THE FUTURE OF GB ELECTRICITY SUPPLY
Security, Cost and Emissions in a Net-zero System

Colin Gibson and Capell Aris

The Global Warming Policy Foundation

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About the authors

Colin Gibson

Colin Gibson was Power Network Director at National Grid from 1993 to 1997, having held various senior positions in generation operation, transmission design, and system planning and operation from 1965 to date.

Capell Aris

Dr Capell Aris worked in the electricity supply industry, first as reactor physics specialist at Wylfa nuclear power station and then at Dinorwig and Ffestiniog pumped storage stations, in the control and instrumentation section and later with additional responsibility for information technology systems.

> When any causes beget a particular inclination or passion, at a certain time and among a certain people, though many individuals may escape the contagion, and be ruled by passions peculiar to themselves; yet the multitude will certainly be seized by the common affection, and be governed by it in all their actions.
>
> — David Hume

> If everyone is thinking alike, then no one is thinking.
>
> — Benjamin Franklin

Summary for policymakers

This paper reanalyses the various electricity system scenarios presented in the most recent release of National Grid's *Future Energy Scenarios* (FES 2019) with particular emphasis on their adequacy in meeting the Standards of Security of the System, and Security of Supply, and in their practicality in meeting emission targets, and doing so at an economic cost.

The FES 2019 scenarios, whilst 'net zero carbon', are dependent on large proportions of 'renewables' and also on interconnection to mainland Europe and Ireland. The current paper offers two alternative scenarios that achieve the required targets at a significantly lower cost. These scenarios envisage the greater use of nuclear power and gas turbines with carbon capture and storage (CCS), while avoiding critical dependency either on renewables or interconnection.

The uncontrollable variability (intermittency) of 'renewables' presents significant difficulties, and energy storage facilities, amongst other measures, are required to mitigate this shortcoming. The present study models these measures and presents estimates of the costs involved in integrating renewable energy generation into the system.

The study concludes that National Grid's *Community Renewables* scenario would regularly fail to meet the Loss of Load Probability (LOLP) Security Standard of 4%, which was the standard in the pre-privatization period. This scenario is heavily dependent on solar generation, amongst other renewables, but the levels of energy storage contemplated by National Grid are inadequate to address the consequent problems with intermittency. In addition to being unreliable and insecure, the scenario is nevertheless extremely expensive compared to the alternative scenarios; the aggregated extra costs to 2050 exceed £1.4 trillion. The current study concludes that the Community Renewables scenario is not worth pursuing.

National Grid's *Two Degrees* scenario has very similar shortcomings to those found in *Community Renewables*, albeit to a lesser degree. The *Two Degrees* scenario is very expensive, has a very large and heavy environmental footprint, and faces considerable technical challenges. The energy storage requirements for this scenario are considerable – over 1 TWh would be required – and to mitigate the severe security of supply problems associated with this scenario 'response' would have to be both very rapid and extremely reliable.

Both the *Community Renewables* and the *Two Degrees* scenarios would struggle to meet the requirements of even a moderately secure system. The inertia of systems based on these scenarios will be very low since solar photovoltaics, interconnection, and wind turbines contribute little or nothing to inertia, thus requiring fast reacting generation to contain frequency within prescribed limits and secure the system in the event of power input loss. This will be expensive, and not readily available. Existing fast-acting pumped storage schemes such as Dinorwig would be too slow to address the rapid falls in frequency that would occur in the event of 'credible' generation losses. Mitigating this would be at considerable cost to the customer.

In the view of the present authors, National Grid's scenarios are inadequate to form the basis of a rigorous and responsible engineering discussion. Scenario planning should consider all available types of generation, should be fully costed at system level, and should set out the consequences for both the security of the system and supply.

The alternative scenarios proposed by the authors of the present study envisage a system incorporating nuclear power and gas turbines equipped with carbon capture and sequestration. These scenarios have similar levels of carbon dioxide emissions to the National Grid scenarios, but comfortably meet the required standards of Security of the System and

Supply, have none of the storage problems associated with intermittency, and provide all the inertia required to deliver a stable system. Furthermore, and crucially, they do so at a much lower cost – £1.4 trillion lower – than that implied in the National Grid scenarios.

1 Introduction

In recent years National Grid has published its *Future Energy Scenarios* (FES), describing four different paths towards electricity generation systems that have reducing carbon dioxide emissions. The FES 2019 edition contains two scenarios – *Community Renewables* (CR) and *Two Degrees* (TD) – that achieve 'net zero carbon' emissions by 2050. (The other two scenarios, *Steady Progression* (SP) and *Consumer Evolution* (CE), do not achieve net zero emissions by 2050; they will not be considered in this study, except in passing.) The scenario descriptions have detailed information on expected plant generation mix, annual production, energy storage capabilities, and export and import via interconnectors to Europe. Half-hourly demand profiles for domestic, industrial, and electric vehicle are given. Onshore and offshore wind and solar generation are prominent in both scenarios.

Any generation system must deliver a secure energy supply. The scenario descriptions include details of energy storage facilities, but they make no attempt to demonstrate that this attempt to overcome the intermittency of renewable generation is successful. In Section 2 we will examine modelled energy flows of both scenarios and demonstrate that they fail to overcome the intermittency problem. In Section 3 we will apply a loss of load probability analysis to the two scenarios, with special regard to the reliance placed upon interconnector capacity to European grids that also contain large proportions of intermittent generators. The CR scenario is shown to perform poorly in many years.

Electrical energy underpins the national economy and should therefore be affordable. In Section 4 we cost the two systems described by National Grid. However, we also introduce two alternative scenarios, designed by the authors, that achieve net zero carbon dioxide emissions by 2050 at much lower cost. These alternatives have greater nuclear capacity than CR and TD, and involve use of combined cycle gas turbine (CCGT) generation with carbon capture and storage (CCS). Both these non-renewable scenarios are much cheaper than CR and TD, and show aggregate savings of approximately £1.4 trillion to 2050.

We conclude with two qualitative sections. Section 5 examines the implications of installing more and more generation plant that is not synchronously connected to the grid, causing the installed system inertia to fall. Solar generation has no inertia at all. Great Britain is an island grid and lowering inertia will make grid frequency control more difficult and lower grid stability. The system integration costs for renewable generation may rise considerably and security of supply reduce. (The authors' *Gas* and *Nuclear* scenarios avoid both of these problems.) Section 6 examines the difficulties of finding large areas with economically viable wind or solar energy in the island of Great Britain, with its restricted land area, and at the same time avoiding generation clustering that will increase the intermittency problem. The authors' *Gas* and *Nuclear* scenarios would make little demand on Britain's landscape.

2 Energy flows in the Future Energy Scenarios

National Grid provides an Excel workbook[1] that contains all the source data for their scenario presentation.[2] This gives supply and demand data for all four scenarios between 2018 and 2050.[3] Figures 1 and 2 show the changes proposed for generation capacity and production between 2018 and 2050; the year-by-year evolution of these changes can be seen in the FES documentation. For CR and TD, generation capacity increases during this period by 210%, but delivers only a 44% increase in production, implying a significant fall in system productivity.

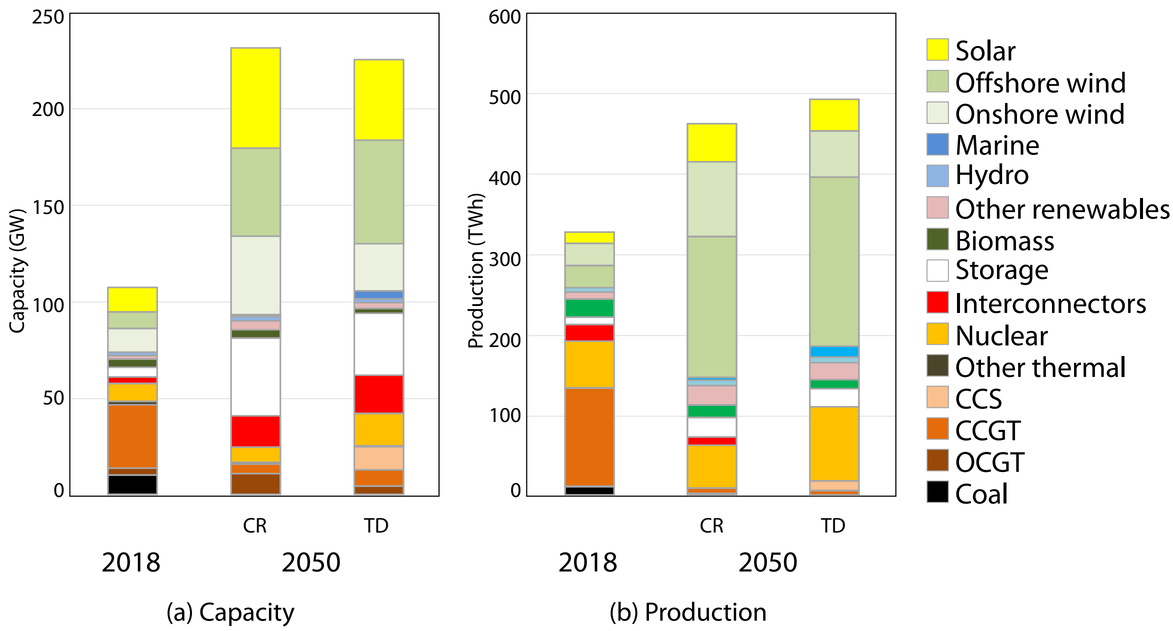


Figure 1: Generation and production in the two scenarios.
Source: National Grid. Charts by the authors.

Most renewable generation is intermittent and not dispatchable, whereas demand is obstinately inflexible, so demand and supply will not be straightforwardly matched at all times, as they would be if dispatchable generation was in use. The FES scenarios use varying amounts of energy storage as one of the methods to overcome this difficulty, making use of four energy storage technologies: batteries, compressed air, pumped storage and liquefaction of air (see Figure 2). The storage power capacities are given, and in all cases are assumed to apply equally to charge and discharge. Table ES1 supplies the information on National Grid's other solution to intermittency: interconnection to Europe.

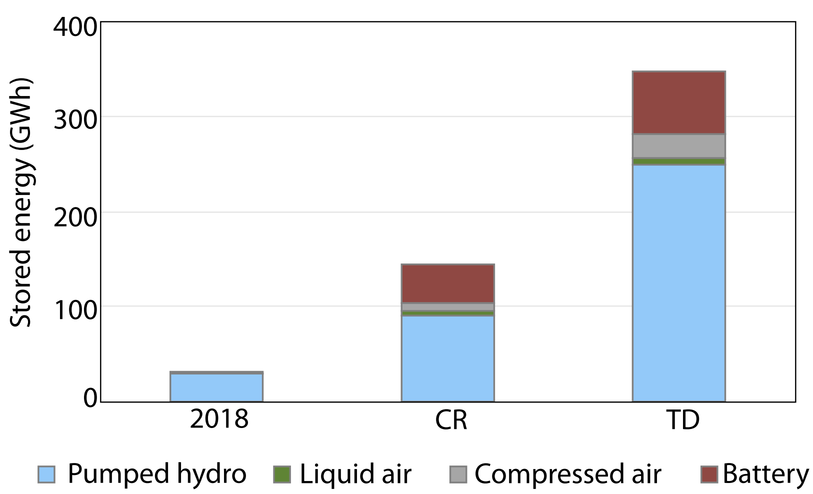


Figure 2: Stored energy capacity
Source: National Grid. Chart by the authors.

The detailed modelling of the interplay between generation, demand, storage and interconnectors is described in Appendix A. Only CR and TD in 2050 are studied. A half-hourly demand profile in 2050 is constructed using data given in the FES Excel workbook.[4] Generation is a function of the generation fleet – the capacity of each type of plant in each scenario – and, for the renewables part of the fleet, the weather conditions. A half-hourly generation profile for wind and solar plant is constructed from data described in previous studies of wind and solar generation in the UK,[5,6] scaled to the size of the installed wind and solar fleets given for 2050. This profile covers 2005–2018, enabling an assessment, across both scenarios, of how 2050 demand will be met in most weather conditions.

The analysis of energy flows for both scenarios starts by calculating the balance between generation and demand for each half hour and then handling any surplus or deficit in a series of steps also described in Appendix A. Surplus generation can be diverted, in turn, to energy storage, hydrogen production by electrolysis, interconnector export or discarded (spilt) if the energy is not needed at the time of generation. Deficit generation can be rectified by import using interconnectors (considered for this exercise to be 100% available), energy extraction from storage, gas generation, then demand-side reduction (DSR) and, if needs be, voltage reduction. Each addition or extraction of energy to/from the scenario stores result in energy losses, which are summed as annual energy wastage.

For each year modelled, periods of surplus generation and of generation deficit are considered separately. Summaries of the results are set out in Sections 2.1 and 2.2. The detail can be found in Tables 9–14 in Appendix A.[7]

2.1 Results for the *Community Renewables* scenario

System performance when demand exceeds production

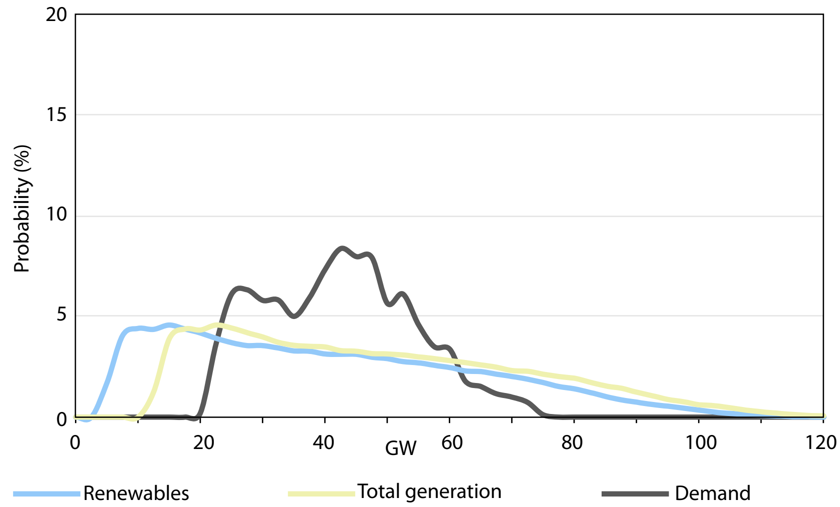
Table 1 summarises the performance of the scenario when production falls below demand. The CR scenario has many hours when the production deficit is large enough to require both DSR and voltage reduction to be applied. For an average of three days in each year the voltage reduction will exceed 7.5% and load disconnections will follow. The store is empty for an average of 867 hours, or 10% of each year, with a consequential reduction of dispatchable generation capacity that will impact upon the loss of load probability, as described in Section 3.

