

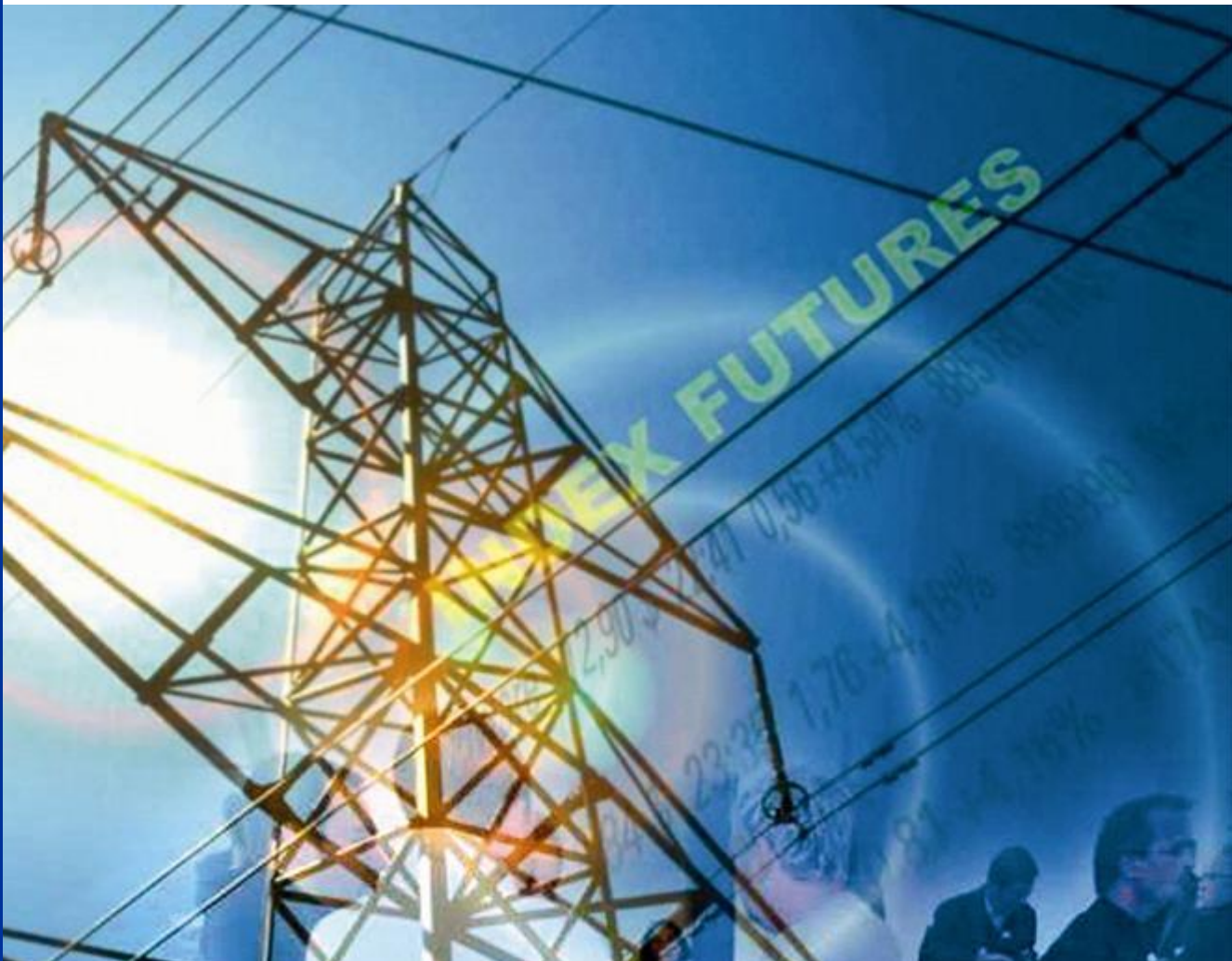


MODELLING THE CAITHNESS MORAY REINFORCEMENT – STAGE TWO

A report to Ofgem

1 April 2014

MODELLING THE CAITHNESS MORAY REINFORCEMENT – STAGE TWO



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EXECUTIVE SUMMARY

Background

The Caithness Moray project comprises a potential set of transmission reinforcements which are critical to export proposed substantial new onshore wind generation in the far north of Scotland southwards through the Scottish transmission network and to the rest of the GB transmission system. The total cost of the Caithness Moray project is indicated by SHE Transmission as being expected to fall within the range £1.3bn - £1.7bn and has been submitted to Ofgem for receipt of funding under the Strategic Wider Works (SWW) process established under RIIO-T1. A preferred HVDC option has been proposed for assessment under the SWW process, and this option is compared to alternative options and to the counterfactual of not reinforcing the system.

In Stage One of this consultancy project, Pöyry assessed and evaluated some key aspects of the Cost-Benefit Analysis ('CBA') of the Caithness Moray reinforcement performed by SKM for SHE Transmission, which assessed four main transmission options for a comparative analysis of its proposed solution:

- Option 1a involves an HVDC subsea cable solution from Spittal in the Caithness area to Blackhillock in Moray, together with associated onshore works, and is expected to be operational by 2018 *This is SHE Transmission's recommended reinforcement option.*
- Option 2a, involves an AC solution along the coast of Caithness, upgrading to 275 kV the circuits from Dounreay down to Beauly, and is expected to be completed by 2026/2027.
- Option 1b comprises 1a and an additional AC OHL between Beauly and Blackhillock (BB400).
- Option 2b comprises 2a and the additional BB400.

In Stage Two of our consultancy support for Ofgem, Pöyry has independently modelled the constrained energy volumes under different generation and transmission scenarios, capturing the recommendations we provided in Stage One. We have not modelled the benefits of Option 2a, as agreed with Ofgem, because it does not provide reinforcements of the B1 boundary which is viewed by Ofgem as a key selection criterion on which options should be considered.

Headline findings

The three key findings from our modelling of constraint costs and volumes are:

- On average, the volume of constraints is 10% to 15% lower than those calculated by SKM for all transmission options as well as for the counterfactual. The differences in constraint volumes between any reinforcement option and the counterfactual, which provide the benefits of the reinforcement option, are similar to SKM.
- On average, the constraint costs per MWh are 50% lower than those calculated by SKM for all transmission options as well as for the counterfactual.
- The annual benefits of the reinforcement options, calculated as the difference between total £m constraint costs with a transmission reinforcement implemented versus the counterfactual of not reinforcing the transmission network, are on average 50% lower than calculated by SKM.

The exact impact of these findings on the NPV of different options for Caithness Moray reinforcement is not within the scope of our work, and will depend on the choice of generation scenario and reinforcement option but will clearly result in lower NPV values.

Overview of our detailed findings

Underpinning our key findings above are a number of detailed observations and findings from our independent modelling conducted in Stage Two.

Constraint volumes need to capture complex weather driven dispatch patterns

The additional detailed findings for modelling of constraint volumes are as follows:

- On average of the five historic ‘weather years’ and of all years modelled by Pöyry, results of constrained energy volumes are lower than SKM’s by 10% to 15% depending on the generation scenario considered north of the B1 boundary.
 - The main explanation for this difference is SKM model dispatchable hydro and pump storage hydro with a fixed hourly profile rather than an optimised dispatch.
 - Other factors such as different wind and hydro input profiles have opposing impacts on constraint volumes, but do not offset non-optimal hydro dispatch.
- SKM used one single wind profile, which doesn’t capture the high sensitivity of constrained energy volumes to yearly wind behaviour.
 - The variability of the wind behaviour, captured by the use of different weather years, significantly impacts the constraint volumes with a symmetric sensitivity of +/-30% over averaged results for all modelled weather years.
 - There is also a temporal effect contributing to the volumes of constrained energy, as high wind must be constrained only if, for example, it coincides with other high renewables output or low demand. This implies that two different weather years with similar annual wind load factors could lead to different curtailment volumes depending on the specific hours/timing of occurrence of high winds.
- Sensitivity of constrained energy volumes to yearly hydro production is very low, in the range of +/-3% for an observed +/-10% of annual hydro production variability, as the dispatchable hydro is optimised in order to avoid constraints and only the run-of-river component increases constraint volumes.

Constraint costs per MWh are on average lower than £130/MWh

In determining the cost of constrained energy, we propose different assumptions to SKM in calculating the costs of constraints as represented by the addition of (1) replacement energy ‘bid-on’ costs; and (2) wind curtailment ‘bid-off’ costs,

- Replacement energy costs are valued at the System Marginal Price (‘SMP’) in GB plus a fixed average balancing mark-up of up to £20/MWh, where:
 - SMPs weighted by constrained energy volumes are calculated by Pöyry’s model on an hourly basis and are £50/MWh on average, with different prices per year and scenario; and
 - a fixed balancing mark-up of up to £20/MWh accounts for the typically higher prices of balancing energy, although this mark-up can go down to £0/MWh as shown by a historic analysis. This historic analysis has shown annual average mark-ups of £6/MWh to £15/MWh, with a wide range of hourly values.
- Wind constraint bid-off costs account for the fact that, when wind power is constrained by the TSO, wind developers can seek higher compensation than their foregone revenues. Competitive market theory suggests that these wind ‘bid-off’

prices could go as low as the foregone subsidy e.g. Feed-in Tariff (FiT), or Renewable Obligation Certificates (ROCs), and Levy Exemption Certificates (LECs), In this case the net constraints mark-up for consumers would be £0/MWh. However in reality we can expect a non zero net bid-off cost but there is no representative historic data to allow us to value this. However we propose an indicative range of £0/MWh to £20/MWh depending on future competitive behaviour. This value is lower than the value proposed by SKM which amounts to 30% of the FiT (circa £30/MWh) which we consider to be on the high side.

- Although both mark-ups are uncertain, we present cost results showing the sensitivity to a combined mark-up ranging from £0/MWh to £30/MWh. As an indicative estimate for central calculations of constraint costs, we propose a combined mark-up of £15/MWh, resulting from a central estimate of £10/MWh for the balancing mark-up and £5/MWh for the constrained bid-off costs under a competitive environment.

The addition of replacement energy costs and constraint bid-off costs provides total constrained energy values in the range of £30/MWh to £100/MWh depending on the year, the scenario, the balancing mark-up and the wind constraint bid-off costs. Using the combined central estimate of £15/MWh for mark-ups, annual constraint costs per scenario range from £40/MWh to £90/MWh.

The fixed constraint cost of £130/MWh used by SKM is above the high side of the range we propose, and is built from higher market prices and higher mark-ups than we assume. They compare to our average of £65/MWh when a central £15/MWh mark-up is used.

Constraint costs per MWh vary over time both within and across years

A key difference in our modelling of constraint costs per MWh versus that adopted by SKM is the derivation/use of varying levels of constraint cost per MWh which naturally occur within year and over a span of years.

- SKM applies a fixed constraint cost of £130/MWh for all constraint volumes incurred across any given year. This overestimates the cost of constraints for example in periods where there are high levels of wind generation and low prevailing SMPs and thus 'bid-on' costs for replacement energy to replace curtailed wind generation.
- SKM also uses an average of £130/MWh for all years modelled, rather than the yearly values they previously calculate to build the period average. This overestimates the savings in the initial years which contribute the most to the NPV calculation, and underestimates the later years which contribute less, as compared to the alternative approach of using the individual yearly values.

With Pöyry's approach, the cost of constraints moderately changes over years, with several factors affecting the average replacement energy costs:

- The seasonal behaviour of SMPs, with higher prices in winter, and the higher constraints also happening in winter, implies that in the earliest years constraints occur in more expensive hours, and average replacement energy prices are higher than the average annual SMPs.
- Beyond a given level of Renewable Energy Sources (RES) penetration, a new phenomenon of national RES curtailment occurs where RES is curtailed to enable flexible plants to remain on for system security. Competition by RES to stay on can lead to prices reaching £0/MWh and examples of this have occurred in Spain and Germany. As the frequency of these situations increases (which we expect from the early 2020s) and constraints in Scotland more frequently coincide with national RES curtailment situations, average replacement energy costs decrease over time, and become lower than the average annual SMPs.

Annual constraint benefits are materially lower but vary by scenario and by year

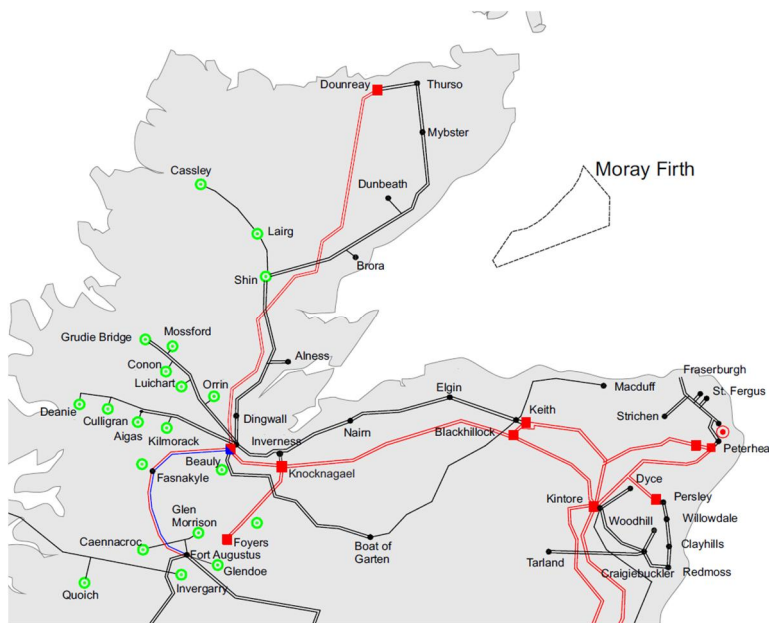
The comparison of total annual benefits of the reinforcement options depends on the mark-ups assumed in Pöyry's approach. Assuming a combined mark-up of £15/MWh on Pöyry's approach, annual benefits are found to be 35% to 80% lower than those calculated by SKM, and 50% lower on average of all years and scenarios.

1. INTRODUCTION

1.1 Context

The Caithness Moray reinforcement is a very large transmission project in northern Scotland proposed by Scottish Hydro Electric Transmission plc (SHE Transmission) to support the expected growth of renewable generation capacity in the area. It is a key project of a wider set of reinforcements in the north of Scotland which will allow the integration of further renewable generation into the GB system by increasing the export capacity between the north and the south of Beauly and Blackhillock (see Figure 1 and Annex B).

Figure 1 – Transmission network in the Caithness Moray area



Source: National Grid – Ten Year Statement 2013

The proposed reinforcement involves an offshore HVDC link between the north of Caithness (in Spittal, near Mybster) and Blackhillock in Moray, and associated onshore works.

In the Needs Case this proposal is compared to an onshore reinforcement in the Caithness area rebuilding the existing 132 kV circuits between Beauly and Dounreay to 275 kV, and associated additional works.

SHE Transmission has requested Ofgem to assess its subsea HVDC proposal under the Strategic Wider Works (SWW) arrangements that were introduced as part of the electricity transmission price control RIIO-T1.

To put forward a project for consideration under the SWW mechanism, the relevant Transmission Owner (TO) must provide a needs case submission followed by a technical case submission. SHE Transmission submitted a Needs Case for this project in 2013.

A significant part of the Caithness Moray reinforcement project assessment is informed by a Cost Benefit Analysis (CBA) submitted by the TO (or its consultant, SKM in this case) as part of the Need Case. This CBA is the most critical justification for the Need Case, as it

explores the costs and the benefits of reinforcing the transmission system with the previous options, versus the counterfactual of not reinforcing the networks (beyond the ongoing or committed works).

1.2 Scope of work

Constrained energy volumes are a key input to the CBA and play a predominant role in determining whether a large transmission project is economic. Constrained energy volumes are modelled based on the expected power flows from a range of generation scenarios, the available network capacity under different reinforcement strategies, and criteria in the National Electricity Transmission System Security and Quality of Supply Standards (NETS SQSS). SKM have conducted a CBA of the Caithness Moray reinforcement options. We reviewed some key aspects of the CBA in Stage One of this consultancy project for Ofgem.

In Stage Two of this project, Ofgem seeks:

- an independent modelling of future energy constraint volumes arising on the transmission network in Northern Scotland;
- a comparative analysis of the results of this modelling and the exercise undertaken by SKM and submitted by SHE Transmission to Ofgem as part of the Needs Case, explaining the differences between the two sets of modelled results; and
- a calculation of replacement energy costs that considers the hourly marginal prices in the GB system (this item is an extension of the initial specifications of the project resulting from conversations with Ofgem during the presentation of the Stage One report).

1.3 Structure of the report

In order to comply with Ofgem's requests in providing an independent assessment of constrained energy volumes:

- Section 2 contains a description of the modelling approach used by Pöyry;
- Section 3 contains all results of the modelling exercise;
- Section 4 contains a comparative analysis between Pöyry's and SKM's modelling of constrained energy volumes;
- Annex A contains a description of Pöyry's dispatch model BID3;
- Annex B contains supporting maps of the Caithness Moray project;
- Annex C contains higher detail of modelling inputs; and
- Annex D contains higher detail of modelling results.

2. PÖYRY’S MODELLING APPROACH

2.1 General approach

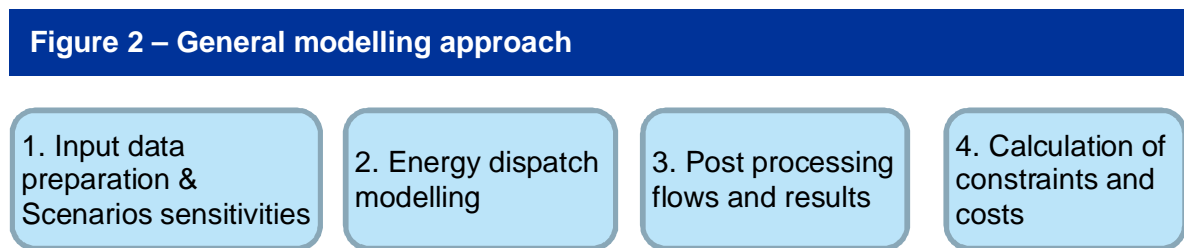
2.1.1 Overview

Pöyry’s modelling approach in calculating constrained energy volumes and costs is based on its dispatching model BID3, described in detail in Annex A.

An hourly dispatch model of the whole GB system is performed to calculate:

- the hourly generation dispatch in the studied area (north of the B1 boundary, as shown in Annex B) and the rest of the GB system;
- the implicit hourly exports under an infinite transfer capability in all boundaries of the studied area;
- the consequent constrained energy flows given the limited transmission capacities; and
- the consequent constrained energy costs.

The general process is described in the following figure.



This process is run for four different generation scenarios in the north of the B1 boundary (Slow Progression, Gone Green, Ofgem and Slower Slow Progression, using installed wind capacities as provided by SHE Transmission/SKM in Stage One), and tested against three transmission options (1a, 1b and 2b) as well as the counterfactual of not building any additional transmission reinforcement.

For each run, the model considers:

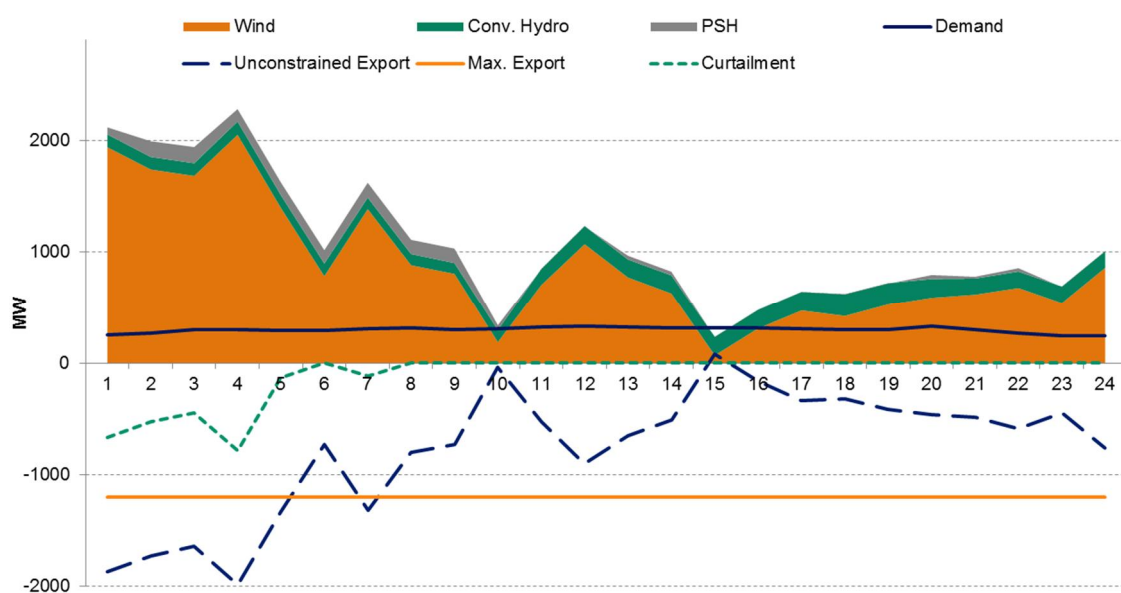
- five weather years (2006, 2007, 2008, 2009, 2010), with their corresponding:
 - hourly demand profile,
 - hourly wind profile, and
 - hourly solar profile;
- the projected modelled years 2018, 2019, 2020, 2021, 2022, 2023, 2024, 2025, 2026, 2027, 2028, 2029, 2030, 2035, and 2040;
- as regards hydro production in the North of boundary B1, yearly values of a central year are used, and sensitivity to year humidity is tested based on historical variability observed;
- a Slow Progression scenario for the rest of the GB system.

2.1.2 Modelling of constrained energy volumes

In order to model the constrained energy volumes and costs in the Caithness Moray area, BID3 is used to model the whole GB system. For each transmission and generation scenario, and for all weather years considered, BID3 models the constrained energy volumes as the energy that cannot be fed into the system because of insufficient transmission capacity in the boundaries B01, B02, B0 and B1.

Figure 3 illustrates in negative values the hourly exports that would occur with infinite transmission capacity in a boundary, the maximum export capacity (1,200 MW in this illustrative example), and the constrained energy volumes as the difference between the previous two.

Figure 3 – Illustrative example of hourly dispatch, exports and curtailments



Source: Pöry

BID3 is fed with all data of the GB system, divided into the five zones created by the four boundaries analysed. An unconstrained run for each generation scenario produces an hourly economic dispatch of the GB system, similar to that of Figure 3, and simulating the behaviour of the market. The exports from Scotland to the rest of GB that would result from the calculated market dispatch are compared to the transmission capacities under each reinforcement option.

The interactions between GB and its neighbours are taken into consideration with a fixed profile resulting from the latest Pöry European market modelling.

In order to make a consistent comparison between the reinforcement options, a unique Slow Progression generation scenario in the rest of GB (south of boundary B1) is tested, whereas throughout this report 'generation scenarios' (SP, GG and Ofgem) refer to different generation capacities only in the north of boundary B1.

The details of the model, the input data and obtained results are further provided.

2.1.3 Modelling of constrained energy costs

When constraints occur, some cheaper units must be blocked from producing as would result from a theoretical unconstrained dispatch (with unlimited transmission capacity), and more expensive units must be started (or increase their output) instead.

An ideal best practice approach would be to model the system with constrained transmission limits for each of the transmission reinforcement options, and calculate the total costs under different transmission scenarios; the difference in generation costs between two transmission scenarios provides the gains associated with a higher transmission capacity and lower constraints.

As discussed with Ofgem, we consider that a simple method is fit for purpose in this instance, allowing the testing of more generation scenarios without significantly different results. Therefore, we did not use this approach in our modelling but are confident in the results obtained by the alternative approach.

Pöyry's alternative approach to evaluate the constrained energy costs consists of calculating two components:

- replacement energy costs; and
- wind curtailment bid-off costs.

2.1.3.1 Replacement energy costs

The replacement energy costs uses as a base the hourly system marginal prices ('SMP') in the rest of the GB system, south of the B1 boundary. This approach relies on the assumption that, for each hour in which curtailments occur, the increased output of the replacement energy in the new dispatch does not provide a new different hourly SMP. For instance, in one hour where the SMP of an unconstrained run (with all available wind included in the dispatch) is £50/MWh, but 200 MW of wind power must be constrained in the north of boundary B1 (and thus removed from the dispatch), it is assumed that both dispatches provide an equal SMP of £50/MWh; hence the replacement energy cost for the system in this hour would be equal to 200 MW x £50/MWh = £10,000.

Figure 11 in Section 3.3 illustrates this approach and the reasonableness of the underlying assumption.

The final replacement energy cost is then calculated as the addition of the base SMP plus a balancing mark-up, which accounts for the fact replacement energy in the balancing mechanism is typically more expensive than the energy prices at day ahead stage.

The BID3 model does not directly account for prices of the GB Balancing Mechanism, which are typically higher than the day-ahead prices. Through the GB Balancing Mechanism, the System Operator (SO) redispatches energy for some producers (upward or downward) to maintain energy and system balance in operational timeframes. An analysis of historic behaviour of the balancing prices and the UK Spot market prices has been conducted to make an estimation of this 'balancing mark-up':

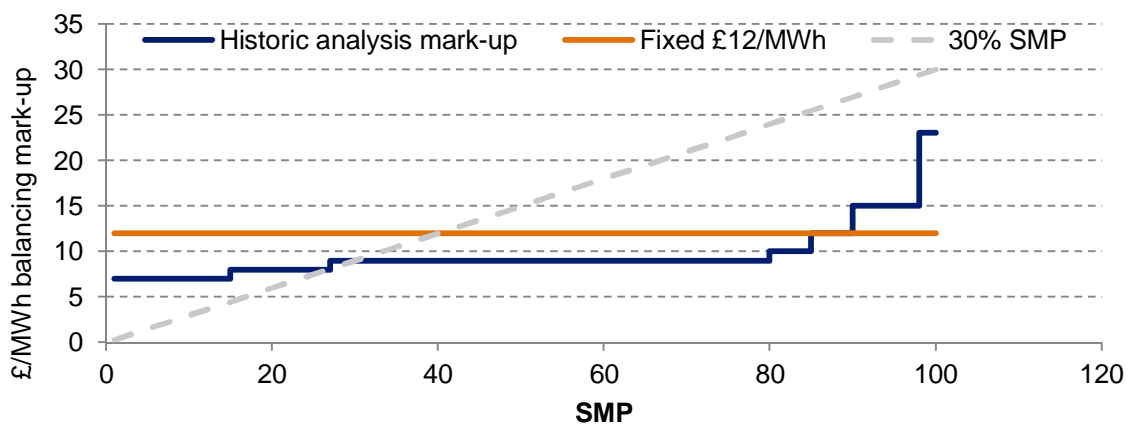
- The APX price index¹ has been used as the UK Spot reference price (used as a proxy to the SMPs calculated in Pöyry's model).

¹ <http://www.apxgroup.com/trading-clearing/apx-power-uk/>

- The System Buy Price ('SBP') has been used as a proxy for balancing prices (equivalent to the replacement energy costs when replacement takes place in the balancing mechanism instead of at day-ahead stage).

The difference between the previous two values shows a historic average difference of £6/MWh to £15/MWh (in real 2012 money) across different years. These values do not show a historic increasing trend. Also, we observe that balancing mark-ups are relatively stable along a wide range of SMPs, and only tend to increase when margins are tight and prices escalate. Therefore we model the balancing mark-up as a flat value which could reach up to £20/MWh over the model's SMPs. Although this value has reached higher hourly levels in the past, and very tight hours may not be optimally captured, a static average mark-up of up to £20/MWh captures the most frequent range of SMPs in a better way than a proportional mark-up would.

Figure 4 – Balancing mark-up vs. SMP



Source: Pöyry

Figure 4 illustrates how flat mark-ups capture reasonably well the trend of historic balancing mark-ups, as opposed to the 30% mark-up used by SKM in building the replacement constraint costs. The 30% approach seems to overestimate or underestimate the balancing mark-up for very high or very low SMP prices respectively. Figure 65 in Annex D shows the full data points used for this analysis.

A new phenomenon occurring in the future is worth describing. Beyond a threshold of wind penetration, there will be situations of high wind and low demand leading to national RES curtailments (different from zonal constraints in Scotland). During some windy hours only RES and few thermal plants can remain online, and competition to stay online may lead to zero and even negative prices. When these situations occur, the model indeed reaches a SMP of £0/MWh.

