UNIVERSITY OF CAMBRIDGE | Energy Policy Research Group

Implications of the *National Energy and Climate Plans* for the Single Electricity Market of the island of Ireland[1]

EPRG Working Paper 2020

Cambridge Working Paper in Economics 2072

David Newbery

Abstract

Member States have published *National Energy and Climate Plans* with challenging variable renewable electricity (VRE) targets. As VRE has a high peak to average output, the Single Electricity Market of the island of Ireland (SEM), will need to consider how best to balance the lost value of curtailment against the extra costs of higher Simultaneous Non-Synchronous Penetration (SNSP), more interconnector capacity and/or more storage. The paper develops a simple spreadsheet model to explore these options for the 2026 VRE targets in the SEM and her neighbours. Raising SNSP from 75% to 85% reduces curtailment from 13.3% to 8.1%, saving 1,338 GWh/yr of spilled wind. Adding the Celtic Link of 700 MW at SNSP of 75% reduces curtailment to 12.4% and saves 235 GWh/yr. Adding 100 MW of batteries saves 18 GWh/yr. The marginal spilled wind can be four times the average.

Keywords Variable renewable electricity**,** curtailment, interconnection, storage

JEL Classification C63, Q42, Q54

Contact dmgn@cam.ac.uk
Publication July 2020
Financial Support

---

[1] The author is an independent member of the Single Electricity Market Committee of the island of Ireland but this paper is written as an independent academic and only draws on published sources. It does not reflect the views of the SEM Committee.

Implications of the *National Energy and Climate Plans* for the Single Electricity Market of the island of Ireland

David Newbery[1]
Energy Policy Research Group, University of Cambridge
20 July 2020

Abstract

Member States have published National Energy and Climate Plans with challenging variable renewable electricity (VRE) targets. As VRE has a high peak to average output, the Single Electricity Market of the island of Ireland (SEM), will need to consider how best to balance the lost value of curtailment against the extra costs of higher Simultaneous Non-Synchronous Penetration (SNSP), more interconnector capacity and/or more storage. The paper develops a simple spreadsheet model to explore these options for the 2026 VRE targets in the SEM and her neighbours. Raising SNSP from 75% to 85% reduces curtailment from 13.3% to 8.1%, saving 1,338 GWh/yr of spilled wind. Adding the Celtic Link of 700 MW at SNSP of 75% reduces curtailment to 12.4% and saves 235 GWh. Adding 100 MW of batteries saves 18 GWh/yr. The marginal spilled wind can be four times the average.

1. Introduction

The *European Green Deal*[2] sets out a roadmap to climate neutrality in 2050. Member States, including the Single Electricity Market of the island of Ireland (SEM), have to set out the decarbonisation path to be followed by the electricity sector. The Regulation on the governance of the energy union and climate action (EU/2018/1999) requires each Member State (MS) to establish a 10-year integrated *National Energy and Climate Plan* (NECP) for the period from 2021 to 2030, and submit it to the Commission by the end of 2019.[3] These NECPs require increased renewables, overwhelmingly solar PV and wind in most MSs, and the phase-out of coal.

In the SEM this also means finally recognising that peat is not a renewable fuel. There is limited scope for more hydro, and the technology of choice is wind, initially mostly on-shore, but in future off-shore looks increasingly attractive. The falling cost of solar PV is beginning to compensate for the poor solar resource.[4] Wind and solar are variable and need controllable flexible back-up, which for more than very short-term demand and supply shifting, will have to come from fossil generation. There are powerful arguments that to deliver an efficient level of the required flexible capacity, long-term contracts of the form delivered by Capacity Remuneration Mechanisms (CRMs) will be required despite the EU's preference for energy-only markets.

---

[1] The author is an independent member of the Single Electricity Market Committee of the island of Ireland but this paper is written as an independent academic and only draws on published sources. It does not reflect the views of the SEM Committee. I am indebted to comments from an EPRG referee.
[2] See https://ec.europa.eu/info/strategy/priorities-2019-2024/european-green-deal_en
[3] See https://ec.europa.eu/energy/topics/energy-strategy/national-energy-climate-plans_en
[4] The Government of Ireland's *Climate Action Plan 2019* envisages up to 6.5 GW of on-shore wind but only 1 GW of off-shore wind by 2025 and only 0.2 GW of PV. Eirgrid (2019) projects hardly any increase in the low level of biomass (which excludes peat).

This note asks what the ambitious renewables targets are likely to imply for storage, interconnection and curtailment, assuming adequate back-up power in the SEM. It is a back-of-the-envelope and hence rough estimate of the trade-offs. It cannot pretend to be a serious study, of the kind that Strbac et al. (2012), Imperial College London (2015), or Carbon Trust (2016) have undertaken for the UK, nor the more relevant, but earlier Weiss and Wänn (2013) study of the SEM. It does, however, illustrate how to grasp the main determinants of the relative costs of different strategies to deal with a high penetration of variable renewable electricity (VRE), bearing in mind interconnection opportunities but recognising that other interconnected countries also face a massive increase in VRE under their own NECPs.

In what follows we assume that sufficient capacity will be procured to meet the security standard, and that no single unit will be larger than 464 MW, the current largest generator, Great Island. The N-1 security standard requires that there is a primary reserve equal to the single largest infeed, which would either be 500 MW if EWIC is importing or the single largest generator otherwise. As we are considering surplus wind conditions, EWIC would not be importing, hence the limit is set by the size of the largest generation unit. There are additional constraints set by the allowable penetration of non-synchronous supplies (from VRE and DC interconnectors if importing).

2. Renewables ambitions on the island of Ireland

Ireland has published its *Climate Action Plan*[5] in 2019, but as of mid-July 2020 had not submitted its final *National Energy and Climate Plan* (due by the end of 2019), although on 6 January 2020 Minister Bruton published the *Draft General Scheme of the Climate Action (Amendment) Bill 2019* and confirmed that it is priority legislation for the Government in the new Dáil term.[6] The 2019 *Climate Action Plan* (the likely basis of the future Irish NECP) has a target of 70% renewables in electricity supply by 2030, with an intermediate 2025 target. Northern Ireland comes under the UK *Climate Change Act 2008* and is subject to the carbon budgets set by the UK Government on the advice of the Committee on Climate Change (CCC), as the UK has left the EU. The CCC's assessment of NI's power sector's projected contribution is somewhat critical (CCC, 2019, p36):

- This projection assumes that there is no coal generation in Northern Ireland beyond 2025.
- It assumes that if all currently committed renewable energy projects deploy, but in the absence of any further policy support for renewables, 40% of all Northern Irish electricity consumption will be met by intermittent renewable sources in each year from 2020 to 2030.
- This is below the Committee's current assessment that 45-60% of electricity generated in the UK could be from intermittent low-carbon sources by 2030.[7]

[5] At https://www.dccae.gov.ie/en-ie/climate-action/publications/Documents/16/Climate_Action_Plan_2019.pdf Note that renewables policy is a national competence and the North and South belong to different jurisdictions, each with her own environmental and energy policy. The SEM covers market arrangements and needs as far as possible to ensure harmonious trading relationships between North and South, hence the decision to exempt NI from the UK Carbon Price Floor to ensure alignment with Irish environmental policy.

[6] https://www.dccae.gov.ie/en-ie/news-and-media/press-releases/Pages/Minister-Bruton-Publishes-Draft-Scheme-of-New-Climate-Law.aspx

[7] CCC (2018) *Reducing UK Emissions, Progress Report to Parliament*.

Ireland's 2025 target for its electricity renewables share in 2025 is 52%, below the linear trend between 40% (2020) and 70% (2030) at 55%. Extrapolating to 2026 (after decisions on coal and interconnectors should have been delivered, the RoI target is taken as 55%. If we add to that an ambitious 50% for NI, assumed to be entirely wind, then we can make a rough estimate of the likely impact this would have on the SEM electricity system.

2.1. Predicting future demand, wind capacity and output

The first step is to determine the 2026 demand that implies the wind generation required to meet the target. The latest publicly available document is Eirgrid (2019, p59), which gives the median total demand in 2026 for RoI as 38.9 TWh, 55% of which for VRE is 21.4 TWh. The median NI demand is 9.67 TWh, 50% of which is 4.84 TWh. The projected 2026 median total SEM demand is 45.5 TWh and the target wind output is therefore 26.2 TWh. The next step is to construct an hourly demand schedule for 2026 by scaling 2018 hourly data by 1.25.

The next step is to allocate projected wind output hourly for 2026, which in turn requires a number of steps to adjust past data for future projected output. Eirgrid publishes wind output by jurisdiction at 15-minute granularity by calendar year up to 2019.[8] This is first aggregated to hourly averages. To provide consistent data for forecasting, these hourly outputs need to be corrected for the commissioned capacity on each day. Unfortunately, capacity data are less complete and often inconsistent across sources. Appendix D discusses the various sources and their differences.

Given the raw data for output, the first step is to normalise it for a normal wind year with a constant level of wind capacity (taken as that at the end of the year, for which data is more likely to be consistent across jurisdictions). Figure 1, taken from Eirgrid (2019), shows that 2018 was an average year, and as the most recent, the logical starting point.[9]

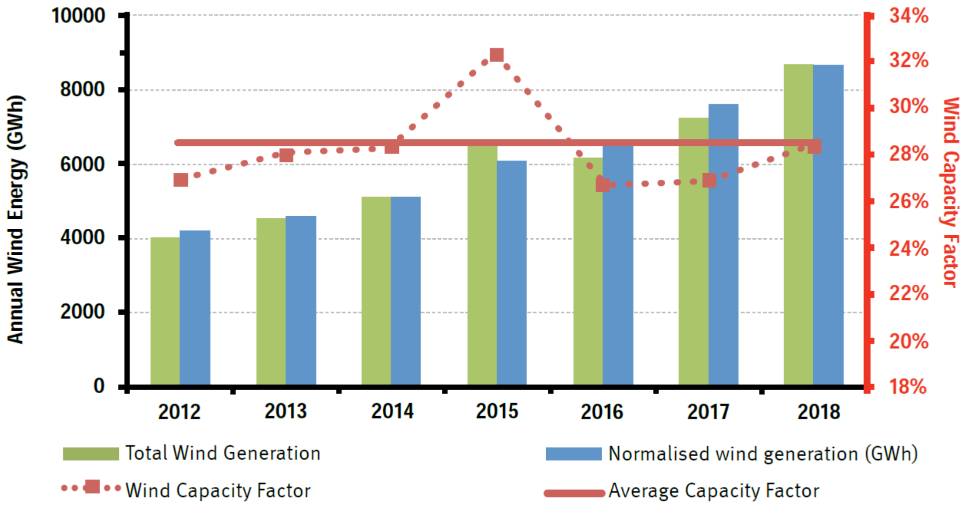

Figure 20 - The actual and normalised annual energy produced from wind power in Ireland over the last six years. In red are the figures for annual wind capacity factor, and their average

Figure 1 Capacity factors and wind generation in the SEM 2012-2018
Source: Eirgrid (2019)

[8] At http://www.eirgridgroup.com/how-the-grid-works/renewables/
[9] Appendix E shows that the choice of base year from which to project to 2026 is unimportant.

