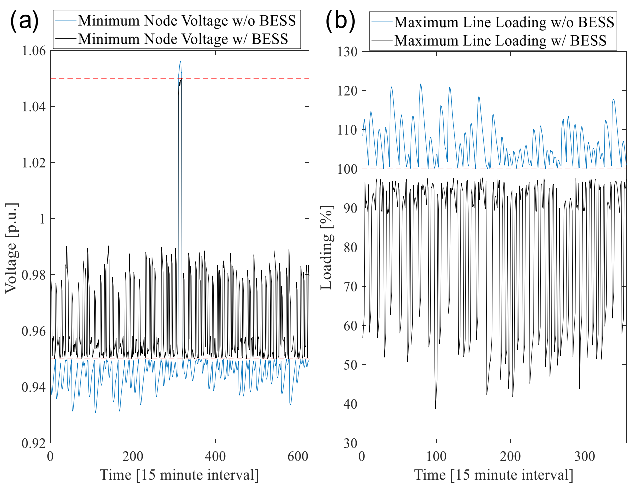

FIGURE 7. Line and node violations with/without the BESS incorporation across the year: (a) minimum node voltage, (b) maximum line loading.

The BESS annual net cash flows that consider the received payments, charging costs and OE for the sole and stacked services are shown in Figure 8 for the three technologies.

As shown in Figure 8, the BESS annual revenues can increase on average by 54% when the revenues are stacked from the DNS and I-SEM compared to the participation in the DNS scheme solely. While stacking the DS3 with the DNS and I-SEM can boost the revenues further by 79% on average. In addition, participating in I-SEM solely has shown to be not cost-effective. While participating in DS3 services solely is seen to be very attractive. However, as mentioned earlier, admission into DS3 services is not guaranteed. The Li-Ion technology achieved the highest annual revenues due to the high round-trip efficiency and low OE. Note that, the number of effective lifetimes for the stacked services differs

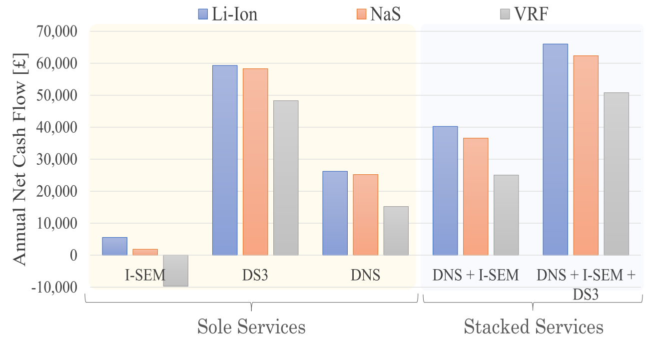

FIGURE 8. Annual net from the participation in the sole/stacked services.

from the sole services for each BESS technology according to the used cycles/year. For the sole services, the lifetime stated in Table 1 is considered, the BESS in the DNS or DS3 may not be cycled daily, however, this lifetime is considered as per the calendric lifetime.

For the DNS+ISEM framework (Figure 5), the BESS completes 378 cycles/year determined from the simulation results for one year. For the DNS+ISEM+DS3 (Figure 6), the BESS undergoes an extra 100 cycles/year calculated assuming that the BESS is utilized by 50% during the DS3 services periods. This change in the number of cycles affects the BESS lifetime and the annual loss in capacity which is considered in the CBA.

For the CBA analysis, an interest rate of 5% is considered to reflect the mid-point value of BEIS interest rates [44]. Besides, ± 30% rate (α) is considered to investigate the impact of increase/decrease on the revenues by 2030. The NPV results for the three technologies at the end of lifetime for the sole/stacked services are shown in Figure 9. From Figure 9, the participation in I-SEM solely is not cost-effective for all the BESS technologies as the NPV is negative, even with a 30% increase in revenues (+30%). The participation in DS3 services solely is attractive as all the BESS achieve positive NPV for the base case (0%) and with +30%. However, the Li-Ion and VRF BESS did not achieve positive results with a 30% decrease in revenues (−30%). While the NaS achieved positive results for all the cases with an average AROI of 5% and a payback period of 9 years due to its associated moderate CE, OE, and long operation time. Furthermore, operating the BESS solely for the DNS is only attractive for the NaS as the investment pay back in 12 years with AROI of 2% for the 0% and +30% cases on average. While the other technologies can hardly pay back in their lifetimes, even with +30%.

