Challenges in the Electricity Market: 2025–2050

REACHING NET ZERO CARBON IN GREAT BRITAIN

GE VERNOVA

EXECUTIVE SUMMARY

The Great Britain (GB) electricity grid is in a state of transition. The 2008 UK Climate Change Act sets a legally binding commitment to ensure the UK reduces its greenhouse gas emissions by 100% from 1990 levels by 2050 with the electricity industry obligated to meet this target by 2035. This commitment is known as the **'net zero target'.**

In order to meet this ambitious challenge, it is essential that GB enables and accelerates significant investment in all types of lower carbon generation and the grid infrastructure during this decade. Furthermore, policies and regulations must ensure that the electricity markets and remuneration mechanisms deliver the necessary signals to incentivise investment 'when and where' needed.

The power system of the future will be complex and multifaceted which requires action focused analysis for informing decision makers to avoid risk of missing the net zero target. GE Vernova has explored alternative generation and transmission investment pathways considering the economic build out of renewables, nuclear, storage and lower carbon thermal generation across GB. This quantifies the cost and impact to the system of ensuring energy security, while respecting the physical constraints of the grid on a 'zonal' basis that recognises the potential locations of electricity generation resources. It is evident by the required significant power system expansion that urgent action is needed to meet the 2050 net zero target thus avoiding regret of no or delayed actions.

With the expectation that electric demand will double by 2050, including electrification of heating, transportation, and industry to meet the UK decarbonisation goals, our analysis shows that an additional 250GW of renewable and decarbonised generation—approximately 2.5 times that of existing capacity—will need to be added to the system.

- 70GW to 100GW of offshore wind is expected to be built with a significant portion in Scotland
- 70GW of solar, mainly in the southern regions of Great Britain
- 60GW of battery energy storage systems (BESS) around the grid
- Up to 27GW of combined cycle gas turbines (CCGTs) with carbon capture and storage (CCS) and 23GW of Hydrogen-capable open cycle gas turbines (OCGTs)
- 10GW to 30GW of onshore wind in addition to the repowering of existing sites
- 10GW to 18GW of new nuclear capacity

Nuclear and gas power will continue to play an important role, as they provide essential reliability services, help manage grid congestion and can be located relatively closer to the demand centres.

In order to deliver the renewable and decarbonised electricity across GB, significant upgrade of grid infrastructure and operations will be required over and above that already outlined out to 2040 by National Grid Electricity System Operator's (ESO).[1] In total, up to 22GW of additional transmission line capacity across the Scottish boundaries and up to 57GW in the English boundaries is required to alleviate congestion and significantly reduces curtailment of renewable electricity while saving system costs of circa £80bn by 2050. About 30% to 50% of available wind energy in Scotland is at risk to be curtailed by 2050 without further investment in the network such as new transmission lines and equipment, increased grid management and controls, and flexible demand (including electrolysers) and energy storage.

The quantum of required growth in the GB power system infrastructure and lead times of deployment of these technologies (e.g., 6–10 years for nuclear, 4–6 years for CCGTs, and 5–15 years for transmission links) demand concrete actions to be taken as early as possible during this decade to establish GB's ability towards efficient delivery of its 2050 net zero target.

Our analysis reveals that there is no silver bullet that will fast forward the GB electricity system to 2050 and deliver the net zero target. We believe a combination of various electricity generation, transmission and system control/management technologies with underlying supportive policy and regulatory measures coupled with reformed markets will be essential. Therefore, our key recommendations are:

- **Enable and accelerate investments** at the required scale and pace in all lower carbon generation technologies (renewables, nuclear, carbon capture and storage and hydrogen) and grid solutions with enhanced digitalization of the energy system including facilitation of active participation by consumers. We estimate that over £50bn investment is required in generation and storage capacity alone by 2030.
- **Expedite the implementation of market reforms** that are technology agnostic, remunerate all system services (energy, capacity, flexibility and stability) and provide adequate signals for investment in generation and grid assets 'when and where' needed.
- **Adapt energy policy and regulation** that bring clarity to the uptake of lower carbon generation (in particular for SMR, CCS and Hydrogen) as well as grid technologies. These should ensure:
  - Rapid permitting and deployment of required flexible resource (circ. 10GW of storage and gas with hydrogen readiness) necessary to integrate over 30GW of new wind and solar capacity by 2030 to ensure system security.
  - Build out and commitment of over 100GW of new generation capacity by 2030.
  - Step up the required grid reinforcement (transmission lines and operational solutions) that is compulsory for the delivery of lower carbon energy to consumers.

Overall, it is essential that the United Kingdom makes tangible progress within the next 1–3 years regarding the above recommendations to mitigate the risk of falling short of achieving a net zero 2035 power system and the 2050 net zero target.

INTRODUCTION

THE GREAT BRITAIN (GB) ELECTRICITY GRID IS IN A STATE OF TRANSITION. The 2008 UK Climate Change Act sets a legally binding commitment to ensure the UK reduces its greenhouse gas emissions by 100% from 1990 levels by 2050 with the electricity industry obligated to meet this target by 2035. This commitment has become known as the 'net zero target'. To meet this target the act specifies that legally binding five-year 'carbon budgets' must be set, at least 12 years in advance, to act as steps towards the 2050 target. To date, six carbon budgets have been set which limit emissions across all sectors to 78% of 1990 levels by 2037.

It is essential that GB make vital progress this decade to enable and accelerate significant investment in renewable and decarbonised generation and the grid networks to meet this ambitious challenge. Policies are needed to ensure the power market and remuneration mechanisms deliver the necessary signals to incentivise investment when and where required. Much of this new generation capacity will be restricted to specific locations on the network, for example wind and solar will be concentrated in areas with both suitable resources and geographies while new thermal generation likely will be located near carbon capture utilisation and storage (CCUS) and hydrogen fuel hubs, and new nuclear plants will predominantly be sited on existing (operating and decommissioned) nuclear sites. This means that the available transmission network capacity will play a driving role in shaping the least cost and timely pathway for the UK meeting the net zero targets.

In this study, GE Vernova evaluates different generation and transmission investment pathways that can help realise this net zero target, including different scenarios on the build out of wind, solar, nuclear, batteries and lower carbon thermal generation across GB. While other technologies can play a significant role, such as other renewables, demand side resources and management programs, grid digitalisation and controls, high voltage DC (HVDC) transmission and flexible AC transmission devices (FACTS), they are not specifically examined in this study. Further, this economic dispatch analysis represents the options of the power plant expansion in GB that can be actioned now and longer-term by 2050 and does not consider the impact of all recent and envisioned energy security policies and government incentive programs that will be topics for further work by GE Vernova.

Importantly, and due to the locational aspects of some technologies and presence of large demand centres, this study aims to quantify the cost and impact to the system on a 'zonal' basis. This zonal modelling captures the locational aspects to deliver net zero, either by determining new investment due to limitations to evacuate the power via the transmission grid or through curtailment of generation. A key challenge to the system will be how to incentivise transmission upgrades and other alternative solutions to avoid curtailment and ensure necessary investment in lower carbon generation. Based on modelled projections on the variation of prices across the studied zones under the different scenarios, we conclude on how zonal price signals are an efficient way to incentivise required transmission reinforcements and upgrades necessary to deliver net zero. For the purposes of this study, we have only considered the transmission system in GB and have excluded the generation and transmission system located in Northern Ireland.

METHODOLOGY + ANALYSIS

The objective of the study is to explore credible least cost pathways of future generation and transmission investment in GB that would be required if the UK is to urgently meet the decarbonisation goal. Secondly, it serves to illustrate how power plants under each pathway would operate to meet demand in the future and the implication on the system as a whole, in particular in relation to the transmission network.

The analysis has been carried out with a zonal model of the GB electricity market developed in PLEXOS.[2] The model captures all existing power plant on the GB system along with a simplified representation of the interconnection with neighbouring countries, including the lines under construction to Denmark and Ireland, refer Figure 1. Future potential inter-connectors, not yet under construction, have been excluded from this study.

The model can be utilised as both a long-term planning tool in which investment decisions over a long horizon can be examined, as well as a dispatch model where the simulation of the electricity market in hourly, or sub-hourly, periods can be undertaken to understand how the market would operate under different future scenarios especially considering the increase in variable generation affected by uncertain weather patterns.

