

The growth of distributed generation and associated challenges: A Great Britain case study

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Abstract

Great Britain has reached high penetrations of distributed generation (DG). Historically, there has been a lack of technical requirements for DG to provide system support and for network operators to monitor, control and gather detailed information on DG installations. As a result, much of it is unobservable and uncontrollable. This work has analysed the available data sources for the amount, size and type of DG installations in GB. It is found that the lack of transparency and consistency of data are likely to act as an obstacle to the development of a more active distribution network. The impact that high DG has on system operation and system stability is discussed, including the potential for DG to offer flexibility services. A system disturbance in GB on August 9th 2019 brought a number of issues into focus: Slow action to change inappropriate settings of DG loss-of-mains protection and the uncertainty that DG adds to the effectiveness of under frequency load shedding schemes. Finally, it is argued that coordination between transmission and distribution networks is central to addressing many of the challenges and is a key enabler to utilising the flexibility available from DERs and releasing capacity for more DERs to be connected.

1 | INTRODUCTION

The drive to decarbonise energy systems and reduction in the cost of renewable energy technologies have significantly increased the share of electricity production taking place at the distribution level. The increased use of distributed generation (DG), in particular wind and solar and other distributed energy resources (DERs), such as energy storage devices, alters power flows within electricity distribution networks and may require changes in an electric power system's operation and commercial and regulatory arrangements [1].

High penetration of variable DG presents several challenges to power system planning, operation and control, including but not limited to, accommodating DG capacity with a growing need for management of distribution network constraints, increasingly localised supply resulting in a less schedulable generation portfolio for the transmission system operator (TSO) and increased converter interfaced generation (CIG) reducing

the system's inertia and short circuit levels and changing its dynamics.

Denmark is an early example of a power system with high amounts of DG, reaching over 50% of installed capacity by 2007. At that time, an innovation project in hybrid network control was launched by the TSO to address power system security problems associated with high DG [2]. Similar issues are being experienced in Great Britain (GB) today and discussed in this paper. In Spain in 2006, the TSO commissioned a dedicated control centre that receives real-time communication of active power produced by generators with capacities of more than 1 MW. This has led to 99% of wind and 70% of PV capacity being observable, and plants of > 10 MW being able to respond to active power set points [3]. Germany also has a significant penetration of variable DG, leading to constraints at various voltage levels, with much of this DG installed at lower voltages and not monitored. Curtailment of DG is possible by the German TSOs. However, it requires well-coordinated

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communications as they must contact the various regional and medium voltage control centres to make a request for manual adjustment [3].

Some areas of GB have now achieved high penetration of variable DG. Initially, technical rules were underdeveloped as connections to distribution networks in GB were made with a ‘fit and forget’ design approach and with an assumption of a strong transmission system. This led to shortcomings in DG technical requirements, including a lack of visibility and control, the under-exploitation of grid support functionality and overly sensitive protection settings which can reduce power system resilience [4, 5]. In GB, there has also been a lack of common protocols for recording DG data leading to uncertainty in the amounts and types of DG at various locations in the network. Therefore, uncertainties arise when considering DG in operational processes, modelling and technical system studies.

This paper discusses system challenges associated with the growth of DG, assessing them through the lens of what has happened in GB. The remainder of the paper is organised as follows: Section 2 provides an assessment of the amounts of DG embedded within the GB power system. Section 3 reviews operational issues related to system balancing, active network management and quasi-steady state voltage control. Section 4 discusses the influence that DG has on the system’s response to disturbances, reflecting on existing issues exposed by a power system disturbance event in GB in 2019, as well as the influence of DG on system fault levels. Section 5 concludes the paper. The contributions of this paper are summarised as follows:

- Analysis of the available sources of data for DG in GB have been reviewed, compared, and analysed to provide a detailed overview of the amounts and types of DG installed in the system. This analysis highlights discrepancies between the available DG data records and reveals a lack of availability and transparency of consistent data for DG that can act as an obstacle to planning and operating a well-coordinated whole electricity system.
- This work provides an overview of the challenges arising from the growth of DG, focussing on those that affect the secure operation of the power system in GB. As a result of this review, the importance of building in observability and controllability to DG connections is highlighted, in order to reduce uncertainty in system operation and improve responses to system disturbances.
- Finally, examples of mitigating actions, ongoing innovation projects and changes to codes and market structures that have occurred in GB are given throughout the paper. Moreover, key questions are raised that remain unanswered and require addressing as the system continues to become increasingly distributed.

2 | DISTRIBUTED GENERATION IN GB: TYPE, SIZE AND LOCATION

A key influence on an ability to study and plan for the efficient operation of a power system with high penetrations of DG

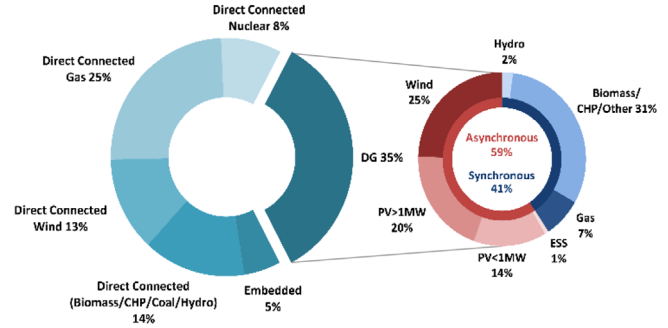


FIGURE 1 Generation mix in GB transmission and distribution

is transparency of network data. There are three main sources of DG data in GB: (1) Future energy scenarios (FES) published by National Grid Electricity System Operator (NGESO) which outlines credible growth scenarios for the whole electricity system; (2) the UK Government’s Department for Business, Energy & Industrial Strategy (BEIS) which publishes historic energy data and trends; and (3) Long Term Development Statements (LTDS) published by Distribution Network Operators (DNOs) for each licence area. Each data source is created by a different organisation with different intentions. When compared, significant variation can be observed in reports of DG installed capacities, technology groupings/labelling and the granularity of data, making it problematic to combine features from each data source [6].