For the stacked services, all the technologies proved to achieve positive gains for the base case and with +30%. Yet, the Li-Ion and VRF can struggle to pay back with −30%. For the base case, the increase in NPV for the stacked revenues (DNS+ I-SEM) compared to the participation in DNS only can be given as 122% for the Li-Ion, 292% for the NaS, and 167% for the VRF. While the NPV can be boosted by 513% for the Li-Ion, 79% for the NaS, and 335% for the VRF

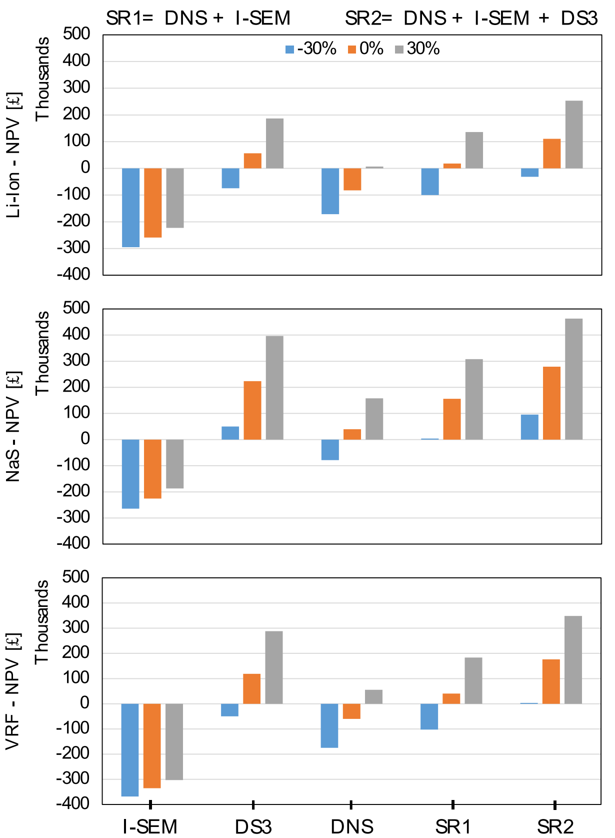

FIGURE 9. NPV for the three BESS technologies at the end of the lifetime.

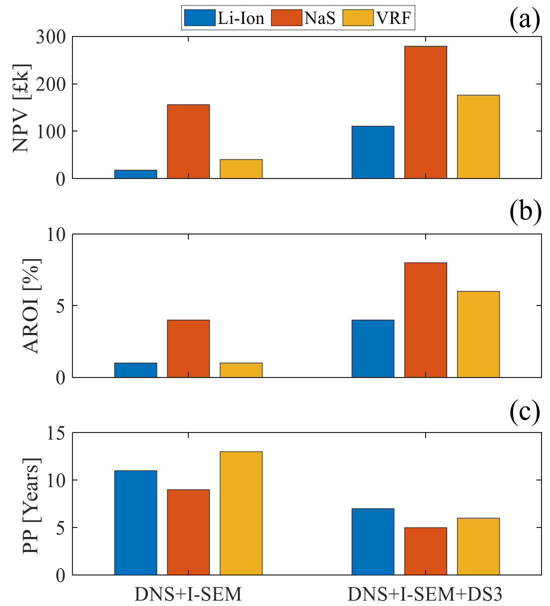

FIGURE 10. Difference between the two different stacked revenues for the 0% case: (a) NPV, (b) AROI, (c) PP.

by stacking the DS3 with the DNS+I-SEM compared to the DNS+I-SEM only as shown in Figure 10. Additionally, on average, the AROI can be boosted by 300% and the payback period can be shortened by 5 years.

It can be concluded from the CBAs that the NaS BESS has shown to be the most economically attractive option due to the responsible operation and capital costs associated with its investment in addition to its long operation lifetime. The VRF BESS achieved good results compared to the Li-Ion, the Li-Ion BESS did not outperform the other two BESS technologies due to its high capital investment and short operation lifetime compared to the two other technologies. The minimum discounted annual revenue required for each BESS technology to pay back in lifetime assuming it completes only one cycle per day can be given as £45k for the Li-Ion, £32k for the NaS, and £41k for the VRF. Yet, other payments should be gathered to make the investment profitable and viable.

