Marginal curtailment and the efficient cost of clean power

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Keywords Variable Renewable Electricity, Marginal Curtailment, Least-cost Expansion.

JEL Classification H23; L94; Q28; Q42; Q48

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Abstract

At high penetration levels, the marginal curtailment of an extra MW of wind is typically 3+ times its average. With a portfolio of different technologies (on- and offshore wind, solar PV), an extra MW of any single technology can increase the curtailment of all technologies, increasing the marginal: average curtailment ratio and the cost of displacing fossil generation. Higher expected future capacity factors amplify this ratio. Increasing nuclear output can also cause renewable curtailment but its effect is smaller than increasing VRE to give equivalent extra output. The choice of the VRE expansion plan depends on whether the potential, average, or marginal capacity factors are used. Storage and trade significantly increase the curtailment ratio but lower delivered costs, with higher VRE penetration in neighbouring markets further amplifying curtailment.

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1. Introduction

Decarbonising electricity requires a massive increase in Variable Renewable Electricity (VRE),[4] and, in some countries, maintaining or even expanding the nuclear fleet. As the peak: average output ratio is high (in Britain, 2-4:1 for wind, 9:1 for PV), high average shares of VRE imply

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[4] Acronyms: *ac*: average curtailment; A(M,P)CF: average (marginal, potential) capacity factor; BES: Battery Electrical Storage; CfD: Contract for difference; FES: Future Energy Scenario; HE: Hydrogen Evolution (FES scenario); HPC: Hinkley Point C nuclear power station; LCoE: Levelised cost of electricity; *mc* marginal curtailment; NECP: National Energy and Climate Plan; O&M: Operations and Maintenance (costs); PS: Pumped Storage; REZ: Renewable Energy Zone; SEM: Single Electricity Market of the Island of Ireland; SNSP: System Non-Synchronous Penetration; UCED: unit commitment and economic dispatch; VRE: Variable Renewable Electricity.

that at some point, VRE will inevitably be curtailed (i.e. spilled or wasted). O'Shaughnessy et al. (2020) find that in Arizona and Hawaii, PV is already *curtailed* (about 3%) because of excess supply, while Texas and other countries *constrain* PV because of transmission constraints. China initially experienced high transmission-constrained wind levels that are being successfully addressed (Bird et al. 2015).[5] Novan & Wang (2024) estimate econometrically that in California, while the average curtailment rate for grid-scale PV was only 4.3%, the marginal rate was 9.2%. However, this did not distinguish constrained and curtailed PV. In 2020, the Single Electricity Market (SEM) of the Island of Ireland had to dispatch down 12.1% of wind output, 6.2% because of transmission constraints and 5.9% *curtailed* because of system-wide constraints (Eirgrid/Soni, 2023). SEM (2024) defines and differentiates between constraints and curtailment, and it is curtailment that is the subject of this paper.

Earlier studies, discussed below, focused on the marginal curtailment of a single technology (wind in the SEM). Most countries have various complementary VRE – solar PV may peak on a summer's day, wind may be stronger in the winter gloom, and offshore wind offers access to stronger and more persistent wind. These different VREs interact with each other in important ways, materially complicating economic analysis and policy design. The key insight of this article is that an additional MW of any VRE technology (PV, on- or offshore wind) impacts the curtailment of other VRE, and these spill-overs typically amplify the ratio of the marginal/average curtailment (*mc/ac*),[6] especially at high levels of VRE. These interactions are of material significance in determining the social value of VRE investment and in choosing appropriate market and auction designs.

Recent empirical studies are beginning to examine these spillover effects. López Prol & Zilberman (2023, p4) find that "solar penetration increases wind and solar curtailment, and that wind penetration increases solar curtailment" in California. Novan & Wang (2024, p6) estimate that "an additional MWh of wind generation during the midday hours reduces utility-scale solar supply by 0.1 MWh. Similarly, a 1 MWh increase in small-scale solar only increases curtailment at utility-scale renewables by 0.033 MWh."

Many countries contemplate a portfolio of zero-carbon solutions to meet their challenging decarbonisation targets. Great Britain (GB) expects a massive expansion of offshore wind and solar PV, completing and probably starting another large nuclear power plant (3,200 MW at Hinkley Point C, HPC, under construction, due between 2029-2031,[7] and an identical plant planned for Sizewell C). The 2024 Labour Government removed the prohibition on onshore wind that is now expected to expand considerably. The latest (Round 6) Contract-for-Difference (CfD) auction (Sep 2024) cleared at strike prices (£2023/MWh) at £67.09 (PV), £68.18 (onshore

[5] Yasuda et al. (2022) gives useful time series of curtailment by country for wind and PV but not distinguishing between constraints and curtailment.
[6] Lower case used for curtailment as upper case is used for e.g. MCF, marginal capacity factor.
[7] See data Appendix B. We assume that HPC is available in 2030 but discuss the impact of its delay.

wind) and £72.65 (offshore wind)[8] when the forward baseload wholesale electricity price in June 2024 was £77/MWh.[9] Thus, all VRE are of apparently comparable cost and the current CfDs appear "subsidy-free" (Jansen et al., 2020). Whether this remains true for efficient procurement designs is explored below.

This article explores the case of curtailment for a portfolio of VRE for the exemplary case of a large region (GB) not synchronised with external trading partners at high levels of VRE penetration - a notional "2030" target. Newbery (2023a) proved that the marginal curtailment of the last MW of a single VRE (wind) is typically 3+ times the average curtailment, falling to 2 at very high curtailment levels. This article extends the result to a portfolio of VRE – on and offshore wind and solar PV – and shows that spill-overs amplify this ratio to 4 or more. The average cost of VRE is inversely proportional to the average capacity factor (ACF, the potential, or PCF, less *ac*). However, the marginal cost is inversely proportional to the marginal capacity factor, or MCF = PCF less *mc*: potentially much higher.

As *mc/ac* may be 4+, reducing *ac* has a disproportional impact on *mc* and hence on lowering marginal cost (Newbery, 2025b). Increasing export potential and storage are the most direct ways of reducing curtailment. Relaxing inertial and other system stability requirements (e.g. through intelligent electronics) can also enable greater use of potential surplus VRE, as can finding other flexible demands for electricity (e.g. water electrolysis, Brown and Reichenberg, 2021; Mills and Wiser, 2015). Increasing economically inflexible nuclear power capacity also displaces VRE, but less than expanding VRE capacity. This paper quantifies the benefits of adding these means of absorbing surplus VRE, starting from a closed economy, then adding electrolysis, Demand-Side Response, and finally, trade and storage.

The hourly pattern of 2030 potential output by technology differs, as Figure 1 shows, where peak total VRE output is considerably affected by the strong diurnal pattern of solar PV. Data Appendix Table B.3 gives a fuller description of the statistical properties of GB VRE.

[8] https://www.gov.uk/government/publications/contracts-for-difference-cfd-allocation-round-6-results
[9] https://www.ofgem.gov.uk/energy-data-and-research/data-portal/wholesale-market-indicators

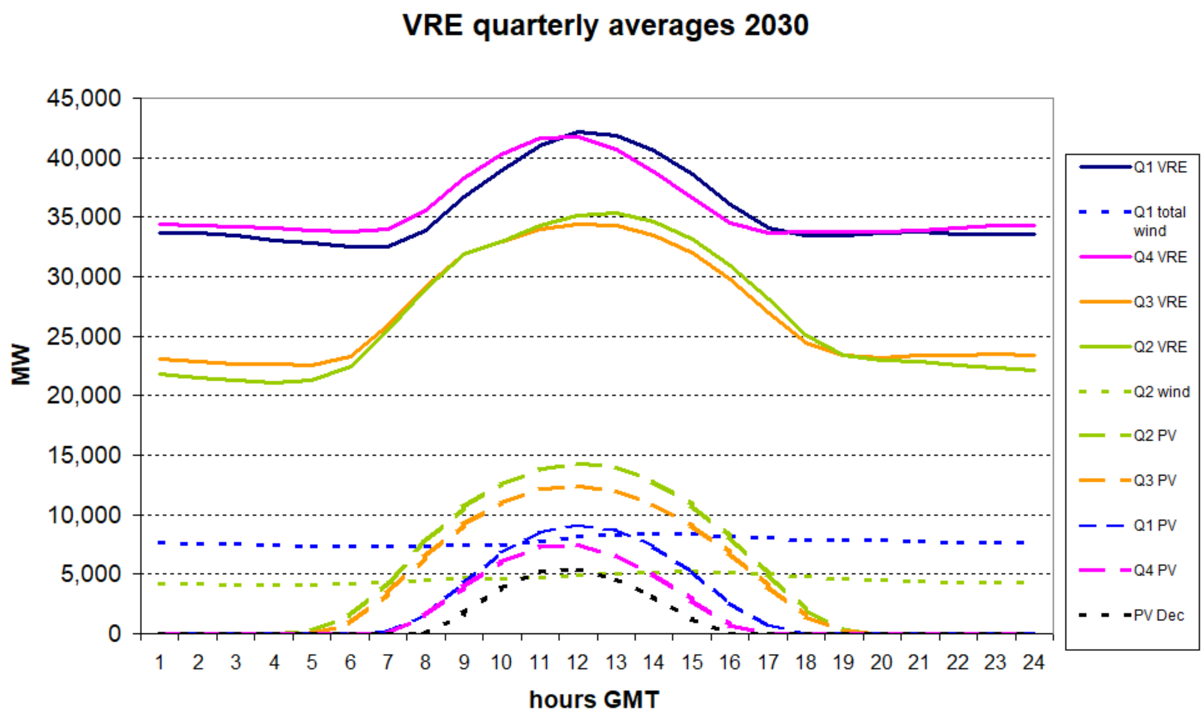

Figure 1 Quarterly averages of potential output per hour by technology and total, 2030
Source: see data Appendix B. Note: wind is combined on- and off-shore wind

At medium levels of PV penetration, this is helpful in meeting peak national demand. At very high penetration levels, PV is likely to be preferentially curtailed (as noted by Halttunen et al., 2020, p14). As the time pattern of each VRE technology's output is different, its contribution to total VRE output in each hour will vary, and so will its contribution to curtailment and impact on total emissions and the social value of additional investment. This article investigates such effects in one of the UK's *Future Energy Scenarios* for 2030 (ESO, 2024), described in Appendix A.

It differs from Newbery and Biggar (2024) in ignoring internal transmission constraints but retains the requirement to maintain system stability through a minimum level of inertia delivered by rotating turbines. In GB's case, this comes primarily from nuclear power stations, but if insufficient, from conventional thermal generation (gas turbines, biomass, etc.). In the isolated SEM, the 2030 target VRE maximum output is a challenging 90% of demand, also assumed here.[10] As such, this article addresses a system-wide phenomenon of general interest for countries with a portfolio of zero-carbon electricity options.

The rest of this article is structured as follows. Section 2 surveys the literature. Section 3 explains the role of marginal and average curtailment in calculating delivered cost. Section 4 studies an isolated system with no access to exporting or storage, to benchmark their importance. It compares the spreadsheet and UCED approaches where the spreadsheet approach is most

[10] We are indebted to Tim Green for the plausibility of this 2030 GB target.

defensible so their differences can be better identified. Section 5 quantifies the impact of exports. Section 6 adds storage. Section 7 presents a sensitivity analysis by increasing the EU's VRE capacity to their *National Energy and Climate Plans* (NECPs), potentially constraining trade with the Continent. Section 8 presents three cost measures, each appropriate under different specified conditions. Section 9 concludes. Appendix A gives methods, Appendix B the data sources, and Appendix C provides additional results for variants of the main case.