There are various international examples of this phenomenon for instance in Spain and Germany on windy nights, or sunny weekends². This implies that if constraints in

² These situations have arisen in Spain since 2010, having occurred over 200 hours, affecting 3 TWh (0.6% of the yearly available wind resource), and seeing a maximum instantaneous curtailment of 5,000 MW of non-admissible wind power. Also, Germany occasionally curtails wind and solar energy for the same reason, for instance on 16 June 2013 with 5,000 MW affected.

Scotland coincide with hours of national RES curtailment, the replacement energy cost is also £0/MWh, as constraining Scottish wind allows curtailing less wind in the rest of GB with a marginal price of £0/MWh.

As a simple rule, we consider that a unique mark-up of up to £20/MWh can be added to SMPs both in:

- normal hours with positive SMPs (for instance when gas plants set the marginal price); and
- hours with national RES curtailment and SMPs of £0/MWh (when ‘excess’ wind energy sets the marginal price).

2.1.3.2 *Constrained wind bid-off costs*

When wind is constrained (disconnected), a bid-off price is paid by the TSO to the constrained producer. Wind disconnection bid-off costs account for the fact that, when wind power is curtailed by the TSO, wind developers are capable of bidding above their foregone revenues.

Competitive market theory suggests that these wind ‘bid-off’ prices (price requested to the TSO in case of curtailment) could go as low as the foregone subsidy (Feed-in Tariff, or ROC and LEC), and hence the net mark-up for consumers would be £0/MWh. However, given that on a few occasions a positive mark-up has been observed over the foregone revenue, we consider that a net bid-off cost should be tested. No representative historic data allows estimating the competitive behaviour in these situations, and higher levels of competition are expected in the coming years as wind penetration increases. We propose to test an indicative range of £0/MWh to £20/MWh depending on competitive behaviour.

For instance, if the ROC price equals £45/MWh³ and the LEC price equals £5/MWh, the foregone revenues in case of curtailment by the TSO would amount to £50/MWh. However, curtailed energy can typically extract higher value from these situations, and the bid-off price could be higher than £50/MWh.

Two situations may occur when assessing the compensations to wind producers:

- When wind is not constrained, consumers incur the payment of the subsidy equal to the ROC and the LEC, amounting to £50/MWh with the previous values.
- When wind is curtailed, the TSO pays the bid-off price, which typically includes an uncertain mark-up previously discussed that we indicatively value at a maximum of £20/MWh.

This would imply that the net mark-up to the customers of these constrained energy situations ranges indicatively from £0/MWh to £20/MWh. This mark-up over the foregone revenue is referred to in this analysis as the net constrained wind bid-off cost, or wind bid-off mark-up.

2.1.4 *Wider benefits of higher wind integration*

From the perspective of the GB energy sector and in the context of the UK Government’s energy policies such as commitment to 2020 renewables targets – there are potential wider benefits from transmission infrastructure projects, especially where they are perceived to enable Government energy policy to be realised or most economically

³ Considering that an onshore wind generator receives 1ROC/MWh.

realised. These benefits indirectly drive further benefits (or losses) for the overall GB energy sector and/or the national economy.

The types of wider benefits which might be ascribed to higher RES integration are qualitatively described in our Stage One report. However, for purposes of assessing transmission infrastructure projects in GB the scope of any cost benefit assessment (CBA) is limited in first instance to considering the system management costs relative to the costs of the investment i.e. the ‘replacement energy’ costs as described in Section 2.1.3 above. Thus assessing wider benefits is out of scope of our Stage 2 modelling and this report.

2.2 Dispatch model

Pöyry’s dispatch model BID3 is described in detail in Annex A. BID3 is a model developed in-house. For all 8,760 hours of the year, it models system dispatch with an hourly step by minimising variable marginal costs, including start-up costs, respecting thermal generation constraints (start-up times, minimum times up/down, ramp rates etc.), hydro system constraints (natural inflows, reservoir size etc.) and zonal transmission constraints. It allows testing multiple ‘weather years’ using different renewable generation and demand profiles. Associated to the least cost dispatch, BID3 produces hourly system marginal prices SMP, based on the cost of the marginal unit and a ‘scarcity rent’. The scarcity rent is a mark-up over the marginal costs that the producers are able to charge when the system margin (total available capacity minus system load) is low, and hence competition is low. The lower the system margin, the higher the scarcity rent. This mark-up contributes to the recovery of fixed costs, on top of those hours where a more expensive technology is fixing a higher SMP than their individual variable cost.

The whole GB system is modelled in BID3, with specific generation and demand data for each of the five zones considered:

- north of B01;
- north of B02;
- north of B0;
- north of B1; and
- south of B1 (rest of GB and flows through interconnected areas).

The results of the dispatch model are the theoretical hourly flows that would result from an ‘unconstrained network’ in which all boundaries would have unlimited capacity. These flows are then capped to the maximum export capacity of each boundary B01, B02, B0 and B1, with cascading rules so that the maximum flows through each boundary already consider the curtailed energy in previous boundaries in the direction of the flows from north to south (there is no need to analyse flows from south to north in non-windy days since low demand ensures that no curtailment occurs). Figure 3 shows an example of hourly curtailments in the boundary B1 for one sample day.

For each hour in which curtailments occur, the hourly constraint costs are calculated as the constrained energy volume multiplied by the hourly SMP, plus the balancing mark-up.

2.3 Input data

The input data used to feed the dispatch model includes:

- annual demand levels and hourly profiles;

- projected installed wind capacity and hourly profiles;
- hydro data (a run-of-river profile and dispatchable hydro inflows);
- pumped hydro storage plant specifications;
- conventional generation units specifications; and
- fuel and CO₂ costs.

The previous information allows producing the hourly dispatch under different system conditions.

Zonal exports between the modelled regions, maximum boundary capacities and hourly curtailments are post-processed based on the results of the unconstrained flows.

Details of the inputs are provided hereunder as well as in Annex C.

2.3.1 Demand

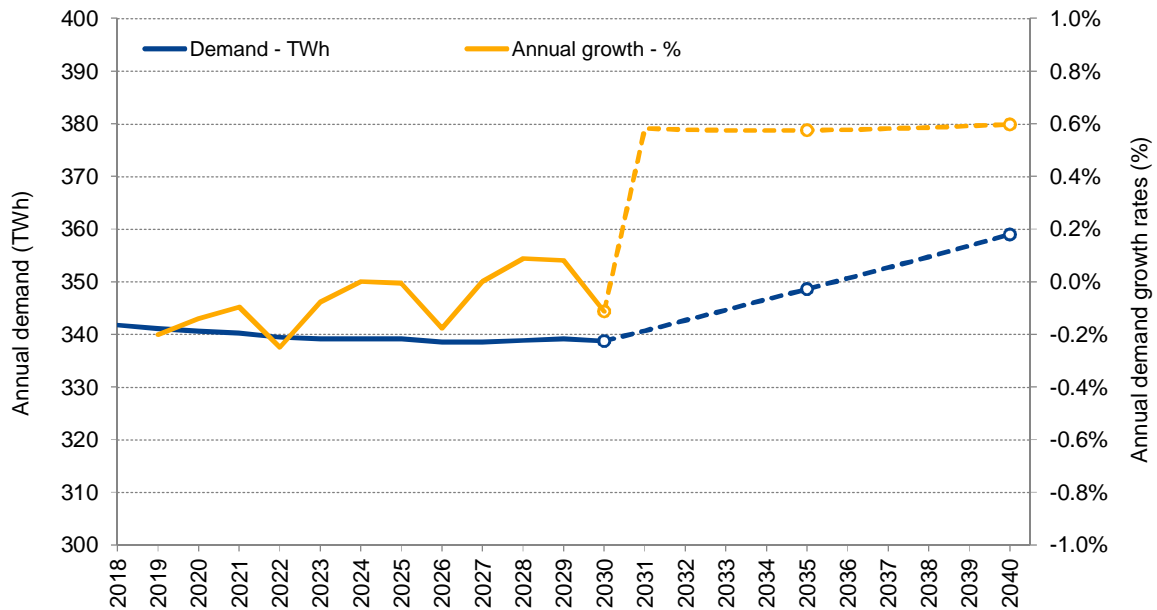
Demand profiles for each of the weather years modelled have been used from Pöyry's historic data. The total yearly demand for each year is forecasted using the yearly growth forecasts of National Grid's Slow Progression scenario. It includes a low negative growth until 2020, and a low positive growth after. The hourly profiles of each of the weather years considered are applied to the yearly demand of each year.

National Grid provided projections out to 2030. We have used Pöyry's projected demand growth rates for all the years post 2030, extracted from our Central scenario⁴

Figure 5 below shows the annual demand levels and the annual growth rate for each year for the GB electricity market.

⁴ We used our latest quarterly updated projections available at the time; therefore Pöyry projections come from our Q4 2013 update.

Figure 5 – Annual demand (TWh) and annual demand growth rates (%) for the GB electricity market



* including network losses of 8%, as electricity demand is modelled at station gate.

Figure 5 shows Pöyry’s demand projections for the GB market (including all consumers north and south of B1). In order to split demand into the five modelling zones, we have used historical demand data from 2008/09. We kept the percentages of demand from each of the modelling zones constant at 2008/09 levels and applied them to the annual demand projections for the whole of GB.

An illustrative example of our demand profiles is provided in Annex C.

2.3.2 Onshore wind

As regards onshore wind capacity, we have used National Grid projections for the GB system. For zonal capacities in Scotland, we have used SKM values which we consider sufficiently updated by SHE Transmission and which allow a fair comparison of results. We have completed forecasts post 2030 with Pöyry’s own projections.

It is important in a wind dependant generation system to understand the variability of wind across years, and its impact on energy curtailments. Therefore wind profiles have been produced for each of the five weather years modelled, and each of the zones modelled. They are built from the Anemos⁵ wind speeds data base which considers historic wind speeds in a 20km x 20km grid, for both onshore and offshore locations. Hourly wind profiles are created for each of the modelled zones (north of B01, B02, B0, B1 and south of B1), for each of the weather years, taking into account the specific locations of existing and planned wind farms and the corresponding wind speeds. This approach allows considering both spatial and temporal correlations between all wind sites.

⁵ The Anemos database registers historic wind speeds in Europe with temporal resolution of 10 minutes and spatial resolution of 20x20 km² (<http://www.anemos.de/en/windatlases.php>)

From the average hourly wind speeds registered by the Anemos database, power curves are used to generate hourly power outputs. Power curves are adapted to the age and technologies of the wind farms, in order to reflect improvements in the efficiency of larger and more modern turbines. Power curves for existing wind farms have been calibrated by real energy measurements.

For those locations where no wind farm exists and therefore no calibration is possible, standard power curves are applied, with a scaling factor aimed at ensuring the average annual load factors obtained by a study from DECC⁶.

Table 1 shows the annual average load factors obtained in the different zones and different weather years considered for the Slow Progression scenario.

Table 1 – Annual average load factors for the various profiles considered

Zone	Profile	Weather Year					Average
		2006	2007	2008	2009	2010	
B01	Existing	27.9%	28.7%	30.2%	26.2%	21.9%	27.0%
	New b.2020	33.9%	33.8%	36.0%	31.7%	27.4%	32.6%
	New a.2020	28.8%	29.7%	31.0%	26.9%	22.8%	27.8%
B02	Existing	30.1%	33.2%	31.9%	28.2%	21.8%	29.1%
	New b.2020	32.8%	35.2%	34.7%	31.5%	24.5%	31.8%
	New a.2020	30.9%	33.5%	32.9%	29.0%	23.0%	29.9%
B0	Existing	29.9%	32.2%	32.5%	27.9%	23.1%	29.1%
	New a.2020	32.6%	34.2%	34.4%	30.2%	25.0%	31.3%
B1	Existing	29.8%	30.9%	30.9%	28.4%	21.2%	28.3%
	New b.2020	34.2%	34.9%	35.2%	32.7%	24.6%	32.3%
	New a.2020	35.0%	36.0%	35.2%	33.0%	24.2%	32.6%
	Western Isles	37.2%	37.7%	37.3%	35.0%	27.9%	35.0%
<i>Capacity-weighted LF for 2025, excl. West.Isles</i>		31.8%	33.0%	33.2%	30.1%	23.3%	30.3%

Slow Progression scenario

Different profiles are used for each of the four generation scenarios, considering the locations and commissioning time of additional wind farms. Because of the different locations and commissioning time of the new wind farms in the different generation scenarios, the load factors of other scenarios are slightly different.

2.3.3 Hydro profiles and other RES

Hydro production can be simplified in two types of generation:

- conventional dispatchable hydro; and
- run-of-river non dispatchable hydro.

⁶ The document can be found in the following link:
https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/245381/scottish_islands_additional_support_consultation.pdf

Conventional dispatchable hydro is modelled using the weekly natural inflows and the total maximum capacity of the existing plants. Detailed interactions between all the hydro plants that build up the Scottish hydro system are not modelled, and instead one aggregated plant of 180 MW is used. This approach is considered suitable to represent the aggregated hydro generation. The hourly production of the available inflows is optimised by BID3, and is an output of the production costs minimisation: i.e. the dispatchable hydro is scheduled hourly across the week in a way that minimises total generation costs and minimises constrained energy.

Run-of-river hydro is not dispatchable, which means that its hourly production profile is taken from historic behaviour.

For both dispatchable and run-of-river hydro, same data of an average year is used in all weather years modelled. Historic variability of yearly hydro production is analysed to test the sensitivity to humidity levels, with values of +10%/-10% annual hydro production observed over the period from 2004 to 2011 (with the exception of a very dry 2010, which showed a -30% production over the average). This approach allows to separate the range of constrained energy volumes as a function of wind profiles (the range obtained by the five weather years), and as a function of hydro production.

2.3.4 Pumped storage hydro plant specifications

Pumped storage hydro (PSH) can be optimised to minimise production costs (and maximise profits in a market environment). Therefore, similarly to the dispatchable hydro, the hourly dispatch of the 300MW PSH plant at Foyers is an internal calculation of the optimisation process and not an input of the model. The hourly dispatch of PSH can not only reduce the production in some windy hours to alleviate the potential constraints, but also to consume in some hours until the upper reservoir is full. PSH is indeed a powerful instrument to integrate intermittent energy sources into the grid, and its hourly dispatch must be calculated by a full optimisation of GB system costs.

Therefore, the input data for PSH are the specifications of the pump and generation units.

2.3.5 Conventional generation units specifications

In order to minimise the total system generation costs, the specifications of all conventional generation units is essential, especially in the context of high integration of renewable sources which force a flexible operation of conventional plants: increased number of start-ups, low up/down times, high ramp rates etc.

The following data per plant is used in the model, and updated by Pöyry's network of country experts on a quarterly basis:

- minimum/maximum power output;
- plant efficiency;
- ramp rates;
- start-up costs;
- start-up time;
- minimum time up/down; and
- contribution to system operational reserves.

This data is available for each of the plants in GB.

The additional plants needed by the GB system for system adequacy purposes (security of supply) are internally calculated as part of the optimisation process, considering security margins and profitability of new build. Further detail is provided in Annex A.

Hourly imports/exports from/to the neighbouring countries are taken from previous European modelling performed by Pöyry, and provide a sound hourly profile of total exchanges. The potential impact of additional wind in Scotland on the interconnectors is not modelled and is not expected to be significant.

2.3.6 Fuel and CO₂ costs

Costs of the different fuels and CO₂ are taken from in-house developed fundamental models. They are updated on a quarterly basis by the network of country experts. Values from Pöyry's Central scenario are used from our Q4 2013 update.

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3. MODELLING RESULTS

3.1 Constrained energy volumes

A total of four generation scenarios and four transmission scenarios have been run. Each of those 16 runs has been executed for five weather years, and a modelling horizon reaching to 2040. Additional runs have tested sensitivity to hydro production for one generation scenario under all four transmission options.

The results are presented for each of the generation scenarios, Slow Progression (SP), Gone Green (GG), Slower Slow Progression (SSP) and Ofgem.

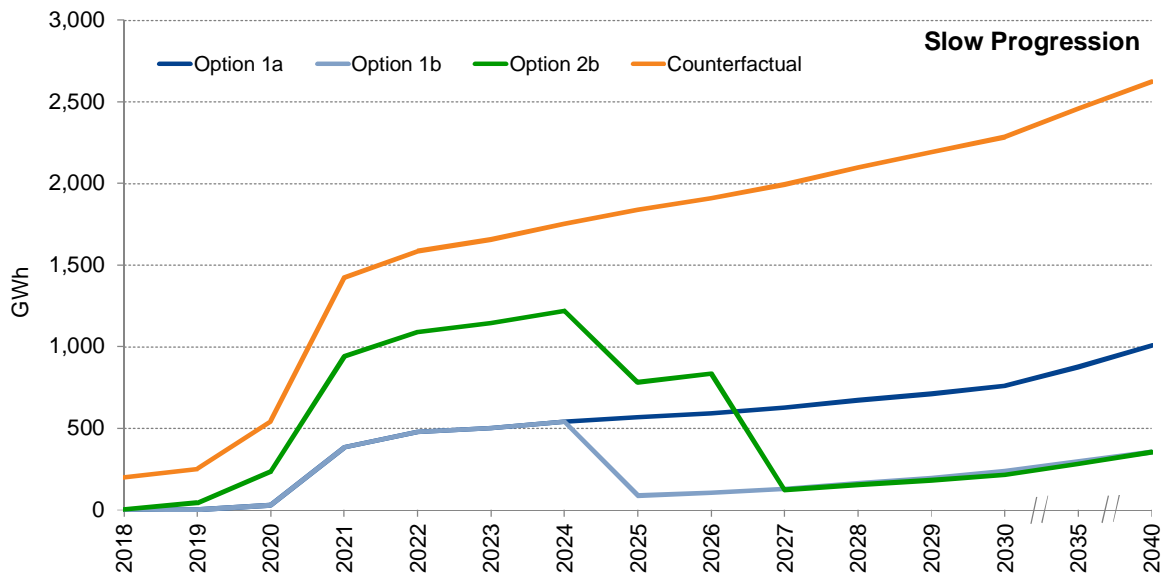
It is worth mentioning that additional reinforcements to those described in the various options 1a, 1b, and 2b, expected for 2017, are not included in the counterfactual, and hence they also impact the calculation of constraints and benefits of all options.

3.1.1 SP

Figure 6 shows the expected yearly constrained energy volumes under the SP scenario, for the different transmission options. We can observe that constrained energy volumes increase with the installation of new wind projects, but decrease dramatically as transmission reinforcements become operational.

Options 1a and 1b provide the highest reductions in constrained energy volumes until 2027 when Option 2b completes all AC reinforcements. Options 1b and 2b allow reaching the same boundary capacities in B1 by 2027, and therefore provide similar volume of constraints from that year onward, whilst Option 1a provides significantly higher volumes.

Figure 6 – Total annual constrained energy volumes, SP (GWh)

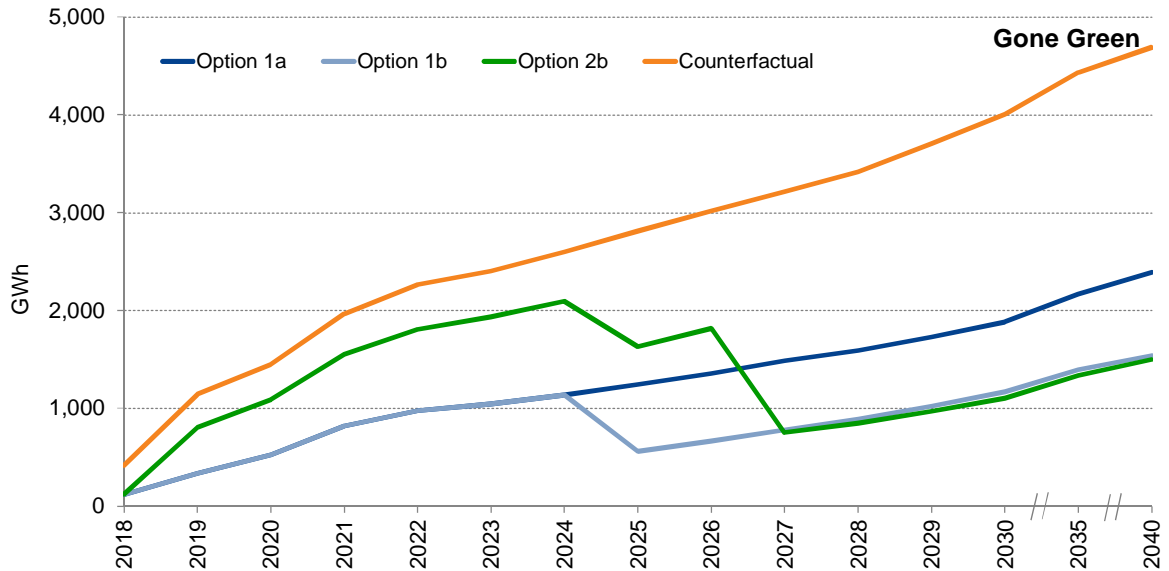


3.1.2 GG

Figure 7 shows the expected annual constrained energy volumes under the GG scenario, for the different transmission options.

It shows similar trends and impacts of the reinforcements; however all constrained energy volumes in the counterfactual and all transmission scenarios are on average double those in the SP generation scenario.

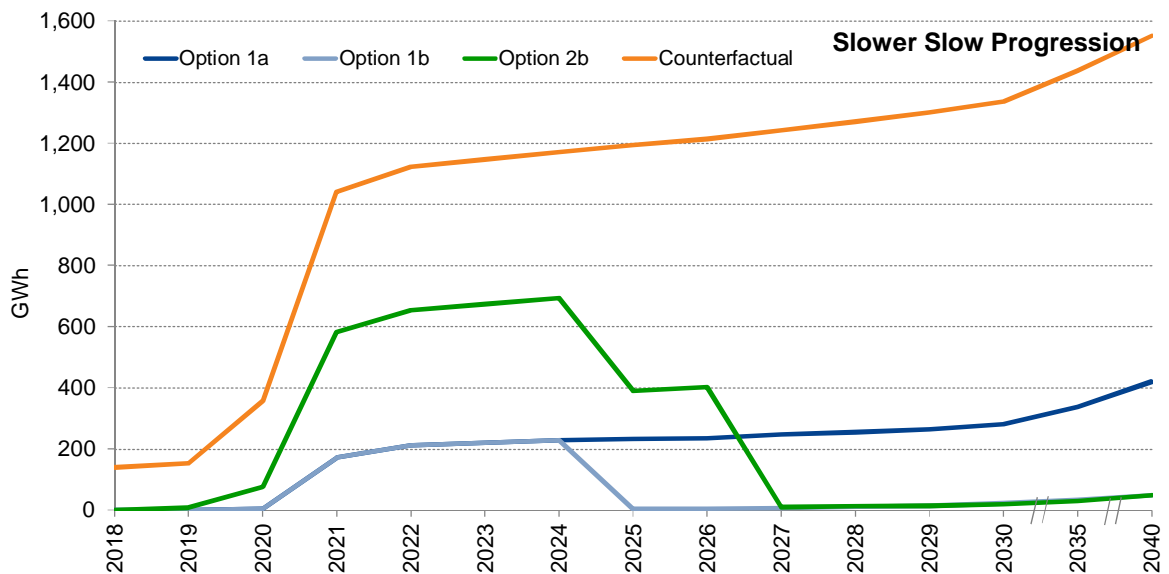
Figure 7 – Total annual constrained energy volumes, GG (GWh)



3.1.3 SSP

Conclusions for the SSP scenario are similar to the Ofgem scenario, except a period of higher constraint volumes at the start of the 2020s. Figure 8 shows the expected annual constrained energy volumes under the SSP scenario, for different transmission options.

Figure 8 – Total annual constrained energy volumes, SSP (GWh)

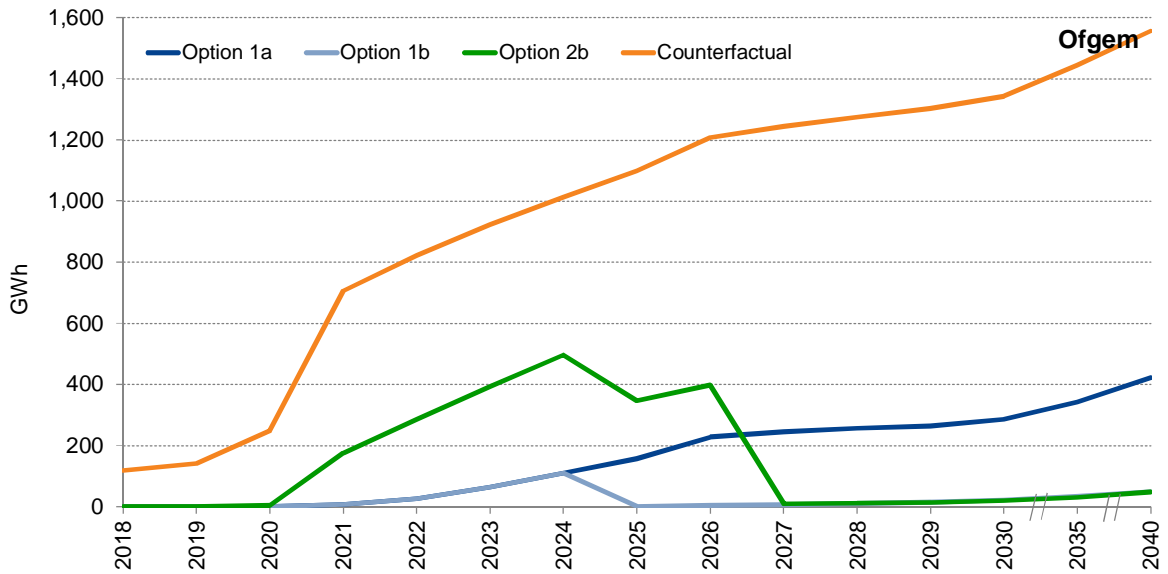


3.1.4 Ofgem

Figure 9 shows the expected annual constrained energy volumes under the Ofgem scenario, for the different transmission options.

Under this low installed wind scenario, all constrained energy volumes are significantly reduced under all options and the counterfactual, and they even become negligible for options 1b and 2b. They also remain very low for Option 1a.

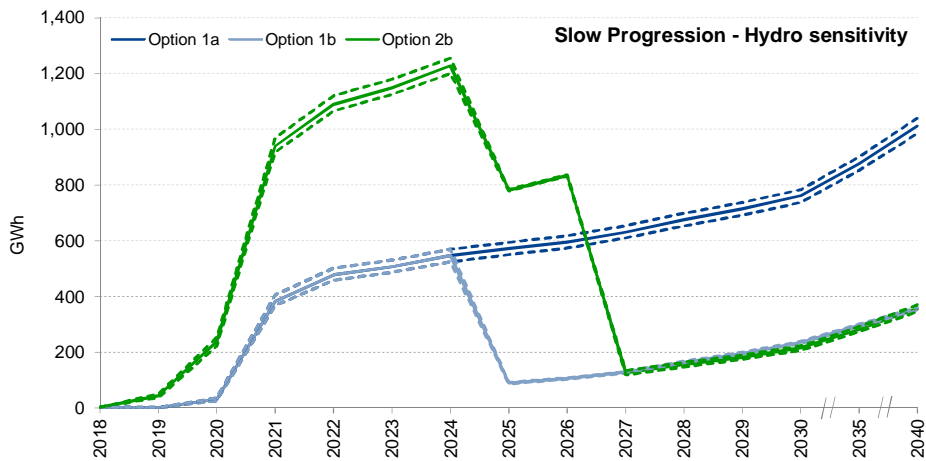
Figure 9 – Total annual constrained energy volumes, Ofgem (GWh)



3.2 Sensitivity analyses

The sensitivity to hydro has been tested by modifying yearly hydro production in +10%/-10%. This variability of hydro production has been analysed over the period 2004 to 2011. Figure 10 shows the range of expected annual constrained energy volumes under the Slow Progression scenario, resulting from the hydro sensitivity. It shows the low impact of the yearly inflows which may vary +10%/-10% over average years, with an impact on constrained energy volumes in the range of +3%/-3%.