Besides the economic analysis, the selection of BESS technology depends on other aspects such as the availability of land, safety, and environmental impact [39], [45]. For instance, the sodium-sulfur NaS technology requires high temperature for the operation which makes them unsafe [39] in addition to other issues related to the corrosive, contamination, and high global warming impact [45]. Whilst the Li-Ion technology has the advantage of very high energy density which decreases the needed land and increases their mobility and the applicability to be moved and connected at different areas as well as low carbon and material footprint [45]. However, the Li-Ion is quite sensitive to overtemperature/(dis)charge. The VRF is attracting many energy sectors such that their development is accelerating, they had the issue of complicated structure, and low energy density, so they require more space for the installation and high operation costs. However, they have a great advantage related to the power to energy ratio as the design of VRF achieves a complete separation of energy and power that can be customized for certain applications.

V. CONCLUSION AND DISCUSSION

This work investigated and quantified the expected revenues of BESS installed in the distribution networks of Northern Ireland. An actual radial 11 kV network was adopted and the anticipated increase in demand and LCTs by 2030 was considered to simulate the network violations. The BESS size was settled by introducing a sizing formulation to determine the minimum system size required to solve all the network violations. The available services for the BESS were discussed and stacking revenues from the participation in multiple services was investigated by identifying the conflicts and synergies that may occur for BESS participating in multiple services. Furthermore, the BESS operation in stacked services was simulated using operation frameworks that aim to maximize the stacked revenues and avoid overlapping in services. Finally, cost-benefit analyses were conducted to investigate the profitability of different technologies under sole and stacked revenues.

It is worth mentioning that the simulations were performed assuming ideal knowledge of the demand and generation as the main aim of this paper is to investigate an applicable framework for BESS revenue stacking in MV networks and evaluate the BESS economic feasibility. This can be considered as one of the research limitations. Hence, the proposed scheduling frameworks can be used as a planning tool for look-ahead applications. However, real-time control [7], [28] is essential to mitigate any issues concerned with the uncertainty of demand and generation. Another limitation that is worth mentioning is that a single BESS operation model has been used to simulate different technologies. This is because the adopted model is capable of simulating the operation of energy storage from theoretical points of view. However, in reality, the operation of these technologies may contain other factors that need to be considered which should be investigated in the future under different operation conditions.

The adopted BESS sizing methodology adopts a simple, yet effective OPF formulation that avoids the need of formulating hard constraints which can be used for any type of network regardless of its size or topology. It is worth mentioning that other OPF formulations can be used for radial distribution networks (i.e., convex relaxation). However, these formulations may fail to converge for large and complex networks. Note that the proposed OPF formulation is limited only to congestion management (i.e., solving voltage and overloads issues), also it can be modified to consider other constraint satisfaction objectives (i.e., frequency limits). However, for other types of objectives such as economic dispatch or minimizing network losses, traditional OPF methods should be used.

BESS has proven its powerful capability in supporting the network operation during energy evolution. Under the circumstances associated with costs and payments considered in this paper, the results revealed that by 2030, BESS can be very attractive as the investment can pay back averagely in around 8 years through stacking revenues. However, the results show that the sole participation of the BESS in the energy market or DNS is not viable as the BESS may struggle to recoup the investment expenditures. It should be noted that the DNS payments can be increased if the DSO would request further services from the BESS such as power quality services, also if the violations increased or for networks with a higher level of violations, the expected payments would increase which will add more gains. Yet the periods where the DSO require the BESS assistance should be pre-defined to avoid any conflicts with other services.

Furthermore, involvement in enhanced services through the DS3 scheme has proven to be very attractive. However, entry into the DS3 programme is not guaranteed. Moreover, the previous results were obtained by considering specific DS3 services, yet other DS3 services may be considered such as the Steady State reactive Power, although limitations should be considered such as the alignment with the DSO regulations for the reactive power control in MV networks. It is worth mentioning that in the previous analysis, some costs were not considered due to the high uncertainties associated with them such as the monitoring and control equipment, infrastructure, and land expenses, as well as other administration and management expenses. These costs should be considered by energy investors and DSO. Most of these costs should be fixed for all the BESS technologies, yet some costs related to the infrastructure and land may be less for the Li-Ion BESS due to its high energy density.