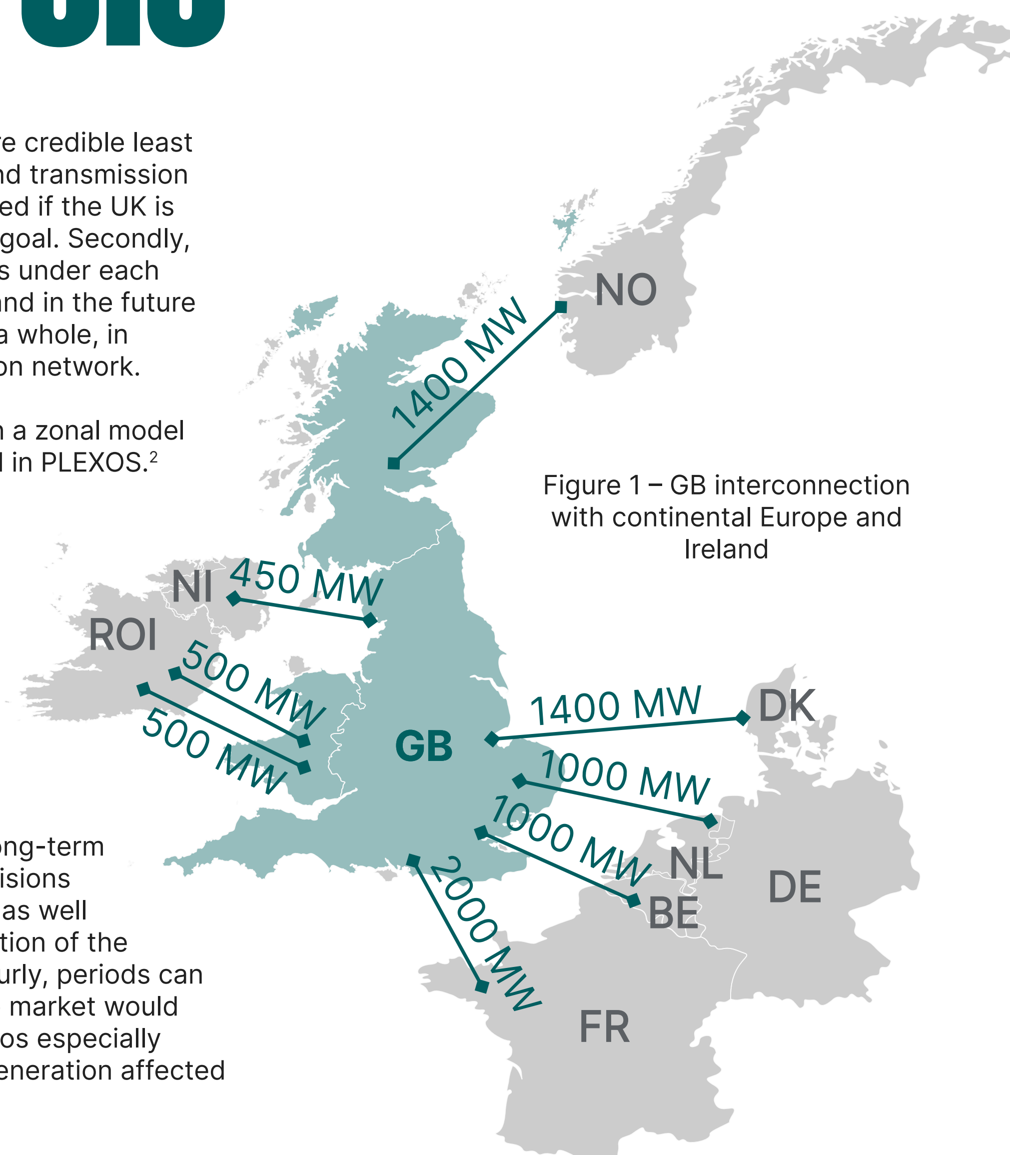

Figure 1 – GB interconnection with continental Europe and Ireland

KEY ASSUMPTIONS

GREAT BRITAIN CARBON TARGETS

The constraint on annual CO_2 emissions from electricity generation over the 2025–2050 time frame in GB have been assumed to be in line with the analysis undertaken by the UK Committee on Climate Change (CCC) in support of the setting of the five-year carbon budgets. Each carbon budget sets the pathway to net zero emissions for the UK across all sectors as well as a pathway for each individual sector. The 5th Carbon Budget[3] sets the pathway from 2028 to 2032, beyond which CO_2 limits set by the 6th Carbon Budget[4] are used from 2033–2037. From 2038 onwards, the carbon intensity of the UK CCC Balanced Net Zero Pathway[5] is followed, which was published alongside the 6th Carbon Budget. The UK targets for GB are shown in Figure 2.

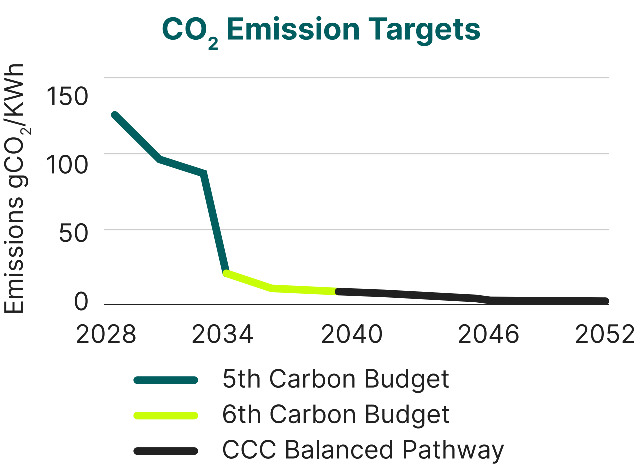

Figure 2 – Modelled CO_2 emission targets for electricity generation for GB

GREAT BRITAIN ELECTRICITY TRANSMISSION ZONES

The current wholesale electricity market in GB operates as a single price zone whereby market participants can trade power up to an hour ahead of real time on the day-ahead market. Transmission constraints and deviations from the traded day-ahead generation and demand, are resolved by National Grid ESO though the balancing market (intraday dispatch) and the costs passed onto all generators and demand on the system. One of the contributing differences between day-ahead and intraday dispatch is the amount of renewables generation variability. As the level of renewables on the system increases, this level of variability also increases due to variations in wind and solar availability.

However, to meet the decarbonisation targets will require a significant level of new renewable and decarbonised generation capacity to be connected to the system and this will similarly require investment in the transmission network otherwise raising the risk of significant curtailment of generation at specific locations particularly during periods of high renewable generation.

To understand the implications to the network, GB is modelled as a zonal market, as opposed to a single zone market. Market participants can freely trade electricity within each zone but trades between zones must comply with transmission constraints between the zones. Under this market model, each zone will have a separate market price which reflects the congestion between zones and provides a signal to where network investment is required. The transmission system in GB has a number of transmission interface limits that effectively divide it into multiple power zones. For this analysis, 17 power zones are assumed, as shown in Figure 3. The future transmission reinforcement assumptions were taken from National Grid ESO Network Options Assessment 2021/2022 optimal path[6] which uses 2021 Future Energy Scenarios (FES) and Electricity Ten Year Statement ETYS[7] data as inputs. These reinforcement plans result in phased upgrades to the transfer capacity between zones between now and 2040. For this analysis, we do not assume any further upgrades beyond 2040 but instead we evaluate where further upgrades could be beneficial to the system.

ELECTRICITY DEMAND

The electricity demand in GB is assumed to align with the Climate Change Committee's (CCC) Balanced Net Zero Pathway demand forecast for GB. This outlook is consistent with the UK meeting the 2050 decarbonisation goal, and as such, include demand related to the electrification of transport, heating, and industry. As a result, demand doubles from about 300TWh in 2025 to 600TWh in 2050.

For the purposes of this study, we have not explicitly modelled demand response but accept that this will play a role in potentially reducing or rescheduling controllable demand at times of system stress. Distributed energy resources, such as rooftop solar, batteries, electric vehicle-to-grid and smart appliances also require a bi-directional and highly digitalised distribution grid, and is a topic of further study by GE Vernova.

Investment in the transmission network is required otherwise raising the risk of significant curtailment of generation at specific locations in GB particularly during periods of high renewable generation.

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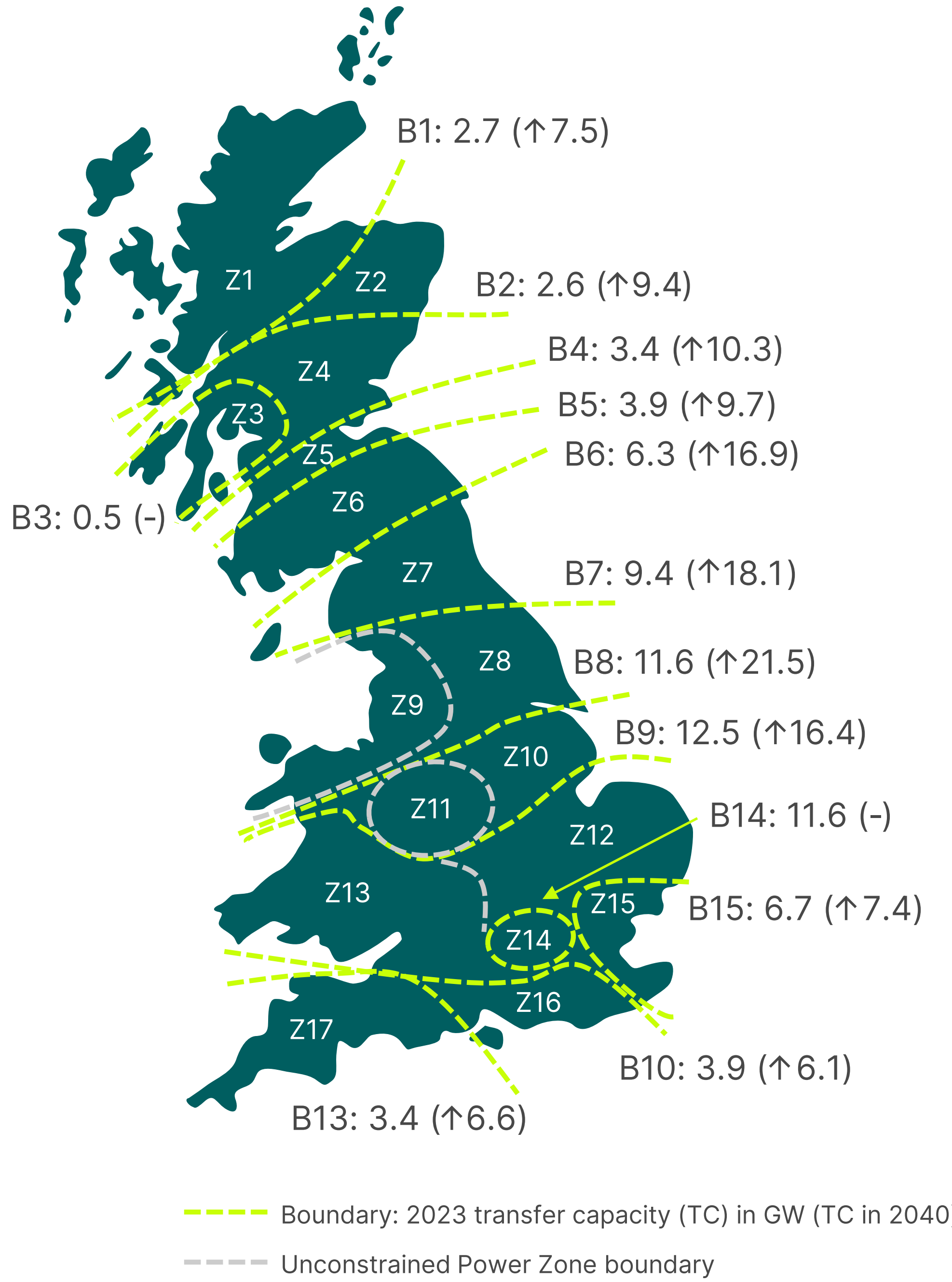


Figure 3 – GB's power zones and transmission limits

RENEWABLE GENERATION PROFILES

Renewable generation will play a key role in the decarbonisation of the power sector of GB, and it is important to capture differences in its potential output profiles between different power zones. Therefore, for the new wind and solar farms, hourly generation profiles were calculated utilising the European Centre for Medium-Range Weather Forecasts' (ECMWF) Reanalysis v5 (ERA5) dataset.[8] This dataset was used to obtain information on wind velocity and solar irradiation across GB, which was used along with wind turbine and photovoltaic (PV) panel configurations to calculate power generation data for each individual power zone. Capacity factor maps for wind and solar PV are shown in Figure 4.