2. Literature Review

The impact of adding VRE to an existing conventional electricity system has been extensively studied mainly for its impact on prices. When VRE with its low/zero variable cost displaces price-setting conventional plant, prices will likely fall as the price-setting marginal plant is replaced by lower cost alternatives - the merit order effect (Sensfuß et al., 2008). Green and Léautier (2015) argued that this is a disequilibrium phenomenon: the equilibrium price "should not depend on the amount of renewable capacity, since this price will tend to the average cost of a baseload station." (Green and Léautier, 2015, p7). This argument fails at high VRE penetration.

Cannibalisation arises when VRE saturates an area or time (e.g. for PV in mid-day) reducing the price and market value of similar VRE (López Prol et al., 2020). Cannibalisation is relevant for merchant VRE and the post-support period of VRE operation that may last a decade (Jansen et al., 2020). Halttunen et al. (2020) surveys both merit-order and cannibalisation effects in 37 electricity markets across Europe, North America, Australia and Japan. Surprisingly, they find that the merit-order effect is less pronounced in countries with higher VRE penetration, but the market value of solar PV falls much more rapidly than for wind (Halttunen et al., 2020, p14).[11]

Cannibalisation and the merit order effect lead to a mismatch between the average wholesale price of electricity and VRE output. At high penetration, VRE will produce most of its output in periods of depressed prices. The Value Factor summarises this as the ratio of the VRE output-weighted market price to the demand-weighted market price (Hirth, 2012), and may be above 1 (e.g. for PV at modest levels, or wind in winter) or below 1 when VRE saturates the market. Appendix Table B.3 indicates these likely value factors, while Newbery (2023b) gives values across different GB regions for wind.

There is an extensive literature on the costs and benefits of high VRE penetration, with recent attempts to integrate the engineering/systems and economic approaches (Ueckerdt et al., 2013). The systems approach reinterprets the costs, starting with the Levelised Cost of (generating) Electricity, LCoE, and adding various integration costs (network expansion, back-up capacity for low VRE output periods, inertia, etc.) to give a System LCoE (surveyed in Zerrahn and Schill, 2017). The economic approach either uses observed market prices to measure the cost of the ancillary services needed for VRE (e.g. Savelli et al., 2022) or values the VRE output at

[11] Perhaps because modest levels of PV concentrated in peak day-time hours displace costly peaking plant but high PV saturates these hours and displaces base-load plant with a flatter cost curve.

(efficient) market prices that give a better measure of its value. The Market or Value LCoE – VLCoE can then be compared with its LCoE.

These effects hold regardless of interactions between different VRE technologies, but these interactions, the subject of this paper, can become significant as penetration increases. While not directly addressing the source of these interactions nor considering marginal rather than average curtailment, Diallo and Kitzing (2020) note that different VRE technologies can impact market prices and the value of different technologies. This becomes important when designing VRE support schemes. They argue that technology-neutral VRE auctions may choose socially less valuable technologies if they compete for the same market price-independent supports. Contract-for-Differences (payable on metered output, sometimes termed sliding premium contracts) and Feed-in-Tariffs offer returns per MWh of output regardless of the market price. As wind and solar PV have very different ratios of peak: average output and markedly different diurnal output patterns, the same number of average MWh can have very different impacts on market prices. Their social value per MWh, measured by (efficient) market prices may differ between technologies. If each receives the same revenue per MWh, this may lead to a less socially valuable technology winning the auction. We find the same result if an investment is based on average (or even nominal) and not marginal capacity factors.

Other authors have noted that VRE can interact adversely with nuclear power, impacting its potential carbon saving (Mezősi et al., 2020). If nuclear power is treated as inflexible, increased nuclear power could exacerbate VRE curtailment. Others (e.g. Cany et al., 2018) argue that French PWRs can respond flexibly, reducing curtailment if VRE has priority dispatch. However, "Increasing the participation of the fleet to load-following results in operating extra costs, because of a higher forced loss rate and higher maintenance requirements." (Cany et al., 2018, p295). The main reason for flexing nuclear power is that until recently the European Commission required priority dispatch for VRE, even though they can ramp down and back up instantly with no cost penalty.[12] In contrast, a nuclear plant is subject to tight limits on ramp rates and should logically be prioritised over VRE.

Mehigan et al. (2020) examined the impact of minimum rotational inertia constraints (specified as the rate of change of frequency, RoCoF, in Herz/sec) on European power systems under two scenarios with differing decarbonisation ambitions for 2030, using a unit commitment and economic dispatch (UCED) model. Higher inertia constraints (i.e. lower RoCoF) increase generation costs, curtailment of variable renewable energy and CO_2 emissions in a high-decarbonisation scenario. The constraints are less important in a low-decarbonisation scenario. In both scenarios constraints influence which countries need to reduce generation. This can result in changed trade patterns with counterintuitive impacts on emissions. The SEM has already moved from 0.5 Hz/sec to 1 Hz/sec to reduce VRE curtailment.

Given the importance of inertia, we assume that VRE cannot exceed 90% of total demand to maintain frequency stability (demand also include electrolysis consumption, exports and

[12] O'Shaughnessy et al. (2021) models the perverse impact of the EU requirement of priority access on curtailment. Steurer et al. (2017) argues for relaxing this requirement.

pumping into pumped storage units likely to be active with surplus VRE). The expected nuclear power station, HPC (average output 3,620 MW) and other must-run units provide adequate inertia for GB alone (ignoring export demand) less than 13% of the time, requiring additional inertia from biomass and fossil (i.e. gas turbines, shown in the ESO, 2024 *FES* HE). Reserve requirement to replace the loss of the largest single infeed is assumed less than the inertial requirement, and so ignored.

Newbery (2025a) used SEM data to demonstrate how marginal curtailment could be used to determine the shadow price of carbon in the electricity sector, where additional wind displaces CO_2 emissions from conventional thermal generation. This target-consistent carbon price (for the target level of decarbonisation) can illuminate the carbon benefits of storage and electrolysis. Chyong et al. (2020) and references therein demonstrate the importance of measuring *marginal* emissions factors when calculating the carbon credit of VRE, while in a similar vein, this article stresses the importance of *marginal* curtailment for the marginal cost of VRE.

A comprehensive review of capacity expansion models investigating VRE integration can be found in Oree et al. (2017), Koltsaklis and Dagoumas (2018), Dagoumas and Koltsaklis (2019), van Ouwerkerk et al. (2022). Li et al. (2024) use a Mean-Variance Portfolio Theory optimisation model to determine Australia's least-cost portfolio of onshore wind and solar PV instead of production cost-based power system models. While these large-scale market optimisation models are crucial in supporting policy and system planning, they can lack transparency in explaining the economic rationale behind investment decisions. Market simulation models need to make assumptions about market design, which may fail to guide efficient investment decisions.

In contrast, this article combines two approaches to identify the contribution of each low-carbon technology to meeting demand. The more transparent approach is to use a simple spreadsheet. This has the advantage that it is simple to vary assumptions about total demand and to consider individual increments of VRE and nuclear capacity or combinations. Its disadvantage is that it ignores ramping constraints and other dispatch non-linearities. However, it does consider the inertia constraint while requiring nuclear power always to run when available. It can also model trade and storage but in a simplified way (as in Newbery, 2021).

The full GB and Pan-European UCED model (for details, see Chyong and Newbery, 2022 and Appendix A) can address these dispatch requirements and model trade and storage more realistically. Its drawback is that it is sensitive to these dispatch constraints and avoidable cost assumptions (discussed in the data Appendix B) needed to derive the dynamic merit order schedule. Iterations between the two approaches help identify particularly sensitive assumptions (e.g., the avoidable cost of biomass, energy from waste, and other dispatchable plants). Various adjustments were made in light of these comparisons.

The UCED model was also used to determine demand for electrolysis, demand-side response and other domestic flexibility options for the closed economy spreadsheet model. In both models marginal curtailment is found by incrementing outputs each hour by the same proportion. Just as marginal cost analysis is fundamental to efficient output choices, here we argue that marginal curtailment analysis (and its counterpart, marginal cost analysis) is fundamental for guiding VRE investment decisions.

3. The role of marginal curtailment in cost calculations

The standard way (e.g. BEIS, 2023) of calculating the Levelised Cost of Electricity for VRE (LCoE) starts with the capital cost (£/kW) and annuitizes this over its life-time to give £/MWyr, to which is added any fixed costs (e.g. grid connection costs, insurance, etc.) to give an annual fixed cost, F_j/MWyr. The LCoE (£/MWh) is then $F_j/(8760*\mathrm{PCF}) + v_j$, where PCF is the potential capacity factor (as a percentage value, so multiplied by hours per year to give cost per MWh) and v_j £/MWh is the variable O&M cost , approximately zero except for onshore wind (BEIS, 2023). ACF is the average and MCF the marginal capacity factors, *ac* average curtailment (as a percentage) and *mc* marginal curtailment *including* spill-overs.

The following equations set out their relationships:

$$\mathrm{ACF}_j = \mathrm{PCF}_j - ac_j, \tag{1}$$

$$\mathrm{MCF}_j = \mathrm{PCF}_j - mc_j. \tag{2}$$

The levelised average and marginal cost of any VRE are then

$$\mathrm{LACoE} = F_j/(8760*\mathrm{ACF}_j)+ v_j, \tag{3}$$

$$\mathrm{LMCoE} = F_j/(8760*\mathrm{MCF}_j)+ v_j. \tag{4}$$

For the simple case in which $v_j = 0$ (e.g. PV)

$$\mathrm{LMCoE}/\mathrm{LACoE} = \mathrm{ACF}_j/\mathrm{MCF}_j. \tag{5}$$

$$\mathrm{LMCoE}/\mathrm{LCoE} = \mathrm{PCF}_j/\mathrm{MCF}_j. \tag{6}$$

The following sections derive *ac* and *mc* (and their ratio) to derive the cost-critical ACF and MCF, whose inverse is (approximately) proportional to the average and marginal cost of delivered VRE.

One further relationship is useful for understanding the relationship between average and marginal curtailment. Newbery and Biggar (2024) proved that for the simple piecewise linear curtailment schedule in which VRE is increased proportionately (i.e. new additions have the same hourly pattern of output as the existing fleet), $mc/ac = (V + V_0)/(V - V_0)$, where V is installed VRE capacity, and V_0 is the capacity at which curtailment first occurs. This demonstrates that increasing VRE penetration V holding V_0 constant reduces mc/ac, and reducing average curtailment by increasing V_0 increases the ratio – both results observed in this article and explored in Newbery (2025b).

4. Results for an isolated system

Curtailment is calculated as the surplus of total VRE output in each hour over the larger of national demand *less* assumed inflexible nuclear output, 5 TWh of run-of-river hydro (which has some limited flexibility) and 2 TWh waste-to-energy power,[13] or 90% of national demand (for inertial reasons), and set to zero if there is no surplus. Curtailment for each technology is initially pro-rated, i.e. curtailment is proportional to offered output.

However, if technologies were curtailed in decreasing order of avoidable costs, onshore wind would be curtailed first, then offshore wind and finally PV. This would result from exposing VRE to spot market prices, which could be combined with CfDs on deemed or yardstick output (i.e. the day-ahead forecast output or the output of a reference installation, as in Newbery, 2023b). At present, Elexon, the balancing market operator, is considering "removing distortion of support mechanisms (such as Contracts for Difference (CfDs) and the Renewables Obligation (RO) schemes) to reduce actions being taken outside of consumer cost order when following the Bid stack merit order."[14] This should ensure efficient curtailment, and although this has not yet been agreed upon, it will also be considered.[15]

Figure 2 shows pro-rated curtailment in the initial case, ignoring exports, storage, and electrolysis and ranking each technology's curtailment separately in decreasing order of the level of curtailment. Figure 3 shows the same data but ranked by total curtailment, showing the contribution of each technology to the total. 30 GW of peak curtailment may seem excessive but peak potential VRE plus nuclear power is 72GW while demand varies between 19-60 GW.