The participation of BESS through stacked revenues will substantially increase the BESS investment profitability and rationalize their existence despite increasing the BESS number of cycles and shortening the expected lifetime by doing so. The added value of stacked revenues can be observed in improvements in the net present value, return on investment, and payback period. Regarding the BESS technology, the VRF and NaS have shown to outperform the Li-Ion in terms of revenue streams due to their lower capital costs in addition to long lifetime. Note that in this study the Li-Ion LFP technology was considered, other Li-Ion technologies such as NMC and NCA can be considered as they have lower capital costs compared to the LFP. However, they have less lifespan compared to LFP. Furthermore, the wide-ranging benefits of the Li-Ion BESS in terms of environmental impact, complexity, and mobility should be considered and monetized which support the BESS economic feasibility. For future work, stacking revenues for multiple BESS installed in the same network shall be investigated in addition to exploring the stackable BESS revenues at low voltage residential networks.

APPENDIX

See Table 3.

TABLE 3. **Optimization solvers performance – one-year simulation.**

Optimization Solver	Processing time [Minutes]	Comments
BESS Sizing		
Surrogate Optimization Algorithm	13.7	Smallest BESS size
NOMAD	12	2% larger
Pattern Search	20	12% larger
Particle Swarm Optimization	77	8% larger
BESS DNS scheduling		
IPOPT	4 mins	
NOMAD	4.9 mins	Achieved better results w.r.t IPOPT

NOMENCLATURE

$AROI$	Annual return on investment [%].
CE	Capital expenditures [£].
dm	Data resolution [minutes].
DoD	BESS depth of discharge [%].
E^{nc}, E^{us}	BESS nameplate/usable capacity [kWh].
$I_{br,t}$, I_{br}^{max}	Line br current flow at time t, Rating [A].
ir	Interest rate [%].
k	Set of BESS.

L	Annual loss in BESS capacity factor [%].
LT	BESS lifetime [Years].
N_b, N_n	Set of feeder lines, Set of nodes.
NPV	Net present value [£].
OE	Annual operation expenditures [£].
P_t^{chr}, P_t^{dis}	BESS (dis)charging power at time t [MW].
P_t^{ch}, P_t^{di}	BESS imported/exported power from/to the grid at time t [MW].
P^{max}, S^{max}	BESS and PCS rating [MW]/[MVA].
P_t, Q_t, S_t	The active, reactive, and apparent power from/to BESS node at time t [kW].
SoC_t	BESS state of charge at time t [%].
SoC^{min}, SoC^{max}	BESS min/max state of charge [%].
T, t, τ	Simulation horizon, Index of time, Time interval.
T_{cg}, T_{cg}^{che}	Congested time-points, Consecutive time-points of highest injected/consumed energy.
TS	Total savings from BESS [£].
V_i^{min}, V_i^{max}	Min/max allowable node voltage [pu].
$V_{i,t}$	Voltage of node i at time t [pu].
z	Set of BESS services.
α	Revenues increase/decrease rate [%].
$\eta^{bt}\eta^{pcs}, \eta$	Efficiency of BESS, PCS, and altogether [%].
ρ_t^{SMP}	System marginal price at time t [£/MWh].
ρ^{bt}, ρ^{pcs}	Investment costs of BESS [£/kWh], and PCS/Inverter [£/kVA].

ACKNOWLEDGMENT

The authors would like to thank NIE Networks for their valuable support and for providing the test feeder and some of the data used in this paper. The views and opinions expressed in this document do not necessarily reflect those of the European Commission or the SEUPB.

REFERENCES

[1] A. A. R. Mohamed, D. J. Morrow, and R. Best, "The deployment of low carbon technologies in modern distribution networks," in *Proc. IEEE PES Innov. Smart Grid Technol. Eur. (ISGT-Europe)*, Bucharest, Romania, Sep. 2019, pp. 1–5.