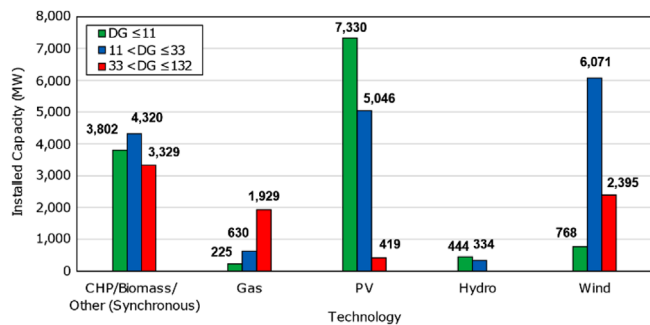
The LTDS are part of a DNO’s distribution licence conditions with the primary function of providing data for generation developers and potential new loads to assess and evaluate local connection opportunities. In July 2020, and since the publication of [6], the ‘embedded capacity registers’ published as part of the LTDS have been standardised and expanded to include further information such as site location and the type of connection that the DER has [7]. This improvement in data collection should, in theory, improve network forecasting and planning functions for the TSO and assist the DNO to transition to a distribution system operator (DSO) [1, 5]. Currently, the LTDS is reported in a common overall format but is generated independently for each of the 14 DNO licence areas in GB.

2.1 | Current DG installations

Figure 1 shows DG, connected to all DNO licence areas in GB and split by technology type, as a proportion of total registered installed generation capacity, according to the LTDS data and the transmission entry capacity register as of 2019 [8]. As the LTDS does not include installations with capacities of less than 1 MW, data for micro-PV installations from BEIS have been included [9], with the assumption that PV makes up the vast majority of small installations. The ‘Embedded’ generation category is generation that has connected to the distribution network yet has contracted with National Grid to obtain rights of access to the transmission network and is therefore ‘visible and

TABLE 1 Project size at different voltage levels (LTDS) for projects of greater than 1 MW

	DG \leq 11 kV	11 kV < DG \leq 33 kV	33 kV < DG \leq 132 kV	Transmission
No. of sites (> 1 MW)	1,902	1,175	127	152
Total installed capacity (MW)	7,385	16,600	8,297	65,683
Mean capacity (MW)	3.9	14.1	65.3	432.1

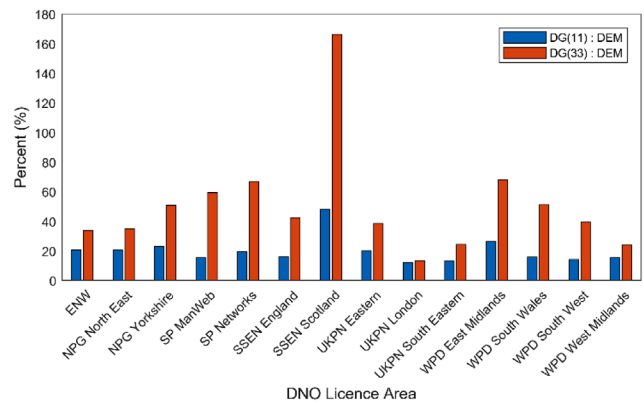
**FIGURE 2** Distributed generation technologies, installed at different distribution voltages in GB

controllable'. DG, which makes up 35% of total installed generation capacity, is largely unobservable and uncontrollable by the TSO. 59% of DG is asynchronous with a variable renewable energy source. 41% of DG is synchronous generation with a storable fuel source. However, much of the synchronous DG lacks the plant level and network level controls to be utilised for system operation.

Table 1 shows the increase in the number of projects connected at lower distribution voltages and their relative sizes. DG connections that are above 1 MW in size and connected at 11 kV or below make up 23% and 8% of distribution connected and total connected capacity, respectively. However, they represent 57% of the total number of sites. As the connection voltage level increases, the mean project size increases and the number of connections reduces significantly. This information shows the extent of the challenge for improving visibility within distribution networks, with a sizeable amount of capacity located across numerous sites at lower distribution voltages.

For the sub-1 MW category, the mean capacity of each site is small due to the volume of installations on residential and commercial buildings. According to BEIS data for solar PV deployment [9], by December 2019 a total of 1,000,552 solar PV installations existed in GB, which make up 12,858 MW of PV capacity. Of this, 99.5% of installations are less than 50 kW. However, the data for the number of installations cannot be reconciled with the LTDS data due to lack of consistency when categorising projects. Despite the introduction of 'embedded capacity registers', sub-1 MW DG capacity must still be inferred from various other sources such as subsidy registers.

Figure 2 shows the installed capacity of each technology type at different distribution voltage levels. To give a more accurate representation of small-scale solar PV installed on residential and commercial premises, an estimate of 5,277 MW of PV capacity made-up of installations less than 1 MW has been estimated from [9] and included in Figure 2. The higher the

**FIGURE 3** Ratio of installed DG capacity at 11 and 33 kV to the sum of DNO peak substation demands

ratio of DG capacity to local demand, the greater impact DG has on the wider system due to (1) a reduction in net demand seen by the transmission system, (2) an increasing occurrence of 'reverse power flow' supplies to the transmission network and (3) increased variability in net transmission demand as true demand is being supplied by variable DG.

Figure 3 shows the ratio of installed DG to demand where DG(11) is all generation connected at 11 kV and below and DG(33) is all generation connected at 33 kV and below. The ratio considers total installed capacity for DG and the combined annual peak of all primary substation demands in each area. Diversity in both demand and generation is not considered; the ratios are therefore intended only as a guiding metric to identify DNO licence areas with high DG capacity.

Visibility of power flows within distribution networks, particularly in 11 kV and low voltage (LV) networks has historically been poor, partly due to lack of need. However, growth in peak demand, network complexity and decentralisation call for greater visibility across network voltage levels, which is a challenge for current data systems and architectures [5, 10]. Furthermore, there are currently no common data sharing protocols or mechanisms for network monitoring data [5]. It is important that energy system data can be shared across platforms and meets the needs of multiple types of users, including the DSO to make decisions and open up flexibility markets, flexible service providers and consumers while respecting privacy and consumer protection.