Table 1: *Community Renewables* performance when production is below demand.

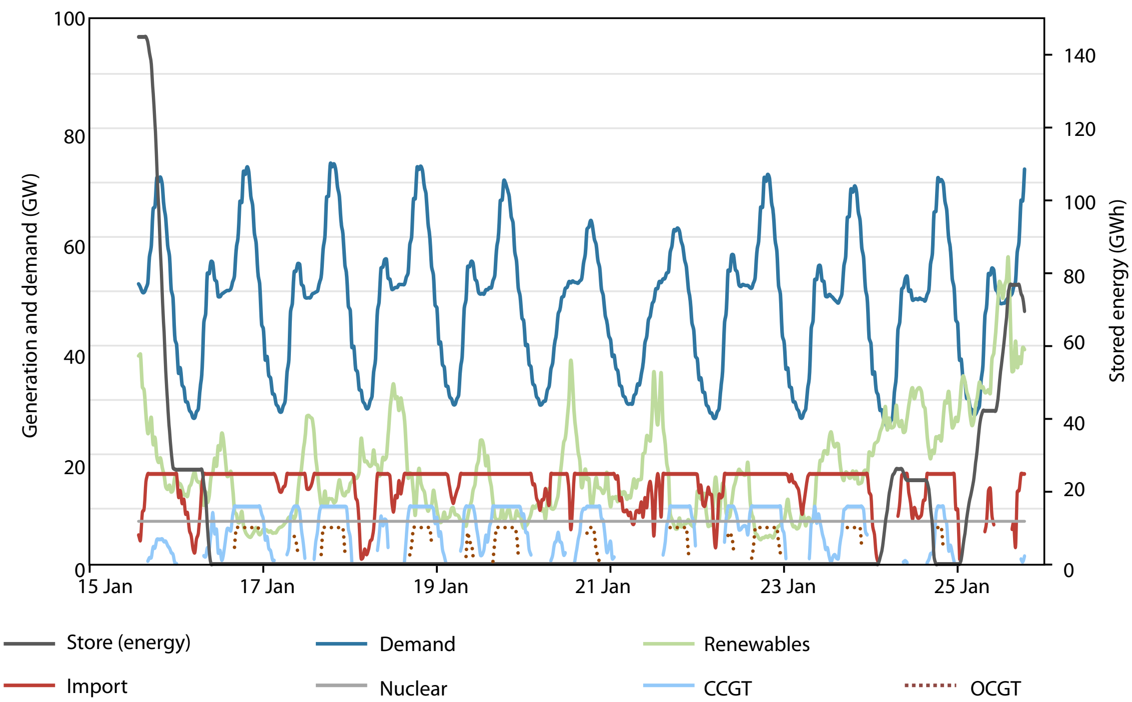
Average hours each year voltage reduction applied	Average hours each year voltage reduction exceeds 7.5%	Average hours each year the store is empty	Average annual DSR applied (GWh)	Annual energy import (TWh)
119	78	867	1082	45.7

Source: Calculations by the authors.

An examination of the probability distribution functions (PDFs, sample width 2.5 GW) for generation and demand for this scenario during the modelling period reveals that for much of the time there is a high probability that there will be a significant generation shortfall on demand (see Figure 3a). The offset between renewable generation (blue) and total generation (green) is created by biomass and nuclear generation. The component PDFs of the renewable generation profile can be seen in Figure 14.



(a) Generation and demand



(b) Longest empty store event during the modelling runs.

Figure 3: CR scenario results
Source: Calculations by the authors.

The longest empty store event for the CR scenario is shown in Figure 3b and illustrates what would happen during a winter high-pressure period (the source data for the generation model was from 2017 meteorological reports).

CR 2050 has only 7.9 GW of nuclear, operating at 77.7% capacity factor, and 4.1 GW of biomass at 37.7% capacity factor, so there is little scope for increased production from these sources at times of power shortages. The performance of the scenario could be improved by:

- modifying the control algorithm during periods of production deficit by first using CCGTs and open cycle gas turbines (OCGTs) and then interconnector production to reduce deficits and maintain the energy storage at high levels, but then gas production would rise above 25 TWh and this scenario would cease to represent a zero-carbon generation system;
- increasing the store size to 1 TWh, but this would be expensive;
- using renewable energy production forecasts to manage store energy flows[5] but the required store capacity would still be considerable – even if a predictive system were in use, an expansion of OCGT capacity would still be required.

The scenario performs badly for several reasons:

- There is too little firm capacity (12 GW of biomass and nuclear). In Figure 3 observe how much of the generation (green) PDF falls below the demand (red) PDF between 0 and 20 GW. (The scenario also has 10.9 GW of CCGT but this is nonsensical: its load factor between 2020 and 2050 averages 9.9% so it has been considered as OCGT, making the total OCGT capacity 15.82 GW in the flow analysis).
- The stored energy is too small (145 GWh).
- The energy store power capacity is too large (40.5 GW), giving an energy/capacity time of only 3.6 hours.
- There is an overreliance on solar production; there is 52.2 GW of solar capacity (22% of total capacity in 2050), which can produce nothing at night, and very little for the four winter months of each year. In the absence of solar, the remaining renewable energy system of 180 GW capacity is expected to deliver 440 TWh, a capacity factor of 28%.

System performance when production exceeds demand

Table 2 summarises the performance of the CR scenario when production exceeds demand. The scenario wastes 45 TWh of production every year, which at £100/MWh amounts to an annual loss of £4.5 billion (£166 per household).

Table 2: *Community Renewables* performance when production exceeds demand.

Annual energy:	TWh
– Export	32.2
– Wasted in store energy changes	3.3
– Expended in hydrogen production	31
– Lost in hydrogen production	10
– Spilt or constrained off	31.7

Source: Calculations by the authors.

From the above analysis it appears that the intermittency issue has not been solved for the CR scenario.

2.2 Results for the *Two Degrees* scenario

The TD scenario has an energy storage capacity of 349 GWh, a power capacity of 32.4 GW (and thus an energy capacity time of 10.8 hours), and a solar capacity of 42 GW (18% of total capacity). Tables 3 and 4 summarise the performance of this scenario.

Table 3: *Two Degrees* performance when production is below demand.

Average hours each year voltage reduction applied	Average hours each year voltage reduction exceeds 7.5%	Average hours each year the store is empty	Average annual DSR applied (GWh)	Annual energy import (TWh)
12	6	121	122	38.5

Source: Calculations by the authors.

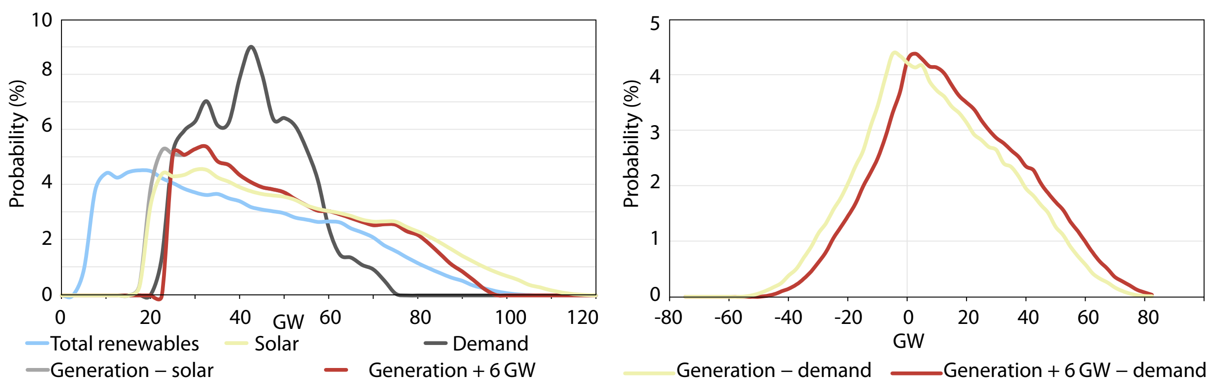
Table 4: *Two Degrees* performance when production exceeds demand.

Annual energy:	TWh
– Export	51.6
– Wasted in store energy changes	1.9
– Expended in hydrogen production	30
– Lost in hydrogen production	10
– Spilt or constrained off	32.6

Source: Calculations by the authors.

The PDFs for generation and demand for this scenario are shown in Figure 4a, while Figure 4b shows the PDF for generation minus demand.

If the TD scenario had an increased firm capacity (more nuclear generation perhaps) then the defects shown in Table 3 (periods of empty energy store, DSR, and voltage reduction)



(a) Generation and demand

(b) Generation less demand

Figure 4: PDFs of generation and demand for the TD scenario.
Source: Calculations by the authors.

might be removed. By trial and error, it was found that an extra 6 GW of firm generation reduces nearly all of the deficit values in Table 3 to zero. In Figure 4a this extra generation shifts the generation curve to the right to fall beneath the lower end of the demand curve; in 4b the whole curve moves to the right (red curve). Like the CR scenario, TD relies on excess renewable capacity to match demand at times when renewable generation is low. Inevitably this results in periods of over-production, shown to the right of the black demand curve of Figure 4a and the large amount of energy spilt in Table 4.

The contribution of solar generation to the power flows of the TD scenario was carried out by removing all solar generation from National Grid's capacity specification for TD and then testing how much firm power returns the scenario to similar performance results as shown in Table 3. This shows that the generation worth of 42 GW of solar power in this scenario is 2 GW, about one nuclear power station.

The TD scenario has a more secure performance than the CR scenario, but does not avoid periods when the energy store is empty; the longest such incident, based on 2006 meteorological reports of wind and solar data, was 105 hours in duration (see Figure 5; see also Table A1.5 which shows 2006 as having an exceptionally large incidence of the empty store condition). This incident occurred during winter, when solar generation is negligible, repeating the observation made for the CR scenario. Eliminating empty store incidents would require increasing the store capacity to 1 TWh, with the cost implications already noted. However, using the alternative control algorithm for the store, described above, in which gas generation is called ahead of store usage to prevent the stored energy falling below 25% of full capacity, successfully eliminates all empty store incidents; doing this lifts gas generation to 10 TWh. Intermittency would be solved, provided we accept some carbon dioxide emissions and considerable energy spillage.

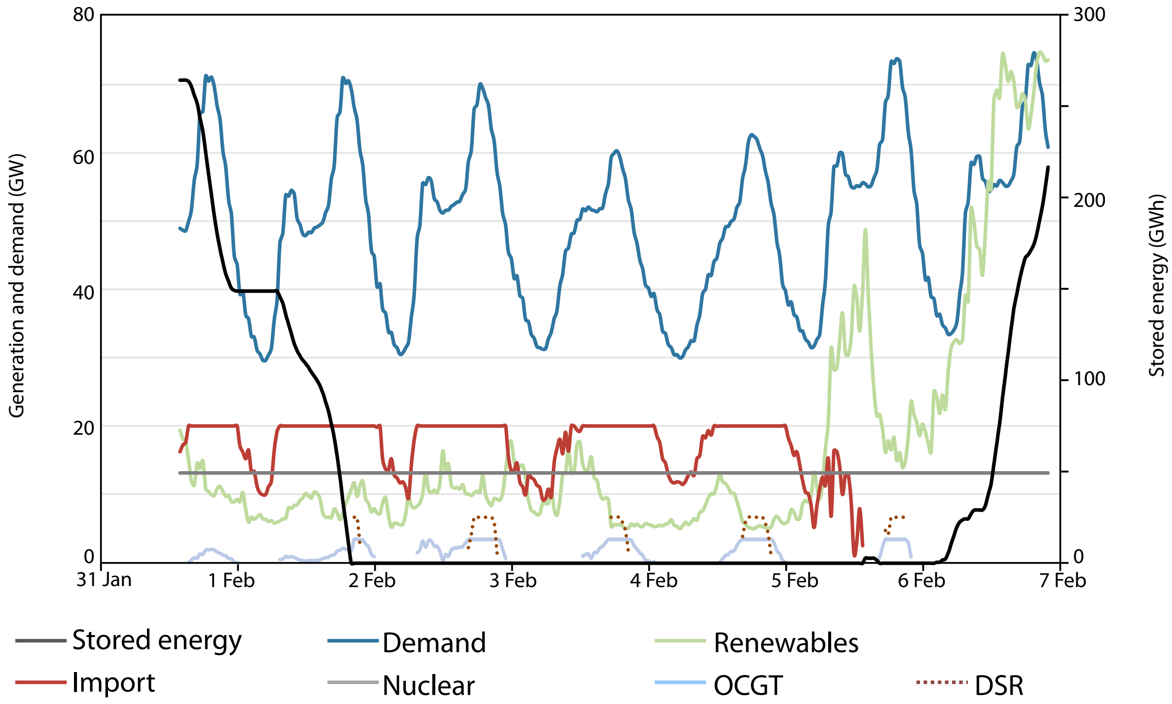


Figure 5: 2050 TD scenario: longest empty store event during the modelling runs.
Source: Calculations by the authors.

2.3 Energy spilt

The CR scenario wastes 13.3 TWh and spills 31.7 TWh of production every year; at £100/MWh that amounts to an annual loss of £4.4 billion. The TD scenario wastes 11.9 TWh and spills 32.6 TWh per annum. National Grid describes the spilled energy as 'planned over-production' as a result of renewable intermittency, and adds:

> Our modelling shows that at times of likely oversupply, excess electricity cannot be exported, as other countries that have decarbonised are likely to be facing similar issues.

Another form of disposal of 'planned over-production' is the production of hydrogen by electrolysis of water, a process which is perhaps only 50% efficient at the point of final energy use. But generation intermittency could further reduce the efficiency of this process:

> Efficiency for electrolysis also depends on supply running conditions e.g. is the unit able to run with a continuous supply or paired with an intermittent renewable source?