[2] OFGEM. (Jun. 2013). *Low Carbon Networks Fund*. [Online]. Available: https://bit.ly/3jos52q

[3] C. Badajoz, S. Dourlens-Quaranta, D. H. Maldonado, and E. Peirano. (Aug. 2018). *Cooperation Between Horizon 2020 Projects in the Field of Smart Grids and Energy Storage*. [Online]. Available: https://bit.ly/3jyxVhO

[4] Northern Ireland Electricity Network. (2020). *FESS*. [Online]. Available: https://bit.ly/3bELisY

[5] A. A. R. Mohamed, R. J. Best, X. Liu, and D. J. Morrow, "Single electricity market forecasting and energy arbitrage maximization framework," *IET Renew. Power Gener.*, vol. 16, no. 1, pp. 105–124, Jan. 2022, doi: 10.1049/rpg2.12345.

[6] A. A. R. Mohamed, D. J. Morrow, and R. J. Best, "Maximizing the profits of battery energy storage systems in the integrated single electricity market," in *Proc. 9th Renew. Power Gener. Conf. (RPG Dublin Online)*, 2021, pp. 383–388, doi: 10.1049/icp.2021.1344.

[7] A. A. R. Mohamed, D. J. Morrow, R. J. Best, A. Cupples, I. Bailie, and J. Pollock, "Distributed battery energy storage systems operation framework for grid power levelling in the distribution networks," *IET Smart Grid*, vol. 4, no. 6, pp. 582–598, Dec. 2021, doi: 10.1049/stg2.12040.

[8] EirGrid. *DS3 System Services Contracts for Regulated Arrangements Recommendations Paper*. [Online]. Available: https://bit.ly/3jtfACs

[9] N. McIlwaine, A. M. Foley, D. A. Kez, R. Best, X. Lu, and C. Zhang, "A market assessment of distributed battery energy storage to facilitate higher renewable penetration in an isolated power system," *IEEE Access*, vol. 10, pp. 2382–2398, 2022, doi: 10.1109/ACCESS.2021.3139159.

[10] P. V. Brogan, R. Best, J. Morrow, R. Duncan, and M. Kubik, "Stacking battery energy storage revenues with enhanced service provision," *IET Smart Grid*, vol. 3, no. 4, pp. 520–529, Aug. 2020.

[11] EirGrid. (2011). *DS3 Programme*. [Online]. Available: http://www.eirgridgroup.com/how-the-grid-works/ds3-programme/

[12] SEMOpx. (2020). *Integrated Single Electricity Market*. [Online]. Available: http://www.semopx.com/

[13] A. S. Sidhu, M. G. Pollitt, and K. L. Anaya, "A social cost benefit analysis of grid-scale electrical energy storage projects: A case study," *Appl. Energy*, vol. 212, pp. 881–894, Feb. 2018.

[14] A. S. Tsagkou, E. D. Kerasidis, D. I. Doukas, D. P. Labridis, A. G. Marinopoulos, and T. Tengnér, "Stacking grid services with energy storage techno-economic analysis," in *Proc. IEEE Manchester PowerTech*, Jun. 2017, pp. 1–6.

[15] T. A. Nguyen, D. A. Copp, and R. H. Byrne, "Stacking revenue from energy storage providing resilience, T&D deferral and arbitrage," in *Proc. IEEE Power Energy Soc. Gen. Meeting (PESGM)*, Aug. 2019, pp. 1–5.

[16] Y. Tian, A. Bera, M. Benidris, and J. Mitra, "Stacked revenue and technical benefits of a grid-connected energy storage system," *IEEE Trans. Ind. Appl.*, vol. 54, no. 4, pp. 3034–3043, Jul./Aug. 2018.

[17] S. Tong, H. Yangy, and W. Torre, "Energy storage system dispatching optimization in stacked applications for utility grid," presented at the Elect. Energy Storage Appl. Technol. Conf. (EESAT), San Diego, CA, USA, 2017. [Online]. Available: https://bit.ly/3BXNskb

[18] M. Kazemi, H. Zareipour, N. Amjady, W. D. Rosehart, and M. Ehsan, "Operation scheduling of battery storage systems in joint energy and ancillary services markets," *IEEE Trans. Sustain. Energy*, vol. 8, no. 4, pp. 1726–1735, Oct. 2017.