Figure 10 – Total annual constrained energy volumes – Hydro sensitivity (GWh)



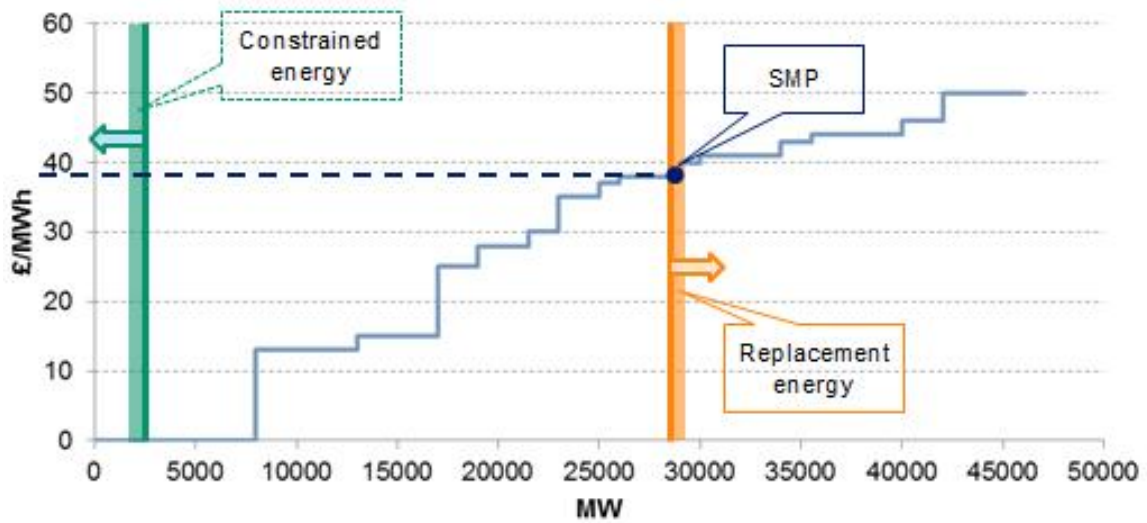
3.3 Replacement energy costs

Replacement energy costs are calculated using the System Marginal Prices (SMP) and two mark-ups, as explained in Section 2.1. The SMPs are calculated as the short run marginal costs of the marginal technology in the market (the most expensive unit that is online) and a ‘scarcity rent’ which contributes to the recovery of fixed costs. The underlying assumption of this approach is that whenever a constraint is needed in the area north of B1 because of insufficient transmission capacity, the incremental generation needed south of B1 has a cost for the system equal to the system marginal price.

Two mark-ups are added to the SMP:

- a balancing mark-up, which captures the typically higher prices of the energy purchased close from real time in the balancing market (instead of at day ahead stage) to replace the constrained wind energy; and
- a constrained wind bid-off mark-up, which reflects the mark-up that wind generators are capable of extracting from the TSO’s compensation mechanism when they are constrained off. The modelling approach also assumes that the constrained energy has a low impact in increasing the SMP. Figure 11 shows the replacement energy costs approach.

Figure 11 – Merit order curve and replacement energy costs



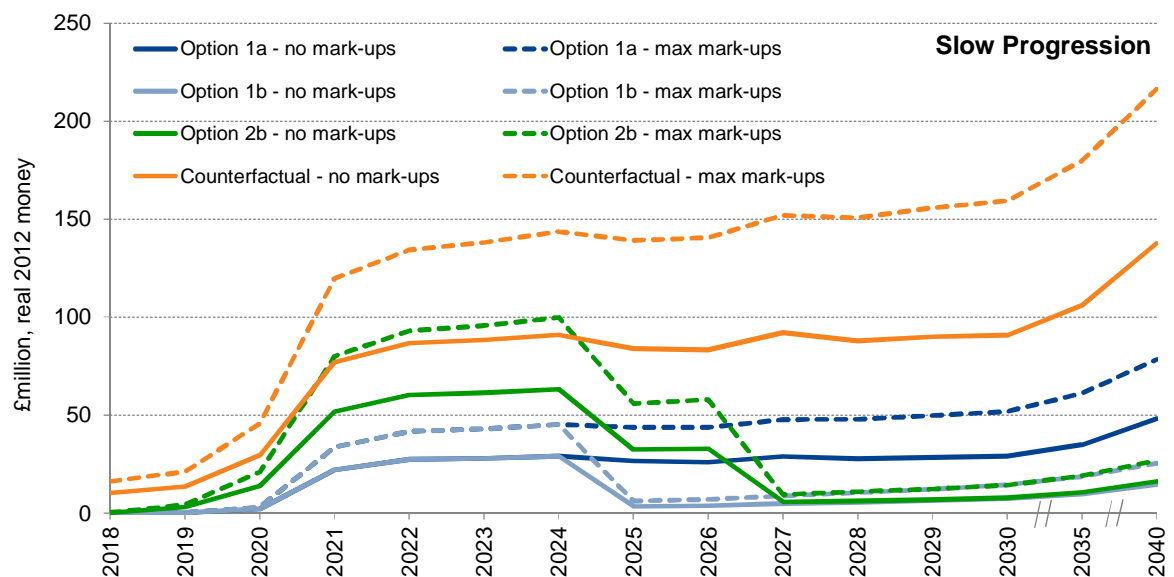
Source: Pöyry

The following sections provide replacement energy costs for the different generation scenarios.

3.3.1 SP

Figure 12 shows the annual costs of constrained energy, as the addition for all hours of the constrained energy volumes multiplied by the concurrent hourly SMP.

Figure 12 – Annual total constraints costs, SP (£m, real 2012 money)



The annual values follow the trend of the constrained energy volumes, affected by the costs of constrained energy, as explained in Section 2.1.3.

These values do not account for the wider benefits as discussed in Section 2.1.4.

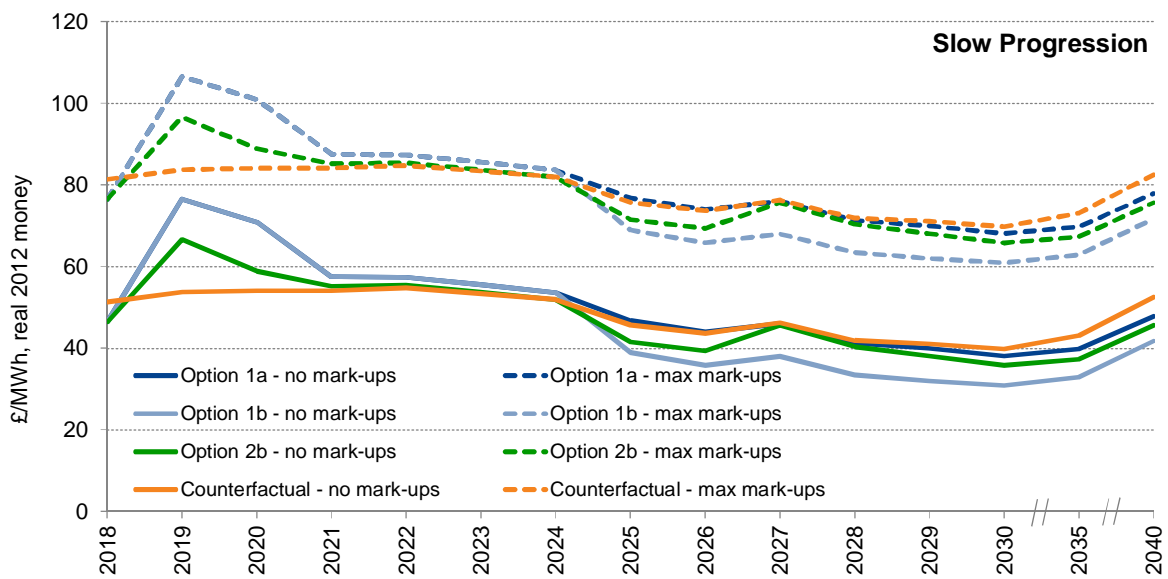
- The continuous lines show the replacement energy costs using the raw SMPs as provided by the model, without any balancing mark-up or any curtailment bid-off cost.
- The dotted lines show the maximum costs of constraints when the maximum mark-ups are applied, both the balancing mark-up (+£20/MWh) and the curtailment bid-off cost (+£10/MWh).

We propose an aggregated maximum mark-up of +£30/MWh covering both mark-ups. Although it is theoretically possible that those mark-ups reach higher values, we expect +£30/MWh to be on the high side.

As an indicative estimate for central calculations of constraint costs, we propose a combined mark-up of £15/MWh, resulting from a central estimate of £10/MWh for the balancing mark-up and £5/MWh for the constrained bid-off costs under a competitive environment.

Figure 13 shows the average constrained energy cost per MWh, calculated as the annual cost of constraints, divided by the annual constrained energy volumes.

Figure 13 – Annual average constraint costs per MWh, SP
(£/MWh, real 2012 money)



We can observe that the average cost of constraints moderately changes over years, with several factors affecting the average replacement energy costs:

- The seasonal behaviour of SMPs, with higher prices in winter, implies that in the earliest years curtailments occur in more expensive hours, and average replacement prices increase year by year.
- A new phenomenon will arise beyond a threshold of RES penetration, with periods of national RES curtailments (different from zonal constraints in Scotland) during which only RES and few thermal plants can remain online, and competition to stay online

may lead to zero and even negative prices⁷. As the frequency of these situations increases, and constrained energy in Scotland more frequently coincides with national RES curtailment situations, average replacement energy costs decrease over time.

Annex D.5 shows the duration curves of the SMPs in different years, which illustrates the increasing frequency of hours with low prices. It also shows that for the SP scenario, the first situations of national wind curtailment and the prices dropping down to £0/MWh occur between 2020 and 2025, and by 2035 they occur approximately 4% of the hours in the year. By 2035 20% of the hours present low prices below £10/MWh.

Figure 14 shows the seasonal behaviour of constrained energy volumes as well as seasonal SMPs. Higher SMPs and higher constrained energy volumes during the winter time explain the increase of average prices in the year show (i.e. 2020). Annex D contains similar graphs for different projected years.

⁷ Marginal prices of £0/MWh already occur in systems such as Spain or Germany in situations of 'excess' RES that cannot be integrated into the system during a few hours per year. As a reference, these situations occur already in Spain since 2010, with circa 20,000 MW of wind power installed, during 200 hours and affecting 3 TWh (0,6% of the yearly available wind resource), and a maximum instantaneous curtailment of 5,000 MW of non-admissible wind power. Also, Germany occasionally curtails wind and solar energy for the same reason, for instance on 16 June 2013 with 5,000 MW affected.

Figure 14 – Monthly generation and monthly constrained volumes (GWh), Slow Progression, Option 2b, 2020

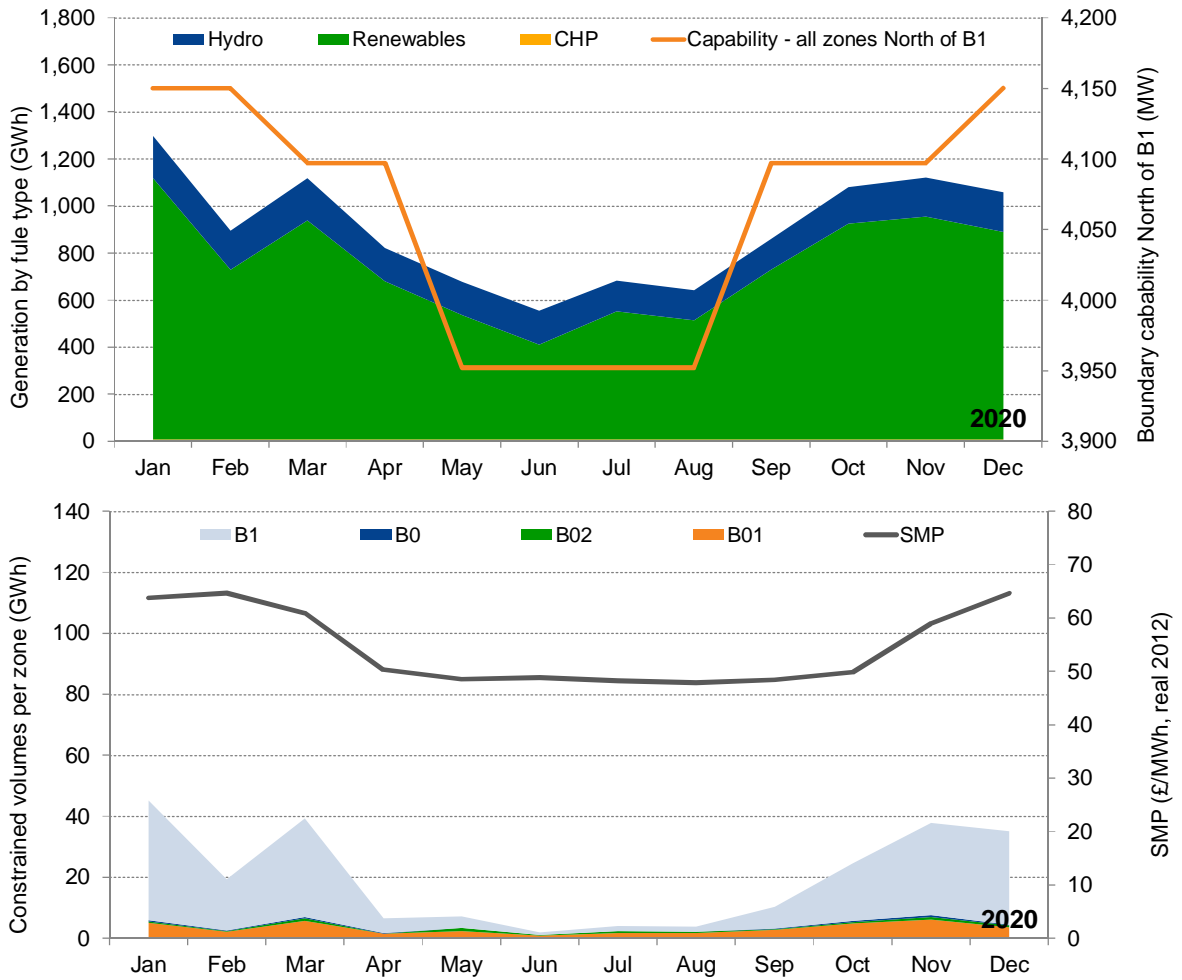
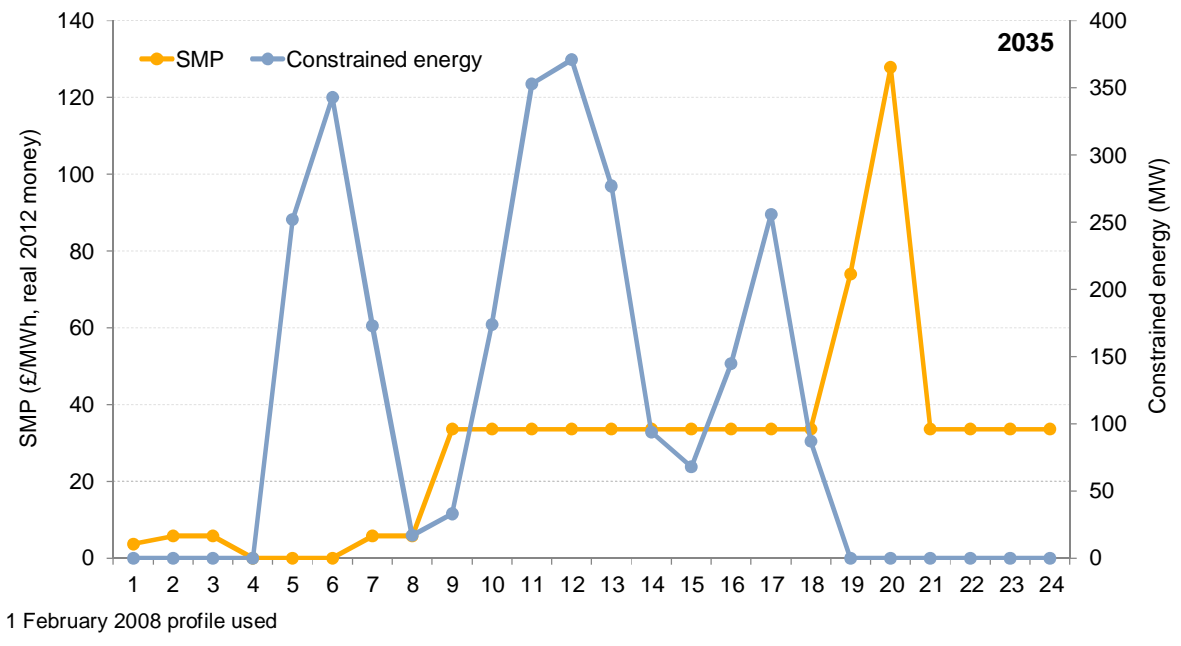


Figure 15 shows the hourly constrained energy and the concurrent SMP for a sample windy day. It shows how SMPs may reach £0/MWh in specific hours as well as high values in other periods

**Figure 15 – Hourly constrained energy and SMP for a sample windy day
Slow Progression, Option 2b, 2035**



As constraints in the Scottish area north of B1 start happening during more frequent situations of national RES curtailment, leading to very low SMPs, the average replacement energy cost is reduced. This phenomenon drives the replacement energy costs reductions gradually from mid-2020s onwards. Annex D.5 illustrates this effect, and its evolution from 2020 until 2035 as more wind is integrated in the GB system.

3.3.2 GG

Similar results are presented for the GG generation scenario.

Figure 16 shows the annual costs of constrained energy, as the addition for all hours of the constrained energy volumes multiplied by the concurrent hourly SMP. These values do not account for the wider benefits as discussed in Section 2.1.4.

- The continuous lines show the replacement energy costs using the raw SMPs as provided by the model, without any balancing mark-up or any curtailment bid-off cost.
- The dotted lines show the maximum costs of constraints when the maximum combined mark-up is applied, including both the balancing mark-up and the curtailment bid-off cost.

An aggregated figure of +£15/MWh covering both mark-ups seems more credible. (although individual maximums of +£20/MWh are considered for the balancing mark-up and the wind bid-off mark-up, we estimate that a combined value of +£30/MWh would be in the high end)

Figure 16 – Annual total constraints costs, GG (£m, real 2012 money)

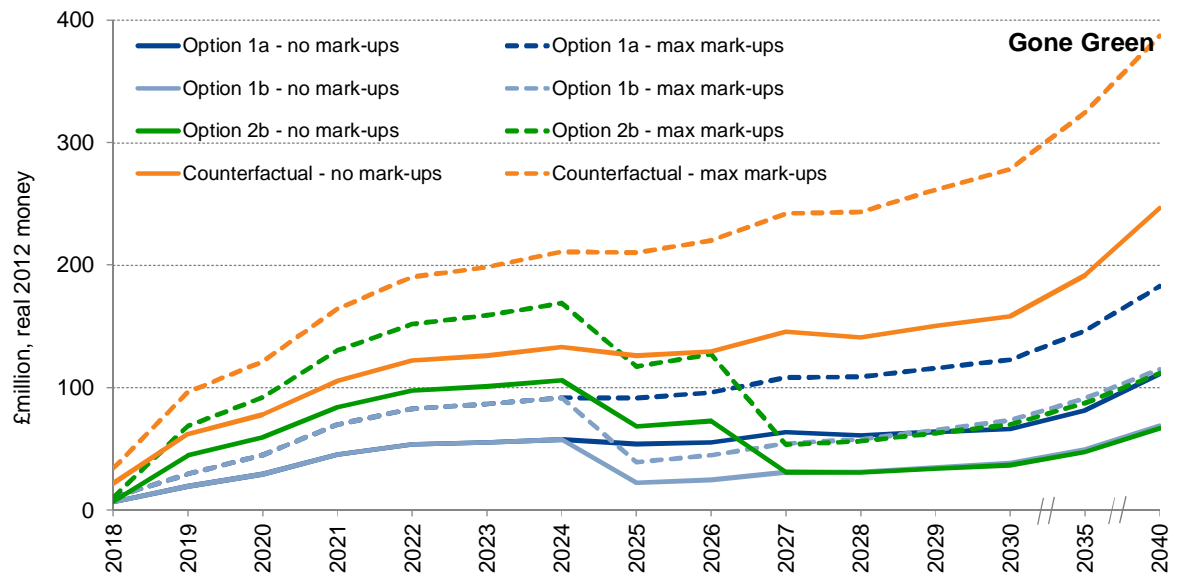
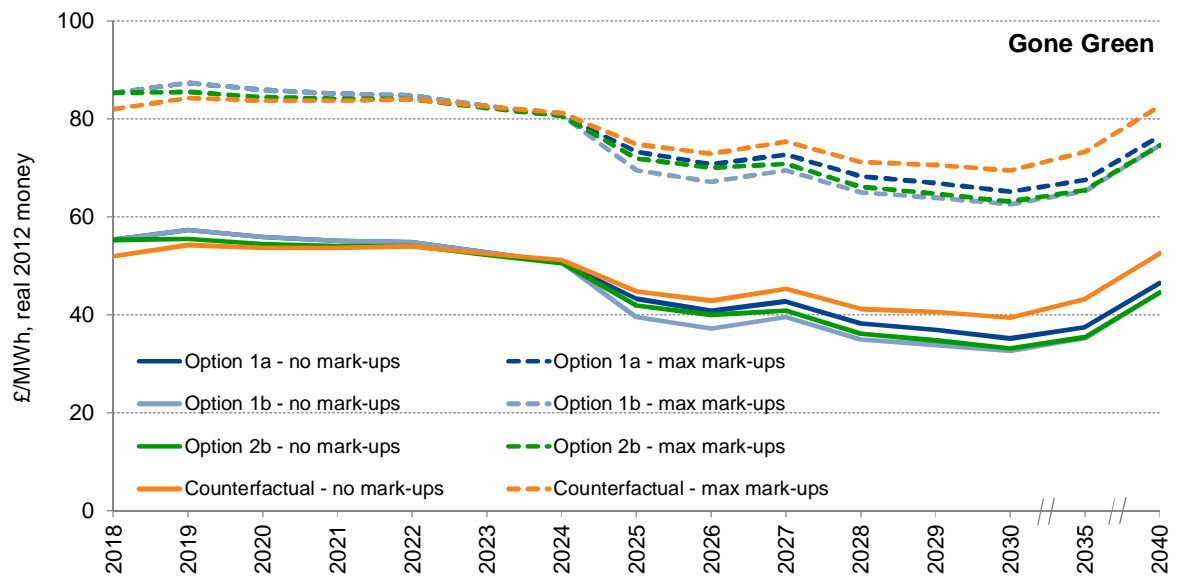


Figure 17 shows the average constrained energy cost per MWh, calculated as the annual cost of constraints, divided by the annual constrained energy volumes.

Figure 17 – Annual average constraint costs per MWh, GG (£/MWh, real 2012 money)



3.3.3 Ofgem

Similar results are presented for the Ofgem generation scenario.

Figure 18 shows the annual costs of constrained energy, as the addition for all hours of the constrained energy volumes multiplied by the concurrent hourly SMP.

Figure 18 – Annual total constraints costs, Ofgem (£m, real 2012 money)

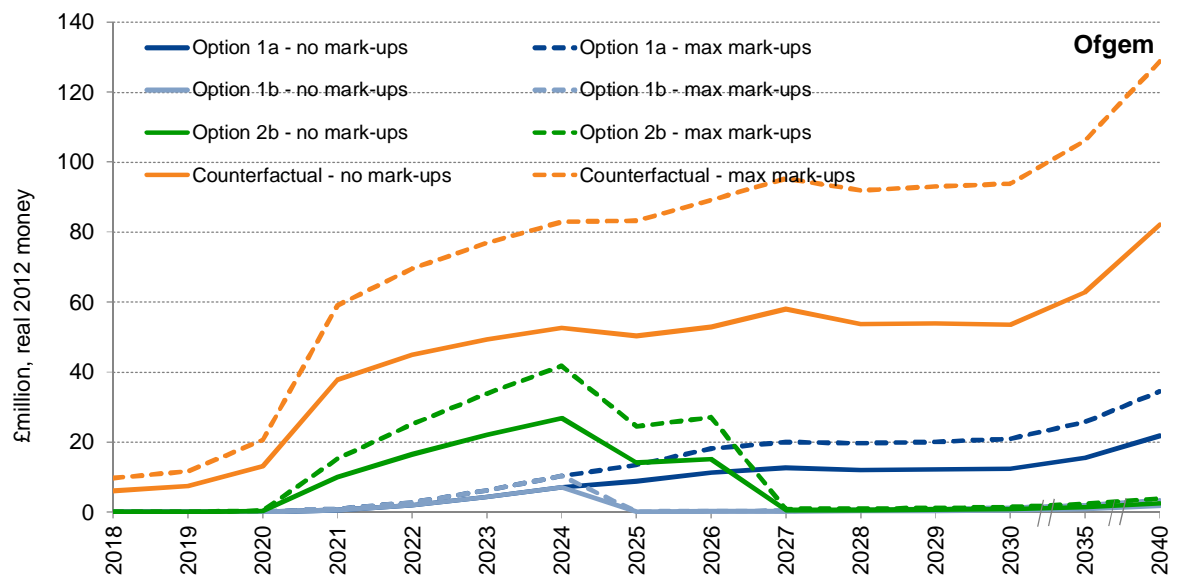
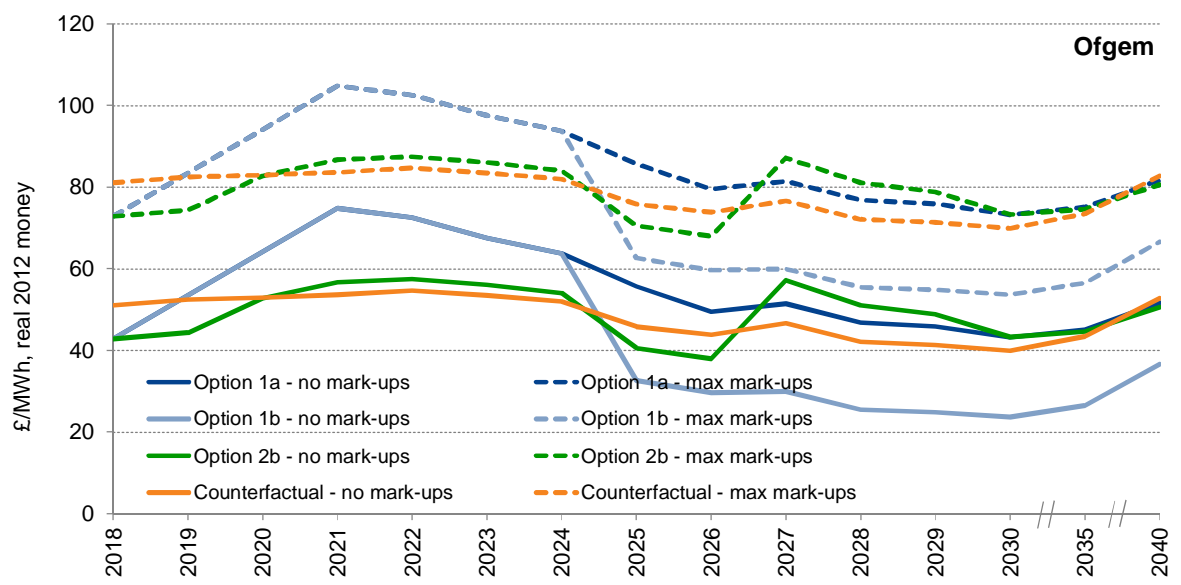


Figure 19 shows the average constrained energy cost per MWh, calculated as the annual cost of constraints, divided by the annual constrained energy volumes.

Figure 19 – Annual average constraint costs per MWh, Ofgem (£/MWh, real 2012 money)



3.4 Replacement energy benefits of reinforcement options

For the purpose of this report, benefits are calculated as the addition of:

- replacement energy costs (including a balancing mark-up over the replacement SMPs); and
- net constrained wind bid-off cost (including a bid-off mark-up over the replacement costs).

The following Figures, Figure 20 to Figure 22, present for the different transmission reinforcement options the benefits under the Slow Progression scenario.

As previously discussed, wider benefits are not considered in this quantitative analysis.

The benefits further presented consider a central combined mark-up of £15/MWh (split indicatively in £10/MWh for the balancing mark-up and £5/MWh for the bid-off mark-up).

We propose a range of £0/MWh to £30/MWh for both mark-ups given uncertain market behaviours, and Pöyry’s indicative central forecasts are closer to £15/MWh.