3 Loss of load probability or risk analysis for the scenarios

Reliability for the UK grid supply system was historically taken as a risk of no more than four winters of grid supply failures (commonly termed 'blackouts') every 100 years, implying a loss of load probability (LOLP) or risk of failure of 4%. Details of how this value is calculated and the source data used are given in Appendix B. The LOLP for each year for each scenario is calculated, taking the dispatchable capacity as the sum of storage, biomass, CCS combined heat and power, gas, coal, other thermal, and nuclear capacities. Varying percentages of interconnector capacity are added to assess any sensitivity of supply security to interconnector reliability. The dispatchable capacities are multiplied by 0.85 to allow for planned and unplanned plant outages, and this value is then taken as the median of a Gaussian production distribution with a standard deviation of 3.75%. The results of these risk calculations are shown in Figure 6.

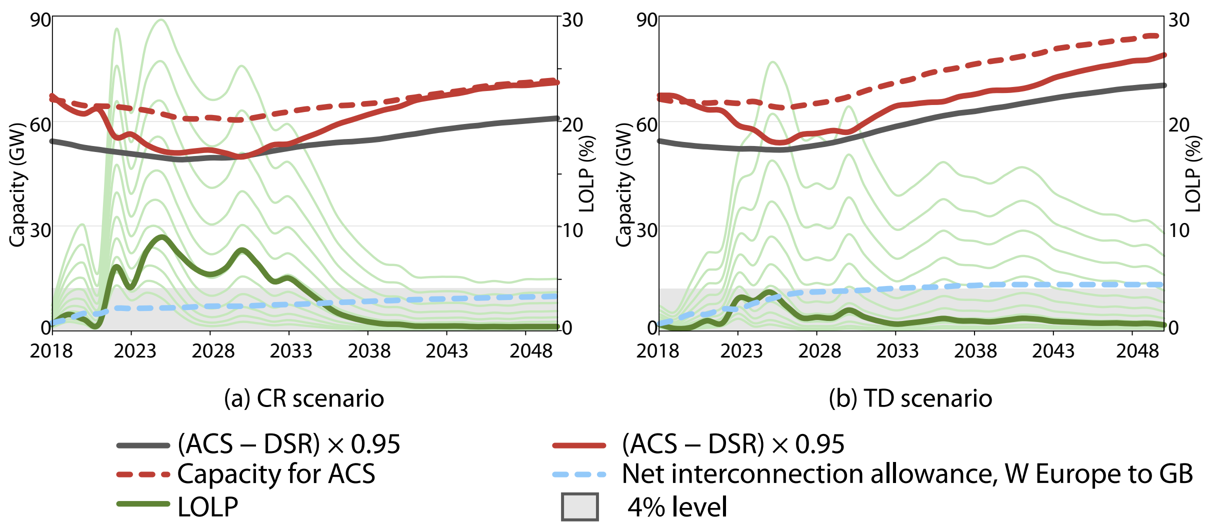


Figure 6: LOLP calculations

ACS, average cold spell. Faint green lines show LOLP with 10% increment of interconnector capacity, zero percent highest line. Source: Calculations by the authors.

Interconnector capacity is an important component of dispatchable power when calculating LOLP in these scenarios. The faint green lines in these two figures show the LOLP values in ten percent increments of allowance for interconnector capacity. A calculation of interconnection allowance has been made using the Circle Diagram Method described in GBSQSS.[8] The dotted blue lines in Figure 6 show the calculated interconnection allowance and the dark green line the resultant LOLP values. Appendix B3 gives more details of this calculation.

The CR scenario does not deliver satisfactory LOLP results between 2020 and 2035. Since the store capacity is a significant part of the dispatchable power and full availability of the energy store's generation capacity has been assumed for the LOLP calculations, the high incidence of periods when the store is empty in this scenario (867 hours per annum, see Section 2.1) mean the LOLP values will probably be much increased in all years to 2050. The TD scenario passes the 4% LOLP standard but suffers in this same respect: the energy store is empty for 121 hours per annum (see Section 2.2), when the dispatchable capacity of the storage system disappears and LOLP will rise.

4 Costing the scenarios

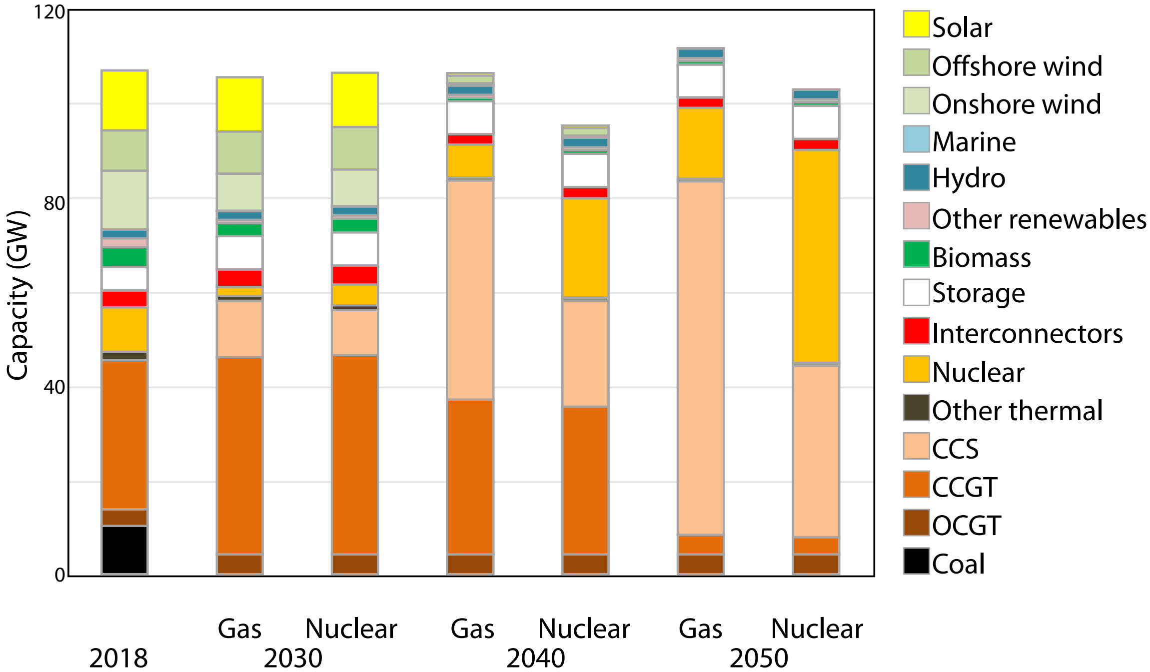
National Grid do not cost their scenarios, and never have. In this paper, both scenarios are costed using a levelised cost of energy (LCOE) method. The details are given in Appendix C. System integration costs, which include the capital and revenue costs of resolving renewable intermittency and the capital cost of providing new transmission links for renewable generation often remote from load centres, are also included.

The cost of increasing transmission losses incurred as generation is added in remote locations is not included, since these can only be estimates. Ofgem calculated annual energy transmission losses of around 5 TWh (£0.6 billion at £120/MWh, 1.5% of national generation cost) in 2011, and recognized that this would increase with installation of renewable plant in Scotland.

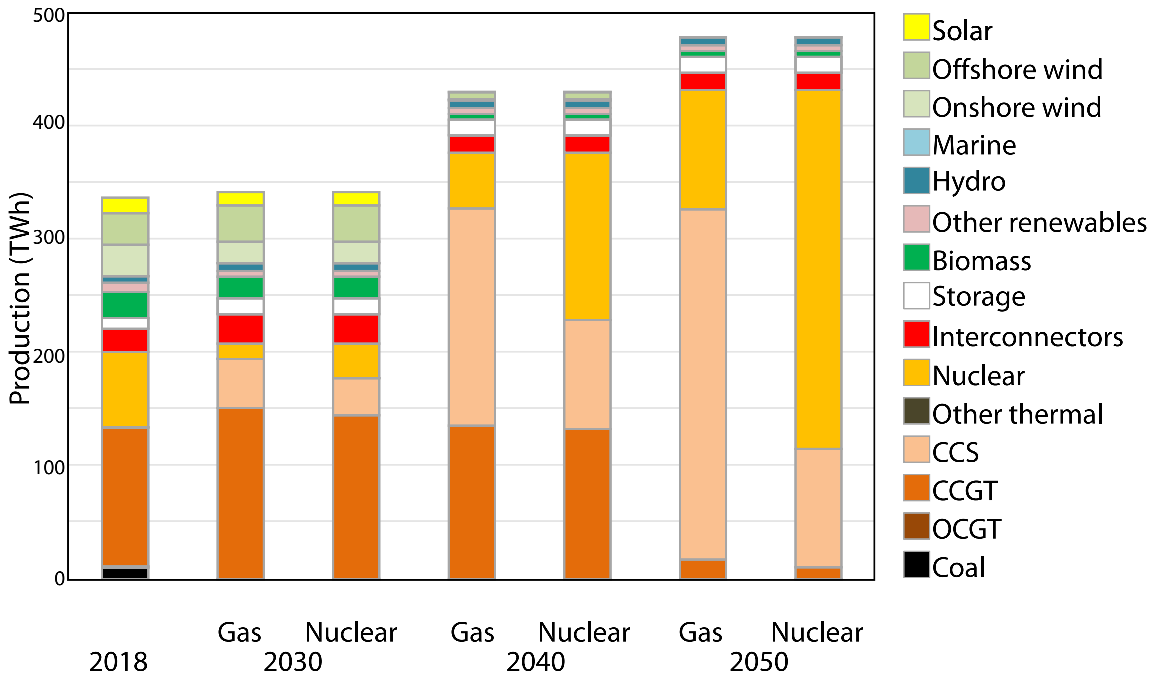
Since the CR and TD scenarios include large amounts of storage capacity by 2050 we have assumed that stored energy will be used to resolve most intermittency problems (but not all, see Section 3). A LCOE costing method has been devised for the use of storage capacity (Appendix C4). Using storage rather than OCGT generation to resolve intermittency problems is more expensive, but avoids carbon dioxide emissions.

Alongside this costing process we have also calculated the carbon dioxide emissions of the scenarios, basing the fossil fuel emission rates on those shown each year in reports in the Digest of United Kingdom Energy Statistics (DUKES).[9]

For a performance comparison, two alternative scenarios have been developed: *Gas* and *Nuclear*. They serve the same demand supplied by TD. The development of both of these scenarios commences by retiring all plant capacities in the 2018 plant mix at the point when they are life-expired; this applies to both renewable and fossil-fired generation. New capacity is then inserted, favouring either new nuclear or new CCGT plant. The new plant mix is then checked for production capability (to meet an equivalent to TD demand) and delivering LOLP values below 2% throughout the whole period – a higher security standard than previously used, but appropriate for our increased reliance on electricity. The move to new capacity configurations does not involve any premature scrappage of previously installed plant.



(a) Capacities



(b) Production

Figure 7: The new *Gas* and *Nuclear* generation scenarios.

For (a), if no CCS technology is included, the gas capacity is equal to the OCGT/CCS plus CCGT capacity. For (b), total production equals that of TD scenario. If no CCS is installed then the OCGT/CCS production is added to CCGT production. Source: Calculations by the authors.

The FES scenarios make use of carbon capture plant for both electricity generation and hydrogen production (from steam methane reforming), so it seems reasonable that any new gas plant in these two additional scenarios could have built-in CCS; it is assumed that this occurs from 2028 onwards, and that OCGTs with CCS will have a capital cost of £3m/MW and an efficiency of 25%. We thus have four new alternatives: gas and nuclear, with and without their gas components having CCS. The development of these alternatives is described in Appendix D. Figure 7 shows the capacity and production evolution for these new scenarios.

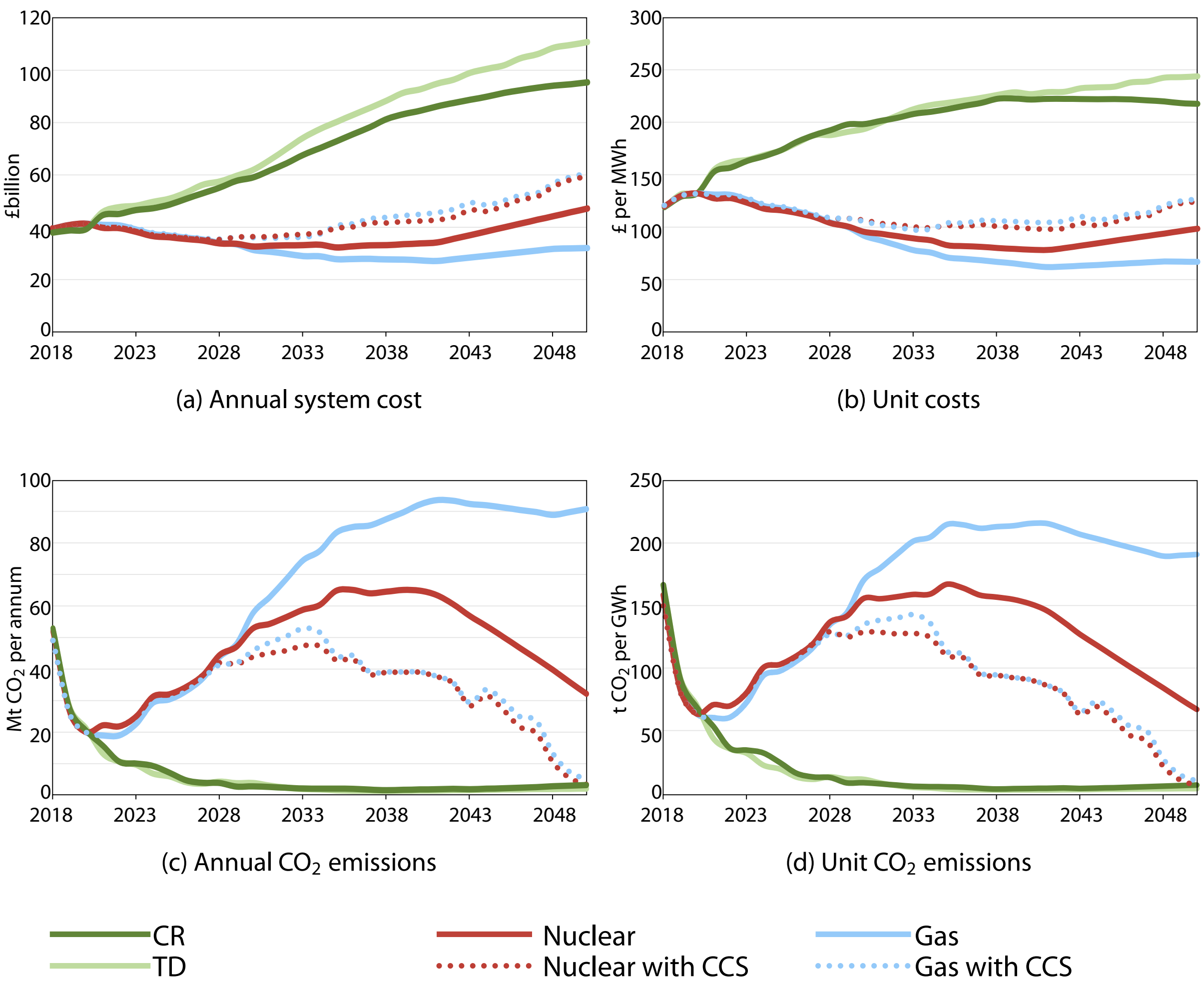


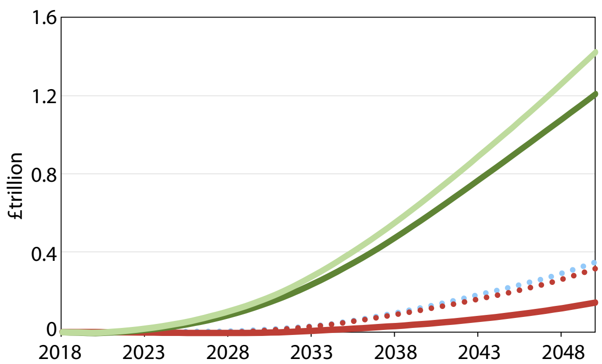
Figure 8: Costs and carbon dioxide emissions of the scenarios.
Source: Calculations by the authors.