Table 1 shows the results for average curtailment rates of variations of what is included in national demand, whether the Hinkley Point C (HPC) power station is delivered on time or not, and the impact of including demand for electrolysis and Demand Side Response (DSR).

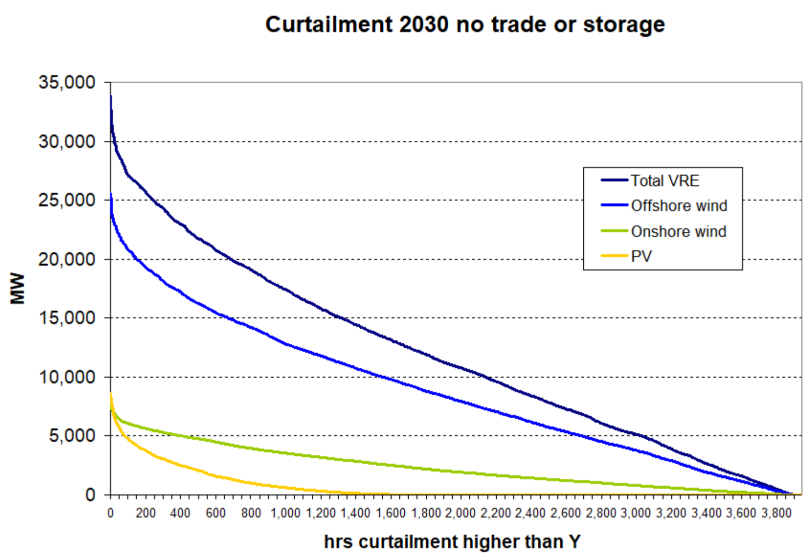

Figure 2 Pro-rated curtailment curves for closed economy case

Note: Technologies separately ranked and not additive, pro-rata curtailment, no exports, no storage

[13] Waste-to-energy bids negative prices to stay on the system and would not be curtailed before VRE.

[14] https://www.elexon.co.uk/mod-proposal/p462/

[15] The higher capital cost of off-shore wind may also be an argument for lower curtailment rates, while on-shore transmission constraints may lead to grid-scale PV curtailment.

Source: FES HE for 2030 - see data Appendix B.

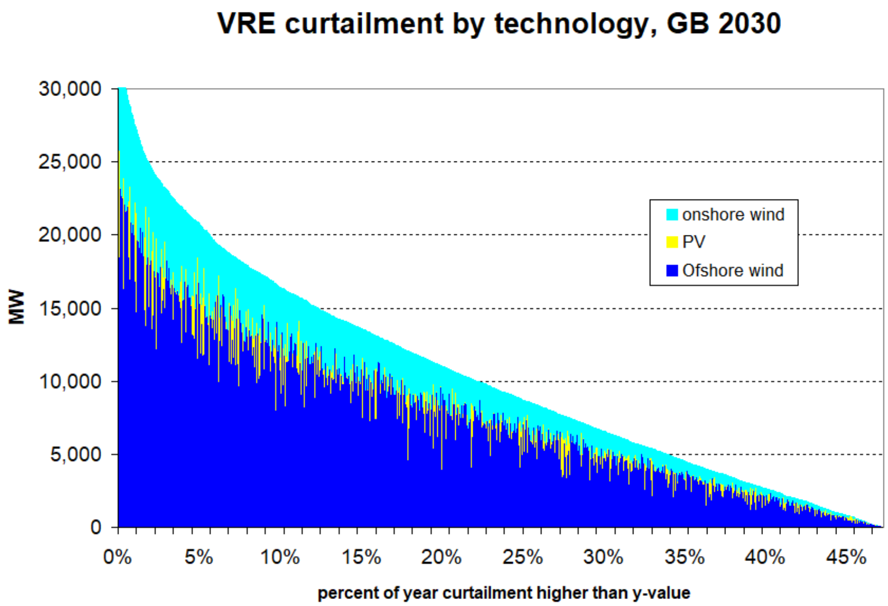

Figure 3 Curtailment curves for closed economy case ranked by total curtailment

Notes: as for figure 2

Table 1 Pro-rated average VRE curtailment under different assumptions, no trade, no storage

Variant	Total TWh	OFF	ON	PV	curtail
D	46.3	8.5%	5.2%	1.4%	48%
D-HPC	43.5	8.0%	4.9%	1.3%	47%
D+Electrolysis	**33.9**	**6.2%**	**3.9%**	**1.0%**	**41%**
D+DSR	45.3	8.4%	5.1%	1.3%	48%
D+DSR+Electrolysis	32.9	6.1%	3.8%	0.9%	41%
Potential	273.4	69%	20%	11%	

Notes: TWh is total VRE curtailed or offered (last line). D is initial national demand. OFF is offshore, and ON is onshore wind, percentages are average curtailment = MWh curtailed/(8760*MW capacity), the column "curtail" is the percent of the year VRE is curtailed. "Potential" is total potential (offered) VRE output, with shares of potential output. Bold line 3 is the baseline case.

The last line gives the potential VRE output offered to the market and their shares in that offer. Average curtailment as a per cent of potential output is shown in the columns under the VRE categories. The top line is national demand assuming HPC, and the line below is without HPC, showing that HPC displaces some VRE and increases curtailment. Adding the demand for electrolysis considerably increases demand in surplus VRE periods and relaxes the inertial constraint, considerably reducing curtailment. Augmenting demand with DSR (with HPC) reduces curtailment by a modest 1 TWh (compared with line 1 or lines 3 and 5). The base case in the following analysis assumes that HPC is commissioned and electrolysis demand averages 2.0 GW with a total installed capacity of 4.4 GW, as in line 3 (bold), but not DSR.

Once the hourly patterns of curtailment have been determined (see methods), the impact of adding incremental VRE capacity can be calculated by scaling potential output in proportion to the incremented effective capacity and then recalculating curtailment.[16]

Table 2 Pro-rated curtailment results for 2030 scenario, no storage, no exports

Table 2a

Spreadsheet raw data	nuclear	Total VRE	OFF	ON	PV	hours
baseline curtailment GWh	0	34,016	23,749	7,808	2,459	3,540
baseline cap GW	3,660	94.09	43.36	23.08	27.64	
av. curtailment MWh/MW, *ac*		362	548	338	89	
capacity increment MW	0	100	100	0	0	
extra curtailment GWh		34,327	23,989	7,861	2,476	3,812
delta GWh		310	240	54	17	272
marg curtail/MW VRE, *mc*		3,105	2,398	536	171	
ratio *mc/ac*			5.7			

Table 2b

Spreadsheet model	nuclear	Total VRE	OFF	ON	PV	hours
Potential Cap. Factor, PCF			60%	34%	11%	
Av. Curtailment, *ac*		4.1%	6.3%	3.9%	1.0%	40.4%
marg curtailment, *mc*			35.4%	22.1%	5.2%	
ratio *mc/ac*			5.7	5.7	5.1	
Marginal CF, MCF			24.6%	11.9%	5.8%	
UCED model						
Av. Curtailment, *ac*		4.0%	6.1%	3.8%	1.0%	
marg curtailment, *mc*			32.3%	25.8%	4.3%	
ratio *mc/ac*			5.3	6.8	4.3	
MCF			27.7%	8.2%	6.7%	

Notes: With HPC commissioned and electrolysis (average 2 GW) but no DSR. Run-of-river hydro with limited ponded storage is dispatched at €10.38/MWh-e. See Appendix C Table C1 for more discussion of variants and an explanation of the derivations of the summarised results.

**ac*: average curtailment; *mc*: marginal curtailment, both in MWh/MW or hours per year as a percentage of the year, MCF: Marginal Capacity Factor = PCF-*mc*. Assumed capacity factors are explained in Appendix B, *Characteristics of GB VRE*

Table 2a shows the raw data for calculating the ratios of marginal to average curtailments and the result of adding 100 MW of offshore wind, illustrating the steps to reach the marginal curtailment (with no exports and no storage). Average curtailment is in MWh/MW or hours per

[16] The scaling is amplified by the ratio of the 2030 nominal capacity factors in Table 2b (top line) to the average capacity factors observed in the 2019 data (51.6% for offshore wind, 27% for onshore wind, and 10.8% for PV). These additional scaling factors are high for wind reflecting the substantial increase in the size of new turbines. More details in Appendix A.

year, e.g. 548 hrs for offshore wind (OFF). The block below shows the result of increasing offshore wind capacity by 100 MW (the capacity increment), leading to 3,105 MWh/MW of total curtailed hours (the sum of the individual curtailments, thus including all the spillovers on other VRE). Its ratio to the average curtailment of 548 hrs is 5.7.

Table 2b shows average and marginal curtailments in hours per year as percentages of the year. Thus, for offshore wind (OFF), the average curtailment of 548 hrs is 6.3%, marginal curtailment is 35.4%, and its ratio to ac is 5.7, as in Table 2a. Similarly, increasing ON and then PV capacity by 100 MW while keeping all other VRE constant results in the *mc/ac* ratios shown.[17] The final line gives the marginal capacity factor, MCF, which, from equation (2), is the PCF in the top line, less *mc*. The top block in Table 2b gives the spreadsheet results, and the bottom block the UCED results. They are within 2% for the average curtailment, but marginal curtailment rates are 9% lower for OFF, 20% higher for ON, and 15% lower for PV. As a result, there are similar differences in the ratios of *mc/ac*. The differences between the spreadsheet model and the UCED is partly that even though curtailment is pro-rata in both cases, UCED takes account of the different avoidable costs of each VRE in scheduling dispatch (£6/MWh for onshore, £1/MWh for offshore wind and zero for PV, see Appendix B). The spreadsheet model is useful in checking the logic of the final choices in the UCED and far quicker in testing such issues as the proportionality and additivity of individual VRE values for *ac* and *mc*.

All ratios in both models are higher than 5 for wind and still above 4 for PV in the UCED case. In all cases, the ratios are higher than earlier estimates for wind expansion in the SEM and higher than expected. As noted above, $mc/ac = (V + V_0)/(V - V_0)$ implying that *mc/ac* should fall as VRE increases. Part of the reason is that the new wind turbines are projected to have substantially higher PCFs than the ACFs (with curtailment) of existing VRE. This scales up the effective capacity increment (and hence the increment in output) by the ratio of the 2030 capacity factors to those observed in the 2019 data. For offshore wind, this is 60%/51.6% = 1.16 and for onshore wind by 34%/27% = 1.26 (see Table B.4). These are lower capacity factors than projected in BEIS (2023) as the 2030 fleet with continuing investment is expected to have a higher ACFs than in 2019. We opted for these conservative estimates as the key consideration is the ratio of 2030 values to the fleet average.

The more important reason is that portfolio spill-overs, in which an extra MW of a single technology can increase curtailment of all others, amplifies total curtailment. Finally, the base case has lower *ac* as extra electrolysis demand relaxes the inertial constraint.