2.2 | Energy from distributed generation

Using the estimates of the installed capacities for different technologies across GB, the associated energy outputs have been

TABLE 2 Estimated DG energy output for 2019

Type	LTDS Total installed capacity (GW)	2019 CFs		Average CFs		2019 Implied contribution of LTDS DG to demand (%)
		CF %	Output from DG (TWh)	CF %	Output from DG (TWh)	
Other	11.45	54.90	55.07	56.20	56.37	15.92
Storage	0.28	7.28	0.18	11.30	0.28	0.05
Gas	2.78	43.02	10.48	38.80	9.45	3.03
PV	12.80	11.16	12.51	10.60	11.89	3.62
Hydro	0.78	38.76	2.65	36.30	2.48	0.77
Wind	9.23	31.42	25.40	30.40	24.58	7.34
Total	37.32	–	106.29	–	105.05	30.73

estimated by using the 2019 UK average capacity factors (CFs) published by BEIS through the Digest of UK Energy Statistics (DUKES). DUKES Table 6.5 [11] which provides CFs for renewable technologies and Table 5.10 [12] for conventional technologies are primarily used. The relevant 2019 CFs are applied to the 2019 LTDS installed capacities in Table 2 for the applicable technology types, as are the average CFs from the years 2011–2019. The bulk of the ‘Other’ category from the LTDS data is expected to be predominately bioenergy technologies such as Anaerobic Digestion, Biofuel and Waste Incineration, as well as combined heat and power (CHP) plant using natural gas. Therefore, the average capacity factor of the bioenergy technologies given in DUKES Table 6.5 and CHP from [13] is applied to ‘Other’ technologies. The capacity factor for pumped storage as per NGENSO in [14] is applied to all ‘Storage’ technologies. Finally, the implied contribution of DG energy output to the total demand of 346 TWh in 2019 [15] is provided. The total demand includes system losses (26 TWh, or 7.6% of demand) and energy industry use (24 TWh, 6.9% of demand) [15].

It is noted that there is a high installed capacity of ‘Other’ technologies and therefore the capacity factor applied significantly influences the overall final estimate. This introduces an increased level of uncertainty in the estimate of energy contribution from DG. Better labelling of data, monitoring and visibility of the operating regimes for the ‘Other’ technologies would allow a more confident estimate of energy supplied by these types of DG. Additionally, the UK average capacity factors used here are expected to vary compared with figures solely for GB.

2.3 | Growth trends for distributed generation

Figure 4 shows the installed capacity connected to the Transmission and Distribution (T and D) networks for the period 2013–2020 inclusive [16]. In this period, DG grew substantially, stimulated by government incentives such as Feed-in Tariffs (FiT). Installed capacity on the distribution network grew by an average of more than 10% per year, driven by additions in renewable

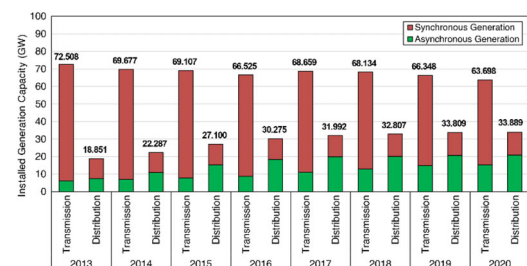


FIGURE 4 Installed generation capacity, split into synchronous and asynchronous generation connected to the transmission and distribution networks in GB

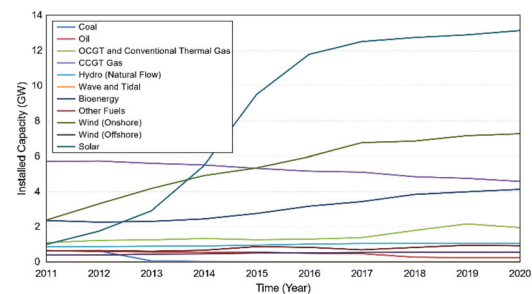


FIGURE 5 Growth of individual DG technologies from 2011–2020

asynchronous generation, primarily variable onshore wind and solar. This is demonstrated in Figure 5, which provides the historic trends for the individual technologies that underpin what is shown in Figure 4. An increase in renewable synchronous generation, specifically bioenergy, is also evident which has countered a reduction in CCGT capacity using natural gas. In the same period, asynchronous generation also grew substantially on the transmission network, with significant additions of onshore and offshore wind connections. Also, during this period, both the overall installed capacity and the share of synchronous generation in the transmission network reduced following closure of thermal plant. This combination of factors results in a less

TABLE 3 Installed generation capacities for three net-zero FES 2021 scenarios in the transmission and distribution networks

Installed Capacity (GW)	Transmission		Distribution	
	2030	2050	2030	2050
Leading the way	137.1	178.1	61.6	141.5
Consumer transformation	125.4	233.1	56.0	124.2
System transformation	121.2	220.1	47.1	85.1

schedulable and less dispatchable generation portfolio for the TSO [17].

In NGENSO's FES 2021 [18], four scenarios are outlined which describe credible pathways for how the future of energy and networks might evolve between now 2020 and 2050, three of these meet net-zero emissions by 2050. These three scenarios: 'Consumer Transformation', 'System Transformation', and 'Leading the Way' all predict a significant increase in connected generation capacity in both transmission and distribution networks. 'Leading the Way' and 'Consumer Transformation' scenarios both lead to a higher uptake of decentralised generation than the 'System Transformation' scenario, but all of them show significant DG capacity being added to the system. Solar PV capacity is projected to dominate in comparison with other technologies, though significant uptakes of onshore wind, hydrogen and storage are anticipated across the discussed scenarios. Table 3 shows the installed capacity for each scenario calculated from [19].

The LTDS includes data for 'accepted' generation projects in each licenced network area. Accepted DG are those that have signed grid connection agreements with the DNO, but projects may be on hold, for example, due to lack of a credible business case following withdrawal of subsidies. Since the withdrawal of support in 2017, the UK Government recognised that "there is a risk that if we were to rely on merchant deployment of these technologies alone at this point in time, we may not see the rate and scale of new projects needed in the near-term to support decarbonisation of the power sector and meet the net zero commitment at low cost" [20]. Subsequently, they have allowed 'established' technologies, which include onshore wind and solar PV of > 5MW, to again apply for centrally awarded, government-backed contracts for difference for low carbon generation [20].