Figure 8a shows that the TD and CR scenarios nearly treble the cost of electricity by 2050. *Gas without CCS* is the cheapest scenario. Section 2.2 reports the energy spilt by the TD scenario in 2050 as 42.6 TWh (excluding wastage in storage import/export which is accounted for in system integration costs). This spillage is all from non-dispatchable renewable energy, reducing the production capacity factor for each technology. For example, the capacity factor for offshore wind falls from 44% to 38% in 2050; this increases the annual system costs in 2050 from £111 billion to £118 billion, and the per-unit costs from £244/MWh to £260/MWh.

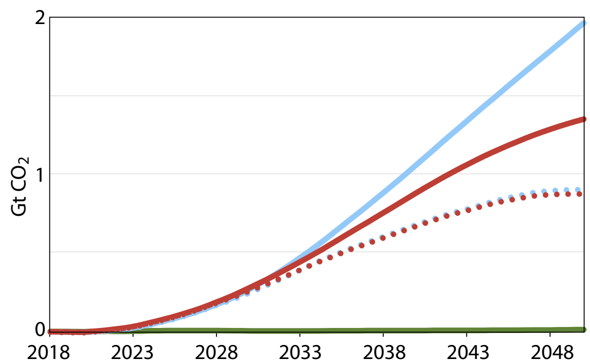
Figure 8c shows rising emissions for the nuclear and gas scenarios between 2018 and 2035. This is caused by the declining contribution of nuclear generation up to 2030 as the

AGR nuclear fleet is retired. In the CR and TD scenarios, the loss of nuclear generation is compensated by adding renewable production. Figure 8d shows only two scenarios reaching zero emissions by 2050.

Figure 9a shows the cumulative extra costs of all the other scenarios compared to the gas scenario. Figure 9b shows the carbon dioxide savings relative to the TD scenario. Up to 2050 TD saves 902 million tonnes of carbon dioxide more than *Gas with CCS* and 873 million tonnes more than *Nuclear with CCS*, but in the process costs £1,215 billion and £1,418 billion more. This puts the TD scenario emissions saving per tonne of carbon dioxide at £1,347 and £1,573 relative to the *Gas with CCS* and *Nuclear with CCS* scenarios.



(a) Cumulative extra costs vs *Gas* scenario



(b) Cumulative extra emissions versus TD scenario

Figure 9: Results on cumulative basis.
Source: Calculations by the authors.

5 Ancillary grid services: the system operability framework, and grid inertia

Grid system operability is the ability to maintain overall system stability, and ratings and operational parameters for all of the grid-connected assets (generators and demand plant) within pre-defined limits, safely, economically and sustainably. In parallel with FES, National Grid publishes System Operability Frameworks (SOFs) to 'study the scenarios described in FES on system operability annually, in a detailed and systematic way that takes into account current system operation experience' and it 'applies this and the FES predictions to future operation'. These future operation scenarios will see:

- a move away from synchronous generators (SGs) to non-synchronous generators (NSGs). All wind, solar, and interconnector generation is non-synchronous.
- a change in the character of the load – large motor loads are disappearing.

The consequence of decreasing synchronous generation will be a fall in system inertia:

> System inertia is a key measure of how strong the system is in response to transient changes in frequency and it also supports the damping of small perturbations in frequency that left undamped can give rise to inter-area modes of oscillation. Inertia is

the sum of the energy stored within the rotating mass of the machines (generators and motors) connected directly [synchronously] to the system. Low system inertia increases the risk of rapid system changes.[10]

Before 2010, synchronous generation formed over 90% of grid capacity. Figure 10 shows the planned decline in synchronous generation (including storage power capacity) for the two scenarios; the actual percentage will vary with plant operational changes.

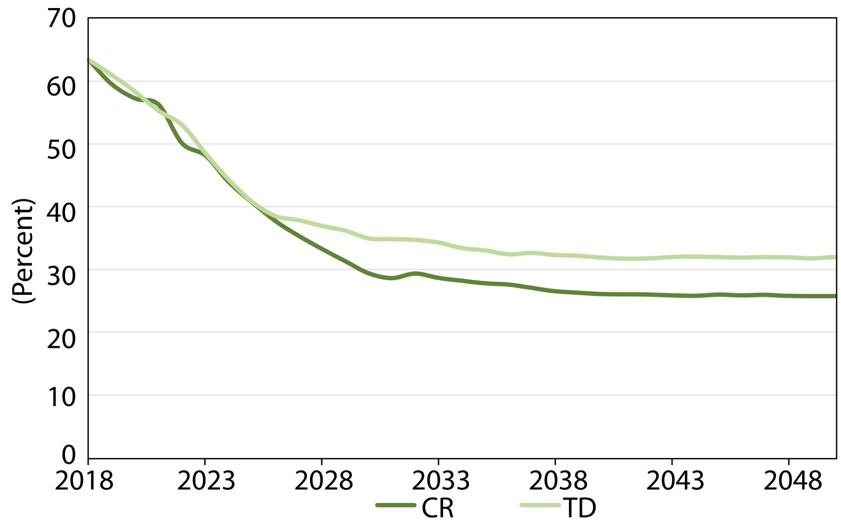


Figure 10: Share of synchronous plant in capacity mix.
Source: National Grid. Chart by the authors.

The SOF 2014 determined the declining grid inertia for each of the FES 2014 scenarios, including *Gone Green* (now *Two Degrees*). The results are shown here as Figure 11.

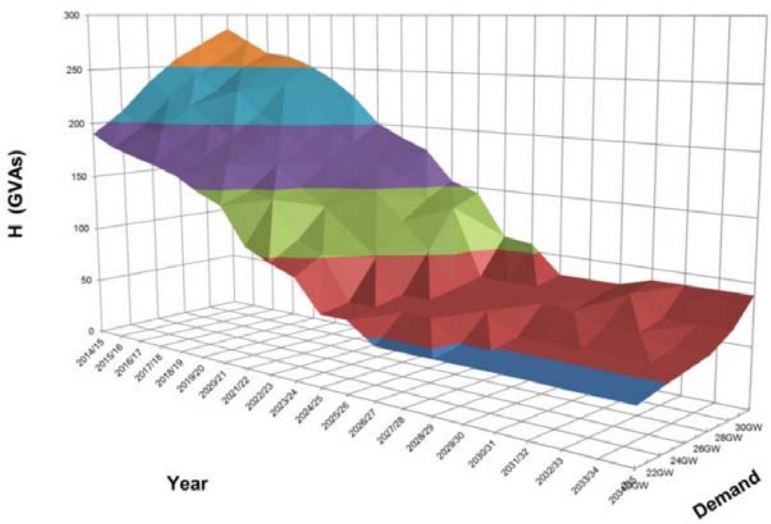


Figure 11: System inertia (H) changes for TD scenario at 70% wind output.
Source: National Grid SOF 2014.

This fall in inertia will have consequences: there will be faster and deeper falls in grid frequency when grid disturbances such as generation tripping occur. Frequency containment will become more difficult.

> Frequency containment is a set of actions that ensure the changes in frequency following a loss of generation or demand are controlled, allowing the frequency to return to 50Hz as soon as possible and without exceeding the operational limits. Sufficient levels of system response have to be scheduled by the system operator to maintain the frequency within statutory levels. Response to a system incident, however, is not instantaneous…lower system inertia leads to a higher Rate of Change of Frequency (RoCoF) following a loss of infeed or demand. High RoCoF causes the frequency to change very quickly and in the case when a large infeed is lost, the frequency may drop to the lower limit and below before a sufficient level of response has had time to start responding the event.

Response requires additional generation to replace the lost infeed. SOF 2014 estimates the scale of response that may be required and the speed at which it is required as inertia falls in the future (see Table 5). Clearly, much faster response will be required in the future. It is not stated how this speed of response will be delivered.

Table 5: Required response rates for falling grid inertia.

Inertia GW.s	RoCoF Hz/s	Time to 49.2 Hz s	Response rate MW/s	Date required
360	0.125	9	185	2014
225	0.2	4	400	2019
205	0.22	3.4	489	2024
180	0.25	2.4	679	2024
150	0.3	1.2	1,148	2024

Source: National Grid

The need for faster response is just one of the many new requirements for the new generation scenarios. Updates to the 2014 SOF have identified a range of initiatives, see Figure 12. Tamrakar et al. provide a literature review of the many techniques that can be used to allow NSGs to provide inertia, in all cases by inserting a virtual inertia algorithm into the DC-to-AC inverter of these generators.[11] These techniques can work, but may create further difficulties such as susceptibility to noise, initiation of grid instability, lack of over-current protection, and slow transient response. As installations of these techniques expands there might well be interaction between their operation. Although virtual inertia provision is being addressed for many grids it should be remembered that the UK is an island grid and the scale of RoCoF will be especially challenging.

The initiatives shown in Figure 12 will all incur additional system integration costs. For example, one of the requirements now being explored is part loading of wind generation so as to provide load following and frequency control.[12] This will decrease the capacity/load factor and increase LCOE of wind generation – a part load reduction of 5% would increase the 2050 TD total generation cost by £5 billion. The costs of the work implied by Figure 12 have not been included in the costing exercise described in Section 4. Almost certainly a new ancillary service – provision of system inertia – will be required. This will add another charge to the system integration costs of renewable generators, but form a source of revenue for nuclear generation.

None of this work would be needed for the gas or nuclear scenarios. The methods of system regulation that had developed over the previous fifty years and worked perfectly

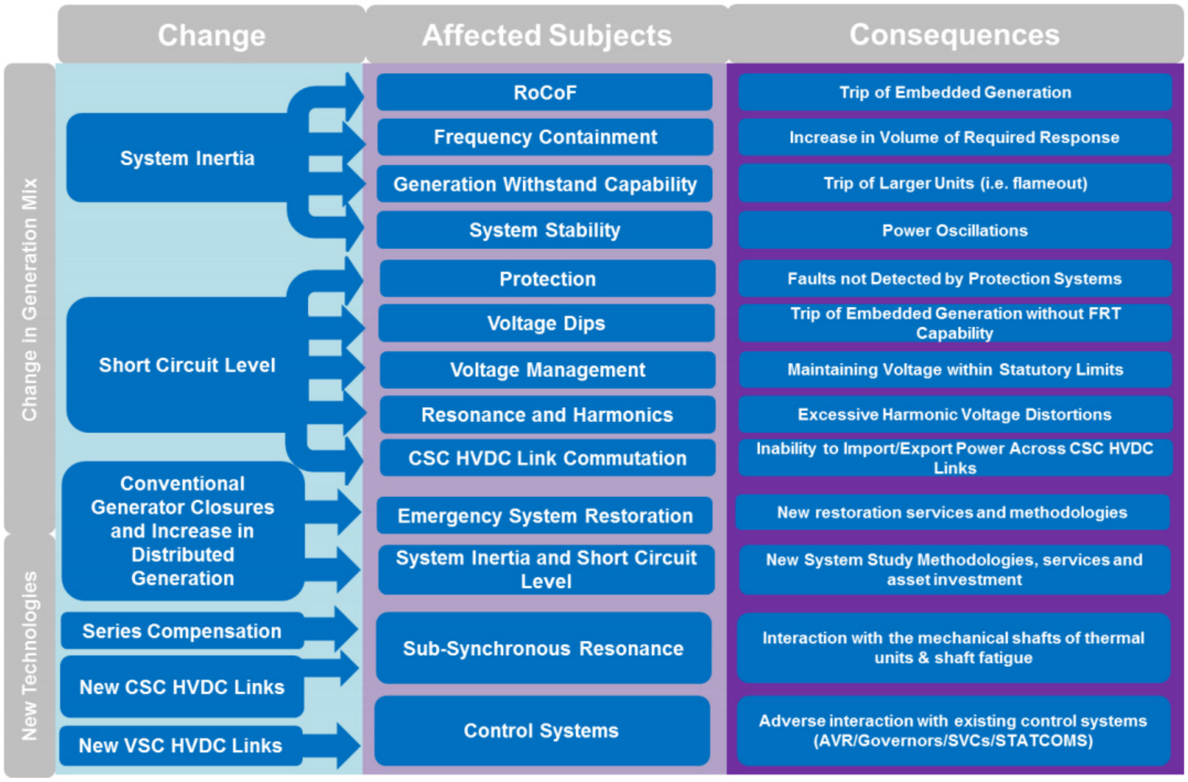


Figure 12: Dealing with renewables.
Changes to grid support services that will be required to meet the changes to generation and load characteristics following the future scenarios. Source: National Grid SOF2014.

well at insignificant cost could be continued. It is likely that very little additional fast response would be needed, and certainly not at the response rates shown in Table 5.