[19] E. Namor, F. Sossan, R. Cherkaoui, and M. Paolone, "Control of battery storage systems for the simultaneous provision of multiple services," *IEEE Trans. Smart Grid*, vol. 10, no. 3, pp. 2799–2808, May 2019.

[20] J. Engels, B. Claessens, and G. Deconinck, "Optimal combination of frequency control and peak shaving with battery storage systems," *IEEE Trans. Smart Grid*, vol. 11, no. 4, pp. 3270–3279, Jul. 2020.

[21] D. Watson, C. Hastie, B. Gaudette, and M. Rodgers, "Demonstrating stacked services of a battery in a wind R&D park," *IEEE Trans. Power Syst.*, vol. 33, no. 2, pp. 1411–1419, Mar. 2018.

[22] A. A. R. Mohamed, D. J. Morrow, R. J. Best, I. Bailie, A. Cupples, and J. Pollock, "Battery energy storage systems allocation considering distribution network congestion," in *Proc. IEEE PES Innov. Smart Grid Technol. Eur. (ISGT-Europe)*, Oct. 2020, pp. 1015–1019.

[23] N. B. Arias, J. C. López, S. Hashemi, J. F. Franco, and M. J. Rider, "Multi-objective sizing of battery energy storage systems for stackable grid applications," *IEEE Trans. Smart Grid*, vol. 12, no. 3, pp. 2708–2721, May 2021.

[24] Y. Zheng, Y. Song, A. Huang, and D. J. Hill, "Hierarchical optimal allocation of battery energy storage systems for multiple services in distribution systems," *IEEE Trans. Sustain. Energy*, vol. 11, no. 3, pp. 1911–1921, Jul. 2020.

[25] F. Sorourifar, V. M. Zavala, and A. W. Dowling, "Integrated multiscale design, market participation, and replacement strategies for battery energy storage systems," *IEEE Trans. Sustain. Energy*, vol. 11, no. 1, pp. 84–92, Jan. 2020.

[26] J. Lopez-Lorente, X. A. Liu, R. J. Best, G. Makrides, and D. J. Morrow, "Techno-economic assessment of grid-level battery energy storage supporting distributed photovoltaic power," *IEEE Access*, vol. 9, pp. 146256–146280, 2021.

[27] Northern Ireland Electricity Networks. *FLEX | Northern Ireland Electricity Networks*. Accessed: Jan. 10, 2022. [Online]. Available: https://www.nienetworks.co.uk/flexibility

[28] A. A. R. Mohamed, D. J. Morrow, and R. J. Best, "Real-time model predictive control of battery energy storage active and reactive power to support the distribution network operation," in *Proc. 9th Renew. Power Gener. Conf. (RPG Dublin Online)*, 2021, pp. 31–36, doi: 10.1049/icp.2021.1356.

[29] J. Scoltock and D. T. Gladwin, "Payment analysis for a BESS providing dynamic frequency response in the Irish grid," in *Proc. 45th Annu. Conf. IEEE Ind. Electron. Soc. (IECON)*, Oct. 2019, pp. 2452–2457.
[30] *The Electricity Safety, Quality and Continuity Regulations 2002*, Regulations, Crown Copyright, U.K., 2002.
[31] *Voltage Ratings for Electric Power Systems and Equipment*, American National Standards Institute (ANSI) C84.1-2006, Nat. Energy Marketers Assoc. (NEM), Rosslyn, VA, USA, 2006.
[32] S. H. Low, "Convex relaxation of optimal power flow—Part I: Formulations and equivalence," *IEEE Trans. Control Netw. Syst.*, vol. 1, no. 1, pp. 15–27, Mar. 2014.
[33] R. T. Marler and J. S. Arora, "Function-transformation methods for multi-objective optimization," *Eng. Optim.*, vol. 37, no. 6, pp. 551–570, Sep. 2005.
[34] SONI. (2020). *Tomorrow's Energy Scenarios Northern Ireland 2020*. [Online]. Available: https://bit.ly/3cMHvfp
[35] SONI. (2019). *System Data Quarter Hourly*. [Online]. Available: http://test.soni.ltd.uk/library/index.xml
[36] Western Power Distribution. (2018). *Changing Load Profiles*. [Online]. Available: https://bit.ly/3JZrT5Q
[37] National Statistics. (2019). *Solar Photovoltaics Deployment*. [Online]. Available: https://bit.ly/3cVobgl
[38] EA Technology. (2016). *Development of the Transform Model for NIE Networks*. [Online]. Available: https://bit.ly/2O6lHkC
[39] IRENA. (2020). *Electricity Storage and Renewables: Costs and Markets to 2030*. [Online]. Available: https://bit.ly/36Pk5T5
[40] SSEN. (2012). *Orkney Energy Storage Park Close-Down Report*. [Online]. Available: https://bit.ly/2Mylw1j
[41] S. Le Digabel, "Algorithm 909: NOMAD: Nonlinear optimization with the MADS algorithm," *ACM Trans. Math. Softw.*, vol. 37, no. 4, pp. 1–15, 2011.
[42] J. Currie, D. I. Wilson, N. Sahinidis, and J. Pinto, "OPTI: Lowering the barrier between open source optimizers and the industrial MATLAB user," *Found. Comput.-Aided Process Oper.*, vol. 24, p. 32, Jan. 2012.
[43] C. Büskens and D. Wassel, "The ESA NLP solver WORHP," in *Modeling and Optimization in Space Engineering*. New York, NY, USA: Springer, 2012, pp. 85–110.
[44] BEIS. (2016). *Electricity Generation Costs*. [Online]. Available: https://rb.gy/zkkp36
[45] C. Mostert, B. Ostrander, S. Bringezu, and T. Kneiske, "Comparing electrical energy storage technologies regarding their material and carbon footprint," *Energies*, vol. 11, no. 12, p. 3386, Dec. 2018.