The limited run of years shows that a high wind year like 2015 might have a capacity factor of 32% rather than the average of 28.5%,[10] or 12% higher, while a low wind year like 2016 might be only 26.5% or 7% lower, and we shall need to check that taking an average year is equivalent to taking an average of a range of years from high to low wind.

For the purposes of calculating the maximum permitted level of wind before curtailment, we need to estimate total demand, which is domestic demand *plus* exports. At present there are two interconnectors – Moyle has potentially 450 MW export capacity, currently limited to 80-400, depending on constraints between Scotland and England; and EWIC with 500 MW. We assume by 2026 that up to 900 MW will be available (depending on market conditions, i.e. scarcity or surplus at each end, which might be somewhat optimistic). By 2026 it is possible that the 700 MW Celtic Link might be available, connecting to France, and this will be considered as a second scenario.

2.2. Adjusting for the system constraints

Eirgrid (2020) has published a list of the minimum generation units that have to be running to ensure various stability conditions, summarised (excluding coal plants and some oil plants) in table 1.

Table 1 Abbreviated list of generation units required

MW	at least	min											
	5 of	795	AD2	DB1	HNC	HN2	TYC	PBA	PBB			WG1	GI4
	1 of			DB1	HNC	HN2							
	2 of			DB1	HNC	HN2		PBA	PBB				
if D>4000	2 of			DB1	HNC			PBA	PBB				
D>4700	3 of			DB1	HNC	HN2		PBA	PBB				
	1 of		AD2							AT2	AT4	WG1	
D>2500	1 of		AD2							AT2	AT4	WG1	GI4
D>4200	1 of		AD2									WG1	GI4
	1 of						TYC						
MSG			130	110	120	121	194	120	120	15	15	160	165
capacity			431	415	342	404	404	232	232	90	90	445	464

Source: Eirgrid (2020)

Abbreviations: AD2: Aghada CCGT; DB1: Dublin Bay CCGT; HNC, HN2: Huntstown CCGTs; TYC: Tynagh CCGT; PBA: Poolbeg A,B, CCGTs; AT2,4 Aghada CTs; WG Whitegate CCGT; GI4: Great Island CCGT.

The first line would seem to be the most stringent condition (S_NBMIN_ROImin) which requires at least five units on load at all time to ensure system stability. The minimum stable generation (MSG) of these units is given at the foot of the table and if the highlighted units are chosen the minimum stable generation will be 795 MW. If the highlighted units are running at MSG, then the other constraints in Table 1 are satisfied, with some flexibility

[10] It is not clear how these capacity factors have been calculated. If we first correct output for a constant level of capacity then we find that the SEM in 2018 had a CF of 31.6%, and this is the CF we shall use.

(substituting WG1 and GI4 for any two might increase the MSG by up to 90 MW). The next constraint is that there must be spinning reserve to deal with the loss of the largest infeed (the N-1 constraint), which could be the largest CCGT of 464 MW or EWIC (500MW), but in excess wind conditions might be as low as the MSG of the largest unit in line 1 of Table 1. In any case the N-1 constraint is automatically met in excess wind conditions by the requirement of five units running at all times.

2.3. Adjusting inertia

If wind is to deliver its target share, then back-up generation will be needed for periods of low wind, and in periods of high wind there are two additional constraints that could limit the amount of wind on the system. The first is the proportion of non-synchronous generation connected to the system relative to demand (see e.g. O'Sullivan et al., 2014). This includes all wind and solar PV and imports over the DC interconnectors and currently is planned to reach 75% Simultaneous Non-Synchronous Penetration (SNSP) by 2020. Perhaps this can be raised to 85% (although I have no means to judging whether that is realistic). If so, then the relevant demand is domestic demand plus any allowed export. Whether or not exports are economic will depend on whether the countries to which it is interconnected (GB initially, potentially France later) are saturated and cannot reduce supply without curtailing their own VRE.

3. Allowing for exports over interconnectors

As a working assumption assume that if neighbouring countries are saturated with VRE that their spot price falls to zero, and that as a result it would not be economic for the SEM to export surplus wind. This requires that wind is not allowed to depress prices below zero, either by regulation, or, more logically, as the outcome of an efficient renewables support mechanism.[11] The size of the market into which to export will depend on export constraints, which for the SEM will be either 900 MW (Moyle plus EWIC) or 1,600 MW (with Celtic Link). GB has plans for 10 GW of interconnection (excluding those to the SEM) by 2026, and those limits would not bind if the destination countries are not capacity constrained to import less than the GB export capacity. The relevant markets into which GB can export is assumed to be France, Belgium, Netherlands and via immediate links, to Spain and Germany. The test is whether they are saturated with zero prices in the hours in which the SEM has surplus wind.

That requires that GB is not similarly saturated (by wind, PV and nuclear power). Appendix D investigates correlations of hourly wind output in the SEM and its neighbours. Rather than rely on such correlations, we assume that surplus wind can only be exported if the export market has positive prices, taken to be the case in which they have no surplus inflexible or VRE output (inflexible output includes nuclear power, which, although it can be turned down, would not voluntarily do so at a zero price). By 2026 GB is so strongly interconnected (to FR, BE, NL and NO) that her export capacity would not be constrained by her surplus inflexible output, and the continued significant volume of nuclear power should ensure that non-synchronous penetration (VRE + SEM imports) can be managed. GB will

[11] The best way to achieve this is to auction a Premium FIT for the first 20,000 full operating hours, so that the wind farm will self-curtail if the spot price falls below the avoidable (non-zero) variable costs.

still need reserves and it is assumed that 400 MW spinning fossil generation and MSG will suffice, given the increasing volume of fast response batteries.

Neighbouring Continental countries (FR, BE, NL, DE and ES) are assumed to be coupled and unconstrained in surplus hours (and have access to sufficient Continental wide inertia for that not to be a constraint), so it is the sum of all surpluses (including GB) that determines whether prices are zero and the SEM unable to export in these hours. Any wind above the 85% SEM SNSP limit (and reserve requirements) would then either have to be stored or spilled (see fig D1 in Appendix D).

3.1. Storage to avoid spilling wind

At present the SEM has access to pumped storage at Turlough Hill of 292 MW and 6 hours' capacity or 1,752 MWh, while an increasing number of batteries are or will be commissioned. We assume that by 2026 there will be 334 MW of batteries with a de-rated capacity of 142 MWh. That suggest a de-rating factor of 0.425 and an average ability to deliver 334 MW for about 1.5 hours, based on the published de-rating factors,[12] giving 500 MWh for batteries and a total maximum storage of 2,250 MWh. However, we are more interested in the maximum rate at which storage can usefully absorb energy, not discharge it. The maximum pumping rate into Turlough Hill is not available, but is presumably no greater than its generation capacity, and as its round trip efficiency is 75% it would take 8 hours of pumping to fully charge it. We therefore assume that it can absorb 292 MW for 8 hours or 2,336 MWh, starting from empty. Again this is generous as our model assumes pumped storage is priority reserved to absorb surplus wind and is allowed to return to zero in deficit wind conditions. A better assumption might be that it is half-full in which case its ability to absorb wind would be only for four hours, and this is tested below.

Lithium Ion batteries (LIB) are normally the preferred choice for grid-scale storage, with high round trip efficiencies (95%) and reasonable life even with depths of discharge of 80% (Chen et al., 2020), and it would appear that they can be charged at 5-10 time the rate at which they discharge. However, while this implies batteries could be charged at a rate of 1,670 MW they would be fully charged starting from zero charge in 20 minutes, so the effective amount that can be absorbed in any hour is limited by their total capacity of 568 MWh, or after allowing for losses in charging, they can absorb 568/95% = 598 MWh. Again, this is optimistic and its true capacity to absorb will be considerably less, tested in the sensitivities below.

3.2. Other forms of storage

Electric vehicles (EVs) are a potentially flexible demand that, if controlled to accept electricity in surplus wind conditions (with smart controllable charging[13]) could potentially

---

[12] The de-rating factors, which are given in Table 3 at https://www.sem-o.com/documents/general-publications/Initial-Auction-Information-Pack_IAIP2122T-2.pdf, depend on the initial capacity. If they are < 20MW each, the de-rating factor for 1.5 hrs storage is 0.48, but if as large as 130 MW de-rating is 0.426. 1.5 hrs is therefore generous.

[13] Of the kind trialled by various projects, such as Ofgem's My Electric Avenue (see https://www.citizensadvice.org.uk/Global/Migrated_Documents/corporate/capturing-the-findings-on-consumer-impacts-from-lcnf-projects.pdf

act as Battery Electric Storage, BES, but without the need to discharge to the grid. There were almost 9,000 electric cars on the roads in Ireland at the end of 2019. The Irish government currently has a target of 950,000 electric vehicles on the road by 2030.[14] This requires that approximately one third of all vehicles sold during the decade will be EVs.[15] Electric and hybrid (alternative fuel) vehicles accounted for one fifth (20.8%) of new private cars licensed in January 2020 in the RoI.[16]

Suppose that there is an acceleration and that of the average annual sales of (at the high end) 150,000 private cars, one-third will be EVs, i.e. 50,000 p.a. Then on average in 2026 at this rate there will be 9,000 + 6.5*50,000 = 334,000 EVs. If they have an average battery capacity of 30 kWh (possibly lower if there is a significant share of PHEVs) then their total storage capacity is 10 GWh. If on average these are 70% charged, there is the ability to absorb 3 GWh. If as many as one-quarter are plugged in with smart charging that allows them to charge at 6 kW whenever there is surplus wind, then they can absorb at a rate of 500 MW in the ROI. If this penetration were achieved in NI, then the total equivalent for the SEM would be 670 MW, with the ability to absorb 1 GWh (= 3 GWh total times ¼ charging, times 4/3 for SEM/RoI), comparable to the projected grid-connected BES.

Electricity can also be stored in the form of hot water by immersion heaters and as heat via storage heaters. Again, on the strong assumption that smart metering and IC equipment can enable surplus electricity to be stored in these forms, it is possible to provide a rough estimate of its potential for absorbing surplus electricity. Both the North and the South currently have high levels of oil heating, some of which may be supplemented by immersion heaters (particularly for summer use). In Ireland, residential space and water heating accounts for approximately 19% of the total energy consumption of the country but only 13.5% of central heating is electric in the RoI and only 5% in Northern Ireland (Kerr et al., 2018).

Some 775,000 homes in the Republic (43% of housing stock) also use oil for heating.[17] Northern Ireland has 68 per cent of homes using oil as their primary heating source,[18] and there are 770,000 households.[19] Thus of the 1.8 million households in the SEM if 50% (i.e. 1.25 million) were to have smart-enabled electric immersion heaters by 2026 and if their average size were 6 kW with a 120 litres tank (both rather large to take advantage of cheap electricity) they could absorb 6.25 kWh if cold, and perhaps 3 kWh if half-charged. If half were able to charge when there is surplus wind, the maximum rate of charging might be 1.25 x 6 x ½ GW = 3.8 GW and 1.9 GWh.