6 Geographic configuration of the generation grid; decentralisation versus centralisation

Section 3 of FES 2019 is entitled 'Decarbonisation and decentralisation'. National Grid see the divide as between transmission connected (centralised) generation and distribution grid connected (decentralised) generation and produce a percentage index[13] for how much each scenario is decentralised. It is questionable how meaningful and accurate this categorisation of generation can be: how do they place a small windfarm in the far north of Scotland, distribution connected, but with aggregate Scottish windfarm production reliant on new transmission connections to reach the main GB load centres? This century began with a generation system based on a small number of large, efficient turbine-alternator generators connected through the newly built post-war transmission grid, see Table 6. By 2008, improving generation efficiency delivered energy prices at half, and carbon dioxide emissions at a third of 1949 values. The larger generator sites were built near existing coalfields, large harbours, or close to the gas grid – they followed the fuel source.

The last decade's development of generation has seen a move towards a greater number of smaller generators located more remotely from load centres. Table 7 follows Table 6 for renewable generators in 2018.

Table 6: Operational power stations by size, 1949 and 2008

Capacity MW	March 1949 Count	March 1949 Total capacity MW	May 2008 Count	May 2008 Total capacity MW
Under 10	143	331	11	56
10 to 24	45	774	13	138
25 to 49	27	1,002	14	311
50 to 99	39	2,815	6	67
100 to 149	21	2,539	6	535
150 to 299	17	3,332	6	1,315
300 to 399	3	1,012	4	1,455
400 to 499	—	—	9	3,698
500 to 999	2	1,038	22	15,685
1,000 to 1,499	—	—	15	18,994
1,500 to 1,999	—	—	9	12,970
2,000 to 2,499	—	—	4	12,576
over 2,500	—	—	1	3,945
Total	297	12,843	120	71,745

From DUKES 60th Anniversary, Table 5.1.[14]

The onshore wind fleet is clustered in two areas: Scotland (60% of onshore wind capacity) and Wales (~10%). These are the areas with the UK's highest wind speeds – generation is still following the fuel source. This clustering increases the correlation of production within each cluster and makes intermittency more severe.

The onshore wind generation fleet is located further from load centres than the generators of 2008, see Table 8. For the development of the Scottish onshore wind fleet two new,

Table 7: Operational renewable generators and capacity, 2018.

Capacity MW	Onshore wind Count	Onshore wind Total capacity MW	Offshore wind Count	Offshore wind Total capacity MW	Solar Count	Solar Total capacity MW
Under 10	3,568	2,101	3	11	8,808	4,213
10 to 24	184	2,883	2	22	171	2,523
24 to 49	80	2,667	2	80	33	1,155
50 to 99	34	2,178	12	981	5	305
100 to 149	9	1,136	1	108	—	—
150 to 299	6	1,276	7	1,475	—	—
300 to 399	1	322	4	1,359	—	—
400 to 499	—	—	2	802	—	—
500 to 999	—	—	5	2,942	—	—
Total	3,882	12,563	38	7,781	9,017	8,196

Source: Renewable Energy Foundation.[15]

Table 8: Location of onshore windfarm capacity with respect to populous cities (2018).

City (in declining size of population)	Summed capacity of closest windfarms MW	Percentage of total onshore wind fleet capacity %
London	186	2
Birmingham	1	0
Glasgow	3,878	35
Leeds	29	0
Bristol	31	0
Liverpool	237	2
Manchester	158	1
Sheffield	74	1
Edinburgh	2,952	27
Cardiff	751	7
Leicester	409	4
Stoke-on-Trent	2	0
Bradford	97	1
Coventry	107	1
Nottingham	85	1
Kingston-upon-Hull	591	5
Belfast	556	5
Newcastle	0	0
Sunderland	504	5
Brighton	68	1
Derby	19	0
Plymouth	193	2
Wolverhampton	170	2

Source: Calculations by the authors.

expensive transmission connections were required: the Beauly-Denny line, which controversially crossed the Cairngorms National Park, and the sub-sea HVDC Western Link. CR and TD will further increase the onshore wind fleet capacities, to 41 and 25 GW respectively by 2050, leading to still higher transmission costs and losses.

Offshore wind simply seeks higher wind speeds – again, following the fuel source. At present there are two clusters of generation, one in the Irish Sea and the other off East Anglia, and this clustering again heightens intermittency. The transmission connections involved are very expensive.

The solar fleet is connected to distribution grids. CR and TD will increase the solar fleet capacities to 52 and 42 GW respectively. The cost impacts of this positioning of the renewable fleets is included within the costing exercise (Section 4).

David MacKay, the Chief Scientist at the Department of Energy and Climate Change, calculated that onshore wind and solar (PV: 10% capacity factor) can produce 2.2 and 10 W respectively for every square metre of land area.[16] So in addition to the UK's 11% urbanised and 35% protected land we can expect another 9.7% (CR) or 9.3% (TD) of the UK landmass to be industrialised for renewable generation by 2050. With CR, outside our cities and national parks, one square kilometre in seven will be occupied by a wind farm and one in twenty-five by a solar farm, so country folk will be able to see and hear the projects they supposedly endorse. There is no reason to think that in the future this clustering of renewable generation will stop, it will always seek the most ideal generation conditions so the present cluster locations will become further congested.

Figure 13: National Grid's vision for the future?
Source: Raconteur.net.[17]

National Grid's FES study documents see a further dimension for decentralisation:

> This year we have assumed that district heating would be higher in a more decentralised world…The average size of such schemes (typically around 30 buildings) is also more aligned to a decentralised world…We have assumed that in a more decentralised world, consumers are more engaged with their energy use and so are likely to choose more efficient options where available…Decentralised solutions for transport demand could include small-scale, dedicated wind and solar plant, built where [electric vehicle] charging demand is greatest, for example in supermarket car parks, with co-located battery storage.

83% of the UK population live in urban areas. It is surely fanciful to expect such district heating schemes to flourish in a built, urban environment. Does National Grid really believe we will have wind and solar farms in the middle of our large conurbations (see Figure 13) supplying electric vehicle charging and district heating? Are we to have urban wind plant for charging electric vehicles, or believe that using battery storage facilities to charge vehicle batteries makes any economic sense?

7 Conclusions

The *Community Renewables* scenario is not worth pursuing

The energy flow analysis carried out in Section 2.1 shows that in the CR scenario consumers will experience a large number of DSR and voltage reduction incidents, and there will be many periods when the energy store is empty. Section 3 reveals that CR has high values of LOLP up to 2035. Although LOLP falls below 4% thereafter, these LOLP calculations were based on the premise that the whole storage capacity was available as a despatchable power resource; if the store is empty, this condition disappears and LOLP will climb to high values. The failings revealed in Sections 2.1 and 3 have common causes: too much solar generation, too little nuclear generation, an energy store that is too small in terms of storage capacity and too high in output capacity, resulting in a low store time. The problem of renewable intermittency has not been resolved.

Solar generation is not worth pursuing

The National Grid Summer Outlook 2019 states:[18]

> During the summer months solar generation has a more prominent impact on demand profiles. For a number of years maximum solar generation output has coincided with the fall in demand after lunchtime.

If this is so, then there seems little point in any expansion of grid connected solar generation, but in 2050 CR has 52 GW and TD has 42 GW of solar capacity compared to 13 GW in 2018. It is not clear how this will be manageable during summer months.

In 2012 National Grid issued a briefing note on the potential impact of solar PV on transmission system operation and balancing.[19] In this they note:

> …at the start of the [power] ramp up [in the morning], there could be no fossil generation synchronised apart from that providing frequency response. This will make the management of the ramp very difficult using plant that has just synchronised, wind, pumped storage and interconnectors…To maintain inertia, fault levels and HVDC commutation, wind/solar output must not exceed 60% of network demand…With 22GW solar PV the system would require an unacceptable dependence on the ability to export over the interconnectors, or the construction of additional storage.

In Section 2.2 it is demonstrated that the 42 GW solar fleet of the TD scenario can be replaced with a firm generation source of 2 GW – one nuclear power station. The financial gain of this switch is obvious. It would also save 420 square kilometres (over 100,000 acres) of agricultural land.

Ferroni and Hopkirk show that the ratio of energy returned over energy invested (EROEI) for solar generation in regions of moderate insolation, inclusive of storage to mitigate intermittency, is 0.8.[20] Their inclusion of storage in EROEI has been criticised since this is not included for baseload generation, but that is obvious nonsense. Nor can there be any requirement for storage for dispatchable plant. The spillage of renewable energy production demonstrated in Section 2.3 establishes the need for storage to be included in EROEI renewable generation. Ferroni and Hopkirk have demonstrated that solar generation in these National Grid scenarios will absorb rather than generate electricity.

With these serious difficulties, and observing that solar production will be near non-existent in winter when peak demand occurs, it seems senseless to support any further expansion of solar generation, either transmission or distribution connected, beyond the 2018 levels.

The *Two Degrees* scenario is very expensive, landscape intrusive, and faces considerable technical challenges

The TD scenario increases annual total system costs fourfold and trebles the per-unit costs between 2018 and 2050. The cumulative extra cost of the TD scenario compared to an alternative gas with CCS scenario is £1.4 trillion, or £52,000 per household spread over 31 years. The costs rise further (Section 4) if we acknowledge that TD wastes 42.6 TWh of 2050 generation in spillage and hydrogen production (Table 4). Not only are the generation technologies expensive to procure and operate but National Grid seeks to mitigate intermittency by designing the scenarios with excess capacity. Electricity generation will not be the only cost of meeting the Net Zero target – other domestic costs will include electric vehicle purchase, house insulation, modifications to heating systems – all high value items. Since there are cheaper alternatives to deal with electricity generation as part of the Net Zero project it would seem sensible to choose those and thus make the other costs easier to reach.

The costs revealed in Section 4 neglect the costs to meet all the SOF requirements, as explained in Section 5. These will be sizeable. The impact of part loading wind generators in order to provide load following[12] will reduce load factor and increase costs; a reduction of 5% would increase costs by £5 billion per annum. Choosing the nuclear or gas scenarios avoids this difficulty and suggests that research funding might be better directed towards carbon capture on the combustion process of CCGTs.[21,22,23]

Section 2 has revealed that the scenario does not run without periods when the system's energy store completely empties. Since the storage power capacity is taken as part of the dispatchable power for the LOLP calculation of Section 3 and this component would be compromised as the store runs down to empty, this would threaten to raise LOLP above the 4% standard. It is therefore important that this issue is resolved. Increasing the store to 1 TWh by adding another 650 GWh to the proposed size fixes the problem, but then so does adding 8 GW of nuclear to the generation mix. The nuclear option will be far cheaper and will provide valuable inertia to the grid at no extra cost.

The planned 349 GWh storage of TD in 2050 includes 250 GWh of pumped storage, three times the present storage capacity. This could be used to provide the response levels shown in Table 5, mitigating the impact of increasing non-synchronous generation in the grid generation mix (see Section 5). However, this will mean that the new pumped storage will have to be built to the standard of Dinorwig, with high head and short hydraulic time constant.

Imports of energy are vital to the management of the stored energy level. In the demand-generation modelling described in Section 2, the availability of interconnector power has been assumed to be 100% at all times. This is very unlikely to be the case if European grids are dominated by wind and solar generation. Solar generation will tend to be low at the same time and season across the whole of Europe, and wind generation can be compromised by pan-European regions of high pressure. The huge German onshore wind fleet operates at very low production levels because the wind resource is much weaker than that of the UK. The German Information and Forschung Institute has commented:

> [for] the year 2011…the installed capacity of [wind and solar] was 54 gigawatts. For some hours up to 27 gigawatts were generated, but at other times it was as low as 0.5

gigawatts. The average generation was 7.3 gigawatts. The secured capacity that was available in 99.5 percent of all hours was only 0.9 gigawatts.[24]

One of the tools used to mitigate intermittency is residential flexibility of demand. This requires time of use tariffs (TOUTs), installation of smart domestic appliances, ubiquitous smart metering and half-hourly tariffs, and more electrically heated hot water tanks in homes. In 2016 National Grid provided predictions of demand reductions due to TOUTs of 1.5 GW by 2040; in 2019 no TOUTs predictions were given, presumably because of the slow rollout of smart metering (the latest scheme cost £12 billion – or £444 per household – and GCHQ are now raising security objections). Given the trivial demand reductions that follow from the use of TOUTs this project hardly seems to offer value for money, but National Grid state that smart metering will deliver cheaper and less carbon-intensive electricity. On present evidence this is difficult to believe.

In 2050, the scenario includes 42 GW and 24 GW of solar and wind generation, requiring 1% of GB's land area, nearly all in rural areas. There are bound to be objections and resentment of this industrialisation of the landscape. Tracking the incoming insolation energy budget of a solar farm shows that the surplus insolation reaching the land beneath is halved; it falls below insolation levels of northern Norway. This will certainly affect amphibian habitat and leave the land in poor condition when the solar farm is decommissioned.

Each of the difficulties of the TD scenario discussed in this section should raise the question of whether this method of reducing carbon dioxide emissions problems is anywhere close to being sensible.

The Gas and Nuclear scenarios work very well

The *Gas* and *Nuclear* scenarios, by comparison with all the National Grid scenarios, are inexpensive, secure, require little new transmission or distribution grid expansion, and no development of augmented ancillary response services. They do create carbon dioxide emissions, but at very low rates. Adding a form of CCS to the gas generation of these scenarios could solve this problem. Or perhaps we could increase nuclear generation beyond the 45 GW of the nuclear scenario.

The alternative is the TD scenario, where emissions saving per ton of carbon dixide costs £1,347 or £1,573 relative to the *Gas* and *Nuclear with CCS* scenarios respectively.

It would be possible to achieve a faster rate of emissions cuts in these scenarios if the deployment of new nuclear generators could be accelerated, perhaps using small modular reactors alongside larger plants, and implementation of an early retirement programme for older CCGT plant, replacing equipment with efficiency below 50% with new CCGTs with over 63% efficiency.