LOWER CARBON TECHNOLOGIES

Delivering the decarbonisation goals will require significant investment in new lower carbon technologies across GB. The first phase of the modelling is to determine the least cost investment pathway over the period 2025 to 2050. The low carbon generation currently under construction or planned is also included, such as Dogger Bank offshore wind, the Eggborough combined cycle gas turbine (CCGT) plant and the open cycle gas turbines (OCGTs) recently awarded capacity contracts.

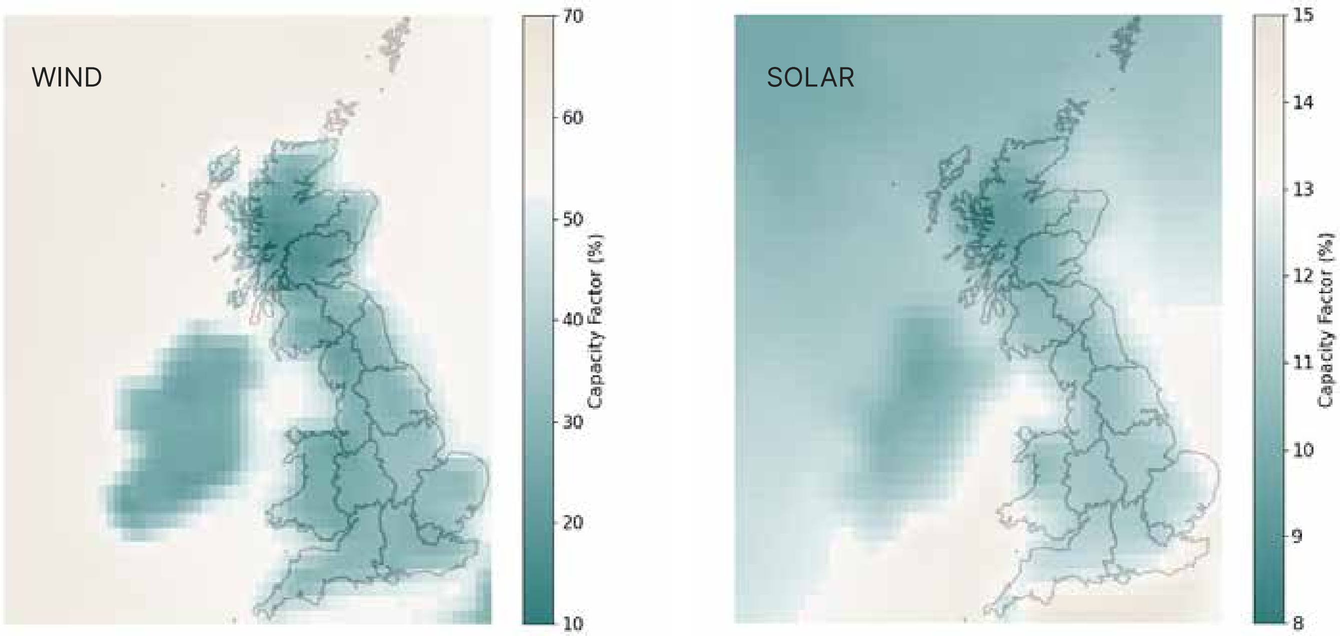


Figure 4 – Capacity factors for wind and solar PV generators in GB

Beyond 2028, the four 1,600MW nuclear units at Hinkley Point and Sizewell C are assumed to be built but all other new generation plant additions will be based on least cost economics and an assumption on a realistic level of build rate. The candidates considered are:

New Capacity Candidates

	Size (MW)	Max MW built per year
CCGT with CCS	800	1,600
OCGT (H_2 ready)	300	900
Onshore Wind	50	2,100
Offshore Wind	100	11,000
Solar	100	4,000
Battery (4 hr storage)	100	2,500
Nuclear SMR	300	600

The model also allows carbon capture and storage (CCS) to be retrofitted to newer CCGT plants as well as to the Drax biomass plant. Recently built OCGTs can also be retrofitted to be capable of operating on hydrogen. We assume CCS will capture 95% of CO_2 emissions and that the combustion of hydrogen is CO_2 free.

For the build cost assumptions for each technology, the Business, Energy & Industrial Strategy (BEIS) 2020 Electricity Generation Costs report[9] was used whenever possible as these should be the most relevant to the UK context. The only exceptions to this are Li-ion battery storage (where we use the BEIS 2016 Generation Costs report[10] because the costs were updated for 2020) and Nuclear small modular nuclear reactor (SMR) (EIA Annual Energy Outlook[11] is used, because BEIS only reports on conventional nuclear). A comparison of the levelised cost of electricity (LCOE) for each technology under the BEIS and EIA assumptions along with the comparable cost from the National Renewable Energy Laboratory (NREL)[12] is shown in Figure 5. The LCOE assumes an economic life of 20 years except for Offshore Wind at 30 years and Nuclear at 60 years and load factors consistent with the modelling results. The cost of CCS includes a component for transport and storage of CO_2.

The economic value of each generator type will be driven by the level of capacity that can be relied upon when the system is at stress, often referred to as the capacity credit of the technology. We assume capacity credits for dispatchable generators will be close to the full capacity but for non-dispatchable generators the credits were set to be the equivalent of the current derating factors National Grid ESO use in their reliability calculations but are modelled to evolve as the timing of system stress events changes.

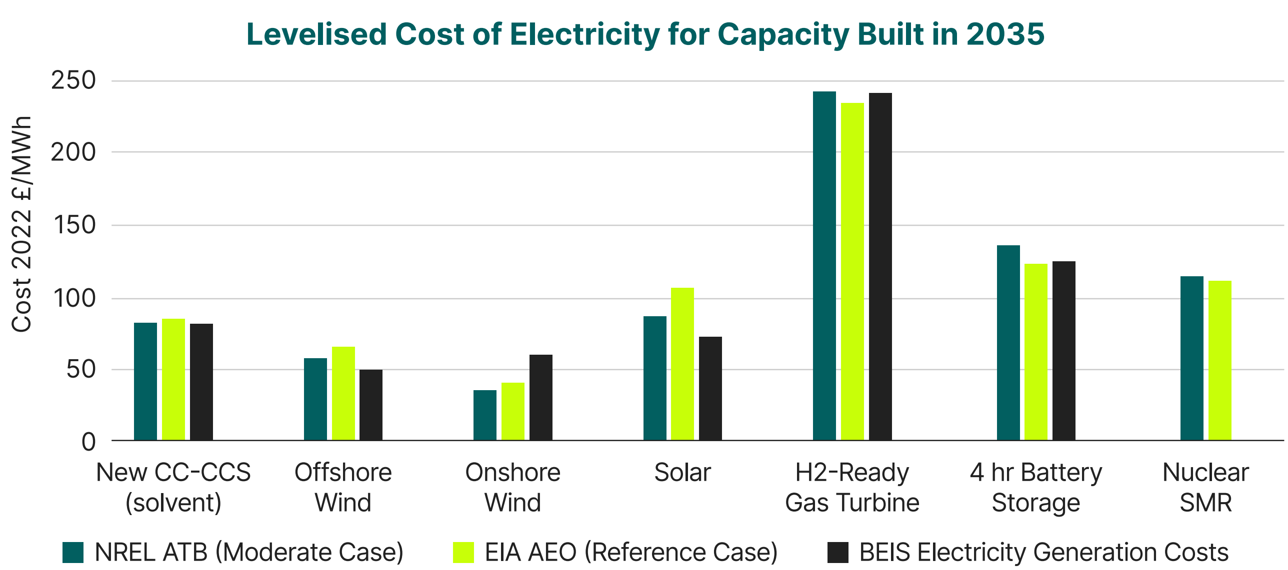


Figure 5 – LCOE comparison

SCENARIOS

We have considered three scenarios on capacity build out to meet the net zero decarbonisation targets:

1. **BASE CASE**
2. **NUCLEAR SMR SENSITIVITY**
3. **HIGH WIND SENSITIVITY**

The Base case represents GE Vernova's modelling of the least cost pathway to deliver the net zero emissions requirements by 2050 given the assumptions on electricity demand, retirement of existing plant, technology costs and build locational limitations presented earlier. The two sensitivities consider the impact of increased nuclear SMR build out and increased wind build out.

CAPACITY BUILD PLAN

The total installed capacity under the Base case pathway will increase from around 100GW in 2024 to 344GW by 2050 to meet both the increasing demand and CO_2 emission targets.

The Base case includes a build out of 27GW of CCGT with CCS capacity providing baseload power along with an additional 23GW of hydrogen-capable OCGT peaking plant.

For the economic component of the nuclear build-out, we modelled the build out of Small Modular Reactors (SMRs) from 2036 onwards and the total capacity of all new nuclear technology under the Base case is 10GW, which is in line with the balanced growth scenario projected by the Committee on Climate Change. The UK government published an Energy Security Strategy[13] in 2022 which outlined an ambition of 24GW of nuclear by 2050, which would involve a mix of European Pressurised Reactor (EPR), SMR and life extension to Sizewell B. In line with this ambition, the Nuclear SMR sensitivity captures a scenario with further incentives encouraging a higher level of nuclear SMR capacity from 2029 onwards, with 12GW of nuclear SMR built over the period 2029–2050, at almost three units built per year, compared with the total SMR build-out of 3.6GW in the Base case but does not include any further EPR after Sizewell C, resulting in a total of 18GW of new nuclear capacity which is approximately the midpoint between the Base case and ambition. To compensate less CCGT with CCS capacity is built. GE Vernova plans further work to explore additional nuclear scenarios.