Figure 20 – Total benefits of Option 1a, SP (£m)

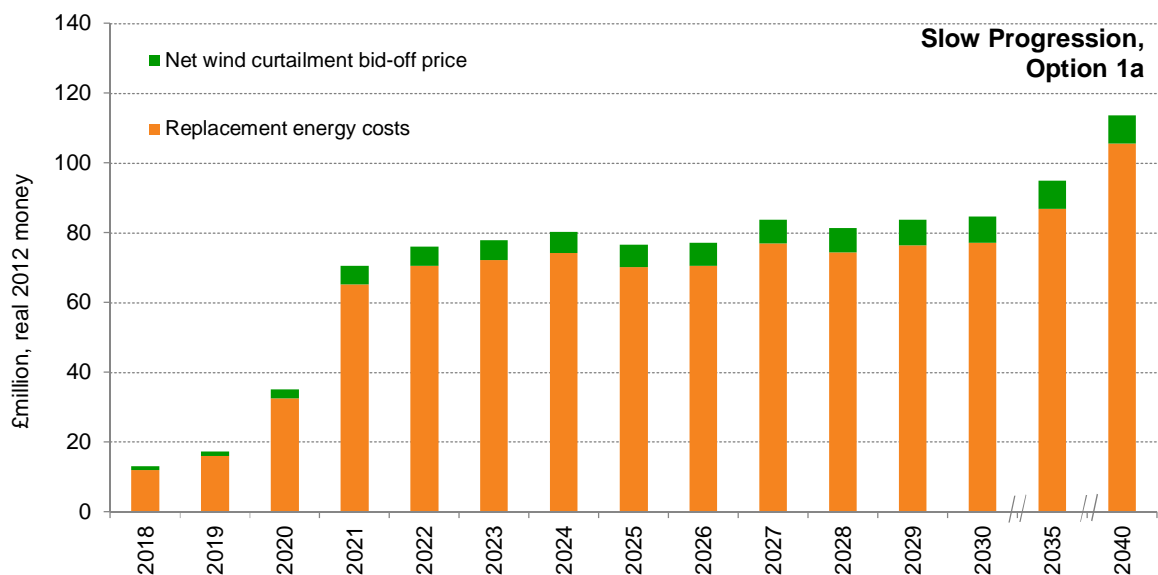


Figure 21 – Total benefits of Option 1b, SP (£m)

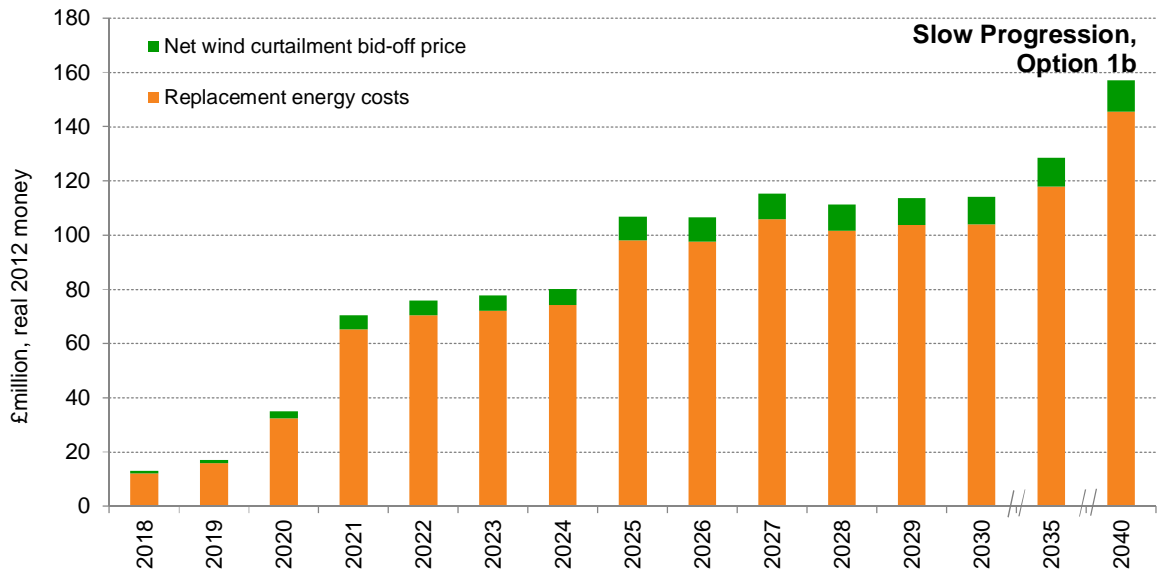
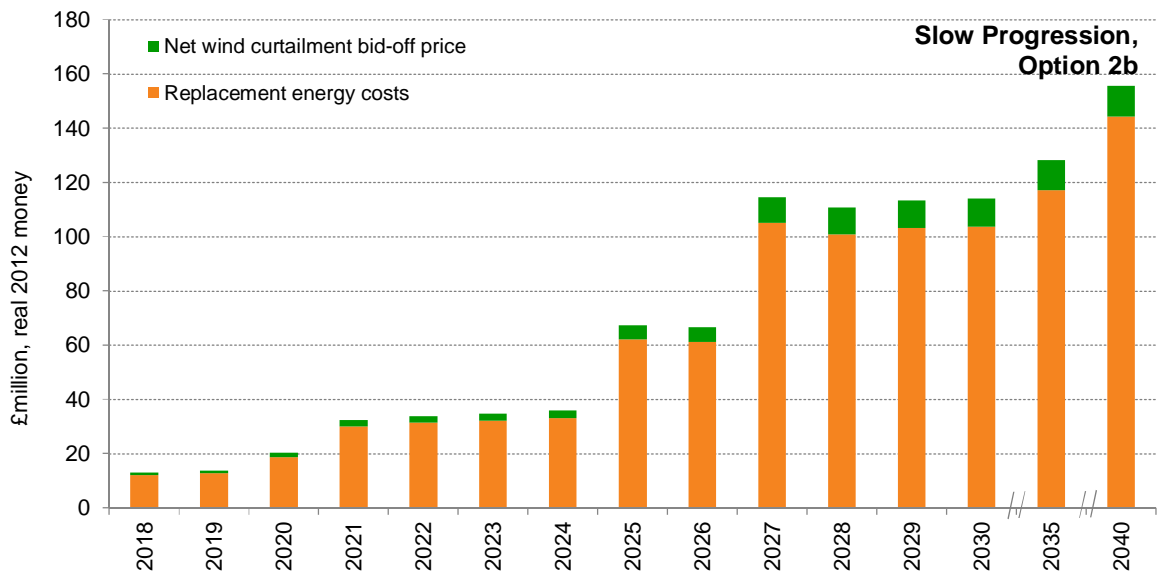


Figure 22 – Total benefits of Option 2b, SP (£m)



Similar figures are presented in Annex D for the remaining generation scenarios GG and Ofgem.

These annual total benefits can be used to calculate the NPV of the different reinforcement options, following the Spackman approach.

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4. COMPARATIVE ANALYSIS

4.1 General approach

The similarities and differences of the Pöyry's and SKM's general approaches in modelling the constrained energy volumes are listed in the following table. Detailed differences in the dispatching model or the source of the input data are further described in further sections.

Table 2 – Similarities and differences in the general approach

Similarities	
<ul style="list-style-type: none"> ▪ Development of a dispatch which looks at exports on each boundary, and the consequent limits imposed by the operational transmission capacity ▪ Cascading approach to the constraints in the boundaries B01, B02, B0 and B1 	
Differences	
Pöyry	SKM
<ul style="list-style-type: none"> ▪ Hourly model 	<ul style="list-style-type: none"> ▪ Half-hourly model
<ul style="list-style-type: none"> ▪ multiple weather years modelled 	<ul style="list-style-type: none"> ▪ single weather year modelled
<ul style="list-style-type: none"> ▪ full optimisation of the generation costs including the dispatching of hydro plants and PSH 	<ul style="list-style-type: none"> ▪ fixed historic hourly profiles for hydro and PSH
<ul style="list-style-type: none"> ▪ modelling of the whole GB system 	<ul style="list-style-type: none"> ▪ modelling of the B1 zone alone (north of boundary B1)
<ul style="list-style-type: none"> ▪ use of historic wind speeds for all new wind farms locations 	<ul style="list-style-type: none"> ▪ use of proxy existing wind farms sites for new wind farms
<ul style="list-style-type: none"> ▪ cost of constraints calculated as <ul style="list-style-type: none"> – replacement costs valued at hourly SMP + balancing mark-up – bid-off cost mark-up ▪ Individual yearly constraint costs based on SMPs at the times of constraint 	<ul style="list-style-type: none"> ▪ fixed cost of constraints calculated as <ul style="list-style-type: none"> – the cost of replacement energy + the value of market income foregone (with 30% mark-up over subsidy) – the cost of wind generation (subsidy) – an average of all yearly constraint costs is calculated and then equally applied to all years ▪ total benefits of reduced constraints valued at £130/MWh

4.2 Dispatch model

As regards the differences in the dispatching model, the most significant are hereunder listed:

Table 3 – Similarities and differences in the dispatch model

Differences	
Pöyry	SKM
<ul style="list-style-type: none"> ▪ optimises the hourly dispatch of hydro, as part of the optimisation of GB's production costs 	<ul style="list-style-type: none"> ▪ Half-hourly model
<ul style="list-style-type: none"> ▪ five weather years 	<ul style="list-style-type: none"> ▪ one weather year
<ul style="list-style-type: none"> ▪ full optimisation of the generation costs including the dispatching of hydro plants and PSH 	<ul style="list-style-type: none"> ▪ fixed historic hourly profiles for hydro and PSH
<ul style="list-style-type: none"> ▪ modelling of the whole GB system 	<ul style="list-style-type: none"> ▪ modelling of the B1 zone alone (north of boundary B1)
<ul style="list-style-type: none"> ▪ modelling years until 2040 	<ul style="list-style-type: none"> ▪ modelling years until 2030

4.3 Input data

Pöyry's input data has some similarities with SKM's study. However, differences in the models and the data sources have led to the use of different inputs, described in the following table.

Table 4 – Similarities and differences in the input data

Similarities	
<ul style="list-style-type: none"> ▪ Wind and other RES generation capacities ▪ Network boundary capacities 	
Differences	
Pöyry	SKM
<ul style="list-style-type: none"> ▪ Specific demand growth rates from NG's scenarios 	<ul style="list-style-type: none"> ▪ Stable generation from 2008/9
<ul style="list-style-type: none"> ▪ Optimised hydro and PSH 	<ul style="list-style-type: none"> ▪ Fixed hydro profiles and PSH

<ul style="list-style-type: none"> five ‘weather years’ wind profiles generated from corresponding wind speeds 	<ul style="list-style-type: none"> One historic year hourly production (2008/9)
<ul style="list-style-type: none"> Replacement energy cost is an hourly result of the dispatch model Balancing Mark-up [0-20 £/MWh] Bid-off mark-up [0-20 £/MWh] Combined mark-up [0-30 £/MWh], central value £15/MWh total benefits of reduced constraints valued at [40-90 £/MWh] depending on the year, the scenario and the mark-ups hypotheses 	<ul style="list-style-type: none"> Market prices of £50/MWh for 2014 to £85/MWh for 2030 as forecasted by DECC ‘bid-off mark-up’ equivalent to 30% of FiT subsidy, amounting to [29-34 £/MWh] Fixed averaged constraint cost of £130/MWh for all studied years

Among several differences in the approach to calculate the constrained energy costs, we do not find a rationale for SKM’s use of a fixed constrained energy cost for the whole period studied. SKM build yearly constraint costs, calculate an average for the period, and apply the average to all years when doing the NPV calculation. This approach overestimates the benefits during the years which most contribute for the NPV, and underestimates the latest years which less contribute to the NPV.

Figure 23 – SKM calculation of average constraint energy costs

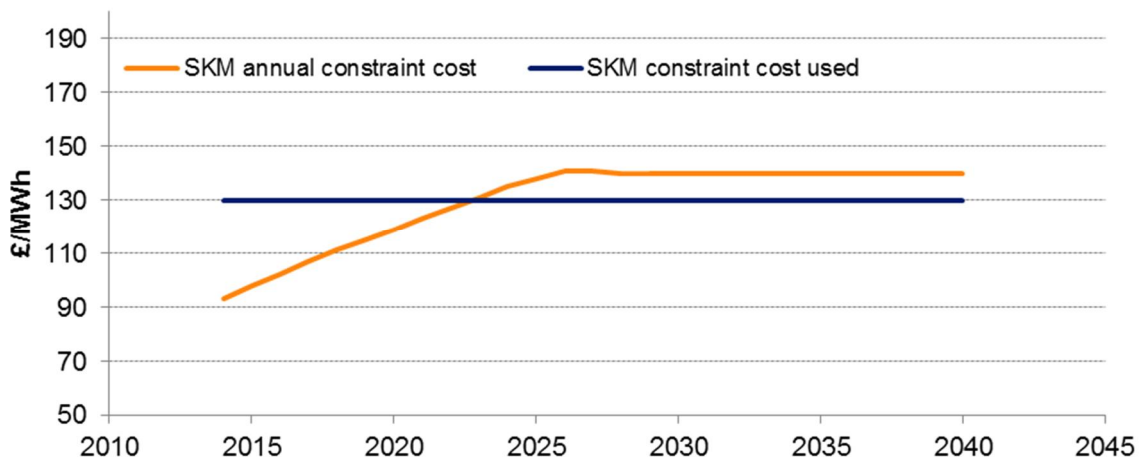
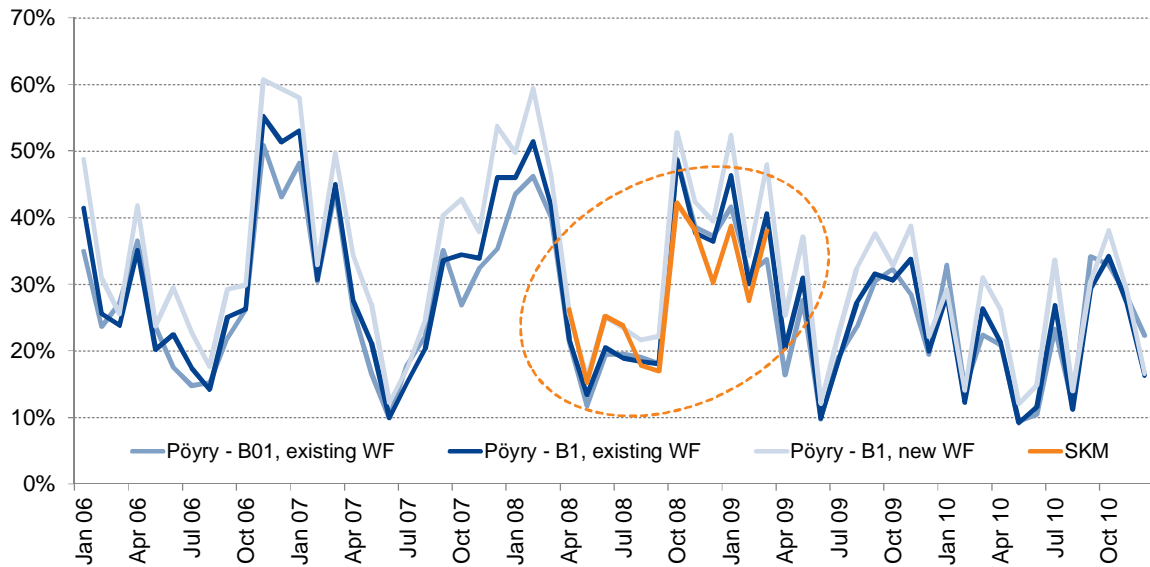


Figure 24 – Example of a sample of the onshore wind profiles for the historical weather years modelled (averaged at a monthly resolution)



4.4 Results

4.4.1 Constrained energy volumes

Figure 25 to Figure 28 show the breakdown of the constrained energy volumes from the different transmission zones, for the Slow Progression scenario. We provide a breakdown of the results for the rest of the generation scenarios in Annex D.

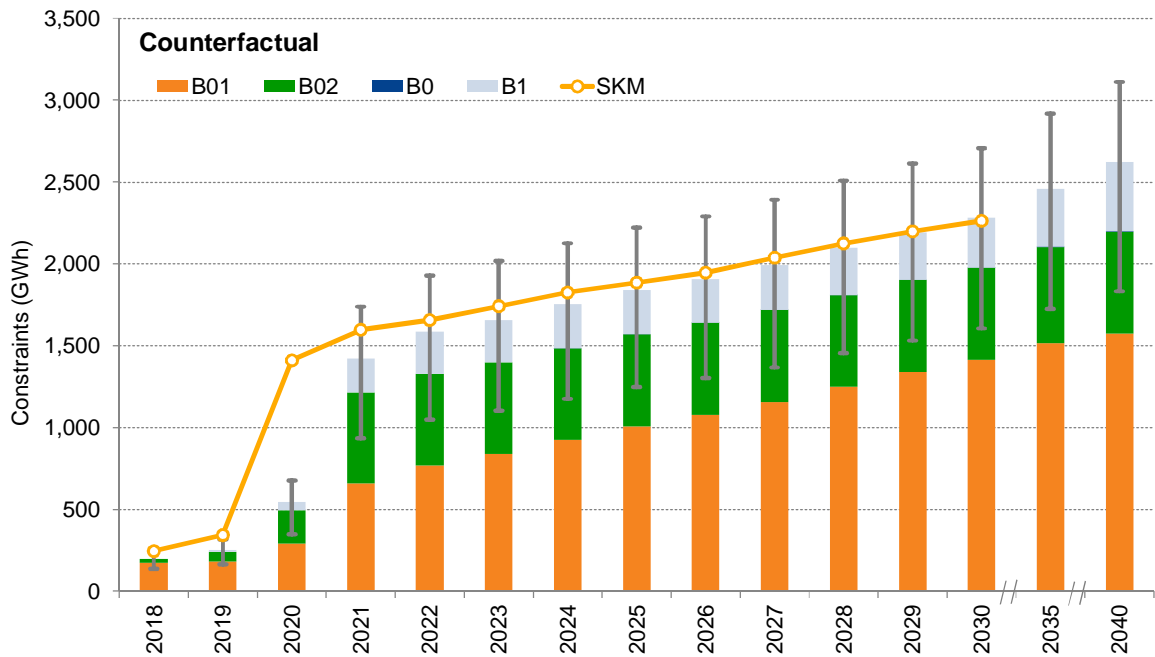
No hydro sensitivity results are included in these figures.

These following figures show that:

- SKM results are on average slightly overestimated depending on the generation and the transmission scenario, mainly as a consequence of the fixed modelling of the dispatchable hydro and the PSH.
- The sensitivity of constrained energy volumes to the wind variability registered in the period 2006 to 2010 is very significant. Over the central volumes resulting from the average of all weather years, a variability of around +/-30% of total constraints is observed, which may result for one specific weather year in higher values than calculated by SKM or significantly lower.

The following figure shows how for this specific case, Pöyry's calculated volumes (in bars) practically match SKM's values (in the line) except for 2020. It also shows with vertical segments the variability of total constrained volumes across the different weather years modelled. These segments show a sensitivity to weather years of broadly around +/-30% over the average volumes.

Figure 25 – Breakdown of annual constrained energy volumes, Counterfactual, SP (GWh)

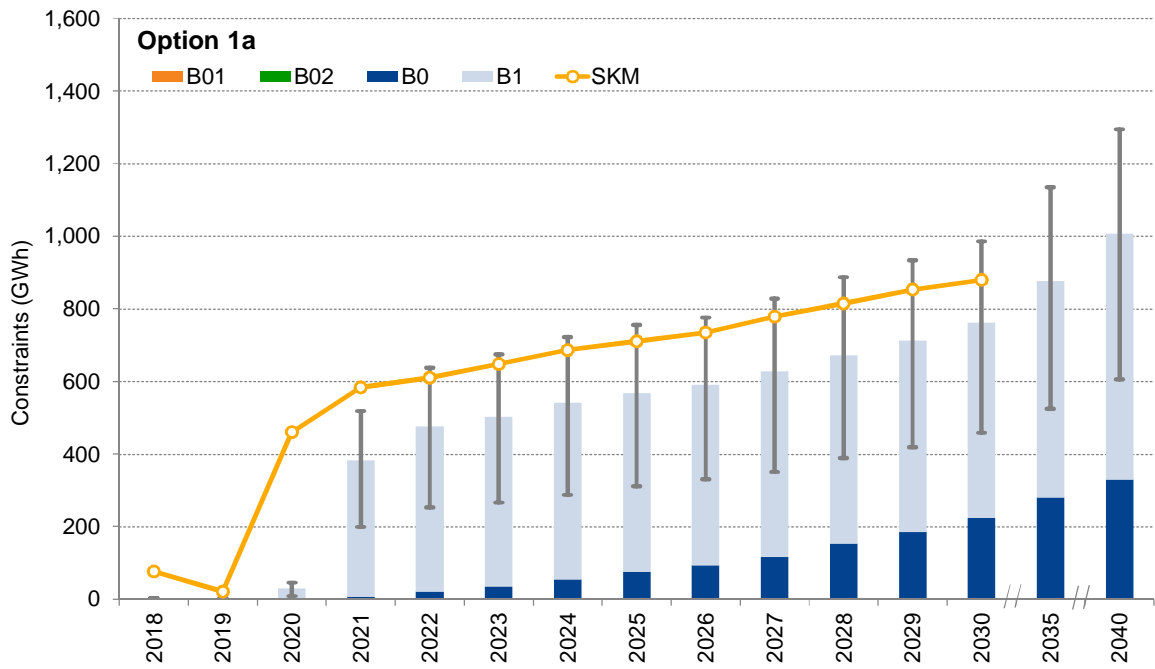


Note: Error bars represent the variability linked to historical weather year conditions. Average values result across the five weather years attributing an equal probability to each.

The following Figure 26 to Figure 28 show how, for these specific scenarios, Pöyry's results are on average generally slightly lower than SKM's, with a few yearly exceptions. The higher end of the most windy weather years usually leads to slightly higher constraints than modelled by SKM, whereas the lower end usually leads to significantly lower volumes.

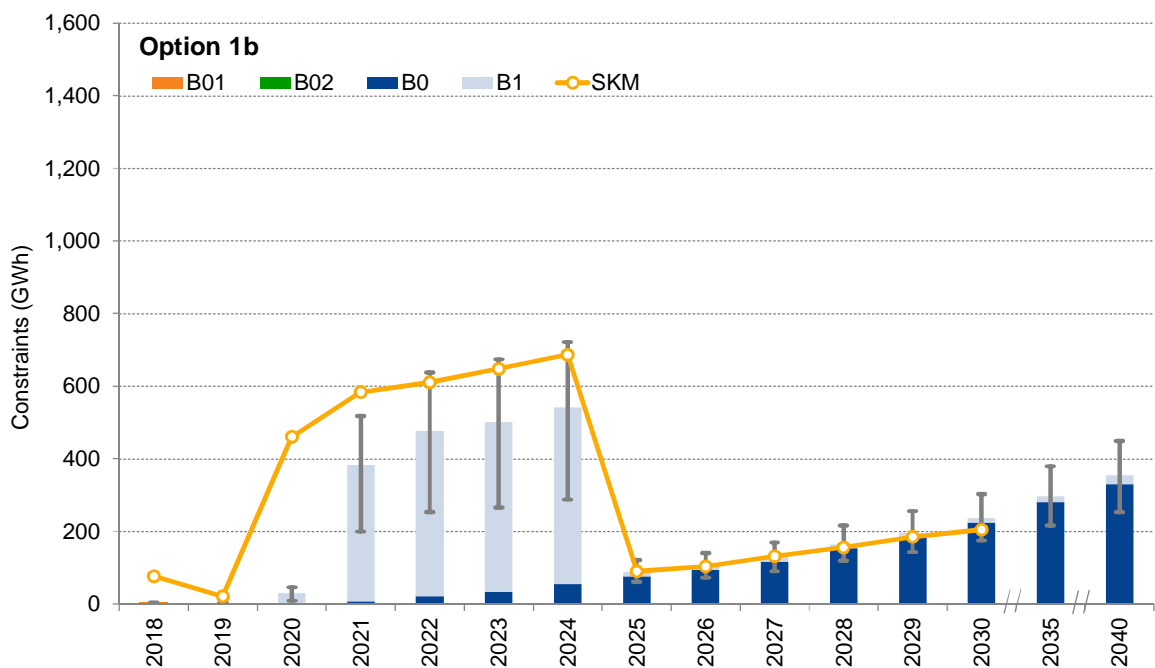
On average of all generation and transmission scenarios, SKM constrained energy volumes are 10% to 15% higher than Pöyry's.

Figure 26 – Breakdown of annual constrained energy volumes, Option 1a, SP (GWh)



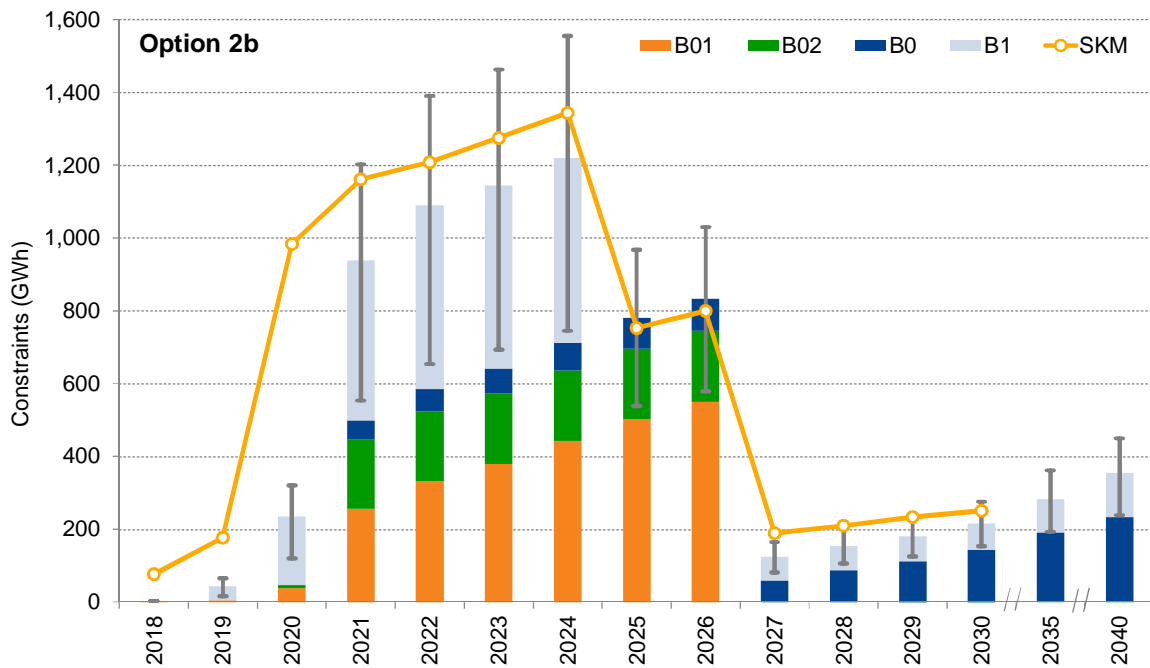
Note: Error bars represent the variability linked to historical weather year conditions. Average values result across the five weather years attributing an equal probability to each.

Figure 27 – Breakdown of annual constrained energy volumes, Option 1b (GWh)



Note: Error bars represent the variability linked to historical weather year conditions. Average values result across the five weather years attributing an equal probability to each.

Figure 28 – Breakdown of annual constrained energy volumes, Option 2b (GWh)



Note: Error bars represent the variability linked to historical weather year conditions. Average values result across the five weather years attributing an equal probability to each.

4.4.2 Constrained energy costs

The approaches used by SKM and Pöyry are significantly different.

On average Pöyry reaches lower average costs of constrained energy than SKM by:

- -28% to -64%, with an average -52% in SP;
- -44% to -63%, with an average -50% in GG; and
- -30% to -70%, with an average -50% in Ofgem.