Costs could be cut further if the target emission level is not set arbitrarily to zero but to a level beyond which the costs of cutting emissions start to rise more quickly. In other words, a simple plant mix of nuclear plant and high-efficiency CCGTs may be considered adequate. Such a production mix would require little new transmission construction, avoid all concerns about grid inertia, and would require no modification to the grid ancillary services regime.

The FES methodology requires improvement

This is perhaps the fifth year that National Grid have published their FES report, each year increasing the time span of their studies and adorning the generation possibilities with more exotic renewable jewellery. But they make no attempt to cost their suggestions, and they neglect any integration of their own work within the System Operability Reports, and their Winter and Summer Outlooks.

It would seem obvious that nuclear generation should play a significant part in any carbon dioxide emissions programme and, free of charge, add valuable synchronous generation and thus system inertia to the generation system. Nuclear generation would bring three benefits: reliable, affordable, year-round baseload, lower values of LOLP even if mixed with renewable generation, and a large increase in system inertia and thus system stability. Despite this, nuclear generation in 2050 falls below 10 GW capacity in all National Grid's scenarios apart from TD.

Hydrogen-powered vehicles arrived in the FES scenarios in 2018 and more detail has been provided in the current iteration. National Grid propose hydrogen vehicle propulsion at levels involving 30 TWh of annual production. This is in addition to another fleet of vehicles powered by batteries, and without any consideration of increased manufacturing costs of two vehicle types, and the possible need for an additional pipeline system for hydrogen delivery.

In order to form the basis for rigorous and responsible engineering discussion the FES scenarios should be expanded to include traditional, low-emission generation such as nuclear and cover the issues raised in this paper.

Appendix A: Analysis of generation and demand flows

The objective of this analysis is to understand and assess the production and demand energy flows of National Grid's *Community Renewables* (CR) and *Two Degrees* (TD) scenarios for 2050. Since the loss of load probability (LOLP) calculations in all scenarios rely on the availability of dispatchable, grid-attached storage in the years towards 2050, this analysis will reveal any conflict between the need to meet demand at all times, and to maintain grid security. The analysis has three components:

- modelling of the total system demand with a time resolution of half an hour,
- modelling of grid production, particularly renewables, with a time resolution of half an hour, and
- modelling of the energy flows between demand and generation, using storage, interconnectors, OCGT production, hydrogen production and all DSR facilities while tracking the status of the grid attached storage.

A1 Modelling total demand

Settlement data are taken from the Elexon website, which details energy supplied for every half hour in 2018; this sums to 275 TWh. Table 4.1 of the FES 2019 workbook gives 2018 demand as 107 TWh residential, 178 TWh industrial, 0.4 TWh electric vehicles, and 0.025 TWh hydrogen production, totalling 285 TWh.

Intertek's *UK Household Electricity Survey* gives us half-hourly household energy consumption data for normal weekdays, weekends, and holidays and an annual household energy consumption of 3,814 kWh.[25] A half-hourly, annual domestic consumption profile is created and then scaled to a national consumption of 107 TWh for 2018.

National Grid's 2018 half-hourly settlement data is scaled from a total of 275 TWh to 285 TWh, the 2018 domestic consumption profile described above is subtracted from this, and the result is assumed to represent the 2018 industrial demand profile.

The 2018 domestic and industrial profiles are scaled to the demand levels for the 2050 *Gone Green* scenario (109 and 175 TWh respectively – the scaling factors are modest).

Tables 4.25–4.27 of the FES spreadsheets give the half-hourly charging profile for one electric vehicle over the course of one week. This indicates a weekly demand of 32 kWh, sufficient for perhaps 120 km per week. This profile can be repeated over a year and then scaled to the 89.5 TWh given for electric vehicle demand[26] for the *Gone Green* scenario in 2050.

Table 4.1 indicates 49.4 TWh will be used in electrolytic production of hydrogen; Figure 4.30, p. 95 of the main FES document[2] indicates 40 TWh demand for hydrogen production, resulting in 30 TWh of hydrogen energy, enjoying an efficiency of 75%. The second of these two productions is modelled. No power capacity is given for this electrolysis plant, so this demand is assumed to consume all surplus generation until the production target is achieved.

A2 Modelling renewable production

No solar production data is given by the Balancing Mechanism Reporting System as published by Elexon. However, solar insolation can be modelled from airfield weather observations with an accuracy of between 2 and 4%.[5] From this data it is possible to develop a solar production profile based on observations between 2005 and 2018. This can be scaled to the capacity of the 2050 CR and TD solar fleets.

Wind data is only partly reported in the settlement data; the embedded fleet is not reported. Wind production can be modelled from airfield weather reports.[6] Figure 14 shows the probability distribution functions of renewable production for the CR and TD scenarios.

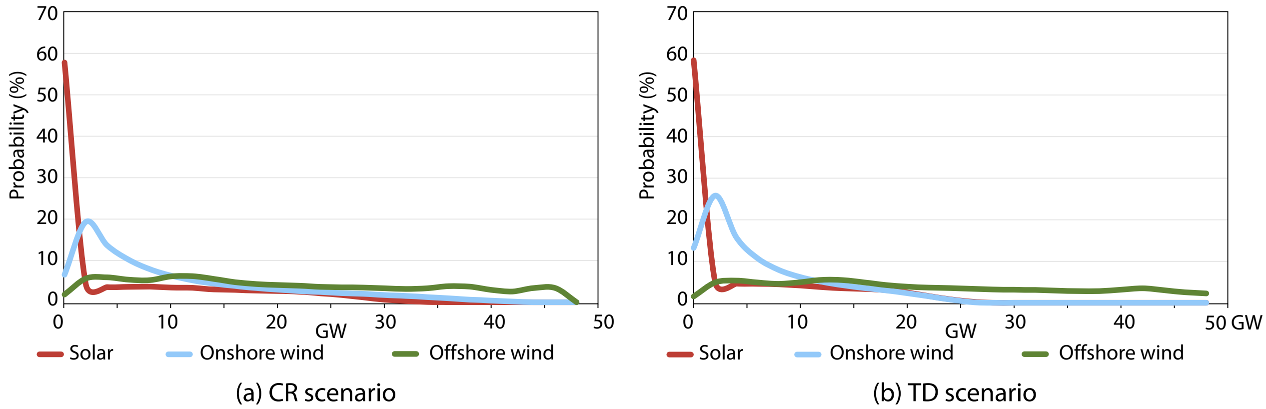


Figure 14: Probability distribution functions for renewable production

In 2009, wind generation was mostly onshore and for that year it was possible to examine the correlation between the settlement wind reports (scaled to reflect post-hoc annual production data) and the model results. Given data from the Renewable Energy Foundation on wind farm locations and monthly production reports, it has been possible to refine the onshore model to match production to within 1% and a correlation factor over 0.7 (see Figure 15a,b).

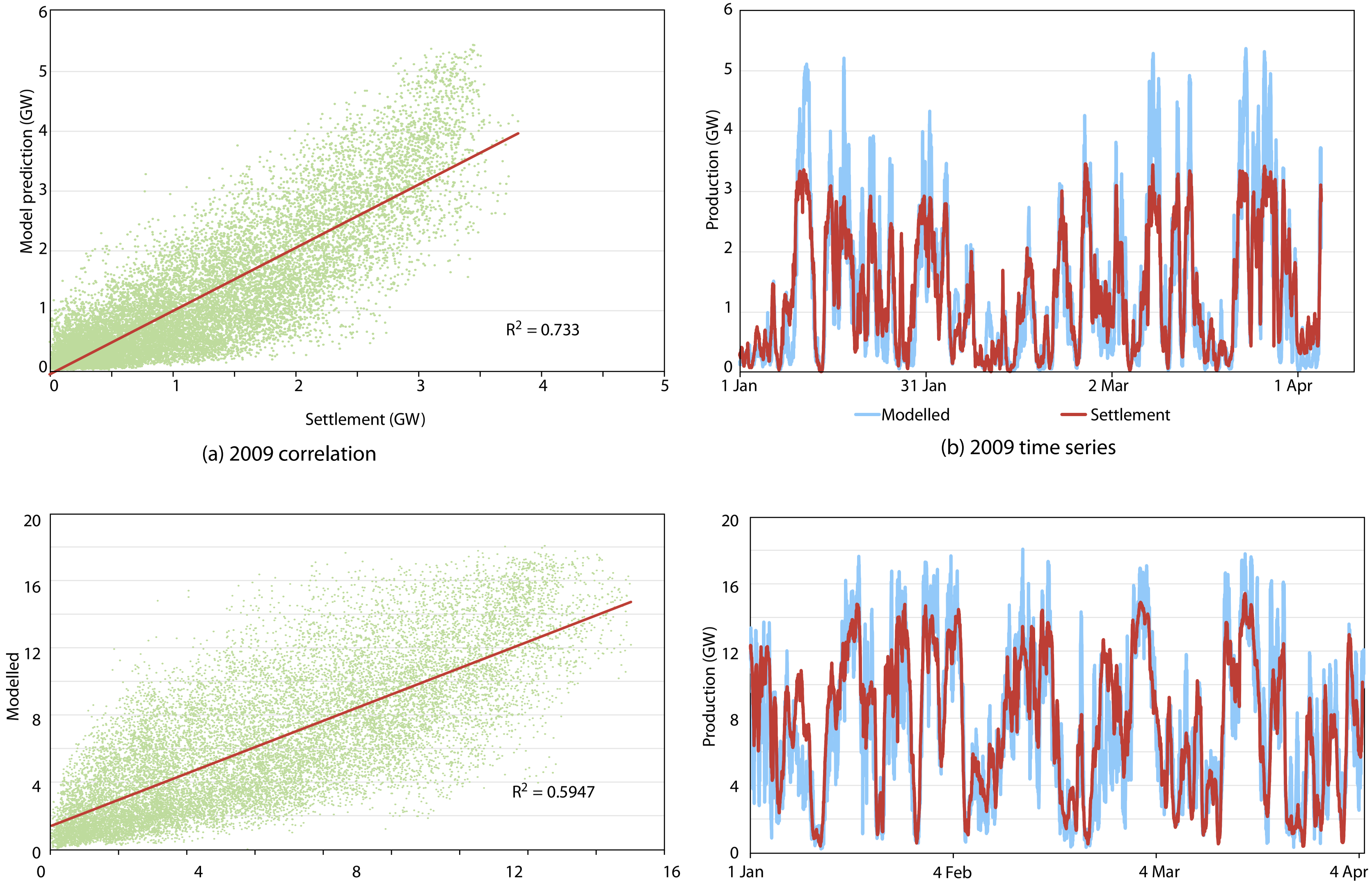
In 2018, offshore wind production is now similar to onshore production and is material to the overall model. However, no previous model of offshore production exists, and we do not have separate production data for the two fleets.

We can scale the 2018 onshore fleet production from the 2009 onshore fleet's production with reasonable confidence since the geographic distribution in the two years are similar. Subtracting this 2018 onshore model data from the 2018 wind settlement gives us an approximation for the offshore fleet production. Most of the offshore wind fleet (90%) is positioned close to only three airfields, so a model of offshore production based on wind data for these airfields is quite simple – the only constants that require adjustment are the von Karman wind shear variables. Figure 15c,d shows the results of this development. The production agreement between 2018 settlement and model data for onshore and offshore wind is within 1%. The separate on- and offshore wind models are scaled to the levels of installed capacity and capacity factor of the TD scenario (c.f. Table ES1[1]).

In both scenarios the production for hydro, marine and other renewables are spread evenly through one year and this added to the solar and wind 14-year time series models. A separate time series describes the contribution of nuclear, CCS and biomass.

A3 The demand flow analysis model

The 14-year production model is run repeatedly against the Demand model for the 2050 *Two Degrees* scenario. The 2050 CR scenario lists CCGT and OCGT capacities of 4,937 MW



(a) 2009 correlation

(b) 2009 time series

(c) 2018 correlation

(d) 2018 time series

Figure 15: 2009 and 2018 production: modelled and settlement data.

and 10,883 MW respectively. The CCGT has hardly run at all over the previous 20 years, so it is difficult to see why this is specified as CCGT rather than OCGT; the combined gas fleet size of 15,820 MW is assumed to act as backup power in the flow analysis model; in TD the combined gas capacity is taken as 12,999 MW.

The storage details are operated to the data limits given in Table ED1 and taken as:

- for CR, as store capacity 145 GWh, store input/output power 40,169 MW, with a turnaround efficiency of 75% applied symmetrically between storage and extraction
- for TD, as 349 GWh store capacity, store input/output power 32,393 MW, with a turnaround efficiency of 72.75% applied symmetrically between storage and extraction.

Interconnector import and export capacity in CR is 16,505 MW, and in TD 20,055 MW.

The store operates in half-hour steps and first calculates the difference between demand and generation. If there is a surplus, then the following sequence attempts to remove it by first:

1. Topping up the energy store if required, taking full account of storage capacity and power input limits, then
2. If the annual hydrogen production has not been reached, the entire surplus is consumed in this activity, and finally
3. If possible any remaining surplus is disposed of via the interconnectors, otherwise it is deemed spilt (i.e. will have to be constrained off).

If there is a deficit in production the following sequence is followed in this order:

1. The interconnectors are used to reduce the deficit.
2. Energy is extracted from the store.
3. The OCGT fleet is run to the required capacity.
4. DSR is applied (in both scenarios to a limit of 6.7 GW).
5. Voltage reduction is applied.

During these energy flows, events such as the store being empty and the voltage reduction being greater than 7.5% (which indicates a need for load shedding) are accumulated for each year of operation.

A4 Overview of results

Each year's meteorological data will produce variable production figures for the generation and the store performance. An overview of these results follows.

Table 9: CR model data for zero-carbon generation.