The observation that the *mc* is considerably higher than *ac* shows that curtailment is a highly non-linear effect. Nevertheless, even multiplying increments of capacity ten-fold only changes the marginal curtailment per MW by 3%, so the effects are reasonably independent of increment size, which is small relative to the installed capacity. The total difference between separately adding 100 MW to each technology (shown in the three results panels in Table 2b) is only 0.5 of 1% of the effect of adding 100 MW to each to give 300 MW of total VRE, so the results are reasonably additive and multiplicative (within the assumptions of no extra demand).

[17] Lower cases are used for curtailment factors, upper case for Capacity Factors.

The data in the tables thus provide valuable insights into the size and causes of curtailment but need careful interpretation. Their relevance will depend on the purpose for which they are used. This is particularly true for comparisons between different technologies.

Table 2c compares estimates of the displacement of VRE by increased nuclear capacity and output, which can then be compared with various combinations of increased VRE. Note that nuclear capacity is measured by its nominal derated value, so 100 MW of incremental derated capacity delivers 100 MW average output. Its PCF is 79%, so this would require an actual 126.6 MW, but when it comes to cost comparisons, Hinkley Point C will be paid for delivered output, and as such, the derated capacity is a more useful measure. Increasing nuclear capacity may provide more inertia and allows more VRE but decreases the space left for VRE after its priority dispatch, which is demonstrated in Table 2c.

Table 2c Impact of nuclear expansion

Spreadsheet model	nuclear	Total VRE	OFF	ON	PV
Derated cap. increment MW	150.2	0	0	0	0
delta VRE curtailed, av. MW/hr		50.2	35.9	10.8	3.5
UCED model					
Derated cap. increment MW	123.3	0	0	0	0
delta VRE curtailed, av. MW/hr		23.2	17.5	5.2	0.5

Note: Same assumptions as Table 2a,b. All capacity increments create a net increase of 100 MW per hour

Table 2c shows that the UCED model requires less de-rated capacity to deliver the 100 MW average output than the spreadsheet model due to its perfect foresight nature and superior representation of system flexibility, making its results preferable. To calculate the increment of VRE capacity that would deliver the same average of 100 MW per hour over a year, the required VRE capacity is 100/MCF. For offshore wind, taking the UCED MCFs, the required increment is 100/27.7%% = 361 MW of extra capacity (and similarly 1,217 MW of ON or 1,486 MW of PV). While 123 MW of nuclear is needed, as 23 MW on average is curtailed, 361 MW of OFF is needed, and on average 361*32.3% = 117 MW is curtailed (32.3% is the *mc* of UCED OFF in Table 2b). In this case, five times as much VRE is curtailed as for nuclear power (and more for ON but only 2.7 times as much for PV). Thus, increasing nuclear capacity delivers more of its total additional output to reducing emissions than replacing it with an amount of VRE that could deliver the same total output. Expanding VRE capacity delivers far less emissions reduction than its nominal output might suggest. Whether this is sufficient to overcome the high cost of new nuclear power will be considered below.

Appendix Table C2 considers efficient curtailment in which onshore wind is curtailed first, then offshore wind and finally PV (never curtailed). Not surprisingly, if onshore wind is curtailed first, most of the initial VRE curtailment comes from this source. The average curtailment (*ac*) levels in Table C2 show that offshore wind *ac* is reduced to one-third and that there is a trebling of onshore wind *ac*. This has the counterintuitive effect that adding 100 MW of offshore wind leads to the same increase in total VRE curtailment (as how curtailment is allocated does not impact the total), but as the initial curtailment is much lower, the *mc/ac* ratio is much increased for offshore wind (trebled), and correspondingly reduced (to one-third) for onshore wind. As PV is not curtailed in the base case, it makes no sense to compute the *mc/ac* ratio for PV. Total curtailment is not affected, nor is the displacement effect of additional nuclear power or extra VRE.

For the remainder of the article, although there are spreadsheet equivalents, only the UCED results are presented.

5. The impact of exports on curtailment

The base case ignored storage and exports to reduce VRE curtailment that Newbery (2021) showed were critical in reducing curtailment in the SEM, although at lower levels of VRE penetration than considered here. High domestic VRE is often associated with high VRE in neighbouring countries, restricting the export potential and making storage more attractive. Section 7 considers the effect of increasing VRE in connected countries to meet their 2030 national targets rather than the (lower) *FES* forecasts.

Table 3 replicates the format of Table 2b, but this time includes DSR and peak shaving (which should not be invoked with curtailed VRE) and allows for trade with connected countries (and within the EU) but excludes storage (other than run-of-river).

Table 3 Curtailment rates and ratios, with trade. No storage

UCED model	Total VRE	OFF	ON	PV
curtailment w/trade GWh	9,467	6,475	2,214	778
curtailment no trade GWh	33,297	23,253	7,652	2,391
trade benefit GWh	23,831	16,779	5,438	1,614
VRE capacity GW	94.20	43.48	23.08	27.64
av curtailment, ac	1.1%	1.7%	1.1%	0.3%
marg. curtailment, mc		10.9%	10.9%	1.4%
mc/ac		6.4	9.9	4.3
MCF		49.1%	23.1%	9.6%

Notes: No trade curtailment from table 2a, pro-rata curtailment.

Compared with the closed economy case, trade (plus DSR) dramatically reduces average curtailment by 70%. It also reduces all marginal curtailments but by somewhat less. so that the *mc/ac* ratios rise by 44% for ON, 20% for OFF, but not at all for PV. The spreadsheet model (not shown) gives 2% less curtailment (perhaps because of ramping constraints) but essentially the same results (although the spreadsheet benefits from using the UCED trade and DSR results).

6. The impact of storage and exports on curtailment

Table 4 replicates Tables 3 and 2c to examine the further impact (after allowing for exports) that storage and nuclear additions have on curtailment. Storage introduces the new element of transferring surpluses over time, which can have unusual impacts on the *mc/ac* ratio. Line 3 shows that 26 GW of storage (85 GWh) reduces curtailment by 5,871 GWh (69 times as much as the storage volume) and by 30% of its previous level with trade but no storage. Part of the benefit of storage is that injections into pumped storage increase demand and reduce inertial curtailment.

Individual average rates of curtailment fall by similar amounts. As a result of the time shifting of storage, the *mc/ac* ratio falls except for PV while all MCFs rise, lowering costs.

Table 4 Pan-European UCED results with trade and storage, pro-rata curtailment

		Total VRE	OFF	ON	PV
Pan-E trade curtailment GWh		6,587	4,531	1,535	522
trade no storage		12,458	9,467	2,214	778
storage benefit		5,871	4,936	679	256
baseline cap MW		94.2	43.48	23.08	27.64
ac		0.8%	1.2%	0.8%	0.2%
marg curtail *mc*			8.9%	6.5%	0.7%
mc/ac			7.5	8.5	3.2
MCF			51.1%	27.5%	10.3%
derated nuclear inc. MW	104.6				
mc MW average		4.6	3.3	1.0	0.3
increments MW		333.6	131.4	69.9	132.3
derated potential output MW		117.2	78.8	23.8	14.6
output increment MW av		100.0	67.1	19.2	13.6
mc MW average		17.2	11.7	4.5	0.9

Note: see data Appendix B for trade, storage and European VRE assumptions

The second panel shows that 104.6 MW of derated nuclear output (requiring 132.4 MW of extra capacity) would be curtailed on average 4.6 MW, thus delivering 100 MW average output. The panel below shows a portfolio increment (in proportion to the planned 2029-30 VRE expansion) that has a derated output of 117.2 MW but a delivered output of 100 MW (to match the nuclear expansion). The 17.2 MW average curtailment is 3.7 times the nuclear curtailment, less than in the closed economy but confirming that nuclear expansion gives relatively more decarbonisation than comparable VRE expansions.

7. Implications of higher EU VRE for curtailment

As results in previous sections show, the persistence of high marginal curtailment, even under optimal storage and trade conditions, reflects key system limitations. The first, temporal constraint, is that VRE surpluses often occur when interconnector and storage capacities are saturated, limiting their ability to alleviate curtailment. The second, for which the Pan-European model is essential, is that simultaneous surpluses across neighbouring regions reduce export opportunities.

To explore the second challenge, we conduct a sensitivity analysis assuming significantly higher shares of wind and solar energy than in the FES HE baseline, aligned with Europe's most recent *National Energy and Climate Plans* (NECP) shown in Figure 4. This alternative and ambitious trajectory for European energy markets limits GB's opportunities to export surplus renewables. Even if not delivered by 2030 (and the GB "2030" target may be delayed), at some later date, these targets likely become more realistic.

Under this high EU VRE scenario, GB's total curtailment rises significantly to 12,295 GWh (Table 5), nearly double the FES trade scenario figure of 6,587 GWh (Table 4). Offshore wind remains the primary contributor, accounting for 8,425 GWh of curtailment, followed by on-shore wind (2,822 GWh) and solar PV (1,047 GWh), highlighting the system-wide impacts of expanded European VRE and their challenge for GB's exports.

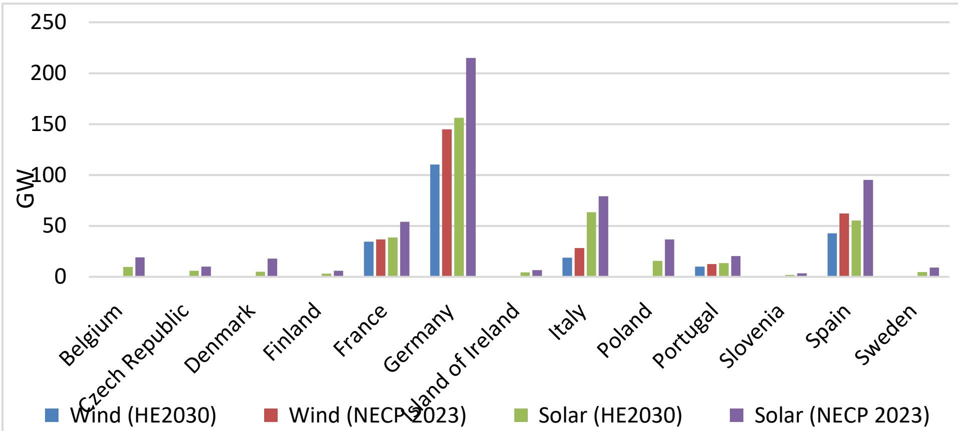

Figure 4 Projected wind and solar capacities for selected European countries under the FES HE2030 baseline scenario and the NECP 2023 high EU VRE scenario

Source: HE2030 (FES Hydrogen Evolution 2030 scenario from NESO); NECP 2023 data taken from: https://ember-energy.org/data/live-eu-necp-tracker

Notes: This chart only shows the NECP 2023 data for wind and solar capacity, which is higher than projected under the FES HE2030 scenario.

Table 5 Curtailment results using the Pan-European UCED model: High EU VRE scenario

	Total VRE	OFF	ON	PV
Pan-E trade curtailment GWh	6,587	4,531	1,535	522
curtailment with high EU VRE	12,295	8,425	2,822	1,047
impact of high EU VRE GWh	5,707	3,894	1,287	526
baseline cap MW	94,201	43,476	23,081	27,644
av. curtailment MWh/MW, *ac*	1.5%	2.2%	1.4%	0.4%
marg curtail *mc*		12.2%	7.5%	4.0%
mc/ac		5.5	5.3	9.2
MCF		47.8%	26.5%	7.0%

Note: pro-rata curtailment

Reduced export opportunities, storage saturation, and systemic constraints drive the rise in curtailment in the high EU VRE case - *ac* increases sharply – over 80% for wind and 100% for PV. As marginal curtailments rise by less for wind (36% for OFF, 15% for ON) but more for PV (nearly six-fold) the *mc/ac* ratio falls for wind and increases for PV (perhaps because Europe has higher PV resources and a strong correlation in solar output in GB and Europe).