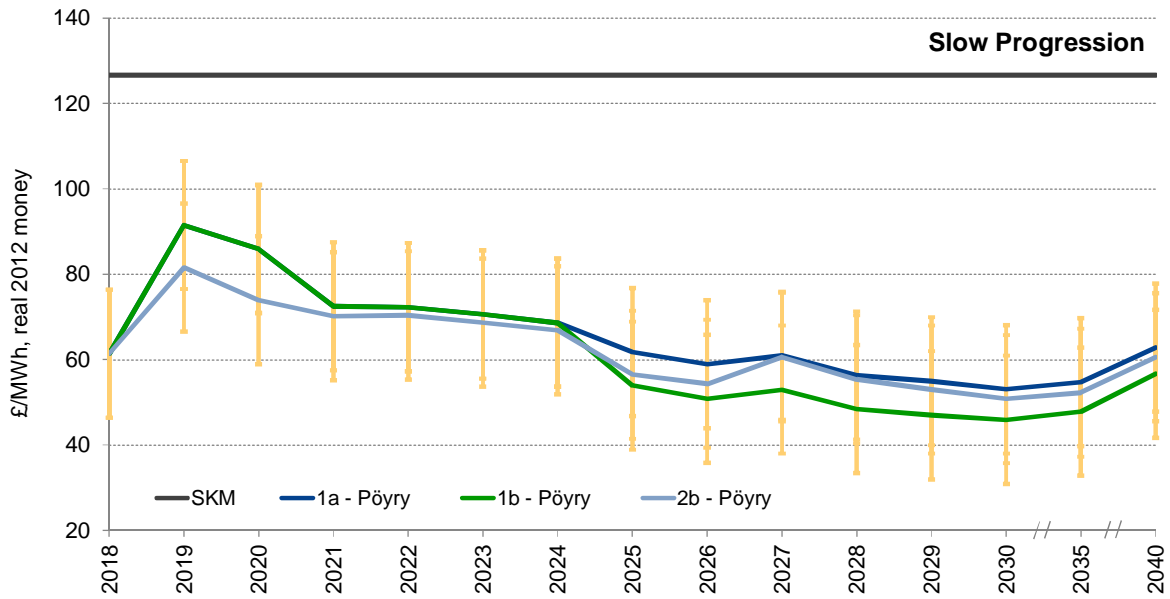
Pöyry’s average constrained energy costs are dynamic year on year, depending on the hourly SMPs during the periods when constraints occur.

The new phenomenon of national RES curtailment produces some situations of very low prices, down to £0/MWh, but also more hours of low prices. The duration curves of SMPs are shown in Annex D.5. The constraints of wind energy in the studied area north of B1 occur mainly during ‘conventional’ hours with positive SMPs. However, the increasing frequency of situations of national RES curtailment with low prices have an impact on the replacement energy costs, which we find significantly lower than those calculated by SKM.

SKM’s sensitivity analysis to the constrained energy cost of £100/MWh allows estimating the impact of our lower constraint benefits.

The following Figure is a comparison of the resulting constraint costs per MWh for the various reinforcement options under the SP scenario. We have assumed a combined central mark-up of £15/MWh.

Figure 29 – Comparison of constraint costs, SP (£/MWh, real 2012 money)



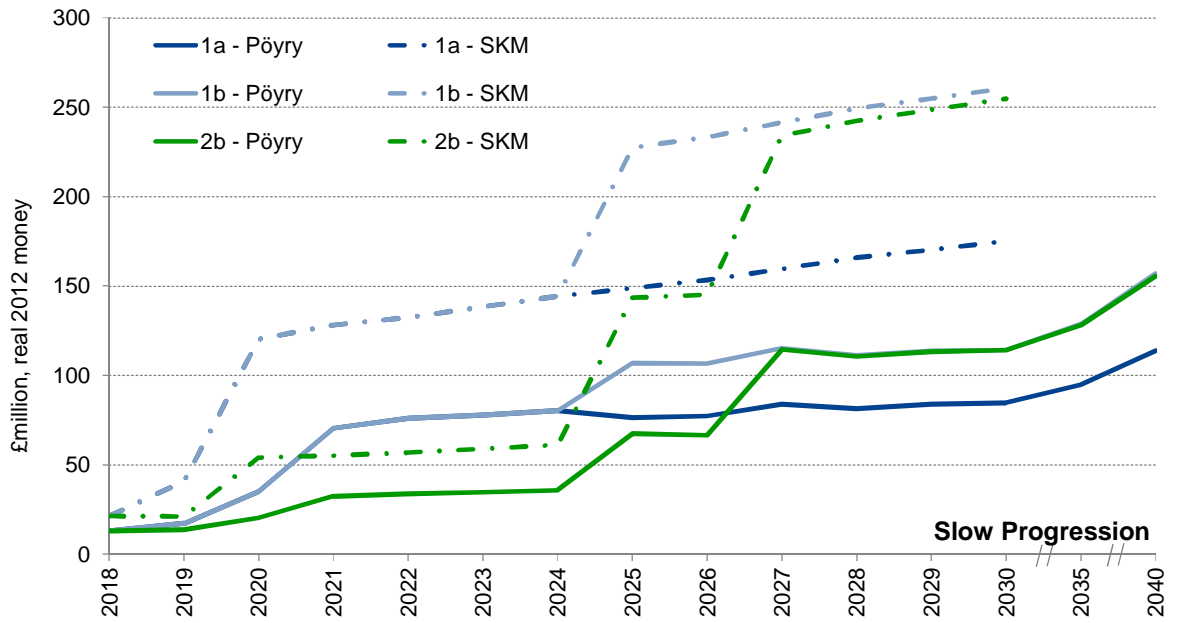
Note: Error bars represent the range of constraint costs per MWh, depending on the mark-up (from as low as £0/MWh to £30/MWh).

Figure 30 shows the comparison between SKM results and Pöyry results (based on a £15/MWh mark-up) of the replacement energy benefits for the various reinforcements, which is calculated as the difference of the constraint costs between each transmission reinforcement option and the counterfactual option, under the SP scenario.

This figure illustrates that SKM and Pöyry’s annual benefits significantly differ. Despite the result that SKM’s constrained energy volumes were found on average of all scenarios 10% to 15% higher than Pöyry’s, it is the difference of constraint volumes between a reinforcement scenario and the counterfactual that provides the benefits. These differences in constraint volumes are found to be minor between SKM and Pöyry’s results. However, the differences in annual constraints costs, on average 50% lower in Pöyry’s modelling, drive differences in benefits of -50% on average, with the following ranges for the different scenarios:

- -35% to -70%, with an average -50% in SP;
- -41% to -56%, with an average -50% in GG; and
- -37% to -80%, with an average -51% in Ofgem.

Figure 30 – Comparison of total benefits of reinforcement options, SP
(£m, real 2012 money)

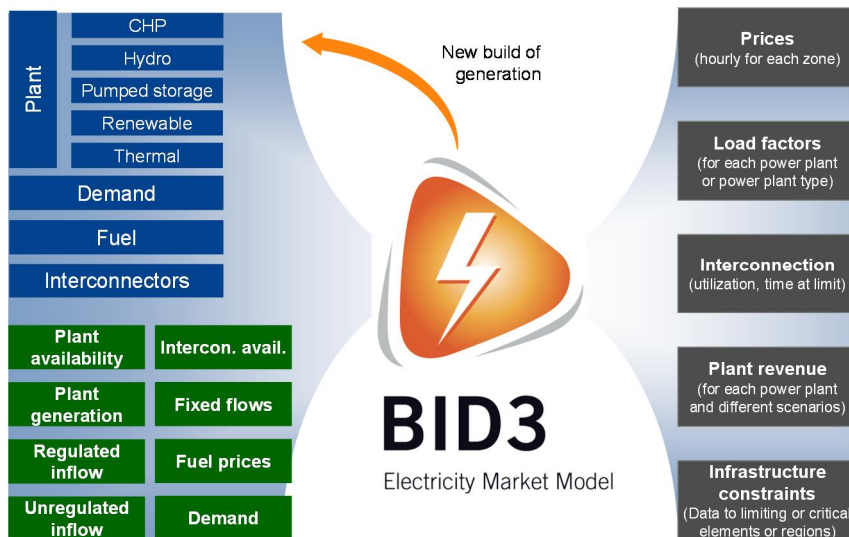


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ANNEX A – DESCRIPTION OF BID3 DISPATCH MODEL

BID3 is Pöyry’s power market model, used to model the dispatch of all generation on the European network. It simulates all 8760 hours per year, with multiple historical weather patterns, generating hourly wholesale prices for each country for each future year and dispatch patterns and revenues for each plant in Europe.

Figure 31 – Overview of BID3



Modelling methodology

BID3 is an economic dispatch model based around optimisation. The model balances demand and supply on an hourly basis by minimising the variable cost of electricity generation. The result of this optimisation is an hourly dispatch schedule for all power plants and interconnectors on the system. At the high level, this is equivalent to modelling the market by the intersection between a supply curve and a demand curve for each hour.

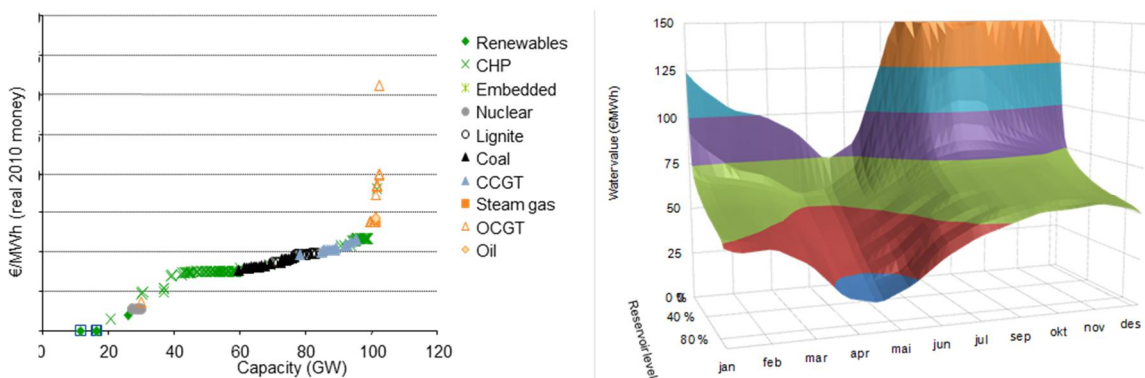
Producing the system schedule

- **Dispatch of thermal plant.** All plants are assumed to bid cost reflectively and plants are dispatched on a merit order basis – i.e. plants with lower short-run variable costs are dispatched ahead of plant with higher short-run variable costs. This reflects a fully competitive market and leads to a least-cost solution. Costs associated with starts and part-loading are included in the optimisation. The model also takes account of all the major plant dynamics, including minimum stable generation, minimum on-times and minimum off-times. Figure 32 below shows an example of a merit order curve for thermal plant.
- **Dispatch of hydro plant.** Reservoir hydro plants can be dispatched in two ways:
 - a perfect foresight methodology, where each reservoir has a one year of foresight of its natural inflow and the seasonal power price level, and is able to fix the seasonality of its operation in an optimal way; or
 - the water value method, where the option value of stored water is calculated using Stochastic Dynamic Programming. This results in a water value curve where the option value of a stored MWh is a function of the filling level of the

reservoir, the filling level of competing reservoirs, and the time of year. Figure 32 below shows an example water value curve.

- **Variable renewable generation.** Hourly generation of variable renewable sources is modelled based on detailed wind speed and solar radiation data which can be constrained, if required, due to operational constraints of other plants or the system.
- **Interconnector flows.** Interconnectors are optimally utilised – this is equivalent to a market coupling arrangement.
- **Demand side response and storage.** Operation of demand side and storage is modelled in a sophisticated way, allowing simulation of flexible load such as electric vehicles and heat while respecting demand side and storage constraints.

Figure 32 – Thermal plant merit-order and water value curve



Power price

The model produces a power price for each hour and for each zone (which may be smaller than one country, for example the different price-zones within Norway). The hourly power price is composed of two components:

- **Short-run marginal cost (SRMC).** The SRMC is the extra cost of one additional unit of power consumption. It is also the minimum price at which all operating plant are recovering their variable costs. Since the optimisation includes start-up and part-load costs all plant will fully cover their variable costs, including fuel, start-up, and part-loading costs.
- **Scarcity rent.** A scarcity rent is included in the market price – we assume power prices are able to rise above the short-run marginal cost at times when the capacity margin is tight. In each hour the scarcity rent is determined by the capacity margin in each market. It is needed to ensure that the plants required to maintain system security are able to recover all of their fixed and capital costs from the market.

Key input data

Pöyry’s power market modelling is based on Pöyry’s plant-by-plant database of the European power market. The database is updated each quarter by Pöyry’s country experts as part of our *Energy Market Quarterly Analysis*. As part of the same process we review our interconnection data, fuel prices, and demand projections.

- **Demand.** Annual demand projections are based on TSO forecasts and our own analysis. For the within year profile of demand we use historical demand profiles – for

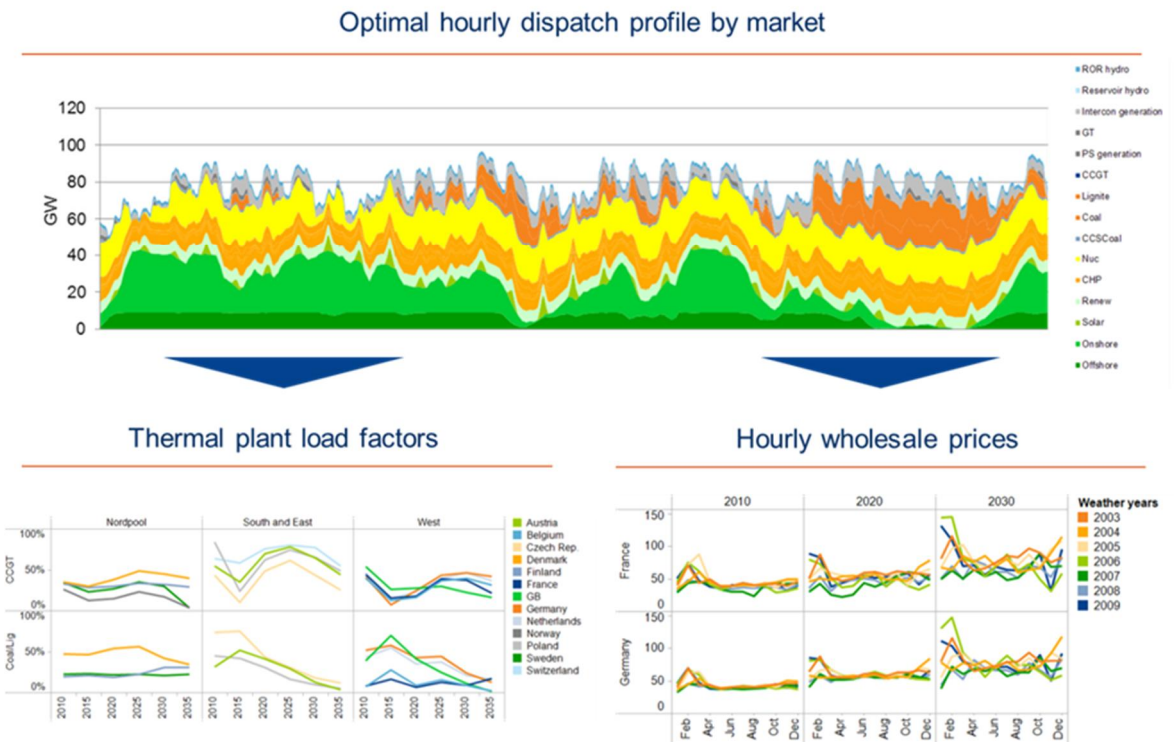
each future year that is modelled we use demand profiles from a range of historical years.

- **Intermittent generation.** We use historical wind speed data and solar radiation data as raw inputs. We use consistent historical weather and demand profiles (i.e. both from the same historical year). This means we capture any correlations between weather and demand, and can also example a variety of conditions – for example a particularly windy year, or a cold, high demand, low wind period:
 - Our wind data is from Anemos and is reanalysis data from weather modelling based on satellite observations. It is hourly wind speeds at grid points on a 20km grid across Europe, at hub height.
 - The solar radiation data is from Transvalor, and is again converted to solar generation profiles based on capacity distributions across each country.
- **Fuel prices.** Pöyry has a full suite of energy market models covering coal, gas, oil, carbon, and biomass. These are used in conjunction with BID3 to produce input fuel prices consistent with the scenarios developed.
- **New generation:** We assess new generation adequacy in an iterative process analysing the generation margins (difference between expected demand and available generation, including outages and different contributions from renewable sources such as wind), and the profitability of new plants in the market context.

Model results

- BID3 provides a comprehensive range of results, from detailed hourly system dispatch and pricing information, to high level metrics such as total system cost and economic surplus. A selection of model results is shown below in Figure 33.

Figure 33 – Hourly dispatch and related metrics



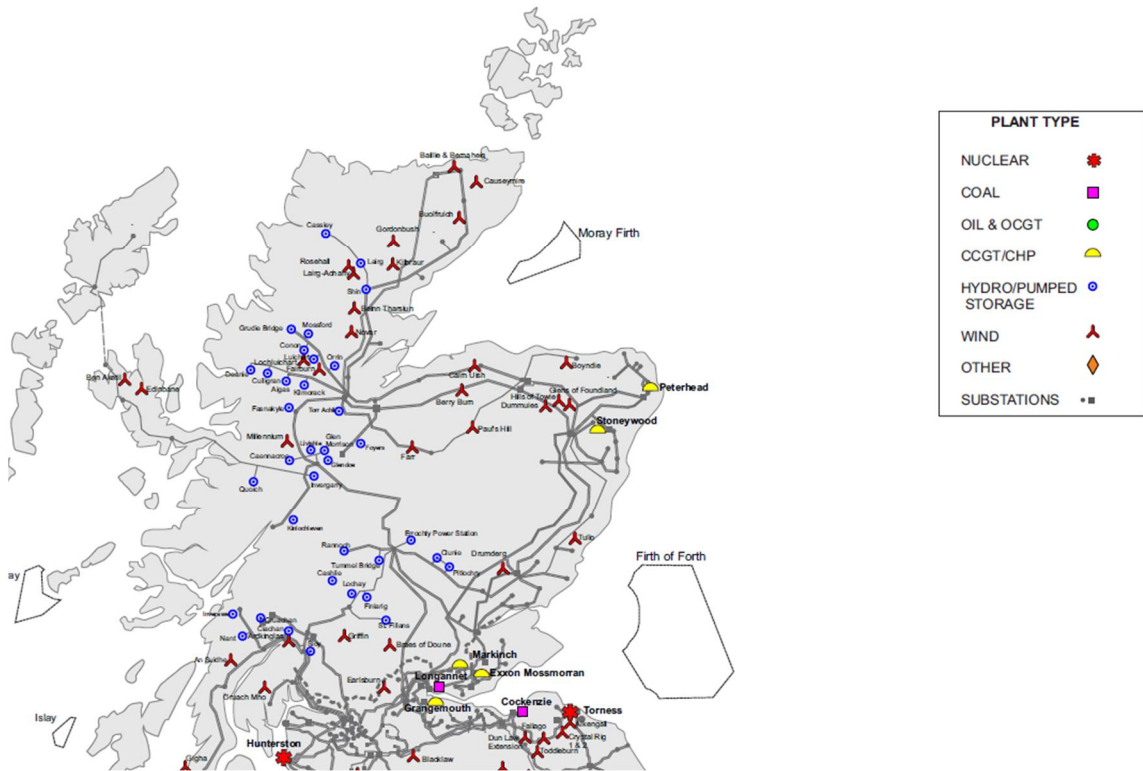
Source: Pöyry BID3 based analysis

For more information about BID3, please visit: www.poyry.com/BID3 or email to BID3@poyry.com.

ANNEX B – CAITHNESS MORAY PROJECT

B.1 Installed generation in Scotland

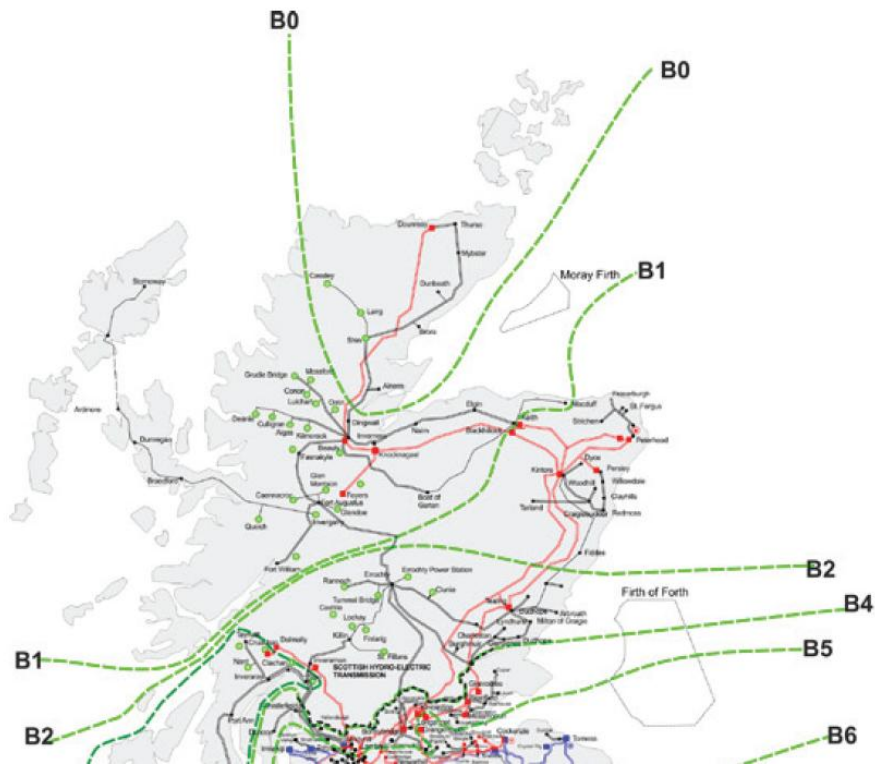
Figure 34 – Existing power stations in Northern Scotland



Source: National Grid – Ten Year Statement 2013

B.2 Transmission boundaries in GB

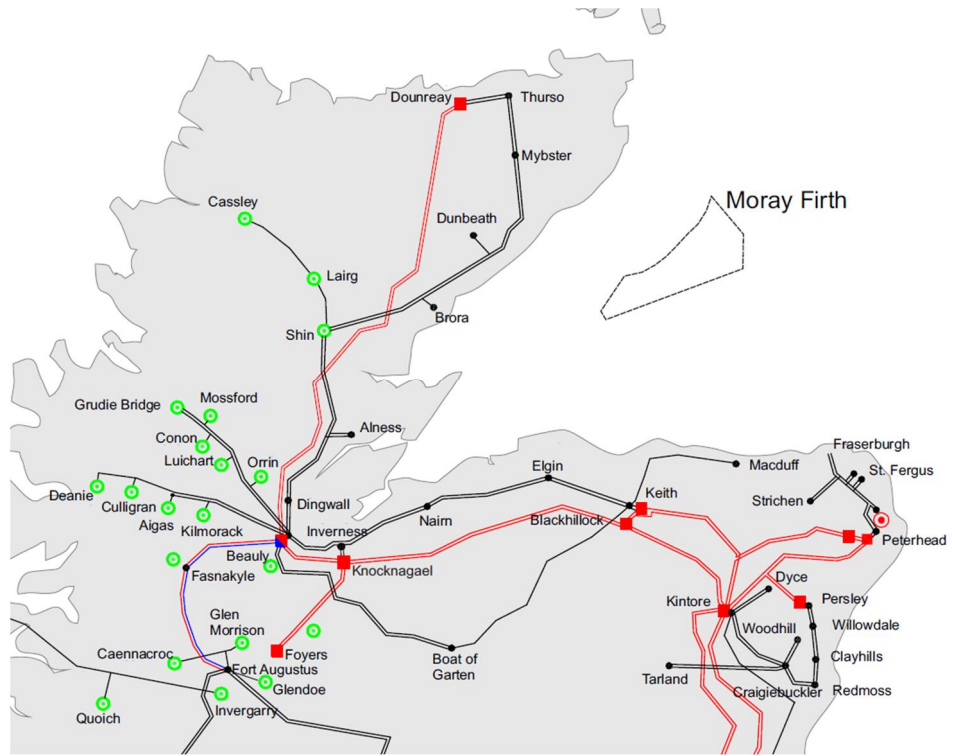
Figure 35 – Transmission boundaries in the north of GB



Source: National Grid – Ten Year Statement 2013

B.3 Transmission network in the Caithness Moray area

Figure 36 – Transmission network in the Caithness Moray area



Source: National Grid – Ten Year Statement 2013

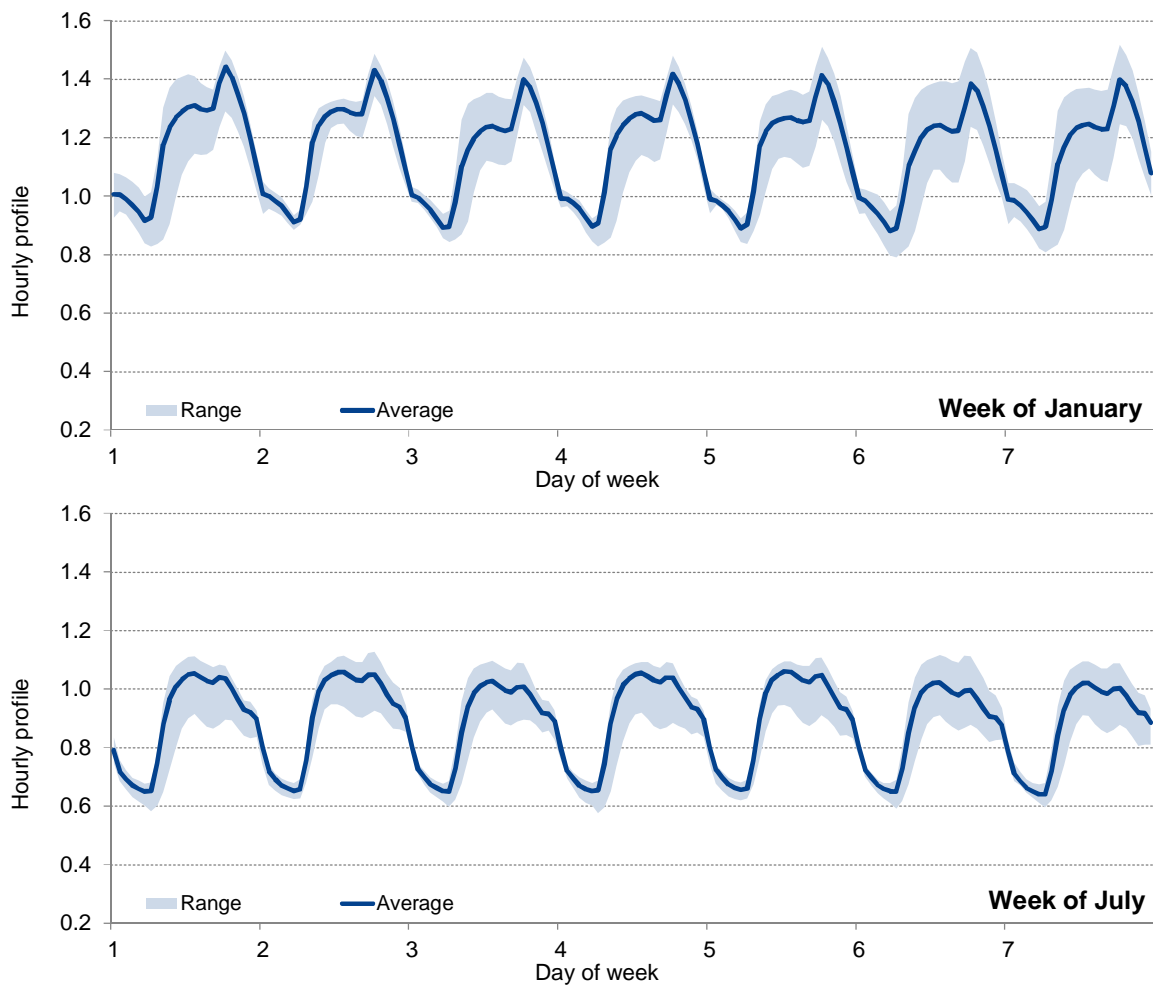
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ANNEX C – DETAILED INPUTS

C.1 Hourly demand profiles

Figure 37 shows the typical hourly demand profiles in January and July, as well as the variability across different weather years.