AHMED A.RAOUF MOHAMED (Graduate Student Member, IEEE) received the B.Sc. and M.Sc. degrees in electrical and control engineering from Arab Academy for Science and Technology, Cairo, Egypt, in 2013 and 2017, respectively. He is currently pursuing the Ph.D. degree with Queen's University Belfast (QUB), Belfast, U.K., as a part of SPIRE 2 Project. He joined the EPIC Research Cluster, QUB, in January 2019. His research interests include renewable energy, energy storage systems, low carbon technologies, optimization, and smart grids. He was a recipient of the First Prize Award in the Graduate Student Poster Contest at the 2021 IEEE Power & Energy Society General Meeting.

ROBERT J. BEST (Member, IEEE) received the M.Eng. and Ph.D. degrees from Queen's University Belfast (QUB), in 2004 and 2008, respectively. After his Ph.D., he spent several years with QUB as a Research Fellow and was appointed as a Lecturer with the Energy, Power and Intelligent Control (EPIC) Research Cluster, QUB, in 2013. His research interests include distributed generation, energy storage, phasor measurement unit applications, and power system operation with high renewable penetration.

XUEQIN (AMY) LIU (Member, IEEE) received the Ph.D. degree in electrical and electronic engineering from Queen's University Belfast (QUB), Belfast, U.K., in 2009. She is currently a Senior Lecturer in smart grid data analytics with the School of Electronics, Electrical Engineering and Computer Science, QUB. Her research interests include the development of advanced data-analysis tools for smart-grid wide-area monitoring and protective control, energy forecasting, and energy storage optimization to facilitate renewable energy integration.

D. JOHN MORROW (Member, IEEE) received the B.Sc. and Ph.D. degrees from Queen's University Belfast (QUB), Belfast, U.K., in 1982 and 1987, respectively. He is currently a Professor Emeritus in electrical engineering with QUB, where he has been, since 1987. His research interests include electric power systems, power system instrumentation, embedded generation, and facilitation of renewable energy integration. He is a member of the IET and the IEEE PES Excitation Systems Subcommittee.

JONATHAN POLLOCK received the master's degree in electrical and electronics engineering from Queen's University Belfast (QUB), Belfast, U.K. He is currently the Network Assets RP7 Project Manager of Northern Ireland Electricity Networks (NIE Networks).

ANDREW CUPPLES is currently the Network Development Manager of NIE Networks. His role involves forecasting load growth and planning network investment to manage this, and the development of innovative technologies, systems and processes to support customers in delivering the decarbonization of the energy system at least cost. He joined NIE Networks, in 2009, and has considerable experience across a range of roles including network operations, planning, and design, with a particular focus on facilitating the integration of renewable technologies on the distribution network.