Several 'accepted' projects may never get built. However, many projects could go ahead in the near term, given the right market conditions. The total accepted connections would increase DG capacity by 60% from 37,611 to 60,836 MW. Of this, 29% would be connected at or below 11 kV and 75% at 33 kV. This shows the scale of capacity in the distribution network that, in principle, is already reserved for connections that are yet to be built.

Each year BEIS publishes energy projections, including installed capacity for renewable energy. The forward projections for 2019 were 25 GW in 2011, 41 GW in 2015 and 44 GW in 2018 [21]. However, capacity for renewable energy at end of 2019 stands at 47.4 GW [22], showing that, given the right

economic and political enabling environment, rapid growth in the renewable energy sector can continuously surpass long term growth forecasts.

3 | OPERATIONAL CHALLENGES OF AN INCREASINGLY DISTRIBUTED SYSTEM

The growth of DG and the concurrent reduction in transmission connected synchronous generation, as discussed in Section 2.3 and shown in Figure 4, can affect many areas of power system operation, notably related to system balancing and management of voltages. In this section we discuss these challenges. Many of them result in increased uncertainty in transmission system operation as well as a need for improved coordination between the transmission and distribution (T&D) systems in order to facilitate whole electricity system operation.

3.1 | Transmission system operation in GB

National electricity system operation in GB at the time of writing is performed by the Electricity System Operator part of National Grid, NGENSO (equivalent to a TSO though without responsibility for owning, maintaining and developing the transmission network's assets). NGENSO must operate the system in compliance with the security and quality of supply standard (SQSS) [23], such that the system remains stable and secure during normal conditions and following a single fault event. This involves balancing supply and demand through the Balancing Mechanism (BM) and ancillary services and determining the optimal re-dispatch of generation or controllable loads during each trading period of the market.

Examples of typical intervening operational actions include managing transmission line thermal constraints or dispatching additional synchronous generation to increase the system's inertia to aid management of system frequency or ensure sufficient reactive power is available for voltage support [24]. 'Constrained on' generation is typically out-of-merit in the unconstrained wholesale market and connected to the transmission system. Its use for system inertia often requires curtailment of output from renewable generators, usually wind, [25, 26]. The costs of these operational actions are recovered from all participants in the GB BM and ultimately passed through to customers.

3.2 | Operation at low net transmission system demand

As previously noted, DG in GB is mostly unobservable by the TSO and its output is a function of its technical availability and the available energy resource, that is, it is not dispatched by the short-term market and, at least for variable renewable sources, its output is decoupled from demand. Generation participating

in the GB wholesale market is scheduled by its owners in merit order. Any available intermittent renewable sources will typically be scheduled before any conventional thermal generation due to its low short-run marginal costs. Baseload nuclear power plants also typically have a lower marginal cost than more flexible gas plants due to high start-up costs and are committed for longer time periods. Therefore, it is becoming increasingly challenging to balance the system during periods of low demand, particularly when outputs from renewable generation are high and the demand gets close to, and in some periods may fall below, the level of inflexible or uncontrollable generation on the system [25]. The TSO may need to curtail output from DG over which, up to the time of writing, it has had extremely limited control.

Critical operating conditions related with low demand and the lack of controllability of DG were exposed during the COVID-19 pandemic which, in March 2020, led to the first national lockdown in GB. The shift in day-to-day activities of people across the entire country had a significant impact on the demand profile of the electricity system. In general, domestic use of electricity increased while commercial and industrial demand fell. According to NGESO [27], the reduction of the in-day demand during April and May 2020 was in the range of 5–20% and the overnight demand in the range of 2–15%. An independent assessment described weekday demand as resembling what would normally be seen at a weekend [28]. On the 28th of June 2020 the lowest ever national transmission system demand of 13.4 GW was recorded. The greatest effect on the demand profile was a reduced peak demand [29], which would be expected as people are less bound by conventional business operating hours.

The pandemic meant that low levels of net demand as seen from the transmission system were experienced some years earlier than had been expected. During low demand conditions with high renewable outputs, the number of actions required to secure the system is often increased and incurs additional costs. According to [30], the average costs of balancing the system for the last decade have been around 5% of the cost of generation production and have been marginally increasing in the last 5 years as the share of variable renewable generation has increased. However, for the second quarter of 2020 (during which severe social restrictions were in place), system balancing costs rose sharply, adding 20% to the cost of generation.

The suppressed demand and high DG output created various additional challenges for the TSO [27, 31], including:

- Downward flexibility—this is required to reduce generation on the system to match demand during low demand conditions, accounting for forecasting errors and to ensure sufficient margin exists to contain high system frequency.
- Voltage management—lower power flows across the network increase reactive gain; meanwhile, fewer generators are available to provide voltage support (discussed further in Section 3.3).
- System stability—operating with a high share of power electronic interfaced generators reduces system inertia and increases the risk of unintended operation of DG protection (discussed further in Section 4.1).

To increase the amount of downward flexibility, a new temporary system service termed Optional Downward Flexibility Management (ODFM) was introduced in 2020 by NGESO and approved by the regulator (Ofgem) [32]. The purpose of ODFM is to ensure that flexible generation can be reduced to match demand. It does this by instructing DG to reduce its output to zero or by increasing demand, both of which increase net transmission system demand. The majority of providers were distributed solar and wind generators, but also included demand turn-up assets. During 2020, the service was instructed five times with a total cost of approximately £7 m. Three of these occasions were over a bank holiday weekend in May, which would be expected to see low demand; the volume of actions required was between 411 and 3,177 MW of downward re-dispatch [27].

The low demand seen during the COVID-19 pandemic, and the need to introduce the ODFM reserve product exposes the challenge of operating the system with high amounts of unobservable and uncontrollable DG. More enduring solutions to improve the amount of downward flexibility available to the system operator include its ongoing reforms of power reserve products and facilitation of wider access to the BM, which, as discussed in Section 3.5, still requires removal of barriers to entry and is dependent on uptake from DERs. However, it is noted that these are transmission system solutions. DSO led solutions could also be used to address this challenge, for example through more active operation and local energy balancing within the distribution networks. In order to facilitate DSO led solutions improved T&D coordination is required. (See Section 3.8).