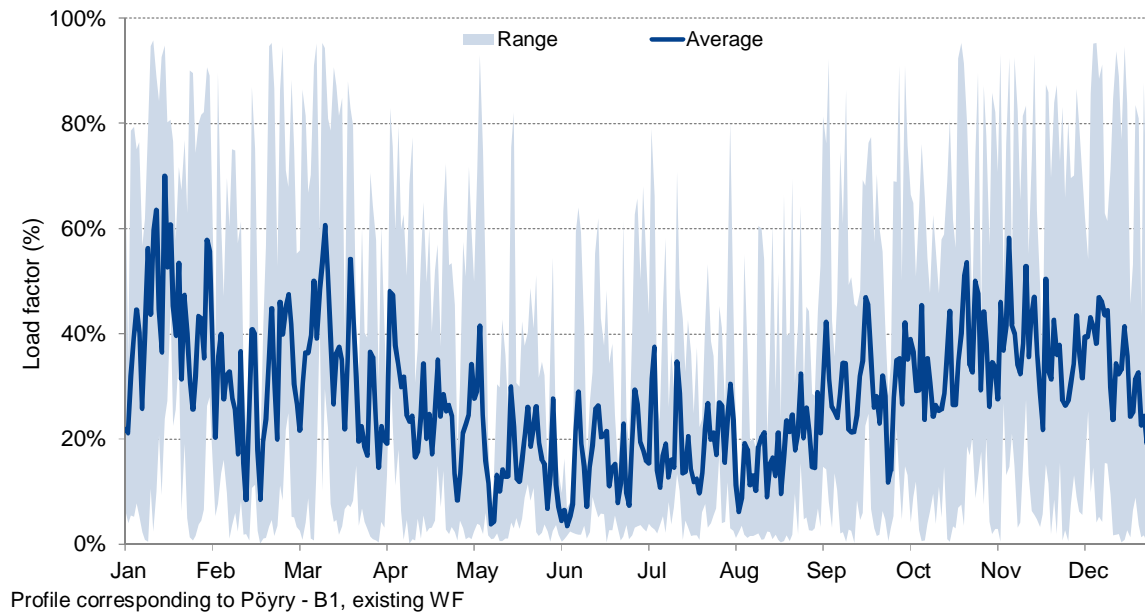
Figure 37 – Weather variability of hourly demand profile for a sample week in January and a sample week in July



C.2 Hourly wind profiles

Figure 38 shows the variability of the hourly wind production profile, which explains the significant sensitivity of constrained energy volumes to the weather year.

Figure 38 – Weather variability of wind load factors profile (averaged at a daily resolution)

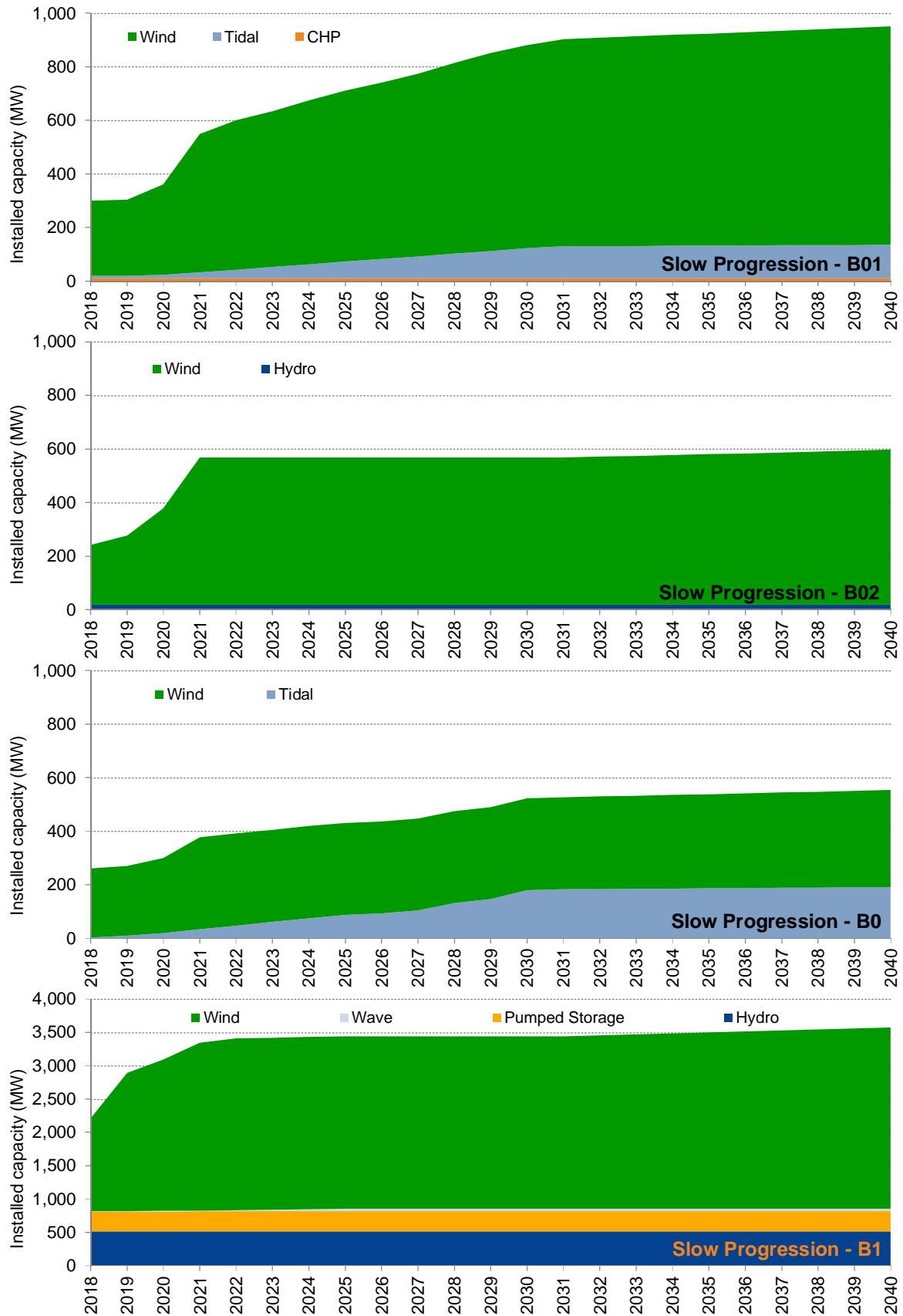


C.3 Installed generation in Scotland

Figure 39 shows the installed capacity North of B1 for the Slow Progression scenario out to 2040⁸.

⁸ National Grid provides projections out to 2030. We have used Pöry's projected renewables growth rates for all the years post 2030, extracted from our Q4 2014 Central scenario assumptions.

Figure 39 – Installed capacity North of B1, Slow Progression (MW)



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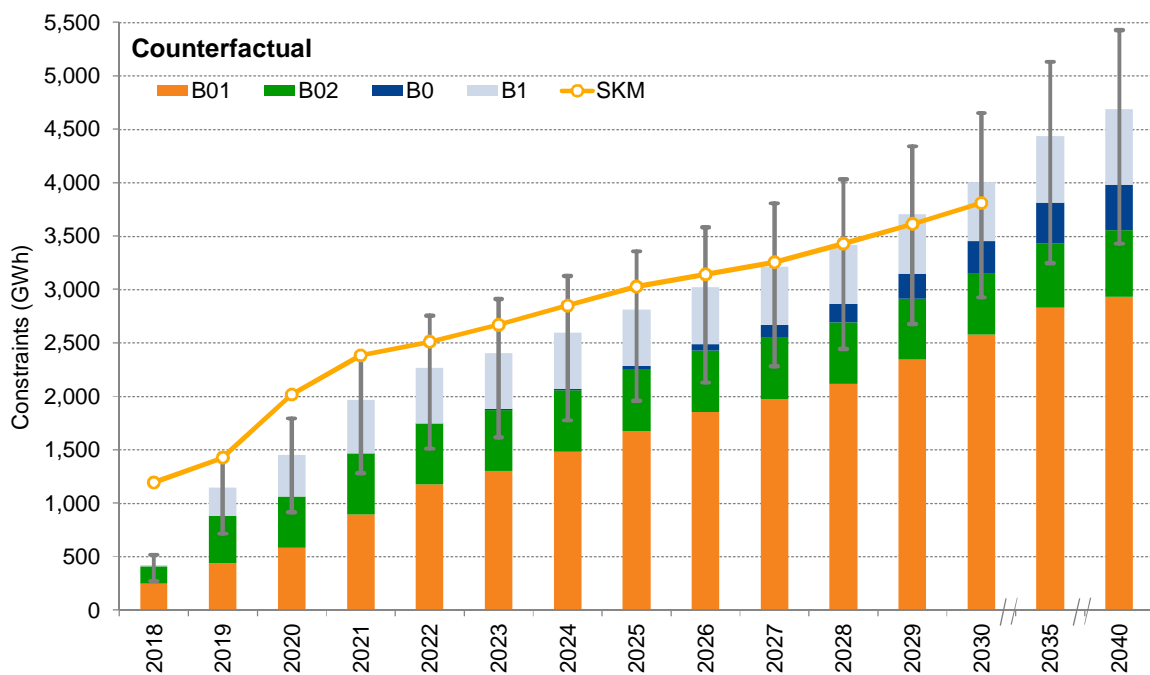
ANNEX D – DETAILED RESULTS

D.1 Annual constraints per border

Figure 40 to Figure 51 show the breakdown of the constrained energy volumes from the different transmission zones, for the remaining of the generation scenarios (GG, Ofgem and SSP).

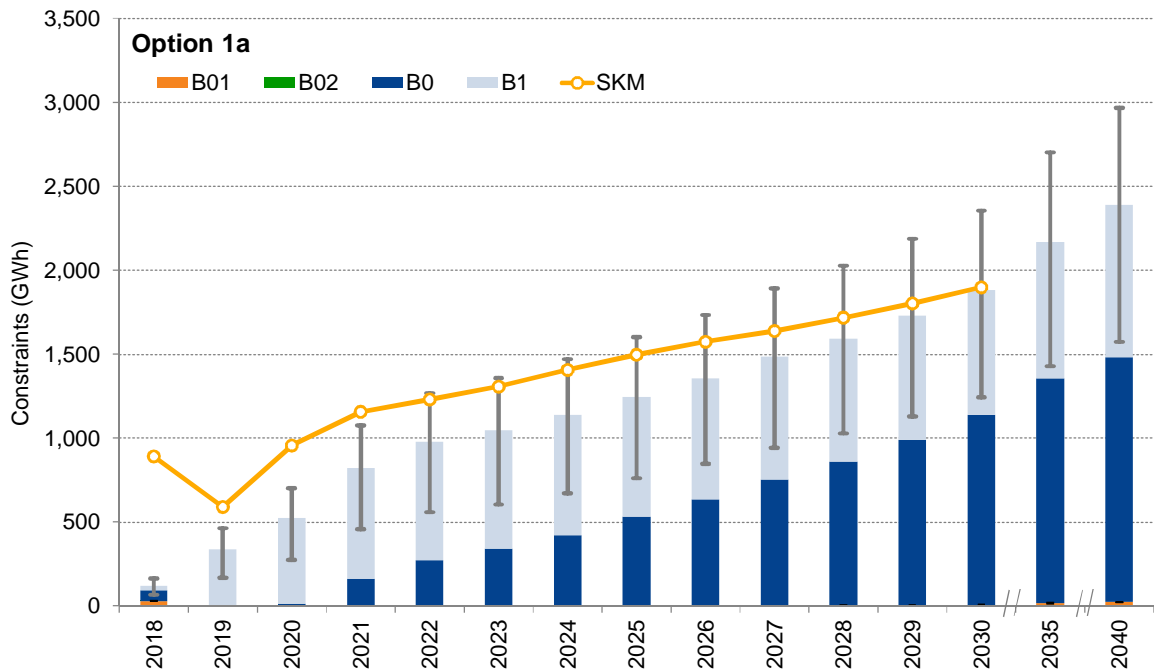
Gone Green

Figure 40 – Breakdown of annual constrained energy volumes (GWh), Gone Green – Counterfactual



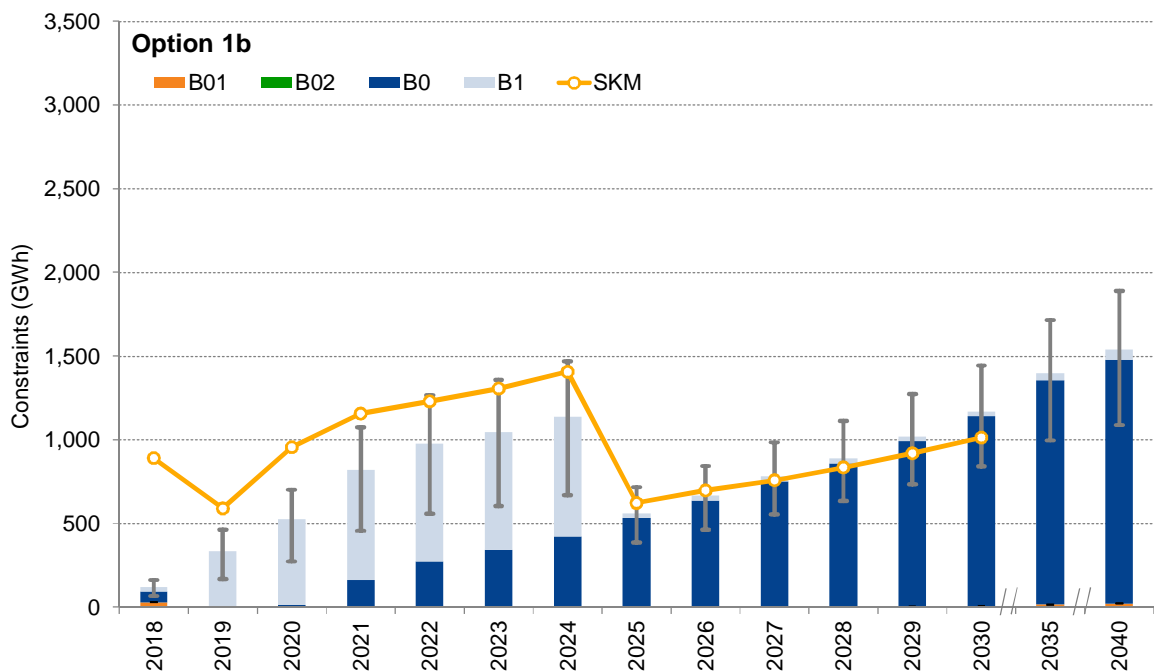
Note: Error bars represent the variability linked to historical weather year conditions. Average values result across the five weather years attributing an equal probability to each.

Figure 41 – Breakdown of annual constrained energy volumes (GWh), Gone Green – Option 1a



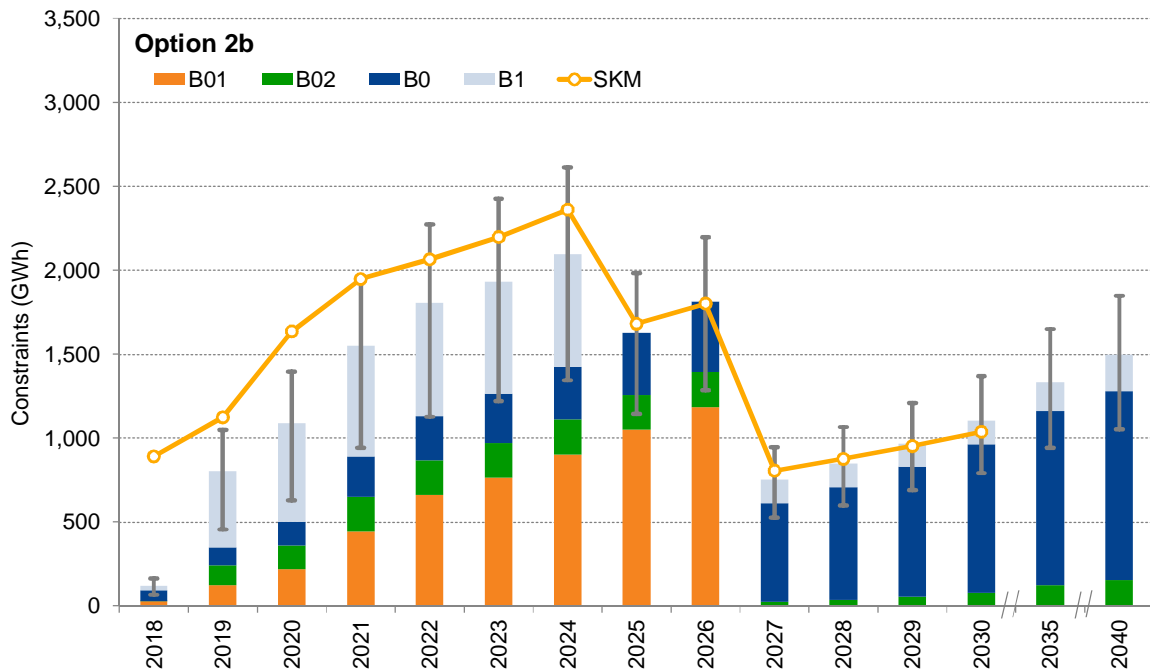
Note: Error bars represent the variability linked to historical weather year conditions. Average values result across the five weather years attributing an equal probability to each.

Figure 42 – Breakdown of annual constrained energy volumes (GWh), Gone Green – Option 1b



Note: Error bars represent the variability linked to historical weather year conditions. Average values result across the five weather years attributing an equal probability to each.

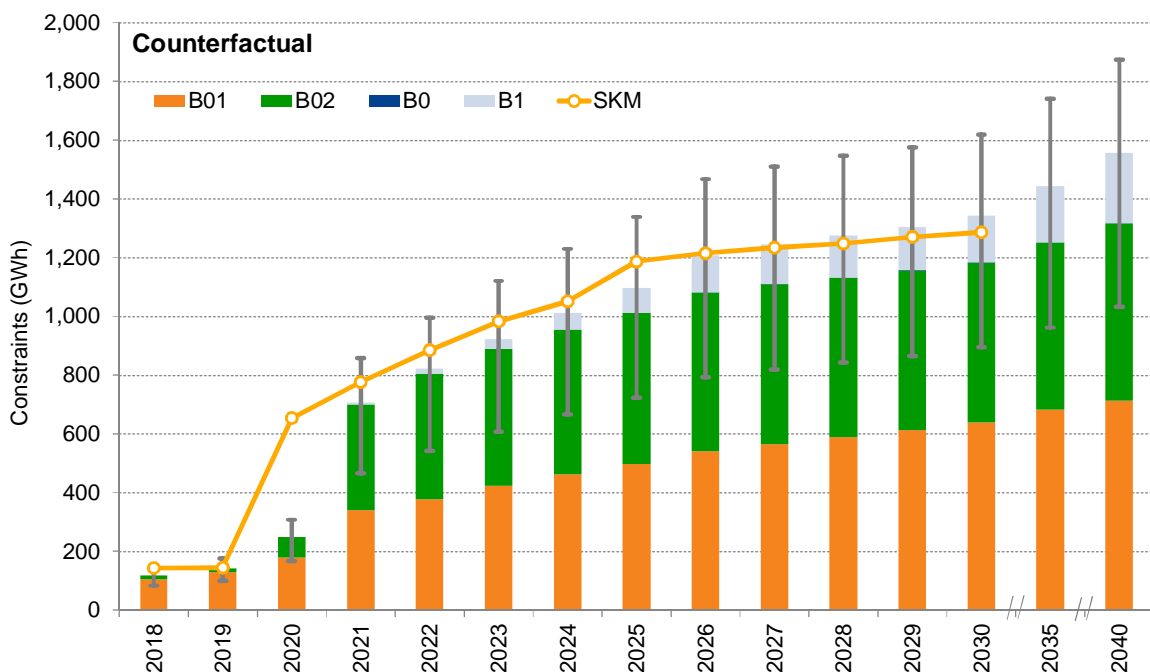
Figure 43 – Breakdown of annual constrained energy volumes (GWh), Gone Green – Option 2b



Note: Error bars represent the variability linked to historical weather year conditions. Average values result across the five weather years attributing an equal probability to each.

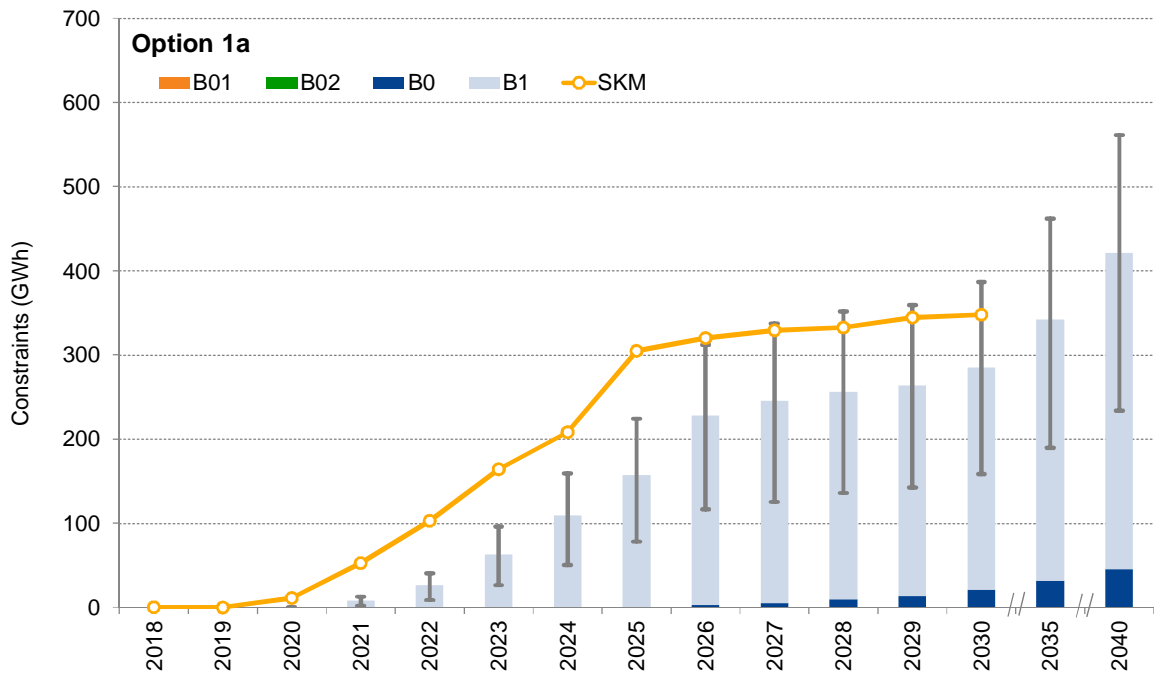
Ofgem

Figure 44 – Breakdown of annual constrained energy volumes (GWh), Ofgem – Counterfactual



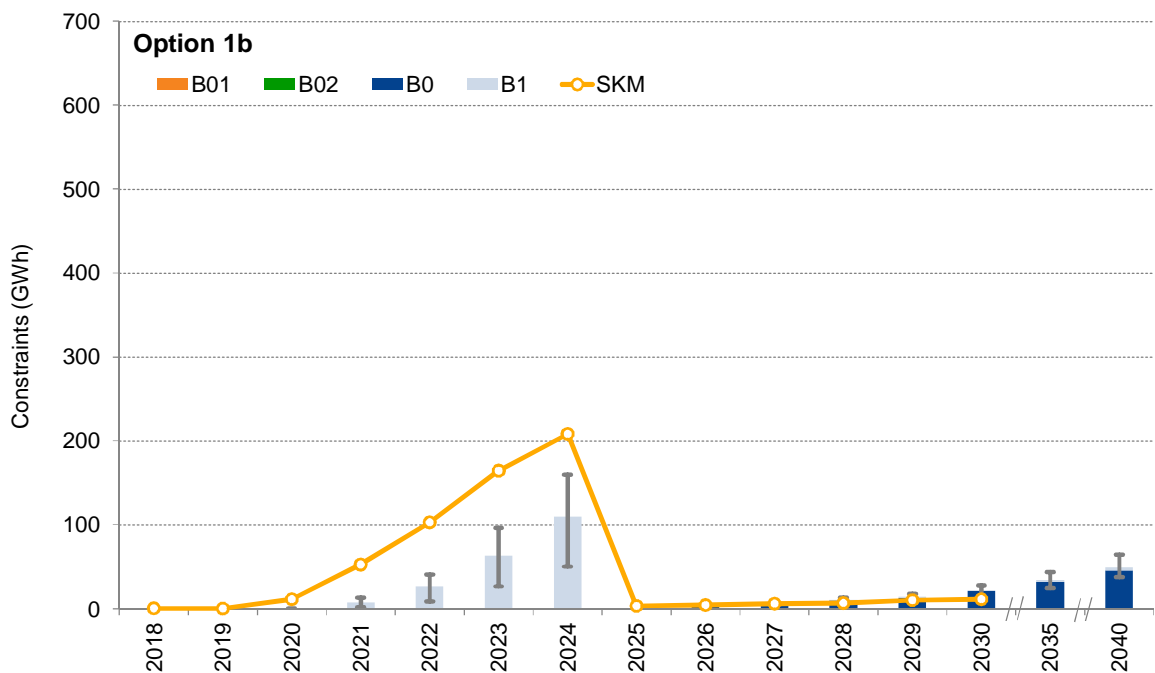
Note: Error bars represent the variability linked to historical weather year conditions. Average values result across the five weather years attributing an equal probability to each.

Figure 45 – Breakdown of annual constrained energy volumes (GWh), Ofgem – Option 1a



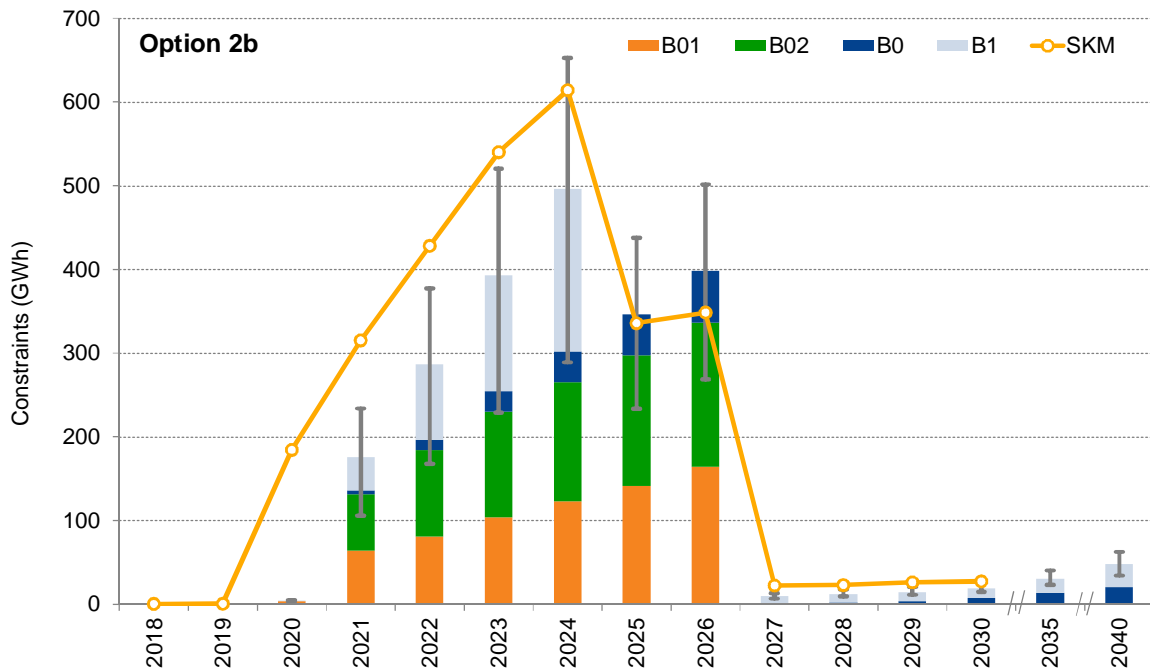
Note: Error bars represent the variability linked to historical weather year conditions. Average values result across the five weather years attributing an equal probability to each.

Figure 46 – Breakdown of annual constrained energy volumes (GWh), Ofgem – Option 1b



Note: Error bars represent the variability linked to historical weather year conditions. Average values result across the five weather years attributing an equal probability to each.