Ireland has a potential electrical heating replacement of around 1 GW for distributed controllable capacity on the grid, with some 360,000 electric storage heaters, excluding the

---

[14] http://www.moneyguideireland.com/electric-cars-facts-figures.html
[15] From the *Climate Action Plan* at https://www.dccae.gov.ie/en-ie/climate-action/publications/Documents/16/Climate_Action_Plan_2019.pdf
[16] https://www.cso.ie/en/releasesandpublications/er/vlftm/vehicleslicensedforthefirsttimejanuary2020/
[17] https://www.goffpetroleum.co.uk/news/irish-homeowners-fear-hike-in-heating-oil-price-following-brexit
[18] See https://www.consumercouncil.org.uk/sites/default/files/original/CCNI_Gas_v_Oil_Cost_Comparison_Final_Brief_May_2013.pdf
[19] From https://www.nisra.gov.uk/publications/northern-ireland-household-projections-2016-based-bulletin-charts

potential NI capacity. (Raadschelders et al. 2013.) Kerr et al. (2018) estimate that if the 10% of DSM enabled storage heaters (on average 2.2 kW with a storage capacity of 15.6 kWh) were available then during the winter NightSaver time period some 465 MWh would have been potentially available to avoid of curtailment because of SNSP constraints (at 75%). If more favourable tariffs encouraged wider take-up, then the potential becomes comparable to and perhaps considerably larger than planned BES impacts. However, its access, as with EVs and immersion heaters, requires considerable institutional and tariff reform to be accessible.

4. Modelling 2026

The first step is to multiply each 2018 hourly demand by 1.25[20] to give the same annual demand as the 2026 median projection, and for the same reason to multiply actual 2018 hourly wind output in each hour by 2.18 to project 2026 output. Figure 2 shows as the middle curve the domestic demand duration curve without any trade over interconnectors or storage. The lowest curve is the wind duration curve assuming no curtailment while the highest curve is domestic demand plus potential exports plus injections into storage (which can be negative), below which is domestic demand plus potential exports. Note that each curve is separately ranked from high to low so that the same percentage on the x-axis corresponds to very different operating hours of the various demand curves. The graph shows the potential importance for avoiding curtailment of exporting and storing surplus wind, and the rather modest contribution that storage appears to make.

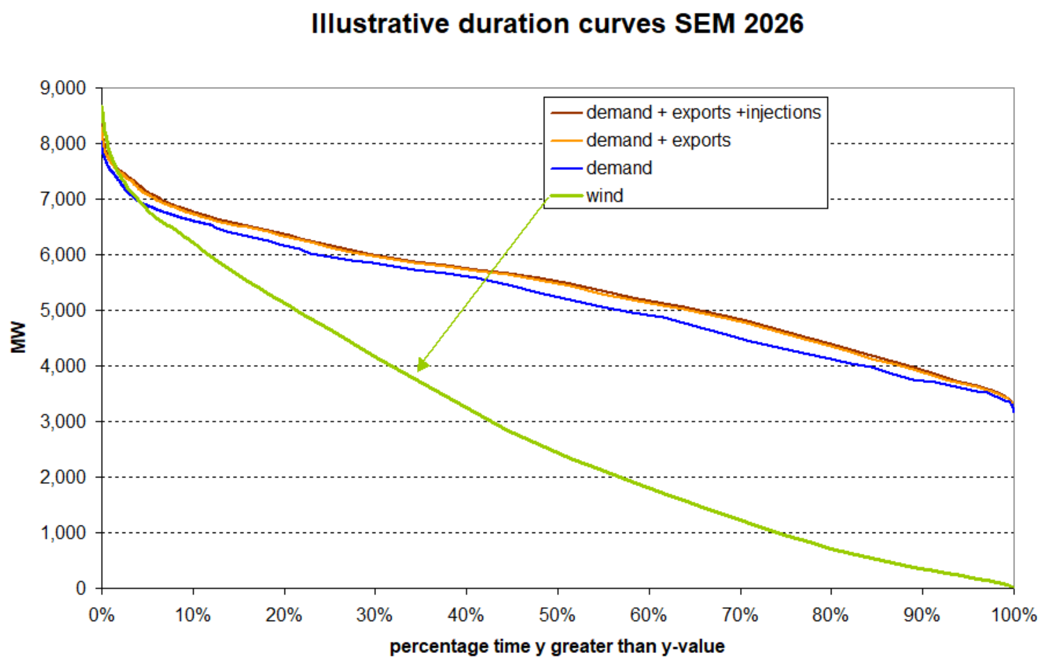

Figure 2 Potential demand duration curves: median forecast 2026

[20] This may seem high, but at the time of the Eirgrid demand forecasts, massive growth in storage farms was anticipated. Whether this is realised after Covid-19 and by 2026 is obviously uncertain.

In this very simple model,[21] the maximum demand is first calculated (domestic demand plus the calculation of maximum export), then the assumed SNSP (85%) and MSG (see Table 1) are applied to determine the surplus wind. If this is less than the ability of the pumped storage to accept it (292 MW up to 2,336 MWh cumulative) then this will be filled up, and any remaining residual surplus can stored by batteries at a maximum rate of 500 MW up to 500 MWh cumulative).[22] Any remaining surplus is curtailed and if there is a shortfall in surplus wind (i.e. if the total wind does not exceed the SNSP limit), then storage can be depleted to make room for later injections. The steps are set out in detail in Appendix B.

Note that this assumes that all storage is solely used to buffer wind, which greatly exaggerates the ability of storage to avoid curtailment, as some, perhaps most, of the storage capacity will be used for ancillary services (reserves, enhanced frequency response), and thus the state of storage will be less favourable than assumed (this is tested in the sensitivity analysis). Even with these extreme storage assumptions we find that on the assumptions above, 8% of the total potential wind is curtailed, reducing the actual wind used from the target 55% to 51%. Figure 3 shows illustrative duration curves for 2026 for scaled wind *less* demand, wind *less* demand *less* exports and wind *less* demand *less* exports *less* injections into storage and the resulting spilled wind. Only the positive values of exports are considered (otherwise set to zero, and similarly for injections).

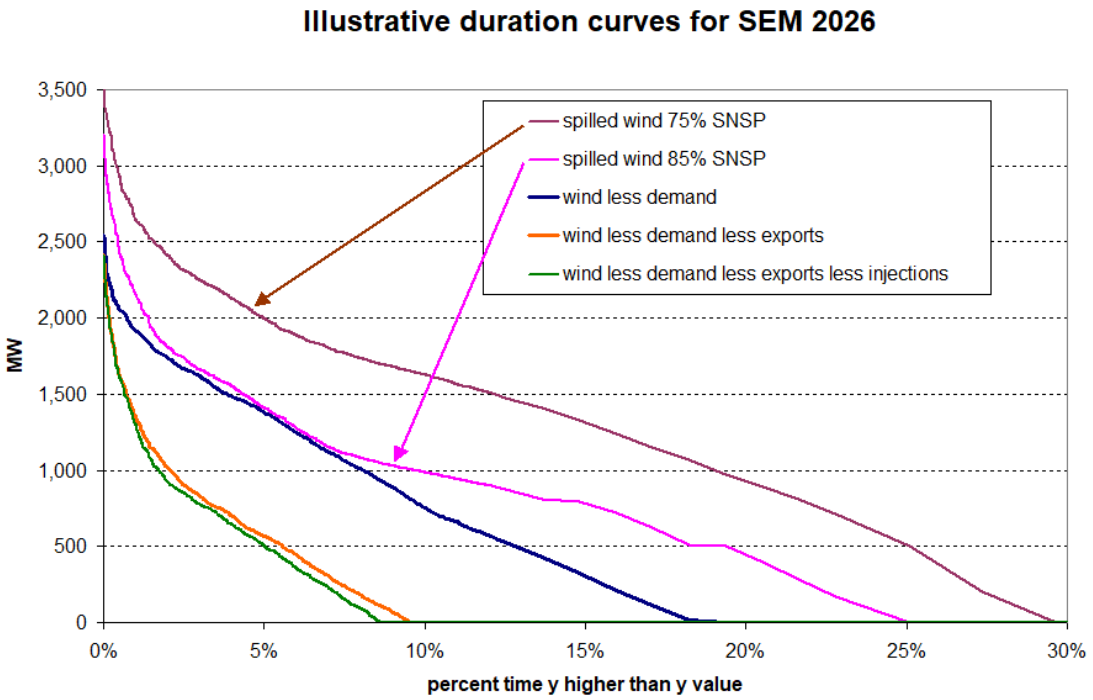

Figure 3 Illustrative duration curves for residual demands and spilled wind scaled to 2026

[21] A more sophisticated model would allow for the uncertainty of the forecast wind, as in Geske and Green (2020)

[22] The order can be disputed, depending on the relative costs of operation, but as the input cost (surplus wind) has effectively zero operating cost, and as batteries have a degradation cost, the order is clear for this case.

As in figure 2 each series is separately sorted from high to low values and so the same percentage point does not correspond to the same hour in the year. The highest curves are the resulting spilled or curtailed wind after allowing for the maximum allowable exports (when export prices are positive), minimum generation and the resulting constraints on SNSP (75% for the top, 85% for the lower). Its main purpose is to show the impact of using interconnectors and storage to export surplus wind that would otherwise be spilled. Storage has a very minor impact, but exports are potentially important. Wind is spilled more frequently than the apparent capacity to absorb wind by exports and storage, because of the SNSP and MSG constraints. The next section examines their impact on curtailment.

While the average amount of potential wind spilled is 8.1%, the proportion of the year in which at least some wind is spilled in considerably larger at nearly 25%. If the aim is that the average wind actually used is 55% of total domestic demand, then the potential wind would have to be 63% of average demand, with 12.6% of potential wind curtailed.

4.1. Marginal rate of curtailment

As it is simple to scale up wind in each hour by a constant proportion, we can use that to determine the marginal curtailment of adding an extra 1% more capacity (and hence 1% more wind in each hour). The marginal curtailment is 38%, more than four times larger than the average curtailment of just 8%.

5. Alternative scenarios varying SNSP, interconnectors and storage

The same simple model can be used to test the impact of higher SNSP, more battery storage, lower storage availability, and adding the 700 MW Celtic link.

5.1. Varying SNSP

Table 2 shows the volumes of spilled wind for different levels of SNSP and as a percentage of potential wind spilled. The final column (delta) shows the impact of raising the SNSP by 5% and shows the diminishing returns to increasing SNSP by 5% increments.

Table 2 Impact of changing SNSP on spilled wind per average year

SNSP	Curtail GWh	percent	Delta GWh
75%	3,388	13.3%	
80%	2,642	10.4%	746
85%	2,050	8.1%	592
90%	1,826	7.2%	224

5.2. Impact of windy and calmer years

The same scaling that was used to estimate marginal curtailment can be used to examine curtailment in windy and calmer years. Thus 2015 was 12% windier than 2018 and calmer years were perhaps 93% of 2018. Table 3 has the same format as Table 2. Compared to a normal year between 47-67% extra wind is spilled (the percentage increasing with SNSP but the amount extra spilled decreasing with SNSP. The average over a run of years (where the average of potential wind is that of the average year) gives almost the same average spilled as in the average year (between 2-5% higher, as spilling is non-linear in wind, as the higher marginal curtailment factors demonstrated).