The total level of offshore wind on the system under the Base case is projected to be 93GW by 2050. This is in line with the Balanced Growth scenario presented under the Future Offshore Wind Scenarios project[14] and used by the Committee on Climate Change in their Balanced Pathway scenario. In this report a High Ambition scenario of 140GW by 2050 is also defined, as a maximum potential for offshore wind. To understand the impact of increased offshore wind on the transmission system with a total of 117GW of offshore wind on the system by 2050 (set at the midpoint between the Balanced Growth and High Ambition future offshore wind scenarios). This higher level of offshore wind reduces the economic need for baseload CCS but increases the requirement for hydrogen-capable OCGTs.

The evolution of the installed capacity by year is shown in Figure 6 and the total additions over the 2025–2050 horizon by category are shown in Figure 7 (following page).

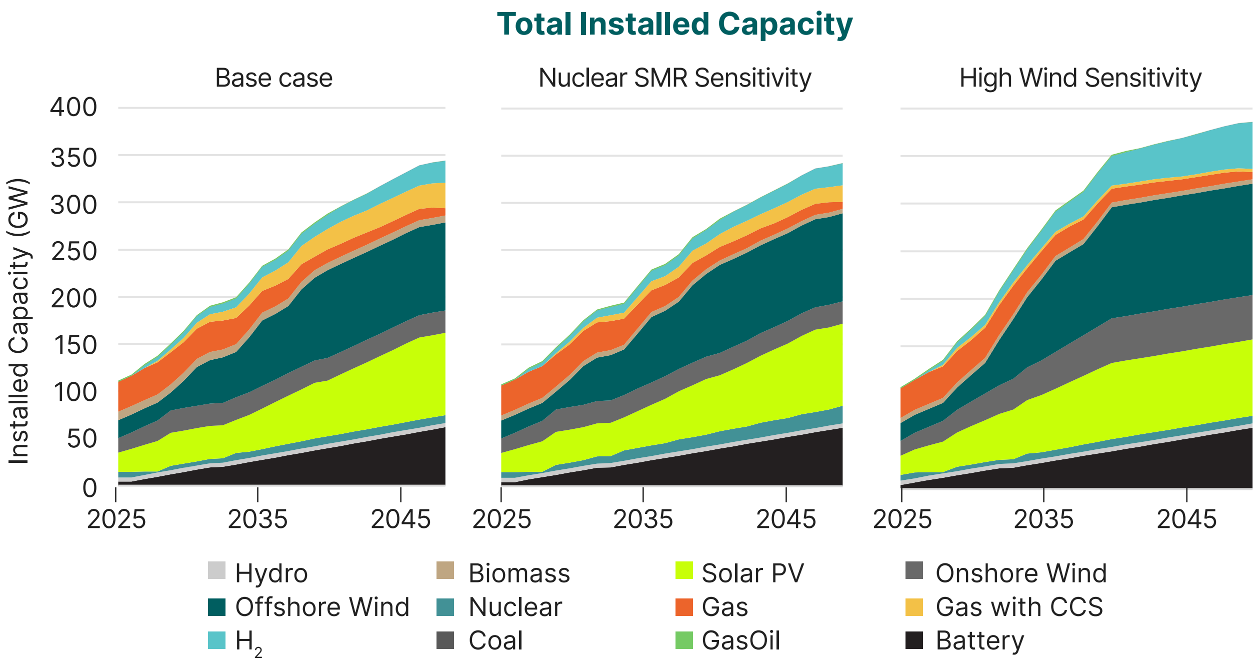


Figure 6 – Total installed capacity in GB under each scenario

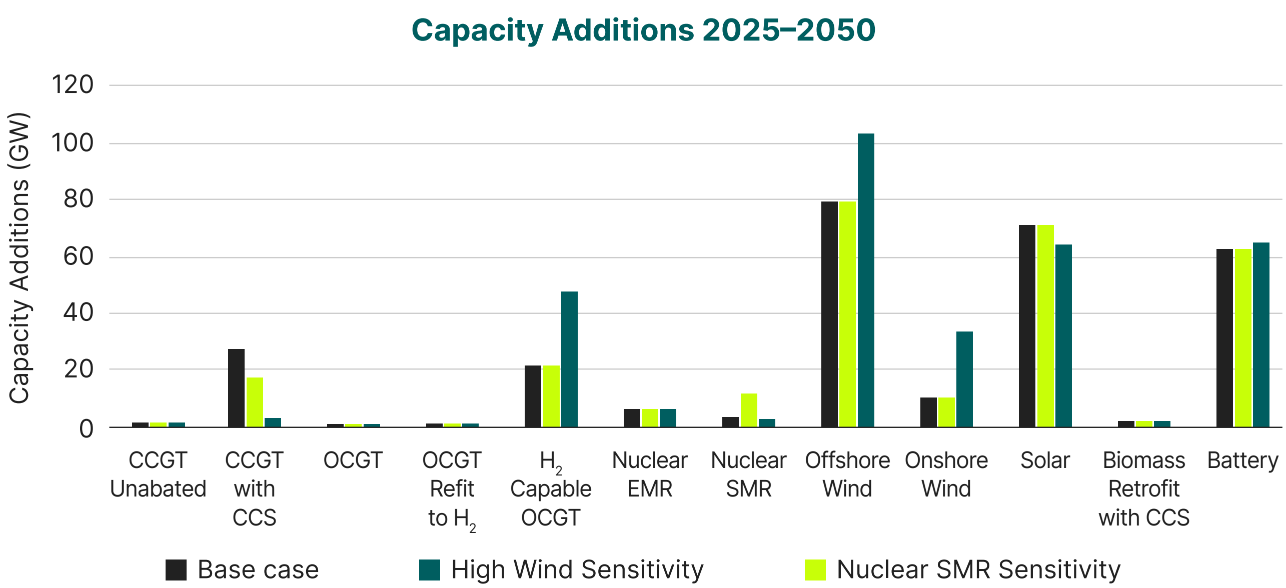


Figure 7 – Capacity additions by technology across each scenario

The new capacity is assigned to the zones based on the following assumptions with regards to where future capacity of each technology would be most likely located.

The only biomass plant that is projected to install CCS is Drax, located in North Yorkshire (power zone 8). However, we note that Drax has paused its planned investment into CCS technology, citing ambiguity of the government's position on this technology.[15] In case the CCS is not installed, and the plant is forced to close, this capacity would need to be replaced with alternative generation technologies.

The analysis suggests that CCGT with CCS is one of the most economical technologies for flexible baseload generation, with 27GW of new CCGTs with CCS located based on where CCS clusters are planned in GB. The East Coast CCS cluster covers power zones 6, 7 and 8, with most promising CCS locations around Teesside and Humber industrial clusters. The HyNet cluster is another potential location for CCS, shortlisted by the government,[16] and is in power zone 9. Further potential for CCS units is in South Wales industrial cluster in power zone 13 and the Southampton industrial cluster in power zone 16. The same geographical distribution was used for new units burning H_2 as it was assumed that they will utilise blue H_2 (produced from Natural Gas via steam reforming with CCS). The analysis also indicated that it is economical to retrofit several of the newer OCGT units to burn H_2. It is also assumed that new OCGTs will locate in the London zone as there is limited alternate lower carbon technologies that can be realistically built in this zone.

A mix of the announced government plans and economic modelling was used to model future nuclear capacity. There will be planned nuclear retirements of Torness in power zone 6, Heysham in power zone 9, and Hartlepool in power zone 7. Sizewell B will be replaced with Sizewell C in power zone 12 in line with the current plans, while Hinkley Point C will be commissioned in power zone 17. For the economic component of the nuclear build-out, the model simulated the build-out of SMRs in power zones 6, 7, 9, 12 and 17 where nuclear units are already installed in GB.

Locations of existing onshore wind and solar PV were used for the distribution of future renewable sites. In the case of onshore wind, the share of wind deployed since 2015 was used. For example, over 60% of the onshore wind installed between 2015 and 2023 was in Scotland. Therefore, over 60% of the future onshore wind sites were allocated to power zones 1–6. In reality, a significant portion of the existing onshore wind fleet will be repowered over this time frame, however we do not explicitly include the repowerings in this build plan but assume the repowered capacity will remain broadly the same as the existing capacity.

For offshore wind, cluster locations identified by the **Future Offshore Wind Scenarios** project within the **Offshore Wind Evidence & Change Programme** was used.[17] The largest of these, is in the North Sea off the Yorkshire coast, corresponding to power zone 8. It was assumed that up to 20GW of offshore wind can be installed in this area with some additional site North of the main cluster, connecting to the grid in power zone 7. In Scotland 25GW of offshore wind sites were leased in 2022[18] and we assume these will come online from 2030 onwards. Further offshore wind will need to be distributed between several other power zones. Projects selected as part of the **Offshore Wind Leasing Round 4**[19] are located off the Lincolnshire coast (corresponding to power zone 10), and off the North Wales coast (corresponding to power zone 9). Crown Estate expects additional floating wind potential in the Celtic Sea (power zones 13 and 17) and north of Scotland (power zone 1). The location of these clusters was used to distribute offshore wind additions between power zones in GB.

A zonal visual representation of capacity additions for each generation type is given in Figure 8 (following page).