The increased volume of surplus generation also places additional pressure on storage systems, which are fully optimised but remain insufficient to manage the higher levels of VRE output. With its consistently high capacity factor, offshore wind contributes disproportionately to storage saturation. System-wide constraints, such as SNSP and thermal and nuclear minimum stable generation requirements, further exacerbate curtailment by limiting the system's ability to absorb incremental renewable output. Solar PV, which typically benefits from its complementary diurnal pattern, faces increased curtailment as higher regional solar penetration aligns its peak output with other surplus conditions. Total curtailment in the high EU VRE case is nearly double that of the baseline (FES HE trade), while marginal curtailment levels rise significantly for all technologies. Offshore wind experiences the most significant absolute increase in marginal curtailment, followed by onshore wind and solar PV. MCFs all fall, and so marginal costs rise compared to the less ambitious (FES) scenario.

The high EU VRE case suggests that the case for increasing interconnector capacity to and within Europe may not be simple if a high correlation of VRE limits interconnector use. It still needs exploring given the considerable benefit that trade compared to no trade has revealed. Expanded storage capacity and advanced technologies, such as seasonal storage and flexible hydrogen production via electrolysis (requiring dramatic fixed cost reductions to be attractive) may become more important for managing elevated surplus VRE.

8. Economic implications

Section 3 identified the relationships between curtailment rates, capacity factors and the implied levelised cost calculations. Table 6 summarises these for the UCED case of Table 2b.

Table 6 Potential, average and marginal capacity factors (no trade, no storage)

Capacity factors (CFs)	OFF	ON	PV
PCF assumed	60%	34%	11%
ACF pro-rata	53.9%	30.2%	10.0%
ACF efficient	58%	21%	11%
MCF	27.7%	23.6%	8.6%
PCF/ACF pro-rata	1.11	1.13	1.10
PCF/ACF efficient	1.04	1.60	1.00
PCF/MCF	2.17	1.44	1.28

Note: MCFs from Table 2b, UCED case, ACF pro-rata from Table 2b, ACF efficient from Table B.2

Table 7 summarises the cost data from Table B.4 and then calculates the various cost measures using the data from Table 6 and the formulas (3) and (4). As noted below the discussion following table 2, although marginal curtailment rates do not depend on curtailment rules (only total curtailment matters), average curtailment rates are quite different when onshore wind is preferentially curtailed, and that affects the average cost of VRE. The cost rankings switch from PV<OFF<ON<PVm for LCoE and pro-rata LACoE to PV<OFF<PVm<ON for

LACoE with efficient curtailment. Perhaps more important, marginal cost rankings are PV<ON<PVm<OFF, a dramatic change.

Table 7 Cost measures (no trade, no storage) £(2018)

	OFF	ON	PV large	PV mid
PCF assumed	60%	34%	11%	11%
lifetime yrs.	30	25	35	30
degradation %p.a.	1%	0.80%	0.50%	0.50%
Fixed cost £/kWyr	£220.96	£125.70	£39.16	£58.74
Fixed cost £/MWh at PCF	£42.04	£42.20	£40.64	£60.96
O&M var £/MWh	£1.00	£6.00	£0.00	£0.00
LCoE £/MWh	£43.04	£48.20	£40.64	£60.96
LACoE pro-rata £/MWh	£47.80	£53.51	£44.70	£67.05
LACoE efficient £/MWh	£44.62	£73.52	£40.64	£60.96
LMCoE £/MWh	£92.06	£66.80	£51.98	£77.97

Source: Table B.4, Table 6. The Fixed cost at PCF is *F*/(8,760*PCF). PVm is mid-scale PV 10-50kW.

Table 8 summarises the remaining three cases with trade and shows that trade has a substantial impact on marginal costs but storage has remarkably little impact. In all cases the cost rankings are the same: PV< OFF< ON< PVm, and as before, marginal costs are considerably higher than average costs (except that average onshore wind costs are higher with efficient than pro-rata curtailment).

Current support systems, such as the GB CfD with Feed-in Tariff, run auctions to set the strike price and pay on metered demand, compensating owners for curtailed output. As such, bidders in the auction look to the LCoE. With free unsubsidised merchant entry (as in Simshauser and Newbery, 2024) and pro-rata curtailment, VRE would experience average curtailment selling on the wholesale market. It might then base entry decisions on the Average LCoE, which is 10% higher than the LCoE. If VRE is offered priority dispatch (the last entrant is curtailed first), the relevant cost signal is the Marginal LCoE, which is substantially higher than the LCoE (1.3 to 2.2 times as high in Table 6). The LCoE cost measure gives the cost ranking PV<OFF<ON<PVm, but the other two give PV<OFF<PVm<ON. Clearly, the cost measure matters and the marginal costs differ greatly from the other costs.

Table 8 Cost measures with trade, UCED model £(2018)

Trade no storage	OFF	ON	PV large	PV mid
ACF pro-rata	58.8%	33.2%	10.8%	10.8%
ACF efficient	60.0%	29.4%	11.0%	11.0%
MCF	51.1%	27.5%	10.3%	10.3%
PCF/ACF pro-rata	1.02	1.02	1.02	1.02
PCF/ACF efficient	1.00	1.16	1.00	1.00
PCF/MCF	1.17	1.24	1.07	1.07
LACoE pro-rata £/MWh	£43.90	£49.22	£41.39	£62.09
LACoE efficient £/MWh	£43.05	£54.89	£40.64	£60.96
LMCoE £/MWh	£50.36	£58.18	£43.40	£65.10
FES trade w/storage				
ACF pro-rata	58.8%	33.2%	10.8%	10.8%
ACF efficient	60.0%	30.7%	11.0%	11.0%
MCF	51.1%	27.5%	10.3%	10.3%
PCF/ACF pro-rata	1.02	1.02	1.02	1.02
PCF/ACF efficient	1.00	1.11	1.00	1.00
PCF/MCF	1.17	1.24	1.07	1.07
LACoE pro-rata £/MWh	£43.89	£49.18	£41.46	£62.19
LACoE efficient £/MWh	£43.04	£52.67	£40.64	£60.96
LMCoE £/MWh	£50.38	£58.13	£43.39	£65.08
NECP trade w/storage				
ACF pro-rata	57.8%	32.6%	10.6%	10.6%
ACF efficient	60.0%	27.9%	11.0%	11.0%
MCF	47.8%	26.5%	7.0%	7.0%
PCF/ACF pro-rata	1.04	1.04	1.04	1.04
PCF/ACF efficient	1.00	1.22	1.00	1.00
PCF/MCF	1.25	1.28	1.56	1.56
LACoE pro-rata £/MWh	£44.65	£50.01	£42.30	£63.45
LACoE efficient £/MWh	£43.05	£57.36	£40.64	£60.96
LMCoE £/MWh	£53.72	£60.06	£63.59	£95.38

Notes: FES trade: see data App. B; NECP: EU meets its NECP 2030 target. Cost data from Table 7.

Finally, Table 9 shows the combined impact of expanding all three VRE in proportion to their expansion path from 2029-2030, representing the marginal choices in 2029,[18] to increase total VRE output by an average of 100 MW.

[18] Except that onshore wind is assumed to grow by 5%, close to its average rate of growth from 2023 to 2035, rather than decreasing as shown in ESO (2024) *FES HE*.

Table 9 Cost implications of simultaneous VRE expansion (£2018)

UCED FES trade	OFF	ON	PV	PVm	Total
increments MW	131.4	69.9	99.4	32.9	333.6
MCF	51.1%	27.5%	10.3%	10.3%	
output increment MW av	67.1	19.2	10.2	3.4	100.0
LMCoE £/MWh	£50.38	£58.13	£43.39	£65.08	£51.66
NECP trade					
increments MW	144.8	77.1	109.6	36.2	367.7
MCF	47.8%	26.5%	7.0%	7.0%	
output increment MW av	69.3	20.5	7.7	2.5	100.0
LMCoE £/MWh	£53.72	£60.06	£63.59	£95.38	£56.84

Notes: Increments proportional to 2029-30 expansion, pro-rata LMCoEs from Table 8. Total is the output-weighted average of LMCoEs. Gridscale and midscale PV in proportion 3:1.

If GB meets its *FES* targets and the EU falls behind (as in the *FES HE* scenario), it is preferable to expand grid-scale PV, but if that is constrained, expanding offshore wind looks best. If the EU achieves its NECP targets or GB is delayed so that we are looking more at 2035, then onshore wind looks cheaper. Clearly, the design of an optimal portfolio is sensitive to assumptions about both GB and EU VRE achievements. For comparison, Hinkley Point C nuclear power station signed a CfD for its output at £92.50/MWh at 2012 prices or £102/MWh at 2018 prices. Under the most optimistic trade assumptions after allowing for VRE curtailment, this would cost £106.73/MWh of zero carbon net output, using the data from Table 4. Even under the more pessimistic NECP trade assumptions, nuclear power (at least without a substantial cost reduction) is still more expensive than VRE. However, system costs and benefits (such as the value of inertia and the cost of extra capacity to deal with low VRE) have been excluded in this very simple comparison and may reverse this conclusion.

All these various comparisons strongly suggest that marginal, not average, curtailment could be important in choosing which technology to favour. They also suggest that technology-neutral auctions may not select the least-cost option, as Diallo and Kitzing (2020) noted.

9. Conclusions

Curtailment of VRE is inevitable beyond some level of penetration (as the cost of absorbing all excess VRE increases rapidly). Earlier research showed that in an economy with a single VRE (wind in the SEM), the marginal/average (*mc/ac*) curtailment was typically 3+. This article extends that analysis to consider a portfolio of VRE, and simulates a notional 2030 target for Britain and the EU, using data from the *Future Energy Scenario Hydrogen Evolution* (ESO, 2024). It finds that the *mc/ac* ratio is typically above 4 for the case of pro-rata curtailment for several cumulative reasons. First, the capacity factors for new VRE in 2030 are considerably higher for wind compared to the existing fleet due to considerably larger turbines (already up to 14 MW for offshore wind). The effective addition to VRE of a MW increment is larger than the fleet average, raising the *mc/ac* ratio - a natural consequence of technical improvements. Second, and the central claim of this article, expanding any single VRE typically causes other VRE curtailment, magnifying total curtailment.

As marginal costs depend on *marginal* capacity factors, and as these are equal to the potential capacity factor *less* marginal curtailment, an increase in *mc* raises costs compared to the traditional Levelised Cost of (VRE) Electricity, the LCoE. Newbery and Biggar (2024) found that in a simple piece-wise linear model of curtailment in which VRE is increased proportionately (i.e. new additions have the same hourly pattern of output as the existing fleet), $mc/ac = (V + V_0)/(V - V_0)$, where V is installed VRE capacity, and V_0 is the capacity at which curtailment first occurs. As a result, increasing VRE penetration V holding V_0 constant reduces *mc/ac*, and reducing *ac* by increasing V_0 increases the ratio. It follows, and the simulations using the UCED model demonstrated, that reducing curtailment (and hence *ac*) has a magnified impact on marginal curtailment and costs. Trade with neighbours that have less correlated VRE output and/or lower VRE penetration is the main route to lowering curtailment, with storage and other demand flexibility options also playing an important role.