Table 3 Impact of varying wind on spilled wind

SNSP	windy year GWh/yr	percent	delta	calm year GWh/yr	percent	delta
75%	4,982	17.5%		2,570	10.9%	
80%	4,090	14.4%	893	1,924	8.1%	646
85%	3,358	11.8%	732	1,424	6.0%	500
90%	3,047	10.7%	311	1,252	5.3%	172

5.3. Additional battery storage

Table 4 shows the impact of adding extra Li-ion battery electrical storage (BES, with the same characteristics as the planned battery expansion). Adding an extra 100 MW of BES reduces spilled wind by 18.47 GWh/yr or 185 MWh/MWyr battery capacity, and adding a further 100 MW further reduces spillage by 179 MWh/MWyr, again showing diminishing returns to scale and the modest contribution from battery storage compared to increasing SNSP (as figure 3 also shows). For comparison, if a battery cycles from 20% to 100% state of charge daily it would manage 7,000 MWh/MWyr, so the reduced curtailment is less than 3% of the battery's potential capacity. On the other hand, 5% extra SNSP increases headroom by 5% of demand (on average 269 MW) and allows 1-3% of wind not to be curtailed (higher values at lower SNSP).

Table 4 Impact of increasing Battery Electric Storage (BES, SNSP=85%))

Extra MW BES	Curtail GWh/yr		Delta GWh
0	2,042	8.0%	
100	2,023	8.0%	18.47
200	2,006	7.9%	17.85

Table 4 can also be used to provide rough estimates of the further potential of controlled charging of electric vehicles, immersion and storage heaters, but given the considerable control and tariff reforms needed to access these useful demand side responses, their potential will be noted but not estimated.

Table 5 Effect of halving storage capacity (SNSP=85%) GWh/yr

SNSP	GWh/yr	percent	delta	rel to full storage
75%	3,536	13.9%		148
80%	2,784	10.9%	753	141
85%	2,187	8.6%	597	137
90%	1,961	7.7%	225	136

Table 5 can be compared with Table 2 to show the effect of only being able to access half the potential storage capacity. Roughly speaking it increases the amount of spilled wind by 140 GWh/year.

5.4. Adding the Celtic Link

If the 700 MW Celtic link is operational in 2026 then more wind can be exported instead of being curtailed. Figure 4 shows this to be the case, although perhaps not as much as might be expected.

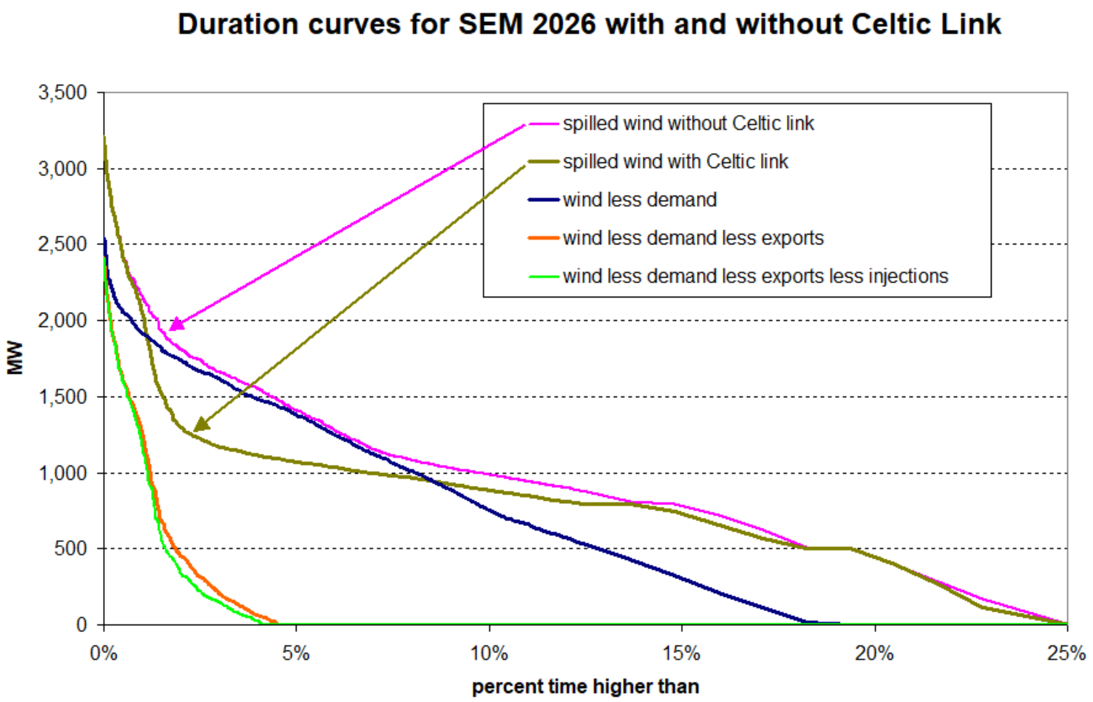

Figure 4 Duration curves with Celtic Link and comparisons of spilled wind without

Table 6 Impact of changing SNSP on spilled wind with Celtic Link

SNSP	curtail GWh/yr	percent	saved by Celtic Link, GWh
75%	3,153.7	12.4%	235
80%	2,392.3	9.4%	250
85%	1,775.1	7.0%	275
90%	1,515.4	6.0%	310

Table 6 gives the same data as Table 2 for the case with the Celtic Link. Benefits increase with increasing levels of SNSP as less wind remains after exports to be curtailed to meet SNSP limits. Curtailment falls from 8.1% to 7%, and the marginal curtailment of an extra 1% more wind capacity falls from 38% to 29%, now less than four times the average curtailment.

Spilled wind (with the same 85% SNSP) falls to 1,775 GWh at 85% SNSP, a reduction of 275 GWh compared to the case without the Celtic Link, so on average 31 MW per hour over the whole year, or 4% of the capacity of the link. As the extra exports would occur in high wind hours their marginal value would be low, and if their value (price *less* variable costs) were as high as €10/MWh, the value of exporting more wind to the Celtic Link would be €2.74 million/year. Although the Irish government has secured a grant of €530 million towards the €1 billion cost,[23] even if completed on budget the net cost to Ireland would be €470 million. The annual interest and depreciation cost at a real WACC of 3% amortized over 30 years would be €23 m/yr, to which the saved curtailed wind might contribute 12%. In contrast raising SNSP by 5% from 75% to 80% without the Celtic Link saves 746 GWh, 2.7 times as much.

The benefit of extra battery storage is almost unchanged by the additional export capacity, and so its benefits from absorbing excess wind would seem to be moderately insensitive to the actual export capacity. However, the economics of both extra interconnection and extra storage rely more on other revenue sources (arbitrage for interconnectors, ancillary services[24] from storage). Suitable batteries (for fast frequency response), pumped storage (for reserves) and interconnectors can provide some of the necessary system services needed to accommodate higher levels of SNSP (Eirgrid, 2020, p5).

It is also straightforward to compare the benefit of the current interconnectors (Moyle and EWIC) rather than running a totally isolated system for the 2026 scenarios. Table 7 does this in the same way as Table 6 evaluated the Celtic Link, and again shows that the benefits of interconnection increase with SNSP. Again, this ignores all the other benefits of interconnection.

Table 7 Comparing value of current interconnection for 2026

SNSP	curtailed GWh/yr	percent	saved by current IC GWh
75%	4,085.0	16.1%	697
80%	3,393.3	13.3%	751
85%	2,907.2	11.4%	858
90%	2,752.8	10.8%	927

6. Conclusions and policy recommendations

Ambitious plans to reduce carbon emissions from electricity, mainly through increased variable renewable electricity (VRE) increase the likelihood of curtailment, as the ratio of peak to average power can be 3:1 for wind, and 6:1 for solar PV. It is tempting to think that surplus VRE can either be exported or stored until there is no longer a surplus, and this paper provides a rough estimate of what can be expected from these options, bearing in mind that the SEM’s neighbours have also committed to ambitious (in some cases more ambitious) decarbonisation plans for their power sectors.

Interconnection indubitably reduces curtailment, as does storage, although increasing SNSP (which in turn benefits from increased interconnection and storage) has a larger effect. The direct impact of interconnection and storage alone would not seem to justify their cost, although would clearly improve their economics, provided their main justification (arbitrage and ancillary services) is (almost) adequate.

[23] https://www.dccae.gov.ie/en-ie/news-and-media/press-releases/Pages/Press-Release-Government-Secures-%E2%82%AC530m-EU-grant-for-Celtic-Interconnector.aspx notes that Dinorwig PS pumped three times the daily amount in April 2020 as for six months last year as demand fell and VRE increased.

[24] See e.g. https://www.ft.com/content/d8368db0-8519-4da3-8467-3496cb15ff9c

This note has employed very simple spreadsheet modelling and as such is easy to replicate and update, but is only a partial substitute for a proper unit dispatch coupled set of system models, of which there are many.[25] By spelling out each link in the determination of VRE curtailment is offers more (or quicker) insight into the determinants of curtailment than more complex black-box optimisation/simulation models. For example, it shows that the marginal curtailment of adding more capacity when VRE penetration is high can be more than four times as high as the average curtailment rate, although this multiple falls with more interconnection. Increasing SNSP has a considerably larger impact on curtailment than building more interconnection or storage.

The main policy conclusion is that the design of support systems for renewable electricity needs to ensure that at the margin extra wind is valued at the spot or even balancing price of electricity to ensure efficient trade and storage decisions (both spot and for long-term investment decisions). Providing subsidies for fixed prices for VRE output in each hour will distort these signals, and instead support should be to effective installed capacity, rather than output. The first priority is to set an adequate carbon price floor (as in GB), to ensure efficient competition with remaining fossil generation. Then the simplest way to provide efficient subsidies (justified by learning externalities that are the main justification for renewables targets) is to auction the premium to be paid per MWh of the first 20,000 (or some other number) of full operating hours (i.e. 20,000 MWh/MW capacity). This ensures that the marginal value of an extra MWh is the spot or balancing price while providing an assured and bankable capacity subsidy.

One interesting implication of such a support system is that forced curtailments should be less necessary, as VRE producers will only supply if the relevant price (spot, balancing or ancillary service) is higher than their short-run avoidable costs. Some curtailment may still be locally necessary to address transmission congestion. If spatially specific congestion is persistent, then curtailing according to last-in first-out for future investments provides strong incentives for more efficient location.

In addition, it is increasingly recognised that optimising the choice of turbine technology for local wind conditions can be important, and possibly more important for reducing system-wide variability that geographic dispersion.[26] Efficient decentralised choices require efficient signals (locational prices may be too cumbersome while last-in first-out curtailment may be cruder but simpler).