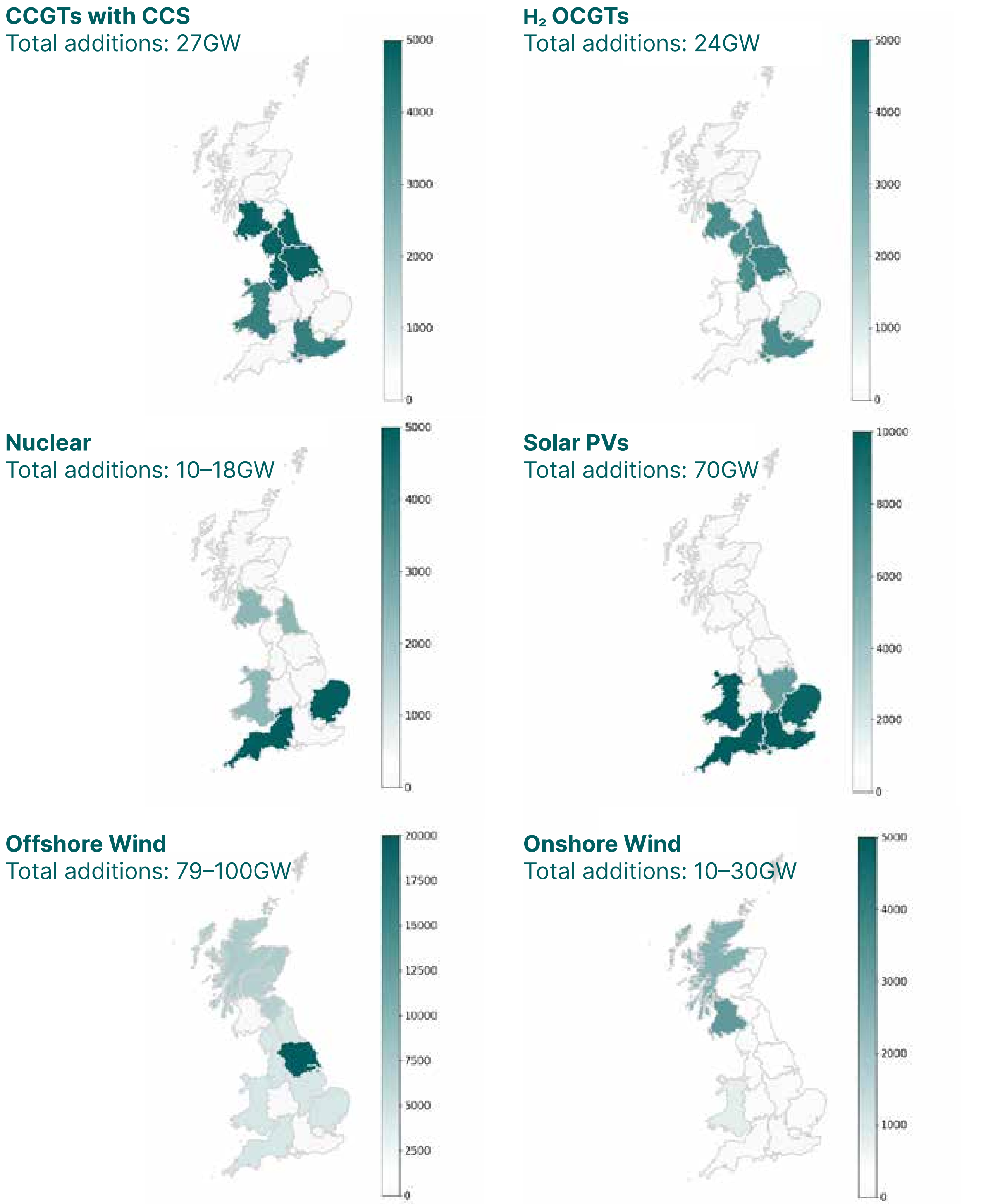


Figure 8 – Geographical distribution of capacity additions (2025–2050) by category under the Base case with ranges reflecting potential additional capacities under sensitivity scenarios

GENERATION

The projected generation under each scenario is shown in Figure 9 and by 2050 over half of the annual generation will be provided by offshore wind due to the significant addition of offshore wind capacity. In the Base case thermal power plants with either CCS or burning hydrogen will provide over 10% of generation, but in later years CCS operation will be curtailed due to emission restrictions and hydrogen usage will increase correspondingly. The remaining generation will be provided through a combination of nuclear, biomass, solar, onshore wind, batteries, and imports. However, onshore wind generation is curtailed post 2030—this is examined further later.

The additional SMR units in the Nuclear SMR sensitivity reduce the reliance on CCGTs with CCS for baseload power, which generate a total of 5TWh in 2050, compared to 14TWh in the Base case. Generation from Hydrogen OCGTs is also partly displaced by additional SMRs, decreasing from 60TWh in 2050 in the Base case, to 45TWh under this sensitivity. It is also projected that GB will import about half as much electricity in 2050 with the increase in SMR capacity. The increase in SMR capacity didn't have a noticeable impact on Wind and Solar curtailment.

The high wind sensitivity results in higher renewable and hydrogen generation with less generation from CCS plants and lower imports. Onshore wind is clearly also curtailed heavily from 2030 onwards, indicating that if meeting the net zero targets is reliant on wind capacity build out then this will require investment in the grid to fully realise the value of this wind generation.

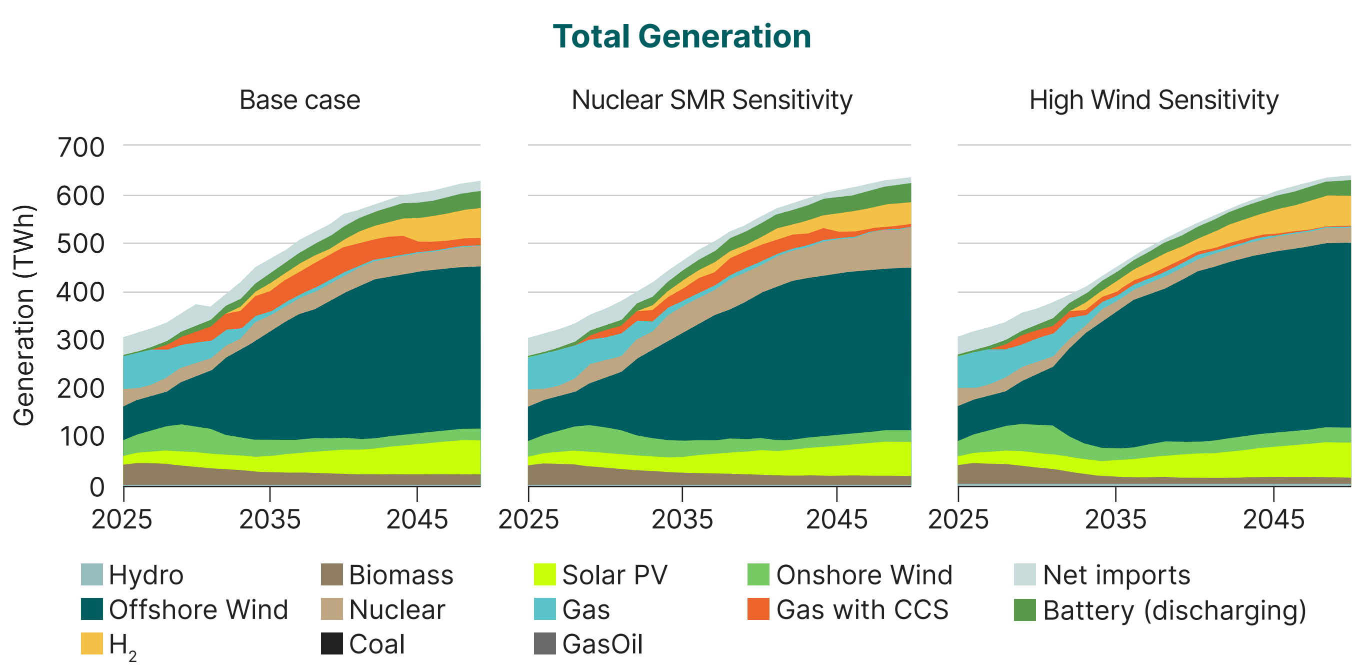


Figure 9 – Total projected generation in GB under each scenario

LOCATIONAL IMPACT

The key purpose of this study was to evaluate how meeting the decarbonisation targets is challenged by transmission constraints across GB and to identify where future investment in transmission upgrades or alternative solutions to manage these constraints may be required.

These transmission constraints will result in generation being curtailed if it exceeds demand within the zone and cannot flow out of the zone to meet demand elsewhere in GB. The increase in generation capacity, in particular offshore wind, on the extremities of the grid will potentially increase the likelihood of curtailment which is reflected in the results shown in Figure 10 (following page). As can be seen, there is currently limited curtailment of generation at a zonal level but by 2040 there is significant curtailment in Scotland and increasing levels of curtailment on the East Coast and in the Southwest as offshore wind is deployed in these regions. The curtailment shown is in TWh and also given as the percentage of available wind and solar energy, given resource availability, that has been curtailed.

The curtailment of generation is highest in Zone 1, driven by the increasing levels of both onshore and offshore wind that is projected to be connected to the grid in this zone. The transfer capability of the grid to export power from this zone is projected to increase from 2.7GW to 7.5GW by 2040. However, even with this additional capacity the wind generation in Zone 1 could be curtailed up to 30% of available capacity by 2050 without further investment.

Energy curtailment is still high in Scotland under the Nuclear SMR scenario, due to the high level of wind as per the Base case. However, a larger nuclear capacity in Cornwall (power zone 17), leads to higher congestion on the boundary limiting power flow from this power zone, refer to Figure 10. The B13 congestion increases to 34% of hours, compared to 24% in the Base case. This boundary is currently limited to 3.4GW with plans by National Grid to increase its capacity to 6.6GW by 2040. Should there be SMR units sited in this power zone, which will also host Hinkley Point C Nuclear unit currently under construction, transmission upgrade plans for this boundary would need to be re-evaluated in line with that presented for the Base case in Figure 11 (following page).

Figure 10 – Curtailment of generation by zone under each scenarios

In the high wind scenario, the curtailment is even higher, reaching 50% from 2040 onwards in parts of Scotland and also reaching 15% in the Southwest. The total annual curtailment for each scenario is shown in Figure 11 and clearly illustrates the significantly increased level of curtailment in the high wind scenario. Should GB wish to harness the upper limits of energy that are considered possible from offshore wind, then grid expansion, system operations strategies and increased demand at nearby locations will be critical to success.