3.3 | Voltage control

As traditional means of voltage control from synchronous generators decreases and load patterns change due to the high penetration of intermittent DG, new approaches for voltage control are required [3]. To address the need for voltage control at the T/D interface, a challenge exists to determine the amount of reactive power available at the interface node [33]. This requires additional visibility and control at the DG plant level but must also be simultaneously coordinated with transformer tap changer control to achieve the desired effect at the transmission system. Under G59 regulations [34] which were superseded by G99 in 2019 [35], DGs in Britain were not required to be capable of regulating active and reactive power or providing voltage droop control at the point of common coupling. Through a lack of need, DGs tended not to install power plant control systems to interface with the grid. However, while the inverters may be capable of regulating reactive power very quickly, as it was not a requirement during the project design stage, the DG owner will seek reimbursement of costs for any lost active power due to limits of converter ratings and financial incentives to make any required changes to plant controls.

In the past these services would have been provided as a mandatory grid code requirement for a large generator. A study to address voltage issues in the southwest of England indicates

that dynamic voltage support from DGs would help with the management of transmission limits. However, at present and due to lack of foresight at the time of connection of the DG, the only way to change the DG's power factor is to send a technician to site to make a manual adjustment and is therefore highly impractical and inflexible [36].

Methods to encourage and enable DG to participate in voltage control will require improvements to DG control systems, improved monitoring on DNO networks and, where the DG is to support transmission system voltage constraints, coordination between DNO and TSO systems. One project which has demonstrated this is discussed in Section 3.8.

3.4 | New uncertainties in operational forecasting

In GB, NGENSO has been the main party in need of forecasts of demand and, in more recent years, of output from transmission connected wind generators. The methods it uses are relatively mature due to the longstanding energy balancing requirement. However, there are many new sources of uncertainty stemming from the continued growth of DERs. As highlighted throughout this paper, the vast majority of DG is un-scheduled and uncontrolled, with much of it driven by weather dependent variable sources (see Section 2). It therefore offsets the true system demand as seen by NGENSO at the boundary between transmission and distribution, that is, at the grid supply points (GSPs). This results in it becoming increasingly difficult to accurately forecast the aggregated national demand, potentially resulting in higher energy imbalance for the ESO to manage close to real time. Based on this need and in the absence of monitoring of DG, the aggregated GSP demand forecasts currently account for distributed solar and wind by obtaining the capacity and location of DG from public databases (BEIS) and utilising weather data from the station in closest proximity to renewable generators to form generation output forecasts [37]. However, one project ongoing at the time of writing aims to improve forecasting by incorporating advanced statistical and machine learning techniques to obtain more frequent forecasts per GSP and improve forecast accuracy [37].

Ambitions by DNOs to more actively manage resources connected to their networks and better utilise available network capacity—a change characterised as one of becoming DSOs—have led to a need for them to develop operational forecasting capabilities [37]. Amongst other things, this will enable DSOs to identify potential threats to regional security of supply and allow for more accurate identification of a need for congestion management ahead of time. These improvements will provide better notice to perform the required actions such as, re-dispatch of generation, flexing of demand and re-configuration of the network that each take time to be carried out. In addition, the optimal utilisation of storage requires confidence in system conditions over a period of time. Regional DSO operational forecasting can also benefit the TSO and national demand and generation forecasts, as DSOs are ultimately best placed to model and predict energy flows on their networks. As

such, there is a requirement for additional data exchange with NGENSO which has its own coordination and security challenges (see Section 3.8).

Even with improved techniques, uncertainties affecting forecasting will remain, for example, due to the lack of visibility of DG in GB, the dispersed nature of different technologies and variations in local weather conditions. Therefore, there is also a requirement for modelling techniques that support uncertainty quantification [38, 39].

3.5 | DG providing flexibility

Flexibility—the ability of a resource to vary its state in light of variations in system conditions or sudden changes—has typically been provided by large, transmission connected generators. However, a broader range of flexible DER are starting to participate in balancing and ancillary service markets operated by NGENSO in response to (1) an opening up of access to these markets to small service providers in the range of 1–100 MW capacity, and (2) to allow some services to be delivered by aggregated assets [40–42]. However, barriers to entry for DG remain, mainly the result of a high cost of compliance with a number of different codes [43].

In recent years there has also been rapid growth in flexibility services being procured by the DNOs in GB. Starting in 2018 with 116 MW of flexibility being contracted, this has increased 16-fold in three years to 1.6 GW being contracted in the period up to July 2021 [44]. These services are typically procured to manage peak demands, for example due to load growth, as an alternative to network re-enforcement. Therefore, participants are limited to dispatchable types of DG able to provide active power turn-up or demand that can provide a turn-down service. For variable DG such as wind or solar, these services would require a suitably sized co-located energy storage system.

The ability of DERs to provide multiple services, that is, to 'stack' them—from the same physical asset—to improve their revenues can maximise their value and therefore can lead to higher participation. There remain some contractual or regulatory barriers to revenue stacking and there is judged to be further room to coordinate different T&D services over different timescales [45]. For example, given the right protections against risk of non-delivery, actions to help limit peak power flows on a distribution network thus enabling deferral of network reinforcement might be combined with short term non-locational services such as frequency response for the TSO. Having clear rules and a supportive regulatory environment is crucial to unlocking the value of flexibility for participants [46].

3.6 | Active network management schemes

To accommodate the growth of intermittent DG, active network management (ANM) schemes are being deployed by DNOs in GB [47, 48]. To date, ANM connections have typically been offered to generators applying to connect to constrained areas of the distribution network where the DG

connection would otherwise have triggered network reinforcements due to, for example, the risk of thermal overloads. The relatively high cost of network reinforcement required to accommodate the DG project would largely be borne by the applicant and would often be prohibitively high. ANM connections allow generators to connect more quickly and at a lower cost by including provisions for automatically curtailing their output during constrained periods. DG developers must accept the cost of unsold energy generation, coupled with the long-term risk that the business case could diminish over time due to changing system conditions impacting the level of curtailment. The authors in [1] argue that the DNO is best placed to manage the curtailment risk for ANM connected projects, given that they are the only party with enough knowledge of the network to appropriately forecast and have control over network constraints. The DNO could be incentivised to do so by paying towards the cost of lost energy through a price for curtailment contracted in the connection agreement.