Finally, we have noted, and attempted very rough estimates of the further potential for absorbing excess wind through smart charging of electric vehicles and domestic storage and immersion heaters, but the challenges of delivering efficient retail prices (or contracts) to access these should not be underestimated.

[25] E.g. Gil et al. (2017) uses REMix, a high temporal and spatial resolution energy system model, Zappa et al. (2019) use Plexos, and METIS simulates the operation of energy systems and markets on an hourly basis over a year, while also factoring in uncertainties like weather variations (at https://ec.europa.eu/energy/data-analysis/energy-modelling/metis_en)

[26] See e.g. https://www.iaee.org/eblast/webinar_madlener.html (Paper by Tim Höfer and Reinhard Madlener "Valuation of the Locational Merit and Benefits of Diversification of Onshore Wind Power" shortly to be released). Also at https://www.youtube.com/watch?v=FJHSHcmtxoM .

References

ACER, 2019. OPINION No 22/2019 OF THE EUROPEAN UNION AGENCY FOR THE COOPERATION OF ENERGY REGULATORS of 17 December 2019 on … the values of CO2 emission limits …, at https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Opinions/Opinions/ACER%20Opinion%2022-2019%20on%20the%20calculation%20values%20of%20CO2%20emission%20limits.pdf

Carbon Trust, 2016. *An analysis of electricity system flexibility for Great Britain*, at https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/568982/An_analysis_of_electricity_flexibility_for_Great_Britain.pdf

CCCC, 2019. *Reducing emissions in Northern Ireland*, Committee on Climate Change, February 2019, at https://www.theccc.org.uk/publication/reducing-emissions-in-northern-ireland/

Chen, T., Jin, Y., Lv, H. et al., 2020. Applications of Lithium-Ion Batteries in Grid-Scale Energy Storage Systems. *Trans. Tianjin Univ*. 26, 208–217. https://doi.org/10.1007/s12209-020-00236-w

Eirgrid, 2019. *All-Island Generation Capacity Statement 2019-2028*, at http://www.eirgridgroup.com/site-files/library/EirGrid/EirGrid-Group-All-Island-Generation-Capacity-Statement-2019-2028.pdf

Eirgrid, 2020. *Operational Constraints Update* 30/04/2020, at http://www.eirgridgroup.com/site-files/library/EirGrid/OperationalConstraintsUpdateVersion1_93_Apr_2020.pdf

Geske J. and Green R, 2020, Optimal storage, investment and management under uncertainty: it is costly to avoid outages!, *Energy Journal*, Vol: 41, Pages: 1-28

Gils, H.C., Y. Scholz, T. Pregger, D. L. de Tena, D. Heide, 2017. Integrated modelling of variable renewable energy-based power supply in Europe. *Energy*, 123, 173-188 at https://doi.org/10.1016/j.energy.2017.01.115

Government of Ireland, 2019 *Climate Action Plan 2019*, at https://www.dccae.gov.ie/en-ie/climate-action/publications/Documents/16/Climate_Action_Plan_2019.pdf

Imperial College London, 2015. *Value of flexibility in a decarbonised grid and system externalities of low-carbon generation technologies, report for the Committee on Climate Change*, available at https://www.theccc.org.uk/publication/value-of-flexibility-in-a-decarbonised-grid-and-system-externalities-of-low-carbon-generation-technologies/

Kerr, W., Laverty, D., & Best, R. (2018). How Electrical Storage Heaters Can Reduce Wind Curtailment by Satisfying System Reserve Requirements. In *2018 3rd International Conference on Power and Renewable Energy* (Vol. 64). https://doi.org/10.1051/e3sconf/20186403002

National Grid, 2019. *Future Energy Scenarios*, at http://fes.nationalgrid.com/fes-document/

O'Sullivan, J., A. Rogers, D. Flynn, P. Smith, A. Mullane and M. O'Malley, 2014. "Studying the Maximum Instantaneous Non-Synchronous Generation in an Island System—Frequency Stability Challenges in Ireland," in *IEEE Transactions on Power Systems*, **29**(6), 2943-2951, https://doi.org/10.1109/TPWRS.2014.2316974 .

Raadschelders, J., F. Sikkema and B. i. Groen, 2013. *Potential for Smart Electric Thermal Storage, Contributing to a low carbon energy system*, DNV KEMA Energy & Sustainability, Arnhem.

Strbac, G., M. Aunedi, D. Pudjianto, P. Djapic, F. Teng, A. Sturt, D. Jackravut, R. Sansom, Vl. Yufit and N. Brandon, 2012. *Strategic Assessment of the Role and Value of Energy Storage Systems in the UK Low Carbon Energy Future; Report for the Carbon Trust*, Energy Futures Lab, Imperial College, June

Weiss, T. and A. Wänn, 2013. *Does Ireland need more storage? Power system overview and RES integration* at https://www.store-project.eu/documents/target-country-results/en_GB/energy-storage-needs-in-ireland-executive-summary

Zappa, W., M. Junginger, M. v.d. Broek, 2019. Is a 100% renewable European power system feasible by 2050? *Applied Energy*, 233–234, 1027-1050 at https://doi.org/10.1016/j.apenergy.2018.08.109

Appendix A Operational Constraints (Eirgrid, 2020)

One key parameter is the Minimum Stable Generation (MSG). This is higher on some units than desirable –Coolkeeragh CCGT has a MSG of 260MW, which can cause additional wind to be curtailed.

TSOs apply a static Largest Single Infeed to set their Reserve requirements around 500MW (EWIC). Simplifying

- Load the MSGs and constraint group data into an integer solver.

- Assume that sufficient wind exists such that no thermal is required except as needed for constraints and reserve (this could be generalised later), further assume no thermal line limits north to south and vice versa (also can be relaxed later but with a bit more work).

- Represent the 500MW N-1 requirement as a second resource with its own constraint on each unit, so that each thermal unit can provide [on/off] x (X1 + X2) <= C; where X1 is active MW and X2 is Reserve, with additional constraint X1 > MSG and global constraint Sum(X2) >=500.

Appendix B Data sources and methodology

Hourly generation and load data can be downloaded from the ENTSOI-E Transparency Platform, and the *Integrated National Energy and Climate Plans* (NECP) can be accessed via the links on the EU website https://ec.europa.eu/energy/topics/energy-strategy/national-energy-climate-plans_en . These documents provide (not very consistent) data on the target levels of renewables for 2030, and sometimes to 2025, either as MW of installed capacity or TWh of generation (the latter is more useable). In each case a scaling factor by which to multiply the 2018 hourly output of each renewable (and nuclear) to give the 2026 is computed. If there is no 2025 target it is assumed to lie on a linear progression from 2018 to 2030, starting either with 2018 TWh or MW capacity. The results of these scaling exercises are presented below.

(Note that ENTSO-E gives DE+AT+LU to end September 2018 and then only DE+LU thereafter, with about a 10% difference. I have scaled DE+LU to the DE+AT+LU, probably an over-estimate of DE grid load but as it is consistent with claimed RES shares, perhaps a better proxy for this integrated market area.)

Methodology

The calculation of the various elements in the graphs and the spilled wind is best illustrated by stepping though the calculations. In Table B1 the scaled wind prediction for 2026 is shown in col A (scaled by a factor of 2.174 times the adjusted 2018 wind (W) to give 55% penetration). Col B gives scaled demand (D) for 2026, and col C is the summed excess of Continental neighbours VRE and inflexible nuclear output over demand in GB, FR, BE, NL, DE and ES. If this is positive then export prices from the SEM are assumed zero, as are SEM exports (which can be notionally negative, i.e. imports if prices are non-zero when SEM prices are also non-zero). Col D is the resulting SEM notional exports (X), and Col E is total demand in the SEM on generation, ($D+X$), used to check that MSG (795 MW) and SNSP (85%) are satisfied – if not then the amount required (M) is calculated and shown in Col F. This is added to surplus wind to make room for the required SEM non-wind generation shown in Col G ($S=W+M-D-X$).

If this is positive, and if Pumped Storage (PS) can accept more inputs, then it is injected into PS at the maximum rate (272 MW) until PSP has 1,752 MWh in store (but additions to PSP are only 0.75*injections to allow for losses). Thus as part of the calculation Col I shows the maximum rate I at which PS can either be added to or run down (which can only happen in this model if there is negative surplus wind, i.e. spare rampable down domestic generation). Again it is optimistic that stored PS can be depleted as fast as possible to make room for surplus wind, ignoring all the other motives for operating PS and hence biasing curtailment downwards. Col J shows the resulting amount (P) stored in PS and its increase over the next hour reduces the notional surplus wind, shown in Col K. A similar calculation is now performed to see how much can be injected into Battery Electrical Storage (BES), given the amount already stored (maximum 500 MWh, which can be withdrawn at no more than 234 MW but can be injected at higher than 500 MW, meaning that BES can be filled from zero in less than one hour. Again negative values in Col K allow BES to be discharged, and Col L shows the state of charge (0.95*cumulative net injections). Again the increment in BES injections gives the amount of the remaining surplus wind that can be absorbed, and hence the final amount (F) of spilled or curtailed wind in Col M.

The formulae for potential injections I into PSP, its level of storage P and the surplus wind remaining, R are

$$I = \text{Min}(S, 272),$$
$$P_t = \text{Max}(0, \text{Min}(1752, 0.75*I + P_{t\text{-}1})),$$
$$R = S + (P_t - P_{t\text{-}1})/0.75.$$

Note, R can be negative to allow battery discharge. Similarly, injections into BES at potential rate b give a state of charge B and final spilled wind F:

$$b = \text{Min}(R, 500),$$
$$B_t = \text{IF}(R<0, \text{Max}(0, B_{t\text{-}1} - \text{Min}(\text{-}R, 334), \text{Min}(0, \text{Max}(500, R + B_{t\text{-}1})),$$
$$F = \text{Max}(0, R - (B_t - B_{t\text{-}1})).$$

Table B1

		A	B	C	D	E	F	G	H	I	J	K	L
date	hour UTC	W = SEM Wind 55%	D = 2026 SEM Demand	EU surplus VRE + nuclear	X = potential SEM exports	$D + X$	M = Min gen (SNSP+constraints)	S = W+M-D-X surplus wind after SNSP, MSG	I = Max PS injection	P = PS Stored	R = remaining surplus wind = surplus - inj into PS	B = battery state of charge	F =final spilled wind
1-Jan-18	14	7041	5368	5091	0	5368	805	2478	292	1752	2478	501	2478
1-Jan-18	15	6200	5320	-4477	880	6200	930	930	292	1752	930	501	930
1-Jan-18	16	5761	5701	-17792	60	5761	864	864	292	1752	864	501	864
1-Jan-18	17	5407	6251	-25592	0	6251	938	94	94	1752	94	501	94
1-Jan-18	18	4600	6097	-26427	0	6097	915	-582	-292	1533	-290	211	0
1-Jan-18	19	3568	5818	-17480	0	5818	873	-1377	-292	1314	-1085	0	0
1-Jan-18	20	3034	5553	-8098	0	5553	833	-1686	-292	1095	-1394	0	0
1-Jan-18	21	2487	5294	-5191	0	5294	795	-2013	-292	876	-1721	0	0
1-Jan-18	22	2214	4935	-2931	0	4935	795	-1926	-292	657	-1634	0	0
1-Jan-18	23	1977	4716	3732	0	4716	795	-1944	-292	438	-1652	0	0
2-Jan-18	0	2010	4334	8110	0	4334	795	-1529	-292	219	-1237	0	0
2-Jan-18	1	2300	4008	10658	0	4008	795	-913	-913	0	-621	0	0
2-Jan-18	2	3066	3807	11364	0	3807	795	54	54	40	0	0	0
2-Jan-18	3	4020	3713	10612	0	3713	795	1102	292	259	810	501	309
2-Jan-18	4	4479	3669	7260	0	3669	795	1606	292	478	1314	501	1314
2-Jan-18	5	5170	3739	-2252	900	4639	795	1327	292	697	1035	501	1035