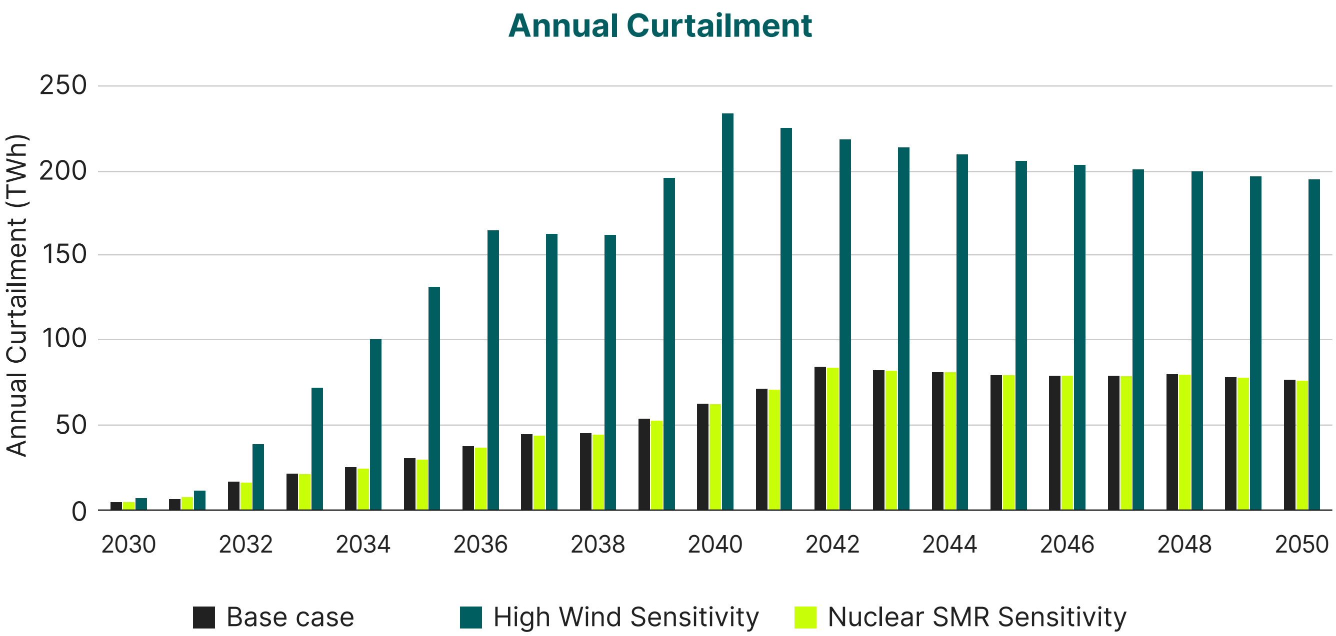


Figure 11 – Annual curtailment under each scenario

If we consider the generation across Zones 1–4 in Scotland for a sample week in 2050, refer to Figure 12, it is clear the congestion of power flowing from Scotland to the south is constrained for a large portion of this week and the wind will be curtailed down to the boundary export limit in those hours where it is in excess of demand in those zones, including BESS load.

A combination of technologies supported by policy and coupled with power market reform are essential. Details on Recommendations page 25

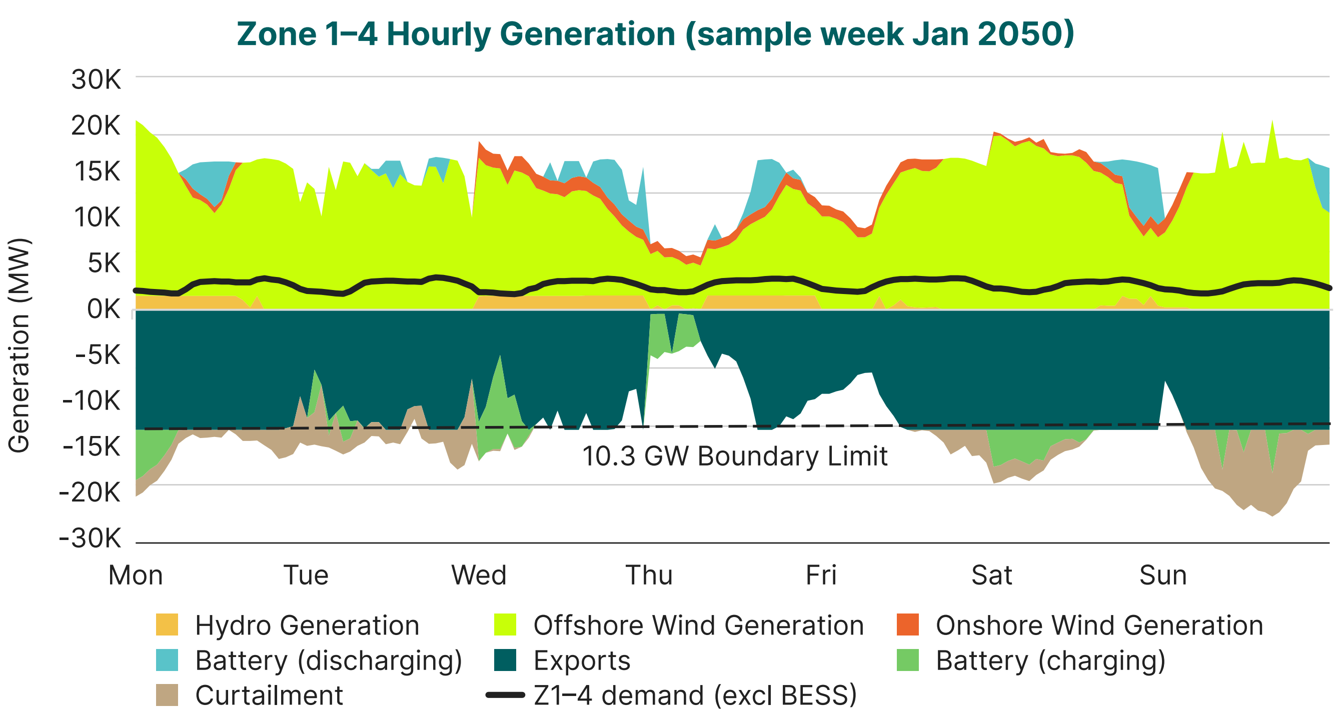


Figure 12 – Generation profile for Zone 1–4 for a sample week

Conversely, while some zones will have curtailment of generation, other zones could have challenges in meeting demand. This is particularly the case for London, where there are limited options for lower carbon generation other than thermal units with CCS or burning hydrogen and batteries. In Figure 13, we present the generation profile for London for a single day in 2050 where the model simulation fails to fully serve load, and where other solutions such as demand response and longer duration storage may be required. The modelling demonstrated that demand response could be required for around 300 hours per year in 2040 to over 600 hours by 2045.

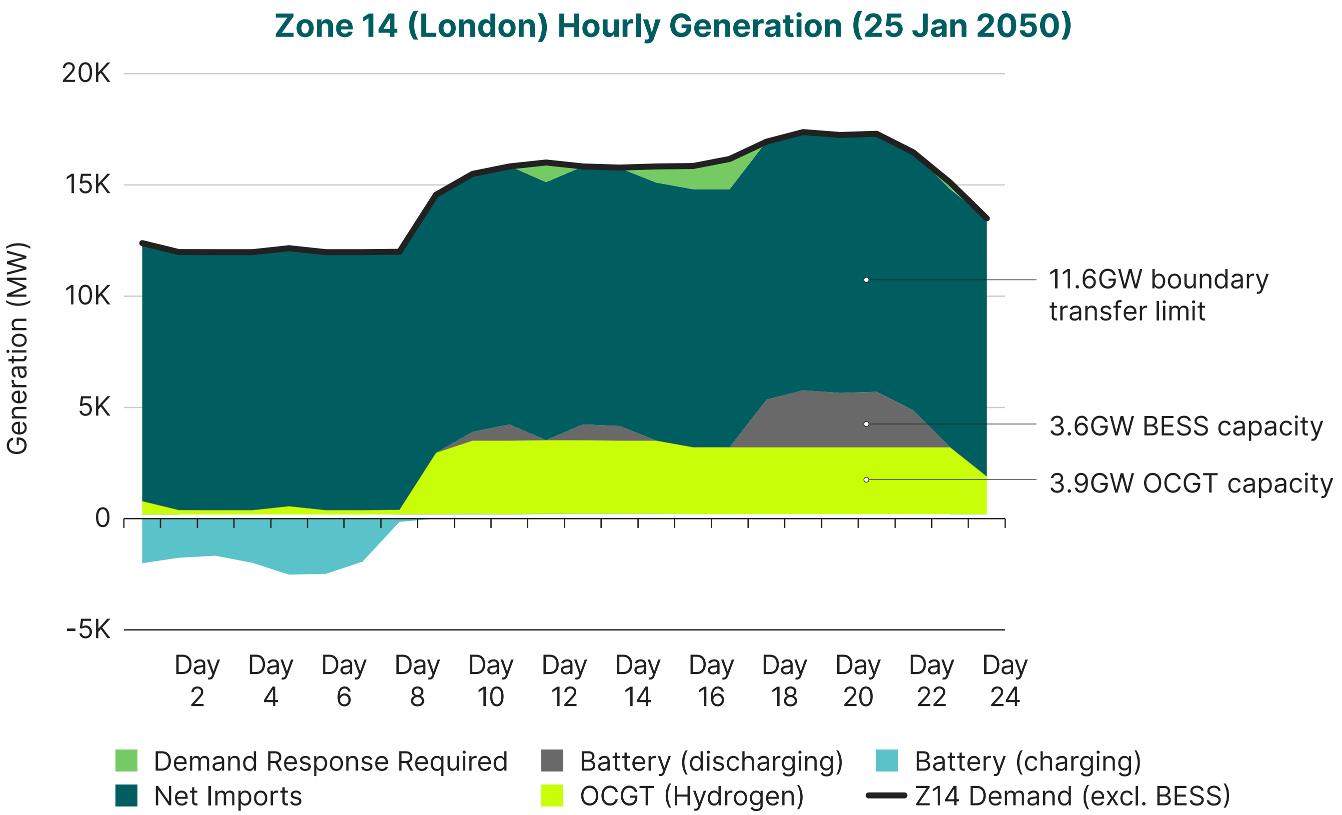
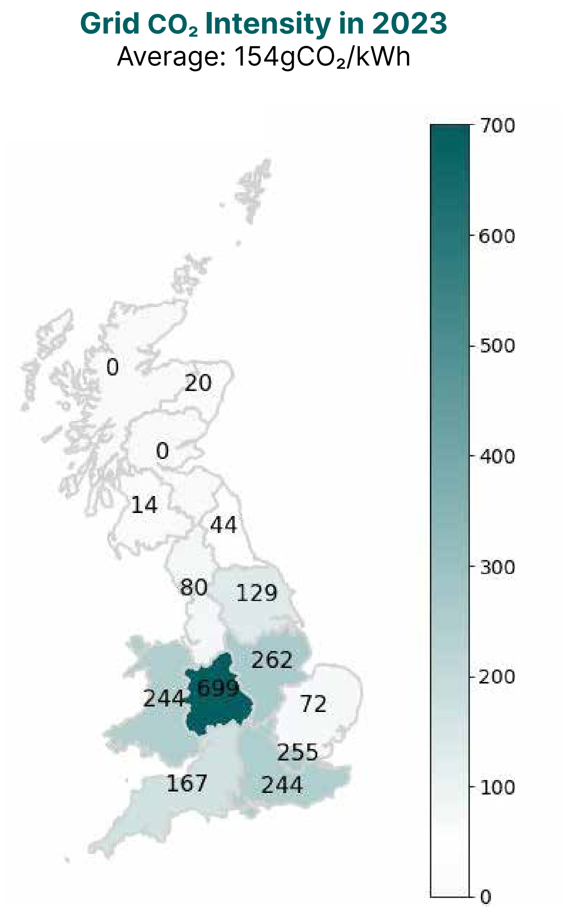