3.7 | Service conflict with ANM schemes

For the most part, procurement of flexibility exists to resolve the issues faced by each system or network operator, and much work remains in the move towards a ‘whole electricity system’ set of grid management services. Both DNOs and the TSO have the potential to benefit from flexible resources located in distribution networks. However, enhanced observability of the significant amounts of DG in the system and coordination between the actions of both system operators is required. The potential for conflicting actions and the need for cooperation are widely recognised and highlight the necessity to improve observability of the distribution networks and better transparency of grid data [49].

ANM systems can exacerbate or create further challenges. The schemes operate without being visible to the TSO. While transmission and distribution constraint conditions might coincide—for example, high wind and low demand conditions—and an ANM action may benefit both constraints (e.g. by curtailing distribution connected wind located within an export-constrained transmission region), actions required by a DNO or the TSO might be in conflict. For example, when the TSO requests an adjustment from DER providing a frequency management service, an ANM system will observe the change in power flow across a monitored distribution constraint and automatically alter the allowable output of the ANM connection, thus offsetting the effect seen at the transmission system and potentially requiring the TSO to procure the response again from elsewhere. Furthermore, the forecasting uncertainty of transmission constraints will be increased, as the TSO is unaware whether the net load observed includes or excludes DG located behind an ANM system [50].

In order to avoid conflict, the ODFM service described in Section 3.2 is not available to assets that have an ANM contract with a DNO [51]. However, this does not prevent other ANM systems counteracting the actions from non-ANM generators delivering ODFM.

3.8 | Transmission and distribution system coordination

New technical and market frameworks, operational processes and information exchanges are required to facilitate T&D coordination. There are different ways in which this can be achieved and various structural and functional models have been proposed in the literature which, in general, vary the roles and responsibilities that are adopted by the TSO and the DSO [1, 49, 52–54].

As discussed in Section 3.5, market rules in GB have been amended to allow an increasing amount of DERs to participate in the balancing mechanism and contribute to ancillary service markets. There are also increasing opportunities to offer flexibility services to the DSO. A suitable coordination model must cater for the effective provision of both transmission and distribution level services from DERs while respecting distribution network constraints. In this setting, a hierarchical model has been proposed to provide reduced operational complexity and a high level of efficiency where use is made of a DSO’s detailed knowledge of the distribution network while allowing a TSO to procure services from DERs. In such a model, the DSO coordinates and dispatches the DERs and validates the delivery of services to the TSO [49, 52]. However, it has been argued that there is a potential conflict of interest for the DSO when validating service bids, operating its own network, and managing and investing in network assets [52, 53]. This might be resolved by introducing another party to operate the distribution network and procure services, separate from asset ownership, that is, an independent DSO (IDSO), a structure that is similar to that of the legally separated network owner and system operator arrangement for electricity transmission in GB. However, the addition of an IDSO adds complexity as multiple new entities may be required, that is, for each DSO area. It would also be counter to the direction taken by the GB regulator in recent years where it has encouraged each DSO to make decisions on the mix of operational and asset-based actions it takes and the minimisation of its ‘totex’—the total of capital and operating expenditure—required to deliver services to network users over the medium to long-term [55].

Another important aspect of coordination is the data exchanges required between DERs, DSOs, potential IDSOs and TSOs. The data that is required to be exchanged will depend on the type of structural model being adopted, for example, the location of interface points and the responsibilities of the parties [1]. In general, data exchange requirements include (1) information on system parameters such as DG type, capacity and location and network characteristics (such as discussed in Section 2), (2) real-time network data such as to provide operational visibility and dispatch instructions, and (3) market data relevant to a particular DER, for example, service volume or active power forecasts [56].

A recent practical example of T&D coordination is the Power Potential project in GB involving one of the DNOs, UKPN, and NGESO. It has developed a distributed energy resource management system (DERMS) which gathers bids from DERs and presents a day-ahead and real-time view of

services to NGENSO at the GSP level and represents a market driven rather than bilateral approach [57]. The project has conducted live-trials with DERs to provide dynamic voltage control services to manage voltage constraints in the transmission network, such as those discussed in Section 3.3. The system can also facilitate active power services while managing potential conflict with ANM connections [58]. The Power Potential project represents a DSO-led solution, where the TSO would provide signals to the DSO, such as information on constraints and the flexibility service volumes it requires and access them through DERs. However, the project did not address the simultaneous procurement of TSO and DSO flexibility services.

The low net demand as seen from the transmission system during the COVID-19 related societal lockdowns, driven by extremely low demand combined with high DG output, have anticipated similarly low transmission demand conditions that were not expected to arise for a few years as DG capacity continued to grow. Development of appropriate arrangements to manage the whole system and coordinate T&D are therefore increasingly urgent.

4 | IMPACT OF DG ON POWER SYSTEM STABILITY AND RESPONSES TO FAULTS

Our analysis in Section 2 suggests that 59% of DG in Britain is converter-fed, intermittent and asynchronous, a proportion that is expected to increase. Some of the key operability challenges for the TSO are associated with a reducing system inertia and reducing fault infeed (herein termed the Short Circuit Level or SCL), caused by the displacement of large transmission connected synchronous generation. Significant amounts of DG in the system contribute to these effects, which are described in the following subsections.

4.1 | Challenges with high DG in a low inertia system

The inertial response of the power system is an inherent physical response of synchronous generation to a sudden imbalance in generation and load [59]. Converter-fed equipment that is used today is fundamentally different from a synchronous machine in that it does not have a rotating mechanical mass that is synchronously coupled with the electrical network. Therefore, it does not provide inertia [60]. With a low inertia comes a higher rate of change of frequency (RoCoF) during a power imbalance [61] that can cause unintended operation of DG protection systems. Faster frequency response and reserve services are therefore required, and conventional frequency response services become unsuitable [62]. In addition, low inertia and high DG challenge the operation of existing systems embedded in the distribution network which influence the resilience of the whole system.