Thus on 1 Jan hr 14 there is surplus EU VRE+nuclear (Col C) and hence exports X = 0, while 15% (=1-85%) of D+X = 0.15*5,368 = 805 MW, which is above the MSG, and hence the binding constraint on domestic fossil generation is set by SNSP at M = 805 MW, which is added to *W-D-X* = 1673 MW to give *S* = *W+M-D-X* =2,478 MWh (col G). In hour 17, although *W<D*, after accounting for SNSP (*M* = 938 MW), *S* > 0 and so curtailment is potentially needed. If, as in hr 15 that day, the EU can absorb SEM exports, the amount exported is the amount of surplus wind (*W-D* = 880 MW) up to the lower of the export capacity (in this case 900 MW, as in Jan 2 hr 5) or the amount that would eliminate the EU ability to absorb SEM exports. We ignore cases in which the SEM could import as these are irrelevant to cases of spilled wind (e.g. hr 17, when exports are set to zero).

Continuing from Col G, the maximum potential injection into PS is the lower of *S* and 292 MWh, but whether that can be accommodated depends on how much is already stored (*P*) in the PS. In this case it is full (at 1752 MWh) so none can be added and *R=S*. In hour 18 there is a deficit of wind, so flexible generation is running and can be scaled back to allow PS to discharge at either its lower of its maximum rate (-292 MW injection, i.e. 292 MW generation), or to remove the wind deficit, or until PS is empty (*P* falls to zero, as it does on 2 Jan hr 1). Depending on how much wind is absorbed injecting into PS, that determines the amount to carry forward for battery charging and discharging (charging if *R*>0 and *B*<500, and discharging if *R*<0 and *B*>0, as in hr 18). The final amount of spilled wind, *F*, is *S* (Col G) *less* the total injections into PS or BES (Col L). By hr 1 of Jan 2, all storage has been exhausted and is ready to absorb surplus wind, which it does in hr 3 on Jan 2, reducing *S* from 1102 MWh to 309 MWh.

Appendix C Renewables targets from NECPs

Great Britain

Future generation and load are taken from the Two Degree Scenario in *Future Energy Scenarios* (National Grid, 2019) to find the ratio of annual 2026 projected output from each element to that in 2018.

The scaling factors are: 0.7 for nuclear, 3.53 for off-shore wind, 1.53 for on-shore wind and 1.33 for solar PV and 1 for run-on-river hydro.

France

According to France's PLAN NATIONAL INTEGRE ENERGIE-CLIMAT de la FRANCE Mars 2020 (NECP)[27] (and via Google translate)

In France there are several "stages" of nuclear reactors: …

· EPR: 1 reactor of 1600 MW which should be commissioned in 2023.

On nuclear power it is proposed to "Postpone to 2035 the prospect of reducing the nuclear share to 50% of the production mix of electricity" (p123).

Apart from closing Fessenheim in 2020 (1,840MW), closures will not start until 2029. Coal plants will close by 2022, so the major nuclear phase-out is deferred.[28]

The main sectors for producing electricity from renewable energy are as follows (capacities at December 31, 2018):

· 25.5 GW of hydraulics: hydraulic capacity has been stable since the late 1980s;

· 15.1 GW of wind power; 8.5 GW of solar; 2.0 GW of bioenergy.

Total electricity production in France reached 548.6 TWh in 2018. It exported 86.3 TWh and imported 26.1 TWh, representing an export balance of 60.2 TWh. Consumption = 489 TWh.

"The energy transition law for green growth has set a target of 40% renewable energy in final electricity consumption in 2030. Wind power is planned to increase from 11,7GW in 2016 to 24,1GW in 2023 and to either 33,2GW or 34,7GW in 2028. PV rises from 10,2 GW in 2018 to 20,1 GW in 2023 and 35,1- 44,0 GW in 2028.

Scaling factors from 2018: PV by 2.6; Wind 26/15 = 1.73; (presumably more offshore, less onshore; nuclear assume unchanged as EPR replaces retirements.

[27] At https://ec.europa.eu/energy/sites/ener/files/documents/fr_final_necp_main_fr.pdf

[28] See https://www.gouvernement.fr/en/multiannual-energy-programme-what-are-its-aims

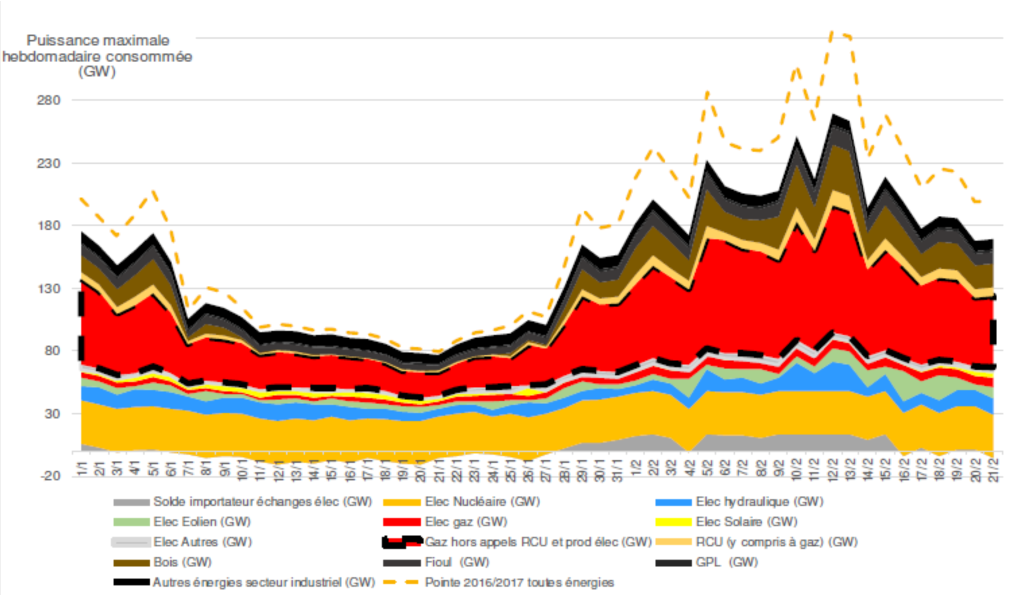

Figure 34 All-energy French power demand curve in 2028 (p182)

Belgium

According to the Draft of *Belgium's Integrated National Energy and Climate Plan 2021-2030* (NECP),[29] "A major change in the energy mix following the phasing out of nuclear power by 2025, with 5,918 MW of decommissioned nuclear capacity having to be replaced." (NECP, p12). Belgium is opting for an energy mix based on flexible capacity, load shifting, storage and renewable energy. The renewables share in electricity will be 40.4% by 2030 (21% in 2018). Wind capacity is shown in 2018 as 3.36 GW (1.2 off-shore, 2.16 onshore) The NECP contains high ambitions for offshore wind, with an expected 4 GW of total installed capacity by 2030. However, the onshore target of 4.2 GW is relatively low. The current draft of the plan incorporates a complete nuclear phase-out by 2025. (Source: https://windeurope.org/newsroom/news/belgium-energy-and-climate-plan-proposes-renewable-energy-target-of-18-3-by-2030/)

The country's cumulative installed PV capacity reached 4.82 GW at the end of 2019 an increase of 0.5 GW on 2018 so 2018 = 4.3 GW. Estimated consumption 2018 84 TWh. At the end of March 2018 the government reaffirmed its phase-out policy and said that it would introduce capacity payments. Elia said that at least 3.6 GWe of new thermal capacity would be needed by the end of 2025. According to the NECP, biomass decreases and Offshore wind does not increase before 2025.

Scaling factors for 2026: nuclear phase-out, 50% increase in on-shore wind, double PV.

Netherlands

The *Integrated National Energy and Climate Plan 2021-2030* (NECP)[30] states "The approach thus focuses on these sources:

i. Generating circa 49 TWh wind energy offshore by 2030;

---

[29] At https://ec.europa.eu/energy/sites/ener/files/documents/ec_courtesy_translation_be_necp.pdf

[30] At https://ec.europa.eu/energy/sites/ener/files/documents/nl_final_necp_main_en.pdf

ii. Generating 35 TWh of renewable energy (wind energy and solar power) on land;
iii. Small-scale generation of renewable electricity from, for example, private solar panels, good for circa 10 TWh.

• From 2030, the use of coal to generate electricity will be prohibited by law. The bill offers companies the option of switching to alternative fuels.

• In addition to the ETS, the Netherlands is introducing a national and gradually increasing minimum price for CO_2 emissions in electricity generation. This minimum price contributes to increased sustainability and investment security.

With this commitment, the share of renewable electricity of total electricity generated in 2030 is expected to amount to 70 percent."

Total is 94 TWh, which if 70% makes total generation makes that 134 TWh in 2030. 2018 demand was 116 TWh, and 2025 is projected at 114 TWh (Table 4.5). To address security of supply, "interconnection capacity is expected to double from 5.55 GW in 2016 to 10.8 GW in 2025." (NECP, 3.3i)

Table 4.6 The Netherlands' interconnection capacity in megawatts (Source: PBL, 2019a)

Capacity in megawatts	**2019**	**2020**	**2025**	**2030**
Connection				
NL-DE	3950	4250	5000	5000
NL-BE (BE-NL)	1400 (2400)	1400 (2400)	3400	3400

Scaling: On-shore wind and PV: 3.5; off-shore: 10 (from a low base).

Germany

Germany's *Draft Integrated National Energy and Climate Plan* (NECP)[31] states that "Taking into account this dismantling of capacity, around 300 TWh of Germany's electricity will be generated from renewable energy sources in 2030. … A further goal enshrined in the coalition agreement is that of increasing the share of renewables in gross electricity consumption to around 65 % by 2030. Depending on gross electricity consumption, this requires the generation of between 360 and 400 TWh of electricity using renewables, or an installed renewables capacity of between 180 and 200 GW; this calls for a significant acceleration in the growth of renewables." (p34).

"Scenario A 2030 assumes net electricity consumption of 512.3 TWh, whereas Scenario B 2030 assumes net electricity consumption of 543.9 TWh and Scenario C assumes net electricity consumption of 576.5 TWh."