Figure 13 – Generation profile for Zone 14 for a sample day

To alleviate this constraint would require either investment in transmission and distribution lines and equipment, grid management tools, further generation capacity in the zone or increased levels of demand response. To incentivise this increased investment in Zone 14 requires a form of locational price signal. Under the existing single uniform price market structure in GB, the locational signal is provided through the zonal Transmission Network Use of System (TNUoS) charges that transmission connected generation and demand both incur. These currently range from £35/kW in North Scotland to -£10/kW in London for a lower carbon thermal generator.[20] While this charge does provide an element of locational price signals it is not reflective of the actual locational stress in any given period which may be better reflected in a zonal wholesale electricity price.

The resulting CO_2 emission intensity across the country falls over time as would be expected, refer to Figure 14. The only region with higher emissions would be Zone 14 where lower carbon thermal generation with CCS is still required to operate to meet demand as discussed earlier.



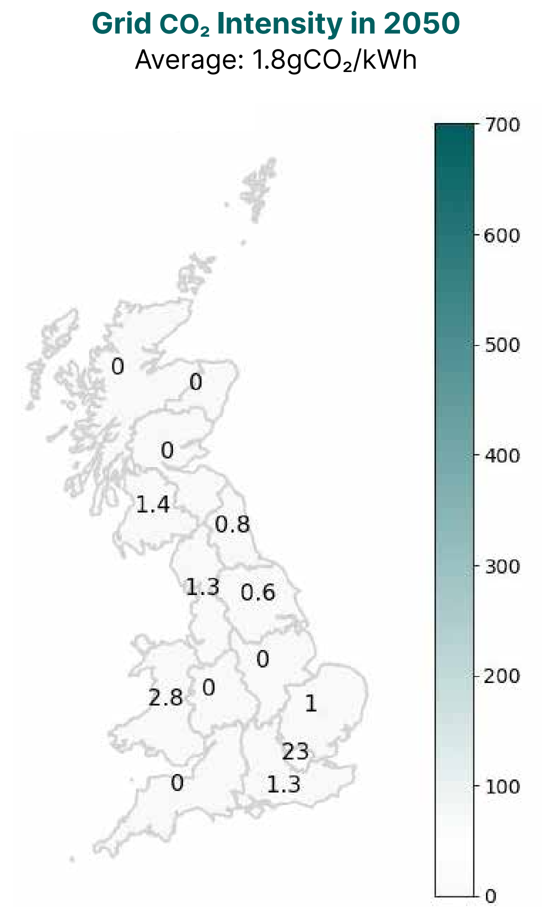


Figure 14 – Zonal CO_2 intensity in gCO_2/kWh under the Base case

In Figure 15, we show the range in wholesale electricity prices under the zonal modelling of the GB system. The price assumes marginal cost bidding to recover energy costs only (fixed and capital costs are assumed to be recovered via a capacity market as is the case currently). Wholesale electricity prices are highest in Zone 14 due to the high demand (London) and amount and type of co-located generation, and lowest in the Northern zones with high levels of wind energy. These prices could help incentivise the investment into additional capacity in Zone 14 while also encouraging investment in demand creation, for example electrolysers to produce hydrogen and alternative lower carbon fuels, and energy intensive industries, in the zones with lower prices.

The zonal wholesale electricity price under the increased wind sensitivity, is similar to the Base case which indicates that the marginal technology in each hour and each zone is likely to be similar in both cases. The advantage of increased wind is not being reflected in lower wholesale electricity prices as the additional wind is being curtailed resulting in the need for more expensive thermal plant burning hydrogen or under CCS to operate and therefore set the marginal wholesale electricity price across many zones in both the Base case and high wind sensitivity.

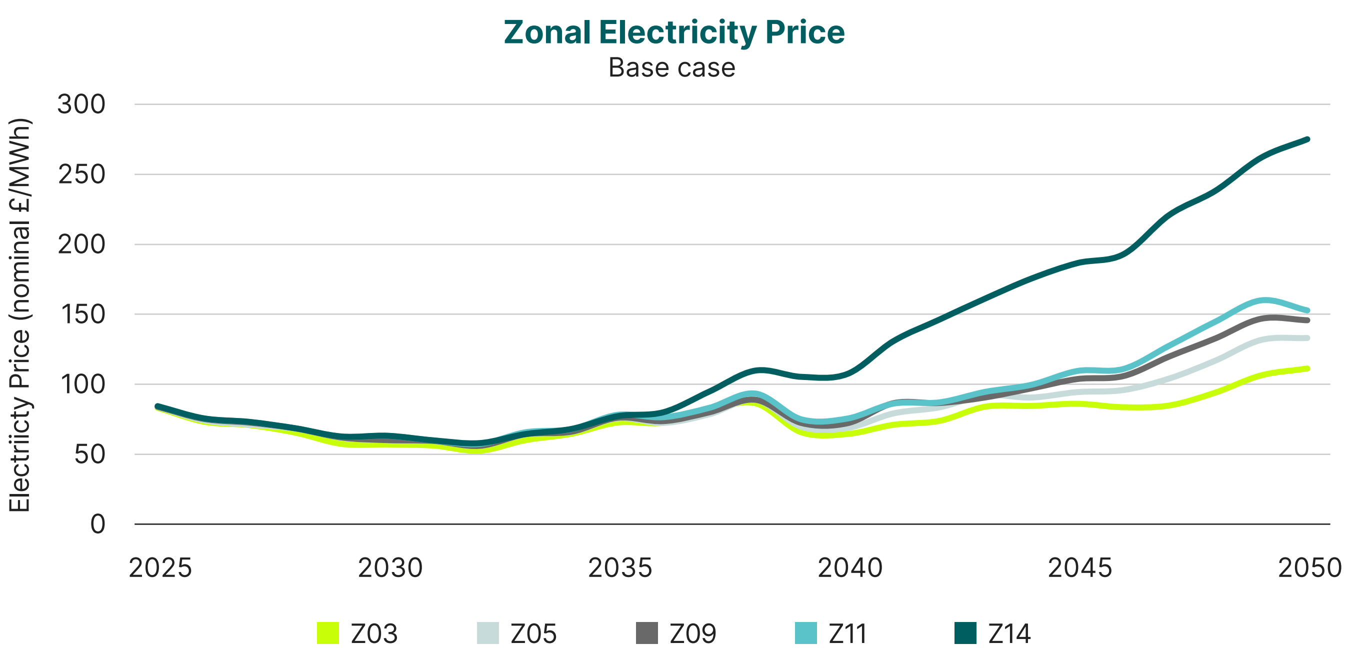


Figure 15 – Zonal wholesale electricity price for the Base case

The overall system generation costs are shown in Figure 16. The capital costs of the capacity additions are annualized with an assumption of 20 years economic life for all technologies except for offshore wind which has been assumed for 30 years and nuclear which has been assumed at 60 years. Costs in the High Wind Sensitivity case are driven higher relative to the base case by capital and fixed costs, as more installed capacity is needed to compensate for renewable de-rating factors and increased curtailment. The Nuclear SMR Sensitivity case costs are more similar with the base case, as higher capital costs are offset by savings on fuel. Many technologies will have a role to play in the decarbonisation of the system, including additional technologies not specifically studied here such as pumped storage hydro, other renewables such as tidal energy, demand-side resources, and grid management and controls to name a few. System shocks due to weather, fuel prices and economic situations were not studied and will also play a role to determine robust plans that provide reliable, affordable, secure and resilient energy.