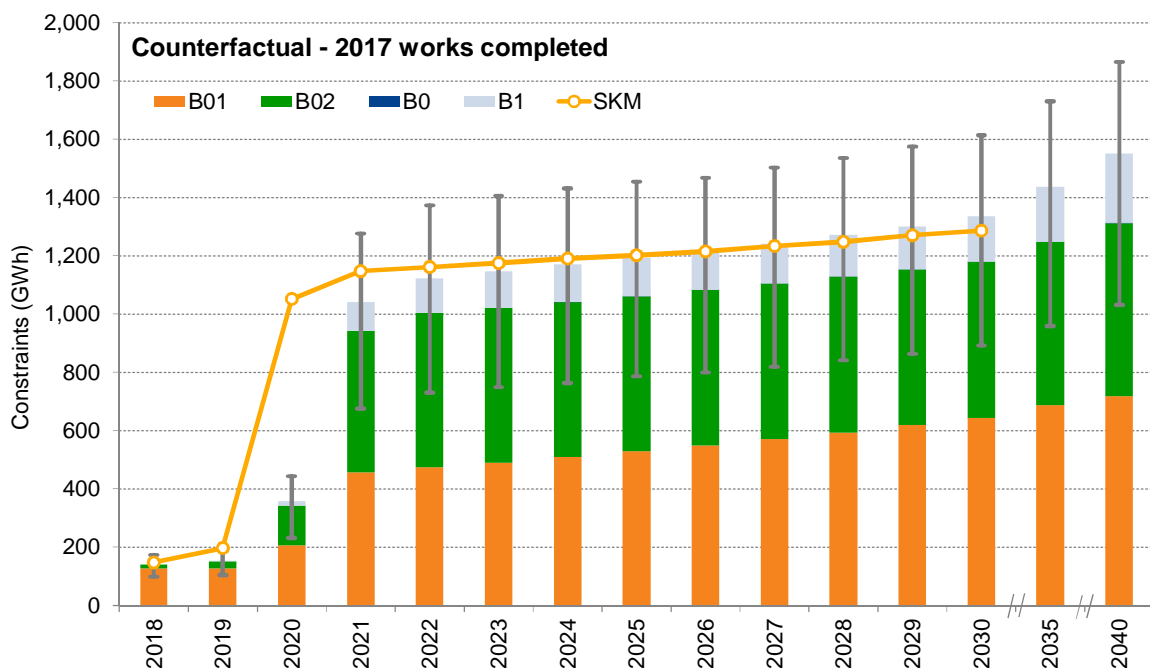
Figure 47 – Breakdown of annual constrained energy volumes (GWh), Ofgem – Option 2b



Note: Error bars represent the variability linked to historical weather year conditions. Average values result across the five weather years attributing an equal probability to each.

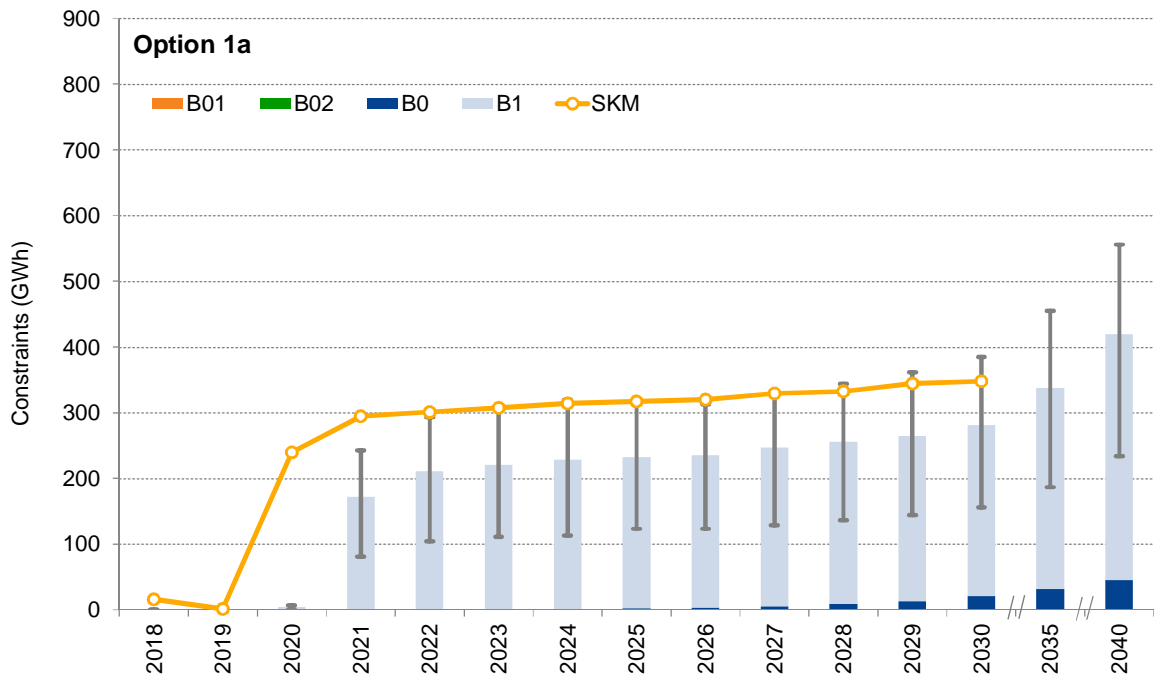
Slower Slow Progression

Figure 48 – Breakdown of annual constrained energy volumes (GWh), SSP – Counterfactual



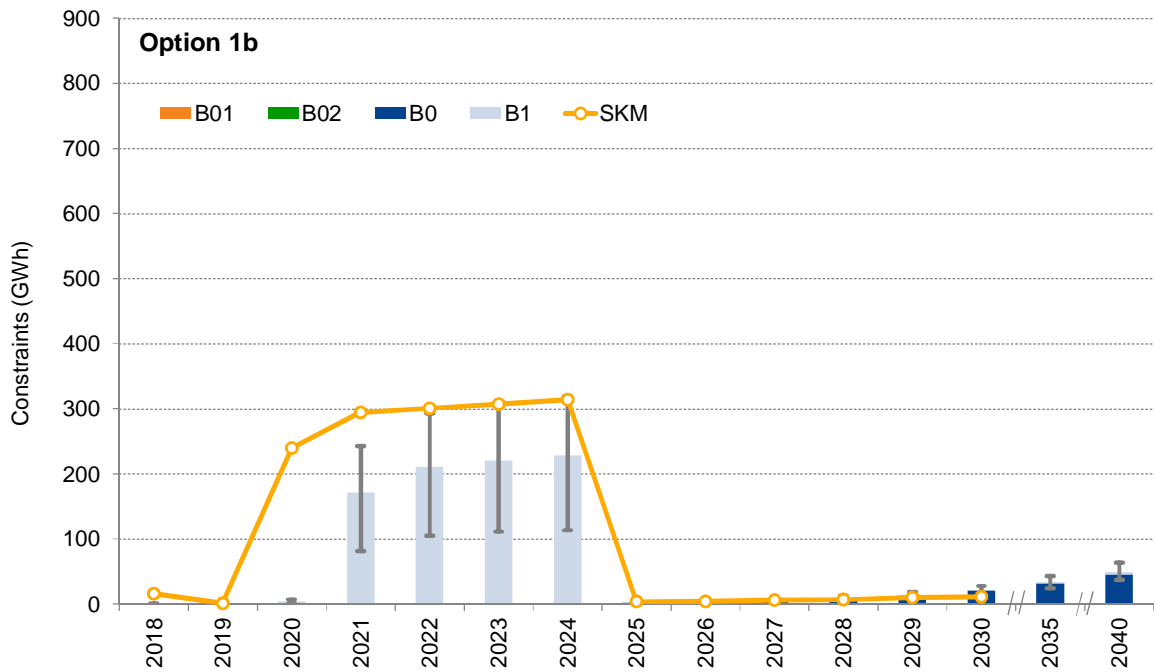
Note: Error bars represent the variability linked to historical weather year conditions. Average values result across the five weather years attributing an equal probability to each.

Figure 49 – Breakdown of annual constrained energy volumes (GWh), SSP – Option 1a



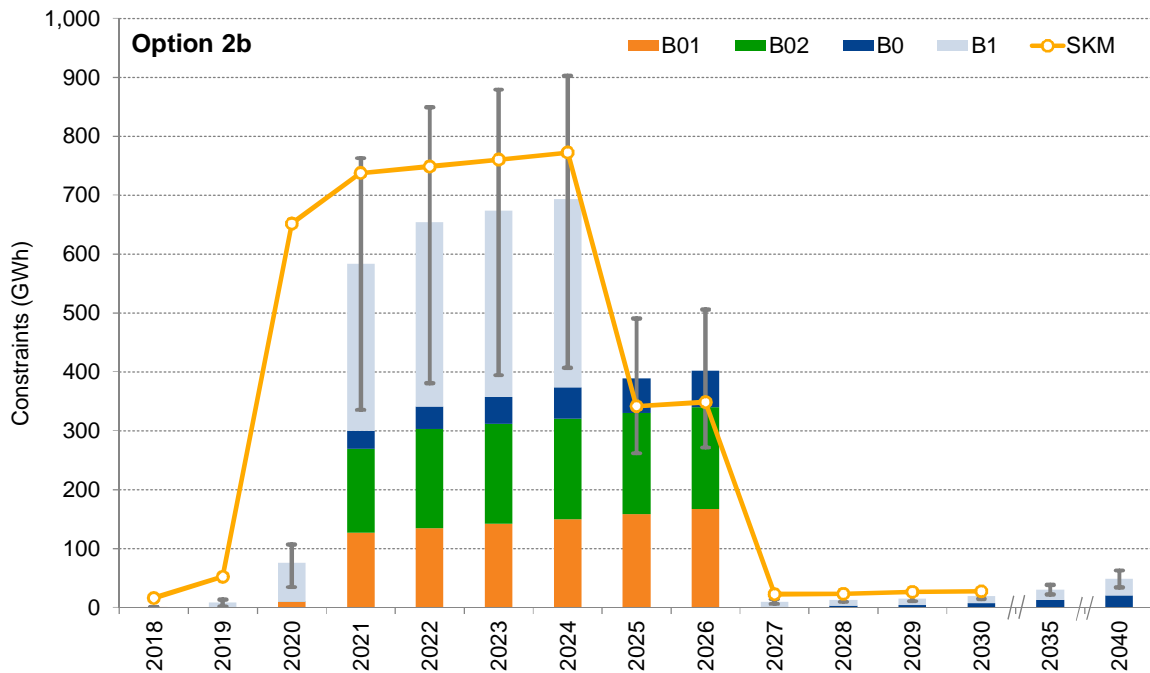
Note: Error bars represent the variability linked to historical weather year conditions. Average values result across the five weather years attributing an equal probability to each.

Figure 50 – Breakdown of annual constrained energy volumes (GWh), SSP – Option 1b



Note: Error bars represent the variability linked to historical weather year conditions. Average values result across the five weather years attributing an equal probability to each.

Figure 51 – Breakdown of annual constrained energy volumes (GWh), SSP – Option 2b



Note: Error bars represent the variability linked to historical weather year conditions. Average values result across the five weather years attributing an equal probability to each.

D.2 Annual total benefits of reinforcement options

Gone Green

The following Figures, Figure 52 to Figure 54, present for the different transmission reinforcement options the replacement energy benefits under the Gone Green scenario, and not including a valuation of the wider benefits. Benefits are calculated as the difference of the total constraint costs for the Counterfactual option and the various transmission reinforcement options, for a combined £15/MWh mark-up.

Figure 52 – Total benefits of Option 1a, GG (£m)

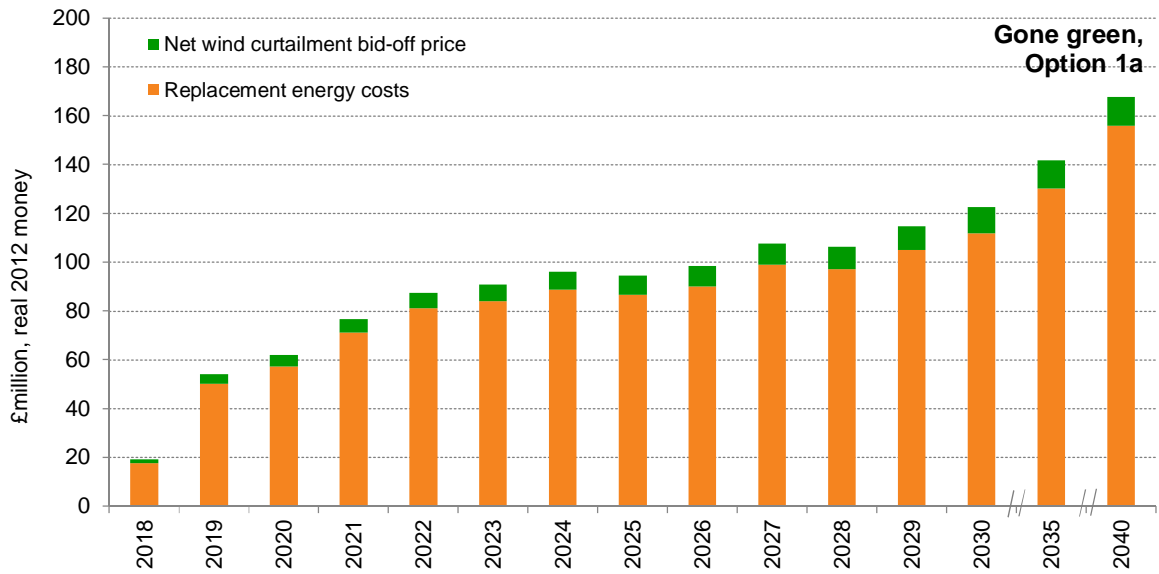


Figure 53 – Total benefits of Option 1b, GG (£m)

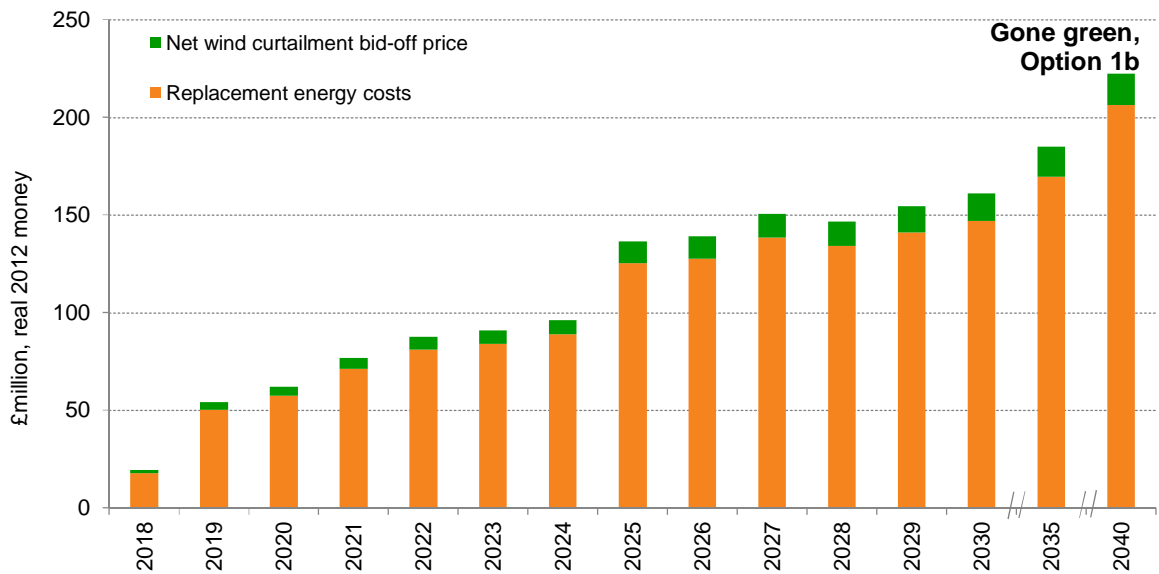


Figure 54 – Total benefits of Option 2b, GG (£m)

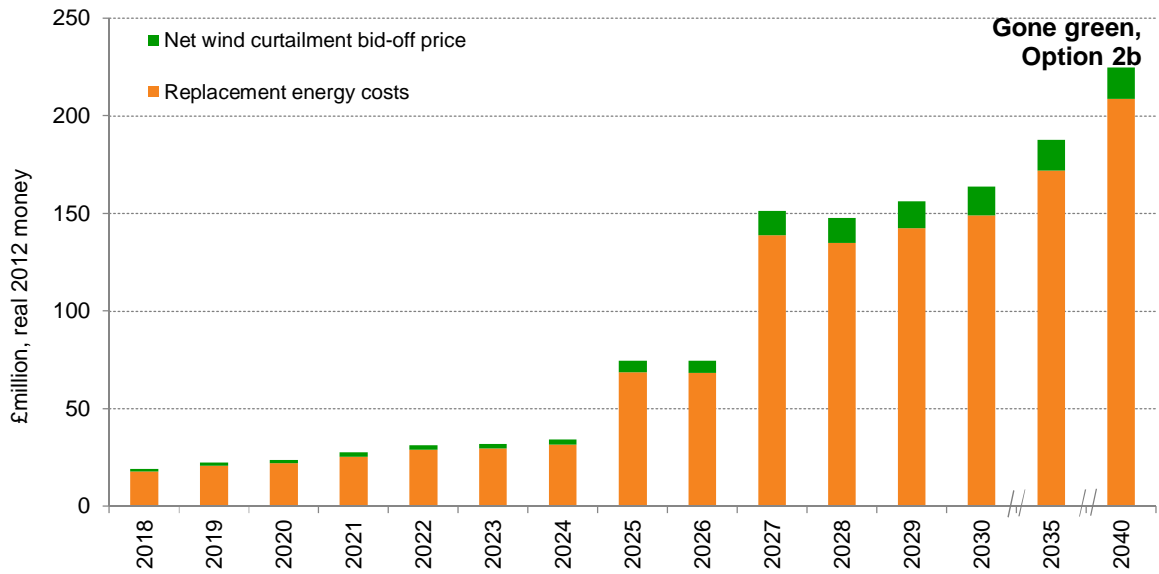
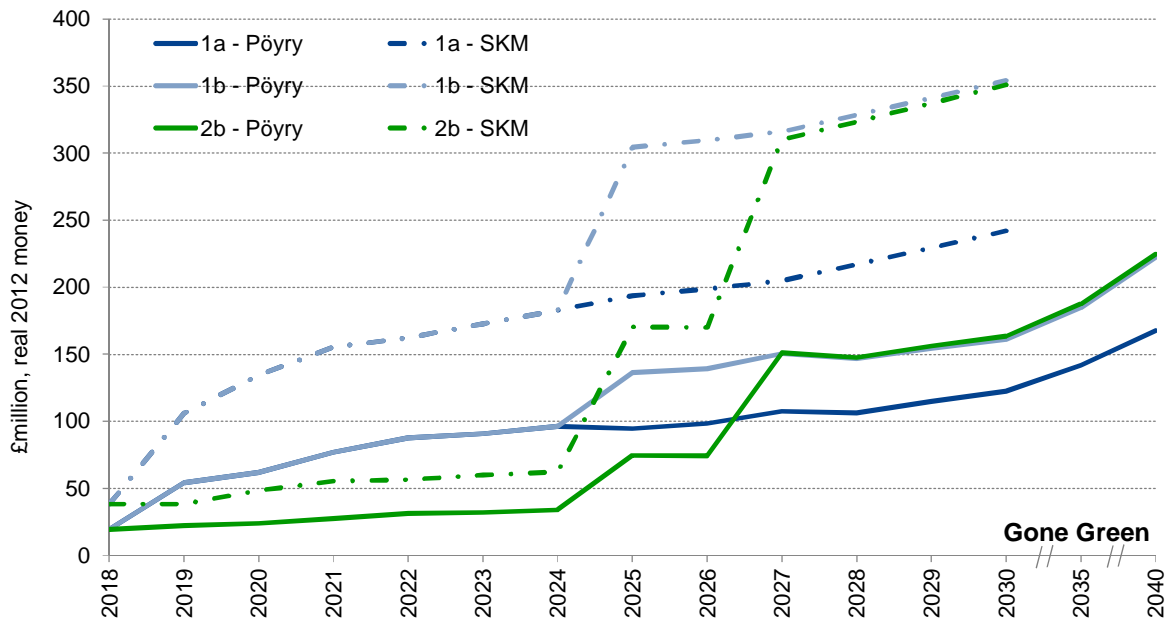


Figure 55 shows the comparison between SKM results and Pöyry results (based on a £15/MWh mark-up) of the total benefits for the various reinforcements, as the difference between each transmission reinforcement option and the counterfactual option, under the GG scenario.

Figure 55 – Comparison of total benefits of reinforcement options, GG (£m, real 2012 money)



Ofgem

The following Figures present for the different transmission reinforcement options the total benefits under the Ofgem scenario, including the valuation of the wider benefits (these are calculated as the difference of the total benefits for the Counterfactual option and the various transmission reinforcement options, for a £15/MWh mark-up).

Figure 56 – Total benefits of Option 1a, Ofgem (£m)

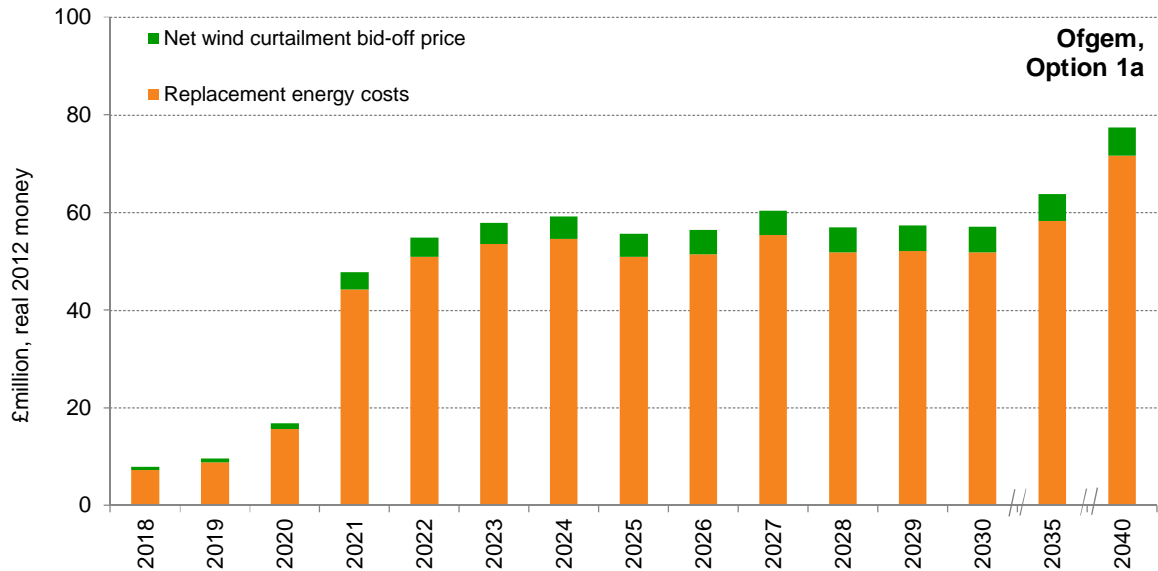


Figure 57 – Total benefits of Option 1b, Ofgem (£m)

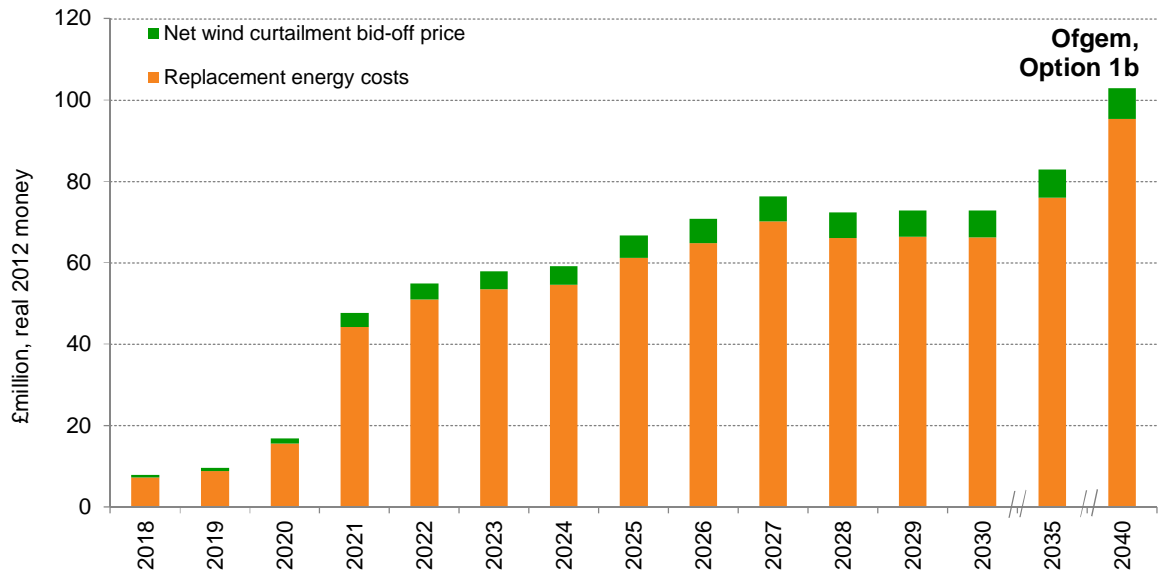


Figure 58 – Total benefits of Option 2b, Ofgem (£m)

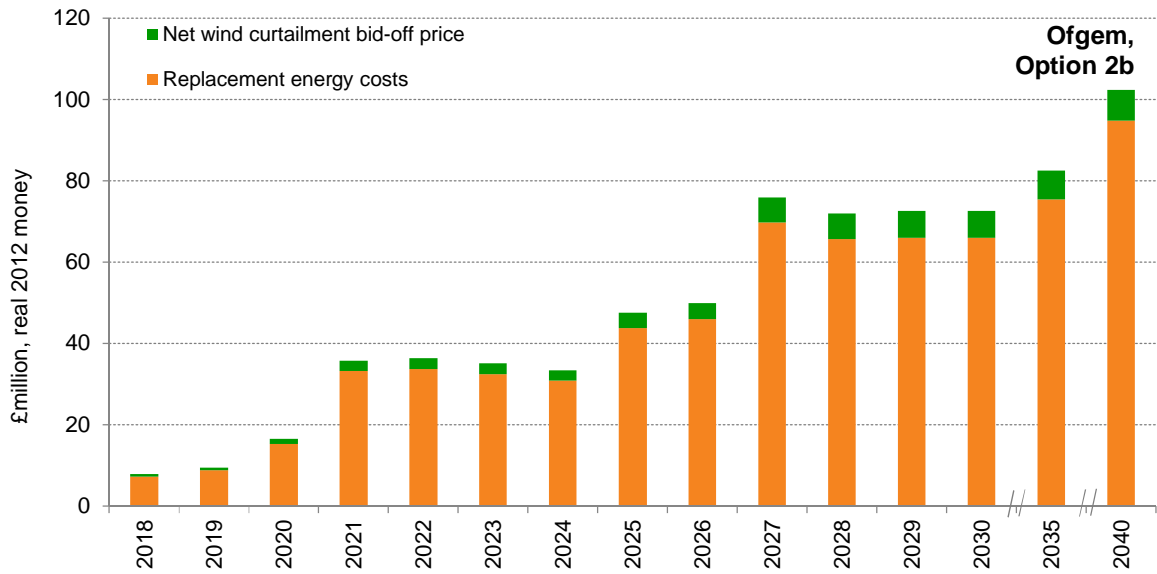
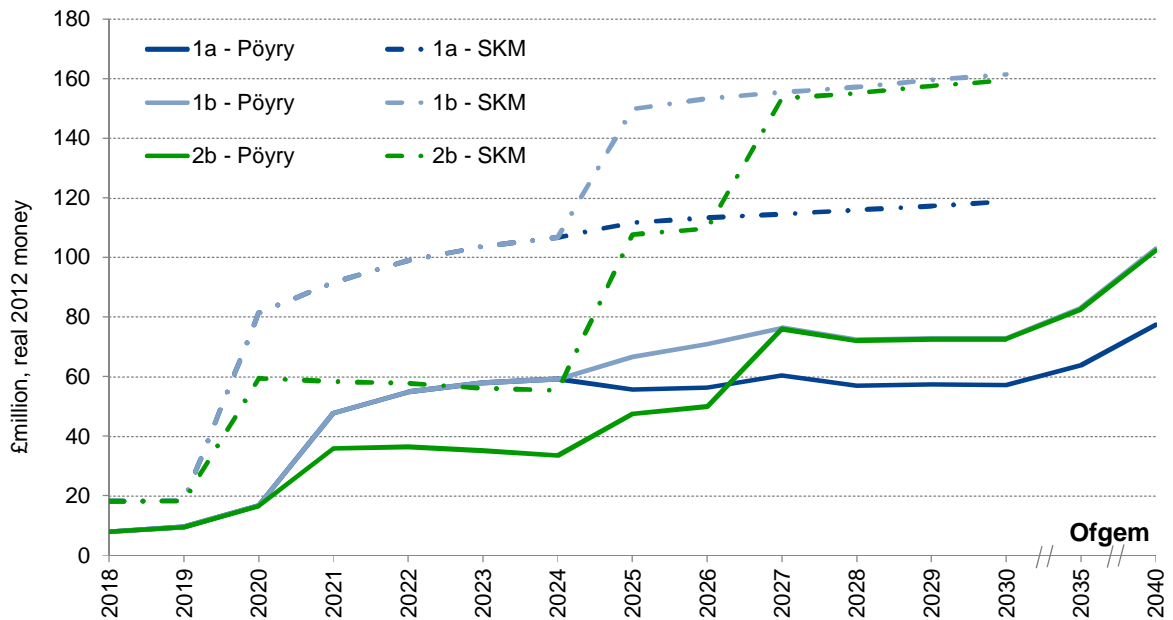


Figure 59 shows the comparison between SKM results and Pöyry results (based on a £15/MWh mark-up) of the total benefits for the various reinforcements, as the difference between each transmission reinforcement option and the counterfactual option, under the Ofgem scenario.