Nuclear will be phased out by 2023. 2018 Consumption is 556.5 TWh

Installed capacity in GW	**Baseline 2017**	**Scenario A 2030**	**Scenario B 2030**	**Scenario C 2030**
Onshore wind	50.5	74.3	81.5	85.5
Offshore wind	5.4	20.0	17.0	17.0
Photovoltaics	42.4	72.9	91.3	104.5
Biomass	7.6	6.0	6.0	6.0
Hydropower	5.6	5.6	5.6	5.6
Other renewables	1.3	1.3	1.3	1.3
Total	112.8	180.1	202.7	219.9

[31] At https://ec.europa.eu/energy/sites/ener/files/documents/ec_courtesy_translation_de_necp.pdf

In 2020 Germany has 49 GW solar PV and onshore wind of 59 GW and over 4 GW off-shore wind in 2018. So if the 2025 targets are midway to 2030, and if PV increases to 100 GW, offshore to 20 GW, onshore wind needs to be 95-117 GW.

Scaling factors for 2026: zero nuclear; multiplying PV and on-shore wind by 1.5 and off-shore wind by 2.5, then both renewables and zero-carbon electricity would be 55% of 2018 grid load.

Spain

According to the NECP, Final electricity demand from non-energy sectors is 232 TWh in 2015, 241 in 2020 and 246 TWh in 2025 (p 240). Recently, the electricity exchange capacity between Spain and France has doubled (from 1,400 MW to 2,800 MW). … An increase in the interconnection capacity with France is planned with the following extensions:

- an interconnection between Aquitaine (FR) and the Basque Country (ES), through a submarine cable through the Bay of Biscay, which will allow the interconnection capacity between Spain and France to reach 5,000 MW;
- an interconnection between Aragon (ES) and Pyrénées-Atlantiques (FR) and an interconnection between Navarre (ES) and Landas (FR), which will increase the interconnection capacity between Spain and France to 8,000 MW.

Gross electricity generation in the Target Scenario* (GWh)

Years	2015	2020	2025	2030
Wind (onshore and offshore)	49,325	60,670	92,926	119,520
Solar photovoltaic	8,302	16,304	39,055	70,491
Solar thermoelectric	5,557	5,608	14,322	23,170
Hydroelectric power	28,140	28,288	28,323	28,351
Storage	3,228	4,594	5,888	11,960
Biogas	743	813	1,009	1,204
Geothermal energy	0		94	188
Marine energy	0		57	113
Coal	52,281	33,160	7,777	0
Combined cycle	28,187	29,291	23,284	32,725
Coal cogeneration	395	78	0	0
Gas cogeneration	24,311	22,382	17,408	14,197
Petroleum products cogeneration	3,458	2,463	1,767	982
Other	216	2,563	1,872	1,769
Fuel/Gas	13,783	10,141	7,606	5,071
Renewables cogeneration	1,127	988	1,058	1,126
Biomass	3,126	4,757	6,165	10,031
Cogeneration with waste	192	160	122	84
Municipal solid waste	1,344	918	799	355
Nuclear	57,196	58,039	58,039	24,952
Total	**280,911**	**281,219**	**307,570**	**346,290**

Scaling from actual 2018 to 2026: wind 1.9, PV 4.4.

Appendix D SEM Wind capacity and correlations of wind output with GB

Figure D1 shows wind capacity in IE from two sources (which only give the year of commissioning, not the date), and similarly figure D2 shows more granular data for NI wind capacity (with date of commissioning for the Ofgem data but only the year for the Eirgrid data) (both TSO and DSO connected).

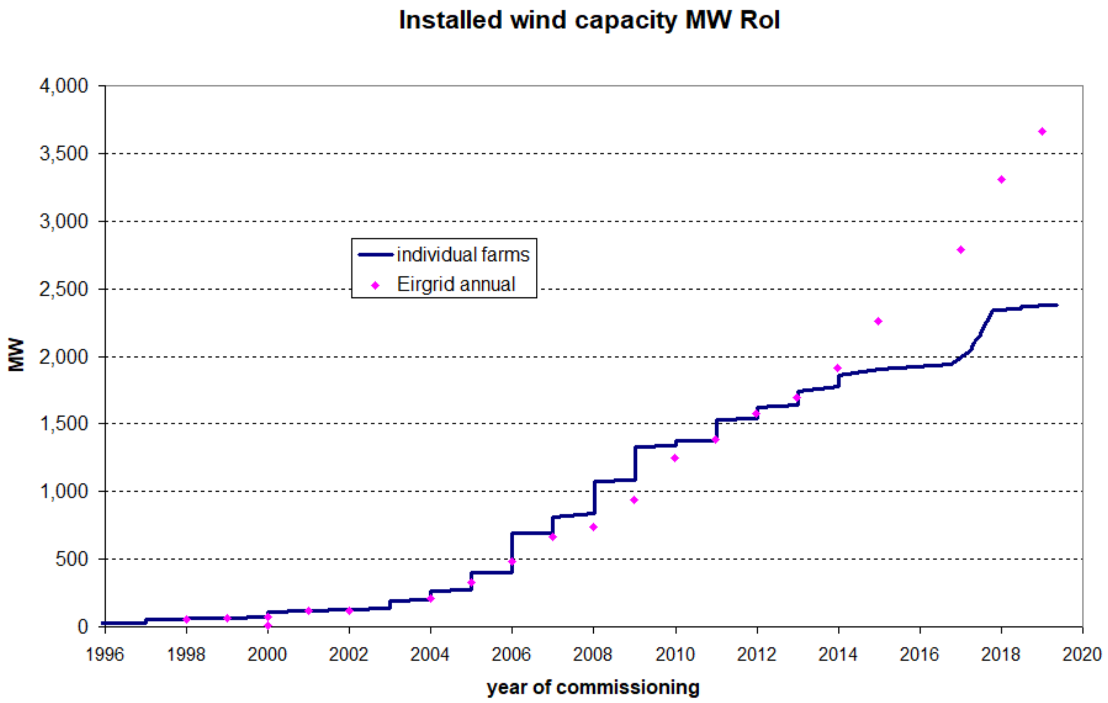

Figure D1 Cumulative wind capacity in Ireland 1996-2019

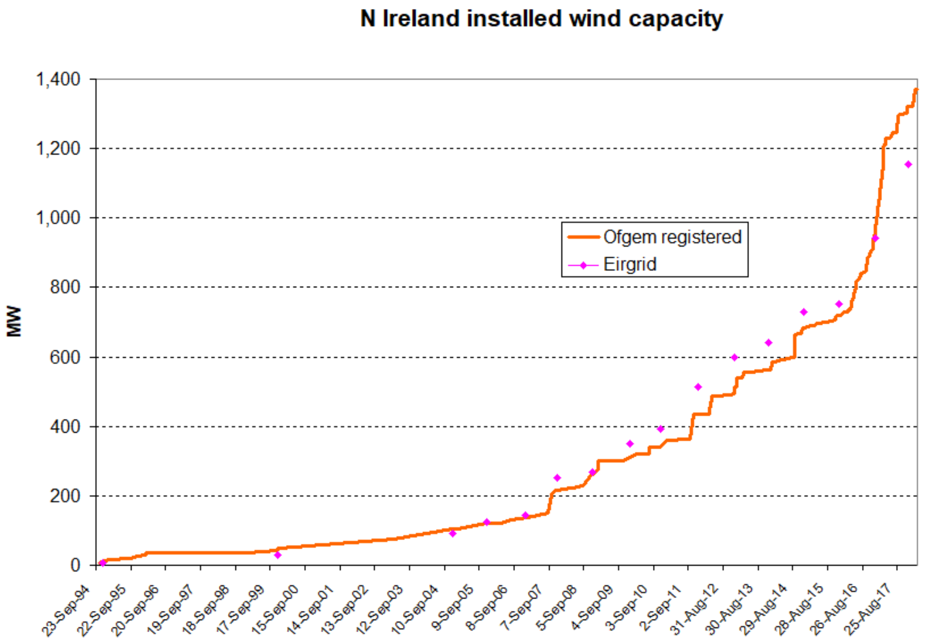

Figure D2 Cumulative commissioned wind capacity in Northern Ireland 1994-2017

Wind output correlations with GB

First impressions are that the correlation of hourly wind output in the SEM and GB (at least over the two whole years 2016-17) is essentially zero (and also over just the winter months). Figure D3 shows the scatter plot of October 2016 to March 2017 – the winter period of higher demand (and wind).

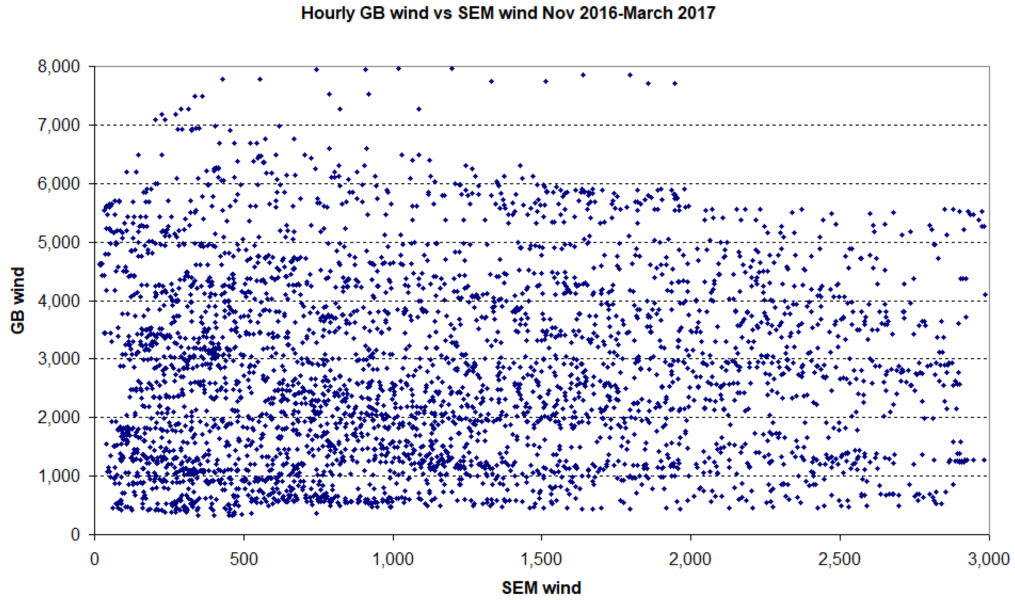

Figure D3 Scatter plot of hourly wind generation in GB against SEM, winter 2016/17