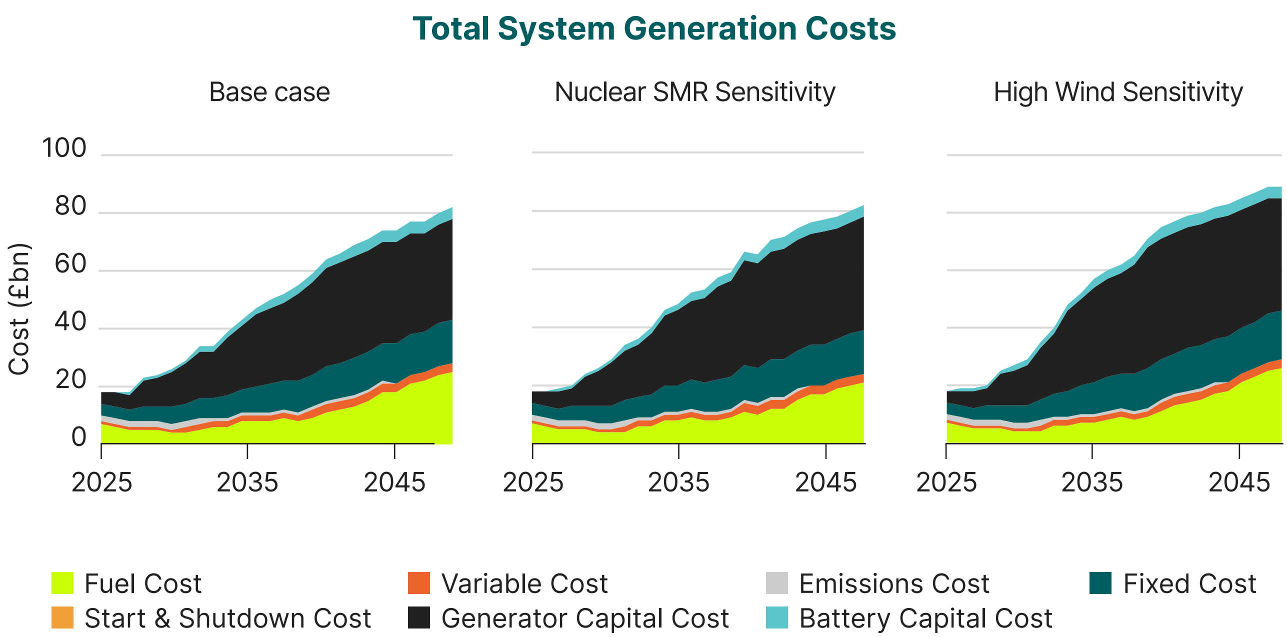


Figure 16 – Total system generation costs under each scenario

TRANSMISSION UPGRADES

To determine the potential transmission upgrades across each boundary we applied the model without any transmission constraints. The resulting maximum flow and a 95th percentile flow across each boundary is shown in Figure 17. The key boundaries are B4–B6 in Scotland, which if upgraded would allow more flow of energy from Scottish wind farms to the South and the constraints B7–B14, which if upgraded would allow more flow of power in London. In total, around 22GW of additional transmission capacity across the Scottish boundaries and 57GW in the English boundaries would be required by 2050 to ensure the boundaries are congested less than 5% of the time.

Transmission upgrades will reduce curtailment, system balancing costs, and the use of more expensive lower carbon generation capacity. The reduction in curtailment will be concentrated in zones with high renewables but they will still experience curtailment at times of low demand. The overall value of reducing curtailments reaches £10bn per annum by 2050.

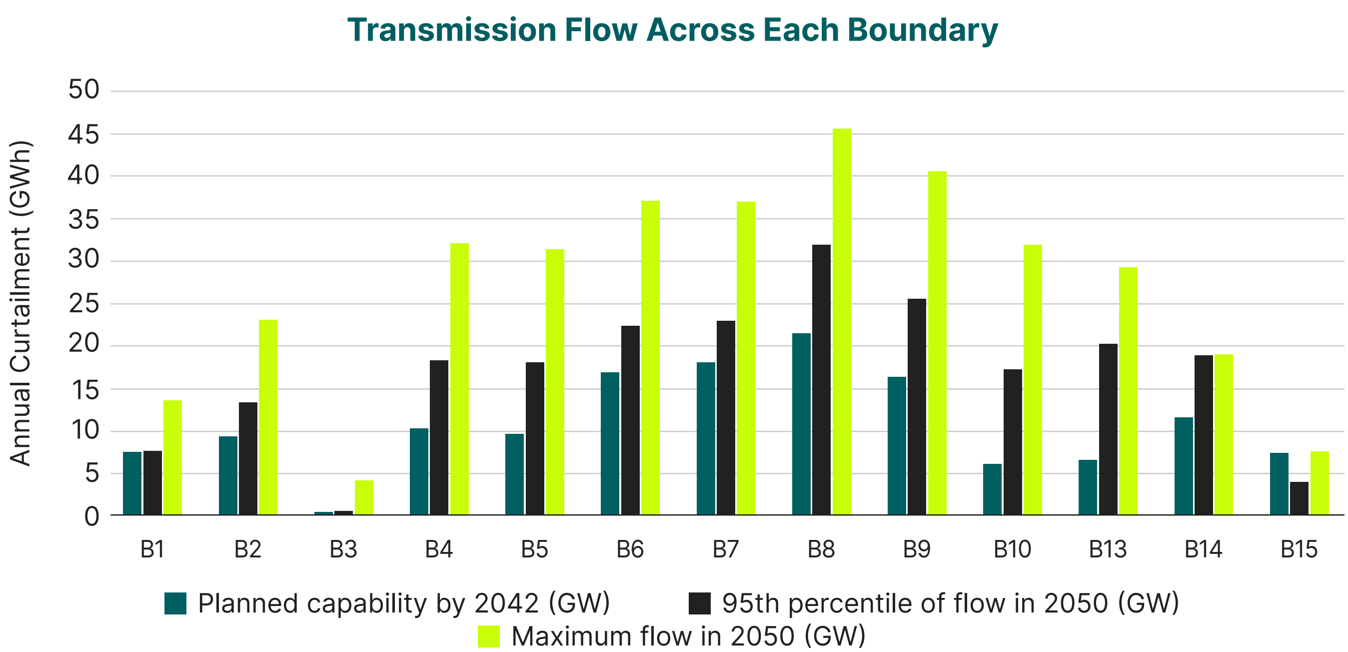


Figure 17 – Potential transmission upgrades

CONCLUSIONS

Great Britain (GB) has an ambitious challenge ahead in delivering its 2050 net zero target. This inevitably will make the power system of the future complex and multifaceted. GE Vernova has carried out a detailed work to analyse the evolution of the GB generation and transmission system in an economically efficient manner while ensuring security of supply.

In the following sections we highlight the key findings of our analysis and provide our recommendations.

KEY FINDINGS

With the expectation that electric demand will double by 2050, including electrification of heating, transportation, and industry to meet the UK decarbonisation goals, our analysis determines that an additional 250GW of renewable and decarbonised generation—approximately 2.5 times that of existing capacity—will need to be added to the system. Although the capacity additions will be largely renewables (i.e., about 2/3 of the new capacity will be wind and solar), however, nuclear and abated gas power will continue to play an important role, as they provide essential reliability services, help manage grid congestion and can be located relatively closer to the demand centres.

The generation capacity additions were evaluated deploying a detailed simulation of the future electricity system of GB while exploring alternative generation and transmission investment pathways. A breakdown of the modelled capacity additions by 2050 is provided below:

- 70GW to 100GW of offshore wind is expected to be built with a significant portion in Scotland
- 70GW of solar, mainly in the southern regions of GB
- 60GW of battery energy storage systems (BESS) around the grid
- Up to 27GW of combined cycle gas turbines (CCGTs) with carbon capture and storage (CCS) and 23GW of Hydrogen-capable open cycle gas turbines (OCGTs)
- 10GW to 30GW of onshore wind in addition to the repowering of existing sites
- 10GW to 18GW of new nuclear capacity

The applied modelling methodology and constraints ensure that energy security by maintaining demand-supply balance while respecting the physical constraints of the grid on a 'zonal' basis that recognises the potential locations of electricity generation resources. Consequently, a significant reinforcement or addition of the transmission grid will be inevitable to securely deliver energy from various generation sources to consumers. These needs are summarised below:

- In total, around 22GW of additional transmission line capacity across the Scottish boundaries and 57GW in the English boundaries is required to alleviate congestion and avoid curtailment of renewable electricity to save system costs of circa £80bn by 2050.
- About 30% to 50% of available wind energy in Scotland is at risk to be curtailed by 2050 without further investment in the network such as new transmission lines and equipment, increased grid management and controls, and flexible demand (including electrolysers) and energy storage. Similar in the absence of these additional investments up to 15% curtailment of available wind and solar energy will occur in the Southwest.
- Congestion in the grid in the Midlands, coupled with the fewer options for lower carbon power in London, will require more grid automation and demand-side resources to efficiently manage demand within the London zone.

RECOMMENDATIONS

The quantum of required growth in the GB power system infrastructure and lead times of deployment of these technologies (e.g., 6–10 years for nuclear, 4–6 years for CCGTs, and 5–15 years for transmission links) demand concrete actions to be taken as early as possible during this decade to establish GB's ability towards efficient delivery of its 2050 net zero target.

Our analysis reveals that there is no silver bullet that will fast forward the GB electricity system to 2050 and deliver the net zero target. We believe a combination of various electricity generation, transmission and system control/management technologies with underlying supportive policy and regulatory measures coupled with reformed markets will be essential. Therefore, our key recommendations are:

- **Enable and accelerate investments** at the required scale in all lower carbon generation technologies (renewables, nuclear, CCS and Hydrogen) and grid solutions, enhanced digitalization of the energy system including facilitation of active participation by consumers. We estimate that over £50bn investment is required in generation and storage capacity alone by 2030.
- **Expedite implementation of market reforms** that are technology agnostic, remunerate all system services (energy, capacity, flexibility and stability) and provide adequate signals for investment in generation and grid assets 'when and where' needed.
- **Adapt energy policy and regulation** that bring clarity to the uptake of lower carbon generation (in particular for SMR, CCS and Hydrogen) as well as grid technologies. These should ensure:
  - Rapid permitting and deployment of required flexible resource (circ. 10GW of storage and gas with hydrogen readiness) necessary to integrate over 30GW of new wind and solar capacity by 2030 to ensure system security.
  - Build out and commitment of over 100GW of new generation capacity by 2030.
  - Step up the required grid reinforcement (transmission lines and operational solutions) that is compulsory for the delivery of lower carbon energy to consumers.

Overall, the United Kingdom must make tangible progress within this decade regarding the above key recommendations. GE Vernova with its unique portfolio of generation and grid technologies, global project experience, comprehensive footprint and expertise is well positioned to enable the UK in delivering its net zero mission. GE Vernova is privileged to work with its customers and stakeholders across the UK to deliver reliable, affordable, secure and resilient energy to help realise net-zero target.

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