Figure 59 – Comparison of total benefits of reinforcement options, Ofgem (£m, real 2012 money)

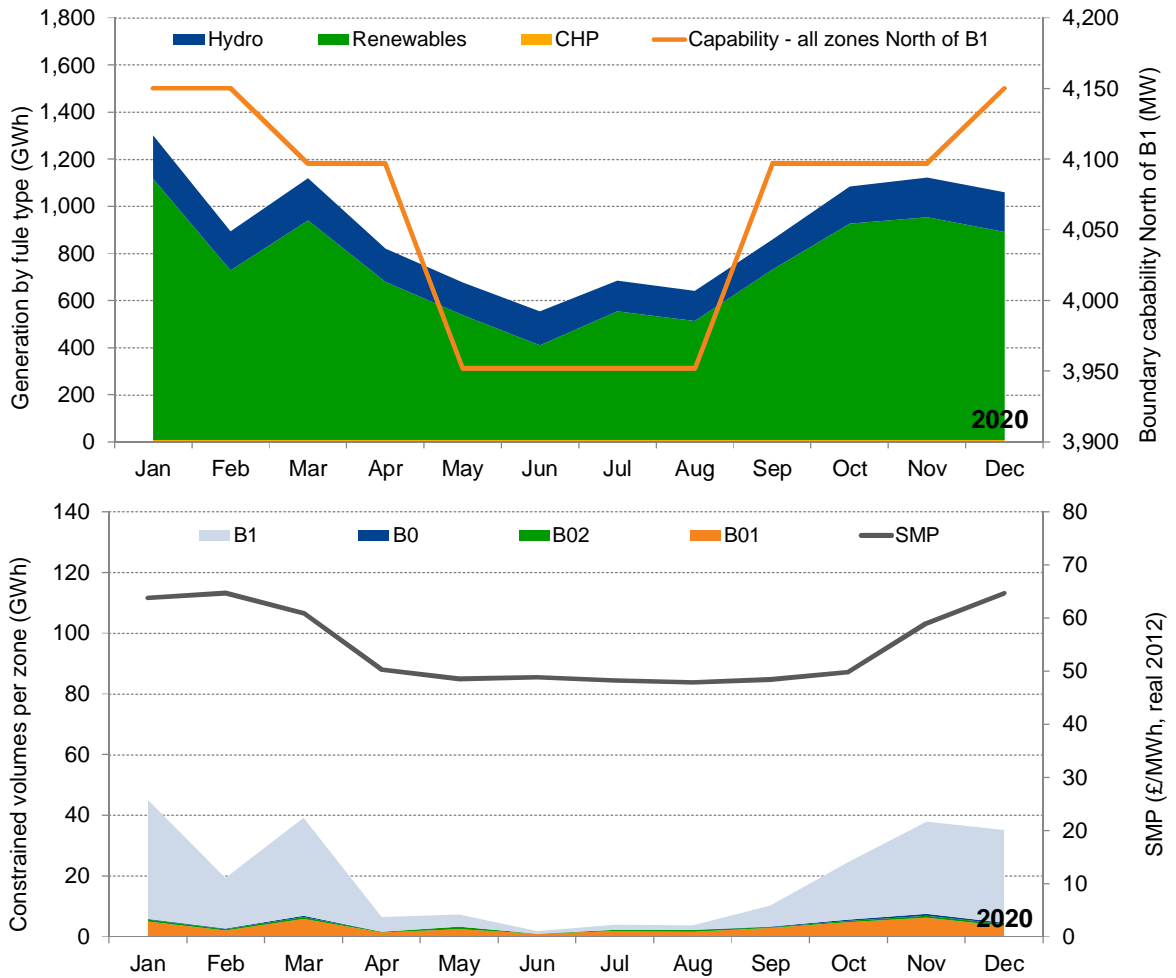


D.3 Monthly constraint volumes and costs

The following figures show the seasonal behaviour of constrained volumes, as well as the seasonal behaviour of wind production, boundary capabilities and SMPs. They illustrate how:

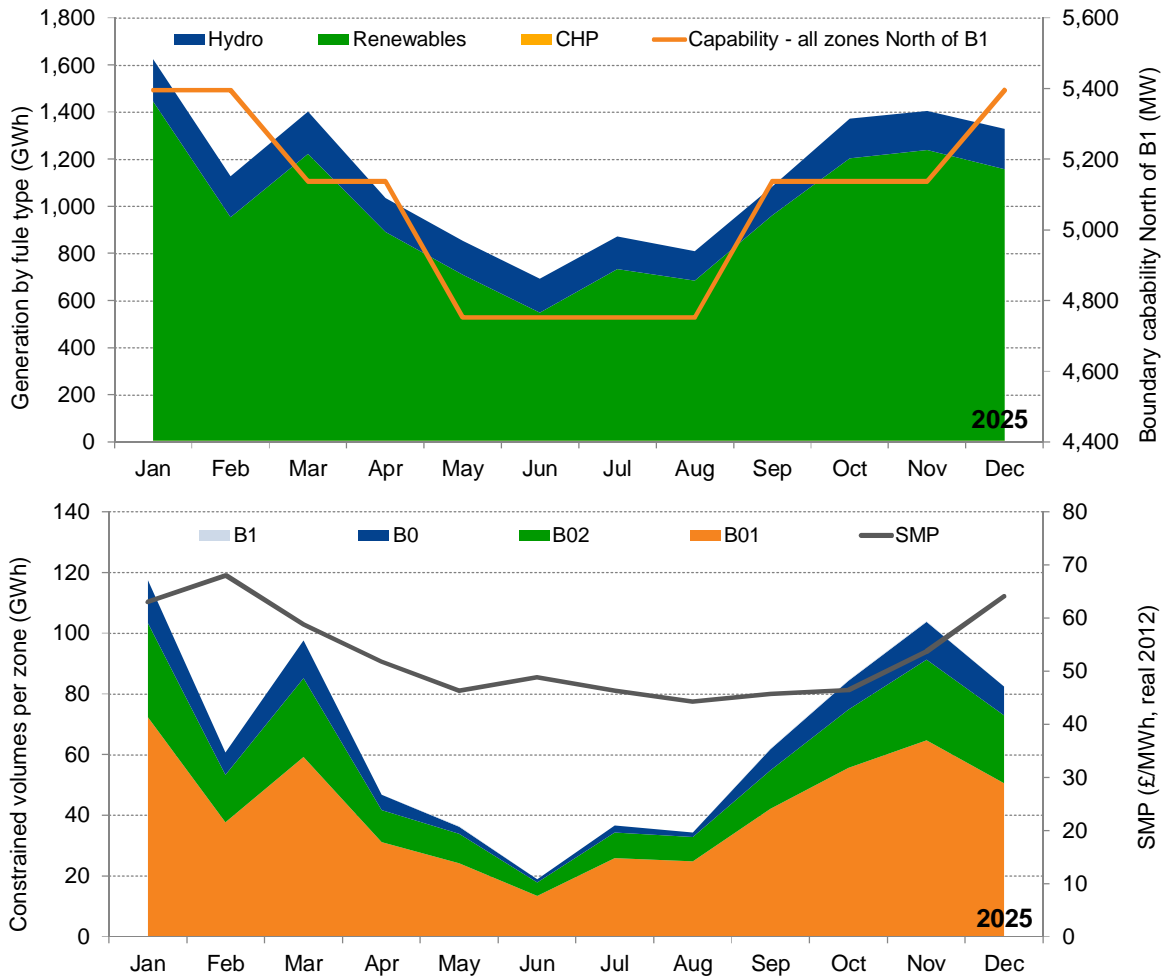
- In 2020:
 - higher winds occur in winter periods;
 - higher SMPs occur in GB during the winter, as a consequence of higher demand and higher gas prices; and
 - higher constrained energy volumes occur during the winter (when prices are generally higher than the annual averages).
- In 2025:
 - prices become more volatile, due to higher levels of wind penetration; and
 - constraints start occurring during periods of lower SMPs as well, during summer or ‘shoulder’ months.
- In 2030
 - prices become even more volatile and, to some extent, lose their seasonal profile, which in the earlier years is driven by gas generation; and
 - constrained volumes are lower as a consequence of high boundary transmission capacities, and they may occur in hours when SMP prices collapse as a consequence of much higher wind penetration to the system.

Figure 60 – Monthly generation and monthly constrained volumes (GWh), Slow Progression, Option 2b, 2020



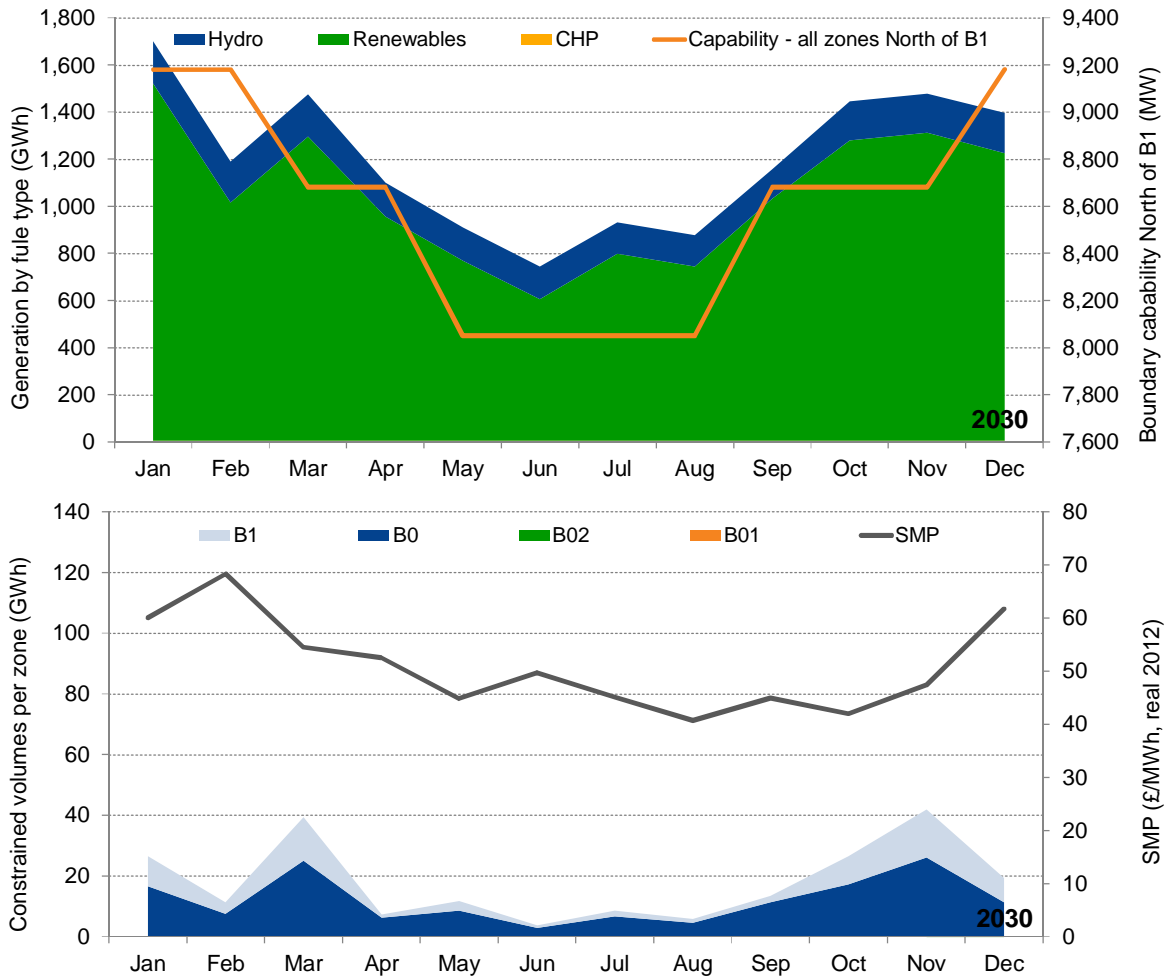
Hydro excludes Pumped Storage

Figure 61 – Monthly generation and monthly constrained volumes (GWh), Slow Progression, Option 2b, 2025



Hydro excludes Pumped Storage

Figure 62 – Monthly generation and monthly constrained volumes (GWh), Slow Progression, Option 2b, 2030



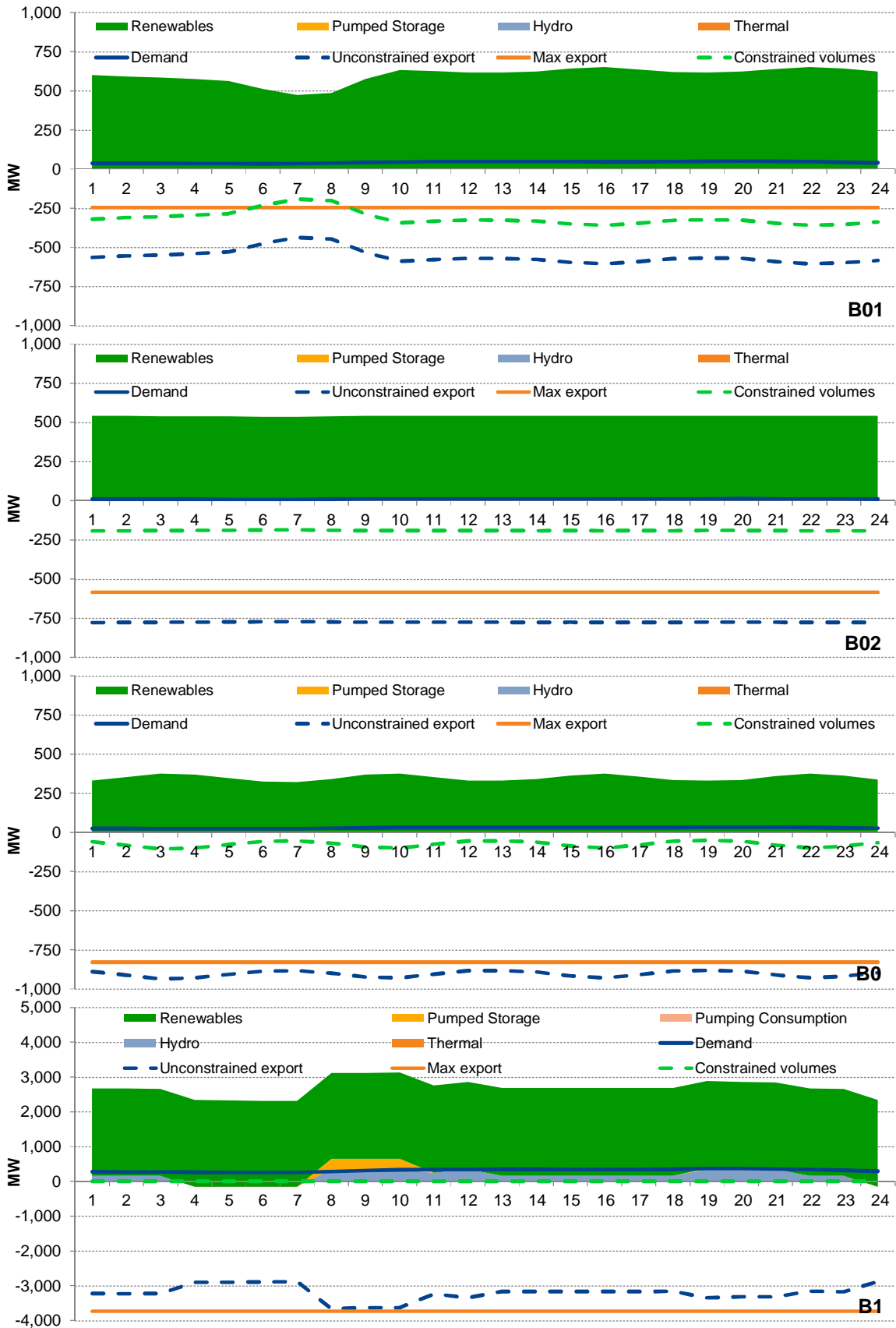
Hydro excludes Pumped Storage

D.4 Hourly dispatch

Figure 63 shows hourly dispatch and the constrained volumes resulting from our model runs for a characteristic windy day⁹. Results are shown for the Slow Progression scenario, year 2025, and Option 2b.

⁹ 21 February 2008 profile used

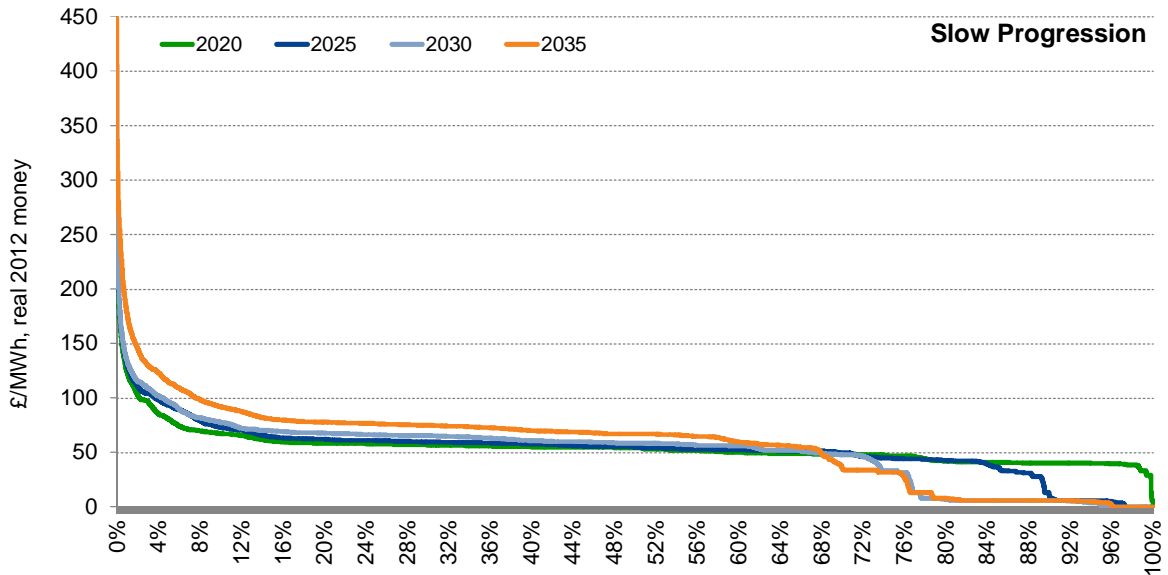
Figure 63 – Constrained volumes and dispatch for a characteristic windy day



D.5 SMP duration curves

Figure 64 shows, for the SP scenario, the duration curves of the SMPs for the years 2020, 2025, 2030 and 2035. It illustrates the higher frequency of situations of low prices as higher wind is integrated in the GB system.

Figure 64 – Price Duration Curves, Slow Progression (£/MWh, real 2012 money)

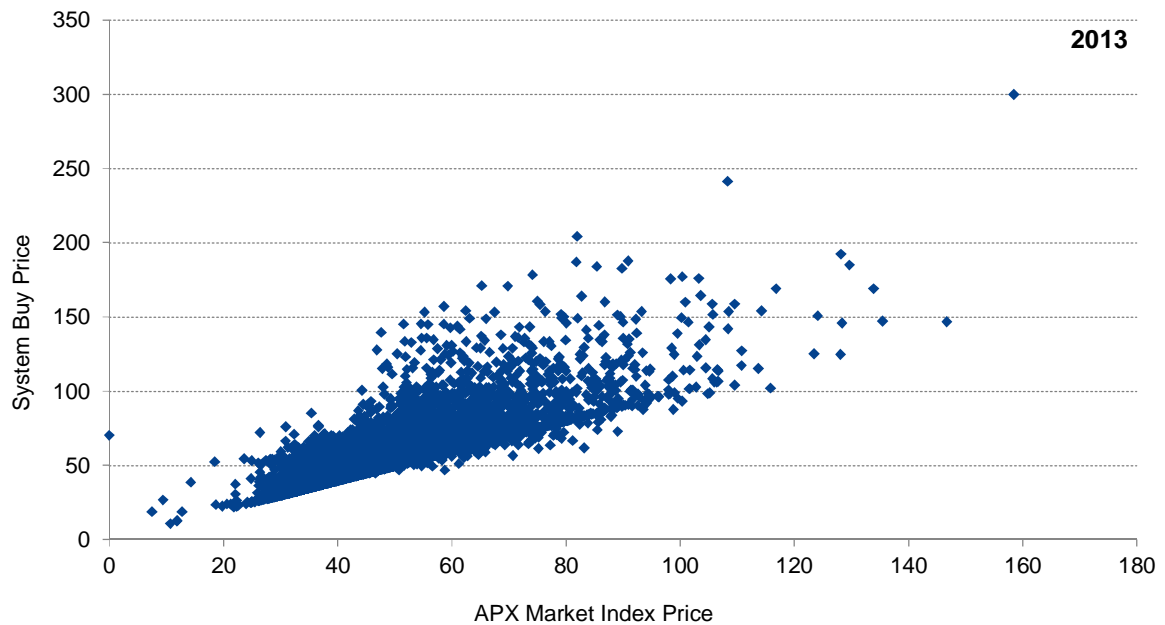


D.6 Balancing energy mark-up

Figure 65 shows the hourly APX market index versus the System Buy Price. The APX index reflects the energy prices, and is used as a proxy for the SMPs calculated by Pöyry’s model. The SBP represents the balancing price at which replacement energy is expected to be purchased in case of constraints.

The year 2013 presented an arithmetic average of £7.5/MWh.

Figure 65 – Historic comparison of energy prices vs. balancing prices



D.7 Summary of annual results

Table 5 to Table 7 summarise the annual results for each of the generation scenarios. More specifically they show:

- annual constrained volumes in GWh per reinforcement option; and
- annual constrained costs in £/MWh (real 2012) per reinforcement option (with a combined mark-up of £15/MWh).

As flagged in Section 3.1 additional reinforcements to those described in the various options 1a, 1b, and 2b, expected for 2017, are not included in the counterfactual, and hence they also impact the calculation of constraints and benefits of all options.

Table 5 – Annual constrained energy volumes and costs, Slow Progression

Constrained energy volumes (GWh)				
	Counterfactual	Option 1a	Option 1b	Option 2b
2018	198.5	3.0	3.0	3.0
2019	251.8	1.5	1.5	44.0
2020	543.5	29.6	29.6	234.8
2021	1,422.3	383.4	383.4	938.8
2022	1,584.3	476.9	476.9	1,089.5
2023	1,656.6	501.4	501.4	1,143.6
2024	1,752.9	540.4	540.4	1,220.2
2025	1,839.0	568.3	88.5	781.5
2026	1,908.1	590.6	105.3	834.4
2027	1,992.8	627.3	128.3	124.1
2028	2,096.4	671.5	164.4	154.1
2029	2,192.2	711.4	196.7	180.8
2030	2,283.5	761.1	236.4	215.5
2035	2,459.0	875.9	296.9	282.1
2040	2,622.7	1,007.5	353.3	354.1
Constraint costs (£/MWh, real 2012 money)				
	Counterfactual	Option 1a	Option 1b	Option 2b
2018	66.3	61.4	61.4	61.4
2019	68.7	91.5	91.5	81.5
2020	69.1	85.9	85.9	73.9
2021	69.0	72.5	72.5	70.2
2022	69.7	72.3	72.3	70.3
2023	68.3	70.6	70.6	68.6
2024	66.9	68.6	68.6	66.8
2025	60.6	61.7	53.9	56.5
2026	58.6	58.9	50.8	54.3
2027	61.2	60.9	52.9	60.6
2028	56.8	56.3	48.4	55.4
2029	56.0	54.9	47.0	53.0
2030	54.7	53.0	45.9	50.8
2035	58.1	54.7	47.8	52.2
2040	67.5	62.8	56.7	60.6

Table 6 – Annual constrained energy volumes and costs, Gone Green

Constrained energy volumes (GWh)				
	Counterfactual	Option 1a	Option 1b	Option 2b
2018	415.9	119.3	119.3	119.3
2019	1,143.5	335.5	335.5	803.0
2020	1,449.1	524.5	524.5	1,088.1
2021	1,963.8	819.2	819.2	1,549.9
2022	2,264.8	974.7	974.7	1,806.9
2023	2,402.4	1,045.3	1,045.3	1,932.7
2024	2,597.0	1,135.9	1,135.9	2,094.2
2025	2,810.2	1,245.3	560.7	1,629.3
2026	3,018.1	1,355.6	664.8	1,815.4
2027	3,214.5	1,485.9	781.1	751.8
2028	3,416.4	1,592.6	886.8	847.4
2029	3,703.3	1,729.1	1,020.3	967.8
2030	4,005.8	1,882.2	1,168.6	1,103.7
2035	4,432.1	2,167.7	1,396.0	1,333.3
2040	4,689.9	2,390.2	1,539.0	1,497.4
Constraint costs (£/MWh, real 2012 money)				
	Counterfactual	Option 1a	Option 1b	Option 2b
2018	66.1	69.2	69.2	69.2
2019	68.3	71.3	71.3	69.5
2020	68.2	70.4	70.4	69.0
2021	68.2	69.7	69.7	68.6
2022	68.5	69.4	69.4	68.6
2023	67.1	67.3	67.3	66.8
2024	65.5	65.2	65.2	65.0
2025	59.3	58.0	54.3	56.6
2026	57.5	55.5	52.0	54.7
2027	60.0	57.5	54.4	55.7
2028	55.8	53.0	49.8	51.0
2029	55.1	51.6	48.6	49.5
2030	54.0	49.9	47.4	47.9
2035	57.4	52.0	49.8	50.1
2040	66.8	61.0	59.1	59.2

Table 7 – Annual constrained energy volumes and costs, Ofgem

Constrained energy volumes (GWh)				
	Counterfactual	Option 1a	Option 1b	Option 2b
2018	118.8	0.0	0.0	0.0
2019	141.2	0.0	0.0	0.2
2020	248.1	0.0	0.0	4.3
2021	705.8	7.8	7.8	175.3
2022	821.1	26.5	26.5	286.4
2023	921.3	63.2	63.2	393.1
2024	1,012.0	109.4	109.4	496.3
2025	1,097.8	157.1	1.0	346.4
2026	1,207.5	227.6	3.9	398.0
2027	1,244.0	245.4	6.2	9.4
2028	1,274.8	255.9	10.4	11.5
2029	1,303.2	263.9	14.2	14.1
2030	1,342.4	285.2	22.0	19.2
2035	1,443.6	342.5	33.8	30.6
2040	1,555.6	421.3	49.0	48.1
Constraint costs (£/MWh, real 2012 money)				
	Counterfactual	Option 1a	Option 1b	Option 2b
2018	66.1	57.8	57.8	57.8
2019	67.4	n.a.	n.a.	59.4
2020	67.9	n.a.	n.a.	67.7
2021	68.6	89.8	89.8	71.7
2022	69.6	87.5	87.5	72.5
2023	68.4	82.5	82.5	71.0
2024	66.9	78.7	78.7	69.0
2025	60.8	70.7	47.6	55.5
2026	58.8	64.5	44.6	52.9
2027	61.6	66.4	44.9	72.1
2028	57.1	61.8	40.4	66.1
2029	56.3	60.9	39.8	63.8
2030	54.9	58.2	38.7	58.2
2035	58.5	60.1	41.5	59.6
2040	67.8	66.7	51.6	65.6

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