4.2 | Unintended operation of DG protection

The planning of DG technical requirements and lack of visibility and control mean that DG has not traditionally contributed towards maintaining the stability of the system in the same way that larger transmission system connected generating units do. This is mainly attributed to DGs not being required to remain connected to the system during disturbances. Loss of mains (LoM) protection is designed to disconnect DG and prevent unintentional islanded operation on the distribution network.

The two original schemes and settings used in GB are based on the static sensing of RoCoF being > 0.125 Hz/s, or a voltage angle deviation of 6 degrees under Vector Shift (VS). In a low inertia system, protection devices with these settings are overly sensitive and can undesirably trip DG off the system in response to faults on the transmission network, even when the original fault is cleared, contributing further to the power imbalance and worsening the effects of the original disturbance [4].

Updates in 2017 to the Engineering Recommendation G59/3-3, which is the DG connection standard in GB, stipulated that VS was banned and old RoCoF settings were not permitted on new or existing plant [34]. Since April 2019 the new G99 connection standard requires DG to have RoCoF protection settings of 1 Hz/s with a time delay of 0.5 s [35].

Regardless of these technical code mandates, DG owners have been slow to change protection settings and changes proved difficult to enforce [63]. The risk of disconnecting large volumes of DG remains the dominant factor throughout 2020 when managing system inertia [24]. NGENSO must either procure more frequency containment reserve from ancillary service markets or must constrain down the largest single infeed to comply with the SQSS and maintain system security. This operational action will become increasingly expensive until the 'Accelerated LoM change programme' is completed to retroactively update DG protection settings [64]. However, as of December 2020, the reduction in the RoCoF LoM protection risk was not yet enough to reduce the operational costs [24].

4.3 | Low frequency demand disconnection

During extreme contingencies, that is, those that are more severe than normal design contingencies, the scheduled frequency response holding may be insufficient to cover demand, causing frequency to fall outside of operational limits. To prevent reaching underfrequency protection limits of generating equipment and collapse of system frequency, in many countries an under-frequency load shedding (UFLS) scheme is in place to automatically disconnect blocks of demand with the aim of restoring system frequency and allowing a new equilibrium to be reached. In GB, UFLS is known as Low Frequency Demand Disconnection (LFDD). As DG penetration increases and demand is increasingly met locally, the effectiveness of the LFDD scheme is challenged, and its level of success becomes

dependent on the demand and generation mix downstream of each relay at the time of operation. Without visibility of DG, uncertainty is introduced into the amount of true demand on the system at any given time and, therefore, the net effect of automatic load shedding on system frequency when activated is uncertain. Studies have shown that the LFDD scheme in GB can be less effective with low system inertia and with a high penetration of DG, including at today's levels of installed DG capacity [65], [66]. Therefore, the settings of the LFDD scheme require further review in order to retain its effectiveness such that it can be relied upon in a wide range of system operating conditions.

Theoretical novel approaches for LFDD schemes have been proposed in the literature which use additional information and measurements to compute the required load shedding and provide an adaptive approach to account for changing system conditions. However, many of them require an improved measurement and communication infrastructure in the distribution network [67, 68], and there are many practical risks and barriers that accompany a complete re-design of a scheme that demands a high dependability. In [66], shorter-term solutions are evaluated. These include relocating relays to lower voltage levels, i.e. closer to the bulk of demand, and reducing the time delay between LFDD stages. These are argued to be more readily available solutions and show potential improvements relative to the present-day scheme. Similar potential solutions are also being investigated by NGENSO [69].

4.4 | Reflections on the August 9th 2019 GB disturbance

A single lightning strike to an overhead transmission line on August 9th 2019 led to the combined loss of two large generators, Hornsea offshore wind farm and Little Barford gas plant, as well as a significant loss of DG due to the operation of VS, RoCoF or internal protection against under frequency. The total loss of power infeed from DG is estimated between 1300 to 1500 MW across the event. This can be compared to a total transmission connected generation loss of 1378 MW. Over the course of the event, frequency response and reserve holdings became exhausted, and the system frequency dropped to 48.8 Hz, triggering the first stage of LFDD, and cutting supplies to 1.15 million customers [63].

The significant amount of DG that was lost during the August 9th event had substantial ramifications, by both contributing towards the loss of infeed, and reducing the net effect of the LFDD scheme. It is reported that 892 MW of demand was disconnected by stage 1 LFDD relays, yet the net demand reduction seen by the transmission system was reported to be 350 MW [63]. This indicates that approximately 550 MW of DG was disconnected by LFDD relay operation. Analysis of the event in [70] showed that if the VS LoM protection had been removed from the system, preventing the loss of 150 MW of DG at the beginning of the event, the system frequency and RoCoF would have remained above the thresholds for the operation of LFDD and RoCoF protection settings, respectively.

In addition, another scenario in [70] shows that had all of the expected net demand been disconnected by the first stage of LFDD relays, the frequency would have quickly recovered to within operational limits, saving numerous instructions by the system operator for generators to increase their output. Following the August 9th event, the GB regulator recommended that a fundamental review of the LFDD scheme is needed taking account the impact of DG [63].

The event reveals some key questions regarding how the GB system is operated and the uncertainties with high penetrations of DG including:

- How much DG really tripped from the system, and why? The amounts of DG lost, for which reasons and at which locations during the event are based on estimates by the DNOs. This is largely because, many years after significant volumes of DG started to be connected, the DNOs lack detailed monitoring of it. In their report on the event, Ofgem made the following statement regarding lessons learnt for DNOs: “The DNOs lack of consistent and complete information on the operational characteristics and performance of distributed generators in response to the network fault, demonstrates the scale of the visibility issue surrounding distributed generation. Significant improvements are required in the data availability, adequacy and communication between the DNOs and the ESO to support management of system operation. DNOs must have a much more detailed understanding of their networks in order to more actively manage them as they transition towards becoming DSOs.” [63].
- Is the “accelerated” programme to change LoM protection on DG accelerated enough? And will it sufficiently remove the concern of DG tripping off the system unexpectedly?
- How much frequency response should be held, and how should variable DG be treated when considering response holdings?