Nuclear power (and other must-run low carbon options) can also cause VRE curtailment (although at low penetration, they have no impact as it is the preferred method of providing inertia for system stability). However, the additional nuclear capacity to deliver a given average amount of zero-carbon electricity is considerably smaller than that of VRE curtailed to give the same delivered output, particularly with trade, storage and other flexibility options. If the EU meets its more ambitious *National Energy and Climate Plans* by 2030, rather than those assumed in the *FES HE* 2030 scenario, EU VRE will increase to the extent that exporting the GB surplus is compromised, considerably raising curtailment compared to the *FES* case. This is a foretaste of the likely situation in years after 2030. Expanding interconnection may help, but with increased EU saturation, the marginal cost of investing in interconnectors to export surplus VRE will increase rapidly.

Finally, average and marginal capacity factors and their associated levelised costs have important implications for the VRE market arrangement. If VRE is auctioned with firm delivery contracts (i.e. compensated for curtailment, as in GB at present), projects will be assessed on the LCoEs. If there is a free entry without a firm contract under pro-rata curtailment, entrants will look to their LACoE (the average cost allowing for average curtailment). Under priority entrance (later entrants are curtailed first), the LMCoE is the relevant cost to consider. These three measures can be considerably different, and the relative apparent costs of different VREs can also differ, so auctions may not select the least economic cost choice.

The central message of this article is that, just as economists have always attached importance to marginal costs, it is essential to recognise that the marginal cost of VRE depends on its *marginal* curtailment, which varies with the portfolio of existing VRE and the opportunities for reducing curtailment. As the marginal curtailment is many times its average, increasing VRE penetration encounters a rapidly rising marginal cost curve.

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Appendix A Methods

Spreadsheet model

The closed economy spreadsheet model takes the same demand and VRE data as the UCED model (see below), which is based on the ESO (2024) *Hydrogen Evolution* scenario (one of the more cautious scenarios in terms of expected VRE capacity additions by 2030, retaining considerable gas-fired generation).

ESO (2024) gives 2030 assumed capacities of VRE for European countries that we also use. The hourly projections are simple scalars for each category of the 1998 hourly values (see Appendix B), preserving the hourly patterns for consistency across VRE outputs (at home and abroad) and related demand. Figure A1 shows that 2030 onshore wind has a slightly higher mean output in mid-day hours, whereas offshore wind has a slightly higher mean output in mid-morning and evening peak hours. The data Appendix B provides statistical data on correlations between different VREs.

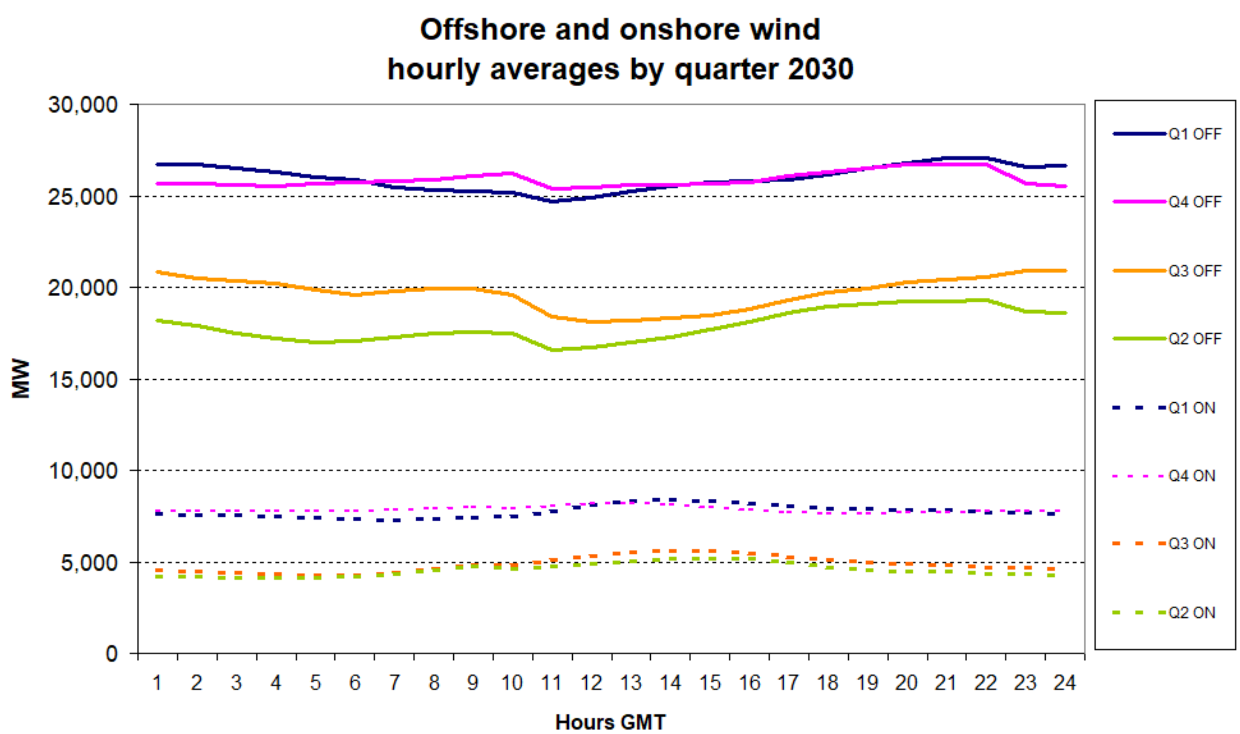

Figure A1 Quarterly averages of potential output per hour for off- and onshore wind, 2030
Source: see data Appendix B. Note: OFF is offshore wind, ON is onshore wind

The initial level of curtailment depends on the amount remaining from total demand, *D*, (which includes demand for exports, injections into pumped storage, and demand for hydrolysis) after allowing for the necessary priority dispatch of nuclear power and waste-to-energy (both of which incur costs from ramping down, in contrast to VRE). After that, the system is constrained to have no more than 90% VRE penetration to maintain adequate inertia for stability (strictly, this is a limit on Simultaneous Non-Synchronous Penetration, SNSP, which also includes imports over DC links and battery discharges, irrelevant if there is surplus VRE). Must-run spinning capacity (mainly Nuclear output), N, is needed for inertia but may be insufficient for the required minimum capacity for inertia, βD ($\beta =$ 1-SNSP). The maximum amount of VRE that can be absorbed, V_a, is D - Max(N, βD) = Max$\{D - N, (1-\beta)D\}$, and so Curtailment, $K =$ Max(0,$V - V_a$) = Max(0, V - Min$\{D - N, (1-\beta)D\}$), where in this case β is 10%. Its allocation to the three technologies is pro-rata to the total potential output in that hour (or, if efficiently curtailed, first curtails onshore wind up to the maximum level offered, then any remaining curtailment is allocated to offshore wind, and finally to PV, in the order of decreasing avoidable cost). The annual sum gives the total curtailment for each technology, which, divided by total capacity, gives curtailment per MW and effective output per MW (potential output less curtailment).

UCED model

The UCED model, an extension of the existing model developed by Chyong and Newbery (2022), considers 19 European national electricity markets (listed in Table B.1), dividing them into 28 zones to consider key transmission constraints explicitly. Thus, GB has seven zones, Denmark has two zones, and Norway has three zones. As nodal pricing for the GB market has been ruled out by HM Government's *Review of Electricity Market Arrangements,*[19] and as it is not yet clear whether zonal pricing will be introduced, the model ignores GB transmission constraints, treating GB as a "copper plate". The impact of zonal pricing is left for future research.

[19] See https://www.gov.uk/government/publications/review-of-electricity-market-arrangements-rema-technical-research-supporting-consultation

Appendix B Data Sources for the UCED Model

Demand

The model considers 19 European national electricity markets (Table B.1), dividing them into 28 zones to explicitly consider key transmission constraints for GB (7 zones), Denmark (2 zones), and Norway (3 Zones).

Table B.1: Annual electricity demand (TWh) projection for 2030

Country	Country Code	2030
GB	GB	314.37
Austria	AT	84.35
Belgium	BE	99.47
Switzerland	CH	71.68
Czech Republic	CZ	80.96
Germany	DE	684.36
Denmark	DK	54.42
Spain	ES	286.63
Finland	FI	103.15
France	FR	516.22
Italy	IT	380.75
Luxembourg	LU	9.01
Netherlands	NL	180.39
Norway	NO	170.26
Poland	PL	197.60
Portugal	PT	60.88
Sweden	SE	168.69
SEM	SEM	52.17
Slovenia	SI	16.59

Annual electricity demand (in TWh) shown in Table B.1 was taken from the recent *Future Energy Scenarios "Hydrogen Evolution"* (FES)[20] produced by the GB's National Energy System Operator (NESO). These annual projections were then multiplied with hourly load profiles to arrive at hourly load time series used in the dispatch model.

The hourly load profiles were taken from the PECD dataset (the 1998 climate year was chosen to represent a normal year; for details on definitions and clustering of weather years, see Ah-Voun et al., 2024) to ensure spatial correlation between the GB and European electricity markets and hourly wind and solar capacity factors (also taken from TYNDP 2022, ENTSO-E, 2022). These hourly load profiles vary by scenario and are created bottom-up based on different types of demand (such as electric vehicles, heat pumps/electric heating, etc.). For more

[20] ESO (2024). The databook is at https://www.neso.energy/fes-data-workbook-2024; electricity demand for GB was taken from the databook, tab "ES1" and demand for European countries are taken from tab "ES2".

information, see "Appendix VI: Demand" in TYNDP (2022) "Scenario Building Guidelines".[21] All inputs will be available at https://github.com/KongChyong

Generation

Electricity generation includes gas CCGTs, thermal coal, oil, biomass, hydrogen CCGTs, nuclear, solar, wind, and other renewable supplies (RES, such as marine and waste-to-energy). Gross installed capacity was taken from FES HE scenario 2030 for GB (tab "ES1") and Europe (tab "ES2"). Table B.2 reports the total installed generation capacity per country in the model.

Technoecomomic parameters such as ramp rates, minimum up and downtime, start and shut down costs, thermal efficiency, and variable operating and maintenance (non-fuel) costs of dispatchable generation were primarily taken from the ENTSO-E (2024).[22] All costs and prices used in the model are Euro 2023 prices.

Biomass, gas, coal, oil and hydrogen-based electricity generation technologies are modelled endogenously (i.e. based on their respective short-run marginal costs). In contrast, wind, solar, nuclear and other RES are modelled exogenously, assuming either near zero short-run marginal cost (for wind and solar and other RES) or must-run due to technical and high cycling costs (for nuclear).

Exogenous generation technologies include Solar PV, Offshore Wind, Onshore Wind, Nuclear, Marine, Waste, and Other Renewables. The data-sourcing approach for exogenous technologies involves sourcing data from established datasets, making adjustments for regional consistency, and calculating relevant parameters such as capacity factors, thermal efficiencies, and carbon intensities.

The installed capacities were primarily sourced from the FES (HE 2030) dataset, with solar and wind hourly capacity factor profiles obtained from the PECD dataset[23] (1998 climate year data). Profiles for Nuclear and other RES were averaged from the hourly 2015–2022 actual generation data available on the ENTSO-E Transparency Platform.

For solar technologies, the analysis distinguished between utility-scale and rooftop PV installations. Rooftop solar profiles were adjusted for utility-scale PV using a factor of 1.11 derived from Jacobson and Jadhav (2018), which accounts for differences in sunlight incidence due to panel tilt and tracking. Weighted averages were then calculated for each zone, incorporating sub-zonal capacities for utility and rooftop solar. Onshore and offshore wind capacity factor profiles were computed using installed capacity weights for each sub-zone, following a similar methodology to solar. While calculating wind profiles was less complex, it

[21] https://2022.entsos-tyndp-scenarios.eu/wp-content/uploads/2022/04/TYNDP_2022_Scenario_Building_Guidelines_Version_April_2022.pdf

[22] https://eepublicdownloads.blob.core.windows.net/public-cdn-container/clean-documents/sdc-documents/ERAA/2023/ERAA2023%20PEMMDB%20Generation.xlsx. The original source for these parameters is the worksheet titled "Thermal Properties" within the Excel file named "ERAA2023 PEMMDB Generation.xlsx", derived from the Pan-European Market Modelling Database.