Basis year*	Solar TWh	Wind Onshore TWh	Wind Offshore TWh	Total renewable TWh	Biomass & nuclear TWh	Total generation† TWh
2005	47.0	93.1	151.8	326.3	68.9	395.2
2006	49.3	89.9	185.6	359.1	68.9	428.0
2007	49.1	94.0	184.7	362.1	68.9	431.0
2008	49.2	99.4	194.3	377.2	68.9	446.1
2009	50.0	92.7	181.6	358.6	68.9	427.5
2010	50.1	71.9	166.3	322.7	68.9	391.6
2011	49.7	94.4	190.7	369.2	68.9	438.1
2012	48.1	87.1	180.2	349.7	68.9	418.6
2013	48.8	96.9	187.1	367.1	68.9	436.0
2014	49.9	91.1	183.3	358.7	68.9	427.6
2015	49.1	103.8	193.1	380.3	68.9	449.2
2016	48.2	81.5	175.2	339.2	68.9	408.1
2017	47.3	91.1	182.1	355.0	68.9	423.9
2018	49.0	87.5	167.6	338.5	68.9	407.4
Stated 2050 FES production	47.7	92.9	175.6	350.5	68.9	428.0

*Meteorological year on which prediction based. †Total generation excludes drawdown from the store, CCGT/OCGT and interconnectors. Figures in red show results where modelled production falls below FES prediction.

Table 10: Performance of the CR scenario when production was below demand.

Basis year*	Hours with voltage reduction: Applied	Hours with voltage reduction: >7.5%	Hours with store empty	DSR total GWh	Import required TWh	Gas prod'n TWh
2005	159	108.5	1,070	1,405	51.8	14.6
2006	124	84.5	898.5	1,163	44.6	13.0
2007	121.5	72	966.5	1,130	44.4	12.4
2008	80	50	714	772	41.1	9.6
2009	138.5	89.5	956	1,220	45.5	12.9
2010	190.5	119.5	1,307.5	1,651	53.4	16.6
2011	86.5	50	688.5	773	43.0	9.7
2012	133	90	920	1,245	46.3	13.1
2013	111	72	774.5	988	43.7	10.9
2014	91.5	64	591	807	44.0	9.5
2015	87	50.5	779	829	41.2	9.8
2016	137	99	1,013.5	1,242	48.5	13.7
2017	107.5	70.5	693.5	929	44.7	10.6
2018	103	67.5	768.5	990	48.3	11.6

*Meteorological year on which prediction based.

Table 11: Performance of CR scenario when production exceeded demand

Basis year*	Export TWh	Store losses TWh	H_2 production Use TWh	H_2 production Losses TWh	Spilt or constrained off TWh
2005	23	3.8	31	10.3	21.0
2006	34	3.1	31	10.3	33.9
2007	35	3.1	31	10.3	35.2
2008	39	3.2	31	10.3	40.7
2009	35	3.3	31	10.3	33.8
2010	22	3.6	31	10.3	21.2
2011	37	3.3	31	10.3	37.0
2012	31	3.3	31	10.3	29.1
2013	37	3.0	31	10.3	36.6
2014	32	3.4	31	10.3	31.8
2015	41	2.8	31	10.3	42.8
2016	27	3.4	31	10.3	25.6
2017	31	3.3	31	10.3	31.0
2018	26	3.4	31	10.3	23.6

Table 12: TD model data for zero-carbon generation.

Basis year*	Solar TWh	Wind Onshore TWh	Wind Offshore TWh	Total renewable TWh	Biomass & nuclear TWh	Total generation† TWh
2005	37.8	57.3	173.1	309.8	115.3	425.1
2006	39.6	55.3	211.7	348.2	115.3	463.5
2007	39.5	57.8	210.7	349.5	115.3	464.8
2008	39.6	61.1	221.5	363.8	115.3	479.2
2009	40.2	57.0	207.1	345.9	115.3	461.2
2010	40.3	44.2	189.7	315.8	115.3	431.1
2011	40.0	58.0	217.5	357.2	115.3	472.5
2012	38.7	53.5	205.5	339.3	115.3	454.7
2013	39.2	59.6	213.4	353.8	115.3	469.1
2014	40.2	56.0	209.1	346.9	115.3	462.2
2015	39.5	63.8	220.2	365.1	115.3	480.4
2016	38.7	50.1	199.9	330.3	115.3	445.6
2017	38.1	56.0	207.7	343.4	115.3	458.8
2018	39.4	53.8	191.2	326.0	115.3	441.3
Stated 2050 FES production	39.6	57.6	210.4	350.5	115.3	470.1

*Meteorological year on which prediction based. †Total generation excludes drawdown from the store, CCGT/OCGT and interconnectors. Figures in red show results where modelled production falls below FES prediction.

Table 13: Performance of the TD scenario when production was below demand.

Basis year*	Hours with voltage reduction: Applied	>7.5%	Hours with store empty	DSR total GWh	Import required TWh	Gas prod'n TWh
2005	16.5	10.5	105.5	153	46.6	3.7
2006	25	9.5	347	272	37.5	3.8
2007	12.5	8.5	82.5	114	37.7	2.6
2008	4.5	1.5	102	64	34.2	2.2
2009	16.5	8	142.5	163	38.8	3.2
2010	14.5	4	119.5	132	45.1	3.4
2011	1	0	52	31	35.7	2.1
2012	14.5	6	101	133	39.3	2.9
2013	12.5	8	110	121	36.7	2.6
2014	9	6	81	83	35.8	2.3
2015	1.5	0	57	18	33.4	1.9
2016	23	10	189	231	40.9	3.5
2017	14.5	7	143.5	138	37.5	2.7
2018	6	4	59.5	59	40.2	2.4

*Meteorological year on which prediction based.

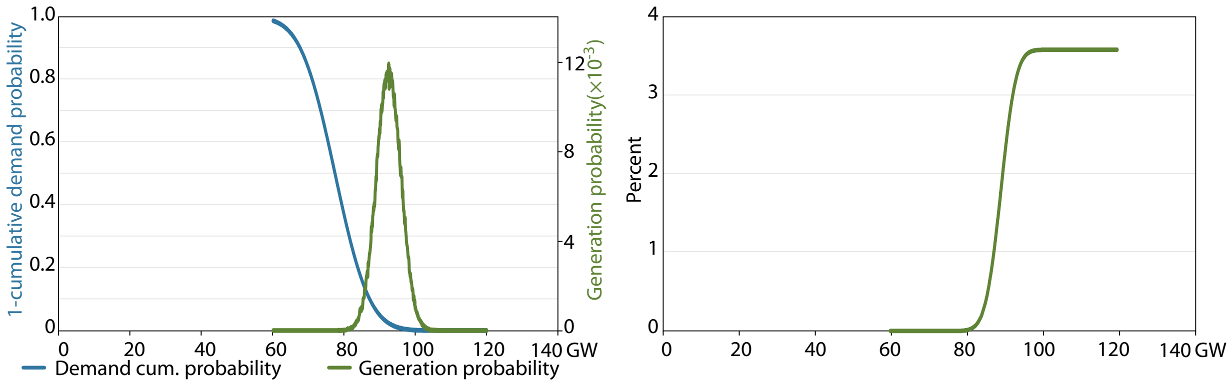
Table 14: Performance of TD scenario when production exceeded demand

Basis year*	Export TWh	Store losses TWh	H_2 production Use TWh	Losses TWh	Spilt or constrained off TWh
2005	38	2.6	30	10.0	21.7
2006	55	1.7	30	10.0	34.7
2007	54	2.0	30	10.0	35.8
2008	61	1.7	30	10.0	40.2
2009	54	2.1	30	10.0	34.0
2010	40	2.5	30	10.0	24.6
2011	57	1.7	30	10.0	38.8
2012	51	2.1	30	10.0	30.9
2013	57	1.8	30	10.0	36.7
2014	53	1.7	30	10.0	32.7
2015	60	1.6	30	10.0	40.9
2016	47	2.0	30	10.0	28.2
2017	52	1.7	30	10.0	32.5
2018	44	1.9	30	10.0	24.5

Appendix B: Loss of load probability calculations

B1 Overview of the analysis method applied to a national system

Loss of load probability (LOLP) provides a measure of the likelihood of supply loss and is calculated by consideration of the probability distributions of the demand and generation functions at the time of system maximum demand. Figure 16a is based on an analysis of the FES 2018 *Gone Green* scenario in 2050.



(a) Demand and generation probabilities

(b) Cumulative risk of loss of supply

Figure 16: LOLP analysis

ACS predicted demand 78 GW, standard deviation 9.8%, 109 GW despatchable nameplate capacity, 85% availability, deviation 3.75%. (a) shows 1-cumulative demand probability against generation probability.

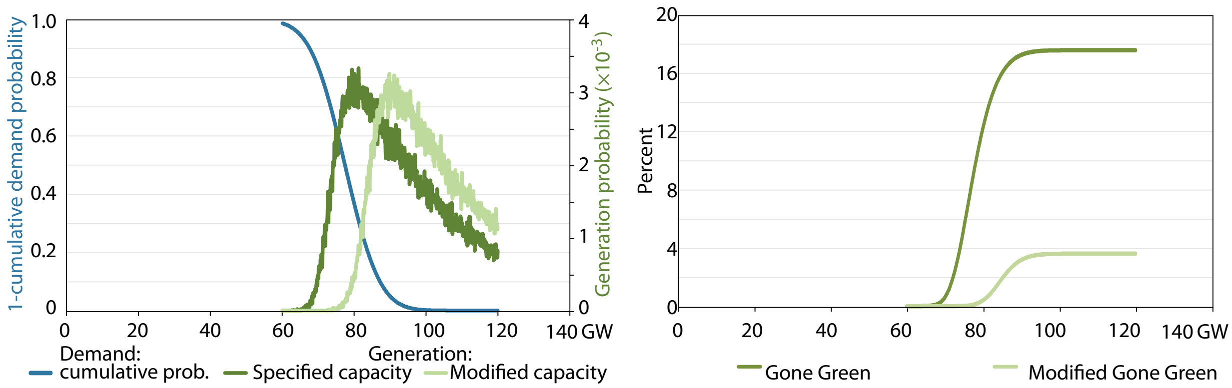
Demand in this analysis was expected to be 78 GW with a standard deviation of 9.8%; the blue curve is the 1-(cumulative probability distribution of demand). At 60 GW of generation it shows a probability of 1 (100% certainty) that the demand will exceed this level and that demand will have low probability of exceeding 100 GW.

The green curve is the generation probability curve for 109 GW of fossil fuel plant, 85% availability and a standard deviation of 3.75% (right hand axis). The demand and generation curves overlap, showing that there is a possibility demand could exceed generation. If we sweep across the generation probability curve and sum the generation/demand probability products we will determine the loss of load probability, see Figure 16b.

For further clarification, imagine two situations:

- Generation far exceeds demand, moving the generation curves to the right, the overlap disappears, and the product of generation and demand probabilities must be zero.
- Demand far exceeds generation, the generation curve always coincides with the demand curve where the probability is always 1, so the product sum will be equal to the area of the generation probability curve, which must be 1 (100% LOLP).

The impact of increasing the proportion of wind to the generation mix is to widen the generation probability function and to shift it away from normal distribution, see Figure 17a. This invariably increases the LOLP and requires additional firm capacity to reduce it again; see Figure 17b.



(a) Demand and generation probabilities

(b) Calculated risk

Figure 17: Effect of increased renewable generation.

Effect on *Two Degrees* scenario estimate from equivalent *Gone Green* scenario from FES2018.
Base scenario has 84 GW dispatchable, 109 GW wind and solar, no interconnectors, 17.6% LOLP.
Modified scenario has extra 12.2 GW firm capacity, no interconnectors, and has only 3.6% LOLP.

B2 Extraction of relevant data from the FES documentation

System maximum demand data for the scenarios are taken from Table 4.2 of the FES workbook.[1] This is reduced by subtracting DSR (Table 4.11) and then 7.5% of remaining demand following two stages of voltage reduction and frequency adjustment. Demand is assumed to have a Gaussian probability density function with a standard deviation driven by a combination of economic and weather uncertainties, as shown in Table 15.

Table 15: Drivers of demand standard deviation over the period 2018–25.

	System maximum demand standard deviation (%)							
	2018	2019	2020	2021	2022	2023	2024	2025
Economic effects	1	1	2.5	4	5.5	7	8	9
Weather effects	3.87	3.87	3.87	3.87	3.87	3.87	3.87	3.87
Resultant SD	4	4	4.6	5.6	6.7	8	8.9	9.8

Based on the Electricity Council Report on the Security Standard, 1985.[27]

Generation data is derived for each scenario as follows:

- All generation capacity is taken from Table ES1 of the FES workbook.[1] Firm, dispatchable capacity is taken as the sum of storage, biomass, CCS combined heat and power, gas, coal, other thermal, and nuclear capacities. These summed capacities are multiplied by 0.85 to allow for planned and un-planned plant outages, and this value is then taken as the median of a Gaussian production distribution with a SD of 3.75%. (The authors are aware that both the demand and the generation PDFs may be 'fat-tailed' and not Gaussian, which would increase the risk values.)
- For wind generation, the power distribution functions are derived from work described in *Wind Power Reassessed*,[6] scaled to match the installed capacities of each scenario.
- Solar generation can make no contribution to meeting demand since maximum demand always occurs in winter.

B3 Calculation of interconnection allowance

All the scenarios in FES 19 place considerable reliance on interconnection. It is necessary, therefore, to consider the proportion of the interconnection capacity that will contribute to generation in-feeds at times of peak demand. Two options were considered. The more classical method would be a full bivariate approach considering Western Europe and Ireland as the larger sub-system, and GB as the smaller sub-system.[28] This would require extensive data on the Western Europe and Ireland systems, which were not immediately available to the authors. It would also require a considerably larger computing facility than was available. A more practical method was to use the Circle Diagram Method described in GBSQSS.[8] It is recognized that this is stretching the normal application of this methodology.

The method was applied by first considering Western Europe (mainland) as the larger sub-system, and GB and Ireland as the smaller sub-system. The method then considered GB as the larger sub-system, and Ireland as the smaller sub-system. Due allowance was made for the limiting capacity of the interconnectors. From these figures, the net interconnector allowance available to GB could be calculated.

Assumptions were made regarding the growth of peak demand in Western Europe, and in Ireland post 2026. For these studies, figures of 2% p.a. for Western Europe, and 1.25% p.a. for Ireland were assumed.

The formula for the circle diagram was determined to be:

$$y = -0.0019x^2 + 0.17x + 0.2283$$

from the 'best fit polynominal' to the diagram in GBSQSS. Where y is the interconnector allowance as a percentage of total ACS peak demand and x is the sum of demand and 'thermal equivalent' generation in the smaller sub-system as a percentage of twice the total ACS peak demand.

Studies were run for the two scenarios CR and TD, and the interconnection allowance was expressed as a percentage of the interconnection capacity. The results are shown in Figure 18.