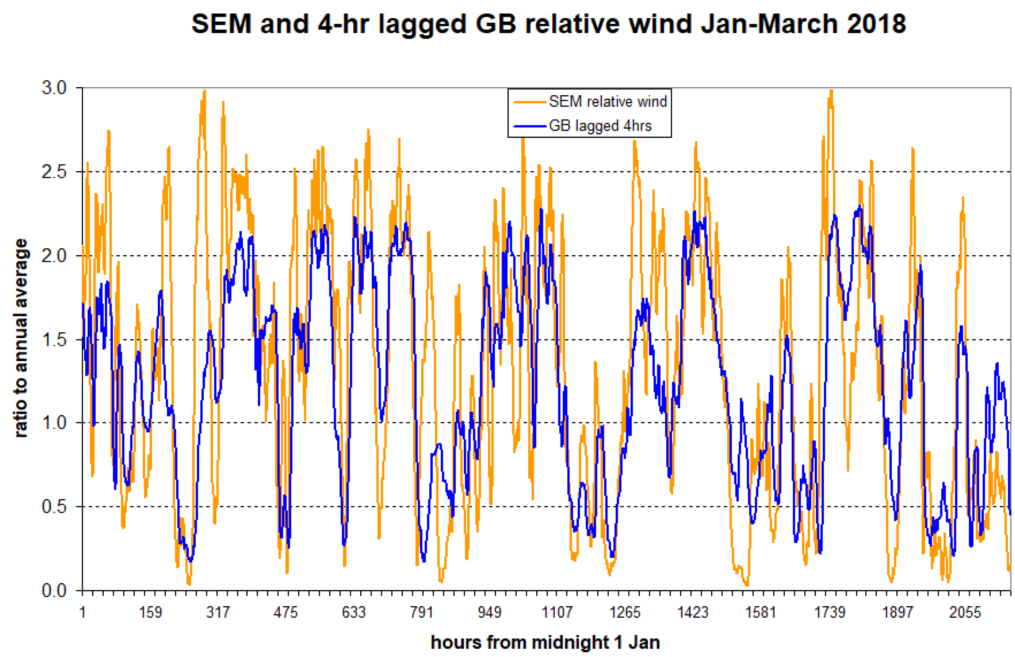

Figure D4 relative wind in GB 4 hours later than relative wind in SEM, Jan-March 2018

However, a more careful study of the kind undertaken by Weiss and Wänn (2013) reveals a closer correlation between current SEM wind output and 4-hour lagged GB wind output, as figures D4 and D5 reveal using more recent data.

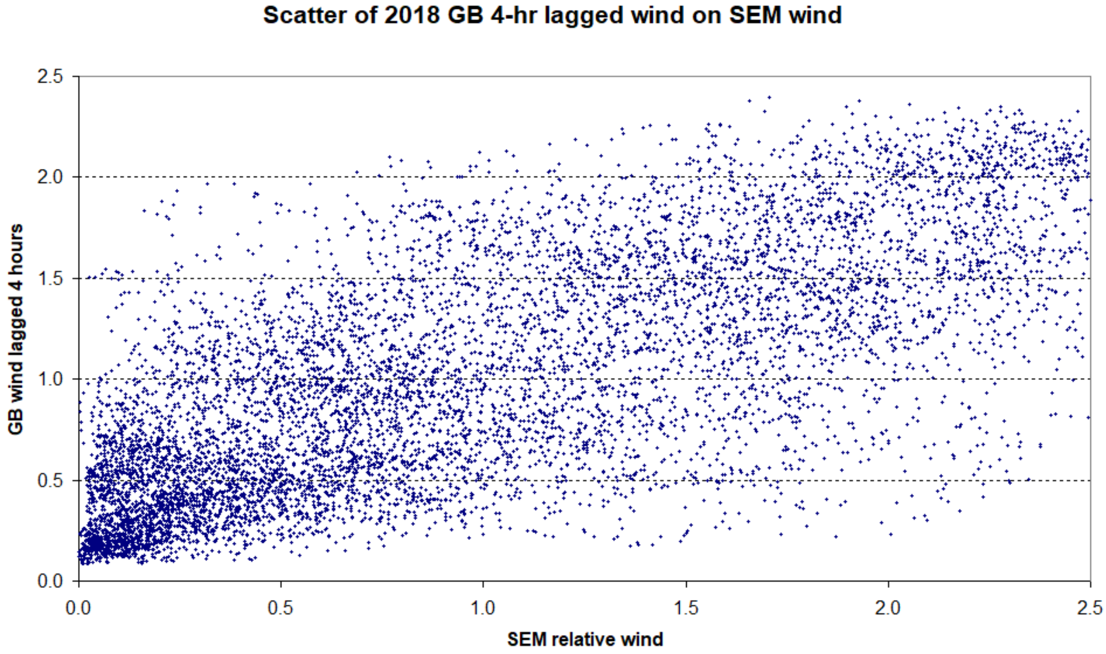

Figure D5 Scatter plot of lagged wind in GB on wind in the SEM, 2018

Correlations across neighours

Figure D6 first derives the wind duration curve for each country separately, scaled to a 40% average penetration, and then the result of adding each country's output in that hour to give the total, and then deriving its wind duration curve. The aggregate curve is flatter, and would exceed twice the average for a considerably smaller fraction of the time.

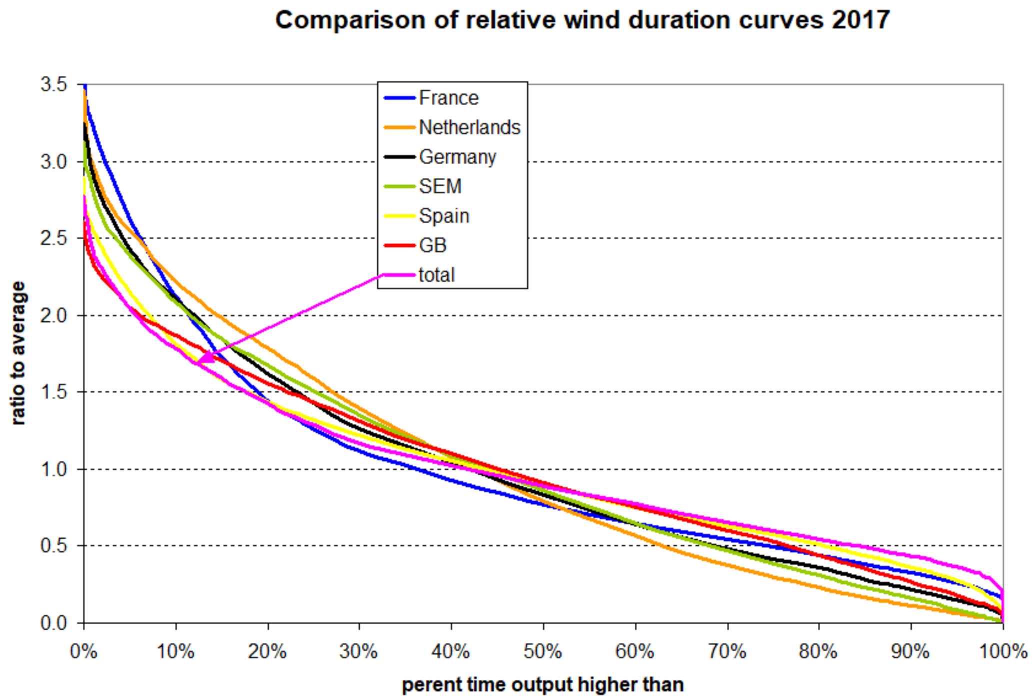

Figure D6 Comparison of isolated and aggregated wind duration curves for 2017.

Table D1 gives the percentage of the time each isolated country would exceed double the average wind penetration, and the amount of wind lost as a percentage of the total wind potentially available (ignoring any curtailment). The amount that would have to be curtailed if each country were isolated (at double average wind) ranges from 5.9% to 15.9% with a weighted average of 11.2%, whilst averaging over all these countries would reduce curtailment to 5.5% (the “total” line in table 1).

Table D1 Impact of aggregating wind

	curtailed	lost
SEM	11.4%	27.3%
GB	5.9%	13.0%
FR	11.5%	29.9%
DE	12.0%	28.9%
ES	7.3%	16.6%
NL	14.7%	35.9%
BE	15.9%	39.0%
DK	14.0%	33.4%
total	5.5%	12.3%
wted av.	11.2%	27.5%

Similarly, the amount of wind generation that would have been lost had it been curtailed at the individual country level varies from 13% to 39% (again with smaller countries having a higher variability and hence more potential curtailment, and larger countries and those like GB with a large share of off-shore wind with less variability). Aggregating the potential loss falls to 12.3%. In each case aggregating wind across these countries more than halves the damaging aspects of variability.

Appendix E SEM Wind variability and scaling

Figure E1 compares the results of taking the 2015 Load and Wind as a basis for scaling up to 2026 and 2018 data, in each case scaling to 55% wind and the same average loads. The two sets of duration curves are almost identical, suggesting that the choice of base year is relatively unimportant, provided they are scaled to the same 2026 conditions.

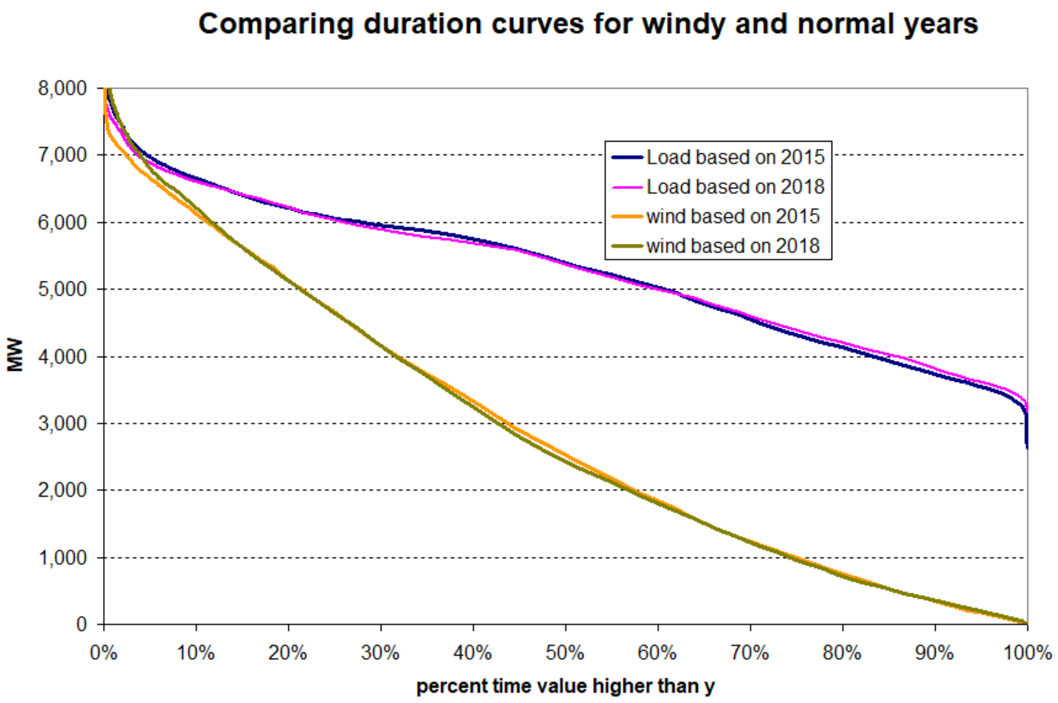

Figure E1 Comparing duration curves based on 2015 and 2018 wind and load data