[23] https://zenodo.org/records/7224854

relied on accurate sub-zonal capacity splits to ensure precision in the resulting hourly capacity factor profiles.

Table B.2: Electricity generation capacity by fuels in 2030 (MW)

	Bio-mass	Coal	Gas	Oil	Hydro-gen	Other RES	Solar	Wind On-shore	Nuclear	Wind Off-shore	**Total**
Austria	585		1,997	164		293	9,620	8,691			**21,349**
Belgium	668		8,772	150		452	9,590	4,396	2,077	5,805	**31,909**
Czech Republic	410	3,690	856		500		6,080	1,506	3,936		**16,978**
Denmark	2,534		628				5,029	5,479		9,730	**23,401**
Finland	1,600		2,969				3,185	14,326	3,380	7,101	**32,561**
France	2,120		12,486	1,041	500	240	38,769	29,632	60,320	4,964	**150,072**
Germany	12,110		35,604	857	500	2,100	156,298	82,128		28,021	**317,619**
Great Britain	4,227		43,414	363	1,260	5,820	27,644	23,081	4,570	43,476	**153,854**
Island of Ireland (SEM)			7,723	693		103	4,496	8,749		4,344	**26,107**
Italy	4,672		50,222				63,568	16,743		1,940	**137,145**
Netherlands	1,059		15,386				28,084	7,795	485	16,979	**69,788**
Norway	732						2,563	6,369		8,779	**18,444**
Poland	1,535	16,584	8,182				15,597	15,554		10,560	**68,012**
Portugal	700		4,016				13,490	9,751		330	**28,287**
Slovenia	23	539	460				1,768	981	696		**4,467**
Spain	1,100		18,875		200		55,227	41,035	4,104	1,680	**122,221**
Sweden	2,220						4,830	22,459	6,881	1,599	**37,989**
Switzerland	400					200	10,264	495	1,220		**12,580**
Total	**36,695**	**20,813**	**211,589**	**3,268**	**2,960**	**9,207**	**456,646**	**299,405**	**87,669**	**145,308**	**275,324**

Characteristics of GB VRE

Table B.3 gives summary statistical data about the projected GB VRE.

Table B.3 Correlations and characteristics of 2030 GB VRE

	ON	OFF	PV	VRE	tot Wind
ON	100%	84%	-8%	88%	92%
OFF	84%	100%	-18%	91%	99%
PV	-8%	-18%	100%	21%	-16%
VRE	88%	91%	21%	100%	93%
total wind	92%	99%	-16%	93%	100%
Demand closed	22%	20%	24%	29%	21%
All Demand	70%	73%	9%	78%	75%
Res D closed	-77%	-82%	-8%	-86%	-83%
Res all demand	-56%	-57%	-22%	-67%	-59%
Max to capacity	68%	89%	86%	73%	81%
CF on max output	40%	56%	14%	46%	52%

Notes: The top box gives the correlation coefficients between elements in the columns and rows, the last two lines gives first, the ratio of the maximum recorded output of each aggregate technology to its installed capacity and below the capacity factor taking the maximum observed output as the effective capacity. Demand closed is total national demand excluding demand for exports and storage, all demand is total demand including for exports and storage.
Res D is residual demand, either for the closed case or including all demand.

Thus onshore and offshore wind have a correlation coefficient of 84% but PV has a negative correlation (-16%) with all wind, showing the complementarity between wind and solar PV. VRE has a modest correlation with demand in the closed economy (29%, as wind dominates and is higher in the higher demand winter period) but a much higher correlation (78%) with total demand, showing that additional sources of demand help match VRE output. All VRE is negatively correlated with residual demand, which in turn is likely positively correlated with the wholesale price, reducing the value of VRE. This value impact is alleviated with increasing uses of surplus VRE by exports and storage. For an example of the relationship of correlations to value see Azevedo et al. (2024).

A critical issue to address before calculating LCoEs is the projected capacity factors for wind, which have dramatically changed since the previous estimates in BEIS (2020), as shown in Table B.4 below. The figures from BEIS are the potential capacity factors, while the figures from the FES HE are the average capacity factors, which will be below their potential. Capacity factors have changed dramatically in a relatively short time period as new technologies are deployed. IRENA (2019, p11) notes, "For onshore wind plants, global weighted average capacity factors would increase from 34% in 2018 to a range of 30% to 55% in 2030 and 32% to 58% in 2050. For offshore wind farms, even higher progress would be achieved, with capacity factors in the range of 36% to 58% in 2030 and 43% to 60% in 2050, compared to an average of 43% in 2018."

Recent offshore wind developments suggest that the move to larger turbines (14 MW) has accelerated and, with them, higher CFs. A recent wind farm in Shetland has a very high CF that is effectively offshore.[24] Onshore wind farms will increasingly have to locate closer

[24] https://www.sserenewables.com/news-and-views/2023/08/final-turbine-installed-at-viking-wind-farm-in-shetland/

to demand to avoid grid congestion, and so will access less windy sites. Taking both considerations, a 2030 offshore wind might well exceed 60% potential PCF, but relative to the average fleet delivering in 2030, a scaling factor of 1.2 seems appropriate, or 60% of offshore wind, 34% for onshore wind.

Table B.4 Projected VRE capacity factors from UK Government

	OFF	ON	OFF	ON
	capacity	factors	output multiples of 2019	
2019 actual	51.6%	28%	1	1
BEIS(2020) for 2030	57%	34%	1.1	1.2
BEIS(2020) for 2035	**60%**	**34%**	**1.2**	**1.2**
BEIS (2023) for 2025	61%	45%	1.2	1.6
BEIS (2023) for 2030	65%	48%	1.3	1.7
FES HE for 2030	43.3%	26.5%		

Sources: BEIS (2020, 2023) ESO (2024). Figures in bold are the preferred values used in the text.
Note: The FES figures are for average (post curtailment) CFs, others are potential CFs

Storage

Conventional storage (pumped storage, hydroelectric generation with reservoir, batteries, compressed and liquid air energy storage) and demand-side response (DSR: load shifting and peak shaving) are modelled (see Table B.5).

Table B.5: Electricity storage and demand side response capacity in 2030

	Conventional storage		DSR	
	Discharge, MW	Duration,* hours	Discharge, MW	Duration*, hours
Austria	16,463	125	1,400	14
Belgium	2,130	3	10,107	11
Czech Republic	4,105	3		
Denmark	364	8		
Finland	4,030	571	4,641	4
France	28,588	152	9,999	11
Germany	32,652	49	6,722	5
Great Britain	27,747	3	4,131	6
Island of Ireland	2,179	3	667	4
Italy	25,431	134	2,286	4
Luxembourg	62	1	90	5
Netherlands	2,362	2	1,687	4
Norway	36,303	4,786	19,713	7
Poland	3,607	2		
Portugal	8,598	271		
Slovenia	1,399	8	110	13
Spain	25,590	527	2,000	4
Sweden	16,826	1,024	3,478	19
Switzerland	18,029	303		

Notes: * average for all storage technologies

All storage and DSR assumptions are taken from FES and ERAA 2023 (ENTSOe, 2024). Table B.6 summarises GB data.

Table B.6 Storage options in 2030 FES HE Scenario

Storage type	GW	GWh
Battery, BES	22.625	40.538

LAES	0.155	0.918
CAES	0.003	0.016
PHS	3.566	44.372
BES+PS	26.191	84.910

Source: FES24 Table ES.18

Hydro energy inflow data, discharge and charge capacities for the modelled market zones are derived from the Pan-European Market Modelling Database (PEMMDB),[25] part of the ERAA2023 study. Hydro inflows are sourced from the "Storage_technology – Year Dependent" sheet in files accessible via Hydro Inflows ZIP,[26] with the reference year set to 1998 under normal climatic conditions. Discharge, charge, and volume capacities are obtained from the sheet "TY2030" in ERAA 2023 PEMMDB Generation.xlsx.

Assumptions and data processing for hydro and PS technologies:

- Zones with positive discharge capacity but zero volume capacity assume discharge capacity equals volume capacity.
- Efficiency losses for pumped storage are assumed to be 25%.

Battery and DSR discharge, charge, and volume capacities are primarily based on FES, supplemented by ERAA 2023 PEMMDB Generation.xlsx for non-GB zones. DSR capacities for Great Britain (GB) are sourced from FES, while for other regions, data is derived from the "TY2030" in ERAA 2023 PEMMDB Generation.xlsx. Note that we take hydro generation capacity from the PEMMDB dataset. In particular, according to the PEMMDB dataset, GB has 2,219.5 MW of hydro-run-of-river generation capacity with storage capability (pondage). Therefore, GB's total storage capacity (discharge, Table B.3) is slightly higher (1,560 MW higher) than the total storage capacity reported under the FES 2030 HE due to additions of pondage storage capacity.

Assumptions and data processing for batteries and DSR:

- GB DSR capacity values are exclusively based on FES, while other zones use PEMMDB data.
- Battery storage calculations are based on the injection/offtake ratio in TYNDP, assuming 3 hours of energy storage for zones without specific data.
- Roundtrip efficiency losses for batteries are assumed to be 15%.
- Implicit (load shifting) DSR assumes a uniform 4-hour "storage" (or shifting) capacity.
- Peak shaving is modelled in great detail following assumptions on price bands, capacity and availability hours, according to ERAA 2023 PEMMDB.

According to FES HE 2030, GB's total consumer DSR (residential, industrial, and commercial consumers) may provide up to 2.07 GW of demand reduction at its peak in 2030. Further, FES HE 2030 assumes 8.16 GW of demand flexibility from smart EV charging (1.97 GW) and flexibility from domestic and industrial heat storage, hybrid heat pumps and thermal storage. Thus, in total, GB is projected to have 10.22 GW of demand-side flexibility

[25] https://eepublicdownloads.blob.core.windows.net/public-cdn-container/clean-documents/sdc-documents/ERAA/2023/ERAA2023%20PEMMDB%20Generation.xlsx
[26] https://2024.entsos-tyndp-scenarios.eu/wp-content/uploads/2024/draft2024-input-output/Hydro-Inflows.zip

by 2030 in the FES HE scenario, which is rather ambitious and sits at the high end of forecasts from other stakeholders and institutions (e.g. Torriti, 2024. Carbon Trust and Imperial College London forecasts optimal DSR capacity to be between 4.1 GW and 11.4 GW by 2030). In our dispatch model, we assume 2.07 GW of implicit DSR (load shifting) and another 2.07 GW of peak shaving, totalling 4.13 GW of DSR for GB by 2030. Note that peak shaving capacity will unlikely help reduce curtailment. They are designed to reduce peak hour demand rather than provide intertemporal flexibility to shift the residual load and lower the curtailment amount.

FES reports capacity for Compressed Air and Liquid Air Storage for GB only. Their discharge, charge and volume capacities for compressed air and liquid air storage are derived from FES data. Data from other regions is unavailable. Other storage options are shown in Table B.5.