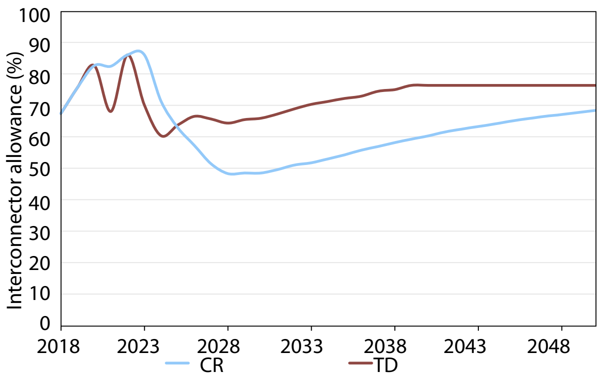


Figure 18: Interconnector allowances as percentage of interconnector capacity.
From circle diagram analysis.

The interconnector allowance values were utilized in the LOLP Security of Supply studies as generation in-feeds having the same probability density function characteristics as thermal generators.

Appendix C: Costing method

C1 Overview

The objective of the present study is to assess the costs (not prices) of the scenarios described in National Grid's *Future Energy Scenarios* 2019 (FES 2019) from the perspective of the UK economy.

We evaluate the costs of generating for each mega-watt hour (MWh) of energy supplied to the grid, usually termed the levelised cost of energy (LCOE). This is defined by the formula:

$$\mathrm{LCOE} = \frac{\text{Net present value of all costs of electricity generation}}{\text{Net present value of all generation}}$$

LCOE is a view of energy costs restricted to the perspective of the owner/operator of the generating plant. The then government department, the Department of Energy and Climate Change (DECC), carried out LCOE studies for a wide range of generation technologies.[29] The technique requires gathering of historical data for plant planning, construction and commissioning, operational performance and maintenance costs, project financing (which includes investment borrowing mechanisms and debt placement during operation), charges for connection to the transmission system and rates and decommissioning. Discounted cash flow analysis is used at several stages, which will require a variety of debt rates. Each generation technology requires a separate study. The method assumes the plant load factor is restricted only by the plant availability, and not by other system issues.

National Grid provide summary data for each technology's costs for specified load factors, generation life, fuel costs and other parameters, but actual LCOE will vary with the achieved load factor that each generator (or technology type) experiences in each year of operation, which is largely dictated by the grid system operator. For this purpose, we have used an alternate LCOE analysis tool produced by IESIS, which allows user entry of parameters (including load factor) in order to estimate operational LCOE.[30] We compared the DECC and IESIS methods in our analysis of FES 2016 generation costs,[31] but since then we have updated various parameters in our calculations of LCOE. As in that earlier paper, Tables 16 and 17 show our present input parameters and compare the results with the (somewhat dated) DECC LCOE values.

The IESIS analysis tool also costs the system integration charges for new, renewable generation. There are four extra charges attached to renewable generation:

- a revenue charge for the provision of response if the generation type cannot provide additional power when asked by the system operator, and/or the output varies in an operational timescale e.g. wind velocity varies;
- a capital charge to build additional plant covering loss of generation due to intermittency;
- a capital charge for new transmission plant;
- a revenue charge for the marginal transmission losses of renewables.

In our study of FES 2016, the first three charges were included; the fourth charge would require full studies of the transmission and distribution networks. The second charge is costed as a back-up fleet of OCGTs covering the available nameplate capacity of the renewable fleet type, subtracting any capacity credit the fleet has as despatchable plant. For solar, with no capacity credit for loss of load mitigation, this OCGT ghost fleet would have the same size as the available solar nameplate capacity. In this study we have removed this second item because mitigation of intermittency is supplied through the provision of storage. The charge is still applied, but costed within the storage component, see Appendix C4. The system integration costs shown in Table 17 include extra transmission capital costs, the operational system costs of intermittency, and the extra generation capital costs required to meet the Standard of Security of Supply. They do not include extra marginal system losses, nor extra system revenue costs associated with low inertia.

Table 16: Input parameters used for comparison with DECC results (see Table17).

	CCGT	OCGT	Biomass	Nuclear	CCS	Wind		Solar
						On	Off	
Construction £000/kW	0.61	0.32	2.5	4.5	9.4	1.5	3.4	0.8
O&M £000/MW/yr	30.8	14.3	111.5	61.5	69.1	44.6	115.8	22.4
Load factor (%)	93	7	65	91	93	28	39	11
Efficiency (%)	47	35	35	35	35			
Planning yrs	2	2	2	3	2	1	2	0
Construction yrs	2	2	2	6	5	1	2	1
Operation yrs	25	25	22	60	25	24	22	25
Fuel cost p/therm	64	64	86	0	16	0	0	0
Overall borrowing rate (%)				8.5				

Source: derived from various tables in the DECC study of LCOE[29] and a study of the UK generation system.[32]

Table 17: Comparison of LCOE per DECC and per the IESIS model used in this study.

LCOE (£/MWh) per:	CCGT	OCGT	Biomass	Nuclear	CCS	Wind On	Wind Off	Solar
DECC (Table 8)	62	149	123	89	116	100	113	122
IESIS:								
Without system costs	59	170	157	106	142	97	124	151
With system costs						157	209	210

The differences between the two can be explained by observing that:

- The biomass LCOE is based on the capital cost of building new biomass plant, whereas the DECC figure is for biomass conversion.
- The CCS IESIS calculation is based on the experience reported at the Boundary Dam Project in Canada.

We have updated our capital and revenue costs for renewables following our recent studies of the UK generation system.[32,33,34]

C2 Variations to DECC parameters used in the present study

We have updated the fuel prices used for the present study. We take gas to be priced at 40 p/therm, and coal at 16.4 p/therm. These are fixed throughout the study.

The impact of ageing is calculated for all renewables. In the case of wind turbines we assume 1.7% per annum, this being a central estimate found in a study by Staffell and Green (2013);[35] Hughes found much higher values[36] and reported 'The normalised load factor for UK onshore wind farms declines from a peak of about 24% at age 1 to 15% at age 10 and 11% at age 15'. We have taken the conservative approach of adopting Staffell and Green's lower figure.

In the case of solar ageing there is an exhaustive literature study of the subject by Jordan and Kurz,[37] from which we take a central value of 1% per annum.

C3 Capacity and production data source

National Grid provide a large data pack with their FES document. This includes an Excel workbook and we have used worksheet ES1 from that to derive this data.[1]

C4 Costing the use of storage

The FES Excel workbook details the store type, store input and output power capacity and energy storage capacity each year for four scenarios. Four storage types are used:

- batteries (round trip efficiency 86%)[38]
- liquid air (50%)[39]
- compressed air (71%)[40]
- pumped storage (72%)

The average annual storage efficiency is calculated as the power capacity weighted average efficiency for these four types. We have developed a new LCOE calculation sheet for storage that follows the same outlines as all the other 'IESIS' LCOE sheets. The four storage technologies have different capital costs, round-trip-efficiencies, and plant life; this data is available in a 2019 US Department of Energy Report[41] and enables us to calculate a unique LCOE for each storage technology. An energy capacity weighted average storage LCOE is then generated for costing purposes. A separate study has investigated how the attached storage will alleviate the intermittency of wind and solar (see *Notes to the Demand Flow analysis spreadsheet*). This provides data on the amount that the storage system is used, i.e. the load factor for the storage system. The production weighted average of the system charges for offshore and onshore wind and solar is calculated and this is used as the fuel cost for the storage costing sheet. With these inputs in place the cost of operating each scenario's storage for each year can be added to the total system costs.

This issue is irrelevant for the Gas and Nuclear scenarios, since these are restricted to using storage only for response and reserve; there are no intermittency problems to resolve.

C5 Miscellaneous LCOE values also used in this study

The IESIS study does not include an analysis of costs for all technologies. Since, for the most part, these do not vary across the scenarios, their comparative impact on costs is small. We have therefore used cost constants extracted from the DECC LCOE study, as shown in Table 18.

Table 18: Additional LCOE values

Technology	£/MWh
CHP	90
Hydro	130
Marine	108
Interconnectors	80

Appendix D: Development of the *Gas* and *Nuclear* scenarios

Both scenarios are based on the production requirements and ACS data for National Grid's TD scenario. The evolutions of the new scenarios follow these common first steps:

1. The two alternative strategies turn away from using wind and solar because they are intermittent, variable, require extension of the transmission and distribution systems, and are expensive. The UK has made a significant investment in these technologies, ignoring the signals of lower costs and carbon dioxide emissions that follow pursuit of a mixed gas/nuclear generation fleet. These alternative systems would have saved 350 million tonnes of carbon dioxide and £90 billion over the period to date compared to our present system (see Figure 19).

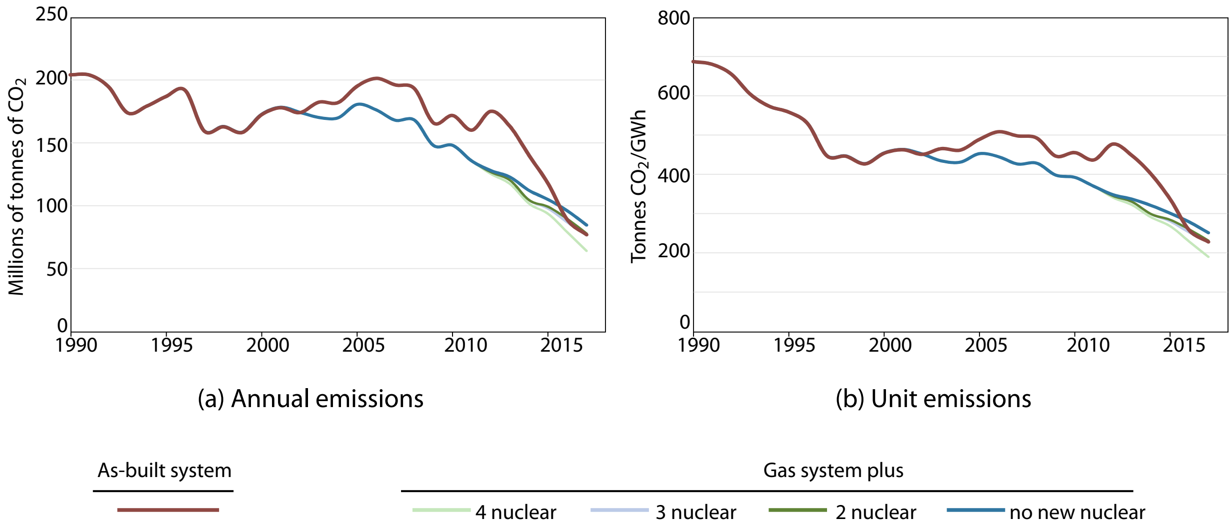


Figure 19: Performance of *Gas* scenario compared to our as-built system.

2. In 2020, the procurement of new wind and solar projects is stopped, with approved projects allowed to complete to 2022. The existing wind and solar projects will have ROCs and CfD contracts in place. These will be run to completion but not renewed. It is assumed that these projects will immediately close at the end of these contracts, leading to a slow reduction in wind and solar generation. This retirement schedule is based on commissioning/accreditation data from REF tables.[42]
3. Support for other types of renewable project (such as anaerobic digestion, small scale hydro) will be curtailed on the same basis as wind and solar.
4. New interconnector projects cease after 2025, since they will not be required to support UK supply. Interconnectors will not be disconnected if they are needed for wheeling supply to Ireland.
5. The environmental impact and carbon reduction scale of burning wood pellets sourced from the USA seems questionable.[43] No new biomass is procured after 2025 and is rolled back to 5 GW capacity by 2035.

6. No new storage is procured beyond an installed capacity of 7 GW of pumped storage since expansion to mitigate renewable intermittency will not be required; these installations will be used to provide ancillary grid services such as response and reserve. The existing, operational pumped storage capacity of around 4 GW would be sufficient for these services, but an additional 3 GW has already had planning approval.
7. Based on the high cost of previous carbon capture trials that depend on exhaust gas scrubbing, no new projects of this type will be attempted.[44] The gas and nuclear scenarios assume that the promising development of high-efficiency, super-critical gas turbines[45,46] or Allam-cycle[47,48,49] gas turbines will be successful. These technologies become available at large scale by 2035. Both Allam-cycle and super-critical gas turbines allow carbon dioxide capture directly from the combustion chamber; the Allam cycle also eliminates NOx emissions.
8. After two decades of wave and tidal stream generation research we have no operational projects working at a scale that can claim the Saltire prize.[50] The proposed Swansea barrage revealed the exceptionally high cost of such projects. It is assumed that this technology will remain insignificant to 2050; see, for example, this latest risible idea:[51] 'A submerged buoy sits a few metres below the surface of the ocean and moves with the ocean's waves. This orbital motion drives a power take-off (PTO) system that converts this motion into electricity'.
9. The expected retirement/closure of nuclear plant and CCGTs is modelled into the capacity and production tables.
10. After completing these retirement programmes the capacity required to maintain LOLP at or below 2% risk is calculated. *This ensures that the final scenario capacities will return LOLP values below 2%.*

The scenarios then assume new building programmes for CCGTs and nuclear that return the production schedule back to the levels for the Gone Green scenario, and that despatchable capacity can deliver a satisfactory risk level.

Notes

1. FES 2019 workbook http://fes.nationalgrid.com/media/1432/fes-data-workbook-v30.xlsx.
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About the Global Warming Policy Foundation

The Global Warming Policy Foundation is an all-party and non-party think tank and a registered educational charity which, while openminded on the contested science of global warming, is deeply concerned about the costs and other implications of many of the policies currently being advocated.

Our main focus is to analyse global warming policies and their economic and other implications. Our aim is to provide the most robust and reliable economic analysis and advice. Above all we seek to inform the media, politicians and the public, in a newsworthy way, on the subject in general and on the misinformation to which they are all too frequently being subjected at the present time.

The key to the success of the GWPF is the trust and credibility that we have earned in the eyes of a growing number of policy makers, journalists and the interested public. The GWPF is funded overwhelmingly by voluntary donations from a number of private individuals and charitable trusts. In order to make clear its complete independence, it does not accept gifts from either energy companies or anyone with a significant interest in an energy company.

GWPF TECHNICAL PAPERS