4.5 | Effects of DG on short circuit level

The short circuit level at any given point in the power system is the amount of current that would flow if there was a short circuit fault at that point. SCL depends on the impedance between the fault and sources of fault current, which includes passive elements in the network, for example, lines and transformers, as well as the capability and behaviour of sources which feed current into a fault, for example, generators and motors. During network faults, synchronous and induction machines behave as a voltage source behind an impedance and provide a high asymmetrical fault current which decays over the transient period of the fault [71]. The main sources of fault currents in the transmission network are large synchronous generators, their response is instantaneous, proportionate, and continuous and they can provide a short circuit current in the region of 6–7 times their nominal rating [72].

In contrast with synchronous generators, the fault response of most converter interfaced devices used in modern power

systems is driven by their control systems and the control strategies in place to interface with the grid. Voltage source converters (VSC) are commonly used and are capable of quickly controlling the active and reactive current that is exchanged with the grid. However, these currents must remain within the limited short-term rated capability of the power electronic switches. Depending on the type of converter, fault current contributions are in the range of up to 2 or 3 per unit in the first 1 to 2 cycles and between 1 to 1.5 per unit thereafter [73, 74]. But, in general, it is assumed that the current limiting function is very close to the rating of the converter.

4.5.1 | Short circuit levels in the distribution networks

For DG, in the previous G59 connection code [34] under-voltage protection settings were designed to detect a genuine fault on the distribution network and then disconnect. However, no dynamic fault ride through was required from the DG plant. In order to support the transmission system during faults, the newer G99 connection code [35] defines fast fault current injection requirements for DG, where operation is not required beyond 1 per unit of rated current.

In the distribution networks, the significant amounts of DG that have been added have created an increasing trend of SCL, where the main challenge is limiting the maximum fault current to within the rating of the DNOs' switchgear. Exceeding these ratings becomes a health and safety and network security risk. Even though CIGs have a relatively low fault current contribution compared with synchronous generators, new connection applications in the distribution network often trigger the need to reinforce the DNO switchgear, especially at locations that already have electrically close synchronous generation, for example, waste to power or CHP plant, or relatively low impedance connections to a part of the transmission network that has high SCL. This can add high costs to connection works and has become a major constraint to new DG connections in many areas in GB [75].

Determining the contribution from a DG connection to the SCL is typically done via desktop studies using industry standards IEC60909 [76] or ER G74 [77]. These standards assume static worst-case conditions and, in reality, the switchgear will spend a significant amount of time at well below its rating during normal operation. Active fault level monitoring has been explored by some of the GB DNOs to release capacity for new connections and actively manage the network [78, 79], with one DNO proposing to implement this technology into business as usual in the next price control period from 2023 to 2028 [75]. The fault level monitors will need to communicate in real-time to the network operator or an automated system to take an action to reduce fault level, for example, through network reconfiguration. Any actions taken will need to be consistent with those taken for other reasons such as congestion management, voltage control and provision of frequency containment reserve.

4.5.2 | Short Circuit Levels in the transmission networks

In contrast to the main concern on distribution networks, SCL is reducing significantly on many parts of the transmission network in GB with the displacement of large synchronous generation by CIG in both T & D networks, See Figure 4. This reduction in the available SCL in the transmission system can introduce a broad set of operational challenges which impact the resilience of the system to network faults, including increasing the severity of a voltage depression close to a fault on the transmission network and compromised performance of protection systems [80, 81].

Due to the increase in DG, the contribution from the distribution system to the transmission system SCL is generally increasing. However, this contribution is limited by the high impedance of the grid transformers [72], and remedial actions for increasing transmission system SCL are generally expected to be most effective at transmission voltages [82]. Furthermore, the amount of any contribution from DG also depends on the nature of the DG and how it is controlled. The authors note that the vast majority of DG in the system currently will have been designed according to the earlier G59 requirements and, therefore, any contribution from DG is difficult to predict and will be subject to whatever the default control system settings are for the individual converter manufacturer at the time of installation. Hence, any contribution from DG should not be considered reliable when assessing minimum SCL.

5 | CONCLUSIONS

This paper has discussed challenges associated with the development and operation of distributed generation (DG), using Great Britain (GB) as a case study. It has reviewed the amounts and types of DG that are installed in GB. This analysis highlights that there can be considerable discrepancies between the available DG data records and that there has been a lack of availability and transparency of consistent data for DG installations. This lack of data has been argued to act as an obstacle to the development of a more active distribution network and planning and operating a well-coordinated whole electricity system.

The development of DG is a market-led response to government-initiated incentives and reductions in the cost of key technologies, notably wind and solar generation. It promises a location of generation that is closer to demand and the potential for many more actors to provide 'flexibility services' such as the ability to change output to help in management of power flows or to provide frequency containment reserve. While relevant market platforms are now being opened up to service providers that have capacities of less 100 MW, further action is needed to address barriers such as limits to the 'stacking' of revenues.

Inadequate management of the operation of DG represents both a threat to the system and the missing of an opportunity to use the services that DG might provide. High volumes of DG which are neither observable nor controllable add a significant amount of uncertainty to operational procedures, the operation of protection and the effectiveness of automatic defence mechanisms such as under-frequency load shedding, thus reducing the resilience of the system. Services such as active network management procured by a distribution network operator and frequency containment reserve procured separately by a transmission system operator have already been seen to come into conflict in some instances.

Many of the solutions that are required to address these challenges demand improvements in the visibility and control of DG, and in coordination between transmission (T) and distribution (D) network operators. Failure to achieve better coordination not only between T&D but between arrangements for the procurement of different services will severely limit realisation of the potential for flexibility from distributed energy resources (DERs) and prevent the release of capacity for more DERs to be connected.

The task to coordinate T&D networks requires a substantial effort and new technical, market and regulatory frameworks are required. The urgency of this is highlighted by the very low levels of net demand seen from the transmission system and the associated operational problems during the COVID-related societal lockdown in 2020, a major system disturbance in GB in August 2019, and the need for accelerated decarbonisation of the whole energy system, not just electricity production.

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DATA AVAILABILITY STATEMENT

Data can be shared upon reasonable request.

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