Assumptions and data processing for Compressed Air and Liquid Air Storage:

- Installed capacities for compressed and liquid air storage reported in the FES databook are treated as discharge and charge capacities.
- Discharge durations are assumed to be 3 hours for compressed air[27] and 5 hours for liquid air: see Vecchi et al. (2021).
- Roundtrip efficiency is assumed to be 57.5% for both technologies, representing the midpoint of the 45–70% range cited by Vecchi et al. (2021).

Network

The network data for interconnections between zones in the model includes Net Transfer Capacities (NTCs), their assumed hourly availability profiles, and associated losses. The primary source for this data is the Pan-European Market Modelling Database (PEMMDB), specifically the file PEMMDB_Transfer_Capacities_2030.xlsx, which contains information on both HVDC and HVAC lines for European market zones. Supplementary data was drawn from FES, Ofgem[28] and public sources to calculate interconnections between GB zones and the rest of Europe.

To create the interconnector data, only interconnections where both connected nodes are listed within the relevant zones were included in the analysis. The NTC values for these interconnections were derived directly from their rated power. Availability profiles for the interconnections were assumed to be 1 (i.e., available at all hours). Where multiple interconnections existed between the same zones, they were categorised as additional lines.

In particular, given public data and our assumptions for 2030, GB is projected to have 14,514 MW of interconnection capacity with the rest of Europe:

1. 2,400 MW with Belgium
2. 1,400 MW with Germany
3. 1,400 MW with Denmark
4. 1000 MW with Netherlands
5. 1,464 MW with Norway
6. 1,450 MW with the Island of Ireland

[27] https://www.modernpowersystems.com/analysis/compressed-and-liquid-air-for-long-duration-high-capacity-11065946/

[28] https://www.ofgem.gov.uk/energy-policy-and-regulation/policy-and-regulatory-programmes/interconnectors

7. 5,400 MW with France

The final dataset includes the processed NTC values and interconnections availability profiles, incorporating the adjustments for GB sub-zones. This approach provides a robust and consistent basis for modelling interconnection capacities across the GB and European power systems.

Costs and prices

Load curtailment cost is assumed to be €4,000/MWh-e, which aligns with the ERAA 2023 price cap assumption. A carbon price is assumed to be €50/tCO_2 in 2030 for both GB and European power markets. Fuel prices were sourced from the BEIS (2023[29]) *Electricity Generation Costs 2023* report (Table B.7).

Table B.7: Assumed fuel prices

	€2023 per MWh-th
Dedicated biomass	11.83
Biomass CHP	14.64
Biomass CCS*	22.02
Hydrogen	66.60
Diesel	79.16
Natural Gas	34.58
Thermal coal	29.48

Notes: * 2020 BEIS cost report, MWh-th is MWh of fuel (thermal content)

Assumed avoidable (variable non-fuel) cost for exogenous generation (non-dispatchable generation) was assumed as follows:

1. Other RES: €40.53/MWh-e.
2. Wave energy: €26.69/MWh-e;
3. Landfill gas: €14.83/MWh-e;
4. Hydroelectric; €10.38/MWh-e;
5. Wind onshore: €8.90/MWh-e;
6. Wind offshore: €1.48/MWh-e;
7. Solar PV: €0/MWh-e;
8. Nuclear: -€10 /MWh-e.

The negative nuclear avoidable cost is an artificial construct designed to ensure that the dispatch model curtails nuclear power only as a last resort. This assumed variable (non-fuel) cost structure prioritises curtailment of other renewable energy sources (RES) first, as they are treated as the most expensive, while solar PV and nuclear power are curtailed last. When solar PV is curtailed, the shadow price of the demand-supply constraint (system marginal cost) will be zero. However, if nuclear power is also curtailed, this value could drop to negative €10.

Costs of GB VRE

The most recent GB data from BEIS (2020) is somewhat outdated. The projected costs £(2018) are shown in Table B.8.

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[29] https://assets.publishing.service.gov.uk/media/6555cb6d046ed4000d8b99bb/annex-a-additional-estimates-and-key-assumptions.xlsx

Table B.8 Annual costs for VRE in 2030 £(2018)

annual costs	OFF	ON	PV large	PV 10-50kW	PV<10kW
fixed at 3.5% £k/MWyr	£199.87	£108.60	£34.34	£50.20	£66.81
fixed at 5% £k/MWyr	£220.96	£125.70	£39.16	£58.74	£78.56
Var O&M £/MWh	£1.00	£6.00	£0.00	£0.00	£0.00

Source: BEIS (2020), with degradation rates from Table 8. To uprate to 2024 prices using the CPI index multiply by 1.25

Emissions factors for fossil fuels

Table B.9 CO_2 emissions factors (tCO_2/MWh-th)

	CCGT	CCGT-CCS*	Oil	Coal
Emissions factors, tCO_2/MWh-th	0.2052	0.0205	0.2808	0.3384

Source: UK Government conversion factors for reporting of greenhouse gas emissions.[30]
Note: MWh-th is the CO_2 content of the fuel so emissions depend on the thermal efficiency of the plant; * we assume a 90% capture rate for CCGT-CCS.

Hydrogen Demand

Hydrogen demand data is sourced from the sheet titled "Hourly H2 Data" in MMStandardOutputFile_NT2030_Plexos_CY2009_2.5_v40.xlsx. The column "Demand [MWH2] (losses included)" provides hourly demand values for relevant zones. Since the dataset contains 8736 hourly values up to 30th December, the values from 30th December are assumed to represent 31st December. This assumption ensures data continuity.

Electrolysis

Electrolysis capacity data for GB is derived from the "ES.R" sheet in FES 2024 *Data Workbook* under the parameter "Networked Electrolysis." For other zones, electrolysis data is sourced from the ERAA 2023 PEMMDB Generation.xlsx, under the parameter "Electrolyser." The techno-economic parameters for electrolysis are also included in this analysis. Electrolysis efficiency is assumed to be 70%.

Hydrogen Storage

Hydrogen storage data, including charge and discharge capacities and availability profiles, is also sourced from MMStandardOutputFile_NT2030_Plexos_CY2009_2.5_v40.xlsx. Charge and discharge profiles are derived from the columns "H2 storage charge (load) [MWH2]" and "H2 storage discharge (gen.) [MWH2]." Capacities are extracted from the "Max [MWH2]:" row.

Volume capacities are sourced from the "H2 storages" sheet, which relies on ERAA, PECD, and PEMMDB data. This information is available for download from ENTSO-E's hydrogen data repository. The volume capacities are taken from the "Max Capacity" column.

[30] https://www.gov.uk/government/collections/government-conversion-factors-for-company-reporting

Hydrogen Network

The hydrogen network data, including NTC values and profiles, is from the "Crossborder H2 exchanges" sheet in MMStandardOutputFile_NT2030_Plexos_CY2009_2.5_v40.xlsx. NTC values are extracted from the "Max [MWH2]:" row, and profiles are calculated in a manner similar to hydrogen storage, representing line-specific data.

Some complexities in the data required specific assumptions. For instance, negative profile values indicate power leaving the system, necessitating a reversal of start and end nodes. In such cases, the NTC is determined as the minimum value. Composite zones like "IB" (representing Iberia, i.e., Spain and Portugal) were split into constituent zones. For example, a composite zone, "IBIT" was divided into PT (Portugal), ES (Spain), and IT (Italy). Interconnections were manually categorised into sequences such as PT → ES → IT → final zone.

Appendix C Supplementary tables

Table C1 Simplest spreadsheet results for 2030, no storage, no exports, no flexibility

	nuclear	Total VRE	OFF	ON	PV	hours
baseline curtailment MWh	0	39,244,636	27,137,187	8,866,572	2,774,557	3,819
baseline cap MW	3,660	94,089	43,365	23,081	27,644	
av. curtailment MWh/MW, *ac*		417	626	384	100	
capacity increment MW	0	100	100	0	0	
incremented curtailment MWh		39,092,270	27,382,432	8,919,017	2,790,821	3,816
delta MWh		313,954	245,245	52,445	16,264	-3
marg curtail MWh/MW VRE, *mc*		3,140	2,452	524	163	
ratio *mc/ac*			5.02			
capacity increment MW	0	100	0	100	0	
incremented curtailment MWh		38,974,509	27,240,228	8,949,397	2,784,884	3,809
delta MWh		196,193	103,041	82,825	10,328	-10
marg curtail MWh/MW VRE, *mc*		1,962	1,030	828	103	
ratio *mc/ac*				5.11		
capacity increment MW	0	100	0	0	100	
incremented curtailment MWh		38,822,273	27,156,853	8,872,931	2,792,488	3,806
delta MWh		43,957	19,666	6,360	17,931	-13
marg curtail MWh/MW VRE, *mc*		440	197	64	179	
ratio *mc/ac*					4.38	
capacity increment MW	157	0	0	0	0	
incremented curtailment MWh		39,745,309	27,825,300	9,073,691	2,846,318	3,852
delta MWh		966,993	688,112	207,120	71,761	33
marg. curtail MWh/100MW av.		9,670	6,881	2,071	718	
capacity increment MW	0	705	277.2	147.1	281.1	
incremented curtailment MWh		40,068,088	28,028,438	9,153,223	2,886,427	3859
delta MWh		1,289,773	891,251	286,652	111,871	40
marg. curtail MWh/100MW av.		12,898	8,913	2,867	1,119	

Notes: Assumes constant nuclear output of 3,660 MW + average run-of river of 562 MW, demand includes a constant 1,962 MW electrolysis demand.

Table C1 shows the raw data from the simple closed economy spreadsheet model with no dispatchable flexibility, instead taking constant average values (as they affect inertia). Its layout shows how the compressed Table 2 is abbreviated where MWh/MW = hours/yr expressed as a percentage. Table 2 includes elements (electrolysis, run-of-river storage, energy from waste) that are dispatched in the UCED model (subject in some cases to ramp constraints) and whose hourly values has been transferred to the spreadsheet to allow a fairer comparison between the two sets of results. Table C1 ignores all flexibility (including their average values). These average additions to demand and must-run capacity relax the inertia constraint, but their lack of responsiveness to surplus VRE increases curtailment by 15% compared to Table 2. As usual, higher curtailment lowers marginal: average curtailment ratios.

Table C2 shows efficient curtailment for the same underlying data as Table 2b.

Table C2 Efficient curtailment results for 2030 scenario, no storage, no exports

Spreadsheet model	Total VRE	OFF	ON	PV	hours
ac	4.1%	2.2%	12.7%	0.0%	40.4%
mc		35.4%	22.1%	4.3%	
mc: ac		16.3	1.7	n.a.	
MCF		24.6%	11.9%	6.7%.	
UCED model					
ac	4.0%	2.1%	12.6%	0.0%	
mc		32.3%	25.8%	4.3%	
mc: ac		15.6	2.1	n.a.	
MCF		27.7%	8.2%	6.7%	

Note: Source as for Table 2b. ON curtailed first, then OFF, finally PV

Table C3 considers the various cost measures for the two models. With efficient curtailment, onshore wind is curtailed to such an extent that it makes little economic sense to expand its capacity, and indeed, the only efficient VRE at the margin is grid-scale PV. The resulting individual cost rankings are PV<OFF<ON for all measures.

Table C3 Cost metrics with efficient curtailment, £(2018)

Spreadsheet model	OFF	ON	PV
LCoE £/MWh	£43.04	£48.20	£40.64
LACoE £/MWh	£44.62	£73.52	£40.64
LMCoE £/MWh	£103.54	£126.58	£66.42
UCED model			
LCoE £/MWh	£43.04	£48.20	£40.64
LACoE £/MWh	£44.55	£72.92	£40.64
LMCoE £/MWh	£92.16	£180.73	£66.42